CO_2 CAPTURE READY COAL POWER PLANTS

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Final Report

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Disclaimer

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LIST OF ACRONYMS AND ABBREVIATIONS

AC	Alternating current
acfm	Actual cubic feet per minute
AGR	Acid gas removal
Ar	Argon
AR	As received
ASU	Air separation unit
BACT	Best available control technology
BAU	Business-as-usual
BEC	Bare erected cost
Btu	British thermal unit
Btu/hr	British thermal unit per hour
CC	Combined Cycle
CCF	Capital Charge Facto
CDR	Carbon Dioxide Recovery
Centr.	Centrifugal
CF	Capacity factor
cfm	Cubic feet per minute
cm	Centimeter
CO_2	Carbon dioxide
COE	Cost of electricity
Cond.	Condensate
CoP	ConocoPhillips
COS	Carbonyl sulfide
CR	Capture-ready
CRT	Cathode ray tube
CS	Carbon steel
CT	Combustion turbine
CTG	Combustion Gas Turbine-Generator
CWT	Cold water temperature
Cyl.	Cylinder
dB	Decibel
DB	Dry Basis
DC	Direct current
DCF	Discounted Cash Flow
DCS	Distributed control system
DI	De-ionized
Dia.	Diameter
DOE	Department of Energy
E-Gas™	ConocoPhillips gasifier technology
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPC	Engineering/Procurement/Construction
EPCM	Engineering/Procurement/Construction Management
EPRI	Electric Power Research Institute

eq.	equivalent
Fab.	Fabricated
FCR	Fixed charge rate
FD	Forced draft
FG	Flue gas
FGD	Flue gas desulfurization
FRP	Fiberglass-reinforced plastic
ft	Foot, Feet
FT WG	Feet of water gauge
FW	Feedwater
gal	Gallon
gal/MWh	Gallon per megawatt hour
GPM	Gallons per minute
GJ	Gigajoule
GT	Gas turbine
H_2	Hydrogen
H_2S	Hydrogen sulfide
H_2SO_4	Sulfuric acid
HCN	Hydrogen cyanide
HDPE	High density polyethylene
HHV	Higher heating value
Horiz.	Horizontal
hp	Horsepower
HP	High pressure
hr	Hour
HRSG	Heat recovery steam generator
HVAC	Heating, ventilating, and air conditioning
HWT	Hot water temperature
Hz	Hertz
ID	Induced draft
in	Inch, inches,
in H_2O	Inches water
in Hga	Inches mercury (absolute pressure)
in W.C.	Inches water column
ICR	Information Collection Request
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IOU	Investor-owned utility
IP	Intermediate pressure
IPM	Integrated Planning Model
kg/hr	Kilogram per hour
kJ	Kilojoules
kJ/hr	Kilojoules per hour
KO	Knockout
kPa	Kilopascal absolute
kV	Kilovolt

kW	Kilowatt
kWe	Kilowatts electric
kWh	Kilowatt-hour
kWt	Kilowatts thermal
lb	Pound
lb/hr	Pounds per hour
lb/ft^2	Pounds per square foot
LCOE	Levelized cost of electricity
LF	Levelizing factor
LHV	Lower heating value
LNB	Low NOx Burner
LP	Low pressure
lpm	Liters per minute
LV	Low voltage
m	Meters
m/min	Meters per minute
m^3/min	Cubic meter per minute
MAF	Moisture and Ash Free
MCR	Maximum continuous rate
MDEA	Methyldiethanolamine
MEA	Monoethanolamine
MHz	Megahertz
MMBtu	Million British thermal units (also shown as 10^6 Btu)
MMBtu/hr	Million British thermal units (also shown as 10^6 Btu) per hour
MMkJ	Million kilo Joules (also shown as 10^6 kJ)
MMkJ/hr	Million kilo Joules per hour (also shown as 10^6 kJ) per hour
MPa	Megapascals absolute
MVA	Capacity rating of transformer (mega volt-amps)
MW	Megawatts
MWe	Megawatts electric
MWh	Megawatt-hour
MWt	Megawatts thermal
Neg.	Negligible
NETL	National Energy Technology Laboratory
N/A	Not applicable
NGCC	Natural gas combined cycle
NH_3	Ammonia
Nm^3	Normal Cubic meter
NOx	Oxides of nitrogen
NSPS	New Source Performance Standards
O&M	Operations and maintenance
OD	Outside diameter
OFA	Overfire Air
OP/VWO	Over pressure/valve wide open
OTR	Ozone transport region
PA	Primary air

PAC	Powdered activated carbon
PC	Pulverized coal
PM	Particulate Matter
PM_{10}	Particulate Matter particles measuring 10mm or less
ppm	Parts per million
ppmd	Parts per million, dry basis
ppmvd	Parts per million volume, dry
PPS	Polyphenylensulfide
psia	Pounds per square inch absolute
psig	Pounds per square inch gage
PTFE	Teflon (Polytetrafluoroethylene)
PV	Present value
Qty	Quantity
RDS	Research and Development Solutions, LLC
Recip.	Reciprocating
rpm	Revolutions per minute
RSC	Radiant syngas cooler
SC	Supercritical
scfd	Standard cubic feet per day
scfm	Standard cubic feet per minute
Sch.	Schedule
scmh	Standard cubic meter per hour
SCR	Selective catalytic reduction
SG	Specific gravity
SNG	Synthetic natural gas
SO_2	Sulfur dioxide
SOx	Oxides of sulfur
SRU	Sulfur recovery unit
SS	Stainless steel
SS Amine	SS Specialty Amine
ST	Steam Turbine
STG	Steam turbine generator
TEWAC	Totally Enclosed Water-to-Air Cooled
TGTU	Tail gas treating unit
TPC	Total plant cost
tpd	Tons per day
tph	Tons per hour
tonne	Metric ton (1000 kg)
TS&M	Transport, storage and monitoring
Vert.	Vertical
V-L	Vapor Liquid portion of stream (excluding solids)
WB	Wet bulb
WG	Water gauge
WGS	Water Gas Shift
wt%	Weight percent

EXECUTIVE SUMMARY

An important issue surrounding CO_2 capture and sequestration from fossil fuel power plants is the added costs associated with the plant design and configuration required to capture most of the carbon from the plant as CO_2. Existing plants are designed to produce power at a minimum cost and maximum efficiency without CO_2 capture. In a carbon-constrained world, future plant designs may have to include equipment for CO_2 capture. Between these two design approaches, new plants have the option of designing the plant in anticipation of having to retrofit with carbon capture equipment at some future date.

This report examines the question of whether it is more cost effective to design a new plant in anticipation of future restrictions on carbon emissions so that the plant is CO_2 capture-ready or to proceed with no anticipation of a future retrofit. A CO_2 capture-ready plant would have a higher initial capital cost than a conventional plant but would cost less to retrofit with carbon capture equipment. Conversely, a conventional plant would have a lower initial capital cost but a higher cost for future CO_2 capture retrofit.

This report also examines the timing of the investment in carbon capture equipment, i.e., is the length of time between initial construction and future retrofit a determining factor in the choice between a CO_2 capture-ready design and a conventional design? To answer this question, a simplified discounted cash flow analysis of the results was conducted to determine the sensitivity of the relationship between the costs of electricity of each option to the time value of money.

DEFINITION OF "CO_2 CAPTURE-READY"

NETL has formulated a definition of CO_2 capture-ready power plants. Apart from either a technology or an emissions perspective, the CO_2 capture-ready plant definition contains the following requirements:

- Plant site should have access to CO_2 storage-either locally or by an identified route.
- Space at the plant site should be available for expansion and addition of plant areas, access to existing plant items, storage of equipment during construction and for the provision of expansion without encroachment into established barrier zones.
- The CO_2 capture system should not contribute to an increase in emission rate levels relative to the before capture configuration.

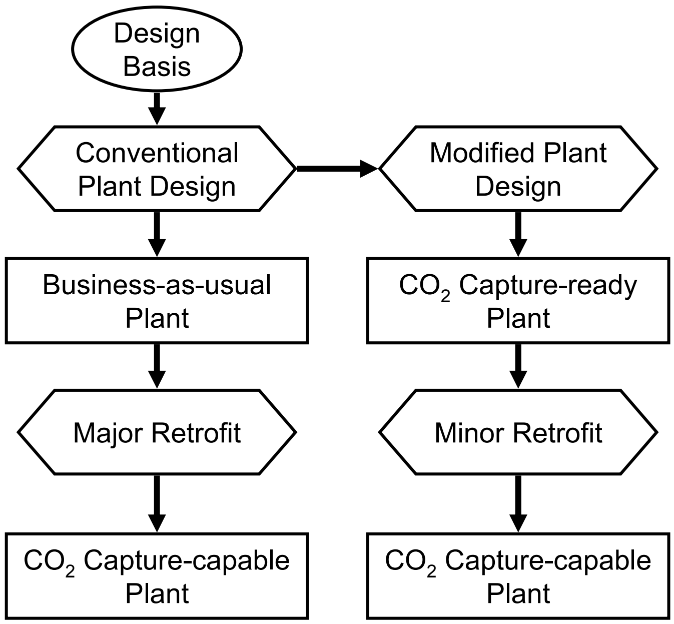
From both a technology and emissions perspective, there are additional issues which are pertinent to CO_2 capture-ready plants as follows:

- From a technology perspective, the CO_2 capture-ready plant is defined as a plant having the technology either in place or readily retrofitted to become CO_2 capture-capable with the ability to meet future carbon mitigation requirements.
- From an emissions perspective, the CO_2 capture-ready plant is defined as a plant for which the baseline emissions are known and the emissions to be achieved when the plant is CO_2 capture-capable are projected.

STUDY OBJECTIVE AND APPROACH

The objective of this study is to perform systems analyses that assess the impacts on performance, costs, and investment risk of constructing new PC and IGCC power plants in a "CO_2 capture-ready" mode. Several cases were analyzed in this report, utilizing the approach illustrated in Exhibit ES-1 to define the cases for analysis.

Exhibit ES-1 Study Approach



The analysis uses the same Design Basis as that published in the recently completed NETL study titled, "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity" [Ref. 1]. For comparison purposes, the design methodology splits into two conceptual configurations, designated "Business-as-usual" (BAU) and "CO_2 capture-ready" (CR). The BAU design concept proceeds from the conventional approach used in the referenced study of designing and configuring the power plant to maximize energy efficiency in the most economical manner, irrespective of the amount of CO_2 produced and emitted to the atmosphere. Following initial startup and operation of the BAU plant, it may be necessary at some point in the future to capture and sequester 90 percent of the carbon as CO_2. This would be done by retrofitting the BAU plant during an extended outage. This CO_2 BAU-Retrofit Case involves significant changes in plant performance and economics.

The design basis for the CO_2 capture-ready configuration is modified in anticipation of future carbon emission mitigation requirements. The plant is designed with the initial objective to operate in a non-CO_2 capture mode (similar to BAU) but to be readily retrofitted to be CO_2 capture-capable with a minimum of cost and only a minor outage. The initial CO_2 capture-ready design includes all equipment sizing and performance requirements necessary to operate in a CO_2 capture mode without the plant derating associated with the BAU cases. This analysis assumes the new CO_2 capture technologies currently under development, which have a high potential to decrease parasitic power loads, <u>may not be available</u> at the scale required to retrofit a full scale commercial power plant in the 2007-2010 time frame. Therefore, this study has chosen to take a more conservative approach and uses the current state-of-the-art design and performance aspects. The retrofitted plant, designated CO_2 Capture-Ready Retrofit (CR Retrofit), is designed to retain the same power output with a lower cost of retrofit.

Pulverized Coal Rankine Cycle Cases

The PC design cases analyzed in this report (designated by odd numbers) are as follows:

- Case 1: "Business as usual" Supercritical Pulverized Coal Rankine Cycle Power Plant
  A supercritical PC power plant designed and constructed in a conventional, "business as usual," mode without CO_2 capture capabilities and assuming no current or future modifications for CO_2 mitigation will be required. It will be referred to throughout this report as the "PC Business-as-Usual" Case or "PC BAU" Case.

- Case 3: CO_2 Capture-Ready Supercritical Pulverized Coal Rankine Cycle Power Plant
  A supercritical PC power plant designed and constructed in a CO_2 capture-ready mode, anticipating future modifications for CO_2 mitigation requirements. It will be referred to throughout this report as the "PC Capture-Ready" Case.

- Case 5: CO_2 Capture-Ready Supercritical PC Power Plant Retrofitted with CO_2 Capture
  A supercritical PC power plant designed and constructed in a CO_2 capture-ready mode and subsequently retrofitted to capture and compress 90% of the CO_2 for pipeline transport and storage. It will be referred to throughout this report as the "PC Capture-Ready Retrofit" Case.

- Case 7: "Business as usual" Supercritical PC Power Plant Retrofitted with CO_2 Capture
  A supercritical PC power plant which was designed and constructed in a conventional, "business as usual," mode without CO_2 capture capabilities and assuming no current or future modifications for CO_2 mitigation would be required and then retrofitted to capture and compress 90% of the CO_2 emissions in preparation for pipeline transport and storage. It will be referred to throughout this report as the as the "PC Business-as-Usual Retrofit" Case or "PC BAU Retrofit" Case.

PC Carbon Dioxide Capture/Compression Technologies

The PC cases utilize a Carbon Dioxide Recovery (CDR) system to remove 90% of the CO_2 in the flue gas exiting the FGD unit, purify it, and compress it to a supercritical condition. This study has chosen to take a more conservative approach and uses the current state-of-the-art design and performance aspects of the amine-based process (Econamine FG+ scrubbing) which is a commercially available technology for the PC plants. The CDR system consists of a flue gas supply and cooling system, CO_2 absorption system, solvent stripping and reclaiming system, and CO_2 compression and purification system. The CO_2 absorption/stripping/solvents reclaim process design is based on the Fluor Econamine FG Plus technology [Ref. 2]. The addition of CO_2 capture to the PC cases has a large impact on efficiency. This is primarily because the low partial pressure of CO_2 in the flue gas from a PC plant requires a chemical absorption process rather than physical absorption. For this chemical absorption process, the regeneration requirements are much more energy intensive, requiring substantial steam quantities (~1,530 Btu/lb CO_2 captured) and increased demand on the cooling system, resulting in a post-capture energy efficiency decrease of approximately 12 percent points (from 39% to 27% on an HHV basis) (see Exhibit ES-2).

To prevent the accumulation of heat-stable salts, the incoming flue gas must have an SO_2 polishing step to achieve an SO_2 concentration of 10 ppmv or less.

The Econamine FG Plus process uses a formulation of monoethanolamine (MEA) and a proprietary inhibitor to recover CO_2 from flue gas. This process is designed to recover high-purity CO_2 from low-pressure streams that contain oxygen, such as flue gases from coal-fired power plants, gas turbine exhaust gases, and other waste gases.

In the compression section, the CO_2 is compressed to 15.2 MPa (2,215 psia) by a five-stage geared centrifugal compressor. During compression, the CO_2 stream is dehydrated to a dewpoint of -40ºF with triethylene glycol. The virtually moisture-free supercritical CO_2 stream is then ready for pipeline transport.

Integrated Coal Gasification Combined Cycle Cases

The IGCC design cases analyzed in this report are based on the power production from dual advanced F-class combined cycle gas turbines. The plants are nominally described as producing net 550 MWe, but this varies due to fixed turbine output and varying auxiliary loads. These cases (designated by even numbers) are as follows:

- Case 2: "Business as usual" Integrated Coal Gasification Combined Cycle Power Plant
  An IGCC power plant using the ConocoPhillips E-Gas™ gasification technology and designed and constructed in a conventional, "business as usual," mode without CO_2 capture capabilities and assuming no current or future modifications for CO_2 mitigation will be required. It will be referred to throughout this report as the "IGCC Business-as-Usual" Case or "IGCC BAU" Case.

- Case 4: CO_2 Capture-Ready Integrated Coal Gasification Combined Cycle Power Plant
  An IGCC power plant using the ConocoPhillips E-Gas™ gasification technology designed and constructed in a CO_2 capture-ready mode anticipating future modifications for CO_2 mitigation requirements. It will be referred to throughout this report as the "IGCC Capture-Ready" Case.

- Case 6: CO_2 Capture-Ready IGCC Power Plant Retrofitted with CO_2 Capture
  An IGCC power plant using the ConocoPhillips E-Gas™ gasification technology and designed and constructed in a CO_2 capture-ready mode retrofitted to capture and compress 90% of the CO_2 in preparation for pipeline transport and storage. It will be referred to throughout this report as the "IGCC Capture-Ready Retrofit" Case.

- Case 8: "Business as usual" IGCC Power Plant Retrofitted with CO_2 Capture
  An IGCC power plant using the ConocoPhillips E-Gas™ gasification technology which was designed and constructed in a conventional, "business as usual," mode without CO_2 capture

capabilities and assuming no current or future modifications for CO_2 mitigation would be required and then retrofitted to capture and compress 90% of the CO_2 emissions in preparation for pipeline transport and storage. It will be referred to throughout this report as the "IGCC Business-as-Usual Retrofit" Case or "IGCC BAU Retrofit" Case.

IGCC Carbon Dioxide Recovery/Capture Technologies

The IGCC cases utilize a Carbon Dioxide Recovery (CDR) system to remove 90% of the CO_2 in the syngas, purify it, and compress it to a supercritical condition. The CDR consists of a water-gas shift reactor, CO_2 absorption system, solvent stripping and reclaiming system, and CO_2 compression and purification system. The CO_2 absorption/stripping/solvents reclaim process design is integrated with the sulfur removal process utilizing the Selexol two-stage Acid Gas Removal (AGR) process. To maximize the CO_2 concentration in the syngas, the raw syngas goes through a water-gas shift process containing a sour gas-compatible shift catalyst before entering the AGR process.

A feature of this plant configuration is that H_2S and CO_2 are removed within the same process system, the Selexol unit. The purpose of the Selexol unit is to preferentially remove H_2S as a product stream and then to remove CO_2 as a separate product stream.

SUPERCRITICAL PULVERIZED COAL CASE SUMMARY

Case 1 (PC business-as-usual) is configured to produce power from Illinois No. 6 coal without CO_2 capture, previously published as Case #11 in the recently completed cost and performance study [Ref. 1]. The plant is based on commercially available supercritical PC technology. The boiler is a dry-bottom, wall-fired unit that employs Low NOx Burners (LNBs) with Overfire Air (OFA) and Selective Catalytic Reduction (SCR) for NOx control, a wet limestone forced oxidation scrubber for SO_2 control, and a fabric filter for particulate control. The plant produces a net output of 550 MW at a net plant efficiency of 39.1%, on an HHV basis.

Case 3 (PC capture-ready) is configured to operate with the same performance as Case 1 (PC BAU), but is designed to be readily converted to capture CO_2 via the Econamine FG+ amine-based scrubbing process at a later date. The Econamine FG+ is one of the only CO_2 removal systems that has been demonstrated at commercial scale and is likely to be the technology of choice in the 2007-2010 timeframe. In designing for the future retrofit of CO_2 capture, the plant capacity is oversized and extra space is allocated for the retrofit equipment. The primary rationale for oversizing plant capacity is to maintain a net output of 550 MW after retrofit despite the increase in auxiliary load of approximately 300% that occurs with capture and compression of CO_2. This oversizing of capacity includes increasing the coal feed and gas cleaning capacities by 43%. The steam and cooling systems are also oversized to accommodate increased demands for Econamine process CO_2 solvent regeneration and increased gross steam power requirement. The net power output and net plant efficiency of Case 3 is the same as Case 1.

Case 5 (PC capture-ready retrofit) is the retrofit of Case 3 (PC capture-ready) to capture and compress 90% of the CO_2. The retrofit of the post-combustion Econamine FG+ process for CO_2 capture imposes a significant auxiliary power load on the system in two ways. First, a significant amount of steam exiting the IP turbine is diverted to the CO_2 stripper reboiler. Second, additional auxiliary power is required to run the CO_2 capture plant as well as to compress the CO_2 captured to 2,215 psia for pipeline transport. In anticipation of these “parasitic losses,” the boiler and steam cycle systems are oversized in the “capture-ready” mode. Therefore, the coal flow rate is increased at this time to offset these losses and maintain a net output of approximately 550 MW as the baseload power output after retrofit. Although the baseload power is maintained, the net efficiency drops to 27.2% (HHV). Unlike the IGCC cases where gross output was fixed by the available size of the combustion turbines, the PC cases utilize steam turbines which can be custom made to any desired output, making it possible to maintain a constant plant net output after retrofit.

Case 7 (PC business-as-usual retrofit) is based on a retrofit of Case 1 (PC BAU) to capture CO_2. Since Case 1 was not designed as CO_2 capture-ready, a substantial rework of the PC plant is required to achieve 90% CO_2 capture. Major plant modifications consist of:

- Adding the post-combustion Econamine FG+ process.
- Adding a booster blower to overcome the CO_2 absorber flue gas pressure drop.
- Adding CO_2 compressors and dryers.

Unlike Case 5 (PC capture-ready retrofit), Case 7 (PC BAU retrofit) undergoes a reduction in gross power output due to the steam load and auxiliary power requirements imposed by the carbon capture equipment that was not factored into the original design. Net plant output drops to 379 MW, as compared to 550 MW for the other three PC cases. Case 7 also has the lowest net efficiency of all the PC cases. The Case 7 net efficiency is 27.0% (HHV).

The performance and economic results of the PC cases are summarized in Exhibit ES-2. The Additional Plant Costs are the costs associated with retrofitting only. This includes the changes in O&M, fuel consumption, consumables, and net power output. The Incremental Levelized Cost of Electricity for the PC cases is the difference between the LCOE for the PC Business-as-Usual case and each PC case.

The data clearly show an economic advantage for the CO_2 capture-ready plant with respect to the cost of retrofit. Comparing the CO_2 capture-ready plant retrofit (Case 5) with the business-as-usual plant retrofit (Case 7), the incremental TPC is about $1,000/kW lower ($2,872 versus $3,865/kW)—meaning a savings of $1,000/kW for planning ahead. After retrofit, the incremental increase in LCOE is about 40% lower for the CO_2 capture-ready plant (4.36 cents/kWh versus 7.06 cents/kWh). The plant owner must decide if the lower cost of retrofitting the CO_2 capture-ready plant is worth the higher initial capital investment. This decision may hinge on the timing of CO_2 reductions. If CO_2 reductions are imposed soon after the plant is constructed, the higher initial capital investment makes economic sense. This timing issue is examined later in this report.

Exhibit ES-2 Supercritical PC Plant Performance and Economic Summary

	Case 1 PC Business-as-Usual	Case 7 PC Business-as-Usual Retrofit	Case 3 PC Capture-Ready	Case 5 PC Capture-Ready Retrofit
Gross Power Output, MW_e	580.3	467.3	580.3	663.4
Net Power Output, MW_e	550.2	379.0	550.2	546.0
Net Plant Efficiency (HHV)	39.1%	27.0%	39.1%	27.2%
Net Plant Heat Rate (HHV), kJ/kWh (Btu/kWh)	9,201 (8,721)	13,357 (12,660)	9,201 (8,721)	13,224 (12,534)
Additional Plant Cost for Retrofit[1], 1000$	N/A	$598,509	N/A	$457,287
Total Plant Cost (TPC)[1], 1000$	$866,391	$1,464,901	$1,110,786	$1,568,073
Incremental TPC[1], 1000$	N/A	$598,509	$244,395	$701,682
Total Plant Cost[1], $/kW	$1,575	$3,865	$2,019	$2,872
Incremental TPC[1], $/kW	N/A	$2,290	$444	$1,297
Total Levelized COE[1,2,3], ¢/kWh	6.33	13.39	7.31	10.69
Incremental Levelized COE[1,2,3], ¢/kWh	N/A	7.06	0.98	4.36
Total CO_2 Emitted, kg/MWh_{net} (lb/MWh_{net})	804 (1,773)	117 (258)	804 (1,773)	115 (254)
Total CO_2 Captured, kg/MWh_{net} (lb/MWh_{net})	N/A	1,052 (2,319)	N/A	1,040 (2,294)
Cost of CO_2 Captured[1,2], $/tonne ($/ton)	N/A	$67 ($61)	N/A	$42 ($38)
Cost of CO_2 Avoided[1,2], $/tonne ($/ton)	N/A	$103 ($93)	N/A	$63 ($57)

Note:
Costs in 2007 Dollars
"Incremental costs" are compared to Case 1—"PC Business-as-Usual"
[1]Transportation, Storage, and Monitoring of CO_2 not included
[2]85% Capacity Factor
[3]20 year levelization period

INTEGRATED GASIFICATION COMBINED CYCLE CASE SUMMARY

Case 2 (IGCC business-as-usual) is configured to produce power from Illinois No. 6 coal without CO_2 capture, previously published as Case #3 in the recently completed cost and performance study [Ref. 1]. The plant utilizes two oxygen-blown, high pressure ConocoPhillips (CoP) E-Gas™ two-stage gasifiers to produce a medium heating value syngas. Oxygen fed to the gasifiers is generated by two cryogenic air separation units (ASUs). The syngas is filtered, scrubbed of particulate, cooled, and cleaned of mercury before entering a Coastal Engineering promoted proprietary amine-based acid gas removal (AGR) system. The AGR process removes H_2S from the gas stream which is sent to a Claus plant to produce elemental sulfur. The clean syngas leaving the AGR is humidified and fired in dual advanced F-class gas turbines. The gas turbines operate in a combined cycle mode, utilizing heat from the gas turbine exhaust to generate steam in a heat recovery steam generator (HRSG) to produce additional power. The plant produces a net output of 623 MW at a net plant efficiency of 39.3% (HHV).

Case 4 (IGCC capture-ready) is configured to operate with the same performance characteristics as Case 2, but has been designed to be readily converted to capture CO_2 at a later date. Syngas cleaning is similar to Case 2, except that a single-stage Selexol™ process is used instead of the amine-based AGR. The Selexol™ process can be modified to capture CO_2 by adding a second absorber stage to the Selexol process. In providing for the future retrofit of CO_2 capture equipment, plant capacity is oversized, and extra space is allocated for the retrofit equipment. Capacity was oversized primarily with respect to air separation, coal handling and gas cleanup, so that net power production would not change substantially after retrofit of CO_2 capture equipment. Until the plant is retrofitted, it is operated with reduced syngas production, but at a full gas turbine load.

Case 6 (IGCC capture-ready retrofit) is the retrofit of Case 4 to capture CO_2. Gas processing equipment added to achieve CO_2 capture includes a water-gas-shift (WGS) process, a second stage to the Selexol absorber, and a CO_2 compression train. The plant produces a net output of 518 MW at a net plant efficiency of 31.7% (HHV), as compared to the pre-retrofit net output of 623 MW and net efficiency of 39.3%.

Case 8 (IGCC business-as-usual retrofit) is the retrofit of Case 2 to capture CO_2. Since Case 2 was not designed with plans for future CO_2 capture, a substantial rework of the IGCC plant is required to achieve 90% CO_2 capture. Plant modifications consist of:

- Adding parallel air compressor to the ASU.
- Removing the COS hydrolysis reactor and the LP steam generator/gas cooler.
- Inserting the three shift reactors and intercoolers.
- Rearranging the aftercoolers between the shift and the condensate heat exchanger.
- Replacing the MDEA unit with a two-stage Selexol.
- Adding CO_2 compressors and dryers.
- Retrofitting the gas turbine to burn hydrogen-rich syngas.

Net power output for Case 8 is 20% lower than the pre-retrofit Case 2 with a similar drop in net plant efficiency. This is due to the fact that the pre-retrofit design of Case 2 was not oversized to account for the higher auxiliary load imposed by the CO_2 capture and compression systems.

The performance and economic results of the IGCC cases are summarized in Exhibit ES-3. Additional Plant Costs are the costs associated with retrofitting only. This includes the changes in O&M, fuel consumption, consumables, and net power output. The Incremental Levelized Cost of Electricity is the difference between the LCOE for the IGCC Business-as-Usual case and each case. Details on the cost estimation and LCOE calculations are included in Section 4 of this report.

Contrary to the results of the PC cases, the IGCC CO_2 capture-ready plants do not show a clear economic advantage over the non-capture-ready plants when fitted with CO_2 capture at a later date. The incremental TPC of the IGCC CO_2 capture-ready plant (Case 6) is $719/kW versus $901/kW for the business-as-usual plant (Case 8). <u>This difference is less than 10% of the total plant cost and, therefore, does not offer sufficient financial incentive to persuade plant owners to invest in CO_2 capture-ready IGCC plant designs</u>.

Exhibit ES-3 IGCC Plant Performance and Economic Summary

	Case 2 IGCC Business-as-Usual	Case 8 IGCC Business-as-Usual Retrofit		Case 4 IGCC Capture-Ready	Case 6 IGCC Capture-Ready Retrofit
Gross Power Output, MW_e	742.5	672.4		742.5	693.8
Net Power Output, MW_e	623.4	500.3		623.4	518.2
Net Plant Efficiency (HHV)	39.3%	31.5%		39.3%	31.7%
Net Plant Heat Rate (HHV), kJ/kWh (Btu/kWh)	9,159 (8,681)	11,411 (10,816)		9,159 (8,681)	11,349 (10,757)
Additional Plant Cost for Retrofit[1], 1000$	N/A	$237,785		N/A	$123,949
Total Plant Cost (TPC)[1], 1000$	$1,080,166	$1,317,951		$1,146,914	$1,270,863
Incremental TPC[1], 1000$	N/A	$237,785		$66,748	$190,697
Total Plant Cost[1], $/kW	$1,733	$2,634		$1,840	$2,452
Incremental TPC[1], $/kW	N/A	$901		$107	$719
Total Levelized COE[1,2,3], ¢/kWh	7.53	10.72		7.91	10.21
Incremental Levelized COE[1,2,3], ¢/kWh	N/A	3.19		0.38	2.68
Total CO_2 Emitted, kg/MWh_{net} (lb/MWh_{net})	785 (1,730)	116 (255)		785 (1,730)	115 (253)
Total CO_2 Captured, kg/MWh_{net} (lb/MWh_{net})	N/A	862 (1,901)		N/A	857 (1,890)
Cost of CO_2 Captured[1,2], $/tonne ($/ton)	N/A	$37 ($34)		N/A	$31 ($28)
Cost of CO_2 Avoided[1,2], $/tonne ($/ton)	N/A	$48 ($43)		N/A	$40 ($36)

Note:
Costs in 2007 Dollars
"Incremental costs" are compared to Case 2—"IGCC Business-as-Usual"
[1]Transportation, Storage, and Monitoring of CO_2 not included
[2]80% Capacity Factor
[3]20 year levelization period

RESULTS

PC Cases: There is a tangible benefit associated with pre-investment for anticipated CO_2 capture for the PC cases. This benefit is achieved by over-sizing the boiler capacity to produce steam as a pre-investment cost, with the result that when retrofitted, the plant is able to maintain rated output, albeit at a lower efficiency. The retrofitted PC business-as-usual plant (Case 7) is seriously penalized with a 31% loss of net power. As a result, the retrofitted CO_2 capture-ready plant (Case 5) generates electricity at a cost 20% lower than the retrofitted business-as-usual plant.

IGCC Cases: The IGCC cases indicate limited benefit with pre-investment for anticipated CO_2 capture. As the retrofit costs are relatively small compared to the total plant costs, and the amount of derating is tolerable, there is no financial incentive for increased upfront costs. Comparing the retrofitted business-as-usual and CO_2 capture-ready plants, there is only a small difference in the cost of electricity and the cost of CO_2 avoided.

The Total Plant Cost for each case is shown in Exhibit ES-4 which indicates that the total cost for the retrofitted PC plants is substantially higher than the IGCC retrofitted plants on a per kW basis.

Exhibit ES-5 indicates the differences between the LCOE for all cases. Consistent with reported results elsewhere (DOE, EPRI, MIT), the bottom-line cost of electricity for a conventional PC power plant without CO_2 capture is the lowest cost option. However, upon retrofitting for CO_2 capture (planned or unplanned), the cost of electricity for PC power plants is estimated to be higher than IGCC.

The additional cost for CO_2 transport, storage, and monitoring (TS&M) in the cases with carbon capture were estimated based on reference data and scaled estimates. The TS&M costs assume the CO_2 is transported 50 miles via pipeline to a geologic sequestration field, injected into a saline formation at a depth of 4,055 ft and monitored for 80 years. These values are shown in Exhibit ES-6. The total levelized costs of electricity including CO_2 transport, storage and monitoring are shown in Exhibit ES-7.

Exhibit ES-4 Total Plant Cost

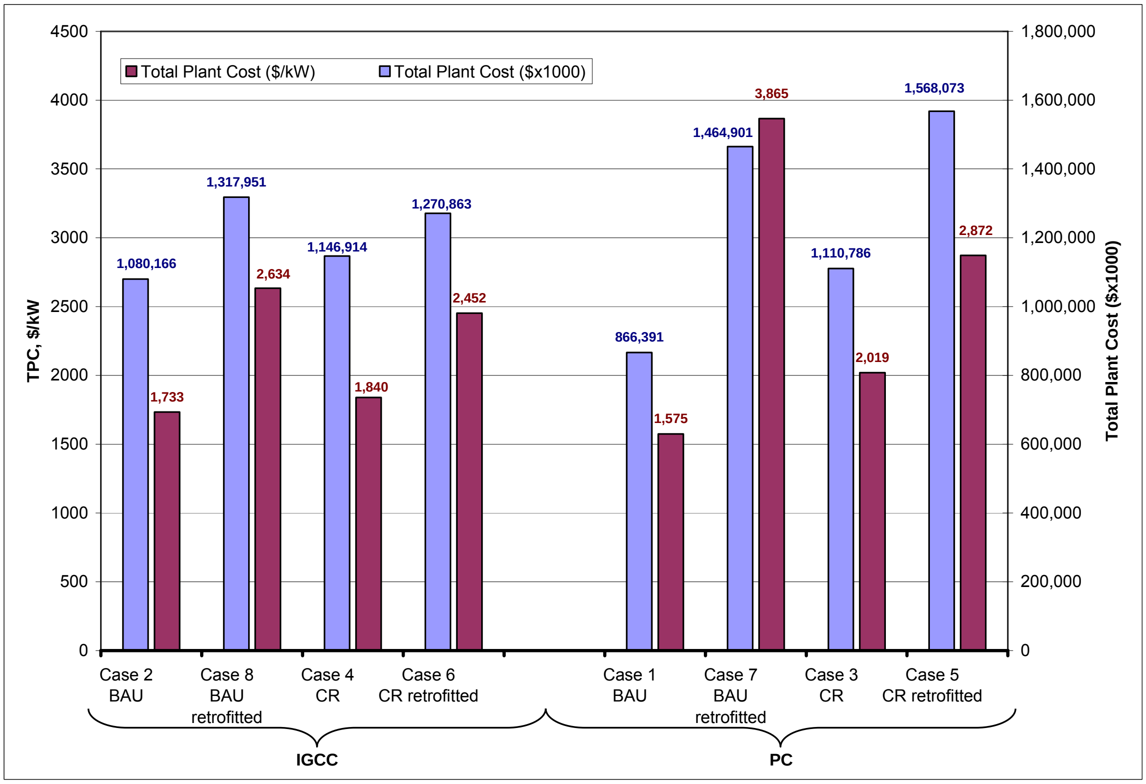


Exhibit ES-5 Levelized Cost of Electricity for Plant Cases

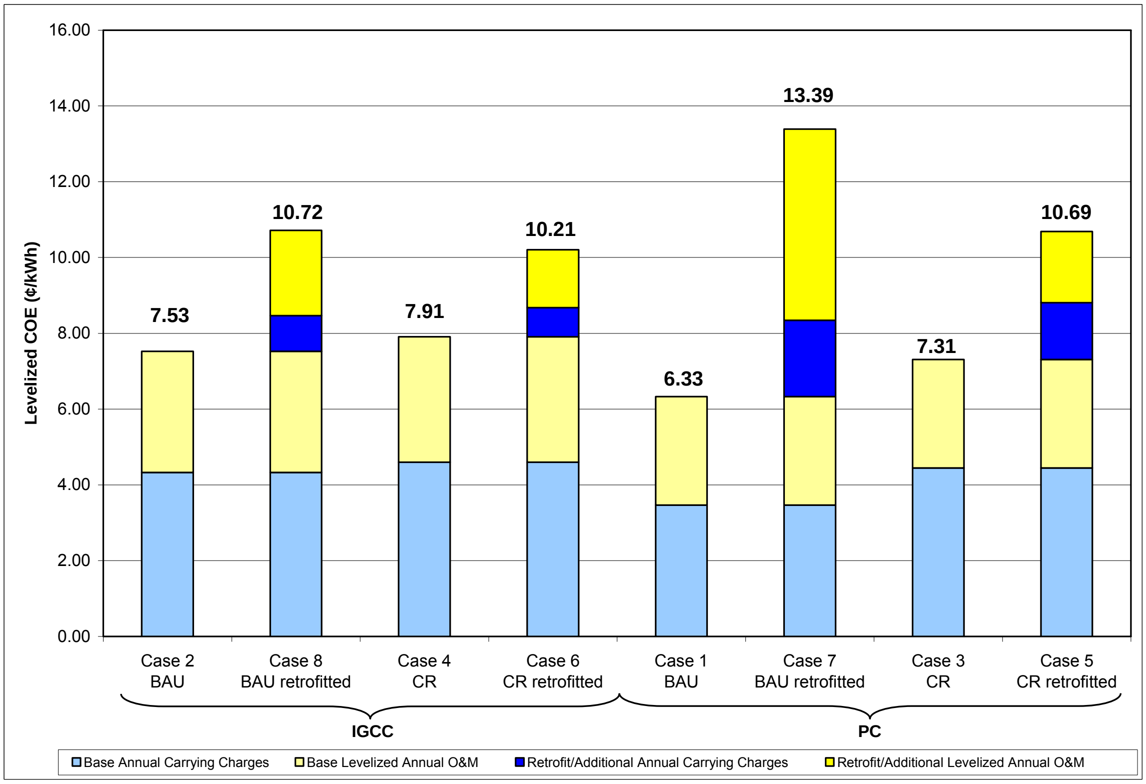
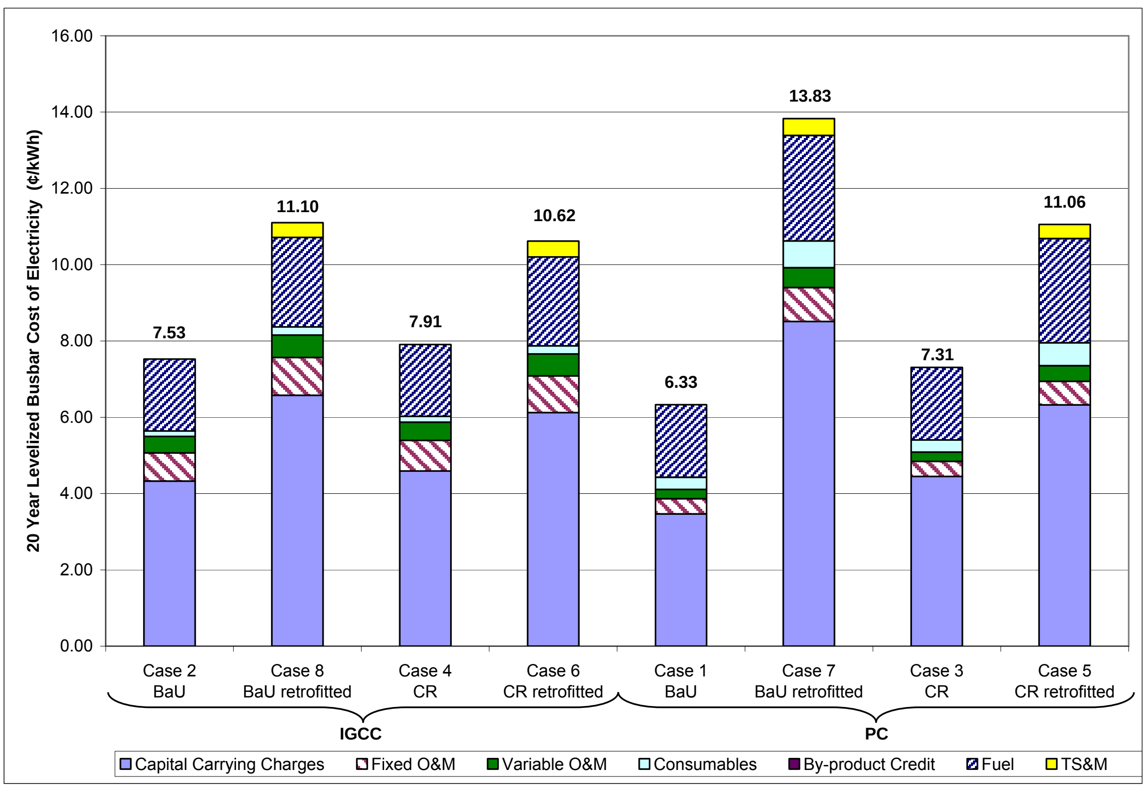


Exhibit ES-6 Levelized Cost of Electricity for CO_2 Transport, Storage, and Monitoring

Study Case	20 yr Levelized Costs (¢/kWh)				
	CO_2 Transport	CO_2 Storage	CO_2 Monitoring	LCOE w/o TS&M	**Total LCOE**
Case 5 - PC Capture-ready Retrofit	0.242	0.038	0.090	10.69	11.06
Case 7 - PC Business-as-usual Retrofit	0.307	0.043	0.091	13.39	13.83
Case 6 - IGCC Capture-ready Retrofit	0.288	0.044	0.079	10.21	10.62
Case 8 - IGCC Business-as-usual Retrofit	0.263	0.046	0.080	10.72	11.10

Exhibit ES-7 Levelized Cost of Electricity Including CO_2 Transport, Storage, and Monitoring



DISCOUNTED CASH FLOW ECONOMIC ANALYSIS

Discounted Cash Flow Economic Analysis: The results of the economic analysis can be misleading because the time value of money associated with the cash flows that span the multi-year planning, construction and startup period for retrofitting is not included in TPC. Therefore a Discounted Cash Flow (DCF) analysis was performed to assess a truer picture of the project economics. The results shown in Exhibit ES-2 through Exhibit ES-5 are based on overnight construction for both the initial and retrofitted plants. Adding the retrofitted costs directly to the initial plant costs is economically equivalent to instantaneously retrofitting the initial plant. In reality, the retrofit installation could occur at anytime during the life of the plant. The year the retrofit occurs determines the impact on the average cost of electricity for the plant. Intuitively, the earlier the additional retrofitting costs and any associated derating occur, the higher the subsequent cost of electricity will be. But because of the varying value of money and commodities over time, the final impact of the additional costs and any associated derating may decrease depending on the specific type and magnitude of the costs.

The simplified DCF analysis approach assumes the plant starts immediately and examines the impact on the average LCOE of the retrofitting costs occurring in each of the next 20 years. Since the analysis is concentrated on comparing the costs of retrofitting operating plants, items such as planning and startup costs, working capital, and financing fees were not included in this simplified analysis. The cost of electricity for each year was estimated based on the present worth values of the initial plant capital, operating costs, and performance until the year of retrofit and then adding the costs of retrofitting and performance impacts for each of the remaining years in the 20 year project life examined in this study. These LCOEs were then averaged over the 20 year period. By comparing changes in these average cost of electricity values for each type of retrofit case (capture-ready versus non-capture-ready), the length of time where pre-investment would be advantageous was determined.

The report on the detailed DCF analysis is included in Appendix C, and the conclusions are as follows:

- A 550 MW Supercritical PC power plant which has been designed and built for future CO_2 capture (Case 3 PC capture-ready) is economically more attractive than a conventional plant (Case 1 PC business-as-usual) if CO_2 capture is either desired or required within the first 10 years of plant operation. The conventional, business-as-usual, plant is economically more attractive if retrofit is to occur after the first 10 years of plant operation. The main reason for this advantage of the capture-ready plant in the early years is that a "business-as-usual" plant's net electrical output is reduced by about 31% when retrofitted for CO_2 capture, whereas the plant designed for future CO_2 capture does not experience the same power output reduction.

- A 623 MW IGCC plant designed for future CO_2 capture (Case 4 IGCC capture-ready) has a limited economic advantage over a conventional plant (Case 2 IGCC business-as-usual) if CO_2 capture will be either desired or required within the first 7 years of the plants operation. Either design is acceptable if retrofitting is expected after 7 years.

1. INTRODUCTION

1.1 BACKGROUND

An issue associated with CO_2 capture from fossil fuel power plants involves the costs associated with the plant design and configuration required to capture most of the carbon from the plant as CO_2. Conceptual plant designs have taken two approaches regarding the capture of CO_2. As shown in the "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity" [Ref. 1], baseline plants have placed emphasis on producing power with a minimum cost and maximum efficiency without CO_2 capture. The primary rationale for designing these plants without CO_2 capture is that there have yet to be regulations promulgated which require the capture and sequestration of CO_2.

Conversely, grass roots designs with provisions for CO_2 capture and compression have been generated to determine the capture and avoided costs of CO_2 removal. These plants were designed with the assumption that CO_2 would need to be captured at the time of initial plant operation.

Between these two plant design approaches is a separate category of plants referred to as CO_2 Capture-ready that would be built to operate initially without CO_2 capture and, upon the imposition of pertinent regulations, would convert to operation in a CO_2-capture mode.

<u>Definition of 'CO_2 Capture-Ready'</u>

In an unpublished version of a Capture-Ready document, the IEA stressed the importance of including a complete definition of Capture-Ready in the study introduction. They addressed the issues which they deemed pertinent to the understanding of the transition from CO_2 Capture-Ready to one of Capture-Capable. Also, the DOE has determined that it is necessary to state a "DOE/NETL Definition of CO_2 Capture-Ready" which emphasizes the views which the DOE holds important in the progression toward a CO_2 Capture-Capable plant design.

Apart from either a technology or an emissions perspective, the CO_2 Capture-Ready plant definition contains the following requirements:

- Plant site should have access to CO_2 storage - either locally or by an identified route.
- Space at the plant site should be available for expansion and addition of plant areas, access to existing plant items, storage of equipment during construction and for the provision of expansion without encroachment into established barrier zones.
- The CO_2 capture system should not contribute to an increase in emission rate levels relative to the before capture configuration.

From both a Technology and Emissions perspective, there are additional issues which are relevant to CO_2 Capture-Ready plants and are identified by the following definitions:

From a Technology Perspective:

The CO_2 Capture-Ready plant is defined as a plant having the technology either in place or readily retrofitted to become CO_2 Capture-Capable. The following plant design features apply:

- The CO_2 Capture-Ready design should fully consider the cost/benefit which can be attributed to utilization of improved technology in an integrated process at the time of plant retrofit to become CO_2 Capture-Capable. For example, developmental membrane separations of hydrogen and CO_2 from syngas could offer improved efficiency. However the cost of membrane and its integration with the plant could create unforeseen issues.
- The CO_2 Capture-Ready design should have a clearly identified economic strategy which is based on changes to state-of-the-art equipment at time of retrofit.
- The CO_2 Capture-Ready design should be sufficiently flexible to accommodate alternate technologies currently under development should they be economically superior to existing technologies at the time of retrofit
- The design should identify possible uses for 'capture-ready' options to enhance overall plant performance in the time frame before capture is added. For example, there may be benefit of utilizing the increased gasifier capacity to produce secondary products such as hydrogen in advance of retrofitting the plant to be CO_2 Capture-Capable.

From an Emissions Perspective:

The CO_2 Capture-Ready plant is defined as a plant for which the baseline emissions are identified and the emissions to be achieved when the plant is CO_2 Capture-Capable are projected. The following plant design features apply:

- The CO_2 Capture-Ready design should fully identify the emissions from the baseline plant and the projected emissions from the CO_2 Capture-Capable plant.
- The CO_2 Capture-Ready design should fully consider the cost/benefit which can be attributed to a comprehensive change in plant emissions at the time of plant retrofit to CO_2 Capture-Capable. This should include the optimized impact on Cost of Electricity and ultimately the Avoided Cost of CO_2.
- The CO_2 Capture-Ready design should have a clearly identified control strategy which is based on changes in plant emissions at time of retrofit.

<u>Investment Approaches to Plant Design</u>

There are two alternative investment approaches to the design of these plants:

- Build a power plant today without provision for carbon capture (<u>lowest</u> initial investment, but highest cost to retrofit with CO_2 capture).
- Build a power plant with a design configuration anticipating future restrictions on carbon emissions that can be easily retrofitted with additional process equipment for CO_2 capture and compression while maintaining the original design plant performance and net power output (<u>highest</u> initial investment, but lowest cost to retrofit with CO_2 capture).

Both designs are then modified to include CO_2 capture and compression in the retrofitted cases.

1.2 STUDY OBJECTIVE

The objective of this study is to perform systems analyses that assess the impacts (performance, costs, investment risk) of constructing new PC and IGCC power plants in a "CO_2 capture-ready" mode that will allow for a future, low-cost CO_2 capture retrofit application in the case of mandated greenhouse gas mitigation. This includes performing a literature search on "CO_2 Capture-Ready" or "CO_2 Sequestration-Ready" power plant designs and summarizing relevant findings.

Several cases were analyzed in this report. They are summarized in Exhibit 1-1.

Exhibit 1-1 Study Matrix

Case	Unit Cycle	Plant Design	Gasifier/Boiler Technology	CO_2 Separation
1	PC	Business-as-usual	Supercritical PC	
2	IGCC	Business-as-usual	CoP E-Gas™	
3	PC	Capture-ready	Supercritical PC	
4	IGCC	Capture-ready	CoP E-Gas™	
5	PC	Capture-ready Retrofitted	Supercritical PC	Amine Absorber
6	IGCC	Capture-ready Retrofitted	CoP E-Gas™	Selexol 2nd stage
7	PC	Business-as-usual Retrofitted	Supercritical PC	Amine Absorber
8	IGCC	Business-as-usual Retrofitted	CoP E-Gas™	Selexol 2nd stage

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2. LITERATURE SEARCH

The results of a literature search indicate an increasing interest in studying and analyzing issues involving CO_2 capture and sequestration as a means of reducing carbon emissions, both nationally and internationally. This includes evaluating the costs and issues for retrofitting existing plants as well as designing new plants with the anticipation of having to retrofit them for carbon capture.

Below is a list of some of the papers and reports that were located along with a brief summary of the information contained in each.

Evaluation of Options for adding CO_2 Capture to ChevronTexaco IGCC by John Griffiths and Stephen Scott of The Jacobs Consultancy

The paper examines the option of placing a shift converter into an IGCC plant before capture is required and operating the same plant without and then with CO_2 capture. The performances and capital costs of these two cases are compared with two other plants, using essentially traditional technology, one without a shift converter and CO_2 capture, and the other with a shift converter and CO_2 capture.

The study raised several interesting lines of further inquiry.

- The two non-capture cases have been designed without regard for possible conversion from non-capture to capture mode of operation. The viability and costs of such conversions could be quantified.
- The non-capture shift scheme (Case 2B) is penalized because its CO_2 diluted fuel gas does not produce the best performance from the selected gas turbine. Measures to improve performance could be investigated with the gas turbine supplier and these could include restricted shift conversion until capture was required.
- The Study indicates that an IGCC could be built with the ability to transfer seamlessly to CO_2 capture, i.e. without loss of scheduled production. This is an option which would enable low cost IGCC plants to compare even more favorably with other forms of power production which do not create additional CO_2 (nuclear and renewables).

http://www.gasification.org/Docs/2003_Papers/28GRIF_paper.pdf

Pre-Investment of IGCC for CO_2 Capture with the Potential for Hydrogen Co-Production by Michael D. Rutkowski, PE and Ronald L. Schoff, Parsons Corporation; Neville A. H. Holt and George Booras, Electric Power Research Institute

This paper explores a method to develop a plant design that initially operates without CO_2 capture and is then retrofitted to incorporate CO_2 removal, with potential cost savings in mind. This paper describes the impact on cost and efficiency for IGCC plants that are retrofitted for CO_2 capture at a later date.

The decision to pre-invest in an IGCC plant can be a business decision based on the probability of having a carbon sequestration requirement in the future. The pre-investment assessment has shown that with pre-investment, the plant has sufficient material handling capability and equipment spacing to readily be retrofitted for CO_2 capture in the future. This investment of an additional 5% capital can be projected to increase the cost of electricity by about 3% without CO_2 capture, and by an additional 22% when retrofitted. Conversely, the cost of electricity increase resulting from CO_2 capture in a plant without pre-investment can be 30%. This is primarily due to the lower power output from the derated gas turbine.

The incremental cost of hydrogen from IGCC plants has been shown to be competitive with hydrogen from full size coal plants. With minor process modifications, the syngas preparation in IGCC plants with CO_2 capture is ideally suited for hydrogen production.
http://www.gasification.org/Docs/2003_Papers/29RUTK_paper.pdf

Making New Power Plants Capture-Ready by Jon Gibbons Energy Technology for Sustainable Development Group, Imperial College London

A presentation on capture and sequestration issues and projects at the June 2006 International CO_2 Network Conference in Copenhagen, Denmark presented the following Conclusions and Issues:

- Capture-Ready not a substitute for capture
- Flexible approach needed for Capture-Ready
- Show-stoppers must be avoided (space, access to storage or H_2 supply, but significant expenditure not justified
- Often no choice in base plant, or capture method but technology changing rapidly
- Choice between IGCC and PC as Capture-Ready depends on technical issues
- Choice between pre- and post- combustion for NGCC depend on future gas and coal prices
- Plan Capture-Ready build capture also an option

http://www.co2captureandstorage.info/docs/capture/H-Gibbins.pdf

Coupling CO_2 Capture and Storage with Coal Gasification: Defining "Sequestration-Ready" IGCC by Stephens, Jennie C. BCSIA Discussion Paper, Discussion Paper 2005-09, Cambridge, Mass., Belfer Center for Science and International Affairs, September 2005.

This paper assesses a spectrum of progressively more involved potential requirements for incorporating consideration of CO_2 capture and storage technology in the design of new IGCC power plants.

If the U.S. government is going to provide a subsidy to promote the deployment of IGCC power plants that are “sequestration-ready,” policy-makers are going to have to define the specific requirements. A complex array of political, economic, and technical uncertainties will be considered in determining the appropriate definition. One of the biggest uncertainties that will

influence opinions on what "sequestration-ready" should mean is the likely timeframe in which a cost of emitting CO_2 to the atmosphere will be imposed. While many are anticipating restrictions on CO_2 emissions that will generate a cost of emitting CO_2 within 5-10 years, some do not anticipate any CO_2 regulations in the U.S. The minimal requirements involving developing a conceptual plan of a future retrofit without actually requiring any actual changes to the initial plant design is likely to be favored by those who view a long time before a real cost will be associated with emitting CO_2, while the more stringent requirements that will involve a significant level of pre-investment will be viewed more favorably by those who anticipate a CO_2 cost in the next few years. This discussion of the term "sequestration-ready" or "CCS-ready" highlights the need for efforts to couple the deployment of IGCC with actual CCS demonstration. The size and complexity of power plants means that there are major inefficiencies associated with optimizing an initial design and construction of a power plant to run one way and then at some point later retrofitting that plant to run in a very different way. In addition there is considerable risk associated with investing for preparedness for potential future retrofits when there is large potential for technological changes in both the IGCC technology and the CO_2 capture technology. Due to the significant costs of installing CO_2 capture equipment and transporting and storing the captured CO_2 in the absence of a CO_2 regulating regime, additional government provided incentives, either regulatory or financial, beyond the support for IGCC deployment, would be required for coupled, integrated projects incorporating both IGCC and CCS.
http://bcsia.ksg.harvard.edu/BCSIA_content/documents/stephens200509.pdf

Carbon Dioxide Capture from Coal-Fired Power Plants: A Real Options Analysis
MIT LFEE 2005-002 RP Prepared by: Ram C. Sekar, Massachusetts Institute of Technology Laboratory for Energy & the Environment

Investments in three coal-fired power generation technologies are valued using the "real options" valuation methodology in an uncertain carbon dioxide (CO_2) price environment. The technologies evaluated are pulverized coal (PC), integrated coal gasification combined cycle (baseline IGCC), and IGCC with pre-investments that make future retrofit for CO_2 capture less expensive (pre-investment IGCC).

There is substantial economic value of temporal flexibility in retrofit decision making, and it increases with increase in CO_2 price uncertainty. This represents the value added by being able to make a retrofit decision based on the CO_2 price at that time as opposed to precommitting on a future retrofit decision.

It is seen that pre-investment IGCC, which is a "Capture-Ready" technology in comparison to baseline IGCC and PC, remains the least cost competitive option using both valuation approaches. However, the cost disadvantage of preinvestment IGCC increases if we use the "Market Based Valuation" method in place of the standard "Discounted Cash Flow" method currently in use.

It is seen that PC has an 88% - 100% chance of being the optimal technology choice. The low upfront investment and operating costs of PC before retrofit outweighs the disadvantages of higher discounted CO_2 emission costs in all three price models. Pre-investment IGCC ends up as the least cost-effective option, while baseline IGCC falls in-between. PC would have been even further ahead had supercritical technology been chosen instead of subcritical technology in the representative case. These results are sensitive to the choice of input assumptions made on the valuation model.

The results are also highly sensitive to changes in fuel prices, with baseline IGCC becoming more cost competitive than PC at higher fuel prices.
http://lfee.mit.edu/metadot/index.pl?id=2234

Capture-Ready Coal Plants - Options, Technologies and Economics Bohm, M.C., M.I.T. Masters Thesis, (2006).
A plant can be considered to be capture-ready if, at some point in the future it can be retrofitted for carbon capture and sequestration and still be economical to operate. The concept of capture-ready is not a specific plant design; rather it is a spectrum of investments and design decisions that a plant owner might undertake during the design and construction of a plant. Power plant owners and policymakers are interested in capture-ready plants because they may offer relatively low cost opportunities to bridge the gap between current coal-fired generation technologies without CO_2 capture to future plants that may be built from the start to capture CO_2, and reduce the risks of possible future regulations of CO_2 emissions. This thesis explores the design options, technologies, and costs of capture-ready coal-fired power plants.

IGCC plants have lower retrofitting costs, and therefore require significantly lower carbon tax prices in order to justify a retrofit. This moves forward the year of retrofit for an IGCC plant significantly, and correspondingly reduces the lifetime CO_2 emissions from the plant, when compared with a PC plant. PC plants require relatively high carbon prices in order to retrofit, and have correspondingly higher lifetime CO_2 emissions. The analysis in this study estimated that for a wide range of carbon price scenarios a PC plant could be expected to have 30%-60% higher lifetime CO_2 emissions than an equivalently sized IGCC plant, indicating that carbon lock-in is a significant issue for these plants. Also, pre-investment for capture-ready in an IGCC plant does not appear to have a large impact on the lifetime CO_2 emissions as compared to a baseline IGCC plant.
http://sequestration.mit.edu/pdf/Mark_Bohm_Thesis.pdf

Advanced Gasification-Combustion Technology for Production of Hydrogen, Power and Sequestration-Ready CO_2 George Rizeq, Janice West, Arnaldo Frydman, Raul Subia, Vladimir Zamansky, GE Global Research (GEGR); Kamalendu Das, U.S. DOE NETL - 2003 Gasification Technologies Conference

GE Global Research (GEGR) is developing an innovative Unmixed Fuel Processor (UFP) technology for coal-based production of hydrogen for fuel cells or combustion turbines. The UFP module can be integrated into a number of advanced power systems. It offers increased energy efficiency relative to conventional gasification and combustion systems and near-zero pollution. The UFP technology converts coal, steam and air into three separate streams of hydrogen, sequestration-ready CO_2, and high temperature/pressure oxygen-depleted air to produce electricity in a gas turbine.

Additional bench-scale testing is planned to provide further insight into the rates and mechanisms of char burnout, CO_2 release, and oxygen transfer material (OTM) reduction

processes. Other continuing work on UFP technology development will include the assembly and initial shakedown testing of the pilot-scale system, which will feature three fully integrated circulating, fluidized bed reactors. The operational evaluation of the pilot-scale system will be conducted, with parametric testing to identify optimal performance.
http://www.gasification.org/Docs/2003_Papers/36RIZE_paper.pdf

Phased Construction of IGCC Plants for CO_2 Capture - Effect of Pre-Investment by EPRI, Report List Price (in US Dollars) $2500, Date Published Dec 2003

The objective of this study is to determine the impact on cost and efficiency for IGCC plants that are retrofitted for CO_2 capture for both of the two investment approaches.

Under separate tasks, the sensitivity that changing the number of CO-shift reactor stages would have on the performance and cost of Case 2b (with pre-investment retrofitted for CO_2 capture) for both Texaco and E-Gas tasks was determined. The two New York Power Authority (NYPA) base case plant designs were expanded to co-produce hydrogen equivalent to production from the unused gasifier capacity, equivalent to about 10 percent additional coal flow. Capital and operating costs for each of those plants were produced.
http://www.epri.com/OrderableitemDesc.asp?product_id=000000000001004537

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3. EVALUATION BASIS

3.1 SITE DESCRIPTION

All plants in this study are assumed to be located at a generic plant site in Midwestern USA, with ambient conditions and site characteristics as presented in Exhibit 3-1 and Exhibit 3-2.

Exhibit 3-1
Site Ambient Conditions

Barometric Pressure, psia	14.7
Design Ambient Temperature, Dry Bulb, °F	59
Design Ambient Temperature, Wet Bulb, °F	51.5
Design Ambient Relative Humidity, %	60

Exhibit 3-2
Site Characteristics

Location	Greenfield, Midwestern USA
Topography	Level
Size, acres	300
Transportation	Rail
Ash Disposal	Off Site
Water	Municipal (50%) + Groundwater (50%)
Access	Land locked, having access by train and highway

3.2 DESIGN COAL

Properties of the design coal assumed for this study are presented in Exhibit 3-3. All coal-fired cases were modeled with Illinois #6 coal.

Exhibit 3-3
Design Coal

Rank	**Bituminous**	
Seam	**Illinois #6 (Herrin)**	
Source	**Old Ben mine**	
Proximate Analysis (weight %)		
	AR	**Dry**
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	100.00	100.00
Sulfur	2.51	2.82
HHV, Btu/lb	11,666	13,126
LHV, Btu/lb	11,252	12,712
Ultimate Analysis (weight %)		
	AR	**Dry**
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen by Diff.	6.88	7.75
Total	100.00	100.00

3.3 DESIGN SORBENT COMPOSITION

Limestone from Greer Limestone mine Morgantown, WV is assumed as a design sorbent for this study. Sorbent is delivered to plant storage by train. Limestone analysis is presented in Exhibit 3-4.

Exhibit 3-4
Sorbent Analysis

Supplier/mine	Greer Industries, Inc.	**Analysis, %**
Calcium Carbonate	$CaCO_3$	80.40
Magnesium Carbonate	$MgCO_3$	3.50
Silica	SiO_2	10.32
Aluminum Oxide	Al_2O_3	3.16
Iron Oxide	Fe_2O_3	1.24
Sodium Oxide	Na_2O	0.23
Potassium Oxide	K_2O	0.72
Balance		0.43
	Total	**100.00**

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4. COST ESTIMATING METHODOLOGY

The estimates carry an accuracy of ±30 percent, consistent with the screening study level of information available for the various study power technologies. An in-house database and conceptual estimating models were used for the capital cost and O&M cost estimates. Costs were further calibrated using a combination of adjusted vendor-furnished and actual cost data from recent design and design/build projects. The capital costs for each cost account were reviewed by comparing individual cases across all of the other cases and technologies to ensure an accurate representation of the relative cost differences between the cases and accounts. All capital and O&M costs are presented as "overnight costs" expressed in January 2007 dollars.

Both the project contingency and process contingency represent costs that are expected to be spent in the development and execution of the project but are not yet fully reflected in the design. It is industry practice to include project contingency in the TPC to cover project uncertainty and the cost of any additional equipment that would result during detailed design. Likewise, the estimates include process contingency to cover the cost of any additional equipment that would be required as a result of continued technology development.

The estimates are based on an Engineering/Procurement/Construction Management (EPCM) approach utilizing multiple subcontracts. This approach provides the Owner with greater control of the project while minimizing, if not eliminating, most of the risk premiums typically included in an Engineer/Procure/Construct (EPC) contract price. This EPCM approach, used as the basis for the estimates here, is anticipated to be the most cost effective approach for the Owner. While the Owner retains the risks, the risks become reduced with time, as there is better scope definition at the time of contract award(s).

The cost estimation methodology is explained in more detail in "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity" [Ref. 1].

4.1 LEVELIZED COST OF ELECTRICITY

The revenue requirement method of performing an economic analysis of a prospective power plant has been widely used in the electric utility industry. This method permits the incorporation of the various dissimilar components for a potential new plant into a single value that can be compared to various alternatives. The revenue requirement figure-of-merit in this report is cost of electricity (COE) levelized over a 20 year period and expressed in mills/kWh (numerically equivalent to $/MWh). The 20-year levelized cost of electricity (LCOE) was calculated using a simplified model derived from the Power Systems Financial Model [Ref. 3].

The equation used to calculate LCOE is as follows:

$$LCOE_P = \frac{(CCF_P)(TPC) + [(LF_{F1})(OC_{F1}) + (LF_{F2})(OC_{F2}) + \ldots] + (CF)[(LF_{V1})(OC_{V1}) + (LF_{V2})(OC_{V2}) + \ldots]}{(CF)(kWh)}$$

where

$LCOE_P$ =	levelized cost of electricity over P years
P =	levelization period (e.g., 10, 20 or 30 years)
CCF_P =	capital charge factor for a levelization period of P years
TPC =	total plant cost
LF_{Fn} =	levelization factor for category n fixed operating cost
OC_{Fn} =	category n fixed operating cost for the initial year of operation (but expressed in "first-year-of-construction" year dollars)
CF =	plant capacity factor
LF_{Vn} =	levelization factor for category n variable operating cost
OC_{Vn} =	category n variable operating cost at 100 percent capacity factor for the initial year of operation (but expressed in "first-year-of-construction" year dollars)
kWh =	annual net kilowatt-hours of power generated at 100 percent capacity factor

All costs are expressed in "first-year-of-construction" year dollars, and the resulting LCOE is also expressed in "first-year-of-construction" year dollars. In this study the first year of plant construction is assumed to be 2007, and the resulting LCOE is expressed in year 2007 dollars.

Capital charge factors and levelization factors are tabulated for levelization periods of ten, twenty, and thirty years. Although their useful life is usually well in excess of thirty years, a twenty-year levelization period is typically used for large energy conversion plants and is the levelization period used in this study.

The technologies modeled in this study were divided into one of two categories for calculating LCOE: investor owned utility (IOU) high risk and IOU low risk. All IGCC cases are considered high risk. The supercritical PC cases are considered low risk. The parameters used are shown in exhibits following the cost exhibits for each case.

4.2 COST OF CO_2 MITIGATION

Carbon dioxide (CO_2) is not currently regulated. However, the possibility exists that carbon limits will be imposed in the future, and this study examines cases that include a reduction in CO_2 emissions. The cost of CO_2 mitigation was calculated in two ways, the cost of CO_2 removed and the cost of CO_2 avoided.

The equation used to calculate the **Cost of CO_2 Captured (or Removed)** is as follows:

$$\text{Removal Cost} = \frac{(\text{LCOE}_{\text{with removal}} - \text{LCOE}_{\text{w/o removal}})}{(CO_2 \text{ Removed})}$$

where

LCOE = levelized cost of electricity ($/MWh)
CO_2 Removed = CO_2 Removed or Captured for each case (tonnes/MWh or tons/MWh)

The equation used to calculate the **Cost of CO_2 Avoided** is as follows:

$$\text{Avoided Cost} = \frac{(\text{LCOE}_{\text{with removal}} - \text{LCOE}_{\text{w/o removal}})}{(\text{Emissions}_{\text{w/o removal}} - \text{Emissions}_{\text{with removal}})}$$

where

LCOE = levelized cost of electricity ($/MWh)
Emissions = CO_2 Emissions for each case (tonnes/MWh or tons/MWh)

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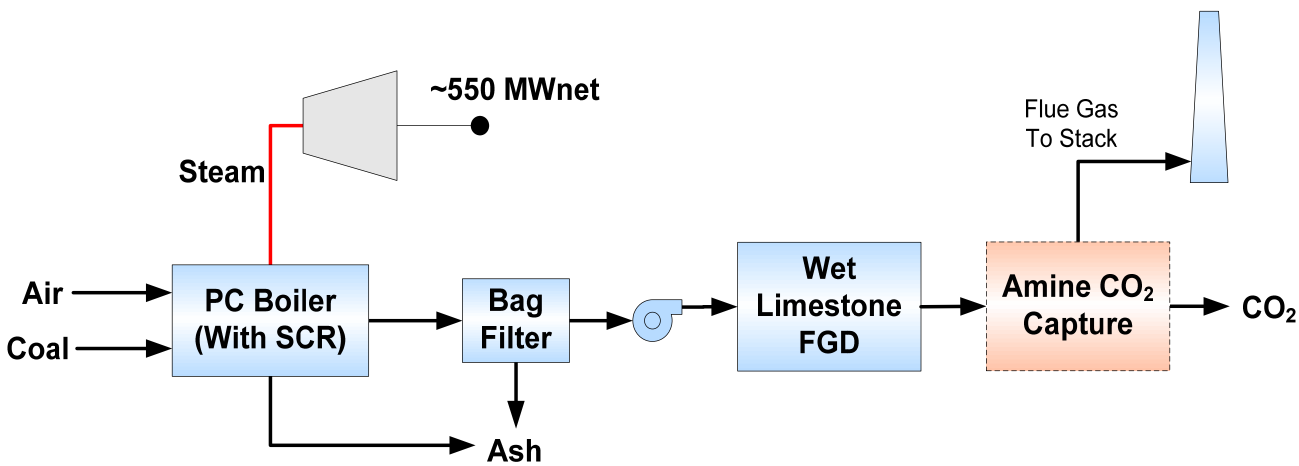
Supercritical Pulverized Coal



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5. SUPERCRITICAL PULVERIZED COAL PLANTS CASES 1 (PC BAU) & 3(PC CR)

Case 1 is configured to produce power from Illinois No. 6 coal without CO_2 capture as presented as Case 11 in the recently completed cost and performance study [Ref. 1]. The plant is based on commercially available supercritical PC technology. The boiler is a dry-bottom, wall-fired unit that employs Low NOx Burners (LNBs) with Overfire Air (OFA) and Selective Catalytic Reduction (SCR) for NOx control, a wet limestone forced oxidation scrubber for SO_2 control, and a fabric filter for particulate control.

5.1 CASE 1 (PC BAU) – SUPERCRITICAL PULVERIZED COAL PLANT - BUSINESS-AS-USUAL (NO CAPTURE)

Exhibit 5-1 is a process block flow diagram for the Case 1 (PC Business-as-usual) overall plant with individual streams identified. Exhibit 5-2 follows the figure with detailed composition and state points for the numbered streams.

The plant produces a net output of 550 MW at a net plant efficiency of 39.1%, on an HHV basis. Overall performance for the entire plant is summarized in Exhibit 5-3 which includes auxiliary power requirements.

5.2 CASE 3 (PC CR) - SUPERCRITICAL PULVERIZED COAL PLANT - CO_2 CAPTURE-READY (NO CAPTURE)

Case 3 (PC Capture-ready) is configured to operate with the same performance characteristics as Case 1 (PC Business-as-usual), but has been designed to be readily converted to capture CO_2 at a later date. *In providing for the future retrofit of CO_2 capture equipment, the plant output capability from increased coal throughput and steam capacity will be oversized and extra space allocated for the retrofit equipment.* The increased capacity and performance capabilities of Case 3 (PC CR) versus Case 1 (PC BAU) are shown in Section 5.3 and are the basis for the increase in capital cost.

The primary rationale for increasing the boiler size and coal flow for Case 3(PC CR) is to have the capability to maintain the 550 MW net output for each plant. Upon retrofit for CO_2 capture, the auxiliary power requirements for the plant more than doubles because of the CO_2 capture process power load and the power requirement for CO_2 compression. This results in the necessity to increase the coal feed and boiler capacities by 43 percent, and the steam system by about 43 percent to accommodate increased steam demand for CO_2 solvent regeneration and increased steam power. Also, the cooling water system load increases by about 90%, due to increased condenser duty and the substantial cooling water demands of the Econamine process.

Exhibit 5-1 Cases 1 (PC BAU) and 3 (PC CR) Process Flow Diagram, Supercritical Unit without CO_2 Capture

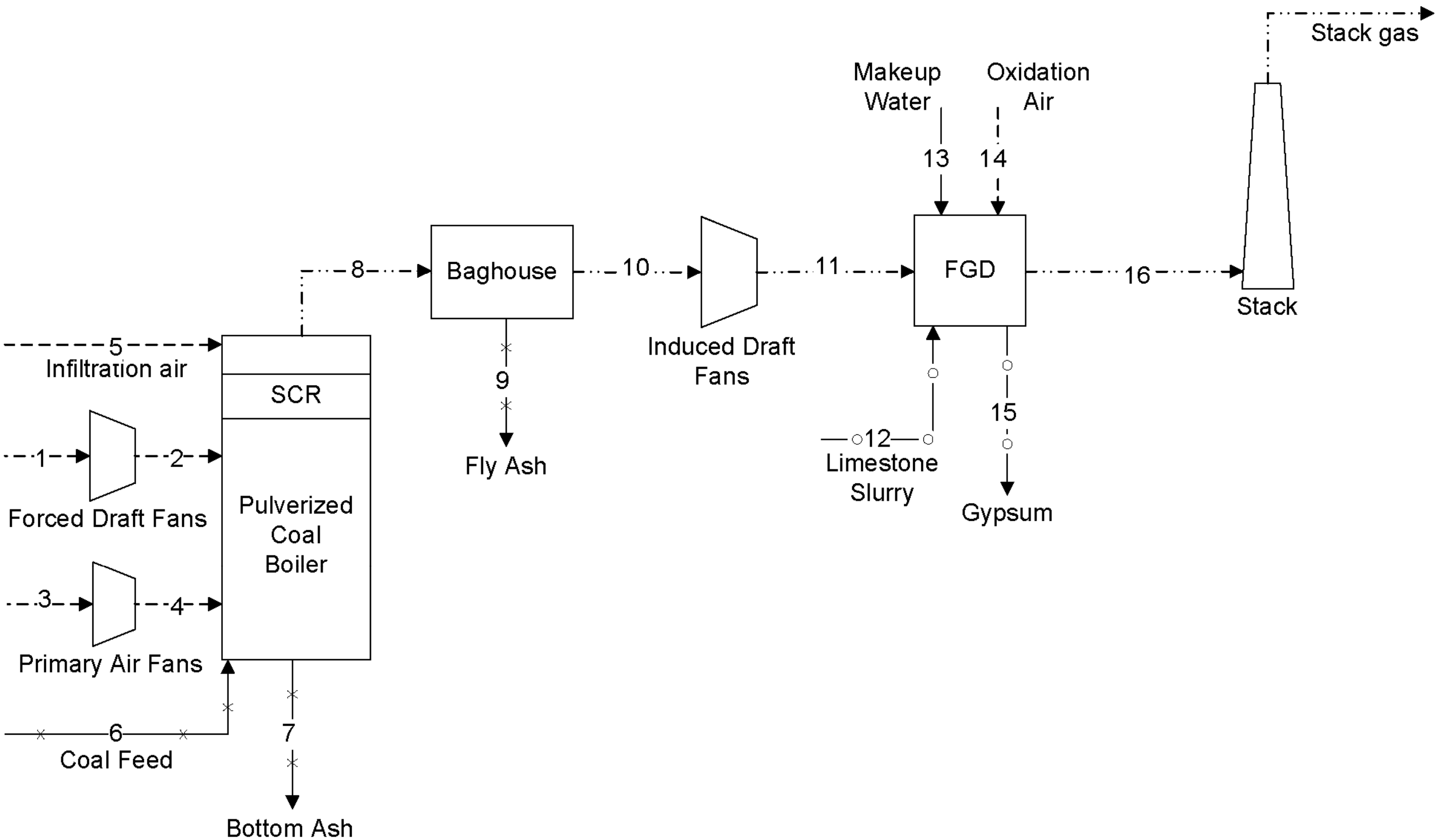


Exhibit 5-2 Cases 1 (PC BAU) and 3 (PC CR) Stream Table, Supercritical PC Plant without CO_2 Capture

	1	2	3	4	5	6	7	8
V-L Mole Fractions								
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000
V-L Flow (lb_{mol}/hr)	107,211	107,211	32,934	32,934	2,477	0	0	150,861
V-L Flow (lb/hr)	3,093,780	3,093,780	950,376	950,376	71,480	0	0	4,487,030
Solids Flowrate	0	0	0	0	0	411,282	7,976	31,905
Temperature (°F)	59	66	59	78	59	59	350	350
Pressure (psia)	14.70	15.25	14.70	16.14	14.70	14.70	14.40	14.40
Enthalpy (BTU/lb)[A]	13.1	14.9	13.1	17.7	13.1	---	---	135.6
Density (lb/ft^3)	0.08	0.08	0.08	0.08	0.08	---	---	0.05
Avg. Molecular Weight	28.86	28.86	28.86	28.86	28.86	---	---	29.74

A - Reference conditions are 32.02 F & 0.089 PSIA

	9	10	11	12	13	14	15	16
V-L Mole Fractions								
Ar	0.0000	0.0087	0.0087	0.0000	0.0000	0.0092	0.0000	0.0080
CO_2	0.0000	0.1450	0.1450	0.0000	0.0000	0.0003	0.0016	0.1326
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0000	0.0870	0.0870	1.0000	1.0000	0.0099	0.9976	0.1669
N_2	0.0000	0.7324	0.7324	0.0000	0.0000	0.7732	0.0008	0.6690
O_2	0.0000	0.0247	0.0247	0.0000	0.0000	0.2074	0.0000	0.0235
SO_2	0.0000	0.0021	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000
Total	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flow (lb_{mol}/hr)	0	150,861	150,861	5,111	24,381	1,705	14,140	167,129
V-L Flow (lb/hr)	0	4,487,030	4,487,030	92,067	439,223	49,200	255,432	4,789,380
Solids Flowrate	31,905	0	0	40,819	0	0	63,529	0
Temperature (°F)	350	350	370	59	60	59	134	134
Pressure (psia)	14.20	14.20	15.26	14.70	14.70	14.70	14.70	14.70
Enthalpy (BTU/lb)[A]	---	136.2	141.5	---	33.3	13.1	87.0	139.1
Density (lb/ft^3)	---	0.05	0.05	62.62	62.59	0.08	36.10	0.07
Avg. Molecular Weight	---	29.74	29.74	18.02	18.02	28.86	18.06	28.66

Exhibit 5-3 Cases 1 (PC BAU) and 3 (PC CR) Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
TOTAL (STEAM TURBINE) POWER, kWe	**580,260**
AUXILIARY LOAD SUMMARY, kWe (Note 1)	
Coal Handling and Conveying	410
Limestone Handling & Reagent Preparation	890
Pulverizers	2,800
Ash Handling	530
Primary Air Fans	1,310
Forced Draft Fans	1,660
Induced Draft Fans	7,130
SCR	50
Baghouse	100
FGD Pumps and Agitators	2,980
Econamine FG Plus Auxiliaries	N/A
CO_2 Compression	N/A
Condensate Pumps	790
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Circulating Water Pumps	4,770
Cooling Tower Fans	2,460
Transformer Loss	1,830
TOTAL AUXILIARIES, kWe	**30,110**
NET POWER, kWe	**550,150**
Net Plant Efficiency (HHV)	39.1%
Net Plant Heat Rate (Btu/kWh)	8,721
CONDENSER COOLING DUTY, 10^6 kJ (10^6 Btu)	2,314 (2,195)
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr) (Note 3)	186,555 (411,282)
Limestone Sorbent Feed, kg/hr (lb/hr)	18,515 (40,819)
Thermal Input, kWt	1,406,161
Makeup Water, m^3/min (gpm)	20.6 (5,441)

Notes:
1. Boiler feed pumps are turbine driven
2. Includes plant control systems, lighting, HVAC, etc.
3. As-received coal heating value: 11,666 Btu/lb (HHV)

5.2.1 Environmental Performance

A summary of the plant air emissions is presented in Exhibit 5-4.

Exhibit 5-4 Cases 1 (PC BAU) and 3 (PC CR) Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% capacity	kg/MWh_{net} (lb/MWh_{net})
SO_2	0.036 (0.085)	1,373 (1,514)	0.335 (0.739)
NO_X	0.030 (0.070)	1,134 (1,250)	0.277 (0.610)
Particulates	0.006 (0.013)	211 (232)	0.051 (0.113)
Hg	$0.492x10^{-6}$ ($1.14x10^{-6}$)	0.0185 (0.0204)	$4.5 x 10^{-6}$ ($10.0x 10^{-6}$)
CO_2	87.5 (203)	3,295,000 (3,632,000)	804 (1,773)

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98%. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since this is very dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NOx emissions are controlled to about 0.5 $lb/10^6$ Btu through the use of low NOx burners (LNBs) and overfire air (OFA). A selective catalytic reduction (SCR) unit then further reduces the NOx concentration by 86% to 0.07 $lb/10^6$ Btu.

Particulate emissions are controlled using a pulse jet fabric filter which operates at an efficiency of 99.8%.

The combination of pollution control technologies used in the PC plants, SCR, fabric filters and flue gas desulfurization (FGD), result in significant co-benefit capture of mercury. This co-benefit capture alone is sufficient to meet current New Source Pollution Standards (NSPS) mercury limits so no activated carbon injection is included in the PC cases.

Overall mass and energy balance information is presented in tabular form in Exhibit 5-5.

Exhibit 5-5 Cases 1 (PC BAU) and 3 (PC CR) Overall Energy and Mass Balance

In			Out		
	Energy Flow, MMBtu/hr	**Mass Flow, lb/hr**		**Energy Flow, MMBtu/hr**	**Mass Flow, lb/hr**
Coal	4,802	411,280	**Stack Gas**	666	4,789,380
Water	18	531,290	**Net Power**	1,909	---
Air	54	4,164,830	**Water**	0	0
Limestone	61	40,820	**Condenser Duty**	2,195	---
	---	---	**Process Losses***	135	---
	---	---	**PM/Ash**	2	39,880
	---	---	**Gypsum**	28	318,960
Total	4,935	5,148,220	**Total**	4,935	5,148,220
Net Plant Efficiency, % HHV (Overall)		39.1%			

* Process Losses are calculated by difference and reflect various boiler, turbine, and other heat and work losses.
Enthalpy reference conditions are 32.02 F & 0.089 psia
Aspen flowsheet balance is within 0.5 percent.

5.2.2 Description of Process Systems

This plant design utilizes a conventional steam turbine for power generation. The single reheat system uses a Rankine cycle with steam conditions of 24.1 MPa/593°C/593°C (3500 psig/1100°F/1100°F).

The following paragraphs describe some of the process sections in more detail. Additional process descriptions are included in Appendix A.

Coal Handing and Preparation

The function of the coal receiving and storage system is to provide the equipment required for unloading, conveying, preparing, and storing the fuel delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the pulverizer inlet. The system is designed to support short-term operation at the 5 percent over pressure/valves wide open (OP/VWO) condition (16 hours) and long-term operation of 90 days or more at the maximum continuous rating (MCR).

The 15 cm x 0 (6" x 0) bituminous Illinois No. 6 coal is delivered to the site by unit trains consisting of 100, 91 tonne (100 ton) rail cars. The unloading is done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The coal from the feeder is discharged onto a belt conveyor (No. 1). The coal is then transferred to a conveyor (No. 2) that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor (No. 3), which transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 8 cm x 0 (3" x 0) by the first of two coal crushers. The coal then enters a second crusher that reduces the coal size to 2.5 cm x 0 (1" x 0). The coal is then transferred by conveyor (No. 4) to the transfer tower. In the transfer tower the coal is routed to the tripper that loads the coal into one of the six boiler silos.

Coal handling system specific technical requirements, however, are functions of the coal burn rate, and for the supercritical plant, they are presented as design conditions in the equipment list for this case. The equipment in the coal handling system is designed to operate at the maximum continuous coal feed rate with a 10% design margin.

Steam Generation

The steam generator in this reference supercritical PC-fired plant is a once-through, wall-fired, balanced draft type unit with water-cooled, dry-bottom furnace. It is assumed for the purposes of this study that the power plant is designed to be operated as a base-load unit but with some consideration for daily or weekly cycling, as can be cost effectively included in the base design. The combustion system is equipped with LNBs and OFA.

Combustion air from the forced draft (FD) fans is heated in Ljungstrom type air preheaters, recovering heat energy from the exhaust gases exiting the boiler. This air is distributed to the burner windbox as secondary air. Air for conveying pulverized coal to the burners is supplied by the primary air (PA) fans. This air is heated in the Ljungstrom type air preheaters to permit drying of the pulverized coal, and a portion of the air from the PA fans bypasses the air preheaters to be used for regulating the outlet coal/air temperature leaving the mills.

The pulverized coal and air mixture flows to the coal nozzles at various elevations of the furnace. The hot combustion products rise to the top of the boiler and pass through the superheater and reheater sections. The gases then pass through the economizer and air preheater. The gases exit the steam generator at this point and flow to the SCR, dust collector, induced draft (ID) fan, FGD system, and stack.

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. The hoppers are of welded steel construction, lined with 23 cm (9 inch) thick refractory. The hopper design incorporates a water-filled seal trough around the upper periphery for cooling and sealing. Water and ash discharged from the hopper pass through the clinker grinder to an ash sluice system for conveyance to hydrobins, where the ash is dewatered before it is transferred to trucks for offsite disposal.

The steam generator is furnished with two vertical-shaft Ljungstrom regenerative type air preheaters. These units are driven by electric motors through gear reducers.

The soot-blowing system utilizes an array of 50 to 150 retractable nozzles and lances that clean the furnace walls and convection surfaces with jets of high-pressure steam. The blowers are sequenced to provide an effective cleaning cycle depending on the coal quality and design of the furnace and convection surfaces. Electric motors drive the soot blowers through their cycles.

Boiler feedwater enters the economizer, recovers heat from the combustion gases exiting the steam generator, and then passes to the water wall circuits enclosing the furnace. After passing through the lower and then the upper furnace circuits in sequence, the fluid passes through the convection enclosure circuits to the primary superheater and then to the secondary superheater. The fluid is mixed in crosstie headers at various locations throughout this path.

The steam then exits the steam generator en route to the high pressure (HP) turbine. Returning cold reheat steam passes through the reheater and then returns to the intermediate pressure (IP) turbine.

<u>Emissions Control</u>

The flue gas exiting the boiler is treated in succession by an SCR unit, a fabric filter, and a wet limestone FGD scrubber.

The average reduction in total Hg emissions developed from EPA's Information Collection Request (ICR) data on U.S. coal-fired boilers using bituminous coal, fabric filters and wet FGD is 98 percent [Ref. 8] The referenced source bounds the co-benefit Hg capture for bituminous coal units employing SCR, a fabric filter and a wet FGD system between 83.8 and 98 percent. Ninety percent was chosen as near the mid-point of this range and it also matches the value used by EPA in their Integrated Planning Model (IPM). Since this combination of pollution control technologies is used in the PC plants, this co-benefit capture alone is sufficient to meet current NSPS mercury limits so no activated carbon injection is included in the PC cases.

The SCR unit operates at a temperature between 260°C and 455°C (500°F to 850°F). An economizer bypass is utilized to maintain the proper reactor operating temperature. The ammonia storage and injection system consists of the unloading facilities, bulk storage tank, vaporizers, dilution air skid, and injection grid. Ammonia slip is limited to 2 ppm at the end of the catalyst life.

Flue gas at 132°C (270°F) enters one of two parallel fabric filters. The ash is collected on the outside of the bags and the dust cake is removed by a pulse of compressed air. The bag material, polyphenylsulfide (PPS) with intrinsic Teflon (PTFE) coating, is rated for a continuous temperature of 180°C (356°F) and a peak temperature of 210°C (410°F). The baghouse efficiency is 99.8%.

Flue gas exits the two ID fans at 146°C (295°F) and enters the FGD system, which consists of a single 100% capacity absorber module. The gas flows upward through the absorber and is contacted in counter-current flow by the limestone slurry injected at multiple elevations. The reagent laden gas passes through several layers of chevron-type mist eliminators before passing to the plant stack.

Air is sparged into the scrubbing slurry in the bottom of the absorber to promote oxidation of calcium sulfite to calcium sulfate (gypsum). Agitators are used to prevent solids settling and to promote the mixture of oxidation air and slurry. Slurry product bleed off (20% solids) and addition of fresh slurry (30% solids) are controlled by monitoring pH and density. The slurry product solids concentration is increased to 90% by hydrocyclones and a horizontal vacuum belt filter. Because local markets for gypsum are extremely variable, no byproduct credit is taken.

Balance of Plant

The balance of plant components consist of the condensate, feedwater, main and reheat steam, extraction steam, ash handling, ducting and stack, waste treatment and miscellaneous systems.

Case 3 (PC CR) Preparation for Retrofit to CO_2 Capture-Capable

The major equipment lists for Cases 1 (PC BAU) and 3 (PC CR) follow in Section 5.3. The Case 3 equipment sizes increase to maintain plant output after the anticipated retrofit with the Econamine FG Plus technology. The system components that experience an increase in design capacity include:

- Coal handling
- Boiler Size
- ID Fans and Baghouse
- Flue Gas Desulfurization
- Cooling Tower
- Ash Handling
- Steam Turbine Generator
- Cooling System

Following retrofit, flue gas exiting the FGD system is directed to the Econamine process. Recovered CO_2 will be compressed to 2,215 psia and dried for delivery off-site. The flue gas exiting the Case 3 (PC CR) FGD system has been cleaned of most sulfur compounds, but will still require a caustic sulfur polisher before the Econamine Absorber to reduce sulfur loading to less than 10 ppmv. The overall steam-production capability is increased in Case 3 (PC CR) to accommodate the increased auxiliary power demand and the steam demand for CO_2 regeneration from the Econamine process. The Steam Turbine Generator output capacity for Case 3 (PC CR) is increased by 15 percent. However, the condenser is the same size as in Case 1 (PC BAU) because a substantial portion of the steam used to generate power is extracted and condensed in the Econamine process before being returned to the feedwater cycle.

5.3 CASE 1 (PC BAU) & 3 (PC CR) - MAJOR EQUIPMENT LIST

Note: Percent increases shown in the equipment lists are changes in design parameter values from the business-as-usual case values to those required for the capture-ready case in anticipation of future CO_2 capture operation performance requirements.

ACCOUNT 1 FUEL AND SORBENT HANDLING

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 3 (PC CR) Design Condition
1A	Bottom Trestle Dumper	NA	181 tonne/hr (200 tph)	2	No Change required for Capture-ready design
1B	Receiving Hoppers	N/A	N/A	2	
2	Feeder	Belt	572 tonne/hr (630 tph)	2	
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	
4	Transfer Tower No. 1	Enclosed	N/A	1	
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	
6	As-Received Coal Sampling System	Two-stage	N/A	1	
7	Conveyor No. 2	Belt conveyor	1,134 tonne/hr (1,250 tph)	1	
8	Reclaim Hopper	N/A	36 tonne (40 ton)	3	54 tonne (60 ton) 43% increase
9	Feeder	Vibratory	154 tonne/hr (170 tph)	3	218 tonne/hr (240 tph) 43% increase
10	Conveyor No. 3	Belt conveyor	308 tonne/hr (340 tph)	1	435 tonne/hr (480 tph) 43% increase
11	Crusher Tower	N/A	N/A	1	N/A
12	Coal Surge Bin w/ Vent Filter	Dual outlet	154 tonne/hr (170 tph)	2	218 tonne/hr (240 tph) 43% increase
13	Crusher	Impactor reduction	8 cm x 0 – 3 cm x 0 (3" x 0 – 1¼" x 0)	2	No Change required for Capture-ready design
14	As-Fired Coal Sampling sys.	Swing hammer	N/A	2	N/A
15	Conveyor No. 4	Belt w/tripper	308 tonne/hr (340 tph)	1	435 tonne/hr (480 tph) 43% increase

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 3 (PC CR) Design Condition
16	Transfer Tower No. 2	Enclosed	N/A	1	N/A
17	Conveyor No. 5	Belt w/tripper	308 tonne/hr (340 tph)	1	435 tonne/hr (480 tph) 43% increase
18	Coal Silo w/ Vent Filter and Slide Gates	Field Erected	726 tonne/hr (800 ton)	3	998 tonne/hr (1,100 ton) 38% increase
19	Limestone Truck Unloading Hopper	N/A	36 tonne (40 ton)	1	No Change required for Capture-ready design
20	Limestone Feeder	Belt	82 tonne/hr (90 tph)	1	109 tonne/hr (120 tph) 33% increase
21	Limestone Conveyor No. 1	Belt	82 tonne/hr (90 tph)	1	109 tonne/hr (120 tph) 33% increase
22	Limestone Reclaim Hopper	N/A	18 tonne/hr (20 tph)	1	No Change required for Capture-ready design
23	Limestone Reclaim Feeder	Belt	64 tonne/hr (70 tph)	1	91 tonne/hr (100 tph) 43% increase
24	Limestone Conveyor No. 2	Belt	64 tonne/hr (70 tph)	1	91 tonne/hr (100 tph) 43% increase
25	Limestone Day Bin	w/ actuator	245 tonne (270 tons)	2	345 tonnes (380 tons) 43% increase

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 3 (PC CR) Design Condition
1	Coal Feeder	Gravimetric	36 tonne/hr (40 tph)	6	45 tonne/hr (50 tph) 25% increase
2	Coal Pulverizer	Ball type or eq.	36 tonne/hr (40 tph)	6	45 tonne/hr (50 tph) 25% increase
3	Limestone Weigh Feeder	Gravimetric	20 tonne/hr (22 tph)	2	29 tonne/hr (32 tph) 45% increase
4	Limestone Ball Mill	Rotary	20 tonne/hr (22 tph)	2	29 tonne/hr (32 tph) 45% increase

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 3 (PC CR) Design Condition
5	Mill Slurry Tank with Agitator	N/A	75,709 liters (20,200 gal)	2	109,778 liters (29,000 gal) 45% increase
6	Mill Recycle Pumps	Horizontal centrifugal	308 lpm @12m H_2O (300 gpm @40ft H_2O)	2	445 lpm @12m H_2O (490 gpm @40ft H_2O) 45% increase
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	82 lpm (90 gpm) per cyclone	2	109 lpm (120 gpm) per cyclone 33% increase
8	Distribution Box	2-way	N/A	2	N/A
9	Limestone Storage Tank with Agitator	Field erected	439,111 liters (116,000 gal)	2	624,593 liters (165,000 gal) 43% increase
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	218 lpm @9m H_2O (240 gpm @30ft H_2O)	2	308 lpm @9m H_2O (340 gpm @30ft H_2O) 43% increase

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 3 (PC CR) Design Condition
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,097,778 liters (290,000 gal)	2	1,570,958 liters (415,000 gal) 43% increase
2	Condensate Pumps	Vert. canned	23,091 lpm @ 213 m H_2O (6,100 gpm @ 700 ft H_2O)	2	No Change required for Capture-ready design
3	Deaerator and Storage Tank	Horiz. spray type	1,828,433 kg/hr (4,031,000 lb/hr), 5 min tank	1	2,614,963 kg/hr (5,765,000 lb/hr), 5 min tank 43% increase
4	Boiler Feed Pump/ Turbine	Barrel type, multi-staged, centrifugal	30,662 lpm @ 3,475 m H_2O (8,100 gpm @11,400 ft H_2O)	2	43,911 lpm @ 3,475 m H_2O (11,600 gpm @11,400 ft H_2O) 43% increase

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 3 (PC CR) Design Condition
5	Startup Boiler Feed Pump, Electric Motor Driven Pumps	Barrel type, multi-staged, centrifugal	9,085 lpm @ 3,475 m H_2O (2,400 gpm @11,400 ft H_2O)	1	13,249 lpm @ 3,475 m H_2O (3,500 gpm @11,400 ft H_2O) 45% increase
6	LP Feedwater Heater 1A/1B	Horiz. U tube	689,461 kg/hr (1,520,000 lb/hr)	2	No Change required for Capture-ready design
7	LP Feedwater Heater 2A/2B	Horiz. U tube	689,461 kg/hr (1,520,000 lb/hr)	2	
8	LP Feedwater Heater 3A/3B	Horiz. U tube	689,461 kg/hr (1,520,000 lb/hr)	2	
9	LP Feedwater Heater 4A/4B	Horiz. U tube	689,461 kg/hr (1,520,000 lb/hr)	2	
10	HP Feedwater Heater 6	Horiz. U tube	1,827,979 kg/hr (4,030,000 lb/hr)	1	2,612,695 kg/hr (5,760,000 lb/hr) 43% increase
11	HP Feedwater Heater 7	Horiz. U tube	1,827,979 kg/hr (4,030,000 lb/hr)	1	2,612,695 kg/hr (5,760,000 lb/hr) 43% increase
12	HP Feedwater Heater 8	Horiz. U tube	1,827,979 kg/hr (4,030,000 lb/hr)	1	2,612,695 kg/hr (5,760,000 lb/hr) 43% increase
13	Auxiliary Boiler	Shop fabricated, water-tube	18,144 kg/hr (40,000 lb/hr) 2.8 MPa (400 psig), 343°C (650°F)	1	No Change required for Capture-ready design
14	Fuel Oil System	No 2 fuel oil for light off	1.135,632 liters (300,000 gal)	1	No Change required for Capture-ready design
15	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 cfm @ 100 psig)	3	
16	Inst. Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	3	
17	Closed Cycle Cooling Heat Exch.	Shell & tube	53MMkJ/hr (50MMBtu/hr) each	2	
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	3	
19	Engine-Driven Fire Pump	Vert. turbine, diesel engine	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	2	

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 3 (PC CR) Design Condition
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	2	
21	Raw Water Pumps	SS, single suction	11,470 lpm @ 43 m H_2O (3,030 gpm @ 140 ft H_2O)	3	25,514 lpm @ 43 m H_2O (6,740 gpm @ 140 ft H_2O)) 120% increase
22	Filtered Water Pumps	SS, single suction	1,438 lpm @ 49 m H_2O (380 gpm @ 160 ft H_2O)	3	2,120 lpm @ 49 m H_2O (560 gpm @ 160 ft H_2O) 48% increase
23	Filtered Water Tank	Vertical, cylindrical	1,377,901 liters (364,000 gal)	1	2,040,353 liters (539,000 gal) 48% increase
24	Makeup Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	606 lpm (130 gpm)	2	1,022 lpm (270 gpm) 110% increase
25	Liquid Waste Treatment System	--	10 years, 25-hour storm	1	No Change required for Capture-ready design

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 3 (PC CR) Design Condition
1	Boiler with superheater, economizer and air heater	Supercritical, drum, wall-fired, low NOx burners, overfire air	1,827,979 kg/hr steam @ 24.1 MPa/593°C/593°C (4,030,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	2,612,695 kg/hr steam @ 24.1 MPa/593°C/593°C (5,760,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F) 43% increase
2	Primary Air Fan	Centrifugal	237,229 kg/hr, 3,245 m^3/min @ 123 cm WG (523,000 lb/hr, 114,600 acfm @ 48 in. WG)	2	339,741 kg/hr, 4,650 m^3/min @ 123 cm WG (749,000 lb/hr, 164,200 acfm @ 48 in. WG) 43% increase
3	FD Fan	Centrifugal	772,015 kg/hr, 10,568 m^3/min @ 47 cm WG (1,702,000 lb/hr, 373,200 acfm @ 19 in. WG)	2	1,105,406 kg/hr, 15,135 m^3/min @ 47 cm WG (2,437,000 lb/hr, 534,500 acfm @ 19 in. WG) 43% increase

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 3 (PC CR) Design Condition
4	ID Fan	Centrifugal	1,119,467 kg/hr, 23,769 m^3/min @ 90 cm WG (2,468,000 lb/hr, 839,400 acfm @ 36 in. WG)	2	1,596,647 kg/hr, 33,898 m^3/min @ 90 cm WG (3,520,000 lb/hr, 1,197,100 acfm @ 36 in. WG) 43% increase
5	SCR Reactor Vessel	Space for spare layer	2,240,749 kg/hr (4,940,000 lb/hr)	2	3,193,294 kg/hr (7,040,000 lb/hr) 43% increase
6	SCR Catalyst	--	--	3	--
7	Dilution Air Blower	Centrifugal	133 m^3/min @ 108 cm WG (4,700 acfm @ 42 in. WG)	3	190 m^3/min @ 108 cm WG (6,700 acfm @ 42 in. WG) 43% increase
8	Ammonia Storage	Horizontal tank	147,632 liter (39,000 gal)	5	208,199 liter (55,000 gal) 43% increase
9	Ammonia Feed Pump	Centrifugal	28 lpm @ 91 m H_2O (7 gpm @ 300 ft H_2O)	3	40 lpm @ 91 m H_2O (11 gpm @ 300 ft H_2O) 43% increase

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 3 (PC CR) Design Condition
1	Bag fabric filter.	Single stage, high-ratio with pulse-jet online cleaning system	1,119,467 kg/hr (2,468,000 lb/hr) 99.8% efficiency	2	1,596,647 kg/hr (3,520,000 lb/hr) 99.8% efficiency 43% increase
2	Absorber Module	Counter-current Open spray	37,662 m^3/min (1,330,000 acfm)	1	52,160 m^3/min (1,842,000 acfm) 38% increase
3	Recirculation Pumps	Horizontal centrifugal	132,490 lpm @ 64 m H_2O (35,000 gpm @ 210 ft H_2O)	6	181,701 lpm @ 64 m H_2O (48,000 gpm @ 210 ft H_2O) 38% increase
4	Bleed Pumps	Horizontal centrifugal	4,013 lpm (1,060 gpm) at 20 wt% solids	3	5,716 lpm (1,510 gpm) at 20 wt% solids 43% increase

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 3 (PC CR) Design Condition
5	Oxidation Air Blowers	Centrifugal	168 m^3/min @ 0.3 MPa (5,930 acfm @ 42 psia)	3	250 m^3/min @ 0.3 MPa (8,820 acfm @ 42 psia) 50% increase
6	Agitators	Side entering	50 hp	6	No Change required for Capture-ready design
7	Dewatering Hydrocyclones	Radial assembly (5 units EA)	1,022 lpm (270 gpm) per cyclone	2	1,438 lpm (380 gpm) per cyclone 43% increase
8	Vacuum Belt Filter	Horizontal belt	32 tonne/hr (35 tph) of 50 wt % slurry	3	45 tonne/hr (50 tph) of 50 wt % slurry 43% increase
9	Filtrate Water Return Pumps	Horizontal centrifugal	606 lpm @ 12 m H_2O (160 gpm @ 40 ft H_2O)	2	871 lpm @ 12 m H_2O (230 gpm @ 40 ft H_2O) 43% increase
10	Filtrate Water Return Storage Tank	Vertical, lined	416,399 lpm (110,000 gal)	1	567,816 lpm (150,000 gal) 33% increase
11	Process Makeup Water Pumps	Horizontal centrifugal	2,271 lpm @ 21 m H_2O (600 gpm @ 70 ft H_2O)	2	3,255 lpm @ 21 m H_2O (860 gpm @ 70 ft H_2O) 33% increase

ACCOUNT 5C CARBON DIOXIDE RECOVERY

N/A

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

N/A

ACCOUNT 7 HRSG, DUCTING & STACK

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 3 (PC CR) Design Condition
1	Stack	Reinforced concrete w/ FRP liner	152 m (500 ft) high x 5.8 m (19 ft) diameter	1	No Change required for Capture-ready design

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 3 (PC CR) Design Condition
1	Steam Turbine	Commercially available advanced steam turbine	610 MW, 24.1 MPa/ 593°C/593°C (3500 psig/ 1100°F/1100°F)	1	700 MW, 24.1 MPa/593°C/593°C (3500 psig/1100°F /1100°F) 15% increase
2	Steam Turbine Generator	Hydrogen cooled, static excitation	680 MVA @ 0.9 p.f., 24 kV, 60 Hz	1	780 MVA @ 0.9 p.f., 24 kV, 60 Hz 15% increase
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,541 MMkJ/hr (2,410 MMBtu/hr), Inlet water temperature 16ºC (60ºF), Water temperature rise 11ºC (20ºF)	1	No Change required for Capture-ready design

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Case 1 Qty	Case 3 (PC CR) Design Condition	Case 3 Qty
1	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 2,657 MMkJ/hr (2,520 MMBtu/hr) heat load	1	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 5,914 MMkJ/hr (5,610 MMBtu/hr) heat load 120% increase	1
2	Circ. Water Pumps	Vertical, wet pit	476,966 lpm @ 30.5 m WG (126,000 gpm @ 100 ft WG)	3	613,241 lpm @ 30.5 m WG (162,000 gpm @ 100 ft WG) 157% increase	6

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 3 (PC CR) Design Condition
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	--
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	--
3	Clinker Grinder	--	3.6 tonnes/hr (4 tph)	2	5.4 tonne/hr (6 tph) 50% increase
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	--
5	Hydroejectors	--	--	12	--
6	Economizer/Pyrites Transfer Tank	--	--	1	--
7	Ash Sluice Pumps	Vertical, wet pit	151 lpm @ 17 m H_2O (40 gpm @ 56 ft H_2O)	2	227 lpm @ 17 m H_2O (60 gpm @ 56 ft H_2O) 50% increase
8	Ash Seal Water Pumps	Vertical, wet pit	7,571 lpm @ 9 m H_2O (2,000 gpm @ 28 ft H_2O)	2	No Change required for Capture-ready design
9	Hydrobins	--	151 lpm (40 gpm)	2	227 lpm (60 gpm) 50% increase
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	--
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	--
12	Air Blower	--	14 m^3/min @ 0.2 MPa (510 scfm@ 24 psi)	2	21 m^3/min @ 0.2 MPa (730 scfm@ 24 psi) 43% increase
13	Fly Ash Silo	Reinforced concrete	500 tonnes (1,100 ton)	2	680 tonnes (1,500 tons) 36% increase
14	Slide Gate Valves	--	--	2	--
15	Unloader	--	91 tonnes/hr (100 tph)	1	127 tonne/hr (140 tph) 40% increase
16	Telescoping Unloading Chute	--	--	1	--

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 3 (PC CR) Design Condition
1	STG Transformer	Oil-filled	24 kV/345 kV, 640 MVA, 3-ph, 60 Hz	1	No Change required for Capture-ready design
2	Auxiliary Transformer	Oil-filled	24 kV/ 4.16 kV, 33 MVA, 3-ph, 60 Hz	2	24 kV/ 4.16 kV, 128 MVA, 3-ph, 60 Hz
3	Low Voltage Transformer	Dry ventilated	4.16 kV /480 V, 5 MVA, 3-ph, 60 Hz	2	4.16 kV /480 V, 19 MVA, 3-ph, 60 Hz
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	No Change required for Capture-ready design
5	Medium Voltage Switchgear	Metal Clad	4.16 kV, 3-ph, 60 Hz	2	
6	Low Voltage Switchgear	Metal Enclosed	480 kV, 3-ph, 60 Hz	2	
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 3 (PC CR) Design Condition
1	DCS - Main Control	Monitor/keyboard; Operator printer – laser color; Eng. Printer – laser black & white	Operator Stations/Printers and Engineering Stations/Printers	1	No Change required for Capture-ready design
2	DCS - Processor	Microprocessor with Redundant Input/Output	N/A	1	
4	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	

5.4 CASE 1 (PC BUSINESS-AS-USUAL) - COST ESTIMATING RESULTS

Exhibit 5-6 through Exhibit 5-9 show the capital and operating costs for this plant. Capital cost estimating methodology is explained in Section 4. The detailed breakdowns of the capital cost estimates for each case are included in Appendix B.

Exhibit 5-6 Case 1 (PC BAU) Total Plant Costs

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST SUMMARY

Case: Case 1 - "Business As Usual" SuperCritical PC w/o CO2 Capture
Plant Size: 550.2 MW,net **Estimate Type:** Conceptual Cost Base Jan 2007 $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL HANDLING SYSTEM	15,481	4,183	9,376		$29,040	2,602		4,746	$36,389	66
2	COAL PREP & FEED SYSTEMS	10,405	603	2,638		$13,646	1,196		2,226	$17,068	31
3	FEEDWATER & MISC. BOP SYSTEMS	40,107		18,856		$58,963	5,369		10,462	$74,795	136
4	PC BOILER & ACCESSORIES										
4.1	PC Boiler & Accessories	148,766		83,888		$232,654	22,535		25,519	$280,708	510
4.2	SCR (w/4.1)										
4.3	Open										
4.4-4.9	Secondary Air System										
	Subtotal 4	148,766		83,888		$232,654	22,535		25,519	$280,708	510
5A	FLUE GAS CLEANUP	78,075		26,700		$104,775	9,955		11,473	$126,203	229
5B	CO2 REMOVAL & COMPRESSION										
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	N/A		N/A							
6.2-6.9	Combustion Turbine Accessories										
	Subtotal 6										
7	HRSG, DUCTING & STACK										
7.1	Heat Recovery Steam Generator	N/A		N/A							
7.2-7.9	Ductwork, Stack	16,653	959	11,402		$29,013	2,656		4,132	$35,801	65
	Subtotal 7	16,653	959	11,402		$29,013	2,656		4,132	$35,801	65
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	48,728		6,532		$55,260	5,291		6,055	$66,606	121
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	23,094	1,042	12,656		$36,792	3,213		5,619	$45,625	83
	Subtotal 8	71,822	1,042	19,188		$92,052	8,504		11,675	$112,231	204
9	COOLING WATER SYSTEM	11,816	6,553	11,613		$29,981	2,799		4,503	$37,283	68
10	ASH/SPENT SORBENT HANDLING SYS	4,232	133	5,628		$9,992	951		1,126	$12,069	22
11	ACCESSORY ELECTRIC PLANT	15,533	5,832	17,190		$38,556	3,411		5,217	$47,183	86
12	INSTRUMENTATION & CONTROL	8,069		8,480		$16,549	1,515		2,222	$20,285	37
13	IMPROVEMENTS TO SITE	2,827	1,625	5,741		$10,194	1,001		2,239	$13,434	24
14	BUILDINGS & STRUCTURES		21,560	20,672		$42,232	3,805		6,906	$52,943	96
	TOTAL COST	**$423,786**	**$42,490**	**$241,370**		**$707,646**	**$66,300**		**$92,445**	**$866,391**	**$1,575**

Exhibit 5-7 Case 1 (PC BAU) Operating Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base Jan	2007
Case 1 - "Business As Usual" SuperCritical PC w/o CO2 Capture					Heat Rate-net(Btu/kWh):	8,721
Plant Output:	CO_2 (tpd): ---		H_2 (mmscfd):		MWe-net:	550.2
					Capacity Factor: (%):	85.0
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Plant			
Skilled Operator	2.0		2.0			
Operator	9.0		9.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	2.0		2.0			
TOTAL-O.J.'s	14.0		14.0			
					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost(calc'd)					$5,261,256	9.56
Maintenance Labor Cost(calc'd)					$5,818,574	10.58
Administrative & Support Labor(calc'd)					$2,769,958	5.03
TOTAL FIXED OPERATING COSTS					**$13,849,788**	**25.17**
VARIABLE OPERATING COSTS						$/kWh-net
Maintenance Material Cost(calc'd)					$8,725,262	0.0021
Consumables	Consumption		Unit	Initial		
	Initial	/Day	Cost	Cost		
Water(/1000 gallons)		3,918	1.03		$1,251,873	0.0003
Chemicals						
MU & WT Chem.(lbs)	132,743	18,963	0.16	$21,876	$969,578	0.0002
Carbon (Mercury Removal) (lb.)			1.00			
COS Catalyst (lb)			2308.40			
Limestone (ton)	3,429	489.8	20.60	$70,633	$3,130,564	0.0008
MEA Solvent (ton)			2142.40			
NaOH (tons)			412.96			
H2SO4 (tons)			132.15			
Corrosion Inhibitor						
Ammonia (28% NH3) ton	517	73.8	123.60	$63,883	$2,831,382	0.0007
Activated Carbon(lb)			1.00			
Subtotal Chemicals				**$156,392**	**$6,931,524**	**0.0017**
Other						
Supplemental Fuel(MBtu)			6.75			
SCR Catalyst Replacement	w/equip.	0.4	5500.00		$747,563	0.0002
Emission Penalties						
Subtotal Other					**$747,563**	**0.0002**
Waste Disposal						
Spent Mercury Catalyst (lb.)			0.40			
Flyash (ton)		96	15.45		$458,782	0.0001
Bottom Ash(ton)		383	15.45		$1,835,187	0.0004
Subtotal Solid Waste Disposal					**$2,293,969**	**0.0006**
By-products & Emissions						
Gypsum (tons)		777				
Sulfur(tons)			-25.00			
Subtotal By-Products						
TOTAL VARIABLE OPERATING COSTS				**$156,392**	**$19,950,191**	**0.0049**
FUEL (tons)	148,062	4,935	42.11	**$6,234,882**	**$64,479,076**	**0.0157**

Exhibit 5-8 Case 1 (PC BAU) Capital Investment Requirement Summary

TITLE/DEFINITION

Case: **Case 1 - "Business As Usual" SuperCritical PC w/o CO2 Capture**

Plant Size:	550.2	(MW,net)	HeatRate:	8,721	(Btu/kWh)
Primary/Secondary Fuel(type):	Illinois #6		Cost:	1.80	($/MMBtu)
Design/Construction:	3	(years)	BookLife:	30	(years)
TPC(Plant Cost) Year:	2007	Jan			
Capacity Factor:	85	(%)	CO2 Removed:	---	(TPD)

CAPITAL INVESTMENT	**$x1000**	**$/kW**
Process Capital & Facilities	707,646	1286.3
Engineering(incl.C.M.,H.O.& Fee)	66,300	120.5
Process Contingency		
Project Contingency	92,445	168.0
TOTAL PLANT COST(TPC)	$866,391	1574.8

OPERATING & MAINTENANCE COSTS (2007 Dollars)	**$x1000**	**$/kW-yr**
Operating Labor	5,261	9.6
Maintenance Labor	5,819	10.6
Maintenance Material	8,725	15.9
Administrative & Support Labor	2,770	5.0
TOTAL OPERATION & MAINTENANCE	$22,575	41.0
FIXED O & M	$13,987	25.4
VARIABLE O & M	$8,589	15.6

CONSUMABLE OPERATING COSTS, less Fuel (2007 Dollars)	**$x1000**	**¢/kWh**
Water	1,252	0.03
Chemicals	6,932	0.17
Other Consumables	748	0.02
Waste Disposal	2,294	0.06
TOTAL CONSUMABLE OPERATING COSTS	$11,225	0.27
BY-PRODUCT CREDITS		
FUEL COST (2007 Dollars)	$64,479	1.57

PRODUCTION COST SUMMARY	**LF**	**Levelized Costs ¢/kWh**
Fixed O & M	1.162	0.40
Variable O & M	1.162	0.24
Consumables	1.162	0.32
By-product Credit	1.162	
Fuel	1.209	1.90
TOTAL PRODUCTION COST		2.86
2007 CARRYING CHARGES (Capital)		3.47
CCF for a 20-Year Levelization Period - IOU - Lower-Risk	**16.4**	
20 YEAR LEVELIZED BUSBAR COST OF POWER		6.33

Exhibit 5-9 Case 1 (PC BAU) Estimate Basis and Financial Criteria Summary

GENERAL DATA/CHARACTERISTICS

Case Title:	**Case 1 - "Business As Usual" SuperCritical PC w/o CO2 Capture**		
Unit Size:/Plant Size:		550.2	MW,net
Location:		Midwestern, USA	
Fuel: Primary/Secondary	Illinois #6	11,666	Btu/lb
Energy From Primary/Secondary Fuels		8,721	Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):		85	%
Capital Cost Year Dollars (Reference Year Dollars):		2007	Jan
Delivered Cost of Primary/Secondary Fuel		1.80	$/MMBtu
Design/Construction Period:		3	years
Plant Startup Date (1st. Year Dollars):		2010	
Financial Parameter/Risk Level		IOU Low Risk	

FINANCIAL CRITERIA

Project Book Life:		30	years
Book Salvage Value:			%
Project Tax Life:		20	years
Tax Depreciation Method:		20 years, 150% declining balance	
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			%
Economic Basis:		20th Year Current Dollars	

Capital Structure		% of Total	Cost(%)
	Common Equity	50.00	12.00
	Preferred Stock		
	Debt	50.00	9.00
Weighted Cost of Capital:(after tax)		8.79 %	

Nominal Escalation		2010 - 2030	
	General	1.87	% per year
	Coal Price	2.35	% per year
	Secondary Fuel:	1.96	% per year

5.5 CASE 3 (PC CAPTURE-READY) - COST ESTIMATING RESULTS

Exhibit 5-10 and Exhibit 5-13 show the capital and operating costs for this plant. Capital cost estimating methodology is explained in Section 4. The detailed breakdowns of the capital cost estimates for each case are included in Appendix B.

Note: Costs impacted by changes in design parameter values from the business-as-usual case values to the capture-ready case values in anticipation of future CO_2 capture operation performance requirements are highlighted in the following capture-ready case cost exhibits.

Exhibit 5-10 Case 3 (PC CR) Total Plant Costs

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST SUMMARY

Case: Case 3 - 1x550 MWnet Super-Critical PC w CO2 Capture Ready
Plant Size: 550.2 MW,net **Estimate Type:** Conceptual Cost Base Jan 2007 $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	**COAL HANDLING SYSTEM**	**19,316**	**5,215**	**11,691**		**$36,222**	**3,246**		**5,920**	**$45,389**	**83**
2	**COAL PREP & FEED SYSTEMS**	**13,126**	**758**	**3,326**		**$17,210**	**1,508**		**2,808**	**$21,527**	**39**
3	**FEEDWATER & MISC. BOP SYSTEMS**	**54,477**		**25,648**		**$80,126**	**7,317**		**14,428**	**$101,870**	**185**
4	PC BOILER & ACCESSORIES										
4.1	**PC Boiler & Accessories**	**190,969**		**107,678**		**$298,647**	**28,927**		**32,757**	**$360,332**	**655**
4.2	SCR (w/4.1)										
4.3	Open										
4.4-4.9	Secondary Air System										
	Subtotal 4	**190,969**		**107,678**		**$298,647**	**28,927**		**32,757**	**$360,332**	**655**
5A	**FLUE GAS CLEANUP**	**102,323**		**35,151**		**$137,474**	**13,063**		**15,054**	**$165,591**	**301**
5B	CO2 REMOVAL & COMPRESSION										
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	N/A		N/A							
6.2-6.9	Combustion Turbine Accessories										
	Subtotal 6										
7	HRSG, DUCTING & STACK										
7.1	Heat Recovery Steam Generator	N/A		N/A							
7.2-7.9	**Ductwork, Stack**	**17,889**	**981**	**12,221**		**$31,091**	**2,840**		**4,457**	**$38,388**	**70**
	Subtotal 7	**17,889**	**981**	**12,221**		**$31,091**	**2,840**		**4,457**	**$38,388**	**70**
8	STEAM TURBINE GENERATOR										
8.1	**Steam TG & Accessories**	**53,763**		**7,192**		**$60,956**	**5,836**		**6,679**	**$73,471**	**134**
8.2-8.9	**Turbine Plant Auxiliaries & Steam Piping**	**26,923**	**1,148**	**14,942**		**$43,013**	**3,724**		**6,698**	**$53,436**	**97**
	Subtotal 8	**80,687**	**1,148**	**22,134**		**$103,969**	**9,561**		**13,377**	**$126,907**	**231**
9	**COOLING WATER SYSTEM**	**21,479**	**11,200**	**19,881**		**$52,559**	**4,900**		**7,796**	**$65,255**	**119**
10	**ASH/SPENT SORBENT HANDLING SYS**	**5,154**	**162**	**6,854**		**$12,169**	**1,158**		**1,371**	**$14,699**	**27**
11	**ACCESSORY ELECTRIC PLANT**	**20,196**	**10,240**	**29,287**		**$59,723**	**5,331**		**8,288**	**$73,343**	**133**
12	**INSTRUMENTATION & CONTROL**	**9,195**		**9,662**		**$18,857**	**1,726**	**943**	**2,648**	**$24,174**	**44**
13	**IMPROVEMENTS TO SITE**	**3,162**	**1,818**	**6,421**		**$11,402**	**1,120**		**2,504**	**$15,026**	**27**
14	**BUILDINGS & STRUCTURES**		**23,760**	**22,735**		**$46,495**	**4,189**		**7,603**	**$58,287**	**106**
	TOTAL COST	**$537,973**	**$55,282**	**$312,690**		**$905,945**	**$84,886**	**$943**	**$119,012**	**$1,110,786**	**$2,019**

Exhibit 5-11 Case 3 (PC CR) Operating Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base Jan	2007
Case 3 - 1x550 MWnet Super-Critical PC w CO2 Capture Ready					Heat Rate-net(Btu/kWh):	8,721
Plant Output:	CO_2 (tpd): ---		H_2 (mmscfd):		MWe-net:	550.2
					Capacity Factor: (%):	85.0
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Plant			
Skilled Operator	2.0		2.0			
Operator	9.0		9.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	2.0		2.0			
TOTAL-O.J.'s	14.0		14.0			
					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost(calc'd)					$5,261,256	9.56
Maintenance Labor Cost(calc'd)					$5,816,841	10.57
Administrative & Support Labor(calc'd)					$2,769,524	5.03
TOTAL FIXED OPERATING COSTS					**$13,847,621**	**25.17**
VARIABLE OPERATING COSTS						$/kWh-net
Maintenance Material Cost(calc'd)					$8,725,262	0.0021
Consumables	Consumption		Unit	Initial		
	Initial	/Day	Cost	Cost		
Water(/1000 gallons)		3,918	1.03		$1,251,873	0.0003
Chemicals						
MU & WT Chem.(lbs)	132,743	18,963	0.16	$21,876	$969,578	0.0002
Carbon (Mercury Removal) (lb.)			1.00			
COS Catalyst (lb)			2308.40			
Limestone (ton)	3,429	489.8	20.60	$70,633	$3,130,564	0.0008
MEA Solvent (ton)			2142.40			
NaOH (tons)			412.96			
H2SO4 (tons)			132.15			
Corrosion Inhibitor						
Ammonia (28% NH3) ton	517	73.8	123.60	$63,883	$2,831,382	0.0007
Activated Carbon(lb)			1.00			
Subtotal Chemicals				$156,392	$6,931,524	0.0017
Other						
Supplemental Fuel(MBtu)			6.75			
SCR Catalyst Replacement	w/equip.	0.4	5500.00		$747,563	0.0002
Emission Penalties						
Subtotal Other					$747,563	0.0002
Waste Disposal						
Spent Mercury Catalyst (lb.)			0.40			
Flyash (ton)		96	15.45		$458,782	0.0001
Bottom Ash(ton)		383	15.45		$1,835,187	0.0004
Subtotal Solid Waste Disposal					$2,293,969	0.0006
By-products & Emissions						
Gypsum (tons)		777				
Sulfur(tons)			-25.00			
Subtotal By-Products						
TOTAL VARIABLE OPERATING COSTS				**$156,392**	**$19,950,191**	**0.0049**
FUEL (tons)	148,062	4,935	42.11	$6,234,882	**$64,479,076**	**0.0157**

Exhibit 5-12 Case 3 (PC CR) Capital Investment Requirement Summary

TITLE/DEFINITION				
Case: Case 3 - 1x550 MWnet Super-Critical PC w CO2 Capture Ready				
Plant Size:	550.2 (MW,net)	HeatRate:	8,721 (Btu/kWh)	
Primary/Secondary Fuel(type):	Illinois #6	Cost:	1.80 ($/MMBtu)	
Design/Construction:	3 (years)	BookLife:	30 (years)	
TPC(Plant Cost) Year:	2007 Jan			
Capacity Factor:	85 (%)	CO2 Removed:	--- (TPD)	
CAPITAL INVESTMENT		**$x1000**		**$/kW**
Process Capital & Facilities		**905,945**		**1646.7**
Engineering(incl.C.M.,H.O.& Fee)		**84,886**		**154.3**
Process Contingency		**943**		**1.7**
Project Contingency		**119,012**		**216.3**
TOTAL PLANT COST(TPC)		**$1,110,786**		**2019.1**
OPERATING & MAINTENANCE COSTS (2007 Dollars)		**$x1000**		**$/kW-yr**
Operating Labor		5,261		9.6
Maintenance Labor		5,817		10.6
Maintenance Material		8,725		15.9
Administrative & Support Labor		2,770		5.0
TOTAL OPERATION & MAINTENANCE		$22,573		41.0
FIXED O & M		$13,987		25.4
VARIABLE O & M		$8,586		15.6
CONSUMABLE OPERATING COSTS, less Fuel (2007 Dollars)		**$x1000**		**¢/kWh**
Water		1,252		0.03
Chemicals		6,932		0.17
Other Consumables		748		0.02
Waste Disposal		2,294		0.06
TOTAL CONSUMABLE OPERATING COSTS		$11,225		0.27
BY-PRODUCT CREDITS				
FUEL COST (2007 Dollars)		$64,479		1.57

PRODUCTION COST SUMMARY	**LF**	**Levelized Costs ¢/kWh**
Fixed O & M	1.162	0.40
Variable O & M	1.162	0.24
Consumables	1.162	0.32
By-product Credit	1.162	
Fuel	1.209	1.90
TOTAL PRODUCTION COST		2.86
2007 CARRYING CHARGES (Capital)		**4.45**
CCF for a 20-Year Levelization Period - IOU - Lower-Risk	**16.4**	
20 YEAR LEVELIZED BUSBAR COST OF POWER		**7.31**

Exhibit 5-13 Case 3 (PC CR) Estimate Basis and Financial Criteria Summary

GENERAL DATA/CHARACTERISTICS

Case Title:	Case 3 - "Capture Ready" SuperCritical PC w/o CO2 Capture		
Unit Size:/Plant Size:		**550.2**	MW,net
Location:		Midwestern, USA	
Fuel: Primary/Secondary	Illinois #6	11,666	Btu/lb
Energy From Primary/Secondary Fuels		**8,721**	Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):		85	%
Capital Cost Year Dollars (Reference Year Dollars):		2007	Jan
Delivered Cost of Primary/Secondary Fuel		1.80	$/MMBtu
Design/Construction Period:		3	years
Plant Startup Date (1st. Year Dollars):		2010	
Financial Parameter/Risk Level		IOU Low Risk	

FINANCIAL CRITERIA

Project Book Life:		30	years	
Book Salvage Value:			%	
Project Tax Life:		20	years	
Tax Depreciation Method:		20 years, 150% declining balance		
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			%	
Economic Basis:		20th Year Current Dollars		
Capital Structure		% of Total		Cost(%)
	Common Equity	50.00		12.00
	Preferred Stock			
	Debt	50.00		9.00
Weighted Cost of Capital:(after tax)		8.79	%	
		2010 - 2030		
Nominal Escalation	General	1.87	% per year	
	Coal Price	2.35	% per year	
	Secondary Fuel:	1.96	% per year	

5.6 SUPERCRITICAL PC PLANTS CASES 1 (PC BAU) AND 3 (PC CR) SUMMARY

Cases 1 and 3 are configured to operate with the same performance and efficiency. Case 3 shows an increase in capital costs which reflects the design modifications required to ready the plant for CO_2 Capture. The Case 3 design includes an increase in equipment capacity throughout, including coal feed, boiler capacity, flue gas handling, cooling water, and steam plant. As shown in Exhibit 5-14, the plant cost increased from $1,575/kW to $2,019/kW. Since the O&M costs do not change, the Cost of Electricity increase from 6.33 ¢/kWh to 7.31 ¢/kWh is attributed to increased capital cost.

Exhibit 5-14 Cases 1 (PC BAU) and 3 (PC CR) Performance and Economic Summary

	Case 1 (PC BAU)	**Case 3 (PC CR)**
Gross Power Output, MW_e	580.3	580.3
Net Power Output, MW_e	550.2	550.2
Net Plant Efficiency (HHV)	39.1%	39.1%
Net Plant Heat Rate (HHV), kJ/kWh (Btu/kWh)	9,201 (8,721)	9,201 (8,721)
Total Plant Cost (TPC)[1], 1000$	$866,391	$1,110,786
Total Plant Cost[1], $/kW	$1,575	$2,019
Incremental TPC[1], $/kW	N/A	$444
Total Levelized COE[1,2,3], ¢/kWh	6.33	7.31
Incremental Levelized COE[1,2,3], ¢/kWh	N/A	0.98
Total CO_2 Emitted,kg/MWh_{net} (lb/MWh_{net})	804 (1,773)	804 (1,773)
Cost of CO_2 Captured[1,2,3], $/tonne ($/ton)	N/A	N/A
Cost of CO_2 Avoided[1,2,3], $/tonne ($/ton)	N/A	N/A

Note:
Costs in 2007 Dollars
"Incremental costs" are compared to Case 1—"PC Business-as-Usual"
[1]Transportation, Storage, and Monitoring of CO_2 not included
[2]85% Capacity Factor
[3]20 year levelization period

6. SUPERCRITICAL PULVERIZED COAL PLANTS RETROFITTED FOR CO_2 CAPTURE

6.1 CASE 5 (PC CR RETROFIT) - PC CO_2 CAPTURE-READY RETROFIT

Case 5 (PC CR retrofit) is configured to produce power from Illinois No. 6 coal with CO_2 capture as a performance replication of Case 12 in the recently completed cost and performance study [Ref. 1]. The plant design is based on retrofitting Case 3 (PC CR) to capture 90% of the CO_2 in the flue gas fed to the Carbon Dioxide Recovery unit (CDR). Plant process equipment which is included in the retrofit is described in the following paragraphs. The Equipment List (Section 6.2) is a side-by-side comparison of Case 3 (PC CR) and Case 5 (PC CR retrofit).

The plant is based on commercially available supercritical PC technology. Flue gas exiting the FGD system is directed to the Econamine process where CO_2 is absorbed in an MEA-based solvent. A booster blower is required to overcome the process pressure drop. CO_2 removed in the Econamine process is dried and compressed to a supercritical condition for subsequent pipeline transport. The CO_2 is delivered to the plant fence line at 15.3 MPa (2,215 psia). The Econamine process imposes a significant auxiliary power load on the system. This is primarily because the low partial pressure of CO_2 in the flue gas from a PC plant requires a chemical absorption process rather than physical absorption. For this chemical absorption process, the regeneration requirements are much more energy intensive, requiring substantial steam quantities (~1,530 Btu/lb CO_2 captured) and increased demand on the cooling system. The removal process also increases the raw water usage by approximately 90%. To maintain a net output of approximately 550 MW, the gross output had to increase to 663 MW (from 580 MW). Unlike the IGCC cases where gross output was fixed by the available size of the combustion turbines, the PC cases utilize steam turbines which can be custom made to any desired output making it possible to maintain a constant net output.

Exhibit 6-1 is a block flow diagram for the overall plant with individual streams identified. Exhibit 6-2 follows the figure with detailed composition and state points for the numbered streams.

Overall performance for the entire plant is summarized in Exhibit 6-3 which includes auxiliary power requirements.

Exhibit 6-1 Case 5 (PC CR Retrofit) Process Flow Diagram, Supercritical PC with Retrofitted CO_2 Capture

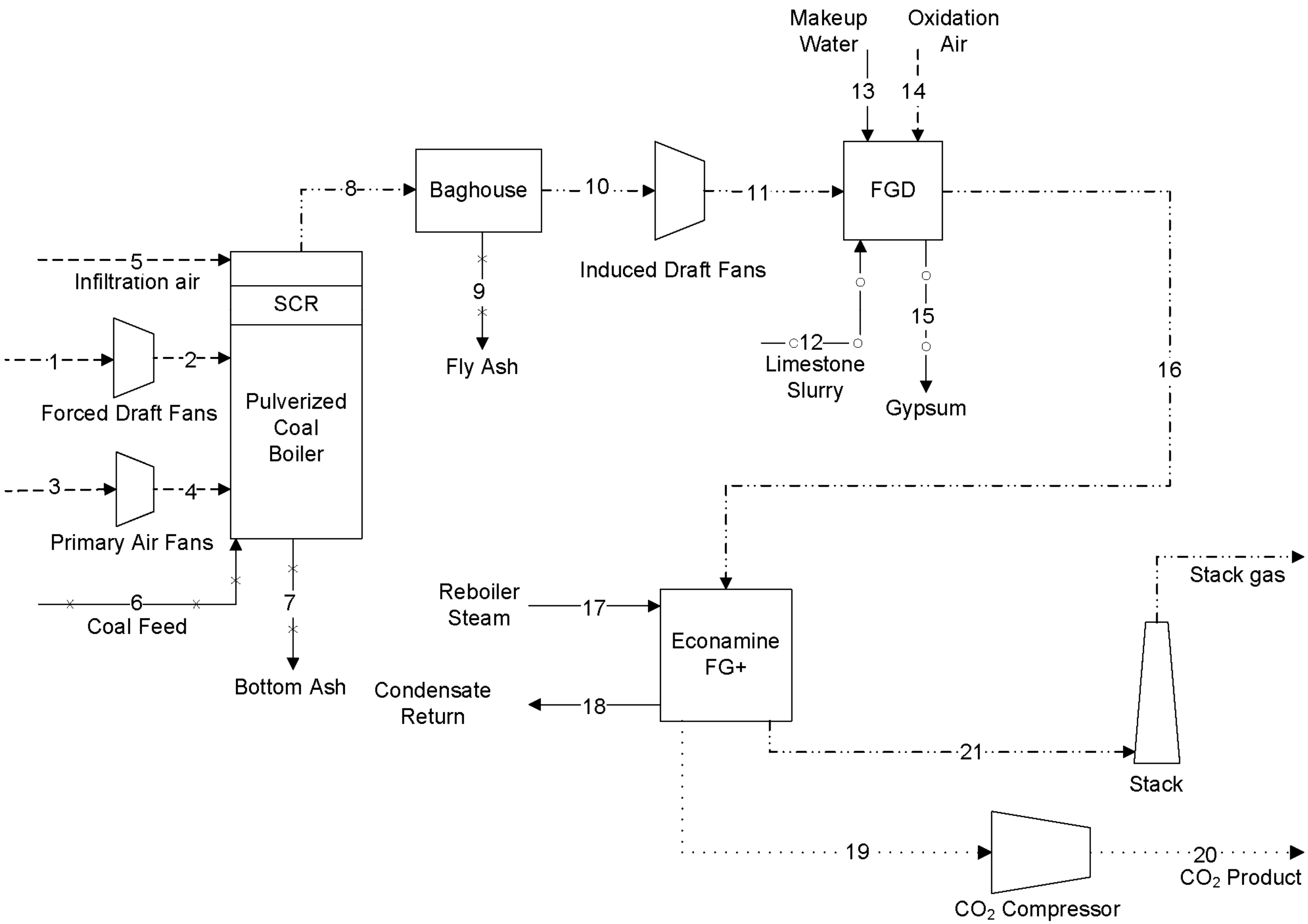


Exhibit 6-2 Case 5 (PC CR Retrofit) Stream Table, Supercritical PC with Retrofitted CO_2 Capture

	1	2	3	4	5	6	7	8	9	10	11
V-L Mole Fractions											
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450	0.1450
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870	0.0870
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324	0.7324
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247	0.0247
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000
V-L Flow (lb_{mol}/hr)	153,570	153,570	47,175	47,175	2,650	0	0	215,146	0	215,146	215,146
V-L Flow (lb/hr)	4,431,560	4,431,560	1,361,330	1,361,330	76,466	0	0	6,399,090	0	6,399,090	6,399,090
Solids Flowrate	0	0	0	0	0	586,627	11,377	45,507	45,507	0	0
Temperature (°F)	59	66	59	78	59	59	350	350	350	350	370
Pressure (psia)	14.70	15.25	14.70	16.14	14.70	14.70	14.40	14.40	14.20	14.20	15.26
Enthalpy (BTU/lb)[A]	13.1	14.9	13.1	17.7	13.1	---	---	135.6	---	136.2	141.5
Density (lb/ft^3)	0.08	0.08	0.08	0.08	0.08	---	---	0.05	---	0.05	0.05
Avg. Molecular Weight	28.86	28.86	28.86	28.86	28.86	---	---	29.74	---	29.74	29.74

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 6-2 Case 5 (PC CR Retrofit) Stream Table, Supercritical PC with Retrofitted CO_2 Capture Continued

	12	13	14	15	16	17	18	19	20	21
V-L Mole Fractions										
Ar	0.0000	0.0000	0.0092	0.0000	0.0080	0.0000	0.0000	0.0000	0.0000	0.0109
CO_2	0.0000	0.0000	0.0003	0.0015	0.1326	0.0000	0.0000	0.9862	1.0000	0.0180
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	0.0099	0.9977	0.1668	1.0000	1.0000	0.0138	0.0000	0.0281
N_2	0.0000	0.0000	0.7732	0.0008	0.6690	0.0000	0.0000	0.0000	0.0000	0.9109
O_2	0.0000	0.0000	0.2074	0.0000	0.0235	0.0000	0.0000	0.0000	0.0000	0.0320
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flow (lb_{mol}/hr)	7,537	34,486	2,535	20,128	238,453	100,792	100,792	28,856	28,458	175,090
V-L Flow (lb/hr)	135,788	621,279	73,155	363,564	6,833,360	1,815,800	1,815,800	1,259,600	1,252,440	4,951,450
Solids Flowrate	58,054	0	0	90,446	0	0	0	0	0	0
Temperature (°F)	59	60	59	135	135	692	348	69	124	74
Pressure (psia)	14.70	14.70	14.70	15.20	15.20	130.86	130.86	23.52	2215.00	14.70
Enthalpy (BTU/lb)[A]	---	33.3	13.1	88.0	139.4	1373.8	319.5	11.4	-70.8	29.6
Density (lb/ft^3)	62.62	62.59	0.08	39.94	0.07	0.19	55.67	0.18	40.76	0.07
Avg. Molecular Weight	18.02	18.02	28.86	18.06	28.66	18.02	18.02	43.65	44.01	28.28

Exhibit 6-3 Case 5 (PC CR Retrofit) Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
TOTAL (STEAM TURBINE) POWER, kWe	**663,445**
AUXILIARY LOAD SUMMARY, kWe (Note 1)	
Coal Handling and Conveying	490
Limestone Handling & Reagent Preparation	1,270
Pulverizers	3,990
Ash Handling	760
Primary Air Fans	1,870
Forced Draft Fans	2,380
Induced Draft Fans	10,120
SCR	70
Baghouse	100
FGD Pumps and Agitators	4,250
Econamine FG Plus Auxiliaries	21,320
CO_2 Compression	46,900
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Condensate Pumps	630
Circulating Water Pumps	12,260
Cooling Tower Fans	6,340
Transformer Loss	2,300
TOTAL AUXILIARIES, kWe	**117,450**
NET POWER, kWe	**545,995**
Net Plant Efficiency (HHV)	27.2%
Net Plant Heat Rate (Btu/kWh)	12,534
CONDENSER COOLING DUTY, 10^6 kJ (10^6 Btu)	1,886 (1,787)
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr) (Note 3)	266,090 (586,627)
Limestone Sorbent Feed, kg/hr (lb/hr)	26,333 (58,054)
Thermal Input, kWt	2,005,660
Makeup Water, m^3/min (gpm)	46.0 (12,159)

Notes:
1. Boiler feed pumps are turbine driven
2. Includes plant control systems, lighting, HVAC, etc.
3. As-received coal heating value: 11,666 Btu/lb (HHV)

6.1.1 Environmental Performance

A summary of the plant air emissions is presented in Exhibit 6-4.

Exhibit 6-4 Case 5 (PC CR Retrofit) Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% capacity	kg/MWh_{net} (lb/MWh_{net})
SO_2	Negligible	Negligible	Negligible
NO_X	0.030 (0.070)	1,618 (1,784)	0.398 (0.877)
Particulates	0.006 (0.013)	300 (331)	0.074 (0.163)
Hg	0.492×10^{-6} (1.14×10^{-6})	0.026 (0.029)	6.5×10^{-6} (14.3×10^{-6})
CO_2	8.7 (20)	468,500 (516,400)	115 (254)

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98%. A polishing SO_2 step is required after the FGD unit to prevent the build up of heat stable salts in the CO_2 capture process, and any remaining sulfur is removed in the CO_2 absorption process so that stack SO_2 emissions are nil. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is very dependent on local market conditions, no byproduct credit is taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NOx emissions are controlled to about 0.5 $lb/10^6$ Btu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 86% to 0.07 $lb/10^6$ Btu.

Particulate emissions are controlled using a pulse jet fabric filter which operates at an efficiency of 99.8%.

The combination of pollution control technologies used in the PC plants, SCR, fabric filters and FGD, result in significant co-benefit capture of mercury. This co-benefit capture alone is sufficient to meet current NSPS mercury limits so no activated carbon injection is included in the PC cases.

CO_2 emissions are controlled using the Econamine FG Plus technology. The system uses an MEA-based solvent to capture 90% of the CO_2 in the flue gas. The solvent is regenerated by steam stripping and the captured CO_2 is dehydrated and compressed.

Overall Mass and Energy Balances

This plant utilizes a conventional steam turbine for power generation. The single reheat system uses a Rankine cycle with steam conditions of 24.1 MPa/593°C/593°C (3500 psig/1100°F/1100°F). Overall Mass and Energy balance information is also presented in tabular form in Exhibit 6-5.

Exhibit 6-5 Case 5 (PC CR Retrofit) Overall Energy and Mass Balance

In			Out		
	Energy Flow, MMBtu/hr	**Mass Flow, lb/hr**		**Energy Flow, MMBtu/hr**	**Mass Flow, lb/hr**
Coal	6,850	586,630	**Stack Gas**	229	4,951,450
Water	135	757,070	**Net Power**	1,860	---
Air	78	5,942,510	**Water**	77	622,300
Limestone	87	58,050	**Condenser Duty**	1,787	---
	---	---	**Process Losses***	125	---
	---	---	**PM/Ash**	3	56,900
	---	---	**Econamine**	3,155	---
	---	---	**CO_2**	-89	1,259,600
	---	---	**Gypsum**	3	454,010
Total	7,150	7,344,260	**Total**	7,150	7,344,260
Net Plant Efficiency, % HHV (Overall)	27.2%				

* Process Losses are calculated by difference and reflect various boiler, turbine, and other heat and work losses.
Enthalpy reference conditions are 32.02 F & 0.089 psia
Aspen flowsheet balance is within 0.5 percent.

6.1.2 Description of Process Systems

Since Case 5 (PC CR retrofit) plant configuration is the result of retrofitting Case 3 (PC CR), which had been designed to anticipate conversion to a CO_2 capture mode, the amount of process equipment utilized in the retrofit is reduced. The process areas are described below and the changes in the Equipment List are identified in a side-by-side comparison in Section 6.2.

Flue gas exiting the FGD system passes through an SO_2 polishing step, a booster blower, and is then cooled to 32°C (90°F) in a direct contact cooler. The cooled flue gas enters the bottom of the CO_2 absorber and flows up the tower countercurrent to a stream of lean monoethanolamine (MEA)-based solvent. Approximately 90% of the CO_2 in the flue gas is absorbed into the lean solvent. The flue gas continues up the column passing through a water wash section designed to minimize solvent losses due to mechanical entrainment and evaporation.

The rich solvent exits the bottom of the absorption column and is preheated in a Rich/Lean heat exchanger designed to decrease the rich solution while at the same time increase the lean solution. The rich solvent then passes to a steam stripper where the amine-CO_2 reaction is reversed and the CO_2 "stripped" from the solvent. The primary energy source to reverse the chemical reaction and to strip the CO_2 out of solution derives from steam condensation in a reboiler at the bottom of the stripping column. This medium quality steam is taken directly from the IP/LP turbine crossover pipe—causing a reduction in LP turbine gross turbine output. The hot, wet vapor from the top of the stripper, containing CO_2, steam, and solvent vapor, is partially condensed using cooling water. Water from the partially condensed stream is separated in a reflux drum and the uncondensed CO_2-rich gas is sent to the CO_2 compressor train.

CO_2 Compression and Dehydration

CO_2 from the reflux drum is cooled further and compressed in a multiple-stage, intercooled compressed to 15.3 MPa (2,215 psia) in preparation for pipeline transport. During compression, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The virtually moisture-free supercritical CO_2 steam is then ready for pipeline transport.

6.2 CASE 3 (PC CR) & 5 (PC CR RETROFIT) - MAJOR EQUIPMENT LIST

ACCOUNT 1 FUEL AND SORBENT HANDLING

Equipment No.	Description	Type	Case 3 (PC CR) Design Condition	Qty	Case 5(PC CR Retrofit) Design Condition
1A	Bottom Trestle Dumper	NA	181 tonne/hr (200 tph)	2	No Change
1B	Receiving Hoppers	N/A	N/A	2	
2	Feeder	Belt	572 tonne/hr (630 tph)	2	
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	
4	Transfer Tower No. 1	Enclosed	N/A	1	
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	
6	As-Received Coal Sampling System	Two-stage	N/A	1	
7	Conveyor No. 2	Belt conveyor	1,134 tonne/hr (1,250 tph)	1	
8	Reclaim Hopper	N/A	54 tonne (60 ton)	3	
9	Feeder	Vibratory	218 tonne/hr (240 tph)	3	
10	Conveyor No. 3	Belt conveyor	435 tonne/hr (480 tph)	1	
11	Crusher Tower	N/A	N/A	1	
12	Coal Surge Bin w/ Vent Filter	Dual outlet	218 tonne/hr (240 tph)	2	
13	Crusher	Impactor reduction	8 cm x 0 – 3 cm x 0 (3" x 0 – 1¼" x 0)	2	
14	As-Fired Coal Sampling sys.	Swing hammer	N/A	2	
15	Conveyor No. 4	Belt w/tripper	435 tonne/hr (480 tph)	1	
16	Transfer Tower No. 2	Enclosed	N/A	1	
17	Conveyor No. 5	Belt w/tripper	435 tonne/hr (480 tph)	1	
18	Coal Silo w/ Vent Filter and Slide Gates	Field Erected	998 tonne/hr (1,100 ton)	3	
19	Limestone Truck Unloading Hopper	N/A	36 tonne (40 ton)	1	

Equipment No.	Description	Type	Case 3 (PC CR) Design Condition	Qty	Case 5(PC CR Retrofit) Design Condition
20	Limestone Feeder	Belt	109 tonne/hr (120 tph)	1	No Change
21	Limestone Conveyor No. 1	Belt	109 tonne/hr (120 tph)	1	
22	Limestone Reclaim Hopper	N/A	18 tonne/hr (20 tph)	1	
23	Limestone Reclaim Feeder	Belt	91 tonne/hr (100 tph)	1	
24	Limestone Conveyor No. 2	Belt	91 tonne/hr (100 tph)	1	
25	Limestone Day Bin	w/ actuator	345 tonnes (380 tons)	2	

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Case 3 (PC CR) Design Condition	Qty	Case 5(PC CR Retrofit) Design Condition
1	Coal Feeder	Gravimetric	45 tonne/hr (50 tph)	6	No Change
2	Coal Pulverizer	Ball type or eq.	45 tonne/hr (50 tph)	6	
3	Limestone Weigh Feeder	Gravimetric	29 tonne/hr (32 tph)	2	
4	Limestone Ball Mill	Rotary	29 tonne/hr (32 tph)	2	
5	Mill Slurry Tank with Agitator	N/A	109,778 liters (29,000 gal)	2	
6	Mill Recycle Pumps	Horizontal centrifugal	445 lpm @12m H_2O (490 gpm @40ft H_2O)	2	
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	109 lpm (120 gpm) per cyclone	2	
8	Distribution Box	2-way	N/A	2	
9	Limestone Storage Tank with Agitator	Field erected	624,593 liters (165,000 gal)	2	
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	308 lpm @9m H_2O (340 gpm @30ft H_2O)	2	

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Case 3 (PC CR) Design Condition	Qty	Case 5(PC CR Retrofit) Design Condition
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,570,958 liters (415,000 gal)	2	No Change
2	Condensate Pumps	Vert. canned	18,927 lpm @ 213 m H_2O (5,000 gpm @ 700 ft H_2O)	2	
3	Deaerator and Storage Tank	Horiz. spray type	2,614,963 kg/hr (5,765,000 lb/hr), 5 min tank	1	
4	Boiler Feed Pump/ Turbine	Barrel type, multi-staged, centrifugal	43,911 lpm @ 3,475 m H_2O (11,600 gpm @11,400 ft H_2O)	2	
5	Startup Boiler Feed Pump, Electric Motor Driven Pumps	Barrel type, multi-staged, centrifugal	13,249 lpm @ 3,475 m H_2O (3,500 gpm @11,400 ft H_2O)	1	
6	LP Feedwater Heater 1A/1B	Horiz. U tube	557,919 kg/hr (1,230,000 lb/hr)	2	
7	LP Feedwater Heater 2A/2B	Horiz. U tube	557,919 kg/hr (1,230,000 lb/hr)	2	
8	LP Feedwater Heater 3A/3B	Horiz. U tube	557,919 kg/hr (1,230,000 lb/hr)	2	
9	LP Feedwater Heater 4A/4B	Horiz. U tube	557,919 kg/hr (1,230,000 lb/hr)	2	
10	HP Feedwater Heater 6	Horiz. U tube	2,612,695 kg/hr (5,760,000 lb/hr)	1	
11	HP Feedwater Heater 7	Horiz. U tube	2,612,695 kg/hr (5,760,000 lb/hr)	1	
12	HP Feedwater Heater 8	Horiz. U tube	2,612,695 kg/hr (5,760,000 lb/hr)	1	
13	Auxiliary Boiler	Shop fabricated, water-tube	18,144 kg/hr (40,000 lb/hr) 2.8 MPa (400 psig), 343°C (650°F)	1	

Equipment No.	Description	Type	Case 3 (PC CR) Design Condition	Qty	Case 5(PC CR Retrofit) Design Condition
14	Fuel Oil System	No 2 fuel oil for light off	1.135,632 liters (300,000 gal)	1	No Change
15	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 cfm @ 100 psig)	3	
16	Inst. Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	3	
17	Closed Cycle Cooling Heat Exch.	Shell & tube	53MMkJ/hr (50MMBtu/hr) each	2	
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	3	
19	Engine-Driven Fire Pump	Vert. turbine, diesel engine	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	2	
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	2	
21	Raw Water Pumps	SS, single suction	25,514 lpm @ 43 m H_2O (6,740 gpm @ 140 ft H_2O)	3	
22	Filtered Water Pumps	SS, single suction	2,120 lpm @ 49 m H_2O (560 gpm @ 160 ft H_2O)	3	
23	Filtered Water Tank	Vertical, cylindrical	2,040,353 liters (539,000 gal)	1	
24	Makeup Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	1,022 lpm (270 gpm)	2	
25	Liquid Waste Treatment System	--	10 years, 25-hour storm	1	

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Case 3 (PC CR) Design Condition	Qty	Case 5(PC CR Retrofit) Design Condition
1	Boiler with superheater, economizer and air heater	Supercritical, drum, wall-fired, low NOx burners, overfire air	2,612,695 kg/hr steam @ 24.1 MPa/593°C/593°C (5,760,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	No Change
2	Primary Air Fan	Centrifugal	339,741 kg/hr, 4,650 m^3/min @ 123 cm WG (749,000 lb/hr, 164,200 acfm @ 48 in. WG)	2	
3	FD Fan	Centrifugal	1,105,406 kg/hr, 15,135 m^3/min @ 47 cm WG (2,437,000 lb/hr, 534,500 acfm @ 19 in. WG)	2	
4	ID Fan	Centrifugal	1,596,647 kg/hr, 33,898 m^3/min @ 90 cm WG (3,520,000 lb/hr, 1,197,100 acfm @ 36 in. WG)	2	
5	SCR Reactor Vessel	Space for spare layer	3,193,294 kg/hr (7,040,000 lb/hr)	2	
6	SCR Catalyst	--	--	3	
7	Dilution Air Blower	Centrifugal	190 m^3/min @ 108 cm WG (6,700 acfm @ 42 in. WG)	3	
8	Ammonia Storage	Horizontal tank	208,199 liter (55,000 gal)	5	
9	Ammonia Feed Pump	Centrifugal	40 lpm @ 91 m H_2O (11 gpm @ 300 ft H_2O)	3	

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	Description	Type	Case 3 (PC CR) Design Condition	Qty	Case 5(PC CR Retrofit) Design Condition
1	Bag fabric filter.	Single stage, high-ratio with pulse-jet online cleaning system	1,596,647 kg/hr (3,520,000 lb/hr) 99.8% efficiency	2	No Change
2	Absorber Module	Counter-current Open spray	52,160 m^3/min (1,842,000 acfm)	1	
3	Recirculation Pumps	Horizontal centrifugal	181,701 lpm @ 64 m H_2O (48,000 gpm @ 210 ft H_2O)	6	
4	Bleed Pumps	Horizontal centrifugal	5,716 lpm (1,510 gpm) at 20 wt% solids	3	
5	Oxidation Air Blowers	Centrifugal	250 m^3/min @ 0.3 MPa (8,820 acfm @ 42 psia)	3	
6	Agitators	Side entering	50 hp	6	
7	Dewatering Hydrocyclones	Radial assembly (5 units EA)	1,438 lpm (380 gpm) per cyclone	2	
8	Vacuum Belt Filter	Horizontal belt	45 tonne/hr (50 tph) of 50 wt % slurry	3	
9	Filtrate Water Return Pumps	Horizontal centrifugal	871 lpm @ 12 m H_2O (230 gpm @ 40 ft H_2O)	2	
10	Filtrate Water Return Storage Tank	Vertical, lined	567,816 lpm (150,000 gal)	1	
11	Process Makeup Water Pumps	Horizontal centrifugal	3,255 lpm @ 21 m H_2O (860 gpm @ 70 ft H_2O)	2	

ACCOUNT 5C CARBON DIOXIDE RECOVERY

Equipment No.	Description	Type	Case 3 (PC CR) Design Condition	Case 5(PC CR Retrofit) Design Condition	Case 5 Qty
1	Econamine FG Plus	Amine-based CO_2 capture technology	NA	1,704,602 kg/hr (3,758,000 lb/hr) 20.4 wt % CO_2 flue gas concentration	2
2	CO_2 Compressor	Reciprocating	NA	312,453 kg/hr@ 15.3 MPa (688,840 lb/hr@ 2,215 psia)	2

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

N/A

ACCOUNT 7 HRSG, DUCTING & STACK

Equipment No.	Description	Type	Case 3 (PC CR) Design Condition	Qty	Case 5(PC CR Retrofit) Design Condition
1	Stack	Reinforced concrete w/ FRP liner	152 m (500 ft) high x 5.5 m (18 ft) diameter	1	No Change

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Case 3 (PC CR) Design Condition	Qty	Case 5(PC CR Retrofit) Design Condition
1	Steam Turbine	Commercially available advanced steam turbine	700 MW, 24.1 MPa/593°C/593°C (3500 psig/1100°F /1100°F)	1	No Change
2	Steam Turbine Generator	Hydrogen cooled, static excitation	780 MVA @ 0.9 p.f., 24 kV, 60 Hz	1	
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,077 MMkJ/hr (1,970 MMBtu/hr), Inlet water temperature 16ºC (60ºF), Water temperature rise 11ºC (20ºF)	1	

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Case 3 (PC CR) Design Condition	Qty	Case 5(PC CR Retrofit) Design Condition
1	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 2,657 MMkJ/hr (2,520 MMBtu/hr) heat load	1	No Change
2	Circ. Water Pumps	Vertical, wet pit	613,241 lpm @ 30.5 m WG (162,000 gpm @ 100 ft WG)	6	

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Case 3 (PC CR) Design Condition	Qty	Case 5(PC CR Retrofit) Design Condition
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	No Change
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	
3	Clinker Grinder	--	5.4 tonne/hr (6 tph)	2	

Equipment No.	Description	Type	Case 3 (PC CR) Design Condition	Qty	Case 5(PC CR Retrofit) Design Condition
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	No Change
5	Hydroejectors	--	--	12	
6	Economizer/Pyrites Transfer Tank	--	--	1	
7	Ash Sluice Pumps	Vertical, wet pit	227 lpm @ 17 m H_2O (60 gpm @ 56 ft H_2O)	2	
8	Ash Seal Water Pumps	Vertical, wet pit	7,571 lpm @ 9 m H_2O (2,000 gpm @ 28 ft H_2O)	2	
9	Hydrobins	--	227 lpm (60 gpm)	2	
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	
12	Air Blower	--	21 m^3/min @ 0.2 MPa (730 scfm@ 24 psi)	2	
13	Fly Ash Silo	Reinforced concrete	680 tonnes (1,500 tons)	21	
14	Slide Gate Valves	--	--	2	
15	Unloader	--	127 tonne/hr (140 tph)	1	
16	Telescoping Unloading Chute	--	--	1	

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Case 3 (PC CR) Design Condition	Qty	Case 5(PC CR Retrofit) Design Condition
1	STG Transformer	Oil-filled	24 kV/345 kV, 640 MVA, 3-ph, 60 Hz	1	No Change
2	Auxiliary Transformer	Oil-filled	24 kV/ 4.16 kV, 128 MVA, 3-ph, 60 Hz	2	

Equipment No.	Description	Type	Case 3 (PC CR) Design Condition	Qty	Case 5(PC CR Retrofit) Design Condition
3	Low Voltage Transformer	Dry ventilated	4.16 kV /480 V, 19 MVA, 3-ph, 60 Hz	2	No Change
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	
5	Medium Voltage Switchgear	Metal Clad	4.16 kV, 3-ph, 60 Hz	2	
6	Low Voltage Switchgear	Metal Enclosed	480 kV, 3-ph, 60 Hz	2	
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Case 3 (PC CR) Design Condition	Qty	Case 5(PC CR Retrofit) Design Condition
1	DCS - Main Control	Monitor/keyboard; Operator printer – laser color; Eng. Printer – laser black & white	Operator Stations/Printers and Engineering Stations/Printers	1	No Change
2	DCS - Processor	Microprocessor with Redundant Input/Output	N/A	1	
4	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	

6.3 CASE 5 (PC CR RETROFIT) - COST ESTIMATING RESULTS

Exhibit 6-6 and Exhibit 6-9 show the capital and operating costs for this plant including the costs of retrofitting it for CO_2 capture. Capital cost estimating methodology is explained in Section 4. The detailed breakdowns of the capital cost estimates for each case are included in Appendix B.

Note: Costs impacted by changes in design and operating parameter values from the capture-ready case values to the CO_2 capture design and operation performance requirements are highlighted in the following capture-ready retrofit case cost exhibits.

Exhibit 6-6 Case 5 (PC CR Retrofit) Total Plant Costs

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST SUMMARY

Case: Case 5 - Retrofit of 1x550 MWnet Capture ReadySuper-Critical PC w CO2 Capture
Plant Size: 546.0 MW,net **Estimate Type:** Conceptual Cost Base Jan 2007 $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL HANDLING SYSTEM	19,316	5,215	11,691		$36,222	3,246		5,920	$45,389	83
2	COAL PREP & FEED SYSTEMS	13,126	758	3,326		$17,210	1,508		2,808	$21,527	39
3	FEEDWATER & MISC. BOP SYSTEMS	54,477		25,648		$80,126	7,317		14,428	$101,870	187
4	PC BOILER & ACCESSORIES										
4.1	PC Boiler & Accessories	190,969		107,678		$298,647	28,927		32,757	$360,332	660
4.2	SCR (w/4.1)										
4.3	Open										
4.4-4.9	Secondary Air System										
	Subtotal 4	190,969		107,678		$298,647	28,927		32,757	$360,332	660
5A	**FLUE GAS CLEANUP**	**102,380**		**35,161**		**$137,541**	**13,069**		**15,061**	**$165,671**	**303**
5B	**CO2 REMOVAL & COMPRESSION**	**229,832**		**69,851**		**$299,683**	**28,443**	**52,879**	**76,201**	**$457,207**	**837**
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	N/A		N/A							
6.2-6.9	Combustion Turbine Accessories										
	Subtotal 6										
7	HRSG, DUCTING & STACK										
7.1	Heat Recovery Steam Generator	N/A		N/A							
7.2-7.9	Ductwork, Stack	17,889	981	12,221		$31,091	2,840		4,457	$38,388	70
	Subtotal 7	17,889	981	12,221		$31,091	2,840		4,457	$38,388	70
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	53,763		7,192		$60,956	5,836		6,679	$73,471	135
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	26,923	1,148	14,942		$43,013	3,724		6,698	$53,436	98
	Subtotal 8	80,687	1,148	22,134		$103,969	9,561		13,377	$126,907	232
9	COOLING WATER SYSTEM	21,479	11,200	19,881		$52,559	4,900		7,796	$65,255	120
10	ASH/SPENT SORBENT HANDLING SYS	5,154	162	6,854		$12,169	1,158		1,371	$14,699	27
11	ACCESSORY ELECTRIC PLANT	20,196	10,240	29,287		$59,723	5,331		8,288	$73,343	134
12	INSTRUMENTATION & CONTROL	9,195		9,662		$18,857	1,726	943	2,648	$24,174	44
13	IMPROVEMENTS TO SITE	3,162	1,818	6,421		$11,402	1,120		2,504	$15,026	28
14	BUILDINGS & STRUCTURES		23,760	22,735		$46,495	4,189		7,603	$58,287	107
	TOTAL COST	**$767,862**	**$55,282**	**$382,550**		**$1,205,695**	**$113,335**	**$53,822**	**$195,221**	**$1,568,073**	**$2,872**

Exhibit 6-7 Case 5 (PC CR Retrofit) Operating Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base Jan	2007
Case 5 - Retrofit of 1x550 MWnet Capture ReadySuper-Critical PC w CO2 Capture					Heat Rate-net(Btu/kWh):	**12,534**
Plant Output:	CO_2 (tpd):	**17,682**	H_2 (mmscfd):		MWe-net:	**546.0**
					Capacity Factor: (%):	85.0
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Total Plant			
Skilled Operator	2.0		2.0			
Operator	**11.3**		**11.3**			
Foreman	1.0		1.0			
Lab Tech's, etc.	2.0		2.0			
TOTAL-O.J.'s	**16.3**		16.3			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost(calc'd)					**$6,138,007**	**11.24**
Maintenance Labor Cost(calc'd)					**$10,271,860**	**18.81**
Administrative & Support Labor(calc'd)					**$4,102,467**	**7.51**
TOTAL FIXED OPERATING COSTS					**$20,512,333**	**37.57**
VARIABLE OPERATING COSTS						$/kWh-net
Maintenance Material Cost(calc'd)					**$15,407,790**	**0.0038**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)		**8,755**	1.03		**$2,797,790**	**0.0007**
Chemicals						
MU & WT Chem.(lb)	**296,665**	**42,381**	0.16	**$48,890**	**$2,166,895**	**0.0005**
Carbon (Mercury Removal) (lb)			1.00			
COS Catalyst (m3)			2308.40			
Limestone (ton)	**4,877**	**697**	20.60	**$100,457**	**$4,452,382**	**0.0011**
MEA Solvent (ton)	**1,065**	**2**	2142.40	**$2,281,656**	**$1,004,996**	**0.0002**
NaOH (tons)	**74**	**7**	412.96	**$30,559**	**$942,457**	**0.0002**
H2SO4 (tons)	**72**	**7**	132.15	**$9,515**	**$294,213**	**0.0001**
Corrosion Inhibitor						
Ammonia (28% NH3) ton	**813**	**116**	123.60	**$100,439**	**$4,451,615**	**0.0011**
Activated Carbon(lb)	**657,450**	**1,800**	1.00	**$657,450**	**$558,450**	**0.0001**
Subtotal Chemicals				**$3,228,966**	**$13,871,007**	**0.0034**
Other						
Supplemental Fuel(MBtu)			6.75			
SCR Catalyst Replacement		**0.6**	5500.00		**$1,058,976**	**0.0003**
Emission Penalties						
Subtotal Other					**$1,058,976**	**0.0003**
Waste Disposal						
Spent Mercury Catalyst (lb.)			0.40			
Flyash (ton)		**137**	15.45		**$654,409**	**0.0002**
Bottom Ash(ton)		**546**	15.45		**$2,617,579**	**0.0006**
Subtotal Solid Waste Disposal					**$3,271,988**	**0.0008**
By-products & Emissions						
Gypsum (tons)		**1,085**				
Sulfur(tons)			-25.00			
Subtotal By-Products						
TOTAL VARIABLE OPERATING COSTS				$3,228,966	$36,407,550	0.0090
FUEL (tons)	**211,186**	**7,040**	42.11	**$8,893,044**	$91,968,899	0.0226

Exhibit 6-8 Case 5 (PC CR Retrofit) Capital Investment Requirement Summary

TITLE/DEFINITION					
Case: **Case 5 - Retrofit of 1x550 MWnet Capture ReadySuper-Critical PC w CO2 Capture**					
Plant Size:	**546.0** (MW,net)	HeatRate:		**12,534**	(Btu/kWh)
Primary/Secondary Fuel(type):	Illinois #6	Cost:		1.80	($/MMBtu)
Design/Construction:	3 (years)	BookLife:		30	(years)
TPC(Plant Cost) Year:	2007 Jan				
Capacity Factor:	85 (%)	CO2 Removed:		**17,682**	(TPD)
CAPITAL INVESTMENT			**$x1000**		**$/kW**
Process Capital & Facilities			**1,205,695**		**2208.3**
Engineering(incl.C.M.,H.O.& Fee)			**113,335**		**207.6**
Process Contingency			**53,822**		**98.6**
Project Contingency			**195,221**		**357.6**
TOTAL PLANT COST(TPC)			**$1,568,073**		**2872.0**
OPERATING & MAINTENANCE COSTS (2007 Dollars)			**$x1000**		**$/kW-yr**
Operating Labor			**6,138**		**11.2**
Maintenance Labor			**10,272**		**18.8**
Maintenance Material			**15,408**		**28.2**
Administrative & Support Labor			**4,102**		**7.5**
TOTAL OPERATION & MAINTENANCE			**$35,920**		**65.8**
FIXED O & M			**$21,546**		**39.5**
VARIABLE O & M			**$14,374**		**26.3**
CONSUMABLE OPERATING COSTS, less Fuel (2007 Dollars)			**$x1000**		**¢/kWh**
Water			**2,798**		**0.07**
Chemicals			**13,871**		**0.34**
Other Consumables			**1,059**		**0.03**
Waste Disposal			**3,272**		**0.08**
TOTAL CONSUMABLE OPERATING COSTS			**$21,000**		**0.52**
BY-PRODUCT CREDITS					
FUEL COST (2007 Dollars)			**$91,969**		**2.26**
				Levelized Costs	
PRODUCTION COST SUMMARY		**LF**		**¢/kWh**	
Fixed O & M		1.162		**0.62**	
Variable O & M		1.162		**0.41**	
Consumables		1.162		**0.60**	
By-product Credit		1.162			
Fuel		1.209		**2.73**	
TOTAL PRODUCTION COST				**4.36**	
2007 CARRYING CHARGES (Capital)				**6.33**	
CCF for a 20-Year Levelization Period - IOU - Lower-Risk	16.4				
20 YEAR LEVELIZED BUSBAR COST OF POWER				**10.69**	

Exhibit 6-9 Case 5 (PC CR Retrofit) Estimate Basis and Financial Criteria Summary

GENERAL DATA/CHARACTERISTICS

Case Title:	Case 5 - "Capture Ready" SuperCritical PC Retrofitted with CO_2 Capture		
Unit Size:/Plant Size:		**546.0**	MW,net
Location:		Midwestern, USA	
Fuel: Primary/Secondary	Illinois #6	11,666	Btu/lb
Energy From Primary/Secondary Fuels		**12,534**	Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):		85	%
Capital Cost Year Dollars (Reference Year Dollars):		2007	Jan
Delivered Cost of Primary/Secondary Fuel		1.80	\$/MMBtu
Design/Construction Period:		3	years
Plant Startup Date (1st. Year Dollars):		2010	
Financial Parameter/Risk Level		IOU Low Risk	

FINANCIAL CRITERIA

Project Book Life:	30	years
Book Salvage Value:		%
Project Tax Life:	20	years
Tax Depreciation Method:	20 years, 150% declining balance	
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		%
Economic Basis:	20th Year Current Dollars	

Capital Structure		% of Total	Cost(%)
	Common Equity	50.00	12.00
	Preferred Stock		
	Debt	50.00	9.00
Weighted Cost of Capital:(after tax)		8.79 %	

		2010 - 2030	
Nominal Escalation	General	1.87	% per year
	Coal Price	2.35	% per year
	Secondary Fuel:	1.96	% per year

6.4 CASE 7 (PC BAU RETROFIT) – PC BUSINESS-AS-USUAL RETROFIT TO CAPTURE CO_2

Case 7 (PC BAU retrofit) is based on retrofitting Case 1 (PC BAU) plant to capture CO_2. Since Case 1 (PC BAU) was not designed to capture CO_2 or made capture-ready, a substantial rework of the PC plant is required to achieve the 90% CO_2-capture mode. Plant process equipment which is included in the retrofit is described in the following paragraphs. Plant modifications consist of:

- Adding booster blower.
- Adding Econamine process unit.
- Adding CO_2 compressors and dryers.

Flue gas exiting the FGD system is directed to the Econamine process where CO_2 is absorbed in an MEA-based solvent. A booster blower is required to overcome the process pressure drop. CO_2 removed in the Econamine process is dried and compressed to a supercritical condition for subsequent pipeline transport. The CO_2 is delivered to the plant fence line at 15.3 MPa (2,215 psia). The Econamine process imposes a significant auxiliary power load on the system and the gross power output is reduced to 467 MW, resulting in net power of 379 MW at 27.0% efficiency HHV. This is primarily because the low partial pressure of CO_2 in the flue gas from a PC plant requires a chemical absorption process rather than physical absorption. For this chemical absorption process, the regeneration requirements are much more energy intensive, requiring substantial steam quantities (~1,530 Btu/lb CO_2 captured) and increased demand on the cooling system.

The Equipment List (Section 6.5) is a side-by-side comparison of the Case 1 (PC BAU) and Case 7 (PC BAU retrofit) equipment changes. Exhibit 6-10 is a block flow diagram for the overall plant with individual streams identified. Exhibit 6-11 follows the figure with detailed composition and state points for the numbered streams.

Overall performance for the entire plant is summarized in Exhibit 6-12 which includes auxiliary power requirements.

Exhibit 6-10 Case 7 (PC BAU Retrofit) Process Flow Diagram, Supercritical PC with Retrofitted CO_2 Capture

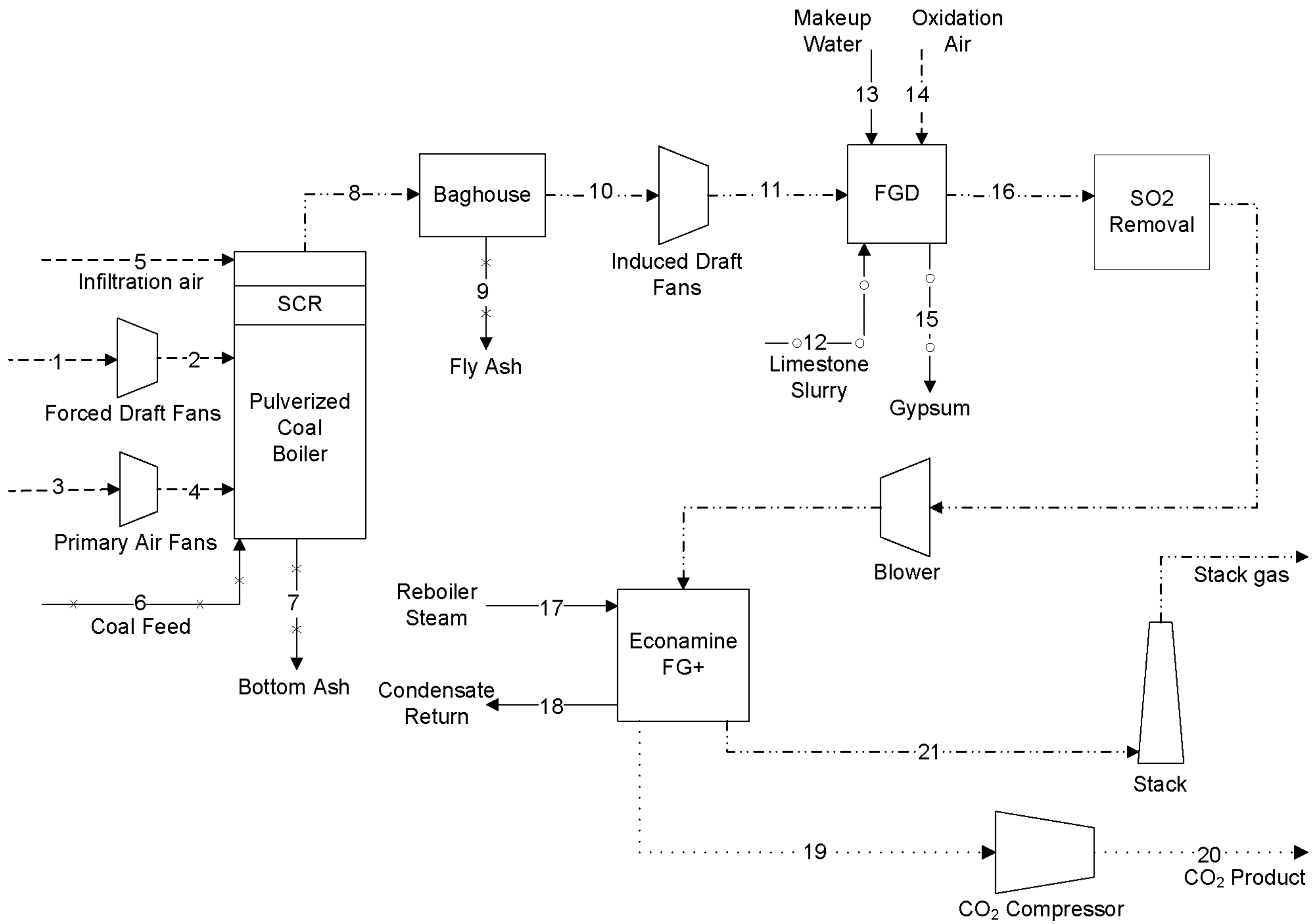


Exhibit 6-11 Case 7 (PC BAU Retrofit) Stream Table, Supercritical PC with Retrofitted CO_2 Capture

	1	2	3	4	5	6	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0088	0.0000	0.0088	0.0088
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1375	0.0000	0.1375	0.1375
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0830	0.0000	0.0830	0.0830
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7345	0.0000	0.7345	0.7345
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0342	0.0000	0.0342	0.0342
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.9980	0.0000	0.9980	0.9980
V-L Flowrate (lb_{mol}/hr)	113,696	113,696	34,926	34,926	2,229	0	0	159,090	0	159,090	159,090
V-L Flowrate (lb/hr)	3,280,916	3,280,916	1,007,863	1,007,863	64,332	0	0	4,724,512	0	4,724,512	4,724,512
Solids Flowrate (lb/hr)	0	0	0	0	0	411,282	7,976	31,905	31,905	0	0
Temperature (°F)	59	70	59	76	59	59	270	270	270	270	295
Pressure (psia)	14.7	15.4	14.7	15.8	14.7	14.7	14.0	14.0	13.8	13.8	15.0
Enthalpy (BTU/lb)[A]	13.1	15.7	13.1	17.2	13.1	---	---	111.7	---	104.6	110.9
Density (lb/ft^3)	0.08	0.08	0.08	0.08	0.08	---	---	0.05	---	0.05	0.05
Molecular Weight	28.86	28.86	28.86	28.86	28.86	---	---	29.70	---	29.70	29.70

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 6-11 Case 7 (PC BAU Retrofit) Stream Table, Supercritical PC with Retrofitted CO_2 Capture Continued

	12	13	14	15	16	17	18	19	20	21
V-L Mole Fraction										
Ar	0.0000	0.0000	0.0128	0.0000	0.0082	0.0000	0.0000	0.0000	0.0000	0.0107
CO_2	0.0000	0.0000	0.0005	0.0000	0.1284	0.0000	0.0000	0.9857	1.0000	0.0169
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	0.0062	1.0000	0.1478	1.0000	1.0000	0.0143	0.0000	0.0374
N_2	0.0000	0.0000	0.7506	0.0000	0.6829	0.0000	0.0000	0.0000	0.0000	0.8920
O_2	0.0000	0.0000	0.2300	0.0000	0.0326	0.0000	0.0000	0.0000	0.0000	0.0430
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	4,976	7,990	1,538	13,664	172,802	72,359	72,359	20,265	19,975	130,976
V-L Flowrate (lb/hr)	89,644	143,945	44,635	246,153	4,979,910	1,303,562	1,303,562	884,317	879,088	3,694,828
Solids Flowrate (lb/hr)	38,712	0	0	61,538	0	0	0	0	0	0
Temperature (°F)	59	59	59	64	129	654	352	69	247	89
Pressure (psia)	17.3	14.7	14.7	14.7	14.7	137.7	137.7	23.5	2,200.0	14.7
Enthalpy (BTU/lb)[A]	481.9	32.4	10.6	369.3	124.1	1,354.4	323.6	11.4	---	---
Density (lb/ft^3)	62.62	62.62	0.08	62.47	0.07	0.21	55.52	0.18	16.80	0.07
Molecular Weight	18.02	18.02	29.03	18.02	28.82	18.02	18.02	43.64	44.01	28.21

Exhibit 6-12 Case 7 (PC BAU Retrofit) Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
TOTAL (STEAM TURBINE) POWER, kWe	**467,300** Reduced from 580,26
AUXILIARY LOAD SUMMARY, kWe (Note 1)	
Coal Handling and Conveying	410
Limestone Handling & Reagent Preparation	890
Pulverizers	2,800
Ash Handling	530
Primary Air Fans	1,310
Forced Draft Fans	1,660
Induced Draft Fans	7,130
SCR	50
Baghouse	100
FGD Pumps and Agitators	2,980
Econamine FG Plus Auxiliaries	15,200
CO_2 Compression	37,350
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Condensate Pumps	800
Circulating Water Pumps	8,200
Cooling Tower Fans	4,900
Transformer Loss	1,590
TOTAL AUXILIARIES, kWe	**88,300**
NET POWER, kWe	**379,000**
Net Plant Efficiency (HHV)	27.0%
Net Plant Heat Rate (Btu/kWh)	12,660
CONDENSER COOLING DUTY, 10^6 kJ (10^6 Btu)	1,361 (1,290)
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr) (Note 3)	186,554 (411,282)
Limestone Sorbent Feed, kg/hr (lb/hr)	17,559 (38,712)
Thermal Input, kWt	1,406,160
Makeup Water, m^3/min (gpm)	31.3 (8,270)

Notes:
1. Boiler feed pumps are turbine driven
2. Includes plant control systems, lighting, HVAC, etc.
3. As-received coal heating value: 11,666 Btu/lb (HHV)

6.4.1 Environmental Performance

A summary of the plant air emissions is presented in Exhibit 6-13.

Exhibit 6-13 Case 7 (PC BAU Retrofit) Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% capacity	kg/MWh_{net} (lb/MWh_{net})
SO_2	Nil (Nil)	Nil (Nil)	Nil (Nil)
NO_X	0.030 (0.070)	1,134 (1,250)	0.402 (0.886)
Particulates	0.006 (0.013)	211 (232)	0.075 (0.165)
Hg	$0.492x10^{-6}$ ($1.14x10^{-6}$)	0.018 (0.020)	$6.6x10^{-6}$ ($14.5x10^{-6}$)
CO_2	8.8 (20)	329,900 (363,650)	117 (257)

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98%. A caustic polishing step is required after the FGD unit to reduce SO_2 to <10 ppm to prevent the build up of heat stable salts in the CO_2 capture process, and any remaining sulfur is removed in the CO_2 absorption process so that stack SO_2 emissions are nil. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is very dependent on local market conditions, no byproduct credit is taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NOx emissions are controlled to about 0.5 $lb/10^6$ Btu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 86% to 0.07 $lb/10^6$ Btu.

Particulate emissions are controlled using a pulse jet fabric filter which operates at an efficiency of 99.8%.

The combination of pollution control technologies used in the PC plants, SCR, fabric filters and FGD, result in significant co-benefit capture of mercury. This co-benefit capture alone is sufficient to meet current NSPS mercury limits so no activated carbon injection is included in the PC cases.

CO_2 emissions are controlled using the Econamine FG Plus technology. The system uses an MEA-based solvent to capture 90% of the CO_2 in the flue gas. The solvent is regenerated by steam stripping and the captured CO_2 is dehydrated and compressed.

Overall Mass and Energy Balance

This plant utilizes a conventional steam turbine for power generation. The single reheat system uses a Rankine cycle with steam conditions of 24.2 MPa/593°C/593°C (3500 psig/1100°F /1100°F). Overall Mass and Energy balance information is also presented in tabular form in Exhibit 6-14.

Exhibit 6-14 Case 7 (PC BAU Retrofit) Overall Energy and Mass Balance

In			Out		
	Energy Flow, MMBtu/hr	**Mass Flow, lb/hr**		**Energy Flow, MMBtu/hr**	**Mass Flow, lb/hr**
Coal	4,802	411,280	**Stack Gas**	514	3,694,828
Water	93	514,925	**Power**	1,293	---
Air	57	4,288,780	**Water**	40	326,980
Limestone	58	38,712	**Condenser Duty**	1,290	---
	---	---	**Process Losses***	129	---
	---	---	**PM/Ash**	3	39,880
	---	---	**Econamine**	1,800	---
	---	---	**CO_2**	-62	884,317
	---	---	**Gypsum**	3	307,692
Total	5,010	5,253,697	**Total**	5,010	5,253,697
Net Plant Efficiency, % HHV (Overall)		27.0%			

* Process Losses are calculated by difference and reflect various boiler, turbine, and other heat and work losses.
Enthalpy reference conditions are 32.02 F & 0.089 psia
Aspen flowsheet balance is within 0.5 percent.

6.4.2 Description of Process Systems

The Case 7 (PC BAU retrofit) plant configuration is the result of retrofitting Case 1 (PC BAU), which was not designed to anticipate conversion to a CO_2 capture mode. The process areas are described below and the changes in the Equipment List are identified in a side-by-side comparison in Section 6.5.

Flue gas exiting the FGD system passes through an SO_2 polishing step, a booster blower, and is then cooled to 32°C (90°F) in a direct contact cooler. The cooled flue gas enters the bottom of the CO_2 absorber and flows up the tower countercurrent to a stream of lean monoethanolamine (MEA)-based solvent called Econamine FG Plus. Approximately 90% of the CO_2 in the flue gas is absorbed into the lean solvent. The flue gas then passes through a water wash vessel to minimize solvent losses due to mechanical entrainment and evaporation.

The rich solvent exits the bottom of the absorption column and is preheated in a Rich/Lean heat exchanger designed to decrease the rich solution while at the same time increase the lean solution. The rich solvent then passes to a steam stripper where the amine-CO_2 reaction is reversed and the CO_2 "stripped" from the solvent. The primary energy source to reverse the chemical reaction and to strip the CO_2 out of solution derives from steam condensation in a reboiler at the bottom of the stripping column. This medium quality steam is taken directly from the IP/LP turbine crossover pipe—causing a reduction in LP turbine gross turbine output. The hot, wet vapor from the top of the stripper, containing CO_2, steam, and solvent vapor, is partially condensed using cooling water. Water from the partially condensed stream is separated in a reflux drum and the uncondensed CO_2-rich gas is sent to the CO_2 compressor train.

CO_2 Compression and Dehydration

CO_2 from the reflux drum is cooled further and compressed in a multiple-stage, intercooled compressed to 15.2 MPa (2,215 psia) in preparation for pipeline transport. During compression, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The virtually moisture-free supercritical CO_2 steam is then ready for pipeline transport.

6.5 CASE 1 (PC BAU) & 7 (PC BAU RETROFIT) - MAJOR EQUIPMENT LIST

ACCOUNT 1 FUEL AND SORBENT HANDLING

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 7(PC BAU retrofit) Design Condition
1A	Bottom Trestle Dumper	NA	181 tonne/hr (200 tph)	2	No Change
1B	Receiving Hoppers	N/A	N/A	2	
2	Feeder	Belt	572 tonne/hr (630 tph)	2	
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	
4	Transfer Tower No. 1	Enclosed	N/A	1	
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	
6	As-Received Coal Sampling System	Two-stage	N/A	1	
7	Conveyor No. 2	Belt conveyor	1,134 tonne/hr (1,250 tph)	1	
8	Reclaim Hopper	N/A	36 tonne (40 ton)	3	
9	Feeder	Vibratory	154 tonne/hr (170 tph)	3	
10	Conveyor No. 3	Belt conveyor	308 tonne/hr (340 tph)	1	
11	Crusher Tower	N/A	N/A	1	
12	Coal Surge Bin w/ Vent Filter	Dual outlet	154 tonne/hr (170 tph)	2	
13	Crusher	Impactor reduction	8 cm x 0 – 3 cm x 0 (3" x 0 – 1¼" x 0)	2	
14	As-Fired Coal Sampling sys.	Swing hammer	N/A	2	
15	Conveyor No. 4	Belt w/tripper	308 tonne/hr (340 tph)	1	
16	Transfer Tower No. 2	Enclosed	N/A	1	
17	Conveyor No. 5	Belt w/tripper	308 tonne/hr (340 tph)	1	
18	Coal Silo w/ Vent Filter and Slide Gates	Field Erected	726 tonne/hr (800 ton)	3	
19	Limestone Truck Unloading Hopper	N/A	36 tonne (40 ton)	1	

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 7(PC BAU retrofit) Design Condition
20	Limestone Feeder	Belt	82 tonne/hr (90 tph)	1	No Change
21	Limestone Conveyor No. 1	Belt	82 tonne/hr (90 tph)	1	
22	Limestone Reclaim Hopper	N/A	18 tonne/hr (20 tph)	1	
23	Limestone Reclaim Feeder	Belt	64 tonne/hr (70 tph)	1	
24	Limestone Conveyor No. 2	Belt	64 tonne/hr (70 tph)	1	
25	Limestone Day Bin	w/ actuator	245 tonne (270 tons)	2	

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 7(PC BAU retrofit) Design Condition
1	Coal Feeder	Gravimetric	36 tonne/hr (40 tph)	6	No Change
2	Coal Pulverizer	Ball type or eq.	36 tonne/hr (40 tph)	6	
3	Limestone Weigh Feeder	Gravimetric	20 tonne/hr (22 tph)	2	
4	Limestone Ball Mill	Rotary	20 tonne/hr (22 tph)	2	
5	Mill Slurry Tank with Agitator	N/A	75,709 liters (20,200 gal)	2	
6	Mill Recycle Pumps	Horizontal centrifugal	308 lpm @12m H_2O (300 gpm @40ft H_2O)	2	
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	82 lpm (90 gpm) per cyclone	2	
8	Distribution Box	2-way	N/A	2	
9	Limestone Storage Tank with Agitator	Field erected	439,111 liters (116,000 gal)	2	
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	218 lpm @9m H_2O (240 gpm @30ft H_2O)	2	

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 7(PC BAU retrofit) Design Condition
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,097,778 liters (290,000 gal)	2	No Change
2	Condensate Pumps	Vert. canned	23,091 lpm @ 213 m H_2O (6,100 gpm @ 700 ft H_2O)	2	
3	Deaerator and Storage Tank	Horiz. spray type	1,828,433 kg/hr (4,031,000 lb/hr), 5 min tank	1	
4	Boiler Feed Pump/ Turbine	Barrel type, multi-staged, centrifugal	30,662 lpm @ 3,475 m H_2O (8,100 gpm @11,400 ft H_2O)	2	
5	Startup Boiler Feed Pump, Electric Motor Driven Pumps	Barrel type, multi-staged, centrifugal	9,085 lpm @ 3,475 m H_2O (2,400 gpm @11,400 ft H_2O)	1	
6	LP Feedwater Heater 1A/1B	Horiz. U tube	689,461 kg/hr (1,520,000 lb/hr)	2	
7	LP Feedwater Heater 2A/2B	Horiz. U tube	689,461 kg/hr (1,520,000 lb/hr)	2	
8	LP Feedwater Heater 3A/3B	Horiz. U tube	689,461 kg/hr (1,520,000 lb/hr)	2	
9	LP Feedwater Heater 4A/4B	Horiz. U tube	689,461 kg/hr (1,520,000 lb/hr)	2	
10	HP Feedwater Heater 6	Horiz. U tube	1,827,979 kg/hr (4,030,000 lb/hr)	1	
11	HP Feedwater Heater 7	Horiz. U tube	1,827,979 kg/hr (4,030,000 lb/hr)	1	
12	HP Feedwater Heater 8	Horiz. U tube	1,827,979 kg/hr (4,030,000 lb/hr)	1	
13	Auxiliary Boiler	Shop fabricated, water-tube	18,144 kg/hr (40,000 lb/hr) 2.8 MPa (400 psig), 343°C (650°F)	1	

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 7(PC BAU retrofit) Design Condition
14	Fuel Oil System	No 2 fuel oil for light off	1.135,632 liters (300,000 gal)	1	No Change
15	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 cfm @ 100 psig)	3	
16	Inst. Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	3	
17	Closed Cycle Cooling Heat Exch.	Shell & tube	53MMkJ/hr (50MMBtu/hr) each	2	
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	3	
19	Engine-Driven Fire Pump	Vert. turbine, diesel engine	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	2	
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	2	
21	Raw Water Pumps	SS, single suction	11,470 lpm @ 43 m H_2O (3,030 gpm @ 140 ft H_2O)	3	
22	Filtered Water Pumps	SS, single suction	1,438 lpm @ 49 m H_2O (380 gpm @ 160 ft H_2O)	3	
23	Filtered Water Tank	Vertical, cylindrical	1,377,901 liters (364,000 gal)	1	
24	Makeup Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	606 lpm (130 gpm)	2	
25	Liquid Waste Treatment System	--	10 years, 25-hour storm	1	

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 7(PC BAU retrofit) Design Condition
1	Boiler with superheater, economizer and air heater	Supercritical, drum, wall-fired, low NOx burners, overfire air	1,827,979 kg/hr steam @ 24.1 MPa/593°C/593°C (4,030,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	No Change
2	Primary Air Fan	Centrifugal	237,229 kg/hr, 3,245 m^3/min @ 123 cm WG (523,000 lb/hr, 114,600 acfm @ 48 in. WG)	2	
3	FD Fan	Centrifugal	772,015 kg/hr, 10,568 m^3/min @ 47 cm WG (1,702,000 lb/hr, 373,200 acfm @ 19 in. WG)	2	
4	ID Fan	Centrifugal	1,119,467 kg/hr, 23,769 m^3/min @ 90 cm WG (2,468,000 lb/hr, 839,400 acfm @ 36 in. WG)	2	
5	SCR Reactor Vessel	Space for spare layer	2,240,749 kg/hr (4,940,000 lb/hr)	2	
6	SCR Catalyst	--	--	3	
7	Dilution Air Blower	Centrifugal	133 m^3/min @ 108 cm WG (4,700 acfm @ 42 in. WG)	3	
8	Ammonia Storage	Horizontal tank	147,632 liter (39,000 gal)	5	
9	Ammonia Feed Pump	Centrifugal	28 lpm @ 91 m H_2O (7 gpm @ 300 ft H_2O)	3	

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 7(PC BAU retrofit) Design Condition
1	Bag fabric filter.	Single stage, high-ratio with pulse-jet online cleaning system	1,119,467 kg/hr (2,468,000 lb/hr) 99.8% efficiency	2	No Change
2	Absorber Module	Counter-current Open spray	37,662 m^3/min (1,330,000 acfm)	1	
3	Recirculation Pumps	Horizontal centrifugal	132,490 lpm @ 64 m H_2O (35,000 gpm @ 210 ft H_2O)	6	
4	Bleed Pumps	Horizontal centrifugal	4,013 lpm (1,060 gpm) at 20 wt% solids	3	
5	Oxidation Air Blowers	Centrifugal	168 m^3/min @ 0.3 MPa (5,930 acfm @ 42 psia)	3	
6	Agitators	Side entering	50 hp	6	
7	Dewatering Hydrocyclones	Radial assembly (5 units EA)	1,022 lpm (270 gpm) per cyclone	2	
8	Vacuum Belt Filter	Horizontal belt	32 tonne/hr (35 tph) of 50 wt % slurry	3	
9	Filtrate Water Return Pumps	Horizontal centrifugal	606 lpm @ 12 m H_2O (160 gpm @ 40 ft H_2O)	2	
10	Filtrate Water Return Storage Tank	Vertical, lined	416,399 lpm (110,000 gal)	1	
11	Process Makeup Water Pumps	Horizontal centrifugal	2,271 lpm @ 21 m H_2O (600 gpm @ 70 ft H_2O)	2	

ACCOUNT 5C CARBON DIOXIDE RECOVERY

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Case 7(PC BAU retrofit) Design Condition	Case 7 Qty
1	Econamine FG Plus	Amine-based CO_2 capture technology	NA	1,262,800 kg/hr (2,784,000 lb/hr) 19.5 wt % CO_2 concentration	2
2	CO_2 Compressor	Reciprocating	NA	222,748 kg/hr@ 15.2 MPa (491,075 lb/hr @ 2,200 psia)	2

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

N/A

ACCOUNT 7 HRSG, DUCTING & STACK

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 7(PC BAU retrofit) Design Condition
1	Stack	Reinforced concrete w/ FRP liner	152 m (500 ft) high x 5.8 m (19 ft) diameter	1	No Change

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 7(PC BAU retrofit) Design Condition
1	Steam Turbine	Commercially available advanced steam turbine	610 MW, 24.1 MPa/ 593°C/593°C (3500 psig/ 1100°F/1100°F)	1	Blading Modifications for lower steam flow
2	Steam Turbine Generator	Hydrogen cooled, static excitation	680 MVA @ 0.9 p.f., 24 kV, 60 Hz	1	

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 7(PC BAU retrofit) Design Condition
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,541 MMkJ/hr (2,410 MMBtu/hr), Inlet water temperature 16ºC (60ºF), Water temperature rise 11ºC (20ºF)	1	No Change

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 7(PC BAU retrofit) Design Condition
1	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 2,657 MMkJ/hr (2,520 MMBtu/hr) heat load	1	No Change
2	Circ. Water Pumps	Vertical, wet pit	476,966 lpm @ 30.5 m WG (126,000 gpm @ 100 ft WG)	3	

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 7(PC BAU retrofit) Design Condition
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	No Change
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	
3	Clinker Grinder	--	3.6 tonnes/hr (4 tph)	2	
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	
5	Hydroejectors	--	--	12	
6	Economizer/Pyrites Transfer Tank	--	--	1	

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 7(PC BAU retrofit) Design Condition
7	Ash Sluice Pumps	Vertical, wet pit	151 lpm @ 17 m H_2O (40 gpm @ 56 ft H_2O)	2	No Change
8	Ash Seal Water Pumps	Vertical, wet pit	7,571 lpm @ 9 m H_2O (2,000 gpm @ 28 ft H_2O)	2	
9	Hydrobins	--	151 lpm (40 gpm)	2	
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	
12	Air Blower	--	14 m^3/min @ 0.2 MPa (510 scfm@ 24 psi)	2	
13	Fly Ash Silo	Reinforced concrete	499 tonnes (1,100 tons)	2	
14	Slide Gate Valves	--	--	2	
15	Unloader	--	91 tonnes/hr (100 tph)	1	
16	Telescoping Unloading Chute	--	--	1	

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 7(PC BAU retrofit) Design Condition
1	STG Transformer	Oil-filled	24 kV/345 kV, 640 MVA, 3-ph, 60 Hz	1	No Change
2	Auxiliary Transformer	Oil-filled	24 kV/ 4.16 kV, 33 MVA, 3-ph, 60 Hz	2	24 kV/ 4.16 kV, 128 MVA, 3-ph, 60 Hz
3	Low Voltage Transformer	Dry ventilated	4.16 kV /480 V, 5 MVA, 3-ph, 60 Hz	2	4.16 kV /480 V, 19 MVA, 3-ph, 60 Hz
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	No Change
5	Medium Voltage Switchgear	Metal Clad	4.16 kV, 3-ph, 60 Hz	2	

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 7(PC BAU retrofit) Design Condition
6	Low Voltage Switchgear	Metal Enclosed	480 kV, 3-ph, 60 Hz	2	No Change
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Case 1 (PC BAU) Design Condition	Qty	Case 7(PC BAU retrofit) Design Condition
1	DCS - Main Control	Monitor/keyboard; Operator printer – laser color; Eng. Printer – laser black & white	Operator Stations/Printers and Engineering Stations/Printers	1	No Change
2	DCS - Processor	Microprocessor with Redundant Input/Output	N/A	1	
4	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	

6.6 CASE 7 (PC BAU RETROFIT) - COST ESTIMATING RESULTS

Exhibit 6-15 through Exhibit 6-18 show the capital and operating costs for this plant. Capital cost estimating methodology is explained in Section 4. The detailed breakdowns of the capital cost estimates for each case are included in Appendix B.

Note: Costs impacted by changes in design and operating parameter values from the business-as-usual case values to the CO_2 capture design and operation performance requirements are highlighted in the following business-as-usual retrofit case cost exhibits.

Exhibit 6-15 Case 7 (PC BAU Retrofit) Total Plant Costs

Client: U.S. DOE / NETL **Report Date:** 06-Feb-08
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST SUMMARY

Case: Case 7 - "Business As Usual" SuperCritical PC Retrofit w CO2 Capture
Plant Size: 379.0 MW,net **Estimate Type:** Conceptual Cost Base Jan 2007 $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL HANDLING SYSTEM	15,481	4,183	9,376		$29,040	2,602		4,746	$36,389	96
2	COAL PREP & FEED SYSTEMS	10,405	603	2,638		$13,646	1,196		2,226	$17,068	45
3	FEEDWATER & MISC. BOP SYSTEMS	40,107		18,856		$58,963	5,369		10,462	$74,795	197
4	PC BOILER & ACCESSORIES										
4.1	PC Boiler & Accessories	148,766		83,888		$232,654	22,535		25,519	$280,708	741
4.2	SCR (w/4.1)										
4.3	Open										
4.4-4.9	Secondary Air System										
	Subtotal 4	148,766		83,888		$232,654	22,535		25,519	$280,708	741
5A	**FLUE GAS CLEANUP**	**109,119**		**37,584**		**$146,703**	**14,148**		**14,932**	**$175,783**	**464**
5B	**CO2 REMOVAL & COMPRESSION**	**229,832**		**69,851**		**$299,683**	**29,968**	**52,879**	**49,448**	**$431,979**	**1,140**
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	N/A		N/A							
6.2-6.9	Combustion Turbine Accessories										
	Subtotal 6										
7	HRSG, DUCTING & STACK										
7.1	Heat Recovery Steam Generator	N/A		N/A							
7.2-7.9	Ductwork, Stack	16,653	959	11,402		$29,013	2,656		4,132	$35,801	94
	Subtotal 7	16,653	959	11,402		$29,013	2,656		4,132	$35,801	94
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories & Modifications	48,728		6,632		$55,360	5,301		6,077	$66,738	176
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	23,094	1,042	12,656		$36,792	3,213		5,619	$45,625	120
	Subtotal 8	71,822	1,042	19,288		$92,152	8,514		11,697	$112,363	296
9	COOLING WATER SYSTEM	11,816	6,553	11,613		$29,981	2,799		4,503	$37,283	98
10	ASH/SPENT SORBENT HANDLING SYS	4,232	133	5,628		$9,992	951		1,126	$12,069	32
11	**ACCESSORY ELECTRIC PLANT**	**23,269**	**13,243**	**37,510**		**$74,022**	**6,958**		**9,706**	**$90,686**	**239**
12	INSTRUMENTATION & CONTROL	8,069		8,480		$16,549	1,515		2,222	$20,285	54
13	**IMPROVEMENTS TO SITE**	**5,849**	**3,362**	**11,876**		**$21,088**	**2,090**		**4,636**	**$27,814**	**73**
14	**BUILDINGS & STRUCTURES**		**45,366**	**43,456**		**$88,822**	**8,464**		**14,593**	**$111,879**	**295**
	TOTAL COST	**$695,420**	**$75,443**	**$371,445**		**$1,142,308**	**$109,767**	**$52,879**	**$159,947**	**$1,464,901**	**$3,865**

Exhibit 6-16 Case 7 (PC BAU Retrofit) Operating Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base Jan	2007
Case 7 - "Business As Usual" SuperCritical PC Retrofit w CO2 Capture					Heat Rate-net(Btu/kWh):	**12,660**
Plant Output:	CO_2 (tpd):	**10,549**	H_2 (mmscfd):		MWe-net:	**379.0**
					Capacity Factor: (%):	85.0
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Plant			
Skilled Operator	2.0		2.0			
Operator	**11.3**		**11.3**			
Foreman	1.0		1.0			
Lab Tech's, etc.	2.0		2.0			
TOTAL-O.J.'s	**16.3**		16.3			
					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost(calc'd)					**$6,138,007**	**16.20**
Maintenance Labor Cost(calc'd)					**$8,886,456**	**23.45**
Administrative & Support Labor(calc'd)					**$3,756,116**	**9.91**
TOTAL FIXED OPERATING COSTS					**$18,780,579**	**49.55**
VARIABLE OPERATING COSTS						$/kWh-net
Maintenance Material Cost(calc'd)					**$15,407,790**	**0.0055**
Consumables	Consumption		Unit	Initial		
	Initial	/Day	Cost	Cost		
Water(/1000 gallons)		**8,332**	1.03		**$2,662,621**	**0.0009**
Chemicals						
MU & WT Chem.(lb)	**245,670**	**40,379**	0.16	**$40,486**	**$2,064,524**	**0.0007**
Carbon (Mercury Removal) (lb)			1.00			
COS Catalyst (m3)			2308.40			
Limestone (ton)	**4,426**	**509**	20.60	**$91,179**	**$3,255,057**	**0.0012**
MEA Solvent (ton)	**734**	**1**	2142.40	**$1,571,840**	**$692,344**	**0.0002**
NaOH (tons)	**51**	**5**	412.96	**$21,052**	**$649,261**	**0.0002**
H2SO4 (tons)	**50**	**5**	132.15	**$6,555**	**$202,684**	**0.0001**
Corrosion Inhibitor				$147,250	$7,000	0.0000
Ammonia (28% NH3) ton	**721**	**103**	123.60	**$89,067**	**$3,947,565**	**0.0014**
Activated Carbon(lb)	**452,919**	**1,240**	1.00	**$452,919**	**$384,718**	**0.0001**
Subtotal Chemicals				**$2,420,348**	**$11,203,154**	**0.0040**
Other						
Supplemental Fuel(MBtu)			6.75			
SCR Catalyst Replacement		**0.6**	5500.00		**$962,097**	**0.0003**
Emission Penalties						
Subtotal Other					**$962,097**	**0.0003**
Waste Disposal						
Spent Mercury Catalyst (lb.)			0.40			
Flyash (ton)		**96**	15.45		**$458,782**	**0.0002**
Bottom Ash(ton)		**383**	15.45		**$1,835,187**	**0.0007**
Subtotal Solid Waste Disposal					**$2,293,969**	**0.0008**
By-products & Emissions						
Gypsum (tons)		**777**				
Sulfur(tons)			-25.00			
Subtotal By-Products						
TOTAL VARIABLE OPERATING COSTS				**$2,420,348**	**$32,529,631**	**0.0115**
FUEL (tons)	**148,062**	**4,935**	42.11	**$6,234,882**	**$64,479,076**	**0.0228**

Exhibit 6-17 Case 7 (PC BAU Retrofit) Capital Investment Requirement Summary

TITLE/DEFINITION					
Case: **Case 7 - "Business As Usual" SuperCritical PC Retrofit w CO2 Capture**					
Plant Size:	**379.0** (MW,net)		HeatRate:	**12,660** (Btu/kWh)	
Primary/Secondary Fuel(type):	Illinois #6		Cost:	1.80 ($/MMBtu)	
Design/Construction:	3 (years)		BookLife:	30 (years)	
TPC(Plant Cost) Year:	2007 Jan				
Capacity Factor:	85 (%)		CO2 Removed:	**10,549** (TPD)	
CAPITAL INVESTMENT			**$x1000**		**$/kW**
Process Capital & Facilities			**1,142,308**		**3014.0**
Engineering(incl.C.M.,H.O.& Fee)			**109,767**		**289.6**
Process Contingency			**52,879**		**139.5**
Project Contingency			**159,947**		**422.0**
TOTAL PLANT COST(TPC)			**$1,464,901**		**3865.2**
OPERATING & MAINTENANCE COSTS (2007 Dollars)			**$x1000**		**$/kW-yr**
Operating Labor			**6,138**		**16.2**
Maintenance Labor			**8,886**		**23.4**
Maintenance Material			**15,408**		**40.7**
Administrative & Support Labor			**3,756**		**9.9**
TOTAL OPERATION & MAINTENANCE			**$34,188**		**90.2**
FIXED O & M			**$21,546**		**56.8**
VARIABLE O & M			**$12,643**		**33.4**
CONSUMABLE OPERATING COSTS, less Fuel (2007 Dollars)			**$x1000**		**¢/kWh**
Water			**2,663**		**0.09**
Chemicals			**11,203**		**0.40**
Other Consumables			**962**		**0.03**
Waste Disposal			**2,294**		**0.08**
TOTAL CONSUMABLE OPERATING COSTS			**$17,122**		**0.61**
BY-PRODUCT CREDITS					
FUEL COST (2007 Dollars)			**$64,479**		**2.28**
				Levelized Costs	
PRODUCTION COST SUMMARY		**LF**		**¢/kWh**	
Fixed O & M		1.162		**0.89**	
Variable O & M		1.162		**0.52**	
Consumables		1.162		**0.70**	
By-product Credit		1.162			
Fuel		1.209		**2.76**	
TOTAL PRODUCTION COST				**4.87**	
2007 CARRYING CHARGES (Capital)				**8.51**	
CCF for a 20-Year Levelization Period - IOU - Lower-Risk		16.4			
20 YEAR LEVELIZED BUSBAR COST OF POWER				**13.39**	

Exhibit 6-18 Case 7 (PC BAU Retrofit) Estimate Basis and Financial Criteria Summary

GENERAL DATA/CHARACTERISTICS

Case Title:	**Case 7 - "Business As Usual" SuperCritical PC Retrofit w CO2 Capture**		
Unit Size:/Plant Size:		**379.0**	MW,net
Location:		Midwestern, USA	
Fuel: Primary/Secondary	Illinois #6	11,666	Btu/lb
Energy From Primary/Secondary Fuels		**12,660**	Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):		85	%
Capital Cost Year Dollars (Reference Year Dollars):		2007	Jan
Delivered Cost of Primary/Secondary Fuel		1.80	$/MMBtu
Design/Construction Period:		3	years
Plant Startup Date (1st. Year Dollars):		2010	
Financial Parameter/Risk Level		IOU Low Risk	

FINANCIAL CRITERIA

Project Book Life:	30	years
Book Salvage Value:		%
Project Tax Life:	20	years
Tax Depreciation Method:	20 years, 150% declining balance	
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		%
Economic Basis:	20th Year Current Dollars	

Capital Structure		% of Total	Cost(%)
	Common Equity	50.00	12.00
	Preferred Stock		
	Debt	50.00	9.00
Weighted Cost of Capital:(after tax)		8.79 %	

		2010 - 2030	
Nominal Escalation	General	1.87	% per year
	Coal Price	2.35	% per year
	Secondary Fuel:	1.96	% per year

6.7 CASES 5 (PC CR RETROFIT) AND 7 (PC BAU RETROFIT) SUMMARY

Cases 5 (PC CR retrofit) and 7 (PC BAU retrofit) are configured to be revised configurations of Cases 3 (PC CR) and 1 (PC BAU) respectively, to capture and compress CO_2 for off-site sequestration. As illustrated in the report sections, the approach to retrofitting varies with Cases 1 and 3. Case 1 (PC BAU) was a baseline PC plant configuration, built with no anticipation of future CO_2 capture. This plant was then retrofitted to capture CO_2 as Case 7 (PC BAU retrofit) with penalties of reduced net power output and efficiency. Conversely, Case 3 (PC CR) was designed to be readily retrofitted for CO_2 capture by designing in additional process equipment capacities and configurations in anticipation of retrofit, thereby avoiding net power loss to the grid. Case 3 was then retrofitted to become Case 5 (PC CR retrofit), capable of capturing CO_2.

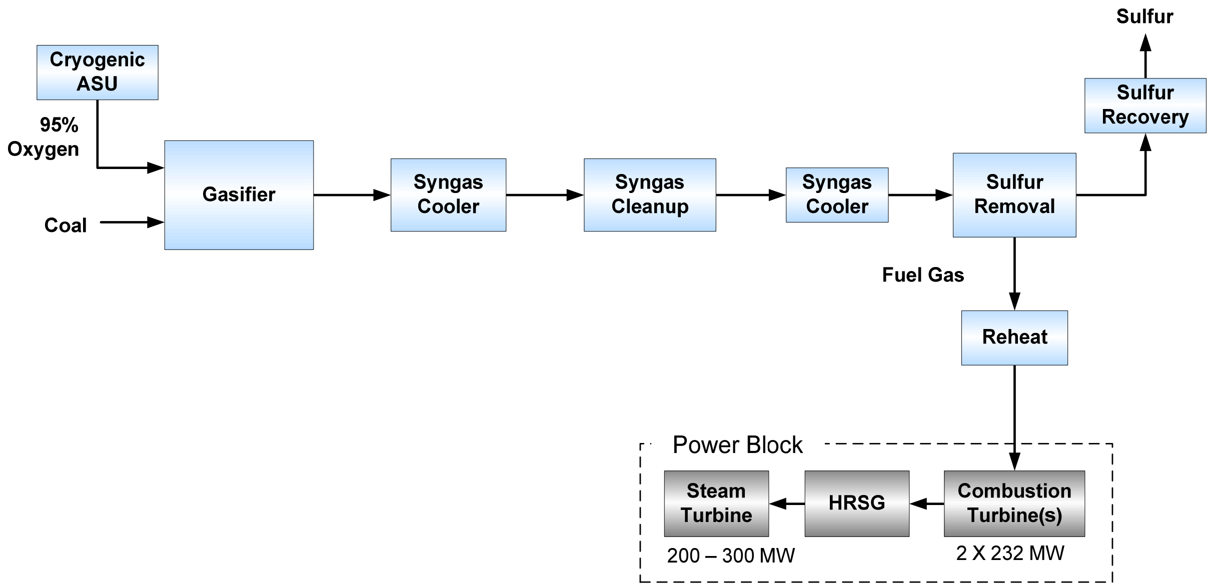
The performance and net economic results of the PC cases are shown in Exhibit 6-19. Case 5 (PC CR retrofit) produces more gross power than Case 7 (PC BAU retrofit). The capital cost to retrofit both plants primarily reflects the addition of CO_2 capture and compression. Case 5 required an additional $701,682,000 while Case 7 required $598,509,000. The total capital cost (TPC) is $2,872/kW and $3,865/kW for the respective plants. Results show that the cost of electricity from Case 5—"Capture Ready Retrofit" is approximately <u>20% less</u> than Case 7—"Business as usual retrofit". The avoided cost per tonne CO_2 is $57/ton for Case 5 (PC CR retrofit) and $93/ton for Case 7 (PC BAU retrofit).

Exhibit 6-19 Supercritical PC Plant Performance and Economic Summary

	Case 1 PC Business-as-Usual	Case 7 PC Business-as-Usual Retrofit	Case 3 PC Capture-Ready	Case 5 PC Capture-Ready Retrofit
Gross Power Output, MW_e	580.3	467.3	580.3	663.4
Net Power Output, MW_e	550.2	379.0	550.2	546.0
Net Plant Efficiency (HHV)	39.1%	27.0%	39.1%	27.2%
Net Plant Heat Rate (HHV), kJ/kWh (Btu/kWh)	9,201 (8,721)	13,357 (12,660)	9,201 (8,721)	13,224 (12,534)
Additional Plant Cost for Retrofit[1], 1000$	N/A	$598,509	N/A	$457,287
Total Plant Cost (TPC)[1], 1000$	$866,391	$1,464,901	$1,110,786	$1,568,073
Incremental TPC[1], 1000$	N/A	$598,509	$244,395	$701,682
Total Plant Cost[1], $/kW	$1,575	$3,865	$2,019	$2,872
Incremental TPC[1], $/kW	N/A	$2,290	$444	$1,297
Total Levelized COE[1,2,3], ¢/kWh	6.33	13.39	7.31	10.69
Incremental Levelized COE[1,2,3], ¢/kWh	N/A	7.06	0.98	4.36
Total CO_2 Emitted, kg/MWh_{net} (lb/MWh_{net})	804 (1,773)	117 (258)	804 (1,773)	115 (254)
Total CO_2 Captured, kg/MWh_{net} (lb/MWh_{net})	N/A	1,052 (2,319)	N/A	1,040 (2,294)
Cost of CO_2 Captured[1,2], $/tonne ($/ton)	N/A	$67 ($61)	N/A	$42 ($38)
Cost of CO_2 Avoided[1,2], $/tonne ($/ton)	N/A	$103 ($93)	N/A	$63 ($57)

Note:
Costs in 2007 Dollars
"Incremental costs" are compared to Case 1—"PC Business-as-Usual"
[1]Transportation, Storage, and Monitoring of CO_2 not included
[2]85% Capacity Factor
[3]20 year levelization period

Integrated Gasification Combined Cycle



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7. INTEGRATED GASIFICATION COMBINED CYCLE PLANTS CASES 2 (IGCC BAU) & 4 (IGCC CR)

7.1 CASE 2 (IGCC BAU) - E-GAS™ IGCC – BUSINESS-AS-USUAL (NO CAPTURE)

Case 2 (IGCC Business-as-usual) is configured to produce power without CO_2 capture. This case was taken directly from the recently completed NETL systems analysis study [Ref. 1]. The plant utilizes two oxygen-blown, high pressure ConocoPhillips (CoP) E-Gas™ two-stage gasifiers to produce a medium heating value syngas. Oxygen fed to the gasifiers is generated by two cryogenic air separation units (ASUs). The syngas is filtered and scrubbed of particulate, cooled, and cleaned of mercury before entering a Coastal Engineering promoted amine-based acid gas removal (AGR) system. The AGR removes H_2S from the gas stream which is sent to a Claus plant to produce elemental sulfur. The clean syngas leaving the AGR is humidified and fired in dual advanced F Class gas turbines. The gas turbines operate in a combined cycle mode, utilizing heat from the gas turbine exhaust to generate steam in a heat recovery steam generator (HRSG) to produce additional power.

The E-Gas™ two-stage coal gasification technology features an oxygen-blown, entrained flow, refractory lined gasifier with continuous slag removal. A coal/water slurry is injected into the gasifier with a 78/22 split to the primary and secondary stages. The slurry reacts with oxygen in the primary stage at about 1,371°C (2,500ºF) and 4.2 MPa (615 psia) while the slurry fraction injected into the second stage quenches the combustion reaction with endothermic gasification reactions. A turnkey, dedicated air separation unit supplies oxygen of 95 percent purity to the gasifier and the Claus plant.

Gas leaving the gasifier is cooled in a fire-tube syngas cooler producing high pressure steam. The cooled gas is cleaned of particulate via a cyclone collector followed by a ceramic candle filter. The raw syngas is then cleaned further in a spray scrubber to remove remaining particulate and trace components such as ammonia, cyanides, alkalis, etc.

Before entering the acid gas removal process, the syngas goes through a mercury removal bed in which 95% of the mercury is removed from the syngas with activated carbon. H_2S is removed from the cool, particulate-free gas stream with a promoted amine (MDEA) solvent. The purpose of the AGR unit is to remove H_2S to less than 30 ppm. The sulfur recovery unit is a Claus bypass-type sulfur recovery unit utilizing oxygen instead of air. The Claus plant produces molten sulfur by converting approximately one-third of the H_2S in the feed to SO_2, then reacting the H_2S and SO_2 to produce sulfur and water.

The gas turbine is an advanced F Class machine. The plant is configured with two gasifiers including processes to progressively cool and clean the gas, making it suitable for combustion in two gas turbines operating in a combined cycle mode with a single steam turbine.

Exhibit 7-1 is a block flow diagram for the overall plant with individual streams identified. Exhibit 7-2 follows the figure with detailed composition and state points for the numbered streams.

The plant produces a net output of 623 MW at a net plant efficiency of 39.3%, on an HHV basis. Performance is based on the properties of Illinois No. 6 coal, described in Section 3.2. Overall performance for the entire plant is summarized in Exhibit 7-3 which includes auxiliary power requirements.

7.2 CASE 4 (IGCC CR) - E-GAS™ IGCC POWER PLANT CO_2 CAPTURE-READY (NO CAPTURE)

Case 4 (IGCC Capture-Ready) is configured to operate with the same performance characteristics as Case 2 (IGCC BAU), but has been designed to be readily converted to capture CO_2 at a later date. In providing for the future retrofit of CO_2 capture equipment, the plant capacity is oversized and extra space allocated for the retrofit equipment. Because of the future addition of the retrofit, more syngas would be needed to fill the turbine than is available. Thus the plant is oversized so the future retrofit would not cause a derating of the turbine. Until the plant is retrofitted it is operated with reduced syngas production, but at a full gas turbine load. Plant performance for Case 2 (IGCC BAU) is retained for Case 4 (IGCC CR) utilizing a consistent gas turbine fuel requirement, coal and oxygen feed, etc.

The coal requirement for the IGCC capture-ready design after it is retrofitted for CO_2 capture is 5,734 TPD versus 5,567 TPD for the IGCC business-as-usual design, resulting in an increase in coal storage of about 4%. Capacity of the installed coal preparation equipment, slag handling equipment and sulfur plant are increased by 5%, with capital costs increased accordingly.

The same E-Gas™ two-stage coal gasification technology as utilized in Case 2 (IGCC BAU) is retained for Case 4 (IGCC CR), without modification to the vessel. The capacities of auxiliary gasifier processes are adjusted to accommodate the anticipated increase in gasifier output. To accommodate an increased flow of raw syngas exiting the gasifier, the total fire-tube heat exchanger duty for the two gasifiers increases from 537 MMBtu/hr to 596 MMBtu/hr (~11%).

Because of the change in acid gas removal requirements from the non-CO_2 case to one of CO_2 capture, the AGR process chosen to make the IGCC plant "Capture-Ready" is the single-stage Selexol process for H_2S removal. This "planned" approach allows easier retrofitting capability in the future by simply adding an additional absorber and CO_2 regeneration stage. Following retrofit, recovered CO_2 will be compressed to 2,215 psia and dried for delivery off-site.

The projected coal feed increase to the gasifier retrofitted for CO_2 capture will result in an increase in ASU capital cost, while continuing to operate at the Case 2 production rate. Upon retrofit, a larger capacity air compressor will be required due to the lack of gas turbine integration.

The increased capacity and performance capabilities of Case 4 (IGCC CR) versus Case 2 (IGCC BAU) are shown in the Equipment List in Section 7.3 and are the basis for the increase in capital cost.

Exhibit 7-1 Case 2 (IGCC BAU) and 4 (IGCC CR) Process Flow Diagram, E-Gas™ IGCC without CO_2 Capture

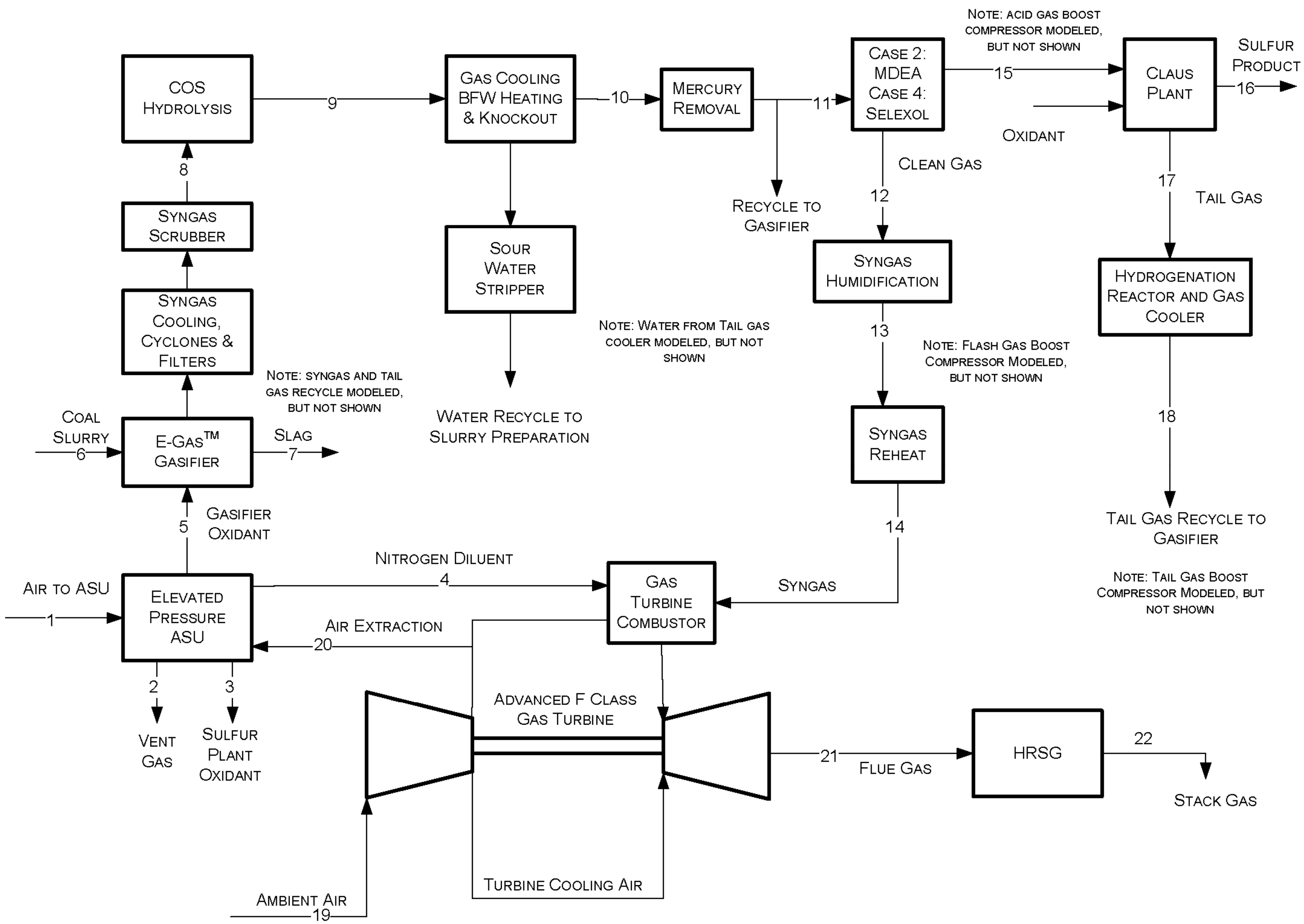

Exhibit 7-2 Case 2 (IGCC BAU) and 4 (IGCC CR) Stream Table, E-Gas™ IGCC without CO_2 Capture

	1	2	3	4	5	6[A]	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0262	0.0360	0.0024	0.0320	0.0000	0.0000	0.0080	0.0080	0.0092	0.0092
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0400	0.0400	0.0457	0.0457
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3851	0.3851	0.4403	0.4403
CO_2	0.0003	0.0090	0.0000	0.0000	0.0000	0.0000	0.0000	0.1468	0.1473	0.1685	0.1685
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2738	0.2738	0.3134	0.3134
H_2O	0.0099	0.2756	0.0000	0.0004	0.0000	1.0000	0.0000	0.1251	0.1246	0.0018	0.0018
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0079	0.0084	0.0092	0.0092
N_2	0.7732	0.4638	0.0140	0.9919	0.0180	0.0000	0.0000	0.0102	0.0102	0.0117	0.0117
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0026	0.0026	0.0002	0.0002
O_2	0.2074	0.2254	0.9500	0.0054	0.9500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	41,839	1,917	242	40,619	10,830	13,452	0	55,289	55,289	48,292	38,633
V-L Flowrate (lb/hr)	1,207,360	51,005	7,811	1,139,740	348,539	242,145	0	1,196,610	1,196,610	1,070,040	856,032
Solids Flowrate (lb/hr)	0	0	0	0	0	412,305	47,201	0	0	0	0
Temperature (°F)	235	70	90	385	191	140	1,850	400	401	103	103
Pressure (psia)	190.0	16.4	125.0	460.0	740.0	850.0	850.0	554.7	544.7	504.7	494.7
Enthalpy (BTU/lb)[B]	55.7	26.8	12.5	88.0	34.4	76.9	457.0	241.5	241.4	25.0	25.0
Density (lb/ft^3)	0.735	0.104	0.683	1.424	3.412	---	---	1.302	1.277	1.852	1.815
Molecular Weight	28.857	26.613	32.229	28.060	32.181	---	---	21.643	21.643	22.158	22.158

A - Solids flowrate includes dry coal; V-L flowrate includes slurry water and water from coal
B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 7-2 Case 2 (IGCC BAU) and 4 (IGCC CR) Stream Table Continued

	12	13	14	15	16	17	18	19	20	21	22
V-L Mole Fraction											
Ar	0.0095	0.0088	0.0088	0.0000	0.0000	0.0059	0.0092	0.0094	0.0094	0.0088	0.0088
CH_4	0.0471	0.0434	0.0434	0.0001	0.0000	0.0000	0.0383	0.0000	0.0000	0.0000	0.0000
CO	0.4544	0.4189	0.4189	0.0014	0.0000	0.0910	0.0003	0.0000	0.0000	0.0000	0.0000
CO_2	0.1513	0.1395	0.1395	0.7034	0.0000	0.4812	0.8551	0.0003	0.0003	0.0822	0.0822
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.3235	0.2982	0.2982	0.0010	0.0000	0.0186	0.0097	0.0000	0.0000	0.0000	0.0000
H_2O	0.0019	0.0798	0.0798	0.0000	0.0000	0.3490	0.0023	0.0108	0.0108	0.0718	0.0718
H_2S	0.0000	0.0000	0.0000	0.2941	0.0000	0.0068	0.0140	0.0000	0.0000	0.0000	0.0000
N_2	0.0120	0.0111	0.0111	0.0000	0.0000	0.0454	0.0710	0.7719	0.7719	0.7360	0.7360
NH_3	0.0002	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2076	0.2076	0.1012	0.1012
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	37,428	40,600	40,600	1,205	0	1,596	1,021	243,395	12,038	298,016	298,016
V-L Flowrate (lb/hr)	806,593	863,729	863,729	49,439	0	50,953	42,010	7,021,820	347,293	8,678,000	8,678,000
Solids Flowrate (lb/hr)	0	0	0	0	11,591	0	0	0	0	0	0
Temperature (°F)	99	266	385	187	368	320	251	59	811	1,111	270
Pressure (psia)	494.2	484.2	479.2	30.0	24.9	24.9	804.1	14.7	234.9	15.2	15.2
Enthalpy (BTU/lb)[B]	24.2	153.9	197.6	33.3	-97.5	288.6	49.1	13.8	200.3	330.6	106.9
Density (lb/ft^3)	1.776	1.324	1.125	0.177	---	0.095	4.340	0.076	0.497	0.026	0.057
Molecular Weight	21.550	21.274	21.274	41.022	---	31.929	41.154	28.849	28.849	29.119	29.119

B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 7-3
Case 2 (IGCC BAU) and 4 (IGCC CR) Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,030
Steam Turbine Power	278,480
TOTAL POWER, kWe	**742,510**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	440
Coal Milling	2,160
Coal Slurry Pumps	570
Slag Handling and Dewatering	1,110
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	47,130
Oxygen Compressor	8,240
Nitrogen Compressor	34,680
Syngas Recycle Blower	2,130
Tail Gas Recycle Blower	1,760
Boiler Feedwater Pumps	4,280
Condensate Pump	220
Flash Bottoms Pump	200
Circulating Water Pumps	3,350
Cooling Tower Fans	1,730
Scrubber Pumps	70
AGR Unit Auxiliaries	3,230
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	200
Miscellaneous Balance of Plant	3,000
Transformer Loss	2,540
TOTAL AUXILIARIES, kWe	**119,140**
NET POWER, kWe	**623,370**
Net Plant Efficiency (HHV)	39.3%
Net Plant Heat Rate (Btu/kWh)	8,681
CONDENSER COOLING DUTY 10^6 kJ (10^6 Btu)	**1,470 (1,393)**
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)	210,417 (463,889)
Thermal Input, kWt	1,586,023
Raw Water Usage, m^3/min (gpm)	14.2 (3,757)

[1] HHV of As-Received Illinois #6 11.12% Moisture Coal is 11,666 Btu/lb

7.2.1 Environmental Performance

The operation of the ConocoPhilips E-Gas™ IGCC combined cycle unit is projected to result in very low levels of emissions of Hg, NOx, SO_2 and particulate matter. A salable byproduct is produced in the form of elemental sulfur, but no credit is taken because of the highly variable local market conditions. A summary of the plant air emissions is presented in Exhibit 7-4.

Exhibit 7-4 Case 2 (IGCC BAU) and 4 (IGCC CR) Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 80% capacity	kg/MWh_{net} (lb/MWh_{net})
SO_2	0.0054 (0.0125)	215 (237)	0.049 (0.108)
NO_X	0.026 (0.059)	1,021 (1,126)	0.234 (0.515)
Particulates	0.003 (0.0071)	122 (135)	0.028 (0.062)
Hg	0.25×10^{-6} (0.57×10^{-6})	0.010 (0.011)	2.3×10^{-6} (5.0×10^{-6})
CO_2	85.7 (199)	3,427,000 (3,778,000)	785 (1,730)

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the Coastal SS Amine AGR process for Case 2 and Selexol™ for Case 4. Both AGR processes are designed to remove over 99 percent of the sulfur compounds in the fuel gas down to a level of less than 30 ppm. This results in a concentration in the flue gas of less than 4 ppm. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated to convert all sulfur species to H_2S, and then recycled back to the gasifier thereby eliminating the need for a tail gas treatment unit (TGU).

NO_X emissions are limited by the use of humidification and nitrogen dilution to 15 ppmvd (as NO_2 @15% O_2). The ammonia is removed with process condensate prior to the low-temperature AGR process. This helps lower NO_X levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber.

Ninety five percent of the mercury is captured from the syngas by an activated carbon bed.

The carbon balance for the plant is shown in Exhibit 7-5. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as dissolved CO_2 in the wastewater blowdown stream, and CO_2 in the stack gas and ASU vent gas. Gray wastewater is recycled within the plant as slurry water.

Exhibit 7-5 Case 2 (IGCC BAU) and 4 (IGCC CR) Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	134,141 (295,729)	**Slag**	1,016 (2,241)
Air (CO_2)	466 (1,027)	**Stack Gas**	133,496 (294,309)
	---	**ASU Vent**	94 (207)
	---	**Wastewater***	0 (0)
Total	134,606 (296,756)	**Total**	134,606 (296,756)

* by difference

Exhibit 7-6 shows the sulfur balance for the plant. Sulfur input includes the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, dissolved SO_2 in the wastewater blowdown stream, and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible. The total sulfur capture is represented by the following fraction

(Sulfur byproduct/Sulfur in the coal) or
(11,591/11,644) or
99.5%

Exhibit 7-6 Case 2 (IGCC BAU) and 4 (IGCC CR) Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,281 (11,644)	**Elemental Sulfur**	5,258 (11,591)
	---	**Stack Gas**	15 (34)
	---	**Wastewater***	9 (19)
Total	5,281 (11,644)	**Total**	5,281 (11,644)

* by difference

Overall Mass and Energy balance information is presented in tabular form in Exhibit 7-7.

Exhibit 7-7 Case 2 (IGCC BAU) and 4 (IGCC CR) Overall Energy and Mass Balance

In			Out		
	Energy Flow, MMBtu/hr	**Mass Flow, lb/hr**		**Energy Flow, MMBtu/hr**	**Mass Flow, lb/hr**
Coal	5,416	463,889	**Stack Gas**	928	8,678,000
Water	4	242,145	**Power**	2,170	---
Air	113	8,229,180	**Water**	18	147,419
	---	---	**Slag**	53	47,200
	---	---	**ASU Vent**	2	51,005
	---	---	**Compressor Intercoolers**	210	---
	---	---	**Condenser Duty**	1,390	---
	---	---	**Process Losses***	717	---
	---	---	**Sulfur**	45	11,590
Total	5,533	8,935,214	**Total**	5,533	8,935,214
Net Plant Efficiency, % HHV (Overall)	39.3%				

*Process Losses reflect various gasification, turbine and other heat and work losses this number was set by difference between Energy In and the sum of all other Energy Out rows.
Enthalpy reference conditions are 32.02 F & 0.089 psia
Aspen Flowsheet Balance is within 0.5%.

7.2.2 <u>Description of Process Systems</u>

The Case 2 (IGCC BAU) plant is based on the syngas fuel requirements for two advanced F Class gas turbines. Ambient operating conditions are indicated in the plant design basis. The pressurized entrained-flow E-Gas™ two-stage gasifier uses a coal/water slurry and oxygen to produce a medium heating value fuel gas. The process configuration for Case 4 (IGCC CR) is identical to Case 2. However, in anticipation of future retrofit for CO_2 Capture, *several process areas require capacity adjustments*.

The syngas produced in the gasifier first stage at about 1,371°C (2,500°F) is quenched to 1,010°C (1,850°F) by reacting with slurry injected into the second stage. The syngas passes through a fire-tube boiler syngas cooler and leaves at 371°C (700°F) where it then is used to heat the fuel gas saturation water. High-pressure saturated steam is generated in the syngas cooler and is joined with the main steam supply.

The gas goes through a series of additional gas coolers and cleanup processes including a cyclone, candle filter, water scrubber, COS hydrolysis reactor, carbon bed for mercury removal and an amine-based or Selexol™-based AGR plant. Slag captured by the filter and syngas scrubber is recovered in a slag recovery unit. Regeneration gas from the AGR plant is fed to a Claus plant, where elemental sulfur is recovered.

This plant utilizes a combined cycle for combustion of the syngas from the gasifier to generate electric power. Syngas humidification and nitrogen dilution aid in minimizing formation of NO_x during combustion in the gas turbine burner section. A Brayton cycle using air and combustion products as working fluid is used in conjunction with a conventional subcritical steam Rankine cycle. The limiting factor which determines the use of a subcritical steam cycle is the maximum design pressure of 12.4 MPa (1,800 psia) which can be tolerated in the E-Gas™ syngas cooler (also known as a firetube boiler). The two cycles are coupled by generation of steam in the heat recovery steam generator (HRSG), by feedwater heating in the HRSG, and by heat recovery from the IGCC process (fire-tube boiler syngas cooler). Energy balance information is presented in tabular form in Exhibit 7-7.

The following paragraphs describe some of the process sections in more detail. Additional process descriptions are included in Appendix A.

<u>Coal Receiving and Storage</u>

The function of the Coal Handling and Storage system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to and including the slide gate valves on the outlet of the coal storage silos.

Generally, the coal receiving facilities are capable of handling a moderate increase in coal flow. The coal required for the future retrofit of the Case 4 (IGCC CR) design is 5,734 TPD versus 5,567 TPD for Case 2 (IGCC BAU), resulting in an increase of about 3.3%. As such, the receiving equipment is not changed for Case 4. However, the 30 day storage pile area is increased by 4%, with Case 4 capital costs reflecting this change.

<u>Coal Grinding and Slurry Preparation</u>

Coal is fed onto a conveyor by vibratory feeders located below each coal silo. The conveyor feeds the coal to an inclined conveyor that delivers the coal to the rod mill feed hopper. The feed hopper provides a surge capacity of about two hours and contains two hopper outlets. A vibrating feeder on each hopper outlet supplies the weigh feeder, which in turn feeds a rod mill. Two rod mills each process 55 percent of the coal feed requirements of the gasifier. The rod mill grinds the coal and wets it with treated slurry water transferred from the slurry water tank by the slurry water pumps. The coal slurry is discharged into the rod mill product tank. Then the slurry is pumped from the rod mill product tank to the slurry storage and slurry blending tanks.

The coal grinding system is equipped with a dust suppression system consisting of water sprays aided by a wetting agent. The degree of dust suppression required depends on local environmental regulations. All of the tanks are equipped with vertical agitators to keep the coal slurry solids suspended.

The equipment in the coal grinding and slurry preparation system is fabricated of materials appropriate for the abrasive environment present in the system. The tanks and agitators are rubber lined. The pumps are either rubber lined or hardened metal to minimize erosion. Piping is fabricated of high-density polyethylene (HDPE).

Due to the anticipated 3.3% increase in coal feed for the future retrofit of the Case 4 (IGCC CR) design, the capacity of the installed coal preparation equipment is increased by 5%, with capital costs increased accordingly.

Gasification

The E-Gas™ two-stage coal gasification technology features an oxygen-blown, entrained flow, refractory lined gasifier with continuous slag removal. A 63 wt% dry coal/water slurry is injected into the gasifier with a 78/22 percent split to the primary and secondary stages, respectively. The slurry reacts with oxygen in the primary stage at about 1,371°C (2,500ºF) and 4.2 MPa (615 psia). The coal undergoes partial combustion, releasing heat that causes the gasification reactions to proceed very rapidly and the ash to fuse and flow. A turnkey, dedicated air separation unit supplies oxygen of 95 percent purity.

The primary gasification zone operates above the ash fusion temperature of 1,204 to 1,371°C (2,200 to 2,500ºF), thereby ensuring the flow and removal of molten slag. This temperature is maintained by a controlled oxygen feed. All of the oxygen is used in the first stage in exothermic partial oxidation/gasification reactions. The molten ash exits through a tap hole at the bottom of the primary stage into a water quench, forming an inert vitreous slag. The molten slag is quenched in water and removed in a novel continuous-pressure letdown/dewatering system. Gaseous products from the primary zone flow upward into the second gasification zone, a vertical refractory-lined vessel.

The remaining 22 percent of preheated slurry is injected in the secondary zone of the gasifier to achieve a full slurry quench. None of the raw fuel gas stream is recycled to promote quenching.

Use of the second stage of gasification is a method for both heating value enhancement and raw syngas cooling. In the secondary zone, hot gaseous products from the primary zone provide the thermal energy required to heat and gasify the atomized slurry. These gasification reactions are endothermic and considerably decrease the sensible heat content of the primary zone gases resulting in quench of the gasification reactions. As a result, the exit temperature of the secondary zone, around 1,010°C (1,850ºF), is much lower than that of the primary zone.

Char produced in the secondary gasification zone leaves the gasifier entrained in the fuel gas stream. Combined downstream cyclone and candle filter particulate control devices remove the char from the fuel gas stream for return to the gasifier first stage.

The same E-Gas™ two-stage coal gasification technology as utilized in Case 2 will be retained for Case 4, without modification to the vessel. The coal feed capacity of each gasifier with full slurry quench is projected to exceed 3,000 TPD, which is well-beyond the retrofit design feed of 2,884 TPD. The capacities of auxiliary gasifier processes are adjusted to accommodate the anticipated increase in gasifier output.

As such, the capital cost for the gasifier vessel is not changed.

Slag Handling

Due to the anticipated 3.3% increase in coal feed with the future retrofit of the Case 4 (IGCC CR) design, the capacity of the slag handling equipment is increased by 5%, with capital costs increased accordingly.

Raw Gas Cooling

Hot raw gas from the secondary gasification zone exits the gasifier at 4.2 MPa (615 psia) and 1,010°C (1,850ºF). This gas stream is cooled to approximately 371°C (700ºF) in a fire-tube boiler. The waste heat from this cooling is used to generate high-pressure steam. Boiler feedwater on the outside of the tubes is saturated, and then steam and water are separated in a steam drum. This steam then forms part of the general heat recovery system that provides steam to the steam turbine.

The Case 4 (IGCC CR) design plant has to accommodate the increased flow of raw syngas exiting the gasifier after future retrofit. The increase in syngas flow over Case 2 (IGCC BAU) presents an increased demand on the syngas cooler. The total fire-tube heat exchanger duty for the two gasifiers increases from 537 MMBtu/hr to 596 MMBtu/hr. This increase affects both the syngas cooler costs and the entire heat recovery system costs.

Particulate Removal

A cyclone and a ceramic candle filter in series are used to remove any particulate material exiting the secondary gasification zone. This material, char and fly ash, is recycled back to the gasifier. The filter is comprised of an array of ceramic candle elements in a pressure vessel. The filter is cleaned by periodically back pulsing it with fuel gas to remove the fines material. Raw gas exits the candle filter at 368°C (695ºF) and 4.0 MPa (585 psia). Below 538°C (1,000°F) a large portion of the alkali and volatile metals will condense on particulates or be captured by the filter element itself.

Gas Scrubbing

The "sour" gas leaving the particulate filter system consists mostly of hydrogen, CO_2, CO, water vapor, nitrogen, and smaller quantities of methane, carbonyl sulfide (COS), H_2S, and NH_3.

The cooled syngas at 166°C (330°F) enters the scrubber for particulate removal. The quench scrubber washes the syngas in a counter-current flow in two packed beds. After leaving the scrubber, the gas has a residual soot content of less than 1 mg/m^3, and is reheated to reach a temperature of about 204°C (400ºF) prior to the COS hydrolysis reactor. The quench scrubber removes traces of entrained particles, principally unconverted carbon, slag, and metals. The quench scrubber also removes soluble trace contaminants such as NH_3, HCN, and halide compounds. The bottoms from the scrubber are sent to the slag removal and handling system for processing. Sour water from the scrubber is stripped of sour gas and treated for recycle or discharge.

Sour Water Stripper

The sour water stripper removes NH_3, SO_2, and other impurities from the waste stream of the scrubber. The sour gas stripper consists of a sour drum that accumulates sour water from the gas scrubber and condensate from syngas coolers. Sour water from the drum flows to the sour stripper, which consists of a packed column with a steam-heated reboiler. Sour gas is stripped from the liquid and sent to the sulfur recovery unit. Remaining water is sent to wastewater treatment.

Mercury Removal

Mercury removal at the plant is based on packed beds of sulfur-impregnated carbon similar to what has been used at Eastman Chemical's gasification plant. Dual beds of sulfur-impregnated carbon with approximately a 20-second superficial gas residence time should achieve 95 percent reduction of mercury in addition to removal of other volatile heavy metals such as arsenic.

After the future retrofit, the syngas which will move through the gas cleanup processes in the Case 4 (IGCC CR) design plant is increased by approximately 100% because of the addition of steam ahead of to the shift reactors. In anticipation of the 100% increase in syngas through the cleanup processes, the capital cost of the gas cleanup equipment downstream of the shift reactors is increased accordingly.

Acid Gas Removal - Case 2 (IGCC BAU)

A refrigerated version of the promoted proprietary amine process from Coastal Engineering was chosen because of its high selectivity toward H_2S and because of the relatively low partial pressure of H_2S in the fuel gas resulting from low gas pressure, making a chemical absorption process rather than a physical absorption process such as Selexol an economically attractive option. The AGR process utilizes the SS amine (methyldiethanolamine – MDEA) solvent and several design features to effectively remove and recover H_2S from the fuel gas stream. The amine solution is costly, and measures are taken to conserve the solution during operations. As the presence of CO causes amine degradation in the form of heat stable salts, an amine reclaimer is included in the process. Also, additional water wash trays are included in the absorber tower to prevent excessive solvent loss due to vaporization.

The rich SS amine solution is pumped to a regeneration/stripping tower in which the H_2S and CO_2 are stripped from the solution by counter-current contact with CO_2 vapors generated in a steam-heated reboiler. The regenerated stream contains 69% CO_2 and 30% H_2S and is sent to the Claus plant.

Fuel gas enters the absorber tower at 39°C (103°F) and 3.4 MPa (495 psia). Over 99 percent of the H_2S is removed from the fuel gas stream. The resulting clean fuel gas stream exits the absorber and is partially humidified in a fuel gas saturator.

Warm, humid fuel gas exits the top of the saturator at 132°C (270°F). It is indirectly heated further to 196°C (385°F) by condensing high-pressure steam.

Saturator water exits the column at 80°C (176°F) after being cooled down from 133°C (272°F). The water is then reheated back to 133°C (272°F) using LP steam. To avoid the buildup of soluble gases, a small blow down to the sour water drum is taken from the pump discharge.

Acid Gas Removal - Case 4 (IGCC CR)

Because of the radical change in acid gas removal requirements from the non-CO_2 case to one with CO_2 capture, the AGR process design for Case 4 must be one that can be readily adapted to remove CO_2 upon retrofit. The AGR process for Case 4 is the single-stage Selexol process for H_2S removal. Upon retrofit, an additional absorber and CO_2 regeneration stage is added to the Selexol process.

Case 4 (IGCC CR) utilizes a single-train Selexol process to remove sulfur with minimal CO_2 capture. The Selexol process treats the stream of synthesis gas to reduce the level of total sulfur (H_2S and COS) to no more than 30 ppm prior to it being sent to the combustion turbine, while maximizing the CO_2 slip. A recycle stream of acid gas from the sulfur recovery unit (SRU) is also treated. An acid gas stream that contains ~50 percent sulfur (as H_2S) is produced.

Untreated gas is sent to the absorber, where it contacts cooled regenerated solvent, which enters at the top of the tower. In the absorber, H_2S, COS, CO_2, and other gases such as hydrogen, are transferred from the gas phase to the liquid phase. The treated gas exits the absorber and is sent to fuel gas saturation and the expander.

The solvent streams from the absorber and reabsorber are termed rich solvent, and are combined and sent to the lean/rich exchanger. In the lean/rich exchanger, the temperature of the rich solvent is increased by heat exchange with the lean solvent. The rich solvent is then sent to the H_2S concentrator, where portions of the CO_2, CO, H_2, and other gases are stripped from the solvent. Nitrogen from the ASU is used as the stripping medium. The temperature of the overhead stream from the H_2S concentrator is reduced in the stripped gas cooler. The stream is then sent to the reabsorber, where H_2S, COS, and a portion of the other gases are transferred to the liquid phase. The stream from the reabsorber is sent to the gas turbine.

The partially regenerated solvent exits the H_2S concentrator and is sent to the stripper, where the solvent is regenerated. Tail gas from the SRU is recycled back to the AGR unit and enters with the feed to the reabsorber.

Claus Unit

The sulfur recovery unit is a Claus bypass type sulfur recovery unit utilizing oxygen instead of air. The Claus plant produces molten sulfur by reacting approximately one third of the H_2S in the feed to SO_2, then reacting the H_2S and SO_2 to sulfur and water. The combination of Claus technology and tail gas recycle results in an overall sulfur recovery exceeding 99 percent. Utilizing oxygen instead of air in the Claus plant reduces the overall cost of the sulfur recovery plant. The sulfur plant produces approximately 125 long tons per day. Feed for this case consists of acid gas from both acid gas cleanup units and a vent stream from the sour water stripper in the gasifier section. Tail gas, after a hydrogenation step, is combined with the CO_2 rich stream from the H_2S concentrator and recycled to the gasifier.

The sulfur plant produces about 125 long tons per day, and will produce about 129 long tons per day after future retrofit for CO_2 capture. This small increase in sulfur capacity does not warrant a change in capital costs for Case 4.

Air Separation Unit (ASU)

For Case 2 (IGCC BAU), the air separation unit (ASU) was designed to produce a nominal output of 3,900 tonnes/day (4,300 TPD) of 95 percent pure O_2 for use in the gasifier and sulfur recovery unit. The plant was designed with two production trains. The air compressor is powered by an electric motor. Approximately 12,400 tonnes/day (13,700 TPD) of nitrogen are also recovered, compressed, and used as dilution in the gas turbine combustor. A nominal 5% of the gas turbine air is used to supply approximately 22% of the ASU air requirements.

In anticipation of the increased coal feed to the gasifier after the future retrofit of the Case 4 (IGCC CR) plant for CO_2 capture, the ASU is designed to produce 4,100 tonnes/day (4,500 TPD) of oxygen. This results in an increase of ASU capital cost, while continuing to operate at the Case 2 production rate. Upon retrofit, a larger capacity air compressor is required due to the lack of gas turbine integration.

Case 4 (IGCC CR) CO_2 Compression and Dehydration

Following retrofit, CO_2 recovered both from the Selexol process is compressed to 2,215 psia and dried for delivery off-site. The cost for this equipment will be assessed at the time of retrofit for CO_2 Capture. This is the configuration for Case 6 (IGCC CR retrofit)

7.3 CASE 2 (IGCC BAU) & 4 (IGCC CR) - MAJOR EQUIPMENT LIST

Note: Percent increases shown in the equipment lists are changes in design parameter values from the business-as-usual case values to those required for the capture-ready case in anticipation of future CO_2 capture operation performance requirements.

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	No Change required for Capture-ready design
2	Feeder	Belt	572 tonne/hr (630 tph)	2	
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	
4	Transfer Tower No. 1	Enclosed	N/A	1	
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	
6	As-Received Coal Sampling System	Two-stage	N/A	1	
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	2	
8	Reclaim Hopper	N/A	45 tonne (50 ton)	3	
9	Feeder	Vibratory	172 tonne/hr (190 tph)	3	181 tonne/hr (200 tph) 5% increase
10	Conveyor No. 3	Belt w/tripper	345 tonne/hr (380 tph)	1	354 tonne/hr (390 tph) 3% increase
11	Crusher Tower	N/A	N/A	1	N/A
12	Coal Surge Bin w/ Vent Filter	Dual outlet	172 tonne/hr (190 tph)	2	181 tonne/hr (200 tph) 5% increase
13	Crusher	Impactor reduction	8 cm x 0 – 3 cm x 0 (3"x0 - 1¼"x0)	2	No Change required for Capture-ready design
14	As-Fired Coal Sampling System	Swing hammer	N/A	2	N/A
15	Conveyor No. 4	Belt w/tripper	345 tonne/hr (380 tph)	1	354 tonne/hr (390 tph) 3% increase

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
16	Transfer Tower No. 2	Enclosed	N/A	1	N/A
17	Conveyor No. 5	Belt w/tripper	345 tonne/hr (380 tph)	1	354 tonne/hr (390 tph) 5% increase
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	No Change required for Capture-ready design

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
1	Feeder	Vibratory	82 tonne/hr (90 tph)	3	No Change required for Capture-ready design
2	Conveyor No. 6	Belt w/tripper	236 tonne/hr (260 tph)	1	
3	Rod Mill Feed Hopper	Dual Outlet	463 tonne (510 ton)	1	481 tonne (530 ton) 4% increase
4	Weight Feeder	Belt	118 tonne/hr (130 tph)	2	No Change required for Capture-ready design
5	Rod Mill	Rotary	118 tonne/hr (130 tph)	2	
6	Slurry Water Storage Tank with Agitator	Field erected	283,908 liters (75,000 gal)	2	295,264 liters (78,000 gal) 4% increase
7	Slurry Water Pumps	Centrifugal	795 lpm (210 gpm)	4	833 lpm (220 gpm) 5% increase
10	Trommel Screen	Course	163 tonne/hr (180 tph)	2	172 tonne/hr (190 tph) 5% increase
11	Rod Mill Product Tank with Agitator	Field erected	303,592 liters (80,000 gal)	2	312,678 liters (82,600 gal) 3% increase
12	Rod Mill Product Pumps	Horizontal, centrifugal	2,536 liters/min (670 gpm)	4	2,612 liters/min (690 gpm) 3% increase
13	Slurry Storage Tank with Agitator	Field erected	908,506 liters (240,000 gal)	2	946,361 liters (250,000 gal) 4% increase

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
14	Slurry Recycle Pumps	Horizontal, centrifugal	5,072 liters (1,340 gpm)	4	5,224 liters (1,380 gpm) 3% increase
15	Slurry Product Pumps	Positive Displacement	2,536 lpm (670 gpm)	4	2,612 lpm (690 gpm) 3% increase

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,101,563 liters (291,000 gal)	2	2,237,196 liters (591,000 gal) Qty: 3 103% increase
2	Condensate Pumps	Vertical canned	6,132 lpm @ 91 m H_2O (1,620 gpm @ 300 ft H_2O)	3	7,874 lpm @ 91 m H_2O (2,080 gpm @ 300 ft H_2O) 28% increase
3	Deaerator (integral with HRSG)	Horiz. spray type	463,118 kg/hr (1,021,000 lb/hr)	2	577,877 kg/hr (1,274,000 lb/hr) 25% increase
4	Intermediate Pressure Feedwater Pump	Horiz. centrifugal single stage	1,325 lpm @ 283 m H_2O (350 gpm @ 930 ft H_2O)	3	2,006 lpm @ 283 m H_2O (530 gpm @ 930 ft H_2O) 52% increase
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	6,511 lpm @ 1,890 m H_2O (1,720 gpm @ 6,200 ft H_2O)	3	6,587 lpm @ 1,890 m H_2O (1,740 gpm @6,200 ft H_2O) 1% increase
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	909 lpm @ 390 m H_2O (240 gpm @ 1,280 ft H_2O)	3	1,476 lpm @ 223 m H_2O (390 gpm @ 730 ft H_2O) 63% increase
7	Auxiliary Boiler	Shop fab., water tube	18,144kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	No Change required for Capture-ready design
8	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	3	

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
9	Inst. Air Dryers	Duplex, regenerative	28 m^3/min (1,000 cfm)	3	No Change required for Capture-ready design
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	58 MMkJ/hr (55MMBtu/hr) each	2	
11	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	20,820 lpm @ 21 m H_2O (5,500 gpm @ 70 ft H_2O)	3	
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	3,785 lpm @ 107m H_2O (1,000 gpm @ 350 ftH_2O)	2	
13	Fire Service Booster Pump	Two-stage horiz., centrifugal	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	2	
14	Raw Water Pumps	SS, single suction	7,912 lpm @ 18 m H_2O (2,090 gpm @ 60 ft H_2O)	3	8,707 lpm @ 18 m H_2O (2,300 gpm @ 60 ft H_2O) 10% increase
15	Filtered Water Pumps	SS, single suction	1,476 lpm @ 49 m H_2O (390 gpm @ 160 ft H_2O)	3	4,088 lpm @ 49 m H_2O (1,080 gpm @ 160 ft H_2O) 175% increase
16	Filtered Water Tank	Vertical, cylindrical	715,448 liters (189,000 gal)	2	1,968,429 liters (520,000 gal) 175% increase
17	Makeup Demineralizer	Anion, cation, and mixed bed	151 lpm (40 gpm)	2	2,574 lpm (680 gpm) 1600% increase
18	Liquid Waste Treatment System		10 years, 24-hour storm	1	No Change required for Capture-ready design

ACCOUNT 4 GASIFIER, ASU, AND ACCESSORIES INCLUDING LOW TEMPERATURE HEAT RECOVERY AND FUEL GAS SATURATION

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
1	Gasifier	Pressurized two-stage, slurry-feed entrained bed	2,812 tonne/day 4.2 MPa (3,100 tpd 615 psia)	2	2,903 tonne/day 4.2 MPa (3,200 tpd 615 psia) 3% increase
2	Synthesis Gas Cooler	Fire-tube boiler	304,361 kg/hr (671,000 lb/hr)	2	326,133 kg/hr (719,000 lb/hr) 7% increase
3	Synthesis Gas Cyclone	High Efficiency	291,660 kg/hr (643,000 lb/hr), Design efficiency 90%	2	313,433 kg/hr (691,000 lb/hr), Design efficiency 90% 7% increase
4	Candle Filter	Pressurized filter with pulse jet cleaning	Metallic filters	2	No Change required for Capture-ready design
5	Syngas Scrubber Including Sour Water Stripper	Vertical, upflow	298,464 kg/hr (658,000 lb/hr)	2	299,825 kg/hr (661,000 lb/hr) 0.5% increase
6	Raw Gas Coolers	Shell and tube with condensate drain	275,784 kg/hr (608,000 lb/hr)	6	455,861 kg/hr (1,005,000 lb/hr) 65% increase
7	Raw Gas Knockout Drum	Vertical with mist eliminator	266,259 kg/hr, 39°C, 3.6 MPa (587,000 lb/hr,103°F, 515 psia)	2	351,988 kg/hr, 38°C, 5.1 MPa (776,000 lb/hr,100°F, 737 psia) 32% increase
8	Saturation Water Economizers	Shell and tube	275,784 kg/hr (608,000 lb/hr)	2	455,861 kg/hr (1,005,000 lb/hr) 65% increase
9	Fuel Gas Saturator	Vertical tray tower	201,395 kg/hr, 103°C, 3.3 MPa (444,000 lb/hr,266°F, 484 psia)	2	62,596 kg/hr, 149°C, 3.2 MPa (138,000 lb/hr,300°F, 458 psia) -70% increase
10	Saturator Water Pump	Centrifugal	4,543 lpm @ 201 m H_2O (1,200 gpm @ 660 ft H_2O)	2	3,785 lpm @ 15 m H_2O (1,000 gpm @ 50 ft H_2O) -17% increase

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
11	Synthesis Gas Reheater	Shell and tube	215,457 kg/hr (475,000 lb/hr)	2	65,771 kg/hr (145,000 lb/hr) -70% increase
12	Flare Stack	Self-supporting, carbon steel, ss top, pilot ignition	298,464 kg/hr (658,000 lb/hr)	2	299,825 kg/hr (661,000 lb/hr) 0.5% increase
13	ASU Main Air Compressor	Centrifugal, multi-stage	4,134 m^3/min @ 1.3 MPa (146,000 scfm @ 190 psia)	2	5,493 m^3/min @ 1.3 MPa (194,000 scfm @ 190 psia)
14	Cold Box	Vendor Design	2,177 tonne/day (2,400 tpd) of 95% purity O_2	2	No Change required for Capture-ready design
15	Oxygen Compressor	Centrifugal, multi-stage	1,076 m^3/min @ 5.1 MPa (38,000 scfm @ 740 psia)	2	1,104 m^3/min @ 5.1 MPa (39,000 scfm @ 740 psia) 3% increase
16	Nitrogen Compressor	Centrifugal, multi-stage	3,540 m^3/min @ 3.4 MPa (125,000 scfm @ 490 psia)	2	3,653 m^3/min @ 3.4 MPa (129,000 scfm @ 490 psia) 3% increase
17	Nitrogen Boost Compressor	Centrifugal, multi-stage	481 m^3/min @ 2.3 MPa (17,000 scfm @ 340 psia)	2	510 m^3/min @ 2.3 MPa (18,000 scfm @ 340 psia) 6% increase

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
1	Mercury Adsorber	Sulfated Carbon Bed	234,054 kg/hr, 39°C, 3.4MPa, (516,000 lb/hr, 103°F, 495 psia)	2	320,690 kg/hr, 34°C, 3.3MPa, (707,000 lb/hr, 93°F, 481 psia) 37% increase
2	Sulfur Plant	Claus plant	139 tonne/day (153 tpd)	1	No Change required for Capture-ready design
3	COS Hydrolysis Reactor	Fixed bed catalytic	298,464 kg/hr, 204°C, 3.8MPa, (658,000 lb/hr, 400°F, 555 psia)	2	
4a	Acid Gas Removal Plant	MDEA	427,285 kg/hr, 39°C, 3.3MPa, (942,000 lb/hr, 103°F, 485 psia)	1	N/A

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
4b	Acid Gas Removal Plant	Single Stage Selexol	N/A	1	427,285 kg/hr, 39°C, 3.3MPa, (942,000 lb/hr, 103°F, 485 psia)
5	Hydrogenation Reactor	Fixed bed, catalytic	25,401 kg/hr, 232°C, 0.2MPa, (56,000 lb/hr, 450°F, 25 psia)	1	No Change required for Capture-ready design
6	Tail Gas Recycle Compressor	Centrifugal	21,772 kg/hr@ 6.6 MPa, (48,000 lb/hr @ 950 psia)	1	

ACCOUNT 5C CARBON DIOXIDE RECOVERY

N/A

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
1	Gas Turbine	Advanced F class w/dry low-NOx burner	232 MWe	2	No Change required for Capture-ready design
2	Gas Turbine Generator	TEWAC	260MVA @0.9 p.f, 24kV, 60Hz, 3-phase	2	

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK (total for plant)

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
1	Stack	Carbon steel plate, type 409 stainless steel liner	76 m high x 8.3 m dia. (250 ft high x 27 ft dia.)	1	No Change required for Capture-ready design
2	Heat Recovery Steam Generator	Drum, multi-pressure, with economizer section and integral deaerator	Main steam - 368,554 kg/hr, 12.4 MPa/566°C (812,522 lb/hr, 1,800 psig/1,050°F) Reheat steam - 361,875 kg/hr, 2.9 MPa/566°C (797,796 lb/hr, 420 psig/1,050°F)	2	Main steam - 372,086 kg/hr, 12.4 MPa/566°C (820,307 lb/hr, 1,800 psig/1,050°F)) 1% increase Reheat steam - No Change

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
1	Steam Turbine	Commercially available advanced steam turbine	293 MWe 12.4 MPa/538°C/538°C (1800psig/1050°F/1050°F)	1	No Change required for Capture-ready design
2	Steam Turbine Generator	Hydrogen cooled, static excitation	330MVA @ 0.9 p.f., 24kV, 60 Hz, 3-phase	1	
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,613 MMkJ/hr (1,530 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	No Change required for Capture-ready design

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
1	Circulating Water Pumps	Vertical, wet pit	336,904 lpm @ 30 m H_2O (89,000 gpm @ 100 ft H_2O)	3	No Change required for Capture-ready design
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT, 1,876 MMkJ/hr (1,780 MMBtu/hr) heat duty	1	

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
1	Slag Quench Tank	Water bath	223,341 liters (59,000 gal)	2	230,91 liters (61,000 gal) 3% increase
2	Slag Crusher	Roll	12 tonne/hr (13 tph)	2	No Change required for Capture-ready design
3	Slag Depressurizer	Proprietary	12 tonne/hr (13 tph)	2	No Change required for Capture-ready design
4	Slag Receiving Tank	Horizontal, weir	147,632 liters (39,000 gal)	2	151,418 liters (40,000 gal) 3% increase
5	Black Water Overflow Tank	Shop fabricated	68,138 liters (18,000 gal)	2	71,923 liters (19,000 gal) 5% increase
6	Slag Conveyor	Drag chain	12 tonne/hr (13 tph)	2	No Change required for Capture-ready design
7	Slag Separation Screen	Vibrating	12 tonne/hr (13 tph)	2	
8	Coarse Slag Conveyor	Belt/bucket	12 tonne/hr (13 tph)	2	
9	Fine Ash Storage Tank	Vertical, gravity	219,556 liters (58,000 gal)	2	227,126 liters (60,000 gal) 38% increase
10	Fine Ash Transfer Pumps	Horizontal /centrifugal	38 lpm @ 14m H_2O (10 gpm @ 46ft H_2O)	4	No Change required for Capture-ready design
11	Grey Water Storage Tank	Field erected	71,923 liters (19,000 gal)	2	

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
12	Grey Water Pumps	Centrifugal	265 lpm @ 433m H_2O (70 gpm @ 1,420 ft H_2O)	4	
13	Grey Water Recycle Heat Exchanger	Shell and tube	15,876 kg/hr (35,000 lb/hr)	2	
14	Storage Bin	Vertical, field erected	816 tonnes (900 tons)	2	907 tonnes (1,000 tons) 11% increase
15	Unloading Equipment	Telescoping chute	100 tonne/hr (110 tph)	1	No Change required for Capture-ready design

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	No Change required for Capture-ready design
2	STG Transformer	Oil-filled	24 kV/345 kV, 190 MVA, 3-ph, 60 Hz	1	
3	Auxiliary Transformer	Oil-filled	24 kV/ 4.16 kV, 130 MVA, 3-ph, 60 Hz	2	
4	Low Voltage Transformer	Dry ventilated	4.16 kV /480 V, 19 MVA, 3-ph, 60 Hz	2	
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	
7	Medium Voltage Switchgear	Metal Clad	4.16 kV, 3-ph, 60 Hz	2	
8	Low Voltage Switchgear	Metal Enclosed	480 kV, 3-ph, 60 Hz	2	No Change required for Capture-ready design
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 4 (IGCC CR) Design Condition
1	DCS - Main Control	Monitor/keyboard; Operator printer – laser color; Eng. Printer – laser black & white	Operator Stations/Printers and Engineering Stations/Printers	1	No Change required for Capture-ready design
2	DCS - Processor	Microprocessor with Redundant Input/Output	N/A	1	
4	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	

7.4 CASE 2 (IGCC BAU) - COST ESTIMATING RESULTS

Exhibit 7-8 and Exhibit 7-11 show the capital and operating costs for this plant. Capital cost estimating methodology is explained in Section 4. The detailed breakdowns of the capital cost estimates for each case are included in Appendix B.

Exhibit 7-8 Case 2 (IGCC BAU) Total Plant Costs

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST SUMMARY

Case: Case 2 -ConocoPhillips E-Gas Dual Train IGCC w/o CO2
Plant Size: 623.4 MW,net **Estimate Type:** Conceptual Cost Base Jan 2007 $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies		TOTAL PLANT COST	
				Direct	Indirect			Process	Project	$	$/kW
1	COAL HANDLING SYSTEM	13,060	2,435	10,233		$25,728	2,088		5,563	$33,379	54
2	COAL PREP & FEED SYSTEMS	22,211	4,065	13,559		$39,835	3,200		8,607	$51,642	83
3	FEEDWATER & MISC. BOP SYSTEMS	9,148	7,886	8,644		$25,678	2,149		6,278	$34,105	55
4	GASIFIER & ACCESSORIES										
4.1	Gasifier, Syngas Cooler & Auxiliaries	90,425		55,527		$145,952	11,971	21,893	26,972	$206,789	332
4.2	Syngas Cooler (w/Gasifier - $)	w/4.1		w/4.1							
4.3	ASU/Oxidant Compression	137,711		w/equip.		$137,711	11,743		14,945	$164,399	264
4.4-4.9	Other Gasifiction Equipment	18,487	8,580	11,695		$38,763	3,285		9,043	$51,091	82
	Subtotal 4	246,624	8,580	67,222		$322,427	26,999	21,893	50,961	$422,279	677
5A	GAS CLEANUP & PIPING	50,895	4,805	38,080		$93,780	8,032	104	20,588	$122,504	197
5B	CO2 REMOVAL & COMPRESSION										
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	82,000		5,071		$87,071	7,338	4,354	9,876	$108,639	174
6.2-6.9	Combustion Turbine Accessories		684	762		$1,446	121		470	$2,037	3
	Subtotal 6	82,000	684	5,833		$88,517	7,459	4,354	10,346	$110,676	178
7	HRSG, DUCTING & STACK										
7.1	Heat Recovery Steam Generator	33,926		4,828		$38,754	3,277		4,203	$46,234	74
7.2-7.9	Ductwork, Stack	3,123	2,198	2,918		$8,239	682		1,450	$10,371	17
	Subtotal 7	37,049	2,198	7,745		$46,992	3,959		5,653	$56,604	91
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	28,109		4,930		$33,039	2,837		3,588	$39,463	63
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	10,092	953	7,185		$18,229	1,473		3,969	$23,671	38
	Subtotal 8	38,201	953	12,115		$51,268	4,310		7,556	$63,135	101
9	COOLING WATER SYSTEM	6,760	7,303	6,124		$20,187	1,661		4,492	$26,340	42
10	ASH/SPENT SORBENT HANDLING SYS	18,173	1,373	9,021		$28,568	2,437		3,382	$34,386	55
11	ACCESSORY ELECTRIC PLANT	22,608	9,796	19,825		$52,229	4,054		10,733	$67,016	108
12	INSTRUMENTATION & CONTROL	9,358	1,752	6,282		$17,391	1,436	870	3,296	$22,992	37
13	IMPROVEMENTS TO SITE	3,155	1,860	7,843		$12,858	1,132		4,197	$18,186	29
14	BUILDINGS & STRUCTURES		6,209	7,240		$13,449	1,095		2,378	$16,922	27
	TOTAL COST	**$559,240**	**$59,898**	**$219,767**		**$838,905**	**$70,010**	**$27,220**	**$144,031**	**$1,080,166**	**$1,733**

Exhibit 7-9 Case 2 (IGCC BAU) Operating Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base Jan	2007
Case 2 -ConocoPhillips E-Gas Dual Train IGCC w/o CO2					Heat Rate-net(Btu/kWh):	8,681
Plant Output:	CO_2 (tpd): ---		H_2 (mmscfd):		MWe-net:	623.4
					Capacity Factor: (%):	80.0
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Plant			
Skilled Operator	2.0		2.0			
Operator	9.0		9.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	3.0		3.0			
TOTAL-O.J.'s	15.0		15.0			
					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost(calc'd)					$5,637,060	9.04
Maintenance Labor Cost(calc'd)					$11,924,540	19.13
Administrative & Support Labor(calc'd)					$4,390,400	7.04
TOTAL FIXED OPERATING COSTS					**$21,951,999**	**35.22**
VARIABLE OPERATING COSTS						$/kWh-net
Maintenance Material Cost(calc'd)					$22,346,706	0.0051
Consumables	Consumption		Unit	Initial		
	Initial	/Day	Cost	Cost		
Water(/1000 gallons)		5,410	1.03		$1,627,136	0.0004
Chemicals						
MU & WT Chem.(lb)	112,811	16,116	0.16	$18,591	$775,520	0.0002
Carbon (Mercury Removal) (lb)	84,449	116.0	1.00	$84,449	$33,872	0.0000
COS Catalyst (m3)	375	0.3	2308.40	$865,651	$173,030	0.0000
Water Gas Shift Catalyst(ft3)			475.00			
Selexol Solution (gal.)			12.90			
MDEA Solution (gal)	280	40.0	8.38	$2,345	$97,820	0.0000
Sulfinol Solution (gal)			9.68			
SCR Catalyst (m3)			5500.00			
Ammonia (28% NH3) ton			123.60			
Claus Catalyst(ft3)	w/equip.	2.1	125.00		$76,650	0.0000
Subtotal Chemicals				$971,037	$1,156,892	0.0003
Other						
Supplemental Fuel(MBtu)			6.75			
SCR Catalyst Replacement			9480.00			
Emission Penalties						
Subtotal Other						
Waste Disposal						
Spent Mercury Catalyst (lb.)		116	0.40		$13,603	0.0000
Flyash (ton)			15.45			
Bottom Ash(ton)		566	15.45		$2,555,311	0.0006
Subtotal Solid Waste Disposal					$2,568,914	0.0006
By-products & Emissions						
Gypsum (tons)						
Sulfur(tons)			-25.00			
Subtotal By-Products						
TOTAL VARIABLE OPERATING COSTS				**$971,037**	**$27,699,648**	**0.0063**
FUEL (tons)	167,000	5,567	42.11	**$7,032,387**	**$68,448,568**	**0.0157**

Exhibit 7-10 Case 2 (IGCC BAU) Capital Investment Requirement Summary

TITLE/DEFINITION

Case: **Case 2 -ConocoPhillips E-Gas Dual Train IGCC w/o CO2**

Plant Size:	623.4 (MW,net)		HeatRate:	8,681 (Btu/kWh)
Primary/Secondary Fuel(type):	Illinois #6		Cost:	1.80 ($/MMBtu)
Design/Construction:	3 (years)		BookLife:	30 (years)
TPC(Plant Cost) Year:	2007 Jan			
Capacity Factor:	80 (%)		CO2 Removed:	--- (TPD)

CAPITAL INVESTMENT	**$x1000**	**$/kW**
Process Capital & Facilities	838,905	1345.8
Engineering(incl.C.M.,H.O.& Fee)	70,010	112.3
Process Contingency	27,220	43.7
Project Contingency	144,031	231.1
TOTAL PLANT COST(TPC)	$1,080,166	1732.8

OPERATING & MAINTENANCE COSTS (2007 Dollars)	**$x1000**	**$/kW-yr**
Operating Labor	5,637	9.0
Maintenance Labor	11,925	19.1
Maintenance Material	22,347	35.8
Administrative & Support Labor	4,390	7.0
TOTAL OPERATION & MAINTENANCE	$44,299	71.1
FIXED O & M	$27,984	44.9
VARIABLE O & M	$16,315	26.2

CONSUMABLE OPERATING COSTS, less Fuel (2007 Dollars)	**$x1000**	**¢/kWh**
Water	1,627	0.04
Chemicals	1,157	0.03
Other Consumables		
Waste Disposal	2,569	0.06
TOTAL CONSUMABLE OPERATING COSTS	$5,353	0.12
BY-PRODUCT CREDITS		
FUEL COST (2007 Dollars)	$68,449	1.57

PRODUCTION COST SUMMARY	**LF**	**Levelized Costs ¢/kWh**
Fixed O & M	1.157	0.74
Variable O & M	1.157	0.43
Consumables	1.157	0.14
By-product Credit	1.157	
Fuel	1.202	1.88
TOTAL PRODUCTION COST		3.20
2007 CARRYING CHARGES (Capital)		4.33
CCF for a 20-Year Levelization Period - IOU - Higher-Risk	**17.5**	
20 YEAR LEVELIZED BUSBAR COST OF POWER		7.53

Exhibit 7-11 Case 2 (IGCC BAU) Estimate Basis and Financial Criteria Summary

GENERAL DATA/CHARACTERISTICS

Case Title:	**Case 2 -"Business As Usual" CoP E-Gas Dual Train IGCC w/o CO_2 Capture**		
Unit Size:/Plant Size:		623.4	MW,net
Location:		Midwestern, USA	
Fuel: Primary/Secondary	Illinois #6	11,666	Btu/lb
Energy From Primary/Secondary Fuels		8,681	Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):		80	%
Capital Cost Year Dollars (Reference Year Dollars):		2007	Jan
Delivered Cost of Primary/Secondary Fuel		1.80	$/MMBtu
Design/Construction Period:		3	years
Plant Startup Date (1st. Year Dollars):		2010	
Financial Parameter/Risk Level		IOU High Risk	

FINANCIAL CRITERIA

Project Book Life:		30	years
Book Salvage Value:			%
Project Tax Life:		20	years
Tax Depreciation Method:		20 years, 150% declining balance	
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			%
Economic Basis:		20th Year Current Dollars	

Capital Structure		% of Total	Cost(%)
	Common Equity	55.00	12.00
	Preferred Stock		
	Debt	45.00	11.00
Weighted Cost of Capital:(after tax)		9.67 %	

		2010 - 2030	
Nominal Escalation	General	1.87	% per year
	Coal Price	2.35	% per year
	Secondary Fuel:	1.96	% per year

7.5 CASE 4 (IGCC CR) - COST ESTIMATING RESULTS

Exhibit 7-12 and Exhibit 7-15 show the capital and operating costs for this plant. Capital cost estimating methodology is explained in Section 4. The detailed breakdowns of the capital cost estimates for each case are included in Appendix B.

Note: Costs impacted by changes in design parameter values from the business-as-usual case values to the capture-ready case values are highlighted in the following capture-ready case cost exhibits.

Exhibit 7-12 Case 4 Total Plant Costs

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST SUMMARY

Case: Case 4 -ConocoPhillips E-Gas Dual Train IGCC w CO2 Capture Ready
Plant Size: 623.4 MW,net **Estimate Type:** Conceptual Cost Base Jan 2007 $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL HANDLING SYSTEM	13,303	2,480	10,424		$26,207	2,127		5,667	$34,000	55
2	COAL PREP & FEED SYSTEMS	22,651	4,146	13,827		$40,624	3,263		8,777	$52,665	84
3	FEEDWATER & MISC. BOP SYSTEMS	9,371	7,975	8,947		$26,292	2,201		6,451	$34,944	56
4	GASIFIER & ACCESSORIES										
4.1	Gasifier, Syngas Cooler & Auxiliaries	93,113		57,142		$150,256	12,324	22,538	27,768	$212,885	342
4.2	Syngas Cooler (w/Gasifier - $)	w/4.1		w/4.1							
4.3	ASU/Oxidant Compression	142,779		w/equip.		$142,779	12,175		15,495	$170,449	273
4.4-4.9	Other Gasifiction Equipment	24,864	8,707	14,165		$47,736	4,057		11,002	$62,795	101
	Subtotal 4	260,756	8,707	71,307		$340,771	28,555	22,538	54,265	$446,129	716
5A	GAS CLEANUP & PIPING	49,771	4,446	49,701		$103,918	8,933	12,942	25,362	$151,156	242
5B	CO2 REMOVAL & COMPRESSION										
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	88,000		5,325		$93,325	7,865	9,333	11,052	$121,575	195
6.2-6.9	Combustion Turbine Accessories		684	762		$1,446	121		470	$2,037	3
	Subtotal 6	88,000	684	6,087		$94,771	7,986	9,333	11,522	$123,611	198
7	HRSG, DUCTING & STACK										
7.1	Heat Recovery Steam Generator	32,356		4,604		$36,960	3,125		4,009	$44,094	71
7.2-7.9	Ductwork, Stack	3,222	2,268	3,011		$8,501	703		1,496	$10,700	17
	Subtotal 7	35,577	2,268	7,615		$45,461	3,829		5,505	$54,794	88
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	25,224		4,105		$29,328	2,518		3,185	$35,030	56
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	9,243	828	6,527		$16,598	1,338		3,645	$21,581	35
	Subtotal 8	34,466	828	10,632		$45,926	3,856		6,829	$56,611	91
9	COOLING WATER SYSTEM	6,318	6,821	5,729		$18,867	1,553		4,194	$24,614	39
10	ASH/SPENT SORBENT HANDLING SYS	18,516	1,396	9,191		$29,103	2,482		3,445	$35,031	56
11	ACCESSORY ELECTRIC PLANT	23,064	11,396	22,575		$57,035	4,450		11,923	$73,409	118
12	INSTRUMENTATION & CONTROL	10,183	1,906	6,836		$18,925	1,562	946	3,586	$25,021	40
13	IMPROVEMENTS TO SITE	3,208	1,891	7,974		$13,073	1,151		4,267	$18,490	30
14	BUILDINGS & STRUCTURES		6,066	6,992		$13,057	1,063		2,319	$16,439	26
	TOTAL COST	$575,185	$61,009	$237,837		$874,031	$73,011	$45,760	$154,112	$1,146,914	$1,840

Exhibit 7-13 Case 4 Operating Cost Summary

INITIAL & ANNUAL O&M EXPENSES

Case 4 -ConocoPhillips E-Gas Dual Train IGCC w CO2 Capture Ready				Cost Base Jan	2007
				Heat Rate-net(Btu/kWh):	**8,681**
Plant Output:	CO_2 (tpd): **---**	H_2 (mmscfd):		MWe-net:	**623.4**
				Capacity Factor: (%):	80.0

OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Total Plant			
Skilled Operator	2.0		2.0			
Operator	**10.0**		**10.0**			
Foreman	1.0		1.0			
Lab Tech's, etc.	3.0		3.0			
TOTAL-O.J.'s	**16.0**		**16.0**			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost(calc'd)					**$6,012,864**	**9.65**
Maintenance Labor Cost(calc'd)					**$13,171,520**	**21.13**
Administrative & Support Labor(calc'd)					**$4,796,096**	**7.69**
TOTAL FIXED OPERATING COSTS					**$23,980,481**	**38.47**
VARIABLE OPERATING COSTS						$/kWh-net
Maintenance Material Cost(calc'd)					**$24,211,567**	**0.0055**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)		**5,954**	1.03		**$1,790,845**	**0.0004**
Chemicals						
MU & WT Chem.(lb)	**124,161**	**17,737**	0.16	**$20,462**	**$853,547**	**0.0002**
Carbon (Mercury Removal) (lb)	**128,090**	**175**	1.00	**$128,090**	**$51,100**	**0.0000**
COS Catalyst (m3)	**375**	**0**	2308.40	**$865,651**	**$173,030**	**0.0000**
Water Gas Shift Catalyst(ft3)			475.00			
Selexol Solution (gal.)	**462**	**66**	12.90	**$5,960**	**$248,630**	**0.0001**
MDEA Solution (gal)			8.38			
Sulfinol Solution (gal)			9.68			
SCR Catalyst (m3)			5500.00			
Ammonia (28% NH3) ton			123.60			
Claus Catalyst(ft3)	**12**	2	125.00	**$1,460**	**$78,840**	**0.0000**
Subtotal Chemicals				**$1,021,623**	**$1,405,146**	**0.0003**
Other						
Supplemental Fuel(MBtu)			6.75			
SCR Catalyst Replacement			9480.00			
Emission Penalties						
Subtotal Other						
Waste Disposal						
Spent Mercury Catalyst (lb.)		**175**	0.40		**$20,522**	**0.0000**
Flyash (ton)			15.45			
Bottom Ash(ton)		**583**	15.45		**$2,632,348**	**0.0006**
Subtotal Solid Waste Disposal					**$2,652,870**	**0.0006**
By-products & Emissions						
Gypsum (tons)						
Sulfur(tons)			-25.00			
Subtotal By-Products						
TOTAL VARIABLE OPERATING COSTS				**$1,021,623**	**$30,060,428**	**0.0069**
FUEL (tons)	**167,000**	**5,567**	42.11	**$7,032,387**	**$68,448,568**	**0.0157**

Exhibit 7-14 Case 4 Capital Investment Requirement Summary

TITLE/DEFINITION				
Case: **Case 4 -ConocoPhillips E-Gas Dual Train IGCC w CO2 Capture Ready**				
Plant Size:	**623.4** (MW,net)	HeatRate:	**8,681** (Btu/kWh)	
Primary/Secondary Fuel(type):	Illinois #6	Cost:	1.80 ($/MMBtu)	
Design/Construction:	3 (years)	BookLife:	30 (years)	
TPC(Plant Cost) Year:	2007 Jan			
Capacity Factor:	80 (%)	CO2 Removed:	**---** (TPD)	

CAPITAL INVESTMENT	**$x1000**	**$/kW**
Process Capital & Facilities	**874,031**	**1402.1**
Engineering(incl.C.M.,H.O.& Fee)	**73,011**	**117.1**
Process Contingency	**45,760**	**73.4**
Project Contingency	**154,112**	**247.2**
TOTAL PLANT COST(TPC)	**$1,146,914**	**1839.9**

OPERATING & MAINTENANCE COSTS (2007 Dollars)	**$x1000**	**$/kW-yr**
Operating Labor	**6,013**	**9.6**
Maintenance Labor	**13,172**	**21.1**
Maintenance Material	**24,212**	**38.8**
Administrative & Support Labor	**4,796**	**7.7**
TOTAL OPERATION & MAINTENANCE	**$48,192**	**77.3**
FIXED O & M	**$30,224**	**48.5**
VARIABLE O & M	**$17,968**	**28.8**

CONSUMABLE OPERATING COSTS, less Fuel (2007 Dollars)	$x1000	**¢/kWh**
Water	**1,791**	**0.04**
Chemicals	**1,405**	**0.03**
Other Consumables		
Waste Disposal	**2,653**	**0.06**
TOTAL CONSUMABLE OPERATING COSTS	**$5,849**	**0.13**
BY-PRODUCT CREDITS		
FUEL COST (2007 Dollars)	**$68,449**	**1.57**

PRODUCTION COST SUMMARY	**LF**	**Levelized Costs ¢/kWh**
Fixed O & M	1.157	**0.80**
Variable O & M	1.157	**0.48**
Consumables	1.157	**0.15**
By-product Credit	1.157	
Fuel	1.202	**1.88**
TOTAL PRODUCTION COST		**3.31**
2007 CARRYING CHARGES (Capital)		**4.59**
CCF for a 20-Year Levelization Period - IOU - Higher-Risk	17.5	
20 YEAR LEVELIZED BUSBAR COST OF POWER		**7.91**

Exhibit 7-15 Case 4 Estimate Basis and Financial Criteria Summary

GENERAL DATA/CHARACTERISTICS

Case Title:	**Case 4 -"Capture Ready" CoP E-Gas Dual Train IGCC w/o CO_2 Capture**		
Unit Size:/Plant Size:		**623.4**	MW,net
Location:		Midwestern, USA	
Fuel: Primary/Secondary	Illinois #6	11,666	Btu/lb
Energy From Primary/Secondary Fuels		**8,681**	Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):		80	%
Capital Cost Year Dollars (Reference Year Dollars):		2007	Jan
Delivered Cost of Primary/Secondary Fuel		1.80	$/MMBtu
Design/Construction Period:		3	years
Plant Startup Date (1st. Year Dollars):		2010	
Financial Parameter/Risk Level		IOU High Risk	

FINANCIAL CRITERIA

Project Book Life:		30	years
Book Salvage Value:			%
Project Tax Life:		20	years
Tax Depreciation Method:		20 years, 150% declining balance	
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			%
Economic Basis:		20th Year Current Dollars	

Capital Structure		% of Total	Cost(%)
	Common Equity	55.00	12.00
	Preferred Stock		
	Debt	45.00	11.00
Weighted Cost of Capital:(after tax)		9.67	%

		2010 - 2030	
Nominal Escalation	General	1.87	% per year
	Coal Price	2.35	% per year
	Secondary Fuel:	1.96	% per year

7.6 IGCC PLANTS CASES 2 (IGCC BAU) AND 4 (IGCC CR) SUMMARY

Cases 2 and 4 are configured to operate with the same performance and efficiency. Case 4 (IGCC CR) shows a slight increase in capital costs which reflects the design modifications required to ready the plant for CO_2 Capture. The Case 4 design did not require a large increase in equipment capacity since the gasifier produces essentially the same amount of fuel for the gas turbine. A small increase in coal feed is anticipated with the CO_2 retrofit to account for the loss of syngas heating value in the shift reaction, and it was necessary to increase the syngas cooler capacity. A small increase in capital cost was also attributed to the changeover from an amine AGR to the Selexol AGR process. As shown in Exhibit 7-16, the plant cost increased from $1,733/kW to $1,840/kW. The O&M costs do not change significantly, so the Cost of Electricity increase from 7.53 cents/kWh to 7.91 cents/kWh is attributed mostly to increased capital.

Exhibit 7-16 Cases 2 (IGCC BAU) and 4 (IGCC CR) Performance and Economic Summary

		Case 2 (IGCC BAU)	Case 4 (IGCC CR)
Gross Power Output,	MW_e	742.5	742.5
Net Power Output,	MW_e	623.4	623.4
Net Plant Efficiency (HHV)		39.3%	39.3%
Net Plant Heat Rate (HHV), kJ/kWh (Btu/kWh)		9,159 (8,681)	9,159 (8,681)
Total Plant Cost (TPC)	1000$	$1,080,166	$1,146,914
Total Plant Cost (TPC)	$/kW	$1,733	$1,840
Incremental TPC,	$/kW	N/A	$107
Total Levelized COE[1,]	¢/kWh	7.53	7.91
Incremental COE[1],	¢/kWh	N/A	0.38
Total CO_2 Emitted,	kg/MWh_{net} (lb/MWh_{net})	785 (1,730)	785 (1,730)
Cost of CO_2 Captured[1]	$/tonne ($/ton)	N/A	N/A
Cost of CO_2 Avoided[1]	$/tonne ($/ton)	N/A	N/A

Note:
Costs in 2007 Dollars
"Incremental costs" are compared to Case 1—"IGCC Business-as-Usual"
[1]Transportation, Storage, and Monitoring of CO_2 not included
[2]80% Capacity Factor
[3]20 year levelization period

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8. INTEGRATED GASIFICATION COMBINED CYCLE PLANTS RETROFITTED WITH CO_2 CAPTURE

8.1 CASE 6 (IGCC CR RETROFIT) – CO_2 CAPTURE-READY RETROFIT

Case 6 (IGCC CR retrofit) is configured to produce power from Illinois No. 6 coal with 90% CO_2 capture—as represented by Case 4 in the recently completed NETL systems analysis study [Ref. 1]. The plant design is based on retrofitting Case 4 (IGCC CR) to capture 90% of the CO_2 in the flue gas to the Carbon Dioxide Recovery unit (CDR). The baseline plant configuration is described is the previous section. Plant process equipment which is included in the retrofit is described in the following paragraphs. The equipment list (Section 8.2) is a side-by-side comparison of the equipment of Case 4 (IGCC CR) and Case 6 (IGCC CR retrofit).

The plant continues to utilize two oxygen-blown, high pressure ConocoPhillips E-Gas™ two-stage gasifiers to produce a medium heating value syngas. Oxygen fed to the gasifiers is generated by two cryogenic air separation units (ASUs). The syngas is filtered and scrubbed of particulate.

Gas processing equipment includes addition of a shift reactor to convert 97% of the CO to hydrogen and CO_2. The shifted gas is cooled and cleaned of mercury before entering the Selexol process, retrofitted for two stages. The first stage Selexol absorber removes H_2S from the gas stream and it is sent to a Claus plant to produce elemental sulfur. The second stage removes 95% of the CO_2 for compression, drying and sequestration off-site. The clean syngas leaving the Selexol unit is humidified and fired in dual advanced F Class gas turbines. The gas turbines operate in a combined cycle mode, utilizing heat from the gas turbine exhaust to generate steam in a heat recovery steam generator (HRSG) with a single steam turbine to produce additional power. A parallel 300,000 lb/hour air compressor is added to the ASU since less air extraction is coming from the gas turbine compressor.

Exhibit 8-1 is a block flow diagram for the overall plant with individual streams identified. Exhibit 8-2 follows the figure with detailed composition and state points for the numbered streams.

Overall performance for the entire plant is summarized in Exhibit 8-3 which includes auxiliary power requirements.

Exhibit 8-1 Case 6 (IGCC CR Retrofit) Process Flow Diagram, E-Gas™ IGCC with Retrofitted CO_2 Capture

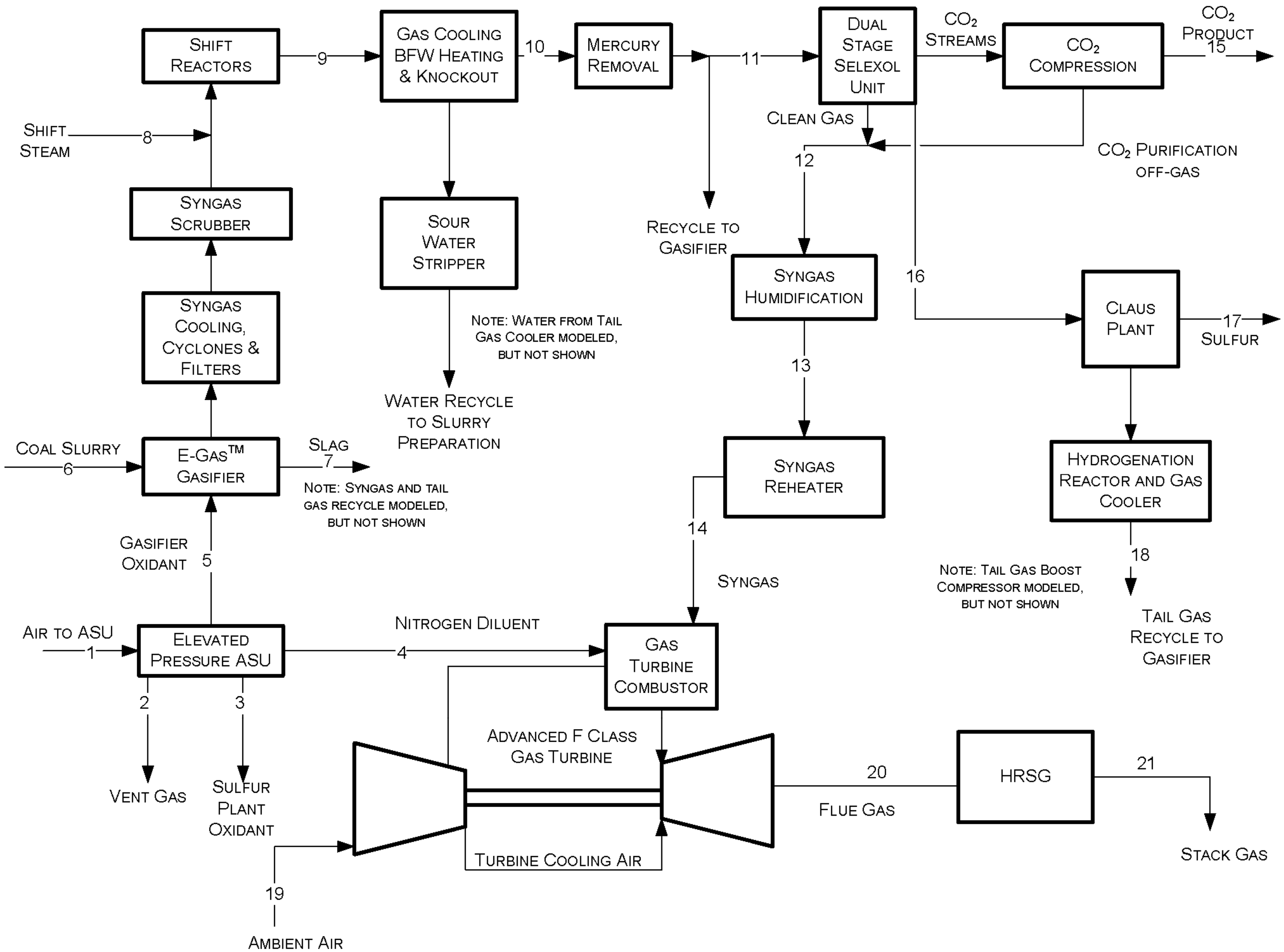

Exhibit 8-2 Case 6 (IGCC CR Retrofit) Stream Table, E-Gas™ IGCC with Retrofitted CO_2 Capture

	1	2	3	4	5	6[A]	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0263	0.0360	0.0023	0.0320	0.0000	0.0000	0.0000	0.0051	0.0065	0.0065
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0238	0.0302	0.0302
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0052	0.0067	0.0067
CO_2	0.0003	0.0092	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3214	0.4122	0.4122
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.4116	0.5275	0.5275
H_2O	0.0099	0.2713	0.0000	0.0004	0.0000	1.0000	0.0000	1.0000	0.2185	0.0014	0.0014
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0051	0.0058	0.0058
N_2	0.7732	0.4665	0.0140	0.9919	0.0180	0.0000	0.0000	0.0000	0.0073	0.0094	0.0094
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0019	0.0004	0.0004
O_2	0.2074	0.2266	0.9500	0.0054	0.9500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	55,654	1,969	278	41,984	11,156	25,799	0	31,642	91,106	71,043	56,835
V-L Flowrate (lb/hr)	1,606,000	52,498	8,944	1,178,060	359,031	249,436	0	570,044	1,827,120	1,465,320	1,172,260
Solids Flowrate (lb/hr)	0	0	0	0	0	424,717	48,622	0	0	0	0
Temperature (°F)	242	70	90	385	191	140	1,850	615	457	93	93
Pressure (psia)	190.0	16.4	125.0	460.0	740.0	850.0	850.0	600.0	516.0	481.0	471.0
Enthalpy (BTU/lb)[B]	57.3	26.7	12.5	88.0	34.4	76.9	457.0	1300.1	384.8	24.1	24.1
Density (lb/ft^3)	0.729	0.103	0.683	1.424	3.412	---	---	0.937	1.052	1.672	1.638
Molecular Weight	28.86	26.67	32.23	28.06	32.18	---	---	18.02	20.05	20.63	20.63

A - Solids flowrate includes dry coal; V-L flowrate includes slurry water and water from coal

B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 8-2 Case 6 (IGCC CR Retrofit) Stream Table, E-Gas™ IGCC with Retrofitted CO_2 Capture Continued

	12	13	14	15	16	17	18	19	20	21
V-L Mole Fraction										
Ar	0.0109	0.0093	0.0093	0.0000	0.0000	0.0000	0.0205	0.0094	0.0089	0.0089
CH_4	0.0508	0.0436	0.0436	0.0000	0.0000	0.0000	0.0880	0.0000	0.0000	0.0000
CO	0.0112	0.0096	0.0096	0.0000	0.0000	0.0000	0.0003	0.0000	0.0000	0.0000
CO_2	0.0243	0.0208	0.0208	1.0000	0.4321	0.0000	0.6024	0.0003	0.0097	0.0097
COS	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.8888	0.7620	0.7620	0.0000	0.0000	0.0000	0.0215	0.0000	0.0000	0.0000
H_2O	0.0001	0.1427	0.1427	0.0000	0.0554	0.0000	0.0006	0.0108	0.1350	0.1350
H_2S	0.0000	0.0000	0.0000	0.0000	0.4035	0.0000	0.0180	0.0000	0.0000	0.0000
N_2	0.0139	0.0119	0.0119	0.0000	0.0774	0.0000	0.2486	0.7719	0.7429	0.7429
NH_3	0.0000	0.0000	0.0000	0.0000	0.0312	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2076	0.1035	0.1035
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	33,733	39,346	39,346	22,257	813	47	628	242,512	308,662	308,662
V-L Flowrate (lb/hr)	162,487	263,603	263,603	979,537	29,677	11,954	22,868	6,996,340	8,438,000	8,438,000
Solids Flowrate (lb/hr)	0	0	0	0	0	11,954	0	0	0	0
Temperature (°F)	99	299	385	156	120	375	95	59	1052	270
Pressure (psia)	468.5	458.5	453.5	2214.7	30.5	25.4	767.5	14.7	15.2	15.2
Enthalpy (BTU/lb)[B]	97.3	699.4	795.2	-46.0	48.7	-96.2	14.5	13.8	372.8	157.8
Density (lb/ft^3)	0.376	0.378	0.335	30.793	0.179	---	4.692	0.076	0.026	0.053
Molecular Weight	4.82	6.70	6.70	44.01	36.49	---	36.39	28.85	27.34	27.34

B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 8-3 Case 6 (IGCC CR Retrofit) Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,000
Steam Turbine Power	229,840
TOTAL POWER, kWe	**693,840**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	440
Coal Milling	2,230
Coal Slurry Pumps	580
Slag Handling and Dewatering	1,140
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	62,760
Oxygen Compressor	8,490
Nitrogen Compressor	36,330
Syngas Recycle Blower	3,400
Tail Gas Recycle Blower	1,090
CO_2 Compressor	25,970
Boiler Feedwater Pumps	5,340
Condensate Pump	270
Flash Bottoms Pump	200
Circulating Water Pumps	3,020
Cooling Tower Fans	1,560
Scrubber Pumps	70
Double-Stage Selexol Unit Auxiliaries	14,840
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	200
Miscellaneous Balance of Plant	3,000
Transformer Loss	2,570
TOTAL AUXILIARIES, kWe	**175,600**
NET POWER, kWe	**518,240**
Net Plant Efficiency (HHV)	31.7%
Net Plant Heat Rate (Btu/kWh)	10,757
CONDENSER COOLING DUTY 10^6 kJ (10^6 Btu)	**1,225 (1,161)**
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)[1]	216,751 (477,855)
Thermal Input, kWt	1,643,511
Raw Water Usage, m^3/min (gpm)	15.65 (4,135)

[1] HHV of As-Received Illinois #6 11.12% Moisture Coal is 11,666 Btu/lb

8.1.1 Environmental Performance

The operation of the ConocoPhilips E-Gas™ IGCC combined cycle unit in this configuration is projected to result in very low levels of emissions of Hg, NO_X, SO_2, CO_2 and particulate matter. A salable byproduct is produced in the form of elemental sulfur, but no credit is taken because of the highly variable local market conditions. A summary of the plant air emissions is presented in Exhibit 8-4.

Exhibit 8-4 Case 6 (IGCC CR Retrofit) Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (tons/year) 80% capacity	kg/MWh_{net} (lb/MWh_{net})
SO_2	0.004 (0.0085)	151 (167)	0.042 (0.092)
NO_X	0.021 (0.050)	882 (972)	0.243 (0.535)
Particulates	0.003 (0.0071)	126 (139)	0.035 (0.076)
Hg	$0.25x10^{-6}$ ($0.57x10^{-6}$)	0.010 (0.011)	$2.8x10^{-6}$ ($6.2x10^{-6}$)
CO_2	10.1 (23.6)	417,000 (460,000)	115 (253)

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the two-stage Selexol AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of less than 30 ppm. This results in a concentration in the flue gas of less than 3 ppm. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated to convert all sulfur species to H_2S, and then recycled back to the gasifier, thereby eliminating the need for a tail gas treatment unit.

NO_X emissions are limited by the use of humidification and nitrogen dilution to 15 ppmvd (NO_2 @15% O_2). The ammonia is removed with process condensate prior to the low-temperature AGR process. This helps lower NO_X levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber.

Ninety five percent of mercury is captured from the syngas by an activated carbon bed. Ninety five percent of the CO_2 from the syngas is captured in the AGR system and compressed for sequestration.

The carbon balance for the plant is shown in Exhibit 8-5. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected in the carbon balance below since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as dissolved CO_2 in the wastewater blowdown stream, and CO_2 in the stack gas, ASU vent and the captured CO_2 product. Gray wastewater is recycled within the plant as slurry water. The captured CO_2 product is the percentage of CO_2

that would result if carbon in the coal feedstock, less carbon contained in solid byproducts (slag), was converted to CO_2, represented by the following fraction:

(Carbon in Product for Sequestration)/[(Carbon in the Coal)-(Carbon in Slag)] or
267,332/(304,633-2,310) *100 or
88.4%

Exhibit 8-5 Case 6 (IGCC CR Retrofit) Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	138,179 (304,633)	**Slag**	1,048 (2,310)
Air (CO_2)	489 (1,078)	**Stack Gas**	16,261 (35,850)
	---	**CO_2 Product**	121,260 (267,332)
	---	**ASU Vent**	99 (218)
	---	**Wastewater***	0 (0)
Total	138,668 (305,710)	**Total**	138,668 (305,710)

* by difference

Exhibit 8-6 shows the sulfur balance for the plant. Sulfur input includes the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, dissolved SO_2 in the wastewater blowdown stream, and sulfur emitted in the stack gas. Sulfur in the slag is considered negligible. The total sulfur capture is represented by the following fraction

(Sulfur byproduct/Sulfur in the coal) or
(11,954/11,994) or
99.7%

Exhibit 8-6 Case 6 (IGCC CR Retrofit) Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,440 (11,994)	**Elemental Sulfur**	5,422 (11,954)
	---	**Stack Gas**	11 (24)
	---	**Wastewater***	7 (16)
Total	5,440 (11,994)	**Total**	5,440 (11,994)

* by difference

Overall Mass and Energy balance information is also presented in tabular form in Exhibit 8-7.

Exhibit 8-7 Case 6 (IGCC CR Retrofit) Overall Energy and Mass Balance

In			Out		
	Energy Flow, MMBtu/hr	**Mass Flow, lb/hr**		**Energy Flow, MMBtu/hr**	**Mass Flow, lb/hr**
Coal	5,580	477,855	**Stack Gas**	1,336	8,438,000
Water	17	766,340	**Power**	1,805	---
Air	117	8,602,340	**Water**	4	315,925
	---	---	**Slag**	55	48,620
	---	---	**ASU**	2	52,500
	---	---	**Condenser Duty**	1,161	---
	---	---	**Compressor Intercoolers**	675	---
	---	---	**Process Losses***	768	---
	---	---	**CO_2**	-45	979,535
	---	---	**Sulfur**	-47	11,955
Total	5,714	9,846,535	**Total**	5,714	9,846,535
Net Plant Efficiency, % HHV (Overall)			31.7%		

*Process Losses reflect various gasification, turbine and other heat and work losses this number was set by difference between Energy In and the sum of all other Energy Out rows.
Enthalpy reference conditions are 32.02 F & 0.089 psia
Aspen Flowsheet Balance is within 0.5%.

8.1.2 Description of Process Systems

Since the Case 6 plant configuration is the result of retrofitting Case 4, which had been designed to anticipate conversion to a CO_2 capture mode, the amount of process equipment utilized in the retrofit is reduced. **The major process areas affected by the retrofit include adding a shift reaction process, adding a second stage to the AGR process, providing CO_2 compression equipment and modifying the gas turbine combustor for operation on a hydrogen-rich syngas fuel.** The process areas are described below and the changes in the Equipment List are identified in a side-by-side comparison in Section 8.5.

Water Gas Shift Reactors

Process Description - The CO shift converter consists of two sets of parallel fixed-bed reactors arranged in series. Cooling is provided between the series of three reactors to control the exothermic temperature rise. The parallel set of reactors is required due to the high gas mass flow rate. Feed to the shift converter is first preheated by hot effluent from the third converter, then heated by hot effluent from the second converter, and finally fed to the top of the two parallel first-stage converters. Effluent from the first stage is cooled and fed to the top of the second-stage converters. Effluent from the second stage is cooled and fed to the top of the third stage converters. Effluent from the third stage is cooled by exchanging heat with incoming feed, by an air cooler and finally by a water cooler. A nominal 98% of the CO is converted to CO_2 and H_2.

Acid Gas Removal

A feature of this plant configuration is that H_2S and CO_2 are removed within the same process system, the Selexol unit. The purpose of the Selexol unit is to preferentially remove H_2S as a product stream and then to remove CO_2 as a separate product stream. This is achieved in the double-stage Selexol unit.

Cool, dry, and particulate-free synthesis gas enters the first absorber unit at approximately 3.4 MPa (495 psia) and 39°C (101°F). In this absorber, H_2S is preferentially removed from the fuel gas stream by "loading" the lean Selexol solvent with CO_2. The solvent, saturated with CO_2, preferentially removes H_2S. The rich solution leaving the bottom of the absorber is regenerated in a stripper through the indirect application of thermal energy via condensing low-pressure steam in a reboiler. The stripper acid gas stream, consisting of 42 percent H_2S and 40 percent CO_2 (with the balance mostly N_2), is then sent to the Claus unit.

Sweet fuel gas flowing from the first absorber is cooled and routed to the second absorber unit. In this absorber, the fuel gas is contacted with "unloaded" lean solvent. The solvent removes approximately 95 percent of the CO_2 remaining in the fuel gas stream. A CO_2 balance is maintained by hydraulically expanding the CO_2-saturated rich solution and then flashing CO_2 vapor off the liquid at reduced pressure. Sweet fuel gas off the second absorber is warmed and humidified in the fuel gas saturator, reheated, and then sent to the burner of the combustion turbine.

Sweet, hydrogen-rich fuel gas from the Selexol unit is piped to the bottom of the fuel gas saturator. The sweet fuel gas rises up through the column while warm water flows downward counter-currently. Internal trays are used to enhance the mass transfer of water vapor into the fuel gas. This process both humidifies the fuel gas and increases its sensible heat content.

Warm, humid fuel gas exits the top of the saturator at 132°C (270°F) and 3.2 MPa (465 psia). It is indirectly heated further to 196°C (385°F) by condensing high-pressure steam.

Saturator water exits the column at 80°C (176°F) after being cooled down from 133°C (272°F). The water is then reheated back to 133°C (272°F) using LP steam. To avoid the buildup of soluble gases, a small blow down to the sour water drum is taken from the pump discharge.

CO_2 Compression and Dehydration

CO_2 is recovered both from a Selexol plant reabsorber at 1.7 MPa (250 psia) and flashed from the rich solution at three pressures. Approximately 20% of the CO_2 is flashed off at 2.1 MPa (300 psia), 25% at 1.1 MPa (160 psia) and the rest at 0.35 MPa (50 psia). The low-pressure CO_2 stream is "boosted" to 1.2 MPa (170 psia) and then combined with the 1.1 MPa CO_2 stream. The higher pressure CO_2 streams are admitted to the compressor at the appropriate pressures. The combined flow is then compressed to 15.3 MPa (2,215 psia) in a multiple-stage, intercooled compressor to supercritical conditions. During compression, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The virtually moisture-free supercritical CO_2 stream is then ready for pipeline transport.

8.2 CASE 4 (IGCC CR) & 6 (IGCC CR RETROFIT) - MAJOR EQUIPMENT LIST

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Qty	Case 6 (IGCC CR retrofit) Design Condition
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	No Change
2	Feeder	Belt	572 tonne/hr (630 tph)	2	
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	
4	Transfer Tower No. 1	Enclosed	N/A	1	
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	
6	As-Received Coal Sampling System	Two-stage	N/A	1	
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	2	
8	Reclaim Hopper	N/A	45 tonne (50 ton)	3	
9	Feeder	Vibratory	181 tonne/hr (200 tph)	3	
10	Conveyor No. 3	Belt w/tripper	354 tonne/hr (390 tph)	1	
11	Crusher Tower	N/A	N/A	1	
12	Coal Surge Bin w/ Vent Filter	Dual outlet	181 tonne/hr (200 tph)	2	
13	Crusher	Impactor reduction	8 cm x 0 – 3 cm x 0 (3"x0 - 1¼"x0)	2	
14	As-Fired Coal Sampling System	Swing hammer	N/A	2	
15	Conveyor No. 4	Belt w/tripper	345 tonne/hr (380 tph)	1	
16	Transfer Tower No. 2	Enclosed	N/A	1	
17	Conveyor No. 5	Belt w/tripper	345 tonne/hr (380 tph)	1	
17	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Qty	Case 6 (IGCC CR retrofit) Design Condition
1	Feeder	Vibratory	82 tonne/hr (90 tph)	3	No Change
2	Conveyor No. 6	Belt w/tripper	236 tonne/hr (260 tph)	1	
3	Rod Mill Feed Hopper	Dual Outlet	481 tonne (530 ton)	1	
4	Weight Feeder	Belt	118 tonne/hr (130 tph)	2	
5	Rod Mill	Rotary	118 tonne/hr (130 tph)	2	
6	Slurry Water Storage Tank with Agitator	Field erected	295,264 liters (78,000 gal)	2	
7	Slurry Water Pumps	Centrifugal	833 lpm (220 gpm)	4	
10	Trommel Screen	Course	172 tonne/hr (190 tph)	2	
11	Rod Mill Product Tank with Agitator	Field erected	312,678 liters (82,600 gal)	2	
12	Rod Mill Product Pumps	Horizontal, centrifugal	2,612 liters/min (690 gpm)	4	
13	Slurry Storage Tank with Agitator	Field erected	946,361 liters (250,000 gal)	2	
14	Slurry Recycle Pumps	Horizontal, centrifugal	5,224 liters (1,380 gpm)	4	
15	Slurry Product Pumps	Positive Displacement	2,612 lpm (690 gpm)	4	

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Qty	Case 6 (IGCC CR retrofit) Design Condition
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	2,237,196 liters (591,000 gal)	3	No Change
2	Condensate Pumps	Vertical canned	7,874 lpm @ 91 m H_2O (2,080 gpm @ 300 ft H_2O)	3	
3	Deaerator (integral with HRSG)	Horiz. spray type	577,877 kg/hr (1,274,000 lb/hr)	2	
4	Intermediate Pressure Feedwater Pump	Horiz. centrifugal single stage	2,006 lpm @ 283 m H_2O (530 gpm @ 930 ft H_2O)	3	
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	6,587 lpm @ 1,890 m H_2O (1,740 gpm @6,200 ft H_2O)	3	
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	1,476 lpm @ 223 m H_2O (390 gpm @ 730 ft H_2O)	3	
7	Auxiliary Boiler	Shop fab., water tube	18,144kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	
8	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	3	
9	Inst. Air Dryers	Duplex, regenerative	28 m^3/min (1,000 cfm)	3	
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	58 MMkJ/hr (55MMBtu/hr) each	2	
11	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	20,820 lpm @ 21 m H_2O (5,500 gpm @ 70 ft H_2O)	3	
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	3,785 lpm @ 107m H_2O (1,000 gpm @ 350 ftH_2O)	2	
13	Fire Service Booster Pump	Two-stage horiz., centrifugal	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	2	
14	Raw Water Pumps	SS, single suction	8,707 lpm @ 18 m H_2O (2,300 gpm @ 60 ft H_2O)	3	
15	Filtered Water Pumps	SS, single suction	4,088 lpm @ 49 m H_2O (1,080 gpm @ 160 ft H_2O)	3	

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Qty	Case 6 (IGCC CR retrofit) Design Condition
16	Filtered Water Tank	Vertical, cylindrical	1,968,429 liters (520,000 gal)	2	No Change
17	Makeup Demineralizer	Anion, cation, and mixed bed	2,574 lpm (680 gpm)	2	
18	Liquid Waste Treatment System		10 years, 24-hour storm	1	

ACCOUNT 4 GASIFIER, ASU, AND ACCESSORIES INCLUDING LOW TEMPERATURE HEAT RECOVERY AND FUEL GAS SATURATION

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Qty	Case 6 (IGCC CR retrofit) Design Condition
1	Gasifier	Pressurized two-stage, slurry-feed entrained bed	2,903 tonne/day 4.2 MPa (3,200 tpd 615 psia)	2	No Change
2	Synthesis Gas Cooler	Fire-tube boiler	326,133 kg/hr (719,000 lb/hr)	2	
3	Synthesis Gas Cyclone	High Efficiency	313,433 kg/hr (691,000 lb/hr), Design efficiency 90%	2	
4	Candle Filter	Pressurized filter with pulse jet cleaning	Metallic filters	2	
5	Syngas Scrubber Including Sour Water Stripper	Vertical, upflow	299,825 kg/hr (661,000 lb/hr)	2	
6	Raw Gas Coolers	Shell and tube with condensate drain	455,861 kg/hr (1,005,000 lb/hr)	6	
7	Raw Gas Knockout Drum	Vertical with mist eliminator	351,988 kg/hr, 38°C, 5.1 MPa (776,000 lb/hr,100°F, 737 psia)	2	
8	Saturation Water Economizers	Shell and tube	455,861 kg/hr (1,005,000 lb/hr)	2	

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Qty	Case 6 (IGCC CR retrofit) Design Condition
9	Fuel Gas Saturator	Vertical tray tower	62,596 kg/hr, 149°C, 3.2 MPa (138,000 lb/hr,300°F, 458 psia)	2	No Change
10	Saturator Water Pump	Centrifugal	3,785 lpm @ 15 m H_2O (1,000 gpm @ 50 ft H_2O)	2	
11	Synthesis Gas Reheater	Shell and tube	65,771 kg/hr (145,000 lb/hr)	2	
12	Flare Stack	Self-supporting, carbon steel, ss top, pilot ignition	299,825 kg/hr (661,000 lb/hr)	2	
13	ASU Main Air Compressor	Centrifugal, multi-stage	5,493 m^3/min @ 1.3 MPa (194,000 scfm @ 190 psia)	2	
14	Cold Box	Vendor Design	2,177 tonne/day (2,400 tpd) of 95% purity O_2	2	
15	Oxygen Compressor	Centrifugal, multi-stage	1,104 m^3/min @ 5.1 MPa (39,000 scfm @ 740 psia)	2	
16	Nitrogen Compressor	Centrifugal, multi-stage	3,653 m^3/min @ 3.4 MPa (129,000 scfm @ 490 psia)	2	
17	Nitrogen Boost Compressor	Centrifugal, multi-stage	510 m^3/min @ 2.3 MPa (18,000 scfm @ 340 psia)	2	

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Qty	Case 6 (IGCC CR retrofit) Design Condition
1	Mercury Adsorber	Sulfated Carbon Bed	320,690 kg/hr, 34°C, 3.3MPa, (707,000 lb/hr, 93°F, 481 psia)	2	No Change
2	Sulfur Plant	Claus plant	143 tonne/day (153 tpd)	1	
3a	COS Hydrolysis Reactor	Fixed bed catalytic	298,464 kg/hr, 204°C, 3.8MPa, (658,000 lb/hr, 400°F, 555 psia)	2	N/A
4a	Acid Gas Removal Plant	Single Stage Selexol	427,285 kg/hr, 39°C, 3.3MPa, (942,000 lb/hr, 103°F, 485 psia)	1	N/A

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Qty	Case 6 (IGCC CR retrofit) Design Condition
3b	Water Gas Shift Reactors	Fixed bed catalytic	N/A	2	455,861 kg/hr, 232°C, 3.9MPa, (1,005,000 lb/hr, 450°F, 562 psia)
3c	Shift Reactor Heat Recovery Exchangers	Shell and Tube	N/A	6	---
4b	Acid Gas Removal Plant	Two-stage Selexol	N/A	1	584,681 kg/hr, 35°C, 3.2MPa, (1,289,000 lb/hr, 95°F, 471 psia)
5	Hydrogenation Reactor	Fixed bed, catalytic	25,401 kg/hr, 232°C, 0.2MPa, (56,000 lb/hr, 450°F, 25 psia)	1	No Change
6	Tail Gas Recycle Compressor	Centrifugal	21,772 kg/hr@ 6.6 MPa, (48,000 lb/hr @ 950 psia)	1	

ACCOUNT 5C CARBON DIOXIDE RECOVERY

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Case 6 (IGCC CR retrofit) Design Condition	Case 6 Qty
2	CO_2 Compressor	Integrally geared, multi-stage centrifugal	NA	1,096 m^3/min @ 15.3 MPa (38,715 scfm @ 2,215 psia)	5

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Qty	Case 6 (IGCC CR retrofit) Design Condition
1	Gas Turbine	Advanced F class w/dry low-NOx burner	232 MWe	2	No Change
2	Gas Turbine Generator	TEWAC	260MVA @0.9 p.f, 24kV, 60Hz, 3-phase	2	

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK (total for plant)

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Qty	Case 6 (IGCC CR retrofit) Design Condition
1	Stack	Carbon steel plate, type 409 stainless steel liner	76 m high x 8.3 m dia. (250 ft high x 27 ft dia.)	1	No Change
2	Heat Recovery Steam Generator	Drum, multi-pressure, with economizer section and integral deaerator	Main steam - 368,554 kg/hr, 12.4 MPa/566°C (812,522 lb/hr, 1,800 psig/1,050°F) Reheat steam - 361,875 kg/hr, 2.9 MPa/566°C (797,796 lb/hr, 420 psig/1,050°F)	2	

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Qty	Case 6 (IGCC CR retrofit) Design Condition
1	Steam Turbine	Commercially available advanced steam turbine	293 MWe 12.4 MPa/538°C/538°C (1800psig/1050°F/1050°F)	1	No Change
2	Steam Turbine Generator	Hydrogen cooled, static excitation	330MVA @ 0.9 p.f., 24kV, 60 Hz, 3-phase	1	
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,613 MMkJ/hr (1,530 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Qty	Case 6 (IGCC CR retrofit) Design Condition
1	Circulating Water Pumps	Vertical, wet pit	336,904 lpm @ 30 m H_2O (89,000 gpm @ 100 ft H_2O)	3	No Change
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT, 1,687 MMkJ/hr (1,600 MMBtu/hr) heat duty	1	

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Qty	Case 6 (IGCC CR retrofit) Design Condition
1	Slag Quench Tank	Water bath	230,91 liters (61,000 gal)	2	No Change
2	Slag Crusher	Roll	12 tonne/hr (13 tph)	2	
3	Slag Depressurizer	Proprietary	12 tonne/hr (13 tph)	2	
4	Slag Receiving Tank	Horizontal, weir	151,418 liters (40,000 gal)	2	
5	Black Water Overflow Tank	Shop fabricated	71,923 liters (19,000 gal)	2	
6	Slag Conveyor	Drag chain	12 tonne/hr (13 tph)	2	
7	Slag Separation Screen	Vibrating	12 tonne/hr (13 tph)	2	
8	Coarse Slag Conveyor	Belt/bucket	12 tonne/hr (13 tph)	2	
9	Fine Ash Storage Tank	Vertical, gravity	227,126 liters (60,000 gal)	2	
10	Fine Ash Transfer Pumps	Horizontal /centrifugal	38 lpm @ 14m H_2O (10 gpm @ 46ft H_2O)	4	
11	Grey Water Storage Tank	Field erected	71,923 liters (19,000 gal)	2	
12	Grey Water Pumps	Centrifugal	265 lpm @ 433m H_2O (70 gpm @ 1,420 ft H_2O)	4	
13	Grey Water Recycle Heat Exchanger	Shell and tube	15,876 kg/hr (35,000 lb/hr)	2	
14	Storage Bin	Vertical, field erected	816 tonnes (900 tons)	2	

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Qty	Case 6 (IGCC CR retrofit) Design Condition
15	Unloading Equipment	Telescoping chute	100 tonne/hr (110 tph)	1	No Change

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Qty	Case 6 (IGCC CR retrofit) Design Condition
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	No Change
2	STG Transformer	Oil-filled	24 kV/345 kV, 80 MVA, 3-ph, 60 Hz	1	
3	Auxiliary Transformer	Oil-filled	24 kV/ 4.16 kV, 191 MVA, 3-ph, 60 Hz	2	
4	Low Voltage Transformer	Dry ventilated	4.16 kV /480 V, 29 MVA, 3-ph, 60 Hz	2	
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	
7	Medium Voltage Switchgear	Metal Clad	4.16 kV, 3-ph, 60 Hz	2	
8	Low Voltage Switchgear	Metal Enclosed	480 kV, 3-ph, 60 Hz	2	
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Case 4 (IGCC CR) Design Condition	Qty	Case 6 (IGCC CR retrofit) Design Condition
1	DCS - Main Control	Monitor/keyboard; Operator printer – laser color; Eng. Printer – laser black & white	Operator Stations/Printers and Engineering Stations/Printers	1	No Change
2	DCS - Processor	Microprocessor with Redundant Input/Output	N/A	1	
4	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	

8.3 CASE 6 (PC CR RETROFIT) - COST ESTIMATING RESULTS

Exhibit 8-8 through Exhibit 8-11 show the capital and operating costs for retrofitting this plant for CO_2 capture. Capital cost estimating methodology is explained in Section 4. The detailed breakdowns of the capital cost estimates for each case are included in Appendix B.

Note: Costs impacted by changes in design and operating parameter values from the capture-ready case values to the CO_2 capture design and operation performance requirements are highlighted in the following capture-ready retrofit case cost exhibits.

Exhibit 8-8 Case 6 (IGCC CR Retrofit) Total Plant Costs

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST SUMMARY

Case: Case 6 -Retrofit of Capture Ready ConocoPhillips E-Gas Dual Train IGCC w CO2
Plant Size: 518.2 MW,net **Estimate Type:** Conceptual Cost Base Jan 2007 $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL HANDLING SYSTEM	13,303	2,480	10,424		$26,207	2,127		5,667	$34,000	66
2	COAL PREP & FEED SYSTEMS	22,651	4,146	13,827		$40,624	3,263		8,777	$52,665	102
3	FEEDWATER & MISC. BOP SYSTEMS	9,371	7,975	8,947		$26,292	2,201		6,451	$34,944	67
4	GASIFIER & ACCESSORIES										
4.1	Gasifier, Syngas Cooler & Auxiliaries	93,113		57,142		$150,256	12,324	22,538	27,768	$212,885	411
4.2	Syngas Cooler (w/Gasifier - $)	w/4.1		w/4.1							
4.3	ASU/Oxidant Compression	142,779		w/equip.		$142,779	12,175		15,495	$170,449	329
4.4-4.9	Other Gasifiction Equipment	24,864	8,707	14,165		$47,736	4,057		11,002	$62,795	121
	Subtotal 4	260,756	8,707	71,307		$340,771	28,555	22,538	54,265	$446,129	861
5A	**GAS CLEANUP & PIPING**	**84,964**	**4,446**	**74,333**		**$163,743**	**14,066**	**21,481**	**40,061**	**$239,350**	**462**
5B	**CO2 REMOVAL & COMPRESSION**	**17,010**		**10,435**		**$27,445**	**2,351**		**5,959**	**$35,754**	**69**
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	88,000		5,325		$93,325	7,865	9,333	11,052	$121,575	235
6.2-6.9	Combustion Turbine Accessories		684	762		$1,446	121		470	$2,037	4
	Subtotal 6	88,000	684	6,087		$94,771	7,986	9,333	11,522	$123,611	239
7	HRSG, DUCTING & STACK										
7.1	Heat Recovery Steam Generator	32,356		4,604		$36,960	3,125		4,009	$44,094	85
7.2-7.9	Ductwork, Stack	3,222	2,268	3,011		$8,501	703		1,496	$10,700	21
	Subtotal 7	35,577	2,268	7,615		$45,461	3,829		5,505	$54,794	106
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	25,224		4,105		$29,328	2,518		3,185	$35,030	68
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	9,243	828	6,527		$16,598	1,338		3,645	$21,581	42
	Subtotal 8	34,466	828	10,632		$45,926	3,856		6,829	$56,611	109
9	COOLING WATER SYSTEM	6,318	6,821	5,729		$18,867	1,553		4,194	$24,614	47
10	ASH/SPENT SORBENT HANDLING SYS	18,516	1,396	9,191		$29,103	2,482		3,445	$35,031	68
11	ACCESSORY ELECTRIC PLANT	23,064	11,396	22,575		$57,035	4,450		11,923	$73,409	142
12	INSTRUMENTATION & CONTROL	10,183	1,906	6,836		$18,925	1,562	946	3,586	$25,021	48
13	IMPROVEMENTS TO SITE	3,208	1,891	7,974		$13,073	1,151		4,267	$18,490	36
14	BUILDINGS & STRUCTURES		6,066	6,992		$13,057	1,063		2,319	$16,439	32
	TOTAL COST	**$627,389**	**$61,009**	**$272,902**		**$961,300**	**$80,494**	**$54,298**	**$174,770**	**$1,270,863**	**$2,452**

Exhibit 8-9 Case 6 (IGCC CR Retrofit) Operating Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base Jan	2007
Case 6 -Retrofit of Capture Ready ConocoPhillips E-Gas Dual Train IGCC w CO2					Heat Rate-net(Btu/kWh):	**10,757**
Plant Output:	CO_2 (tpd):	**14,693**	H_2 (mmscfd):		MWe-net:	**518.2**
					Capacity Factor: (%):	80.0
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Total Plant			
Skilled Operator	2.0		2.0			
Operator	10.0		10.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	3.0		3.0			
TOTAL-O.J.'s	16.0		16.0			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost(calc'd)					$6,012,864	**11.60**
Maintenance Labor Cost(calc'd)					$13,171,520	**25.42**
Administrative & Support Labor(calc'd)					$4,796,096	**9.25**
TOTAL FIXED OPERATING COSTS					$23,980,481	**46.27**
VARIABLE OPERATING COSTS						$/kWh-net
Maintenance Material Cost(calc'd)					**$24,211,567**	**0.0067**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)		5,954	1.03		$1,790,845	**0.0005**
Chemicals						
MU & WT Chem.(lb)	124,161	17,737	0.16	$20,462	$853,547	0.0002
Carbon (Mercury Removal) (lb)	128,090	175	1.00	$128,090	$51,100	0.0000
COS Catalyst (m3)			2308.40			
Water Gas Shift Catalyst(ft3)	**11,053**	**8**	475.00	**$5,250,175**	**$1,049,363**	**0.0003**
Selexol Solution (gal.)	462	66	12.90	$5,960	$248,630	0.0001
MDEA Solution (gal)			8.38			
Sulfinol Solution (gal)			9.68			
SCR Catalyst (m3)			5500.00			
Ammonia (28% NH3) ton			123.60			
Claus Catalyst(ft3)	12	2	125.00	$1,460	$78,840	0.0000
Subtotal Chemicals				**$5,406,147**	**$2,281,480**	**0.0006**
Other						
Supplemental Fuel(MBtu)			6.75			
SCR Catalyst Replacement			9480.00			
Emission Penalties						
Subtotal Other						
Waste Disposal						
Spent Mercury Catalyst (lb.)		175	0.40		$20,522	0.0000
Flyash (ton)			15.45			
Bottom Ash(ton)		583	15.45		$2,632,348	**0.0007**
Subtotal Solid Waste Disposal					$2,652,870	**0.0007**
By-products & Emissions						
Gypsum (tons)						
Sulfur(tons)			-25.00			
Subtotal By-Products						
TOTAL VARIABLE OPERATING COSTS				**$5,406,147**	**$30,936,762**	**0.0085**
FUEL (tons)	**172,028**	**5,734**	42.11	**$7,244,101**	**$70,509,250**	**0.0194**

Exhibit 8-10 Case 6 (IGCC CR Retrofit) Capital Investment Requirement Summary

TITLE/DEFINITION					
Case: **Case 6 -Retrofit of Capture Ready ConocoPhillips E-Gas Dual Train IGCC w CO2**					
Plant Size:	**518.2** (MW,net)	HeatRate:		**10,757** (Btu/kWh)	
Primary/Secondary Fuel(type):	Illinois #6	Cost:		1.80 ($/MMBtu)	
Design/Construction:	3 (years)	BookLife:		30 (years)	
TPC(Plant Cost) Year:	2007 Jan				
Capacity Factor:	80 (%)	CO2 Removed:		**14,693** (TPD)	
CAPITAL INVESTMENT			**$x1000**		**$/kW**
Process Capital & Facilities			**961,300**		**1854.9**
Engineering(incl.C.M.,H.O.& Fee)			**80,494**		**155.3**
Process Contingency			**54,298**		**104.8**
Project Contingency			**174,770**		**337.2**
TOTAL PLANT COST(TPC)			**$1,270,863**		**2452.3**
OPERATING & MAINTENANCE COSTS (2007 Dollars)			**$x1000**		**$/kW-yr**
Operating Labor			6,013		**11.6**
Maintenance Labor			13,172		**25.4**
Maintenance Material			24,212		**46.7**
Administrative & Support Labor			4,796		**9.3**
TOTAL OPERATION & MAINTENANCE			$48,192		**93.0**
FIXED O & M			$30,224		**58.3**
VARIABLE O & M			$17,968		**34.7**
CONSUMABLE OPERATING COSTS, less Fuel (2007 Dollars)			$x1000		**¢/kWh**
Water			1,791		**0.05**
Chemicals			**2,281**		**0.06**
Other Consumables					
Waste Disposal			**2,653**		**0.07**
TOTAL CONSUMABLE OPERATING COSTS			**$6,725**		**0.19**
BY-PRODUCT CREDITS					
FUEL COST (2007 Dollars)			**$70,509**		**1.94**
				Levelized Costs	
PRODUCTION COST SUMMARY		**LF**		**¢/kWh**	
Fixed O & M		1.157		**0.96**	
Variable O & M		1.157		**0.57**	
Consumables		1.157		**0.21**	
By-product Credit		1.157			
Fuel		1.202		**2.33**	
TOTAL PRODUCTION COST				**4.08**	
2007 CARRYING CHARGES (Capital)				**6.12**	
CCF for a 20-Year Levelization Period - IOU - Higher-Risk		17.5			
20 YEAR LEVELIZED BUSBAR COST OF POWER				**10.21**	

Exhibit 8-11 Case 6 (IGCC CR Retrofit) Estimate Basis and Financial Criteria Summary

GENERAL DATA/CHARACTERISTICS

Case Title:	**Case 6 - "Capture Ready" CoP E-Gas Dual Train IGCC Retrofitted with CO2 Capture**		
Unit Size:/Plant Size:		**518.2**	MW,net
Location:		Midwestern, USA	
Fuel: Primary/Secondary	Illinois #6	11,666	Btu/lb
Energy From Primary/Secondary Fuels		**10,757**	Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):		80	%
Capital Cost Year Dollars (Reference Year Dollars):		2007	Jan
Delivered Cost of Primary/Secondary Fuel		1.80	$/MMBtu
Design/Construction Period:		3	years
Plant Startup Date (1st. Year Dollars):		2010	
Financial Parameter/Risk Level		IOU High Risk	

FINANCIAL CRITERIA

Project Book Life:	30	years
Book Salvage Value:		%
Project Tax Life:	20	years
Tax Depreciation Method:	20 years, 150% declining balance	
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		%
Economic Basis:	20th Year Current Dollars	

Capital Structure		% of Total	Cost(%)
	Common Equity	55.00	12.00
	Preferred Stock		
	Debt	45.00	11.00
Weighted Cost of Capital:(after tax)		9.67 %	

		2010 - 2030	
Nominal Escalation	General	1.87	% per year
	Coal Price	2.35	% per year
	Secondary Fuel:	1.96	% per year

8.4 CASE 8 (IGCC BAU RETROFIT) – BUSINESS-AS-USUAL RETROFIT TO CAPTURE CO_2

Case 8 (IGCC BAU retrofit) is based on retrofitting Case 2 (IGCC BAU) to capture 90% of the CO_2 in the flue gas to the Carbon Dioxide Recovery unit (CDR). The Case 2 business-as-usual baseline plant configuration is described in Section 7.1. Since Case 2 was not designed to capture CO_2 or made capture-ready, a substantial rework of the IGCC plant is required to achieve the 90% CO_2-capture mode.

Plant modifications for each gasifier train consist of:

- **Add parallel air compressor to the ASU.**
- **Remove the COS hydrolysis reactor and the LP steam generator/gas cooler.**
- **Insert 2 parallel trains of three shift reactors and intercoolers for each gasification train (therefore, a total of 6 shift reactors will be used to treat all the syngas).**
- **Re-arrange the aftercoolers between the shift and the condensate heat exchanger.**
- **Replace the MDEA unit with a two-stage Selexol.**
- **Add CO_2 compressors and dryers.**
- **Retrofit the gas turbine to burn hydrogen-rich syngas.**

Plant process equipment which is included in the retrofit is described in the following paragraphs. The equipment list (Section 8.5) is a side-by-side comparison of the equipment of Case 2 (IGCC BAU) and Case 8 (IGCC BAU retrofit).

For this case the baseline E-Gas IGCC plant is retrofitted for CO_2 capture. **While more raw syngas is needed in this case to operate the gas turbine at full load, the approach taken was to keep the coal and oxygen flow the same as the baseline Case 2 and to derate the gas turbine. Because of the conversion to hydrogen-rich combustion, the ASU is no longer integrated with the gas turbine. Multiple WGS reactors are required to capture a nominal 90 percent of the CO_2. The quantity of steam produced is reduced somewhat, so the same steam turbine can be used with modification to the blading.**

The resulting retrofitted plant produces a net output of 500 MW at a net efficiency of 31.5 percent on an HHV basis. The net output is the result of a decrease in combustion turbine power of 3.1 percent and a 20.1 percent decrease in steam turbine power. The steam turbine power loss is predominantly due to the large steam demand for regeneration of CO_2 from the Selexol process. The 3.1 percent reduction in combustion turbine power is directly proportional to the reduction in lower heating value (LHV) of the shifted syngas fuel stream. The LHV combustor feed for Case 2 (IGCC BAU) is 3,944 MMBtu/hr, whereas the LHV feed for Case 8 (IGCC BAU Retrofit) is 3,657 MMBtu/hr.

CO_2 and H_2S are removed from the cool, particulate-free fuel gas stream with a retrofit Selexol process. The purpose of the Selexol unit is to preferentially remove H_2S as a product stream and then to remove CO_2 as a separate product stream. This is achieved by retrofitting the amine process with the so-called double-stage or double-absorber Selexol unit. CO_2 removed with the

Selexol process is dried and compressed to a supercritical condition for subsequent pipeline transport.

Exhibit 8-12 is a block flow diagram for the overall plant with individual streams identified. Exhibit 8-13 follows the figure with detailed composition and state points for the numbered streams.

Overall performance for the entire plant is summarized in Exhibit 8-14, which includes auxiliary power requirements.

Exhibit 8-12 Case 8 (IGCC BAU Retrofit) Process Flow Diagram, E-Gas™ IGCC with Retrofitted CO_2 Capture

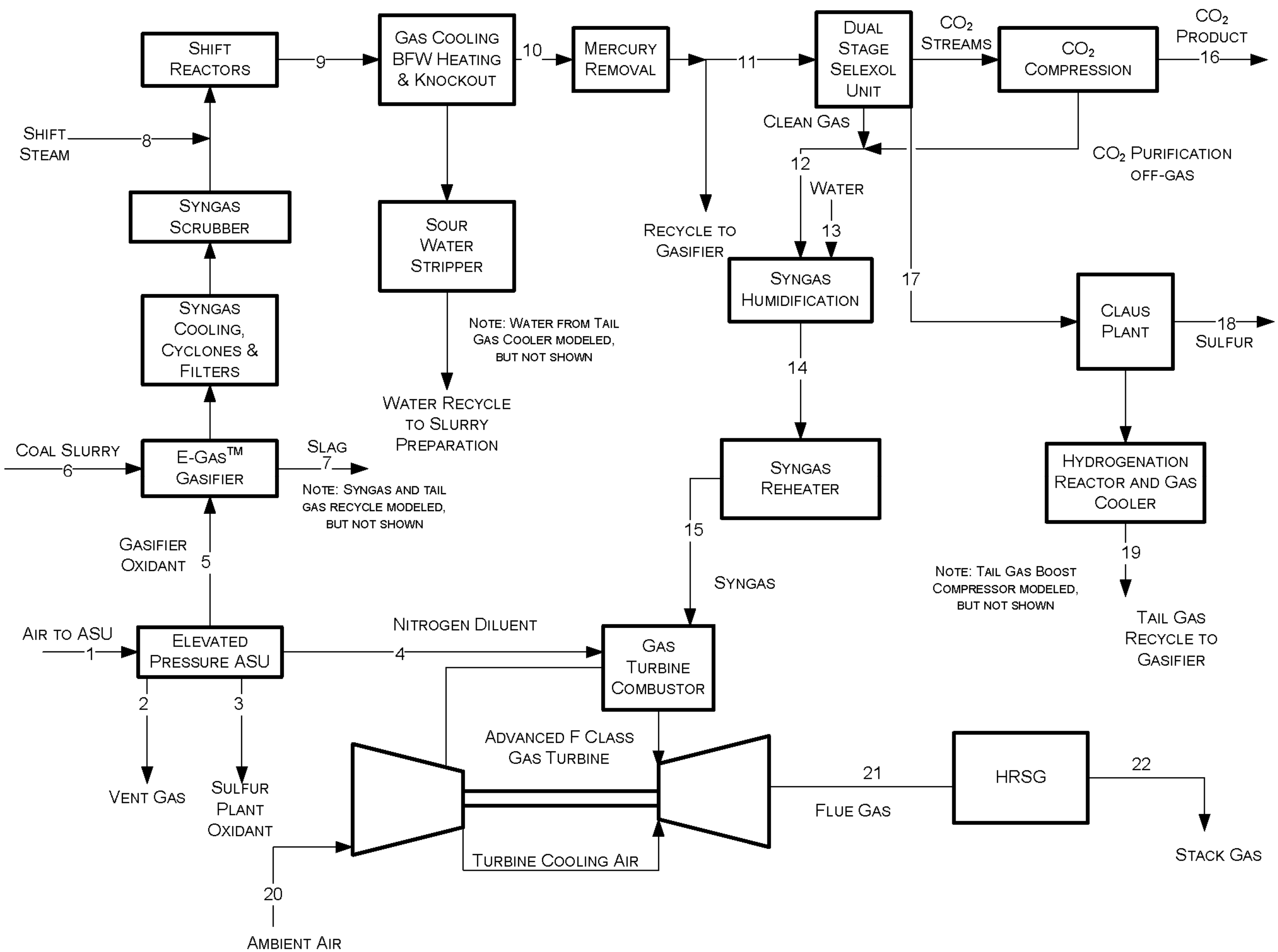

Exhibit 8-13 Case 8 (IGCC BAU Retrofit) Stream Table, E-Gas™ IGCC with Retrofitted CO_2 Capture

	1	2	3	4	5	6[A]	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0265	0.0318	0.0023	0.0318	0.0000	0.0000	0.0000	0.0051	0.0065	0.0065
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0238	0.0301	0.0301
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0052	0.0067	0.0067
CO_2	0.0003	0.0093	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3215	0.4122	0.4122
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.4118	0.5276	0.5276
H_2O	0.0099	0.2649	0.0000	0.0003	0.0000	1.0000	0.0000	1.0000	0.2182	0.0014	0.0014
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0051	0.0057	0.0057
N_2	0.7732	0.4707	0.0178	0.9919	0.0178	0.0000	0.0000	0.0000	0.0073	0.0094	0.0094
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0019	0.0005	0.0005
O_2	0.2074	0.2286	0.9504	0.0054	0.9504	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	54,036	1,895	272	40,754	10,831	13,453	0	30,691	88,426	68,969	55,176
V-L Flowrate (lb/hr)	1,559,310	50,669	8,738	1,143,550	348,538	242,145	0	552,900	1,773,370	1,422,360	1,137,890
Solids Flowrate (lb/hr)	0	0	0	0	0	412,305	47,201	0	0	0	0
Temperature (°F)	59	70	90	385	90	140	1,850	615	457	98	98
Pressure (psia)	14.4	16.4	125.0	460.0	125.0	850.0	850.0	600.0	516.0	481.0	471.0
Enthalpy (BTU/lb)[B]	13.1	26.6	12.5	88.0	12.5	76.9	457.0	1,343.7	384.6	25.8	25.8
Density (lb/ft^3)	0.07	0.10	0.682	1.42	0.68	---	---	0.94	1.05	1.66	1.62
Molecular Weight	28.86	26.74	32.181	28.06	32.18	---	---	18.02	20.05	20.62	20.62

A - Solids flowrate includes dry coal; V-L flowrate includes slurry water and water from coal

B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 8-13 Case 8 (IGCC BAU Retrofit) Stream Table, E-Gas™ IGCC with Retrofitted CO_2 Capture Continued

	12	13	14	15	16	17	18	19	20	21	22
V-L Mole Fraction											
Ar	0.0109	0.0000	0.0092	0.0092	0.0000	0.0000	0.0000	0.0208	0.0094	0.0089	0.0089
CH_4	0.0508	0.0000	0.0431	0.0431	0.0000	0.0000	0.0000	0.0889	0.0000	0.0000	0.0000
CO	0.0112	0.0000	0.0095	0.0095	0.0000	0.0000	0.0000	0.0003	0.0000	0.0000	0.0000
CO_2	0.0243	0.0000	0.0206	0.0206	1.0000	0.4337	0.0000	0.6008	0.0003	0.0097	0.0097
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.8889	0.0000	0.7545	0.7545	0.0000	0.0000	0.0000	0.0215	0.0000	0.0000	0.0000
H_2O	0.0001	1.0000	0.1512	0.1512	0.0000	0.0555	0.0000	0.0025	0.0108	0.1362	0.1362
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.3957	0.0000	0.0184	0.0000	0.0000	0.0000
N_2	0.0139	0.0000	0.0118	0.0118	0.0000	0.0777	0.0000	0.2469	0.7719	0.7420	0.7420
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0371	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2076	0.1033	0.1033
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	32,751	50,369	38,581	38,581	21,608	787	0	614	235,188	299,783	299,783
V-L Flowrate (lb/hr)	157,732	907,420	262,761	262,761	950,979	28,639	0	22,308	6,785,050	8,191,350	8,191,350
Solids Flowrate (lb/hr)	0	0	0	0	0	0	11,605	0	0	0	0
Temperature (°F)	99	325	303	385	156	120	375	251	59	1,053	270
Pressure (psia)	468.5	480.0	458.5	453.5	2,214.7	30.5	25.4	804.1	14.7	15.2	15.2
Enthalpy (BTU/lb)[B]	97.3	313.9	716.4	806.7	-46.0	48.8	---	52.6	13.8	374.0	158.7
Density (lb/ft^3)	0.38	52.94	0.38	0.34	30.79	0.18	---	3.83	0.08	0.03	0.05
Molecular Weight	4.82	18.02	6.81	6.81	44.01	36.40	---	36.34	28.85	27.32	27.324

Exhibit 8-14 Case 8 (IGCC BAU Retrofit) Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power[1]	449,760 Reduced from 464,030
Steam Turbine Power[2]	222,630 Reduced from 278,480
TOTAL POWER, kWe	**672,390**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	440
Coal Milling	2,160
Coal Slurry Pumps	570
Slag Handling and Dewatering	1,110
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	60,910
Oxygen Compressor	8,240
Nitrogen Compressor	34,850
Syngas Recycle Blower	3,420
Tail Gas Recycle Blower	1,080
CO_2 Compressor	25,210
Boiler Feedwater Pumps	4,830
Condensate Pump	260
Flash Bottoms Pump	190
Circulating Water Pumps	2,930
Cooling Tower Fans	1,690
Scrubber Pumps	70
Double-Stage Selexol Unit Auxiliaries	14,410
Gas Turbine Auxiliaries	2,000
Steam Turbine Auxiliaries	1,000
Claus Plant/TGTU Auxiliaries	200
Miscellaneous Balance of Plant	3,000
Transformer Loss	2,490
TOTAL AUXILIARIES, kWe	**172,060**
NET POWER, kWe	**500,330**
Net Plant Efficiency (HHV)	31.5%
Net Plant Heat Rate (Btu/kWh)	10,816
CONDENSER COOLING DUTY 10^6 kJ (10^6 Btu)	**1,184 (1,122)**
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)[1]	210,418 (463,889)
Thermal Input, kWt	1,586,023
Raw Water Usage, m^3/min (gpm)	15.2 (4,010)

[1] Coal flow rate is fixed, syngas mass flow decreases due to CO_2 capture
[2] Derated due to water-gas-shift steam extraction

8.4.1 Environmental Performance

The operation of the ConocoPhilips E-Gas™ IGCC combined cycle unit in this configuration is projected to result in very low levels of emissions of Hg, NO_X, SO_2, CO_2 and particulate matter. A salable byproduct is produced in the form of elemental sulfur, but no credit is taken because of the highly variable local market conditions. A summary of the plant air emissions is presented in Exhibit 8-15.

Exhibit 8-15 Case 8 (IGCC BAU Retrofit) Air Emissions

	kg/GJ (lb/10^6 Btu)	**Tonne/year (tons/year) 80% capacity**	**kg/MWh_{net} (lb/MWh_{net})**
SO_2	0.004 (0.0084)	144 (159)	0.041 (0.091)
NO_X	0.021 (0.050)	856 (943)	0.244 (0.538)
Particulates	0.003 (0.0071)	122 (135)	0.035 (0.077)
Hg	0.25×10^{-6} (0.57×10^{-6})	0.010 (0.011)	2.8×10^{-6} (6.2×10^{-6})
CO_2	10.1 (23.5)	446,468 (405,029)	116 (255)

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the two-stage Selexol AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of less than 30 ppm. This results in a concentration in the flue gas of less than 3 ppm. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated to convert all sulfur species to H_2S, and then recycled back to the gasifier, thereby eliminating the need for a tail gas treatment unit.

NO_X emissions are limited by the use of humidification and nitrogen dilution to 15 ppmvd (NO_2 @15% O_2). The ammonia is removed with process condensate prior to the low-temperature AGR process. This helps lower NO_X levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber.

Ninety five percent of mercury is captured from the syngas by an activated carbon bed. Ninety five percent of the CO_2 from the syngas is captured in the AGR system and compressed for sequestration.

The carbon balance for the plant is shown in Exhibit 8-16. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected in the carbon balance below since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as dissolved CO_2 in the wastewater blowdown stream, and CO_2 in the stack gas, ASU vent and the captured CO_2 product. Gray wastewater is recycled within the plant as slurry water. The captured CO_2 product is the percentage of CO_2

that would result if carbon in the coal feedstock, less carbon contained in solid byproducts (slag), was converted to CO_2, represented by the following fraction:

(Carbon in Product for Sequestration)/[(Carbon in the Coal)-(Carbon in Slag)] or
259,538/(295,729-2,243) *100 or
88.4%

Exhibit 8-16 Case 8 (IGCC BAU Retrofit) Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	134,141 (295,729)	**Slag**	1,017 (2,243)
Air (CO_2)	474 (1,045)	**Stack Gas**	15,777 (34,782)
	---	**CO_2 Product**	117,725 (259,538)
	---	**ASU Vent**	96 (212)
	---	**Wastewater***	0 (0)
Total	134,615 (296,775)	**Total**	134,615 (296,775)

* by difference

Exhibit 8-17 shows the sulfur balance for the plant. Sulfur input includes the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, dissolved SO_2 in the wastewater blowdown stream, and sulfur emitted in the stack gas. Sulfur in the slag is considered negligible. The total sulfur capture is represented by the following fraction

(Sulfur byproduct/Sulfur in the coal) or
(11,605/11,664) or
99.7%

Exhibit 8-17 Case 8 (IGCC BAU Retrofit) Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,281 (11,664)	**Elemental Sulfur**	5,264(11,605)
	---	**Stack Gas**	10 (23)
	---	**Wastewater***	7 (16)
Total	5,281 (11,664)	**Total**	5,281 (11,664)

* by difference

Overall Mass and Energy balance information is presented in tabular form in Exhibit 8-18.

Exhibit 8-18 Case 8 (IGCC BAU Retrofit) Overall Energy and Mass Balance

In			Out		
	Energy Flow, MMBtu/hr	**Mass Flow, lb/hr**		**Energy Flow, MMBtu/hr**	**Mass Flow, lb/hr**
Coal	5,416	463,889	**Stack Gas**	1,297	8,191,350
Water	17	743,174	**Power**	1,707	---
Air	114	8,344,360	**Water**	3	299,618
	---	---	**Slag**	53	47,200
	---	---	**ASU**	2	50,670
	---	---	**Condenser Duty**	1,122	---
	---	---	**Compressor Intercoolers**	655	---
	---	---	**Process Losses***	797	---
	---	---	**CO_2**	-44	950,980
	---	---	**Sulfur**	-46	11,605
Total	5,547	9,551,423	**Total**	5,546	9,551,423
Net Plant Efficiency, % HHV (Overall)			31.5%		

*Process Losses reflect various gasification, turbine and other heat and work losses this number was set by difference between Energy In and the sum of all other Energy Out rows.
Enthalpy reference conditions are 32.02 F & 0.089 psia
Aspen Flowsheet Balance is within 0.5%.

8.4.2 Retrofit Process and Equipment Adjustments

In the pre-retrofit configuration, the IGCC plant would be operating and producing power at the rated capacity of the gasifier and gas turbine, fired on clean syngas. To retrofit the plant for 90 percent CO_2 capture, the first process required is the water-gas-shift to convert the CO and to CO_2 and H_2. Steam is supplied to enhance the WGS reactions. Since the gasifier is operating at maximum capacity, along with the air separation unit (ASU), the retrofitted plant will operate in a derated mode due to the addition of this steam prior to the shift reaction. The following retrofit modifications are made to the baseline IGCC:

- Add a parallel air compressor to the ASU since less air extraction is coming from the gas turbine compressor. The compressor size is 300,000 lb/hour.
- Remove the COS hydrolysis reactor and the syngas reheater.
- Install a raw syngas cooler and move the syngas scrubber further upstream, leaving a void between the syngas cooler and the saturator hot water heater.
- Insert the two high temperature water-gas-shift trains for each gasification train. Includes intercoolers and an aftercooler upstream of the saturator hot water heater.
- Install the low-temperature shift reactor down stream of the saturator hot water heater.
- Remove and salvage the amine-based AGR process.
- Install a two-stage Selexol process to remove and capture H_2S and CO_2.
- Add a multi-stage CO_2 compressor and dryer.
- Retrofit the gas turbine to burn hydrogen-rich syngas.
- Modify the steam turbine as needed. There will be less steam available.

8.5 CASE 2 (IGCC BAU) & 8 (IGCC BAU RETROFIT) - MAJOR EQUIPMENT LIST

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 8 (IGCC BAU Retrofit) Design Condition
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	No Change
2	Feeder	Belt	572 tonne/hr (630 tph)	2	
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	
4	Transfer Tower No. 1	Enclosed	N/A	1	
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	
6	As-Received Coal Sampling System	Two-stage	N/A	1	
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	2	
8	Reclaim Hopper	N/A	45 tonne (50 ton)	3	
9	Feeder	Vibratory	172 tonne/hr (190 tph)	3	
10	Conveyor No. 3	Belt w/tripper	345 tonne/hr (380 tph)	1	
11	Crusher Tower	N/A	N/A	1	
12	Coal Surge Bin w/ Vent Filter	Dual outlet	172 tonne/hr (190 tph)	2	
13	Crusher	Impactor reduction	8 cm x 0 – 3 cm x 0 (3"x0 - 1¼"x0)	2	
14	As-Fired Coal Sampling System	Swing hammer	N/A	2	
15	Conveyor No. 4	Belt w/tripper	345 tonne/hr (380 tph)	1	
16	Transfer Tower No. 2	Enclosed	N/A	1	
17	Conveyor No. 5	Belt w/tripper	345 tonne/hr (380 tph)	1	
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 8 (IGCC BAU Retrofit) Design Condition
1	Feeder	Vibratory	82 tonne/hr (90 tph)	3	No Change
2	Conveyor No. 6	Belt w/tripper	236 tonne/hr (260 tph)	1	
3	Rod Mill Feed Hopper	Dual Outlet	463 tonne (510 ton)	1	
4	Weight Feeder	Belt	118 tonne/hr (130 tph)	2	
5	Rod Mill	Rotary	118 tonne/hr (130 tph)	2	
6	Slurry Water Storage Tank with Agitator	Field erected	283,908 liters (75,000 gal)	2	
7	Slurry Water Pumps	Centrifugal	795 lpm (210 gpm)	4	
10	Trommel Screen	Course	163 tonne/hr (180 tph)	2	
11	Rod Mill Product Tank with Agitator	Field erected	303,592 liters (80,000 gal)	2	
12	Rod Mill Product Pumps	Horizontal, centrifugal	2,536 liters/min (670 gpm)	4	
13	Slurry Storage Tank with Agitator	Field erected	908,506 liters (240,000 gal)	2	
14	Slurry Recycle Pumps	Horizontal, centrifugal	5,072 liters (1,340 gpm)	4	
15	Slurry Product Pumps	Positive Displacement	2,536 lpm (670 gpm)	4	

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 8 (IGCC BAU Retrofit) Design Condition
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,101,563 liters (291,000 gal)	2	No Change
2	Condensate Pumps	Vertical canned	6,132 lpm @ 91 m H_2O (1,620 gpm @ 300 ft H_2O)	3	
3	Deaerator (integral with HRSG)	Horiz. spray type	463,118 kg/hr (1,021,000 lb/hr)	2	
4	Intermediate Pressure Feedwater Pump	Horiz. centrifugal single stage	1,325 lpm @ 283 m H_2O (350 gpm @ 930 ft H_2O)	3	
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	6,511 lpm @ 1,890 m H_2O (1,720 gpm @ 6,200 ft H_2O)	3	
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	909 lpm @ 390 m H_2O (240 gpm @ 1,280 ft H_2O)	3	
7	Auxiliary Boiler	Shop fab., water tube	18,144kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	
8	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	3	
9	Inst. Air Dryers	Duplex, regenerative	28 m^3/min (1,000 cfm)	3	
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	58 MMkJ/hr (55MMBtu/hr) each	2	
11	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	20,820 lpm @ 21 m H_2O (5,500 gpm @ 70 ft H_2O)	3	
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	3,785 lpm @ 107m H_2O (1,000 gpm @ 350 ftH_2O)	2	
13	Fire Service Booster Pump	Two-stage horiz., centrifugal	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	2	
14	Raw Water Pumps	SS, single suction	7,912 lpm @ 18 m H_2O (2,090 gpm @ 60 ft H_2O)	3	
15	Filtered Water Pumps	SS, single suction	1,476 lpm @ 49 m H_2O (390 gpm @ 160 ft H_2O)	3	

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 8 (IGCC BAU Retrofit) Design Condition
16	Filtered Water Tank	Vertical, cylindrical	715,448 liters (189,000 gal)	2	No Change
17	Makeup Demineralizer	Anion, cation, and mixed bed	151 lpm (40 gpm)	2	
18	Liquid Waste Treatment System		10 years, 24-hour storm	1	

ACCOUNT 4 GASIFIER, ASU, AND ACCESSORIES INCLUDING LOW TEMPERATURE HEAT RECOVERY AND FUEL GAS SATURATION

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 8 (IGCC BAU Retrofit) Design Condition
1	Gasifier	Pressurized two-stage, slurry-feed entrained bed	2,812 tonne/day 4.2 MPa (3,100 tpd 615 psia)	2	No Change
2	Synthesis Gas Cooler	Fire-tube boiler	304,361 kg/hr (671,000 lb/hr)	2	
3	Synthesis Gas Cyclone	High Efficiency	291,660 kg/hr (643,000 lb/hr), Design efficiency 90%	2	
4	Candle Filter	Pressurized filter with pulse jet cleaning	Metallic filters	2	
5	Syngas Scrubber Including Sour Water Stripper	Vertical, upflow	298,464 kg/hr (658,000 lb/hr)	2	
6	Raw Gas Coolers	Shell and tube with condensate drain	275,784 kg/hr (608,000 lb/hr)	6	
7	Raw Gas Knockout Drum	Vertical with mist eliminator	266,259 kg/hr, 39°C, 3.6 MPa (587,000 lb/hr,103°F, 515 psia)	2	
8	Saturation Water Economizers	Shell and tube	275,784 kg/hr (608,000 lb/hr)	2	

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 8 (IGCC BAU Retrofit) Design Condition
9	Fuel Gas Saturator	Vertical tray tower	201,395 kg/hr, 103°C, 3.3 MPa (444,000 lb/hr,266°F, 484 psia)	2	No Change
10	Saturator Water Pump	Centrifugal	4,543 lpm @ 201 m H_2O (1,200 gpm @ 660 ft H_2O)	2	
11	Synthesis Gas Reheater	Shell and tube	215,457 kg/hr (475,000 lb/hr)	2	
12	Flare Stack	Self-supporting, carbon steel, ss top, pilot ignition	298,464 kg/hr (658,000 lb/hr)	2	
13	ASU Main Air Compressor	Centrifugal, multi-stage	4,134 m^3/min @ 1.3 MPa (146,000 scfm @ 190 psia)	2	3rd compressor added in parallel
14	Cold Box	Vendor Design	2,177 tonne/day (2,400 tpd) of 95% purity O_2	2	No Change
15	Oxygen Compressor	Centrifugal, multi-stage	1,076 m^3/min @ 5.1 MPa (38,000 scfm @ 740 psia)	2	
16	Nitrogen Compressor	Centrifugal, multi-stage	3,540 m^3/min @ 3.4 MPa (125,000 scfm @ 490 psia)	2	
17	Nitrogen Boost Compressor	Centrifugal, multi-stage	481 m^3/min @ 2.3 MPa (17,000 scfm @ 340 psia)	2	

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 8 (IGCC BAU Retrofit) Design Condition
1	Mercury Adsorber	Sulfated Carbon Bed	234,054 kg/hr, 39°C, 3.4MPa, (516,000 lb/hr, 103°F, 495 psia)	2	No Change
2	Sulfur Plant	Claus plant	139 tonne/day (153 tpd)	1	
3a	COS Hydrolysis Reactor	Fixed bed catalytic	298,464 kg/hr, 204°C, 3.8MPa, (658,000 lb/hr, 400°F, 555 psia)	2	N/A

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 8 (IGCC BAU Retrofit) Design Condition
4a	Acid Gas Removal Plant	MDEA	427,285 kg/hr, 39°C, 3.3MPa, (942,000 lb/hr, 103°F, 485 psia)	1	N/A
3b	Water Gas Shift Reactors	Fixed bed catalytic	N/A	2	427,285 kg/hr, 39°C, 3.3MPa, (942,000 lb/hr, 103°F, 485 psia)
3c	Shift Reactor Heat Recovery Exchangers	Shell and Tube	N/A	6	---
4b	Acid Gas Removal Plant	Two-stage Selexol	N/A	1	427,285 kg/hr, 39°C, 3.3MPa, (942,000 lb/hr, 103°F, 485 psia)
5	Hydrogenation Reactor	Fixed bed, catalytic	25,401 kg/hr, 232°C, 0.2MPa, (56,000 lb/hr, 450°F, 25 psia)	1	No Change
6	Tail Gas Recycle Compressor	Centrifugal	21,772 kg/hr@ 6.6 MPa, (48,000 lb/hr @ 950 psia)	1	

ACCOUNT 5C CARBON DIOXIDE RECOVERY

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Case 8 (IGCC BAU Retrofit) Design Condition	Case 8 Qty
1	CO_2 Compressor	Integrally geared, multi-stage centrifugal	NA	992 $m^{3/}$min @ 15.3 MPa (35,000 scfm @ 2,215 psia)	5

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 8 (IGCC BAU Retrofit) Design Condition
1	Gas Turbine	Advanced F class w/dry low-NOx burner	232 MWe	2	Modified to burn hydrogen rich syngas
2	Gas Turbine Generator	TEWAC	260MVA @0.9 p.f, 24kV, 60Hz, 3-phase	2	

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK (total for plant)

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 8 (IGCC BAU Retrofit) Design Condition
1	Stack	Carbon steel plate, type 409 stainless steel liner	76 m high x 8.3 m dia. (250 ft high x 27 ft dia.)	1	No Change
2	Heat Recovery Steam Generator	Drum, multi-pressure, with economizer section and integral deaerator	Main steam - 368,554 kg/hr, 12.4 MPa/566°C (812,522 lb/hr, 1,800 psig/1,050°F) Reheat steam - 361,875 kg/hr, 2.9 MPa/566°C (797,796 lb/hr, 420 psig/1,050°F)	2	

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 8 (IGCC BAU Retrofit) Design Condition
1	Steam Turbine	Commercially available advanced steam turbine	293 MWe 12.4 MPa/538°C/538°C (1800psig/1050°F/1050°F)	1	Blading Modifications for lower steam flow
2	Steam Turbine Generator	Hydrogen cooled, static excitation	330MVA @ 0.9 p.f., 24kV, 60 Hz, 3-phase	1	
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,613 MMkJ/hr (1,530 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 8 (IGCC BAU Retrofit) Design Condition
1	Circulating Water Pumps	Vertical, wet pit	336,904 lpm @ 30 m H_2O (89,000 gpm @ 100 ft H_2O)	3	No Change
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT, 1,876 MMkJ/hr (1,780 MMBtu/hr) heat duty	1	

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 8 (IGCC BAU Retrofit) Design Condition
1	Slag Quench Tank	Water bath	223,341 liters (59,000 gal)	2	No Change
2	Slag Crusher	Roll	12 tonne/hr (13 tph)	2	
3	Slag Depressurizer	Proprietary	12 tonne/hr (13 tph)	2	
4	Slag Receiving Tank	Horizontal, weir	147,632 liters (39,000 gal)	2	
5	Black Water Overflow Tank	Shop fabricated	68,138 liters (18,000 gal)	2	
6	Slag Conveyor	Drag chain	12 tonne/hr (13 tph)	2	
7	Slag Separation Screen	Vibrating	12 tonne/hr (13 tph)	2	
8	Coarse Slag Conveyor	Belt/bucket	12 tonne/hr (13 tph)	2	
9	Fine Ash Storage Tank	Vertical, gravity	219,556 liters (58,000 gal)	2	
10	Fine Ash Transfer Pumps	Horizontal /centrifugal	38 lpm @ 14m H_2O (10 gpm @ 46ft H_2O)	4	
11	Grey Water Storage Tank	Field erected	71,923 liters (19,000 gal)	2	
12	Grey Water Pumps	Centrifugal	265 lpm @ 433m H_2O (70 gpm @ 1,420 ft H_2O)	4	
13	Grey Water Recycle Heat Exchanger	Shell and tube	15,876 kg/hr (35,000 lb/hr)	2	
14	Storage Bin	Vertical, field erected	816 tonnes (900 tons)	2	

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 8 (IGCC BAU Retrofit) Design Condition
15	Unloading Equipment	Telescoping chute	100 tonne/hr (110 tph)	1	No Change

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 8 (IGCC BAU Retrofit) Design Condition
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	No Change
2	STG Transformer	Oil-filled	24 kV/345 kV, 190 MVA, 3-ph, 60 Hz	1	
3	Auxiliary Transformer	Oil-filled	24 kV/ 4.16 kV, 130 MVA, 3-ph, 60 Hz	2	
4	Low Voltage Transformer	Dry ventilated	4.16 kV /480 V, 19 MVA, 3-ph, 60 Hz	2	
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	
7	Medium Voltage Switchgear	Metal Clad	4.16 kV, 3-ph, 60 Hz	2	
8	Low Voltage Switchgear	Metal Enclosed	480 kV, 3-ph, 60 Hz	2	
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Case 2 (IGCC BAU) Design Condition	Qty	Case 8 (IGCC BAU Retrofit) Design Condition
1	DCS - Main Control	Monitor/keyboard; Operator printer – laser color; Eng. Printer – laser black & white	Operator Stations/Printers and Engineering Stations/Printers	1	No Change
2	DCS - Processor	Microprocessor with Redundant Input/Output	N/A	1	
4	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	

8.6 CASE 8 (IGCC BAU RETROFIT) - COST ESTIMATING RESULTS

Exhibit 8-19 through Exhibit 8-22 show the capital and operating costs for retrofitting this plant for CO_2 capture. Capital cost estimating methodology is explained in Section 4. The detailed breakdowns of the capital cost estimates for each case are included in Appendix B.

Note: Costs impacted by changes in design and operating parameter values from the business-as-usual case values to the CO_2 capture design values are highlighted in the following business-as-usual retrofit case cost exhibits.

Exhibit 8-19 Case 8 (IGCC BAU Retrofit) Total Plant Costs

Client: U.S. DOE / NETL **Report Date:** 12-Feb-08
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST SUMMARY

Case: Case 8 -Retrofit of Non-Capture Ready ConocoPhillips E-Gas Dual Train IGCC w CO2
Plant Size: 500.3 MW,net **Estimate Type:** Conceptual Cost Base Jan 2007 $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL HANDLING SYSTEM	13,060	2,435	10,233		$25,728	2,088		5,563	$33,379	67
2	COAL PREP & FEED SYSTEMS	22,211	4,065	13,559		$39,835	3,200		8,607	$51,642	103
3	FEEDWATER & MISC. BOP SYSTEMS	9,148	7,886	8,644		$25,678	2,149		6,278	$34,105	68
4	GASIFIER & ACCESSORIES										
4.1	Gasifier, Syngas Cooler & Auxiliaries	90,425		55,527		$145,952	11,971	21,893	26,972	$206,789	413
4.2	Syngas Cooler (w/Gasifier - $)	w/4.1		w/4.1							
4.3	ASU/Oxidant Compression	151,491		w/equip.		$151,491	13,121		17,977	$182,589	365
4.4-4.9	Other Gasifiction Equipment	18,487	8,580	11,695		$38,763	3,285		9,043	$51,091	102
	Subtotal 4	260,404	8,580	67,222		$336,207	28,377	21,893	53,993	$440,469	880
5A	**GAS CLEANUP & PIPING**	**112,175**	**4,805**	**84,968**		**$201,948**	**17,355**	**21,490**	**48,356**	**$289,149**	**578**
5B	**CO2 REMOVAL & COMPRESSION**	**17,010**		**10,435**		**$27,445**	**2,744**		**4,528**	**$34,717**	**69**
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	82,000		5,071		$87,071	7,338	4,354	9,876	$108,639	217
6.2-6.9	Combustion Turbine Modifications	6,000	684	1,016		$7,700	746		1,846	$10,292	21
	Subtotal 6	88,000	684	6,087		$94,771	8,084	4,354	11,722	$118,931	238
7	HRSG, DUCTING & STACK										
7.1	Heat Recovery Steam Generator	33,926		4,828		$38,754	3,277		4,203	$46,234	92
7.2-7.9	Ductwork, Stack	3,123	2,198	2,918		$8,239	682		1,450	$10,371	21
	Subtotal 7	37,049	2,198	7,745		$46,992	3,959		5,653	$56,604	113
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories & Modifications	28,109		5,030		$33,139	2,847		3,610	$39,595	79
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	10,092	953	7,185		$18,229	1,473		3,969	$23,671	47
	Subtotal 8	38,201	953	12,215		$51,368	4,320		7,578	$63,267	126
9	COOLING WATER SYSTEM	6,760	7,303	6,124		$20,187	1,661		4,492	$26,340	53
10	ASH/SPENT SORBENT HANDLING SYS	18,173	1,373	9,021		$28,568	2,437		3,382	$34,386	69
11	ACCESSORY ELECTRIC PLANT	22,608	9,796	19,825		$52,229	4,054		10,733	$67,016	134
12	INSTRUMENTATION & CONTROL	9,358	1,752	6,282		$17,391	1,436	870	3,296	$22,992	46
13	**IMPROVEMENTS TO SITE**	**3,155**	**4,500**	**11,379**		**$19,034**	**1,749**		**6,235**	**$27,019**	**54**
14	**BUILDINGS & STRUCTURES**		**6,620**	**7,565**		**$14,185**	**1,169**		**2,580**	**$17,935**	**36**
	TOTAL COST	**$657,310**	**$62,951**	**$281,305**		**$1,001,565**	**$84,782**	**$48,606**	**$182,997**	**$1,317,951**	**$2,634**

Exhibit 8-20 Case 8 (IGCC BAU Retrofit) Operating Cost Summary

INITIAL & ANNUAL O&M EXPENSES						
Case 8 -Retrofit of Non-Capture Ready ConocoPhillips E-Gas Dual Train IGCC w CO2					Cost Base Jan	2007
					Heat Rate-net(Btu/kWh):	**10,816**
Plant Output:	CO_2 (tpd):	**11,412**	H_2 (mmscfd):		MWe-net:	**500.3**
					Capacity Factor: (%):	80.0
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Plant			
Skilled Operator	2.0		2.0			
Operator	**10.0**		**10.0**			
Foreman	1.0		1.0			
Lab Tech's, etc.	3.0		3.0			
TOTAL-O.J.'s	**16.0**		**16.0**			
					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost(calc'd)					**$6,012,864**	**12.02**
Maintenance Labor Cost(calc'd)					**$13,058,597**	**26.10**
Administrative & Support Labor(calc'd)					**$4,767,865**	**9.53**
TOTAL FIXED OPERATING COSTS					**$23,839,327**	**47.65**
VARIABLE OPERATING COSTS						$/kWh-net
Maintenance Material Cost(calc'd)					**$24,042,691**	**0.0069**
	Consumption		Unit	Initial		
Consumables	Initial	/Day	Cost	Cost		
Water(/1000 gallons)		**5,847**	1.03		**$1,758,533**	**0.0005**
Chemicals						
MU & WT Chem.(lb)	**121,921**	**17,417**	0.16	**$20,093**	**$838,146**	**0.0002**
Carbon (Mercury Removal) (lb)	**128,090**	**163**	1.00	**$128,090**	**$47,700**	**0.0000**
COS Catalyst (m3)			2308.40			
Water Gas Shift Catalyst(ft3)	**11,053**	**6**	475.00	**$5,250,175**	**$842,241**	**0.0002**
Selexol Solution (gal.)	**371**	**53**	12.90	**$4,784**	**$199,556**	**0.0001**
MDEA Solution (gal)			8.38			
Sulfinol Solution (gal)			9.68			
SCR Catalyst (m3)			5500.00			
Ammonia (28% NH3) ton			123.60			
Claus Catalyst(ft3)	**12**	2	125.00	**$1,460**	**$78,408**	**0.0000**
Subtotal Chemicals				**$5,404,601**	**$2,006,050**	**0.0006**
Other						
Supplemental Fuel(MBtu)			6.75			
SCR Catalyst Replacement			9480.00			
Emission Penalties						
Subtotal Other						
Waste Disposal						
Spent Mercury Catalyst (lb.)		**163**	0.40		**$19,156**	**0.0000**
Flyash (ton)			15.45			
Bottom Ash(ton)		**580**	15.45		**$2,617,142**	**0.0007**
Subtotal Solid Waste Disposal					**$2,636,299**	**0.0008**
By-products & Emissions						
Gypsum (tons)						
Sulfur(tons)			-25.00			
Subtotal By-Products						
TOTAL VARIABLE OPERATING COSTS				**$5,404,601**	**$30,443,572**	**0.0087**
FUEL (tons)	**167,000**	**5,567**	42.11	**$7,032,387**	**$68,448,568**	**0.0195**

Exhibit 8-21 Case 8 (IGCC BAU Retrofit) Capital Investment Requirement Summary

TITLE/DEFINITION					
Case:	**Case 8 -Retrofit of Non-Capture Ready ConocoPhillips E-Gas Dual Train IGCC w CO2**				
Plant Size:	**500.3**	(MW,net)	HeatRate:	**10,816**	(Btu/kWh)
Primary/Secondary Fuel(type):	Illinois #6		Cost:	1.80	($/MMBtu)
Design/Construction:	3	(years)	BookLife:	30	(years)
TPC(Plant Cost) Year:	2007	Jan			
Capacity Factor:	80	(%)	CO2 Removed:	**11,412**	(TPD)
CAPITAL INVESTMENT			**$x1000**		**$/kW**
Process Capital & Facilities			**1,001,565**		**2001.8**
Engineering(incl.C.M.,H.O.& Fee)			**84,782**		**169.5**
Process Contingency			**48,606**		**97.1**
Project Contingency			**182,997**		**365.8**
TOTAL PLANT COST(TPC)			**$1,317,951**		**2634.2**
OPERATING & MAINTENANCE COSTS (2007 Dollars)			**$x1000**		**$/kW-yr**
Operating Labor			**6,013**		**12.0**
Maintenance Labor			**13,059**		**26.1**
Maintenance Material			**24,043**		**48.1**
Administrative & Support Labor			**4,768**		**9.5**
TOTAL OPERATION & MAINTENANCE			**$47,882**		**95.7**
FIXED O & M			**$30,056**		**60.1**
VARIABLE O & M			**$17,826**		**35.6**
CONSUMABLE OPERATING COSTS, less Fuel (2007 Dollars)			$x1000		**¢/kWh**
Water			**1,759**		**0.05**
Chemicals			**2,006**		**0.06**
Other Consumables					
Waste Disposal			**2,636**		**0.08**
TOTAL CONSUMABLE OPERATING COSTS			**$6,401**		**0.18**
BY-PRODUCT CREDITS					
FUEL COST (2007 Dollars)			**$68,449**		**1.95**
				Levelized Costs	
PRODUCTION COST SUMMARY		**LF**		**¢/kWh**	
Fixed O & M		1.157		**0.99**	
Variable O & M		1.157		**0.59**	
Consumables		1.157		**0.21**	
By-product Credit		1.157			
Fuel		1.202		**2.35**	
TOTAL PRODUCTION COST				**4.14**	
2007 CARRYING CHARGES (Capital)				**6.58**	
CCF for a 20-Year Levelization Period - IOU - Higher-Risk		17.5			
20 YEAR LEVELIZED BUSBAR COST OF POWER				**10.72**	

Exhibit 8-22 Case 8 (IGCC BAU Retrofit) Estimate Basis and Financial Criteria Summary

GENERAL DATA/CHARACTERISTICS

Case Title:	**Case 8 -Retrofit of Non-Capture Ready ConocoPhillips E-Gas Dual Train IGCC w CO2**		
Unit Size:/Plant Size:		**500.3**	MW,net
Location:		Midwestern, USA	
Fuel: Primary/Secondary	Illinois #6	11,666	Btu/lb
Energy From Primary/Secondary Fuels		**10,816**	Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):		80	%
Capital Cost Year Dollars (Reference Year Dollars):		2007	Jan
Delivered Cost of Primary/Secondary Fuel		1.80	$/MMBtu
Design/Construction Period:		3	years
Plant Startup Date (1st. Year Dollars):		2010	
Financial Parameter/Risk Level		IOU High Risk	

FINANCIAL CRITERIA

Project Book Life:		30	years	
Book Salvage Value:			%	
Project Tax Life:		20	years	
Tax Depreciation Method:		20 years, 150% declining balance		
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			%	
Economic Basis:		20th Year Current Dollars		
Capital Structure		% of Total		Cost(%)
	Common Equity	55.00		12.00
	Preferred Stock			
	Debt	45.00		11.00
Weighted Cost of Capital:(after tax)		9.67	%	
		2010 - 2030		
Nominal Escalation	General	1.87	% per year	
	Coal Price	2.35	% per year	
	Secondary Fuel:	1.96	% per year	

8.7 IGCC PLANTS CASES 6 (IGCC CR RETROFIT) AND 8 (IGCC BAU RETROFIT) SUMMARY

Cases 6 and 8 are configured to be revised configurations of Cases 4 (IGCC CR) and 2 (IGCC BAU) respectively, to capture and compress CO_2 for off-site sequestration. As illustrated in the report sections, the approach to retrofitting varied with Cases 2 and 4. Case 2 was an IGCC plant constructed in a "Business-as-usual" configuration—no anticipation of future CO_2 capture. This plant was then retrofitted to capture CO_2 and is represented as Case 8 with penalties of reduced net power output and efficiency. Conversely, Case 4 was designed in a "Capture-ready mode" – to be readily retrofitted for CO_2 capture by designing in additional process equipment capacities and configurations in anticipation of retrofit, thereby avoiding turbine derating. Case 4 was then retrofitted to become Case 6, capable of capturing CO_2.

The performance and economic results of the IGCC cases are shown in Exhibit 8-23. Case 6 produces more gross (and net) power than the derated Case 8. The capital cost to retrofit both plants primarily reflects the addition of shift reactors and CO_2 capture and compression. Case 6 required an additional $123,949,000 while Case 8 required $237,785,000. Adding the retrofit capital costs to the initial plant costs resulted in the total plant costs for Cases 6 and 8 at the performance ratings of the retrofitted plants. The resultant total capital is $2,452/kW and $2,634/kW for the respective plants.

The incremental cost of CO_2 avoided is less for Case 6 at $36/ton CO_2 than for Case 8 at $48/ton. These results show that the Cost of Electricity from Case 8 (11 ¢/kWh) is slightly higher than that of Case 6 (10 ¢/kWh) and thus there is only about a 1¢/kWh (~10%) penalty for <u>not preparing</u> for future CO_2 capture during the initial design stages.

Exhibit 8-23 IGCC Plant Performance and Economic Summary

	Case 2 IGCC Business-as-Usual	Case 8 IGCC Business-as-Usual Retrofit	Case 4 IGCC Capture-Ready	Case 6 IGCC Capture-Ready Retrofit
Gross Power Output, MW_e	742.5	672.4	742.5	693.8
Net Power Output, MW_e	623.4	500.3	623.4	518.2
Net Plant Efficiency (HHV)	39.3%	31.5%	39.3%	31.7%
Net Plant Heat Rate (HHV), kJ/kWh (Btu/kWh)	9,159 (8,681)	11,411 (10,816)	9,159 (8,681)	11,349 (10,757)
Additional Plant Cost for Retrofit[1], 1000$	N/A	$237,785	N/A	$123,949
Total Plant Cost (TPC)[1], 1000$	$1,080,166	$1,317,951	$1,146,914	$1,270,863
Incremental TPC[1], 1000$	N/A	$237,785	$66,748	$190,697
Additional Plant Cost for Retrofit[1], $/kW	N/A	$901	N/A	$612
Total Plant Cost[1], $/kW	$1,733	$2,634	$1,840	$2,452
Incremental TPC[1], $/kW	N/A	$901	$107	$719
Additional Levelized COE for Retrofit[1,2,3], ¢/kWh	N/A	1.34	N/A	0.69
Total Levelized COE[1,2,3], ¢/kWh	7.53	10.72	7.91	10.21
Incremental Levelized COE[1,2,3], ¢/kWh	N/A	3.19	0.38	2.68
Total CO_2 Emitted, kg/MWh_{net} (lb/MWh_{net})	785 (1,730)	116 (255)	785 (1,730)	115 (253)
Total CO_2 Captured, kg/MWh_{net} (lb/MWh_{net})	N/A	862 (1,901)	N/A	857 (1,890)
Cost of CO_2 Captured[1,2], $/tonne ($/ton)	N/A	$37 ($34)	N/A	$31 ($28)
Cost of CO_2 Avoided[1,2], $/tonne ($/ton)	N/A	$48 ($43)	N/A	$40 ($36)

Note:
Costs in 2007 Dollars
"Incremental costs" are compared to Case 2—"IGCC Business-as-Usual"
[1]Transportation, Storage, and Monitoring of CO_2 not included
[2]80% Capacity Factor
[3]20 year levelization period

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9. CONCLUSIONS AND RECOMMENDATIONS

PC Cases: This study indicates there is tangible benefit to pre-investment for anticipated CO_2 Capture for the PC cases. This benefit is achieved by over-sizing the boiler capacity as a pre-investment cost, with the result that when retrofitted, the plant is able to maintain rated output, albeit at a lower efficiency. The PC "Business-as-usual" plant, when retrofitted, is seriously penalized with a 31% loss of net power. As a result, the CO_2 Capture-Ready PC plant, Case 5 (PC CR retrofit), when retrofitted, generates electricity at a **cost 20% lower than the Non-CO_2 Capture-Ready plant**, Case 7 (PC BAU retrofit)—11 ¢/kWh versus 13 ¢/kWh.

IGCC Cases: This study indicates that for the IGCC cases there is **limited benefit to pre-investment for anticipated CO_2 Capture**. This is because 1.) the retrofit costs are relatively small compared to the total plant costs, 2.) the amount of derating is tolerable, and 3.) the initial costs added to the incremental costs result in roughly the same capital for both plants. This results in about the same bottom line COE for "planning" and "unplanned" capture—10 ¢/kWh versus 11 ¢/kWh.

Exhibit 9-1 shows that the retrofit costs are higher for the PC cases. Exhibit 9-2 shows that while the initial COE for the PC plants is lower, the incremental COE for the PC retrofit cases is significantly higher than that for the retrofitted IGCC cases. Exhibit 9-3 shows the significantly lower costs of CO_2 avoided for the retrofitted IGCC cases. Costs in these exhibits do not include CO_2 Transport, Storage, and Monitoring.

Exhibit 9-1 Total Plant Costs for Retrofit Cases

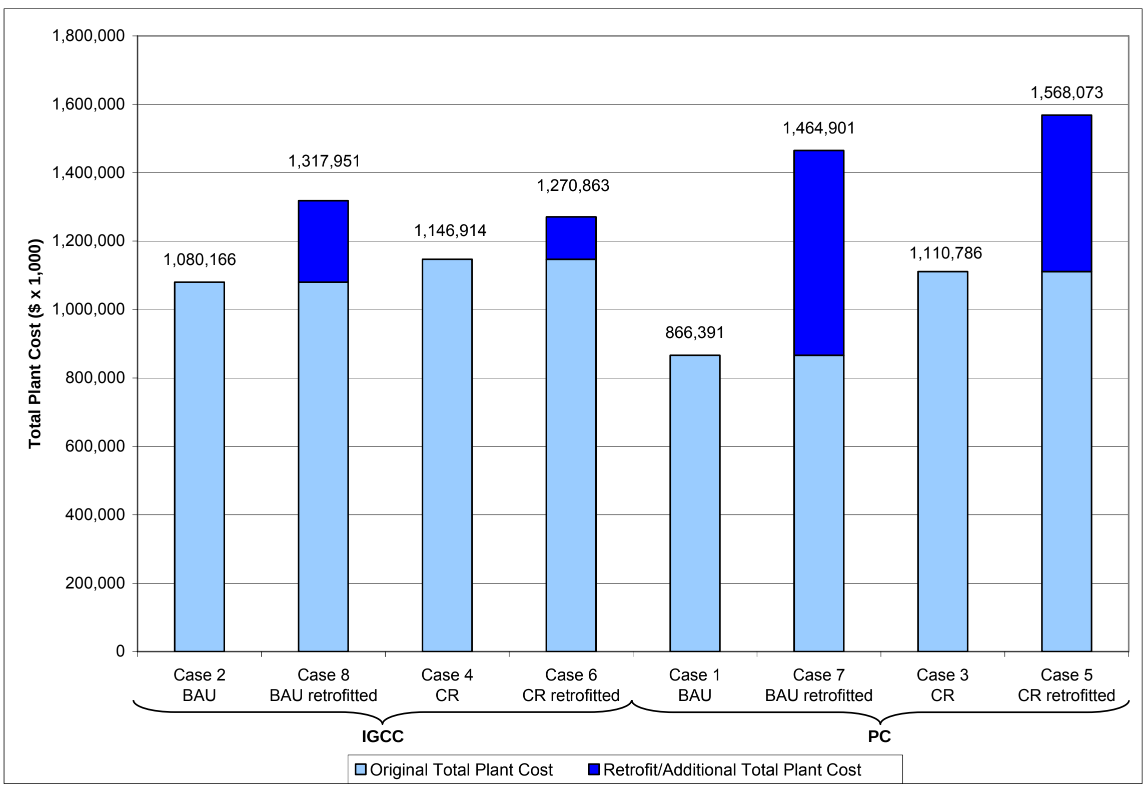


Exhibit 9-2 Levelized Cost of Electricity for Retrofit Cases

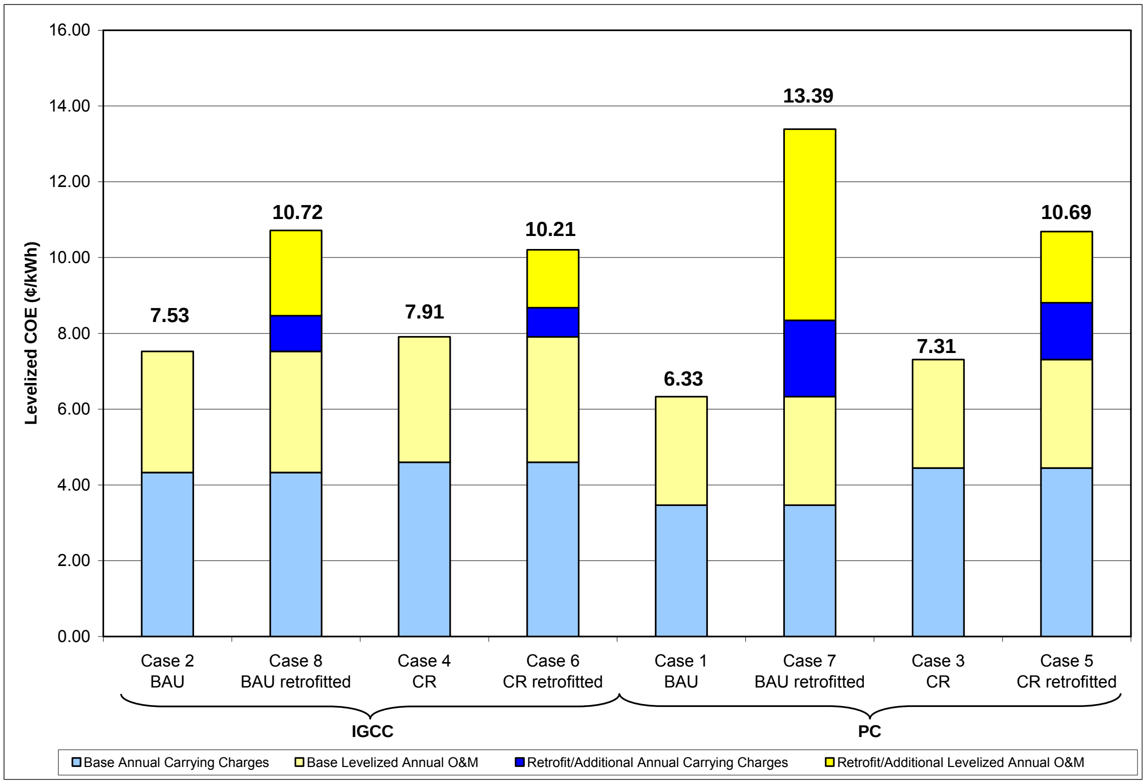
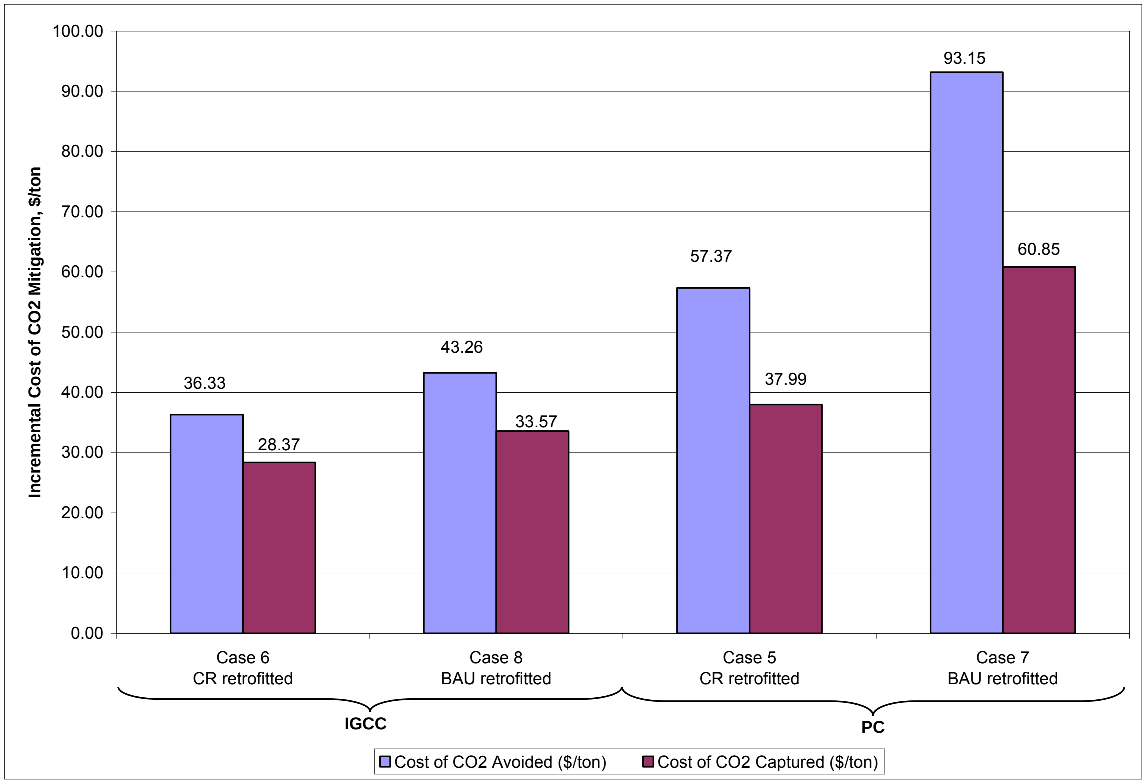


Exhibit 9-3 Cost of CO_2 Mitigation for Retrofit Cases



Discounted Cash Flow (DCF) Economic Analysis: This analysis was conducted to determine the true present worth of each case, and is included with this report as Appendix C. The purpose of the DCF analysis is to identify the optimal year in which retrofit of each plant configuration would occur.

The conclusions are as follows:

- A 550 MW Supercritical PC power plant which has been designed and built for future CO_2 capture (Case 3 PC Capture-Ready) is economically **more attractive** than a conventional plant (Case 1 PC Business-as-usual) if CO_2 capture is either desired or required **within the first 10 years of the plants operation**. The conventional, business-as-usual, plant is economically more attractive if retrofit is to occur after the first 10 years of plant operation. The main reason for this advantage of the Capture-Ready plant in the early years is that a conventional plant's net electrical output is reduced by about 31% when retrofitted for CO_2 capture, whereas the plant designed for future CO_2 capture does not experience the same power output reduction.

- A 623 MW IGCC plant designed for future CO_2 capture (Case 4 IGCC capture-ready) has a limited economic advantage over a conventional plant (Case 2 IGCC business-as-usual) if CO_2 capture will be either desired or required within the first 7 years of the plants operation. Either design is acceptable if retrofitting is expected after 7 years.

Future Cases to Study: Future cases to be studied could include retrofitting the base case plants with advanced technologies being developed by DOE and others for gas separation. Typically these would include membrane and sorbent technologies.

The sensitivity of the LCOE and the length of time where pre-investment would be advantageous to the following issues should be explored.

- Coal price fluctuations (increasing or decreasing).
- Implementation of a carbon tax.
- Implementation of a CO_2 emission penalty or allowance purchase requirements.
- Credit for CO_2 captured or sale of CO_2.
- Increasing cost of retrofit equipment due to increased demand.
- Improved financing structure as CO_2 capture and IGCC technologies become more commercial.

The evolving issues surrounding retrofitting plants for CO_2 capture warrant continued analysis to evaluate using CO_2 capture and sequestration as a means of reducing carbon emissions from coal-fired power plants.

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APPENDIX A - ADDITIONAL PROCESS DESCRIPTIONS

STEAM GENERATION ISLAND

Heat Recovery Steam Generator

The heat recovery steam generator (HRSG) is a horizontal gas flow, drum-type, multi-pressure design that is matched to the characteristics of the gas turbine exhaust gas when firing medium-Btu gas. High-temperature flue gas exiting the CT is conveyed through the HRSG to recover the large quantity of thermal energy that remains. It is assumed that the flue gas heat loss through the HRSG duct corresponds to 1.7°C (3°F). Flue gases travel through the HRSG gas path and exit at 118°C (245°F).

The HP drum produces steam at main steam pressure; while the IP drum produces steam for export to the cold reheat. The HRSG drum pressures are nominally 1800/420 psia for the HP/IP turbine sections, respectively. In addition to generating and superheating steam, the HRSG performs reheat duty for the cold/hot reheat steam for the steam turbine, provides condensate and feedwater heating, and also provides deaeration of the condensate.

Natural circulation of steam is accomplished in the HRSG by utilizing differences in densities due to temperature differences of the steam. The natural circulation HRSG provides the most cost-effective and reliable design.

The HRSG drums include moisture separators, internal baffles, and piping for feedwater/steam. Also included with the drum is a visual sight glass to monitor drum water level. All tubes, including economizers, superheaters, and headers and drums, are equipped with drains.

Safety relief valves are furnished in order to comply with appropriate codes and ensure a safe work place.

Superheater, boiler, and economizer sections are supported by shop-assembled structural steel. Inlet and outlet duct is provided to route the gases from the gas turbine outlet to the HRSG inlet and the HRSG outlet to the stack. A diverter valve is included in the inlet duct to bypass the gas when appropriate. Suitable expansion joints are also included.

A Selective Catalytic Reduction (SCR) process is included in the flue gas stream of the HRSG. Ammonia (NH_3) is injected into the turbine exhaust gas as it passes through the HRSG and reacts with nitrogen oxides (NOx) in the presence of a catalyst to form molecular nitrogen and water. The reaction takes place over a limited temperature range, 315-400°C (600-750°F). The total sulfur content of the syngas is controlled to <15 ppm to prevent formation of ammonium bisulfate deposition downstream from the SCR.

Steam Turbine Generator and Auxiliaries

The following section provides a description of the steam turbines and their auxiliaries.

The steam turbine consists of an HP section, an IP section, and one double-flow LP section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single-span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine has a last stage bucket length of 30 inches.

Main steam from the HRSG and gasifier island is combined in a header, and then passes through the stop valves and control valves and enters the turbine at 1800 psig/1050°F. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 375 to 400 psig/1050°F. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections, exhausting downward into the condenser.

Turbine bearings are lubricated by a closed-loop, water-cooled, pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip an emergency oil pump mounted on the reservoir pumps the oil. When the turbine reaches 95 percent of synchronous speed, the main pump mounted on the turbine shaft pumps oil. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure-regulating valves control the gland header pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator is a hydrogen-cooled synchronous type, generating power at 23 kV. Static, transformer type exciter is provided. The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Gas is prevented from escaping at the rotor shafts by a closed-loop oil seal system. The oil seal system consists of storage tank, pumps, filters, and pressure controls, all skid-mounted.

The steam turbine generator is controlled by a triple-redundant, microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, color CRT operator interfacing, and datalink interfaces to the balance-of-plant distributed control system (DCS), and incorporates on-line repair capability.

CONDENSATE SYSTEM

The condensate system transfers condensate from the condenser hotwell to the deaerator, through the gland steam condenser, gasifier, and the low-temperature economizer section in the HRSG. The system consists of one main condenser; two 50 percent capacity, motor-driven, vertical condensate pumps; one gland steam condenser; and a low-temperature tube bundle in the HRSG. Condensate is delivered to a common discharge header through separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

FEEDWATER SYSTEM

The function of the feedwater system is to pump the various feedwater streams from the deaerator storage tank in the HRSG to the respective steam drums. Two 50 percent capacity boiler feed pumps are provided. Each pump is provided with inlet and outlet isolation valves, and outlet check valve. Minimum flow recirculation to prevent overheating and cavitation of the pumps during startup and low loads is provided by an automatic recirculation valve and associated piping that discharges back to the deaerator storage tank. Pneumatic flow control valves control the recirculation flow.

The feedwater pumps are supplied with instrumentation to monitor and alarm on low oil pressure, or high bearing temperature. Feedwater pump suction pressure and temperature are also monitored. In addition, the suction of each boiler feed pump is equipped with a startup strainer.

MAIN AND REHEAT STEAM SYSTEMS

The function of the main steam system is to convey main steam generated in the RSC and HRSG from the HRSG superheater outlet to the HP turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the HRSG reheater, and to the turbine reheat stop valves.

Main steam at approximately 1900 psig/1050°F exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine. Cold reheat steam at approximately 450 psig/645°F exits the HP turbine, flows through a motor-operated isolation gate valve, to the HRSG reheater. Hot reheat steam at approximately 370 to 420 psig/1050°F exits the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

Steam piping is sloped from the HRSG to the drip pots located near the steam turbine for removal of condensate from the steam lines. Condensate collected in the drip pots and low-point drains is discharged to the condenser through the drain system.

Steam flow is measured by means of flow nozzles in the steam piping. The flow nozzles are located upstream of any branch connections on the main headers.

Safety valves are installed to comply with appropriate codes and to ensure the safety of personnel and equipment.

CIRCULATING WATER SYSTEM

The circulating water system is a closed-cycle cooling water system that supplies cooling water to the condenser to condense the main turbine exhaust steam. The system also supplies cooling water to the auxiliary cooling system. The heat transferred from the steam to the circulating water in the condenser is removed by a mechanical draft cooling tower.

The system consists of two 50 percent capacity vertical circulating water pumps, a mechanical draft evaporative cooling tower, and carbon steel cement-lined interconnecting piping. The pumps are single-stage vertical pumps. The piping system is equipped with butterfly isolation valves and all required expansion joints. The cooling tower is a multi-cell wood frame counterflow mechanical draft cooling tower.

The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

The condenser is equipped with an air extraction system to evacuate the condenser steam space for removal of non-condensable gases during steam turbine operation and to rapidly reduce the condenser pressure from atmospheric pressure before unit startup and admission of steam to the condenser.

RAW WATER, FIRE PROTECTION, AND CYCLE MAKEUP WATER SYSTEMS

The raw water system supplies 1,700 gpm of cooling tower makeup, 200 gpm for the cycle makeup, and 15 gpm for service water use and potable water requirements. The pumps will be installed on an intake structure located on the river in close proximity to the plant.

The fire protection system provides water under pressure to the fire hydrants, hose stations, and fixed water suppression system within the buildings and structures. The system consists of pumps, underground and aboveground supply piping, distribution piping, hydrants, hose stations, spray systems, and deluge spray systems. One motor-operated booster pump is supplied on the intake structure of the cooling tower with a diesel engine pump installed on the intake structure located on the river.

The cycle makeup water system provides high quality demineralized water for makeup to the HRSG cycle, and for injection steam to the combustion turbine for control of NOx emissions and auxiliary boiler.

The cycle makeup system will consist of two 100 percent trains, each with a full-capacity activated carbon filter, primary cation exchanger, primary anion exchanger, mixed bed exchanger, recycle pump, and regeneration equipment. The equipment will be skid-mounted and include a control panel, and associated piping, valves, and instrumentation.

ACCESSORY ELECTRIC PLANT

The accessory electric plant consists of switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, and wire and cable. It also includes the main power transformer, all required foundations, and standby equipment.

INSTRUMENTATION AND CONTROL

An integrated plant-wide distributed control system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally distributed control system. The control room houses an array of multiple video monitor (CRT) and keyboard units. The CRT/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to be operational and accessible 99.5% of the time it is required for use (99.5% availability). The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are manually implemented, with operator selection of modular automation routines available. The exception to this, and an important facet of the control system for gasification, is the critical controller system, which is a part of the license package from the gasifier supplier and is a dedicated and distinct hardware segment of the DCS.

This critical controller system is used to control the gasification process. The partial oxidation of the fuel feed and oxygen feed streams to form a syngas product is a stoichiometric, temperature- and pressure-dependent reaction. The critical controller utilizes a redundant microprocessor executing calculations and dynamic controls at 100- to 200-millisecond intervals. The enhanced execution speeds as well as evolved predictive controls allow the critical controller to mitigate process upsets and maintain the reactor operation within a stable set of operating parameters.

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APPENDIX B – DETAIL CAPITAL COST ESTIMATIONS

CASE 1 (PC BAU) - PULVERIZED COAL SUPERCRITICAL PLANT WITHOUT CO_2 CAPTURE

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 1 - "Business As Usual" SuperCritical PC w/o CO2 Capture
Plant Size: 550.2 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL HANDLING SYSTEM										
1.1	Coal Receive & Unload	3,183		1,469		$4,652	415		760	$5,827	11
1.2	Coal Stackout & Reclaim	4,113		942		$5,055	442		825	$6,322	11
1.3	Coal Conveyors & Yd Crush	3,824		932		$4,756	417		776	$5,949	11
1.4	Other Coal Handling	1,001		216		$1,216	106		198	$1,521	3
1.5	Sorbent Receive & Unload	127		39		$166	15		27	$208	0
1.6	Sorbent Stackout & Reclaim	2,056		381		$2,437	212		397	$3,047	6
1.7	Sorbent Conveyors	734	158	182		$1,073	93		175	$1,341	2
1.8	Other Sorbent Handling	443	103	235		$781	69		128	$978	2
1.9	Coal & Sorbent Hnd.Foundations		3,922	4,982		$8,904	832		1,460	$11,197	20
	SUBTOTAL 1.	**$15,481**	**$4,183**	**$9,376**		**$29,040**	**$2,602**		**$4,746**	**$36,389**	**$66**
2	COAL PREP & FEED SYSTEMS										
2.1	Coal Crushing & Drying	1,823		359		$2,182	190		356	$2,728	5
2.2	Prepared Coal Storage & Feed	4,668		1,030		$5,698	498		929	$7,125	13
2.3	Slurry Prep & Feed										
2.4	Misc.Coal Prep & Feed										
2.5	Sorbent Prep Equipment	3,493	150	733		$4,376	381		714	$5,470	10
2.6	Sorbent Storage & Feed	421		163		$584	52		95	$731	1
2.7	Sorbent Injection System										
2.8	Booster Air Supply System										
2.9	Coal & Sorbent Feed Foundation		453	353		$807	74		132	$1,013	2
	SUBTOTAL 2.	**$10,405**	**$603**	**$2,638**		**$13,646**	**$1,196**		**$2,226**	**$17,068**	**$31**
3	FEEDWATER & MISC. BOP SYSTEMS										
3.1	FeedwaterSystem	17,490		5,725		$23,214	2,033		3,787	$29,034	53
3.2	Water Makeup & Pretreating	4,278		1,376		$5,654	530		1,237	$7,420	13
3.3	Other Feedwater Subsystems	5,404		2,293		$7,697	686		1,257	$9,641	18
3.4	Service Water Systems	844		456		$1,300	121		284	$1,705	3
3.5	Other Boiler Plant Systems	6,403		6,264		$12,667	1,188		2,078	$15,933	29
3.6	FO Supply Sys & Nat Gas	247		304		$551	51		90	$692	1
3.7	Waste Treatment Equipment	2,883		1,652		$4,535	439		995	$5,969	11
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	2,558		788		$3,346	321		733	$4,400	8
	SUBTOTAL 3.	**$40,107**		**$18,856**		**$58,963**	**$5,369**		**$10,462**	**$74,795**	**$136**

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 1 - "Business As Usual" SuperCritical PC w/o CO2 Capture
Plant Size: 550.2 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
4	PC BOILER & ACCESSORIES										
4.1	PC Boiler & Accessories	148,766		83,888		$232,654	22,535		25,519	$280,708	510
4.2	SCR (w/4.1)										
4.3a	Open										
4.3b	Open										
4.4	Boiler BoP (w/ ID Fans)	w/4.1		w/4.1							
4.5	Primary Air System	w/4.1		w/4.1							
4.6	Secondary Air System		w/4.1	w/4.1							
4.8	Major Component Rigging		w/14.1	w/14.1							
4.9	Boiler Foundations		w/14.1	w/14.1							
	SUBTOTAL 4.	**$148,766**		**$83,888**		**$232,654**	**$22,535**		**$25,519**	**$280,708**	**$510**
5	FLUE GAS CLEANUP										
5.1	Absorber Vessels & Accessories	54,227		11,683		$65,910	6,238		7,215	$79,363	144
5.2	Other FGD	2,830		3,209		$6,039	582		662	$7,283	13
5.3	Bag House & Accessories	15,654		9,942		$25,596	2,448		2,804	$30,849	56
5.4	Other Particulate Removal Materials	1,059		1,134		$2,194	211		241	$2,646	5
5.5	Gypsum Dewatering System	4,304		732		$5,036	476		551	$6,063	11
5.6	Mercury Removal System										
	Open										
5.9	Open										
	SUBTOTAL 5A.	**$78,075**		**$26,700**		**$104,775**	**$9,955**		**$11,473**	**$126,203**	**$229**
5B	CO2 REMOVAL & COMPRESSION										
5B.1	CO2 Removal System										
5B.2	CO2 Compression & Drying										
	SUBTOTAL 5B.										
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	N/A		N/A							
6.2	Combustion Turbine Accessories										
6.3	Compressed Air Piping										
6.9	Combustion Turbine Foundations										
	SUBTOTAL 6.										
7	HRSG, DUCTING & STACK										
7.1	Heat Recovery Steam Generator	N/A		N/A							
7.2	HRSG Accessories										
7.3	Ductwork	8,242		5,379		$13,621	1,190		2,222	$17,033	31
7.4	Stack	8,411		4,925		$13,336	1,274		1,461	$16,071	29
7.9	Duct & Stack Foundations		959	1,097		$2,056	192		449	$2,697	5
	SUBTOTAL 7.	**$16,653**	**$959**	**$11,402**		**$29,013**	**$2,656**		**$4,132**	**$35,801**	**$65**

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 1 - "Business As Usual" SuperCritical PC w/o CO2 Capture
Plant Size: 550.2 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	48,728		6,532		$55,260	5,291		6,055	$66,606	121
8.2	Turbine Plant Auxiliaries	334		716		$1,050	102		115	$1,268	2
8.3	Condenser & Auxiliaries	6,405		2,204		$8,610	818		943	$10,370	19
8.4	Steam Piping	16,354		8,078		$24,433	2,039		3,971	$30,443	55
8.9	TG Foundations		1,042	1,658		$2,699	254		591	$3,544	6
	SUBTOTAL 8.	**$71,822**	**$1,042**	**$19,188**		**$92,052**	**$8,504**		**$11,675**	**$112,231**	**$204**
9	COOLING WATER SYSTEM										
9.1	Cooling Towers	8,669		2,702		$11,371	1,079		1,245	$13,695	25
9.2	Circulating Water Pumps	1,765		111		$1,876	160		204	$2,239	4
9.3	Circ.Water System Auxiliaries	515		69		$583	55		64	$702	1
9.4	Circ.Water Piping		4,150	3,958		$8,108	747		1,328	$10,183	19
9.5	Make-up Water System	457		605		$1,062	101		174	$1,337	2
9.6	Component Cooling Water Sys	411		324		$735	69		121	$924	2
9.9	Circ.Water System Foundations		2,403	3,844		$6,247	588		1,367	$8,202	15
	SUBTOTAL 9.	**$11,816**	**$6,553**	**$11,613**		**$29,981**	**$2,799**		**$4,503**	**$37,283**	**$68**
10	ASH/SPENT SORBENT HANDLING SYS										
10.1	Ash Coolers	N/A		N/A							
10.2	Cyclone Ash Letdown	N/A		N/A							
10.3	HGCU Ash Letdown	N/A		N/A							
10.4	High Temperature Ash Piping	N/A		N/A							
10.5	Other Ash Recovery Equipment	N/A		N/A							
10.6	Ash Storage Silos	563		1,735		$2,298	224		252	$2,774	5
10.7	Ash Transport & Feed Equipment	3,669		3,735		$7,403	700		810	$8,914	16
10.8	Misc. Ash Handling Equipment										
10.9	Ash/Spent Sorbent Foundation		133	158		$291	27		64	$381	1
	SUBTOTAL 10.	**$4,232**	**$133**	**$5,628**		**$9,992**	**$951**		**$1,126**	**$12,069**	**$22**
11	ACCESSORY ELECTRIC PLANT										
11.1	Generator Equipment	1,524		249		$1,773	164		145	$2,083	4
11.2	Station Service Equipment	2,578		882		$3,460	331		284	$4,075	7
11.3	Switchgear & Motor Control	3,063		525		$3,588	332		392	$4,312	8
11.4	Conduit & Cable Tray		1,967	6,693		$8,660	829		1,423	$10,913	20
11.5	Wire & Cable		3,568	7,051		$10,619	895		1,727	$13,241	24
11.6	Protective Equipment	243		861		$1,104	108		121	$1,333	2
11.7	Standby Equipment	1,176		28		$1,204	114		132	$1,450	3
11.8	Main Power Transformers	6,950		165		$7,116	541		766	$8,422	15
11.9	Electrical Foundations		297	735		$1,032	98		226	$1,356	2
	SUBTOTAL 11.	**$15,533**	**$5,832**	**$17,190**		**$38,556**	**$3,411**		**$5,217**	**$47,183**	**$86**

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 1 - "Business As Usual" SuperCritical PC w/o CO2 Capture
Plant Size: 550.2 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
12	INSTRUMENTATION & CONTROL										
12.1	PC Control Equipment	w/12.7		w/12.7							
12.2	Combustion Turbine Control	N/A		N/A							
12.3	Steam Turbine Control	w/8.1		w/8.1							
12.4	Other Major Component Control										
12.5	Signal Processing Equipment	W/12.7		w/12.7							
12.6	Control Boards,Panels & Racks	413		258		$671	65		110	$846	2
12.7	Distributed Control System Equipment	4,172		760		$4,932	470		540	$5,942	11
12.8	Instrument Wiring & Tubing	2,305		4,674		$6,979	594		1,136	$8,710	16
12.9	Other I & C Equipment	1,179		2,787		$3,966	386		435	$4,788	9
	SUBTOTAL 12.	**$8,069**		**$8,480**		**$16,549**	**$1,515**		**$2,222**	**$20,285**	**$37**
13	IMPROVEMENTS TO SITE										
13.1	Site Preparation		48	958		$1,005	99		221	$1,325	2
13.2	Site Improvements		1,578	1,974		$3,552	349		780	$4,681	9
13.3	Site Facilities	2,827		2,809		$5,637	553		1,238	$7,428	14
	SUBTOTAL 13.	**$2,827**	**$1,625**	**$5,741**		**$10,194**	**$1,001**		**$2,239**	**$13,434**	**$24**
14	BUILDINGS & STRUCTURES										
14.1	Boiler Building		7,843	6,990		$14,833	1,332		2,425	$18,590	34
14.2	Turbine Building		11,220	10,597		$21,817	1,964		3,567	$27,348	50
14.3	Administration Building		554	594		$1,147	104		188	$1,439	3
14.4	Circulation Water Pumphouse		159	128		$286	26		47	$359	1
14.5	Water Treatment Buildings		565	471		$1,036	93		169	$1,299	2
14.6	Machine Shop		370	252		$623	55		102	$780	1
14.7	Warehouse		251	255		$506	46		83	$635	1
14.8	Other Buildings & Structures		205	177		$382	34		62	$479	1
14.9	Waste Treating Building & Str.		393	1,208		$1,601	151		263	$2,015	4
	SUBTOTAL 14.		**$21,560**	**$20,672**		**$42,232**	**$3,805**		**$6,906**	**$52,943**	**$96**
	TOTAL COST	**$423,786**	**$42,490**	**$241,370**		**$707,646**	**$66,300**		**$92,445**	**$866,391**	**$1,575**

CASE 7 (PC BAU RETROFIT) - RETROFIT OF CASE 1 TO CAPTURE CO_2

Client: U.S. DOE / NETL **Report Date:** 07-Feb-08
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 7 - "Business As Usual" SuperCritical PC Retrofit w CO2 Capture
Plant Size: 379.0 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL HANDLING SYSTEM										
1.1	Coal Receive & Unload	3,183		1,469		$4,652	415		760	$5,827	15
1.2	Coal Stackout & Reclaim	4,113		942		$5,055	442		825	$6,322	17
1.3	Coal Conveyors & Yd Crush	3,824		932		$4,756	417		776	$5,949	16
1.4	Other Coal Handling	1,001		216		$1,216	106		198	$1,521	4
1.5	Sorbent Receive & Unload	127		39		$166	15		27	$208	1
1.6	Sorbent Stackout & Reclaim	2,056		381		$2,437	212		397	$3,047	8
1.7	Sorbent Conveyors	734	158	182		$1,073	93		175	$1,341	4
1.8	Other Sorbent Handling	443	103	235		$781	69		128	$978	3
1.9	Coal & Sorbent Hnd.Foundations		3,922	4,982		$8,904	832		1,460	$11,197	30
	SUBTOTAL 1.	**$15,481**	**$4,183**	**$9,376**		**$29,040**	**$2,602**		**$4,746**	**$36,389**	**$96**
2	COAL PREP & FEED SYSTEMS										
2.1	Coal Crushing & Drying	1,823		359		$2,182	190		356	$2,728	7
2.2	Prepared Coal Storage & Feed	4,668		1,030		$5,698	498		929	$7,125	19
2.3	Slurry Prep & Feed										
2.4	Misc.Coal Prep & Feed										
2.5	Sorbent Prep Equipment	3,493	150	733		$4,376	381		714	$5,470	14
2.6	Sorbent Storage & Feed	421		163		$584	52		95	$731	2
2.7	Sorbent Injection System										
2.8	Booster Air Supply System										
2.9	Coal & Sorbent Feed Foundation		453	353		$807	74		132	$1,013	3
	SUBTOTAL 2.	**$10,405**	**$603**	**$2,638**		**$13,646**	**$1,196**		**$2,226**	**$17,068**	**$45**
3	FEEDWATER & MISC. BOP SYSTEMS										
3.1	FeedwaterSystem	17,490		5,725		$23,214	2,033		3,787	$29,034	77
3.2	Water Makeup & Pretreating	4,278		1,376		$5,654	530		1,237	$7,420	20
3.3	Other Feedwater Subsystems	5,404		2,293		$7,697	686		1,257	$9,641	25
3.4	Service Water Systems	844		456		$1,300	121		284	$1,705	4
3.5	Other Boiler Plant Systems	6,403		6,264		$12,667	1,188		2,078	$15,933	42
3.6	FO Supply Sys & Nat Gas	247		304		$551	51		90	$692	2
3.7	Waste Treatment Equipment	2,883		1,652		$4,535	439		995	$5,969	16
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	2,558		788		$3,346	321		733	$4,400	12
	SUBTOTAL 3.	**$40,107**		**$18,856**		**$58,963**	**$5,369**		**$10,462**	**$74,795**	**$197**

Client: U.S. DOE / NETL **Report Date:** 07-Feb-08

Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 7 - "Business As Usual" SuperCritical PC Retrofit w CO2 Capture

Plant Size: 379.0 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct		Equipment	Material	Labor		Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Cost $	H.O.& Fee	Process	Project	$	$/kW
4	PC BOILER & ACCESSORIES										
4.1	PC Boiler & Accessories	148,766		83,888		$232,654	22,535		25,519	$280,708	741
4.2	SCR (w/4.1)										
4.3a	Open										
4.3b	Open										
4.4	Boiler BoP (w/ ID Fans)	w/4.1		w/4.1							
4.5	Primary Air System	w/4.1		w/4.1							
4.6	Secondary Air System		w/4.1	w/4.1							
4.8	Major Component Rigging		w/14.1	w/14.1							
4.9	Boiler Foundations		w/14.1	w/14.1							
	SUBTOTAL 4.	**$148,766**		**$83,888**		**$232,654**	**$22,535**		**$25,519**	**$280,708**	**$741**
5	FLUE GAS CLEANUP										
5.1	**Absorber Vessels & Accessories**	**75,522**		**16,270**		**$91,792**	**8,826**		**9,350**	**$109,968**	**290**
5.2	**Other FGD**	**3,941**		**4,469**		**$8,410**	**819**		**858**	**$10,087**	**27**
5.3	**Bag House & Accessories**	**22,437**		**14,250**		**$36,686**	**3,557**		**3,719**	**$43,963**	**116**
5.4	**Other Particulate Removal Materials**	**1,518**		**1,626**		**$3,144**	**306**		**319**	**$3,770**	**10**
5.5	**Gypsum Dewatering System**	**5,701**		**969**		**$6,670**	**639**		**686**	**$7,995**	**21**
5.6	Mercury Removal System										
	Open										
5.9	Open										
	SUBTOTAL 5A.	**$109,119**		**$37,584**		**$146,703**	**$14,148**		**$14,932**	**$175,783**	**$464**
5B	CO2 REMOVAL & COMPRESSION										
5B.1	**CO2 Removal System**	**202,944**		**61,453**		**$264,397**	**26,440**	**52,879**	**43,625**	**$387,341**	**1022**
5B.2	**CO2 Compression & Drying**	**26,888**		**8,398**		**$35,286**	**3,529**		**5,822**	**$44,637**	**118**
	SUBTOTAL 5B.	**$229,832**		**$69,851**		**$299,683**	**$29,968**	**$52,879**	**$49,448**	**$431,979**	**$1,140**
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	N/A		N/A							
6.2	Combustion Turbine Accessories										
6.3	Compressed Air Piping										
6.9	Combustion Turbine Foundations										
	SUBTOTAL 6.										
7	HRSG, DUCTING & STACK										
7.1	Heat Recovery Steam Generator	N/A		N/A							
7.2	HRSG Accessories										
7.3	Ductwork	8,242		5,379		$13,621	1,190		2,222	$17,033	45
7.4	Stack	8,411		4,925		$13,336	1,274		1,461	$16,071	42
7.9	Duct & Stack Foundations		959	1,097		$2,056	192		449	$2,697	7
	SUBTOTAL 7.	**$16,653**	**$959**	**$11,402**		**$29,013**	**$2,656**		**$4,132**	**$35,801**	**$94**

Client: U.S. DOE / NETL **Report Date:** 07-Feb-08

Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 7 - "Business As Usual" SuperCritical PC Retrofit w CO2 Capture

Plant Size: 379.0 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories & Modifications	48,728		6,632		$55,360	5,301		6,077	$66,738	176
8.2	Turbine Plant Auxiliaries	334		716		$1,050	102		115	$1,268	3
8.3	Condenser & Auxiliaries	6,405		2,204		$8,610	818		943	$10,370	27
8.4	Steam Piping	16,354		8,078		$24,433	2,039		3,971	$30,443	80
8.9	TG Foundations		1,042	1,658		$2,699	254		591	$3,544	9
	SUBTOTAL 8.	**$71,822**	**$1,042**	**$19,288**		**$92,152**	**$8,514**		**$11,697**	**$112,363**	**$296**
9	COOLING WATER SYSTEM										
9.1	Cooling Towers	8,669		2,702		$11,371	1,079		1,245	$13,695	36
9.2	Circulating Water Pumps	1,765		111		$1,876	160		204	$2,239	6
9.3	Circ.Water System Auxiliaries	515		69		$583	55		64	$702	2
9.4	Circ.Water Piping		4,150	3,958		$8,108	747		1,328	$10,183	27
9.5	Make-up Water System	457		605		$1,062	101		174	$1,337	4
9.6	Component Cooling Water Sys	411		324		$735	69		121	$924	2
9.9	Circ.Water System Foundations		2,403	3,844		$6,247	588		1,367	$8,202	22
	SUBTOTAL 9.	**$11,816**	**$6,553**	**$11,613**		**$29,981**	**$2,799**		**$4,503**	**$37,283**	**$98**
10	ASH/SPENT SORBENT HANDLING SYS										
10.1	Ash Coolers	N/A		N/A							
10.2	Cyclone Ash Letdown	N/A		N/A							
10.3	HGCU Ash Letdown	N/A		N/A							
10.4	High Temperature Ash Piping	N/A		N/A							
10.5	Other Ash Recovery Equipment	N/A		N/A							
10.6	Ash Storage Silos	563		1,735		$2,298	224		252	$2,774	7
10.7	Ash Transport & Feed Equipment	3,669		3,735		$7,403	700		810	$8,914	24
10.8	Misc. Ash Handling Equipment										
10.9	Ash/Spent Sorbent Foundation		133	158		$291	27		64	$381	1
	SUBTOTAL 10.	**$4,232**	**$133**	**$5,628**		**$9,992**	**$951**		**$1,126**	**$12,069**	**$32**
11	ACCESSORY ELECTRIC PLANT										
11.1	**Generator Equipment**	**1,658**		**271**		**$1,929**	**180**		**158**	**$2,267**	**6**
11.2	**Station Service Equipment**	**6,014**		**2,059**		**$8,073**	**792**		**665**	**$9,530**	**25**
11.3	**Switchgear & Motor Control**	**7,147**		**1,224**		**$8,371**	**811**		**918**	**$10,100**	**27**
11.4	**Conduit & Cable Tray**		**4,589**	**15,616**		**$20,206**	**1,983**		**3,011**	**$25,200**	**66**
11.5	**Wire & Cable**		**8,324**	**16,452**		**$24,776**	**2,310**		**3,674**	**$30,760**	**81**
11.6	Protective Equipment	243		861		$1,104	108		121	$1,333	4
11.7	**Standby Equipment**	**1,258**		**30**		**$1,288**	**122**		**141**	**$1,551**	**4**
11.8	**Main Power Transformers**	**6,950**		**183**		**$7,133**	**542**		**768**	**$8,443**	**22**
11.9	**Electrical Foundations**		**329**	**814**		**$1,143**	**109**		**250**	**$1,502**	**4**
	SUBTOTAL 11.	**$23,269**	**$13,243**	**$37,510**		**$74,022**	**$6,958**		**$9,706**	**$90,686**	**$239**

Client: U.S. DOE / NETL **Report Date:** 07-Feb-08

Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 7 - "Business As Usual" SuperCritical PC Retrofit w CO2 Capture

Plant Size: 379.0 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
12	INSTRUMENTATION & CONTROL										
12.1	PC Control Equipment	w/12.7		w/12.7							
12.2	Combustion Turbine Control	N/A		N/A							
12.3	Steam Turbine Control	w/8.1		w/8.1							
12.4	Other Major Component Control										
12.5	Signal Processing Equipment	W/12.7		w/12.7							
12.6	Control Boards,Panels & Racks	413		258		$671	65		110	$846	2
12.7	Distributed Control System Equipment	4,172		760		$4,932	470		540	$5,942	16
12.8	Instrument Wiring & Tubing	2,305		4,674		$6,979	594		1,136	$8,710	23
12.9	Other I & C Equipment	1,179		2,787		$3,966	386		435	$4,788	13
	SUBTOTAL 12.	**$8,069**		**$8,480**		**$16,549**	**$1,515**		**$2,222**	**$20,285**	**$54**
13	IMPROVEMENTS TO SITE										
13.1	**Site Preparation**		**98**	**1,981**		**$2,079**	**206**		**457**	**$2,743**	**7**
13.2	**Site Improvements**		**3,264**	**4,084**		**$7,348**	**728**		**1,615**	**$9,692**	**26**
13.3	**Site Facilities**	**5,849**		**5,811**		**$11,660**	**1,156**		**2,563**	**$15,379**	**41**
	SUBTOTAL 13.	**$5,849**	**$3,362**	**$11,876**		**$21,088**	**$2,090**		**$4,636**	**$27,814**	**$73**
14	BUILDINGS & STRUCTURES										
14.1	**Boiler Building**		**16,501**	**14,705**		**$31,206**	**2,969**		**5,126**	**$39,301**	**104**
14.2	**Turbine Building**		**23,367**	**22,069**		**$45,436**	**4,326**		**7,464**	**$57,227**	**151**
14.3	**Administration Building**		**1,131**	**1,212**		**$2,344**	**224**		**385**	**$2,952**	**8**
14.4	**Circulation Water Pumphouse**		**324**	**261**		**$585**	**55**		**96**	**$737**	**2**
14.5	**Water Treatment Buildings**		**1,154**	**963**		**$2,117**	**201**		**348**	**$2,666**	**7**
14.6	**Machine Shop**		**763**	**519**		**$1,282**	**121**		**210**	**$1,614**	**4**
14.7	**Warehouse**		**759**	**772**		**$1,531**	**148**		**252**	**$1,932**	**5**
14.8	**Other Buildings & Structures**		**564**	**487**		**$1,051**	**101**		**173**	**$1,325**	**3**
14.9	**Waste Treating Building & Str.**		**802**	**2,467**		**$3,269**	**318**		**538**	**$4,126**	**11**
	SUBTOTAL 14.		**$45,366**	**$43,456**		**$88,822**	**$8,464**		**$14,593**	**$111,879**	**$295**
	TOTAL COST	**$695,420**	**$75,443**	**$371,445**		**$1,142,308**	**$109,767**	**$52,879**	**$159,947**	**$1,464,901**	**$3,865**

CASE 3 (PC CR) - SUPERCRITICAL PC PRE-DESIGNED FOR CO_2 CAPTURE

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07

Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 3 - 1x550 MWnet Super-Critical PC w CO2 Capture Ready

Plant Size: 550.2 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct		Equipment	Material	Labor		Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Cost $	H.O.& Fee	Process	Project	$	$/kW
1	COAL HANDLING SYSTEM										
1.1	Coal Receive & Unload	3,967		1,831		$5,797	518		947	$7,262	13
1.2	Coal Stackout & Reclaim	5,126		1,174		$6,300	551		1,028	$7,879	14
1.3	Coal Conveyors & Yd Crush	4,766		1,161		$5,927	520		967	$7,414	13
1.4	Other Coal Handling	1,247		269		$1,516	132		247	$1,895	3
1.5	Sorbent Receive & Unload	160		49		$208	18		34	$260	0
1.6	Sorbent Stackout & Reclaim	2,576		477		$3,053	266		498	$3,817	7
1.7	Sorbent Conveyors	919	198	228		$1,345	116		219	$1,680	3
1.8	Other Sorbent Handling	555	129	294		$979	87		160	$1,225	2
1.9	Coal & Sorbent Hnd.Foundations		4,888	6,210		$11,097	1,037		1,820	$13,955	25
	SUBTOTAL 1.	**$19,316**	**$5,215**	**$11,691**		**$36,222**	**$3,246**		**$5,920**	**$45,389**	**$83**
2	COAL PREP & FEED SYSTEMS										
2.1	Coal Crushing & Drying	2,305		454		$2,759	241		450	$3,449	6
2.2	Prepared Coal Storage & Feed	5,901		1,301		$7,203	630		1,175	$9,007	16
2.3	Slurry Prep & Feed										
2.4	Misc.Coal Prep & Feed										
2.5	Sorbent Prep Equipment	4,391	188	922		$5,501	479		897	$6,878	13
2.6	Sorbent Storage & Feed	529		205		$734	65		120	$919	2
2.7	Sorbent Injection System										
2.8	Booster Air Supply System										
2.9	Coal & Sorbent Feed Foundation		570	444		$1,014	93		166	$1,274	2
	SUBTOTAL 2.	**$13,126**	**$758**	**$3,326**		**$17,210**	**$1,508**		**$2,808**	**$21,527**	**$39**
3	FEEDWATER & MISC. BOP SYSTEMS										
3.1	FeedwaterSystem	22,090		7,230		$29,320	2,567		4,783	$36,670	67
3.2	Water Makeup & Pretreating	7,572		2,435		$10,007	938		2,189	$13,134	24
3.3	Other Feedwater Subsystems	6,826		2,896		$9,722	866		1,588	$12,176	22
3.4	Service Water Systems	1,495		807		$2,301	214		503	$3,018	5
3.5	Other Boiler Plant Systems	8,357		8,175		$16,533	1,551		2,713	$20,796	38
3.6	FO Supply Sys & Nat Gas	267		329		$596	55		98	$749	1
3.7	Waste Treatment Equipment	5,103		2,923		$8,027	778		1,761	$10,565	19
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	2,768		853		$3,621	348		794	$4,762	9
	SUBTOTAL 3.	**$54,477**		**$25,648**		**$80,126**	**$7,317**		**$14,428**	**$101,870**	**$185**

	Client:	U.S. DOE / NETL						**Report Date:**	02-Sep-07		
	Project:	Advanced CO2 Capture-Ready Power Plants									
					TOTAL PLANT COST DETAIL						
	Case:	Case 3 - 1x550 MWnet Super-Critical PC w CO2 Capture Ready									
	Plant Size:	550.2 MW,net		**Estimate Type:**	Conceptual		**Cost Base (January)**		2007 ; $x1000		

Acct No.	**Item/Description**	**Equipment Cost**	**Material Cost**	**Labor Direct**	**Labor Indirect**	**Bare Erected Cost $**	**Eng'g CM H.O.& Fee**	**Contingencies Process**	**Contingencies Project**	**TOTAL PLANT COST $**	**TOTAL PLANT COST $/kW**
4	PC BOILER & ACCESSORIES										
4.1	PC Boiler & Accessories	190,969		107,678		$298,647	28,927		32,757	$360,332	655
4.2	SCR (w/4.1)										
4.3a	Open										
4.3b	Open										
4.4	Boiler BoP (w/ ID Fans)										
4.5	Primary Air System	w/4.1		w/4.1							
4.6	Secondary Air System	w/4.1		w/4.1							
4.8	Major Component Rigging		w/4.1	w/4.1							
4.9	Boiler Foundations		w/14.1	w/14.1							
	SUBTOTAL 4.	**$190,969**		**$107,678**		**$298,647**	**$28,927**		**$32,757**	**$360,332**	**$655**
5	FLUE GAS CLEANUP										
5.1	**Absorber Vessels & Accessories**	**71,002**		**15,297**		**$86,298**	**8,168**		**9,447**	**$103,913**	**189**
5.2	**Other FGD**	**3,705**		**4,202**		**$7,907**	**762**		**867**	**$9,536**	**17**
5.3	**Bag House & Accessories**	**20,830**		**13,229**		**$34,059**	**3,258**		**3,732**	**$41,049**	**75**
5.4	**Other Particulate Removal Materials**	**1,410**		**1,510**		**$2,919**	**281**		**320**	**$3,520**	**6**
5.5	**Gypsum Dewatering System**	**5,377**		**914**		**$6,291**	**594**		**689**	**$7,574**	**14**
5.6	Mercury Removal System										
	Open										
5.9	Open										
	SUBTOTAL 5A.	**$102,323**		**$35,151**		**$137,474**	**$13,063**		**$15,054**	**$165,591**	**$301**
5B	CO2 REMOVAL & COMPRESSION										
5B.1	**CO2 Removal System**										
5B.2	**CO2 Compression & Drying**										
	SUBTOTAL 5B.										
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	N/A		N/A							
6.2	Combustion Turbine Accessories										
6.3	Compressed Air Piping										
6.9	Combustion Turbine Foundations										
	SUBTOTAL 6.										
7	HRSG, DUCTING & STACK										
7.1	Heat Recovery Steam Generator	N/A		N/A							
7.2	HRSG Accessories										
7.3	Ductwork	9,280		6,057		$15,337	1,340		2,501	$19,178	35
7.4	Stack	8,609		5,041		$13,650	1,304		1,495	$16,450	30
7.9	Duct & Stack Foundations		981	1,123		$2,104	196		460	$2,760	5
	SUBTOTAL 7.	**$17,889**	**$981**	**$12,221**		**$31,091**	**$2,840**		**$4,457**	**$38,388**	**$70**

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 3 - 1x550 MWnet Super-Critical PC w CO2 Capture Ready
Plant Size: 550.2 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	53,763		7,192		$60,956	5,836		6,679	$73,471	134
8.2	Turbine Plant Auxiliaries	368		789		$1,158	112		127	$1,397	3
8.3	Condenser & Auxiliaries	5,563		1,956		$7,519	715		823	$9,057	16
8.4	Steam Piping	20,992		10,369		$31,362	2,617		5,097	$39,076	71
8.9	TG Foundations		1,148	1,827		$2,975	280		651	$3,906	7
	SUBTOTAL 8.	**$80,687**	**$1,148**	**$22,134**		**$103,969**	**$9,561**		**$13,377**	**$126,907**	**$231**
9	COOLING WATER SYSTEM										
9.1	Cooling Towers	15,181		4,731		$19,911	1,890		2,180	$23,982	44
9.2	Circulating Water Pumps	3,928		285		$4,213	361		457	$5,031	9
9.3	Circ.Water System Auxiliaries	907		121		$1,028	97		112	$1,237	2
9.4	Circ.Water Piping		7,315	6,977		$14,292	1,317		2,341	$17,950	33
9.5	Make-up Water System	740		981		$1,721	163		283	$2,167	4
9.6	Component Cooling Water Sys	723		571		$1,294	121		212	$1,628	3
9.9	Circ.Water System Foundations		3,884	6,215		$10,099	951		2,210	$13,260	24
	SUBTOTAL 9.	**$21,479**	**$11,200**	**$19,881**		**$52,559**	**$4,900**		**$7,796**	**$65,255**	**$119**
10	ASH/SPENT SORBENT HANDLING SYS										
10.1	Ash Coolers	N/A		N/A							
10.2	Cyclone Ash Letdown	N/A		N/A							
10.3	HGCU Ash Letdown	N/A		N/A							
10.4	High Temperature Ash Piping	N/A		N/A							
10.5	Other Ash Recovery Equipment	N/A		N/A							
10.6	Ash Storage Silos	685		2,113		$2,799	273		307	$3,379	6
10.7	Ash Transport & Feed Equipment	4,468		4,548		$9,016	853		987	$10,856	20
10.8	Misc. Ash Handling Equipment										
10.9	Ash/Spent Sorbent Foundation		162	192		$354	33		77	$464	1
	SUBTOTAL 10.	**$5,154**	**$162**	**$6,854**		**$12,169**	**$1,158**		**$1,371**	**$14,699**	**$27**
11	ACCESSORY ELECTRIC PLANT										
11.1	**Generator Equipment**	**1,647**		**270**		**$1,917**	**178**		**157**	**$2,251**	**4**
11.2	**Station Service Equipment**	**4,617**		**1,581**		**$6,197**	**593**		**509**	**$7,299**	**13**
11.3	**Switchgear & Motor Control**	**5,487**		**940**		**$6,427**	**595**		**702**	**$7,724**	**14**
11.4	**Conduit & Cable Tray**		**3,523**	**11,989**		**$15,512**	**1,485**		**2,549**	**$19,546**	**36**
11.5	**Wire & Cable**		**6,390**	**12,630**		**$19,020**	**1,603**		**3,093**	**$23,716**	**43**
11.6	Protective Equipment	243		861		$1,104	108		121	$1,333	2
11.7	**Standby Equipment**	**1,253**		**30**		**$1,282**	**121**		**140**	**$1,544**	**3**
11.8	**Main Power Transformers**	**6,950**		**182**		**$7,132**	**542**		**767**	**$8,441**	**15**
11.9	**Electrical Foundations**		**326**	**806**		**$1,133**	**108**		**248**	**$1,488**	**3**
	SUBTOTAL 11.	**$20,196**	**$10,240**	**$29,287**		**$59,723**	**$5,331**		**$8,288**	**$73,343**	**$133**

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07

Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 3 - 1x550 MWnet Super-Critical PC w CO2 Capture Ready

Plant Size: 550.2 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
12	INSTRUMENTATION & CONTROL										
12.1	PC Control Equipment	w/12.7		w/12.7							
12.2	Combustion Turbine Control	N/A		N/A							
12.3	Steam Turbine Control	w/8.1		w/8.1							
12.4	Other Major Component Control										
12.5	Signal Processing Equipment	W/12.7		w/12.7							
12.6	Control Boards,Panels & Racks	471		294		$765	74	38	131	$1,008	2
12.7	Distributed Control System Equipment	4,754		866		$5,620	535	281	644	$7,080	13
12.8	Instrument Wiring & Tubing	2,626		5,327		$7,953	677	398	1,354	$10,382	19
12.9	Other I & C Equipment	1,343		3,176		$4,520	440	226	519	$5,704	10
	SUBTOTAL 12.	**$9,195**		**$9,662**		**$18,857**	**$1,726**	**$943**	**$2,648**	**$24,174**	**$44**
13	IMPROVEMENTS TO SITE										
13.1	**Site Preparation**		**53**	**1,071**		**$1,124**	**111**		**247**	**$1,482**	**3**
13.2	**Site Improvements**		**1,765**	**2,208**		**$3,973**	**390**		**873**	**$5,236**	**10**
13.3	**Site Facilities**	**3,162**		**3,142**		**$6,305**	**619**		**1,385**	**$8,308**	**15**
	SUBTOTAL 13.	**$3,162**	**$1,818**	**$6,421**		**$11,402**	**$1,120**		**$2,504**	**$15,026**	**$27**
14	BUILDINGS & STRUCTURES										
14.1	**Boiler Building**		**8,384**	**7,472**		**$15,857**	**1,424**		**2,592**	**$19,873**	**36**
14.2	**Turbine Building**		**12,152**	**11,477**		**$23,629**	**2,128**		**3,864**	**$29,621**	**54**
14.3	**Administration Building**		**608**	**651**		**$1,259**	**114**		**206**	**$1,579**	**3**
14.4	**Circulation Water Pumphouse**		**279**	**225**		**$503**	**45**		**82**	**$631**	**1**
14.5	**Water Treatment Buildings**		**999**	**834**		**$1,833**	**164**		**300**	**$2,297**	**4**
14.6	**Machine Shop**		**406**	**277**		**$683**	**61**		**112**	**$855**	**2**
14.7	**Warehouse**		**275**	**280**		**$555**	**50**		**91**	**$696**	**1**
14.8	**Other Buildings & Structures**		**225**	**194**		**$419**	**38**		**69**	**$525**	**1**
14.9	**Waste Treating Building & Str.**		**431**	**1,325**		**$1,756**	**166**		**288**	**$2,210**	**4**
	SUBTOTAL 14.		**$23,760**	**$22,735**		**$46,495**	**$4,189**		**$7,603**	**$58,287**	**$106**
	TOTAL COST	**$537,973**	**$55,282**	**$312,690**		**$905,945**	**$84,886**	**$943**	**$119,012**	**$1,110,786**	**$2,019**

CASE 5 (PC CR RETROFIT) - RETROFIT OF CASE 3 TO CAPTURE CO_2

Client: U.S. DOE / NETL — **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 5 - Retrofit of 1x550 MWnet Capture ReadySuper-Critical PC w CO2 Capture
Plant Size: 546.0 MW,net — **Estimate Type:** Conceptual — **Cost Base (January)** 2007 ; $x1000

Acct		Equipment	Material	Labor		Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Cost $	H.O.& Fee	Process	Project	$	$/kW
1	COAL HANDLING SYSTEM										
1.1	Coal Receive & Unload	3,967		1,831		$5,797	518		947	$7,262	13
1.2	Coal Stackout & Reclaim	5,126		1,174		$6,300	551		1,028	$7,879	14
1.3	Coal Conveyors & Yd Crush	4,766		1,161		$5,927	520		967	$7,414	14
1.4	Other Coal Handling	1,247		269		$1,516	132		247	$1,895	3
1.5	Sorbent Receive & Unload	160		49		$208	18		34	$260	0
1.6	Sorbent Stackout & Reclaim	2,576		477		$3,053	266		498	$3,817	7
1.7	Sorbent Conveyors	919	198	228		$1,345	116		219	$1,680	3
1.8	Other Sorbent Handling	555	129	294		$979	87		160	$1,225	2
1.9	Coal & Sorbent Hnd.Foundations		4,888	6,210		$11,097	1,037		1,820	$13,955	26
	SUBTOTAL 1.	**$19,316**	**$5,215**	**$11,691**		**$36,222**	**$3,246**		**$5,920**	**$45,389**	**$83**
2	COAL PREP & FEED SYSTEMS										
2.1	Coal Crushing & Drying	2,305		454		$2,759	241		450	$3,449	6
2.2	Prepared Coal Storage & Feed	5,901		1,301		$7,203	630		1,175	$9,007	16
2.3	Slurry Prep & Feed										
2.4	Misc.Coal Prep & Feed										
2.5	Sorbent Prep Equipment	4,391	188	922		$5,501	479		897	$6,878	13
2.6	Sorbent Storage & Feed	529		205		$734	65		120	$919	2
2.7	Sorbent Injection System										
2.8	Booster Air Supply System										
2.9	Coal & Sorbent Feed Foundation		570	444		$1,014	93		166	$1,274	2
	SUBTOTAL 2.	**$13,126**	**$758**	**$3,326**		**$17,210**	**$1,508**		**$2,808**	**$21,527**	**$39**
3	FEEDWATER & MISC. BOP SYSTEMS										
3.1	FeedwaterSystem	22,090		7,230		$29,320	2,567		4,783	$36,670	67
3.2	Water Makeup & Pretreating	7,572		2,435		$10,007	938		2,189	$13,134	24
3.3	Other Feedwater Subsystems	6,826		2,896		$9,722	866		1,588	$12,176	22
3.4	Service Water Systems	1,495		807		$2,301	214		503	$3,018	6
3.5	Other Boiler Plant Systems	8,357		8,175		$16,533	1,551		2,713	$20,796	38
3.6	FO Supply Sys & Nat Gas	267		329		$596	55		98	$749	1
3.7	Waste Treatment Equipment	5,103		2,923		$8,027	778		1,761	$10,565	19
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	2,768		853		$3,621	348		794	$4,762	9
	SUBTOTAL 3.	**$54,477**		**$25,648**		**$80,126**	**$7,317**		**$14,428**	**$101,870**	**$187**

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 5 - Retrofit of 1x550 MWnet Capture ReadySuper-Critical PC w CO2 Capture
Plant Size: 546.0 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
4	PC BOILER & ACCESSORIES										
4.1	PC Boiler & Accessories	190,969		107,678		$298,647	28,927		32,757	$360,332	660
4.2	SCR (w/4.1)										
4.3a	Open										
4.3b	Open										
4.4	Boiler BoP (w/ ID Fans)										
4.5	Primary Air System	w/4.1		w/4.1							
4.6	Secondary Air System	w/4.1		w/4.1							
4.8	Major Component Rigging		w/4.1	w/4.1							
4.9	Boiler Foundations		w/14.1	w/14.1							
	SUBTOTAL 4.	**$190,969**		**$107,678**		**$298,647**	**$28,927**		**$32,757**	**$360,332**	**$660**
5	FLUE GAS CLEANUP										
5.1	Absorber Vessels & Accessories	71,002		15,297		$86,298	8,168		9,447	$103,913	190
5.2	Other FGD	3,705		4,202		$7,907	762		867	$9,536	17
5.3	Bag House & Accessories	20,830		13,229		$34,059	3,258		3,732	$41,049	75
5.4	Other Particulate Removal Materials	1,410		1,510		$2,919	281		320	$3,520	6
5.5	**Gypsum Dewatering System**	**5,434**		**924**		**$6,357**	**601**		**696**	**$7,654**	**14**
5.6	Mercury Removal System										
	Open										
5.9	Open										
	SUBTOTAL 5A.	**$102,380**		**$35,161**		**$137,541**	**$13,069**		**$15,061**	**$165,671**	**$303**
5B	CO2 REMOVAL & COMPRESSION										
5B.1	**CO2 Removal System**	**202,944**		**61,453**		**$264,397**	**25,093**	**52,879**	**68,474**	**$410,843**	**752**
5B.2	**CO2 Compression & Drying**	**26,888**		**8,398**		**$35,286**	**3,350**		**7,727**	**$46,363**	**85**
	SUBTOTAL 5B.	**$229,832**		**$69,851**		**$299,683**	**$28,443**	**$52,879**	**$76,201**	**$457,207**	**$837**
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	N/A		N/A							
6.2	Combustion Turbine Accessories										
6.3	Compressed Air Piping										
6.9	Combustion Turbine Foundations										
	SUBTOTAL 6.										
7	HRSG, DUCTING & STACK										
7.1	Heat Recovery Steam Generator	N/A		N/A							
7.2	HRSG Accessories										
7.3	Ductwork	9,280		6,057		$15,337	1,340		2,501	$19,178	35
7.4	Stack	8,609		5,041		$13,650	1,304		1,495	$16,450	30
7.9	Duct & Stack Foundations		981	1,123		$2,104	196		460	$2,760	5
	SUBTOTAL 7.	**$17,889**	**$981**	**$12,221**		**$31,091**	**$2,840**		**$4,457**	**$38,388**	**$70**

	Client:	U.S. DOE / NETL							**Report Date:**	02-Sep-07	
	Project:	Advanced CO2 Capture-Ready Power Plants									
					TOTAL PLANT COST DETAIL						
	Case:	Case 5 - Retrofit of 1x550 MWnet Capture ReadySuper-Critical PC w CO2 Capture									
	Plant Size:	546.0 MW,net		**Estimate Type:**		Conceptual		**Cost Base (January)**		2007 ; $x1000	

Acct No.	**Item/Description**	**Equipment Cost**	**Material Cost**	**Labor Direct**	**Labor Indirect**	**Bare Erected Cost $**	**Eng'g CM H.O.& Fee**	**Contingencies Process**	**Contingencies Project**	**TOTAL PLANT COST $**	**TOTAL PLANT COST $/kW**
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	53,763		7,192		$60,956	5,836		6,679	$73,471	135
8.2	Turbine Plant Auxiliaries	368		789		$1,158	112		127	$1,397	3
8.3	Condenser & Auxiliaries	5,563		1,956		$7,519	715		823	$9,057	17
8.4	Steam Piping	20,992		10,369		$31,362	2,617		5,097	$39,076	72
8.9	TG Foundations		1,148	1,827		$2,975	280		651	$3,906	7
	SUBTOTAL 8.	**$80,687**	**$1,148**	**$22,134**		**$103,969**	**$9,561**		**$13,377**	**$126,907**	**$232**
9	COOLING WATER SYSTEM										
9.1	Cooling Towers	15,181		4,731		$19,911	1,890		2,180	$23,982	44
9.2	Circulating Water Pumps	3,928		285		$4,213	361		457	$5,031	9
9.3	Circ.Water System Auxiliaries	907		121		$1,028	97		112	$1,237	2
9.4	Circ.Water Piping		7,315	6,977		$14,292	1,317		2,341	$17,950	33
9.5	Make-up Water System	740		981		$1,721	163		283	$2,167	4
9.6	Component Cooling Water Sys	723		571		$1,294	121		212	$1,628	3
9.9	Circ.Water System Foundations		3,884	6,215		$10,099	951		2,210	$13,260	24
	SUBTOTAL 9.	**$21,479**	**$11,200**	**$19,881**		**$52,559**	**$4,900**		**$7,796**	**$65,255**	**$120**
10	ASH/SPENT SORBENT HANDLING SYS										
10.1	Ash Coolers	N/A		N/A							
10.2	Cyclone Ash Letdown	N/A		N/A							
10.3	HGCU Ash Letdown	N/A		N/A							
10.4	High Temperature Ash Piping	N/A		N/A							
10.5	Other Ash Recovery Equipment	N/A		N/A							
10.6	Ash Storage Silos	685		2,113		$2,799	273		307	$3,379	6
10.7	Ash Transport & Feed Equipment	4,468		4,548		$9,016	853		987	$10,856	20
10.8	Misc. Ash Handling Equipment										
10.9	Ash/Spent Sorbent Foundation		162	192		$354	33		77	$464	1
	SUBTOTAL 10.	**$5,154**	**$162**	**$6,854**		**$12,169**	**$1,158**		**$1,371**	**$14,699**	**$27**
11	ACCESSORY ELECTRIC PLANT										
11.1	Generator Equipment	1,647		270		$1,917	178		157	$2,251	4
11.2	Station Service Equipment	4,617		1,581		$6,197	593		509	$7,299	13
11.3	Switchgear & Motor Control	5,487		940		$6,427	595		702	$7,724	14
11.4	Conduit & Cable Tray		3,523	11,989		$15,512	1,485		2,549	$19,546	36
11.5	Wire & Cable		6,390	12,630		$19,020	1,603		3,093	$23,716	43
11.6	Protective Equipment	243		861		$1,104	108		121	$1,333	2
11.7	Standby Equipment	1,253		30		$1,282	121		140	$1,544	3
11.8	Main Power Transformers	6,950		182		$7,132	542		767	$8,441	15
11.9	Electrical Foundations		326	806		$1,133	108		248	$1,488	3
	SUBTOTAL 11.	**$20,196**	**$10,240**	**$29,287**		**$59,723**	**$5,331**		**$8,288**	**$73,343**	**$134**

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07

Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 5 - Retrofit of 1x550 MWnet Capture ReadySuper-Critical PC w CO2 Capture

Plant Size: 546.0 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct		Equipment	Material	Labor		Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	**Item/Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Cost $**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**
12	INSTRUMENTATION & CONTROL										
12.1	PC Control Equipment	w/12.7		w/12.7							
12.2	Combustion Turbine Control	N/A		N/A							
12.3	Steam Turbine Control	w/8.1		w/8.1							
12.4	Other Major Component Control										
12.5	Signal Processing Equipment	W/12.7		w/12.7							
12.6	Control Boards,Panels & Racks	471		294		$765	74	38	131	$1,008	2
12.7	Distributed Control System Equipment	4,754		866		$5,620	535	281	644	$7,080	13
12.8	Instrument Wiring & Tubing	2,626		5,327		$7,953	677	398	1,354	$10,382	19
12.9	Other I & C Equipment	1,343		3,176		$4,520	440	226	519	$5,704	10
	SUBTOTAL 12.	**$9,195**		**$9,662**		**$18,857**	**$1,726**	**$943**	**$2,648**	**$24,174**	**$44**
13	IMPROVEMENTS TO SITE										
13.1	Site Preparation		53	1,071		$1,124	111		247	$1,482	3
13.2	Site Improvements		1,765	2,208		$3,973	390		873	$5,236	10
13.3	Site Facilities	3,162		3,142		$6,305	619		1,385	$8,308	15
	SUBTOTAL 13.	**$3,162**	**$1,818**	**$6,421**		**$11,402**	**$1,120**		**$2,504**	**$15,026**	**$28**
14	BUILDINGS & STRUCTURES										
14.1	Boiler Building		8,384	7,472		$15,857	1,424		2,592	$19,873	36
14.2	Turbine Building		12,152	11,477		$23,629	2,128		3,864	$29,621	54
14.3	Administration Building		608	651		$1,259	114		206	$1,579	3
14.4	Circulation Water Pumphouse		279	225		$503	45		82	$631	1
14.5	Water Treatment Buildings		999	834		$1,833	164		300	$2,297	4
14.6	Machine Shop		406	277		$683	61		112	$855	2
14.7	Warehouse		275	280		$555	50		91	$696	1
14.8	Other Buildings & Structures		225	194		$419	38		69	$525	1
14.9	Waste Treating Building & Str.		431	1,325		$1,756	166		288	$2,210	4
	SUBTOTAL 14.		**$23,760**	**$22,735**		**$46,495**	**$4,189**		**$7,603**	**$58,287**	**$107**
	TOTAL COST	**$767,862**	**$55,282**	**$382,550**		**$1,205,695**	**$113,335**	**$53,822**	**$195,221**	**$1,568,073**	**$2,872**

CASE 2 (IGCC BAU) - E-GAS™ IGCC WITHOUT CO_2 CAPTURE

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 2 -ConocoPhillips E-Gas Dual Train IGCC w/o CO2
Plant Size: 623.4 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies		TOTAL PLANT COST	
				Direct	Indirect			Process	Project	$	$/kW
1	COAL HANDLING SYSTEM										
1.1	Coal Receive & Unload	3,430		1,693		$5,123	411		1,107	$6,641	11
1.2	Coal Stackout & Reclaim	4,432		1,086		$5,517	433		1,190	$7,141	11
1.3	Coal Conveyors & Yd Crush	4,120		1,074		$5,195	409		1,121	$6,724	11
1.4	Other Coal Handling	1,078		249		$1,327	104		286	$1,717	3
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		2,435	6,132		$8,566	731		1,860	$11,157	18
	SUBTOTAL 1.	**$13,060**	**$2,435**	**$10,233**		**$25,728**	**$2,088**		**$5,563**	**$33,379**	**$54**
2	COAL PREP & FEED SYSTEMS										
2.1	Coal Crushing & Drying										
2.2	Prepared Coal Storage & Feed	1,462	348	232		$2,042	157		440	$2,638	4
2.3	Slurry Prep & Feed	19,945		8,962		$28,908	2,310		6,244	$37,462	60
2.4	Misc.Coal Prep & Feed	804	582	1,772		$3,158	259		684	$4,101	7
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		3,135	2,592		$5,727	473		1,240	$7,441	12
	SUBTOTAL 2.	**$22,211**	**$4,065**	**$13,559**		**$39,835**	**$3,200**		**$8,607**	**$51,642**	**$83**
3	FEEDWATER & MISC. BOP SYSTEMS										
3.1	FeedwaterSystem	3,088	5,369	2,836		$11,293	934		2,445	$14,672	24
3.2	Water Makeup & Pretreating	502	52	280		$834	71		271	$1,176	2
3.3	Other Feedwater Subsystems	1,705	578	521		$2,804	225		606	$3,634	6
3.4	Service Water Systems	289	590	2,049		$2,928	254		955	$4,137	7
3.5	Other Boiler Plant Systems	1,553	596	1,478		$3,626	305		786	$4,717	8
3.6	FO Supply Sys & Nat Gas	299	565	527		$1,391	119		302	$1,812	3
3.7	Waste Treatment Equipment	697		427		$1,124	98		367	$1,588	3
3.8	Misc. Power Plant Equipment	1,015	136	526		$1,678	145		547	$2,369	4
	SUBTOTAL 3.	**$9,148**	**$7,886**	**$8,644**		**$25,678**	**$2,149**		**$6,278**	**$34,105**	**$55**

	Client:	U.S. DOE / NETL							**Report Date:**	02-Sep-07	
	Project:	Advanced CO2 Capture-Ready Power Plants									
					TOTAL PLANT COST DETAIL						
	Case:	Case 2 -ConocoPhillips E-Gas Dual Train IGCC w/o CO2									
	Plant Size:	623.4 MW,net		**Estimate Type:**	Conceptual	**Cost Base (January)**			2007 ; $x1000		
Acct No.	**Item/Description**	**Equipment Cost**	**Material Cost**	**Labor Direct**	**Labor Indirect**	**Bare Erected Cost $**	**Eng'g CM H.O.& Fee**	**Contingencies Process**	**Contingencies Project**	**TOTAL PLANT COST $**	**TOTAL PLANT COST $/kW**
4	GASIFIER & ACCESSORIES										
4.1	Gasifier, Syngas Cooler & Auxiliaries	90,425		55,527		$145,952	11,971	21,893	26,972	$206,789	332
4.2	Syngas Cooler (w/Gasifier - $)	w/4.1		w/4.1							
4.3a	ASU/Oxidant Compression	137,711		w/equip.		$137,711	11,743		14,945	$164,399	264
4.3b	ITM Oxygen System										
4.4	LT Heat Recovery & FG Saturation	18,487		6,956		$25,443	2,191		5,527	$33,160	53
4.5	Misc Gasification Equipment	w/4.1&4.2		w/4.1&4.2							
4.6	Other Gasifiction Equipment		1,142	465		$1,607	137		349	$2,092	3
4.8	Major Component Rigging	w/4.1&4.2		w/4.1&4.2							
4.9	Gasification Foundations		7,439	4,275		$11,713	957		3,168	$15,838	25
	SUBTOTAL 4.	**$246,624**	**$8,580**	**$67,222**		**$322,427**	**$26,999**	**$21,893**	**$50,961**	**$422,279**	**$677**
5A	GAS CLEANUP & PIPING										
5A.1	MDEA-LT AGR	34,245		16,003		$50,248	4,291		10,908	$65,447	105
5A.2	Elemental Sulfur Plant	11,411	2,265	14,734		$28,410	2,454		6,173	$37,037	59
5A.3	Mercury Removal	1,177		897		$2,074	178	104	471	$2,827	5
5A.4	COS Hydrolysis	3,651		4,771		$8,422	728		1,830	$10,980	18
5A.5	Shift Reactors										
5A.6	Blowback Gas Systems	410	230	130		$770	65		167	$1,002	2
5A.7	Fuel Gas Piping		1,161	800		$1,961	160		424	$2,546	4
5A.8	HGCU Foundations		1,149	746		$1,895	155		615	$2,666	4
	SUBTOTAL 5A.	**$50,895**	**$4,805**	**$38,080**		**$93,780**	**$8,032**	**$104**	**$20,588**	**$122,504**	**$197**
5B	CO2 REMOVAL & COMPRESSION										
5B.1	CO2 Removal System										
5B.2	CO2 Compression & Drying										
	SUBTOTAL 5B.										
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	82,000		5,071		$87,071	7,338	4,354	9,876	$108,639	174
6.2	Combustion Turbine Accessories										
6.3	Compressed Air Piping										
6.9	Combustion Turbine Foundations		684	762		$1,446	121		470	$2,037	3
	SUBTOTAL 6.	**$82,000**	**$684**	**$5,833**		**$88,517**	**$7,459**	**$4,354**	**$10,346**	**$110,676**	**$178**
7	HRSG, DUCTING & STACK										
7.1	Heat Recovery Steam Generator	33,926		4,828		$38,754	3,277		4,203	$46,234	74
7.2	SCR System										
7.3	Ductwork		1,577	1,143		$2,719	214		587	$3,520	6
7.4	Stack	3,123		1,174		$4,296	366		466	$5,129	8
7.9	HRSG,Duct & Stack Foundations		622	601		$1,223	102		397	$1,722	3
	SUBTOTAL 7.	**$37,049**	**$2,198**	**$7,745**		**$46,992**	**$3,959**		**$5,653**	**$56,604**	**$91**

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07

Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 2 -ConocoPhillips E-Gas Dual Train IGCC w/o CO2

Plant Size: 623.4 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	28,109		4,930		$33,039	2,837		3,588	$39,463	63
8.2	Turbine Plant Auxiliaries	198		455		$654	57		71	$782	1
8.3	Condenser & Auxiliaries	4,660		1,421		$6,082	517		660	$7,259	12
8.4	Steam Piping	5,233		3,687		$8,920	682		2,400	$12,002	19
8.9	TG Foundations		953	1,621		$2,574	217		837	$3,629	6
	SUBTOTAL 8.	**$38,201**	**$953**	**$12,115**		**$51,268**	**$4,310**		**$7,556**	**$63,135**	**$101**
9	COOLING WATER SYSTEM										
9.1	Cooling Towers	4,397		967		$5,364	455		873	$6,692	11
9.2	Circulating Water Pumps	1,383		86		$1,469	113		237	$1,819	3
9.3	Circ.Water System Auxiliaries	116		17		$132	11		22	$165	0
9.4	Circ.Water Piping		4,910	1,253		$6,163	489		1,330	$7,982	13
9.5	Make-up Water System	284		403		$688	58		149	$895	1
9.6	Component Cooling Water Sys	579	693	490		$1,762	146		382	$2,290	4
9.9	Circ.Water System Foundations		1,699	2,909		$4,608	389		1,499	$6,497	10
	SUBTOTAL 9.	**$6,760**	**$7,303**	**$6,124**		**$20,187**	**$1,661**		**$4,492**	**$26,340**	**$42**
10	ASH/SPENT SORBENT HANDLING SYS										
10.1	Ash Coolers	15,861		7,828		$23,688	2,024		2,571	$28,283	45
10.2	Cyclone Ash Letdown										
10.3	HGCU Ash Letdown										
10.4	High Temperature Ash Piping										
10.5	Other Ash Recovery Equipment										
10.6	Ash Storage Silos	523		569		$1,092	94		178	$1,365	2
10.7	Ash Transport & Feed Equipment	706		169		$876	72		142	$1,090	2
10.8	Misc. Ash Handling Equipment	1,083	1,327	397		$2,807	238		457	$3,502	6
10.9	Ash/Spent Sorbent Foundation		46	58		$104	9		34	$147	0
	SUBTOTAL 10.	**$18,173**	**$1,373**	**$9,021**		**$28,568**	**$2,437**		**$3,382**	**$34,386**	**$55**
11	ACCESSORY ELECTRIC PLANT										
11.1	Generator Equipment	901		899		$1,800	153		195	$2,148	3
11.2	Station Service Equipment	3,498		328		$3,827	326		415	$4,568	7
11.3	Switchgear & Motor Control	6,686		1,226		$7,911	657		1,285	$9,853	16
11.4	Conduit & Cable Tray		3,181	10,327		$13,508	1,157		3,666	$18,331	29
11.5	Wire & Cable		5,842	3,930		$9,772	640		2,603	$13,015	21
11.6	Protective Equipment		624	2,365		$2,989	262		488	$3,739	6
11.7	Standby Equipment	215		218		$433	37		71	$541	1
11.8	Main Power Transformers	11,308		138		$11,446	776		1,833	$14,056	23
11.9	Electrical Foundations		149	394		$543	46		177	$766	1
	SUBTOTAL 11.	**$22,608**	**$9,796**	**$19,825**		**$52,229**	**$4,054**		**$10,733**	**$67,016**	**$108**

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 2 -ConocoPhillips E-Gas Dual Train IGCC w/o CO2
Plant Size: 623.4 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct		Equipment	Material	Labor		Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Cost $	H.O.& Fee	Process	Project	$	$/kW
12	INSTRUMENTATION & CONTROL										
12.1	PC Control Equipment	w/12.7		w/12.7							
12.2	Combustion Turbine Control	N/A		N/A							
12.3	Steam Turbine Control	w/8.1		w/8.1							
12.4	Other Major Component Control	924		643		$1,566	135	78	267	$2,047	3
12.5	Signal Processing Equipment	W/12.7		W/12.7							
12.6	Control Boards,Panels & Racks	212		142		$354	31	18	80	$483	1
12.7	Computer & Accessories	4,928		164		$5,092	432	255	578	$6,357	10
12.8	Instrument Wiring & Tubing		1,752	3,666		$5,418	412	271	1,525	$7,626	12
12.9	Other I & C Equipment	3,294		1,666		$4,960	426	248	845	$6,480	10
	SUBTOTAL 12.	**$9,358**	**$1,752**	**$6,282**		**$17,391**	**$1,436**	**$870**	**$3,296**	**$22,992**	**$37**
13	IMPROVEMENTS TO SITE										
13.1	Site Preparation		99	2,132		$2,231	197		728	$3,156	5
13.2	Site Improvements		1,761	2,357		$4,118	362		1,344	$5,824	9
13.3	Site Facilities	3,155		3,354		$6,509	572		2,124	$9,206	15
	SUBTOTAL 13.	**$3,155**	**$1,860**	**$7,843**		**$12,858**	**$1,132**		**$4,197**	**$18,186**	**$29**
14	BUILDINGS & STRUCTURES										
14.1	Boiler Building		221	127		$348	27		75	$451	1
14.2	Turbine Building		2,309	3,334		$5,643	464		916	$7,024	11
14.3	Administration Building		793	583		$1,375	110		223	$1,708	3
14.4	Circulation Water Pumphouse		156	84		$240	19		39	$298	0
14.5	Water Treatment Buildings		399	395		$794	64		129	$987	2
14.6	Machine Shop		406	281		$687	55		111	$853	1
14.7	Warehouse		655	428		$1,083	86		175	$1,345	2
14.8	Other Buildings & Structures		392	310		$702	56		152	$910	1
14.9	Waste Treating Building & Str.		877	1,698		$2,575	214		558	$3,348	5
	SUBTOTAL 14.		**$6,209**	**$7,240**		**$13,449**	**$1,095**		**$2,378**	**$16,922**	**$27**
	TOTAL COST	**$559,240**	**$59,898**	**$219,767**		**$838,905**	**$70,010**	**$27,220**	**$144,031**	**$1,080,166**	**$1,733**

CASE 8 (IGCC BAU RETROFIT) – RETROFIT OF CASE 2 TO CAPTURE CO_2

Client: U.S. DOE / NETL **Report Date:** 12-Feb-08
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 8 -Retrofit of Non-Capture Ready ConocoPhillips E-Gas Dual Train IGCC w CO2
Plant Size: 500.3 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL HANDLING SYSTEM										
1.1	Coal Receive & Unload	3,430		1,693		$5,123	411		1,107	$6,641	13
1.2	Coal Stackout & Reclaim	4,432		1,086		$5,517	433		1,190	$7,141	14
1.3	Coal Conveyors & Yd Crush	4,120		1,074		$5,195	409		1,121	$6,724	13
1.4	Other Coal Handling	1,078		249		$1,327	104		286	$1,717	3
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		2,435	6,132		$8,566	731		1,860	$11,157	22
	SUBTOTAL 1.	**$13,060**	**$2,435**	**$10,233**		**$25,728**	**$2,088**		**$5,563**	**$33,379**	**$67**
2	COAL PREP & FEED SYSTEMS										
2.1	Coal Crushing & Drying										
2.2	Prepared Coal Storage & Feed	1,462	348	232		$2,042	157		440	$2,638	5
2.3	Slurry Prep & Feed	19,945		8,962		$28,908	2,310		6,244	$37,462	75
2.4	Misc.Coal Prep & Feed	804	582	1,772		$3,158	259		684	$4,101	8
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		3,135	2,592		$5,727	473		1,240	$7,441	15
	SUBTOTAL 2.	**$22,211**	**$4,065**	**$13,559**		**$39,835**	**$3,200**		**$8,607**	**$51,642**	**$103**
3	FEEDWATER & MISC. BOP SYSTEMS										
3.1	FeedwaterSystem	3,088	5,369	2,836		$11,293	934		2,445	$14,672	29
3.2	Water Makeup & Pretreating	502	52	280		$834	71		271	$1,176	2
3.3	Other Feedwater Subsystems	1,705	578	521		$2,804	225		606	$3,634	7
3.4	Service Water Systems	289	590	2,049		$2,928	254		955	$4,137	8
3.5	Other Boiler Plant Systems	1,553	596	1,478		$3,626	305		786	$4,717	9
3.6	FO Supply Sys & Nat Gas	299	565	527		$1,391	119		302	$1,812	4
3.7	Waste Treatment Equipment	697		427		$1,124	98		367	$1,588	3
3.8	Misc. Power Plant Equipment	1,015	136	526		$1,678	145		547	$2,369	5
	SUBTOTAL 3.	**$9,148**	**$7,886**	**$8,644**		**$25,678**	**$2,149**		**$6,278**	**$34,105**	**$68**

Client: U.S. DOE / NETL **Report Date:** 12-Feb-08
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 8 -Retrofit of Non-Capture Ready ConocoPhillips E-Gas Dual Train IGCC w CO2
Plant Size: 500.3 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
4	GASIFIER & ACCESSORIES										
4.1	Gasifier, Syngas Cooler & Auxiliaries	90,425		55,527		$145,952	11,971	21,893	26,972	$206,789	413
4.2	Syngas Cooler (w/Gasifier - $)	w/4.1		w/4.1							
4.3a	ASU/Oxidant Compression	137,711		w/equip.		$137,711	11,743		14,945	$164,399	329
4.3b	Additional Air Compressor	13,780				$13,780	1,378		3,032	$18,190	36
4.4	LT Heat Recovery & FG Saturation	18,487		6,956		$25,443	2,191		5,527	$33,160	66
4.5	Misc Gasification Equipment	w/4.1&4.2		w/4.1&4.2							
4.6	Other Gasifiction Equipment		1,142	465		$1,607	137		349	$2,092	4
4.8	Major Component Rigging	w/4.1&4.2		w/4.1&4.2							
4.9	Gasification Foundations		7,439	4,275		$11,713	957		3,168	$15,838	32
	SUBTOTAL 4.	**$260,404**	**$8,580**	**$67,222**		**$336,207**	**$28,377**	**$21,893**	**$53,993**	**$440,469**	**$880**
5A	GAS CLEANUP & PIPING										
5A.1	**Double Selexol AGR**	**91,696**		**65,282**		**$156,979**	**13,470**	**21,346**	**38,359**	**$230,153**	**460**
5A.2	**Elemental Sulfur Plant**	**11,411**	**2,265**	**14,734**		**$28,410**	**2,454**		**6,173**	**$37,037**	**74**
5A.3	**Mercury Removal**	**1,635**		**1,245**		**$2,881**	**259**	**144**	**649**	**$3,932**	**8**
5A.4	**COS Hydrolysis**	**(1,091)**		**(1,002)**		**($2,093)**	**(323)**		**(483)**	**($2,900)**	**-6**
5A.5	**Shift Reactors**	**8,113**		**3,033**		**$11,146**	**1,115**		**2,452**	**$14,713**	**29**
5A.6	Blowback Gas Systems	410	230	130		$770	65		167	$1,002	2
5A.7	Fuel Gas Piping		1,161	800		$1,961	160		424	$2,546	5
5A.8	HGCU Foundations		1,149	746		$1,895	155		615	$2,666	5
	SUBTOTAL 5A.	**$112,175**	**$4,805**	**$84,968**		**$201,948**	**$17,355**	**$21,490**	**$48,356**	**$289,149**	**$578**
5B	CO2 REMOVAL & COMPRESSION										
5B.1	**CO2 Removal System**										
5B.2	**CO2 Compression & Drying**	**17,010**		**10,435**		**$27,445**	**2,744**		**4,528**	**$34,717**	**69**
	SUBTOTAL 5B.	**$17,010**		**$10,435**		**$27,445**	**$2,744**		**$4,528**	**$34,717**	**$69**
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	82,000		5,071		$87,071	7,338	4,354	9,876	$108,639	217
6.2	Combustion Turbine Modifications	6,000		254		$6,254	625		1,376	$8,255	16
6.3	Compressed Air Piping										
6.9	Combustion Turbine Foundations		684	762		$1,446	121		470	$2,037	4
	SUBTOTAL 6.	**$88,000**	**$684**	**$6,087**		**$94,771**	**$8,084**	**$4,354**	**$11,722**	**$118,931**	**$238**
7	HRSG, DUCTING & STACK										
7.1	Heat Recovery Steam Generator	33,926		4,828		$38,754	3,277		4,203	$46,234	92
7.2	SCR System										
7.3	Ductwork		1,577	1,143		$2,719	214		587	$3,520	7
7.4	Stack	3,123		1,174		$4,296	366		466	$5,129	10
7.9	HRSG,Duct & Stack Foundations		622	601		$1,223	102		397	$1,722	3
	SUBTOTAL 7.	**$37,049**	**$2,198**	**$7,745**		**$46,992**	**$3,959**		**$5,653**	**$56,604**	**$113**

	Client:	U.S. DOE / NETL							**Report Date:**	12-Feb-08	
	Project:	Advanced CO2 Capture-Ready Power Plants									
					TOTAL PLANT COST DETAIL						
	Case:	Case 8 -Retrofit of Non-Capture Ready ConocoPhillips E-Gas Dual Train IGCC w CO2									
	Plant Size:	500.3 MW,net		**Estimate Type:**	Conceptual		**Cost Base (January)**		2007 ; $x1000		
Acct		**Equipment**	**Material**	**Labor**		**Bare Erected**	**Eng'g CM**	**Contingencies**		**TOTAL PLANT COST**	
No.	**Item/Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Cost $**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories & Modifications	28,109		5,030		$33,139	2,847		3,610	$39,595	79
8.2	Turbine Plant Auxiliaries	198		455		$654	57		71	$782	2
8.3	Condenser & Auxiliaries	4,660		1,421		$6,082	517		660	$7,259	15
8.4	Steam Piping	5,233		3,687		$8,920	682		2,400	$12,002	24
8.9	TG Foundations		953	1,621		$2,574	217		837	$3,629	7
	SUBTOTAL 8.	**$38,201**	**$953**	**$12,215**		**$51,368**	**$4,320**		**$7,578**	**$63,267**	**$126**
9	COOLING WATER SYSTEM										
9.1	Cooling Towers	4,397		967		$5,364	455		873	$6,692	13
9.2	Circulating Water Pumps	1,383		86		$1,469	113		237	$1,819	4
9.3	Circ.Water System Auxiliaries	116		17		$132	11		22	$165	0
9.4	Circ.Water Piping		4,910	1,253		$6,163	489		1,330	$7,982	16
9.5	Make-up Water System	284		403		$688	58		149	$895	2
9.6	Component Cooling Water Sys	579	693	490		$1,762	146		382	$2,290	5
9.9	Circ.Water System Foundations		1,699	2,909		$4,608	389		1,499	$6,497	13
	SUBTOTAL 9.	**$6,760**	**$7,303**	**$6,124**		**$20,187**	**$1,661**		**$4,492**	**$26,340**	**$53**
10	ASH/SPENT SORBENT HANDLING SYS										
10.1	Ash Coolers	15,861		7,828		$23,688	2,024		2,571	$28,283	57
10.2	Cyclone Ash Letdown										
10.3	HGCU Ash Letdown										
10.4	High Temperature Ash Piping										
10.5	Other Ash Recovery Equipment										
10.6	Ash Storage Silos	523		569		$1,092	94		178	$1,365	3
10.7	Ash Transport & Feed Equipment	706		169		$876	72		142	$1,090	2
10.8	Misc. Ash Handling Equipment	1,083	1,327	397		$2,807	238		457	$3,502	7
10.9	Ash/Spent Sorbent Foundation		46	58		$104	9		34	$147	0
	SUBTOTAL 10.	**$18,173**	**$1,373**	**$9,021**		**$28,568**	**$2,437**		**$3,382**	**$34,386**	**$69**
11	ACCESSORY ELECTRIC PLANT										
11.1	Generator Equipment	901		899		$1,800	153		195	$2,148	4
11.2	Station Service Equipment	3,498		328		$3,827	326		415	$4,568	9
11.3	Switchgear & Motor Control	6,686		1,226		$7,911	657		1,285	$9,853	20
11.4	Conduit & Cable Tray		3,181	10,327		$13,508	1,157		3,666	$18,331	37
11.5	Wire & Cable		5,842	3,930		$9,772	640		2,603	$13,015	26
11.6	Protective Equipment		624	2,365		$2,989	262		488	$3,739	7
11.7	Standby Equipment	215		218		$433	37		71	$541	1
11.8	Main Power Transformers	11,308		138		$11,446	776		1,833	$14,056	28
11.9	Electrical Foundations		149	394		$543	46		177	$766	2
	SUBTOTAL 11.	**$22,608**	**$9,796**	**$19,825**		**$52,229**	**$4,054**		**$10,733**	**$67,016**	**$134**

	Client:	U.S. DOE / NETL							**Report Date:**	12-Feb-08		
	Project:	Advanced CO2 Capture-Ready Power Plants										
		TOTAL PLANT COST DETAIL										
	Case:	Case 8 -Retrofit of Non-Capture Ready ConocoPhillips E-Gas Dual Train IGCC w CO2										
	Plant Size:	500.3 MW,net		**Estimate Type:**	Conceptual		**Cost Base (January)**		2007 ; $x1000			
Acct		**Equipment**	**Material**	**Labor**		**Bare Erected**	**Eng'g CM**	**Contingencies**		**TOTAL PLANT COST**		
No.	**Item/Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Cost $**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**	
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7		w/12.7								
12.2	Combustion Turbine Control	N/A		N/A								
12.3	Steam Turbine Control	w/8.1		w/8.1								
12.4	Other Major Component Control	924		643		$1,566	135	78	267	$2,047	4	
12.5	Signal Processing Equipment	W/12.7		W/12.7								
12.6	Control Boards,Panels & Racks	212		142		$354	31	18	80	$483	1	
12.7	Computer & Accessories	4,928		164		$5,092	432	255	578	$6,357	13	
12.8	Instrument Wiring & Tubing		1,752	3,666		$5,418	412	271	1,525	$7,626	15	
12.9	Other I & C Equipment	3,294		1,666		$4,960	426	248	845	$6,480	13	
	SUBTOTAL 12.	**$9,358**	**$1,752**	**$6,282**		**$17,391**	**$1,436**	**$870**	**$3,296**	**$22,992**	**$46**	
13	IMPROVEMENTS TO SITE											
13.1	**Site Preparation**		**99**	**2,132**		**$2,231**	**197**		**728**	**$3,156**	**6**	
13.2	**Site Improvements**		**4,401**	**5,893**		**$10,295**	**980**		**3,382**	**$14,657**	**29**	
13.3	**Site Facilities**	**3,155**		**3,354**		**$6,509**	**572**		**2,124**	**$9,206**	**18**	
	SUBTOTAL 13.	**$3,155**	**$4,500**	**$11,379**		**$19,034**	**$1,749**		**$6,235**	**$27,019**	**$54**	
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building		221	127		$348	27		75	$451	1	
14.2	Turbine Building		2,309	3,334		$5,643	464		916	$7,024	14	
14.3	Administration Building		793	583		$1,375	110		223	$1,708	3	
14.4	Circulation Water Pumphouse		156	84		$240	19		39	$298	1	
14.5	Water Treatment Buildings		399	395		$794	64		129	$987	2	
14.6	Machine Shop		406	281		$687	55		111	$853	2	
14.7	Warehouse		655	428		$1,083	86		175	$1,345	3	
14.8	**Other Buildings & Structures**		**804**	**635**		**$1,439**	**130**		**354**	**$1,923**	**4**	
14.9	Waste Treating Building & Str.		877	1,698		$2,575	214		558	$3,348	7	
	SUBTOTAL 14.		**$6,620**	**$7,565**		**$14,185**	**$1,169**		**$2,580**	**$17,935**	**$36**	
	TOTAL COST	**$657,310**	**$62,951**	**$281,305**		**$1,001,565**	**$84,782**	**$48,606**	**$182,997**	**$1,317,951**	**$2,634**	

CASE 4 (IGCC CR) - E-GAS IGCC POWER PLANT PRE-DESIGNED FOR CO_2 CAPTURE

Client: U.S. DOE / NETL — **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 4 -ConocoPhillips E-Gas Dual Train IGCC w CO2 Capture Ready
Plant Size: 623.4 MW,net — **Estimate Type:** Conceptual — **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL HANDLING SYSTEM										
1.1	Coal Receive & Unload	3,493		1,725		$5,218	418		1,127	$6,764	11
1.2	Coal Stackout & Reclaim	4,514		1,106		$5,620	441		1,212	$7,274	12
1.3	Coal Conveyors & Yd Crush	4,197		1,094		$5,291	416		1,141	$6,849	11
1.4	Other Coal Handling	1,098		253		$1,351	106		291	$1,749	3
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		2,480	6,246		$8,726	745		1,894	$11,365	18
	SUBTOTAL 1.	**$13,303**	**$2,480**	**$10,424**		**$26,207**	**$2,127**		**$5,667**	**$34,000**	**$55**
2	COAL PREP & FEED SYSTEMS										
2.1	Coal Crushing & Drying										
2.2	Prepared Coal Storage & Feed	1,491	355	236		$2,082	160		448	$2,690	4
2.3	Slurry Prep & Feed	20,340		9,140		$29,480	2,356		6,367	$38,204	61
2.4	Misc.Coal Prep & Feed	820	593	1,807		$3,221	265		697	$4,182	7
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		3,197	2,644		$5,841	483		1,265	$7,588	12
	SUBTOTAL 2.	**$22,651**	**$4,146**	**$13,827**		**$40,624**	**$3,263**		**$8,777**	**$52,665**	**$84**
3	FEEDWATER & MISC. BOP SYSTEMS										
3.1	FeedwaterSystem	3,088	5,369	2,836		$11,293	934		2,445	$14,672	24
3.2	Water Makeup & Pretreating	537	56	300		$893	76		290	$1,259	2
3.3	Other Feedwater Subsystems	1,705	578	521		$2,804	225		606	$3,634	6
3.4	Service Water Systems	309	632	2,194		$3,135	272		1,022	$4,428	7
3.5	Other Boiler Plant Systems	1,662	638	1,582		$3,882	326		842	$5,050	8
3.6	FO Supply Sys & Nat Gas	299	565	527		$1,391	119		302	$1,812	3
3.7	Waste Treatment Equipment	746		457		$1,203	104		392	$1,700	3
3.8	Misc. Power Plant Equipment	1,024	138	531		$1,693	146		552	$2,390	4
	SUBTOTAL 3.	**$9,371**	**$7,975**	**$8,947**		**$26,292**	**$2,201**		**$6,451**	**$34,944**	**$56**

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 4 -ConocoPhillips E-Gas Dual Train IGCC w CO2 Capture Ready
Plant Size: 623.4 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
4	GASIFIER & ACCESSORIES										
4.1	**Gasifier, Syngas Cooler & Auxiliaries**	**93,113**		**57,142**		**$150,256**	**12,324**	**22,538**	**27,768**	**$212,885**	**342**
4.2	Syngas Cooler (w/Gasifier - $)	w/4.1		w/4.1							
4.3a	**ASU/Oxidant Compression**	**142,779**		**w/equip.**		**$142,779**	**12,175**		**15,495**	**$170,449**	**273**
4.3b	ITM Oxygen System										
4.4	**LT Heat Recovery & FG Saturation**	**24,864**		**9,355**		**$34,219**	**2,946**		**7,433**	**$44,598**	**72**
4.5	Misc Gasification Equipment	w/4.1&4.2		w/4.1&4.2							
4.6	**Other Gasifiction Equipment**		**1,157**	**471**		**$1,629**	**139**		**354**	**$2,121**	**3**
4.8	Major Component Rigging	w/4.1&4.2		w/4.1&4.2							
4.9	**Gasification Foundations**		**7,550**	**4,339**		**$11,889**	**972**		**3,215**	**$16,075**	**26**
	SUBTOTAL 4.	**$260,756**	**$8,707**	**$71,307**		**$340,771**	**$28,555**	**$22,538**	**$54,265**	**$446,129**	**$716**
5A	GAS CLEANUP & PIPING										
5A.1	**Single Selexol AGR**	**34,471**		**29,568**		**$64,038**	**5,507**	**12,808**	**16,471**	**$98,824**	**159**
5A.2	**Elemental Sulfur Plant**	**9,709**	**1,927**	**12,535**		**$24,170**	**2,088**		**5,252**	**$31,510**	**51**
5A.3	**Mercury Removal**	**1,531**		**1,166**		**$2,697**	**232**	**135**	**613**	**$3,676**	**6**
5A.4	COS Hydrolysis	3,651		4,771		$8,422	728		1,830	$10,980	18
5A.5	Shift Reactors										
5A.6	Blowback Gas Systems	410	230	130		$770	65		167	$1,002	2
5A.7	**Fuel Gas Piping**		**1,150**	**793**		**$1,943**	**159**		**420**	**$2,522**	**4**
5A.8	**HGCU Foundations**		**1,138**	**739**		**$1,878**	**154**		**609**	**$2,641**	**4**
	SUBTOTAL 5A.	**$49,771**	**$4,446**	**$49,701**		**$103,918**	**$8,933**	**$12,942**	**$25,362**	**$151,156**	**$242**
5B	CO2 REMOVAL & COMPRESSION										
5B.1	CO2 Removal System										
5B.2	CO2 Compression & Drying										
	SUBTOTAL 5B.										
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	**Combustion Turbine Generator**	**88,000**		**5,325**		**$93,325**	**7,865**	**9,333**	**11,052**	**$121,575**	**195**
6.2	Combustion Turbine Accessories										
6.3	Compressed Air Piping										
6.9	Combustion Turbine Foundations		684	762		$1,446	121		470	$2,037	3
	SUBTOTAL 6.	**$88,000**	**$684**	**$6,087**		**$94,771**	**$7,986**	**$9,333**	**$11,522**	**$123,611**	**$198**
7	HRSG, DUCTING & STACK										
7.1	**Heat Recovery Steam Generator**	**32,356**		**4,604**		**$36,960**	**3,125**		**4,009**	**$44,094**	**71**
7.2	SCR System										
7.3	**Ductwork**		**1,627**	**1,179**		**$2,806**	**221**		**605**	**$3,632**	**6**
7.4	**Stack**	**3,222**		**1,211**		**$4,433**	**378**		**481**	**$5,292**	**8**
7.9	**HRSG,Duct & Stack Foundations**		**641**	**620**		**$1,262**	**105**		**410**	**$1,777**	**3**
	SUBTOTAL 7.	**$35,577**	**$2,268**	**$7,615**		**$45,461**	**$3,829**		**$5,505**	**$54,794**	**$88**

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 4 -ConocoPhillips E-Gas Dual Train IGCC w CO2 Capture Ready
Plant Size: 623.4 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
8	STEAM TURBINE GENERATOR										
8.1	**Steam TG & Accessories**	**25,224**		**4,105**		**$29,328**	**2,518**		**3,185**	**$35,030**	**56**
8.2	**Turbine Plant Auxiliaries**	**168**		**385**		**$553**	**48**		**60**	**$662**	**1**
8.3	**Condenser & Auxiliaries**	**4,112**		**1,235**		**$5,348**	**455**		**580**	**$6,382**	**10**
8.4	**Steam Piping**	**4,962**		**3,497**		**$8,459**	**647**		**2,276**	**$11,382**	**18**
8.9	**TG Foundations**		**828**	**1,409**		**$2,237**	**189**		**728**	**$3,154**	**5**
	SUBTOTAL 8.	**$34,466**	**$828**	**$10,632**		**$45,926**	**$3,856**		**$6,829**	**$56,611**	**$91**
9	COOLING WATER SYSTEM										
9.1	**Cooling Towers**	**4,081**		**897**		**$4,978**	**422**		**810**	**$6,210**	**10**
9.2	**Circulating Water Pumps**	**1,284**		**77**		**$1,361**	**104**		**220**	**$1,685**	**3**
9.3	**Circ.Water System Auxiliaries**	**108**		**15**		**$123**	**10**		**20**	**$154**	**0**
9.4	**Circ.Water Piping**		**4,606**	**1,175**		**$5,781**	**459**		**1,248**	**$7,488**	**12**
9.5	**Make-up Water System**	**301**		**427**		**$729**	**62**		**158**	**$949**	**2**
9.6	**Component Cooling Water Sys**	**544**	**650**	**459**		**$1,653**	**137**		**358**	**$2,148**	**3**
9.9	**Circ.Water System Foundations**		**1,564**	**2,678**		**$4,242**	**358**		**1,380**	**$5,981**	**10**
	SUBTOTAL 9.	**$6,318**	**$6,821**	**$5,729**		**$18,867**	**$1,553**		**$4,194**	**$24,614**	**$39**
10	ASH/SPENT SORBENT HANDLING SYS										
10.1	**Ash Coolers**	**16,165**		**7,978**		**$24,143**	**2,063**		**2,621**	**$28,826**	**46**
10.2	Cyclone Ash Letdown										
10.3	HGCU Ash Letdown										
10.4	High Temperature Ash Piping										
10.5	Other Ash Recovery Equipment										
10.6	**Ash Storage Silos**	**532**		**579**		**$1,111**	**96**		**181**	**$1,387**	**2**
10.7	**Ash Transport & Feed Equipment**	**718**		**172**		**$890**	**73**		**145**	**$1,108**	**2**
10.8	**Misc. Ash Handling Equipment**	**1,101**	**1,350**	**403**		**$2,854**	**242**		**464**	**$3,560**	**6**
10.9	**Ash/Spent Sorbent Foundation**		**47**	**59**		**$106**	**9**		**34**	**$149**	**0**
	SUBTOTAL 10.	**$18,516**	**$1,396**	**$9,191**		**$29,103**	**$2,482**		**$3,445**	**$35,031**	**$56**
11	ACCESSORY ELECTRIC PLANT										
11.1	**Generator Equipment**	**866**		**864**		**$1,730**	**147**		**188**	**$2,065**	**3**
11.2	**Station Service Equipment**	**4,122**		**387**		**$4,509**	**384**		**489**	**$5,381**	**9**
11.3	**Switchgear & Motor Control**	**7,876**		**1,444**		**$9,320**	**773**		**1,514**	**$11,608**	**19**
11.4	**Conduit & Cable Tray**		**3,748**	**12,166**		**$15,914**	**1,363**		**4,319**	**$21,596**	**35**
11.5	**Wire & Cable**		**6,883**	**4,630**		**$11,512**	**754**		**3,067**	**$15,333**	**25**
11.6	Protective Equipment		624	2,365		$2,989	262		488	$3,739	6
11.7	**Standby Equipment**	**208**		**211**		**$419**	**36**		**68**	**$524**	**1**
11.8	**Main Power Transformers**	**9,992**		**132**		**$10,124**	**687**		**1,622**	**$12,432**	**20**
11.9	**Electrical Foundations**		**142**	**376**		**$518**	**44**		**169**	**$730**	**1**
	SUBTOTAL 11.	**$23,064**	**$11,396**	**$22,575**		**$57,035**	**$4,450**		**$11,923**	**$73,409**	**$118**

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 4 -ConocoPhillips E-Gas Dual Train IGCC w CO2 Capture Ready
Plant Size: 623.4 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct		Equipment	Material	Labor		Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Cost $	H.O.& Fee	Process	Project	$	$/kW
12	INSTRUMENTATION & CONTROL										
12.1	PC Control Equipment	w/12.7		w/12.7							
12.2	Combustion Turbine Control	N/A		N/A							
12.3	Steam Turbine Control	w/8.1		w/8.1							
12.4	**Other Major Component Control**	**1,005**		**699**		**$1,705**	**147**	**85**	**291**	**$2,227**	**4**
12.5	Signal Processing Equipment	W/12.7		W/12.7							
12.6	**Control Boards,Panels & Racks**	**231**		**154**		**$385**	**33**	**19**	**88**	**$525**	**1**
12.7	**Computer & Accessories**	**5,362**		**179**		**$5,541**	**470**	**277**	**629**	**$6,918**	**11**
12.8	**Instrument Wiring & Tubing**		**1,906**	**3,990**		**$5,896**	**448**	**295**	**1,660**	**$8,299**	**13**
12.9	**Other I & C Equipment**	**3,584**		**1,813**		**$5,398**	**464**	**270**	**920**	**$7,052**	**11**
	SUBTOTAL 12.	**$10,183**	**$1,906**	**$6,836**		**$18,925**	**$1,562**	**$946**	**$3,586**	**$25,021**	**$40**
13	IMPROVEMENTS TO SITE										
13.1	**Site Preparation**		**101**	**2,167**		**$2,268**	**200**		**740**	**$3,209**	**5**
13.2	**Site Improvements**		**1,790**	**2,397**		**$4,187**	**368**		**1,367**	**$5,922**	**9**
13.3	**Site Facilities**	**3,208**		**3,410**		**$6,618**	**582**		**2,160**	**$9,360**	**15**
	SUBTOTAL 13.	**$3,208**	**$1,891**	**$7,974**		**$13,073**	**$1,151**		**$4,267**	**$18,490**	**$30**
14	BUILDINGS & STRUCTURES										
14.1	Boiler Building		221	127		$348	27		75	$451	1
14.2	**Turbine Building**		**2,058**	**2,971**		**$5,030**	**414**		**816**	**$6,260**	**10**
14.3	**Administration Building**		**814**	**598**		**$1,412**	**113**		**229**	**$1,753**	**3**
14.4	**Circulation Water Pumphouse**		**153**	**82**		**$235**	**18**		**38**	**$291**	**0**
14.5	**Water Treatment Buildings**		**427**	**423**		**$850**	**69**		**138**	**$1,057**	**2**
14.6	**Machine Shop**		**417**	**289**		**$705**	**56**		**114**	**$876**	**1**
14.7	**Warehouse**		**672**	**440**		**$1,112**	**88**		**180**	**$1,381**	**2**
14.8	**Other Buildings & Structures**		**403**	**318**		**$721**	**58**		**156**	**$934**	**1**
14.9	**Waste Treating Building & Str.**		**900**	**1,744**		**$2,644**	**220**		**573**	**$3,437**	**6**
	SUBTOTAL 14.		**$6,066**	**$6,992**		**$13,057**	**$1,063**		**$2,319**	**$16,439**	**$26**
	TOTAL COST	**$575,185**	**$61,009**	**$237,837**		**$874,031**	**$73,011**	**$45,760**	**$154,112**	**$1,146,914**	**$1,840**

CASE 6 (IGCC CR RETROFIT) – RETROFIT OF CASE 4 TO CAPTURE CO_2

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07
Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 6 -Retrofit of Capture Ready ConocoPhillips E-Gas Dual Train IGCC w CO2
Plant Size: 518.2 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct		Equipment	Material	Labor		Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Cost $	H.O.& Fee	Process	Project	$	$/kW
1	COAL HANDLING SYSTEM										
1.1	Coal Receive & Unload	3,493		1,725		$5,218	418		1,127	$6,764	13
1.2	Coal Stackout & Reclaim	4,514		1,106		$5,620	441		1,212	$7,274	14
1.3	Coal Conveyors & Yd Crush	4,197		1,094		$5,291	416		1,141	$6,849	13
1.4	Other Coal Handling	1,098		253		$1,351	106		291	$1,749	3
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		2,480	6,246		$8,726	745		1,894	$11,365	22
	SUBTOTAL 1.	**$13,303**	**$2,480**	**$10,424**		**$26,207**	**$2,127**		**$5,667**	**$34,000**	**$66**
2	COAL PREP & FEED SYSTEMS										
2.1	Coal Crushing & Drying										
2.2	Prepared Coal Storage & Feed	1,491	355	236		$2,082	160		448	$2,690	5
2.3	Slurry Prep & Feed	20,340		9,140		$29,480	2,356		6,367	$38,204	74
2.4	Misc.Coal Prep & Feed	820	593	1,807		$3,221	265		697	$4,182	8
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		3,197	2,644		$5,841	483		1,265	$7,588	15
	SUBTOTAL 2.	**$22,651**	**$4,146**	**$13,827**		**$40,624**	**$3,263**		**$8,777**	**$52,665**	**$102**
3	FEEDWATER & MISC. BOP SYSTEMS										
3.1	FeedwaterSystem	3,088	5,369	2,836		$11,293	934		2,445	$14,672	28
3.2	Water Makeup & Pretreating	537	56	300		$893	76		290	$1,259	2
3.3	Other Feedwater Subsystems	1,705	578	521		$2,804	225		606	$3,634	7
3.4	Service Water Systems	309	632	2,194		$3,135	272		1,022	$4,428	9
3.5	Other Boiler Plant Systems	1,662	638	1,582		$3,882	326		842	$5,050	10
3.6	FO Supply Sys & Nat Gas	299	565	527		$1,391	119		302	$1,812	3
3.7	Waste Treatment Equipment	746		457		$1,203	104		392	$1,700	3
3.8	Misc. Power Plant Equipment	1,024	138	531		$1,693	146		552	$2,390	5
	SUBTOTAL 3.	**$9,371**	**$7,975**	**$8,947**		**$26,292**	**$2,201**		**$6,451**	**$34,944**	**$67**

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07

Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 6 -Retrofit of Capture Ready ConocoPhillips E-Gas Dual Train IGCC w CO2

Plant Size: 518.2 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
4	GASIFIER & ACCESSORIES										
4.1	Gasifier, Syngas Cooler & Auxiliaries	93,113		57,142		$150,256	12,324	22,538	27,768	$212,885	411
4.2	Syngas Cooler (w/Gasifier - $)	w/4.1		w/4.1							
4.3a	ASU/Oxidant Compression	142,779		w/equip.		$142,779	12,175		15,495	$170,449	329
4.3b	ITM Oxygen System										
4.4	LT Heat Recovery & FG Saturation	24,864		9,355		$34,219	2,946		7,433	$44,598	86
4.5	Misc Gasification Equipment	w/4.1&4.2		w/4.1&4.2							
4.6	Other Gasifiction Equipment		1,157	471		$1,629	139		354	$2,121	4
4.8	Major Component Rigging	w/4.1&4.2		w/4.1&4.2							
4.9	Gasification Foundations		7,550	4,339		$11,889	972		3,215	$16,075	31
	SUBTOTAL 4.	**$260,756**	**$8,707**	**$71,307**		**$340,771**	**$28,555**	**$22,538**	**$54,265**	**$446,129**	**$861**
5A	GAS CLEANUP & PIPING										
5A.1	2nd Stage Selexol AGR	57,451		49,279		$106,730	9,179	21,346	27,451	$164,707	318
5A.2	Elemental Sulfur Plant	9,709	1,927	12,535		$24,170	2,088		5,252	$31,510	61
5A.3	Mercury Removal	1,531		1,166		$2,697	232	135	613	$3,676	7
5A.4	COS Hydrolysis	3,651		4,771		$8,422	728		1,830	$10,980	21
5A.5	**Shift Reactors**	**12,213**		**4,919**		**$17,133**	**1,461**		**3,719**	**$22,312**	**43**
5A.6	Blowback Gas Systems	410	230	130		$770	65		167	$1,002	2
5A.7	Fuel Gas Piping		1,150	793		$1,943	159		420	$2,522	5
5A.8	HGCU Foundations		1,138	739		$1,878	154		609	$2,641	5
	SUBTOTAL 5A.	**$84,964**	**$4,446**	**$74,333**		**$163,743**	**$14,066**	**$21,481**	**$40,061**	**$239,350**	**$462**
5B	CO2 REMOVAL & COMPRESSION										
5B.1	**CO2 Removal System**										
5B.2	**CO2 Compression & Drying**	**17,010**		**10,435**		**$27,445**	**2,351**		**5,959**	**$35,754**	**69**
	SUBTOTAL 5B.	**$17,010**		**$10,435**		**$27,445**	**$2,351**		**$5,959**	**$35,754**	**$69**
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	88,000		5,325		$93,325	7,865	9,333	11,052	$121,575	235
6.2	Combustion Turbine Accessories										
6.3	Compressed Air Piping										
6.9	Combustion Turbine Foundations		684	762		$1,446	121		470	$2,037	4
	SUBTOTAL 6.	**$88,000**	**$684**	**$6,087**		**$94,771**	**$7,986**	**$9,333**	**$11,522**	**$123,611**	**$239**
7	HRSG, DUCTING & STACK										
7.1	Heat Recovery Steam Generator	32,356		4,604		$36,960	3,125		4,009	$44,094	85
7.2	SCR System										
7.3	Ductwork		1,627	1,179		$2,806	221		605	$3,632	7
7.4	Stack	3,222		1,211		$4,433	378		481	$5,292	10
7.9	HRSG,Duct & Stack Foundations		641	620		$1,262	105		410	$1,777	3
	SUBTOTAL 7.	**$35,577**	**$2,268**	**$7,615**		**$45,461**	**$3,829**		**$5,505**	**$54,794**	**$106**

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07

Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 6 -Retrofit of Capture Ready ConocoPhillips E-Gas Dual Train IGCC w CO2

Plant Size: 518.2 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	25,224		4,105		$29,328	2,518		3,185	$35,030	68
8.2	Turbine Plant Auxiliaries	168		385		$553	48		60	$662	1
8.3	Condenser & Auxiliaries	4,112		1,235		$5,348	455		580	$6,382	12
8.4	Steam Piping	4,962		3,497		$8,459	647		2,276	$11,382	22
8.9	TG Foundations		828	1,409		$2,237	189		728	$3,154	6
	SUBTOTAL 8.	**$34,466**	**$828**	**$10,632**		**$45,926**	**$3,856**		**$6,829**	**$56,611**	**$109**
9	COOLING WATER SYSTEM										
9.1	Cooling Towers	4,081		897		$4,978	422		810	$6,210	12
9.2	Circulating Water Pumps	1,284		77		$1,361	104		220	$1,685	3
9.3	Circ.Water System Auxiliaries	108		15		$123	10		20	$154	0
9.4	Circ.Water Piping		4,606	1,175		$5,781	459		1,248	$7,488	14
9.5	Make-up Water System	301		427		$729	62		158	$949	2
9.6	Component Cooling Water Sys	544	650	459		$1,653	137		358	$2,148	4
9.9	Circ.Water System Foundations		1,564	2,678		$4,242	358		1,380	$5,981	12
	SUBTOTAL 9.	**$6,318**	**$6,821**	**$5,729**		**$18,867**	**$1,553**		**$4,194**	**$24,614**	**$47**
10	ASH/SPENT SORBENT HANDLING SYS										
10.1	Ash Coolers	16,165		7,978		$24,143	2,063		2,621	$28,826	56
10.2	Cyclone Ash Letdown										
10.3	HGCU Ash Letdown										
10.4	High Temperature Ash Piping										
10.5	Other Ash Recovery Equipment										
10.6	Ash Storage Silos	532		579		$1,111	96		181	$1,387	3
10.7	Ash Transport & Feed Equipment	718		172		$890	73		145	$1,108	2
10.8	Misc. Ash Handling Equipment	1,101	1,350	403		$2,854	242		464	$3,560	7
10.9	Ash/Spent Sorbent Foundation		47	59		$106	9		34	$149	0
	SUBTOTAL 10.	**$18,516**	**$1,396**	**$9,191**		**$29,103**	**$2,482**		**$3,445**	**$35,031**	**$68**
11	ACCESSORY ELECTRIC PLANT										
11.1	Generator Equipment	866		864		$1,730	147		188	$2,065	4
11.2	Station Service Equipment	4,122		387		$4,509	384		489	$5,381	10
11.3	Switchgear & Motor Control	7,876		1,444		$9,320	773		1,514	$11,608	22
11.4	Conduit & Cable Tray		3,748	12,166		$15,914	1,363		4,319	$21,596	42
11.5	Wire & Cable		6,883	4,630		$11,512	754		3,067	$15,333	30
11.6	Protective Equipment		624	2,365		$2,989	262		488	$3,739	7
11.7	Standby Equipment	208		211		$419	36		68	$524	1
11.8	Main Power Transformers	9,992		132		$10,124	687		1,622	$12,432	24
11.9	Electrical Foundations		142	376		$518	44		169	$730	1
	SUBTOTAL 11.	**$23,064**	**$11,396**	**$22,575**		**$57,035**	**$4,450**		**$11,923**	**$73,409**	**$142**

Client: U.S. DOE / NETL **Report Date:** 02-Sep-07

Project: Advanced CO2 Capture-Ready Power Plants

TOTAL PLANT COST DETAIL

Case: Case 6 -Retrofit of Capture Ready ConocoPhillips E-Gas Dual Train IGCC w CO2

Plant Size: 518.2 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2007 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
12	INSTRUMENTATION & CONTROL										
12.1	PC Control Equipment	w/12.7		w/12.7							
12.2	Combustion Turbine Control	N/A		N/A							
12.3	Steam Turbine Control	w/8.1		w/8.1							
12.4	Other Major Component Control	1,005		699		$1,705	147	85	291	$2,227	4
12.5	Signal Processing Equipment	W/12.7		W/12.7							
12.6	Control Boards,Panels & Racks	231		154		$385	33	19	88	$525	1
12.7	Computer & Accessories	5,362		179		$5,541	470	277	629	$6,918	13
12.8	Instrument Wiring & Tubing		1,906	3,990		$5,896	448	295	1,660	$8,299	16
12.9	Other I & C Equipment	3,584		1,813		$5,398	464	270	920	$7,052	14
	SUBTOTAL 12.	**$10,183**	**$1,906**	**$6,836**		**$18,925**	**$1,562**	**$946**	**$3,586**	**$25,021**	**$48**
13	IMPROVEMENTS TO SITE										
13.1	Site Preparation		101	2,167		$2,268	200		740	$3,209	6
13.2	Site Improvements		1,790	2,397		$4,187	368		1,367	$5,922	11
13.3	Site Facilities	3,208		3,410		$6,618	582		2,160	$9,360	18
	SUBTOTAL 13.	**$3,208**	**$1,891**	**$7,974**		**$13,073**	**$1,151**		**$4,267**	**$18,490**	**$36**
14	BUILDINGS & STRUCTURES										
14.1	Boiler Building		221	127		$348	27		75	$451	1
14.2	Turbine Building		2,058	2,971		$5,030	414		816	$6,260	12
14.3	Administration Building		814	598		$1,412	113		229	$1,753	3
14.4	Circulation Water Pumphouse		153	82		$235	18		38	$291	1
14.5	Water Treatment Buildings		427	423		$850	69		138	$1,057	2
14.6	Machine Shop		417	289		$705	56		114	$876	2
14.7	Warehouse		672	440		$1,112	88		180	$1,381	3
14.8	Other Buildings & Structures		403	318		$721	58		156	$934	2
14.9	Waste Treating Building & Str.		900	1,744		$2,644	220		573	$3,437	7
	SUBTOTAL 14.		**$6,066**	**$6,992**		**$13,057**	**$1,063**		**$2,319**	**$16,439**	**$32**
	TOTAL COST	**$627,389**	**$61,009**	**$272,902**		**$961,300**	**$80,494**	**$54,298**	**$174,770**	**$1,270,863**	**$2,452**

APPENDIX C – DISCOUNTED CASH FLOW (DCF) ANALYSIS OF CO_2 CAPTURE-READY POWER PLANTS

BACKGROUND

The results of the baseline economic analysis can be misleading because the time value of money associated with the cash flows that span the multi-year planning, construction, and startup period is not included in Total Plant Cost (TPC). Therefore, a Discounted Cash Flow (DCF) analysis was performed to assess a truer picture of the project economics. The objective of this analysis is to compare the power plant retrofit scenarios and determine the effect of retrofit timing on the cost of electricity for retrofit of conventional and capture-ready plants.

The study addresses two types of power plants - Pulverized Coal (PC) Supercritical units and Integrated Gasification Combined Cycle (IGCC) units. This DCF analysis addresses two different economic comparisons of power plants cases:

- Supercritical Pulverized Coal (SC PC) units, Cases 1 (PC BAU) & 7 (PC BAU Retrofit) versus Cases 3 (PC CR) & 5 (PC CR Retrofit).
- ConocoPhillips E-Gas™ Integrated Gasification Combined Cycle (IGCC) units, Cases 2 (IGCC BAU) & 8 (IGCC BAU Retrofit) versus Cases 4 (IGCC CR) & 6 (IGCC CR Retrofit).

METHODOLOGY

The results shown in the baseline study report are based on **overnight construction** for both the initial and retrofitted plants. Adding the retrofitted costs directly to the initial plant costs is economically equivalent to **instantaneously retrofitting** the initial plant. In reality, the retrofit installation could occur at anytime during the life of the plant. The year the retrofit occurs determines the impact on the average cost of electricity for the plant. Intuitively, the earlier the additional retrofitting costs and any associated derating occur, the higher the subsequent cost of electricity will be. But because of the varying value of money and commodities over time, the final impact of the additional costs and any associated derating may decrease depending on the specific type and magnitude of the costs.

This simplified DCF analysis approach assumes the base plant starts immediately and examines the impact of the retrofitting costs on the average Levelized Cost of Electricity (LCOE) for retrofits occurring in each of the next 20 years. Since the analysis is concentrated on comparing the costs of retrofitting operating plants, items such as planning and startup costs, working capital, and financing fees were not included in this simplified analysis.

The cost of electricity for each year was estimated based on the present worth values of the initial plant capital, operating costs, and performance and levelized over the first 20 years of operation. When the plant is retrofitted with capture, the present worth values of the costs of retrofitting and performance impacts are levelized over the next 20 year period and added to the base plant costs for each of the remaining years in the 20 year averaging period examined in this study. There is an implicit assumption that the operational life of the plant will exceed the 20 year levelization period assumed for the baseline plant and the additional 20 year levelization period assumed for the retrofitted project costs. This assumption is reasonable considering that it would not be economically feasible to retrofit a plant if the expected life of the plant was only a few additional years. No additional charges for extending the life of the plant were included in the study since this analysis is concentrated on comparing the costs of retrofitting within the first 20 years of operation and not the actual COE throughout the life of the plant.

The goal of this analysis is to determine the economics of retrofit timing for the different retrofit scenarios given that retrofit of all base plants is expected to occur within the first 20 years following the base plant's startup. This allows a comparison between the cost of electricity produced from a retrofitted conventional, business-as-usual (BAU-Retrofit) plant with that produced from a retrofitted plant pre-designed in anticipation of future CO_2 capture (Capture-Ready Retrofit). A comparative assessment is made by calculating the average LCOE over the first 20 years of each plant's operation versus the year of retrofit for the PC and IGCC cases. **It is important to note that no conclusions can be drawn regarding the overall LCOE because of the simplifying assumptions that excluded startup costs, working capital, financing fees, life extension, and other charges that were assumed to be similar and, therefore, would have no impact on the comparison.**

This analysis uses the same methodology as the baseline study report to determine the LCOE. The LCOE is the total annual levelized capital and production charges for the plant divided by the total MWh produced by the plant. LCOE is calculated as follows:

$$\text{LCOE} = \frac{(\text{Capital Cost x CCF + Operating Costs x } LF_{O\&M} \text{ +Fuel Costs x } LF_{Fuel})}{\text{Plant Capacity x CF x 8760}}$$

Where:

Capital Costs (January 2007 Dollars x 1000)
Operating Costs (annual 2007 Dollars x 1000)
Fuel Costs (annual 2007 Dollars x 1000)
CCF (Capital Charge Factor) is 0.164 for PC cases and 0.175 for the IGCC cases
$LF_{O\&M}$ (Operating and Maintenance Cost excluding Fuel Levelizing Factor) is 1.162 for PC cases and 1.157 for IGCC cases
LF_{Fuel} (Fuel Levelizing Factor) is 1.209 for PC cases and 1.202 for IGCC cases
Plant Capacity is in Megawatts
CF (Capacity Factor) is 85 % for PC plants and 80 % for IGCC plants

The present value (PV) in 2007 dollars has been determined for the capital and operating costs for each of the retrofit cases as a function of the year of retrofit. The present value for plant costs is calculated as below.

Present Value (2007 PV) = 2007 cost × escalation factor × discount factor

Where:

Escalation factor for year X is $(1 + \text{escalation rate})^{\text{Year X}}$
Discount factor is $1/(1+\text{discount rate})^{\text{Year X}}$

Capital costs are escalated at a rate of 1.87%. Fuel and non-fuel production costs are calculated/presented separately because the escalation rate is 2.35% for fuel and 1.87% for non-fuel production costs. The discount factor for PC base plants and their retrofitted plants is 0.0879 since they are deemed low risk. The discount factor for IGCC plants—both base plants and retrofitted plants—is assumed to be 0.0967 because they are deemed high risk cases.

Chart 1 and Chart 2 show the escalation factor, discount rate, and present values (PV) factors determined using the aforementioned economic assumptions. Note that as time goes further out into the future, the PV becomes smaller, even when escalation is taken into consideration. This normally means that dollars spent initially are more significant than dollars spent several years in the future.

ASSUMPTIONS

The following assumptions were used in this analysis:

- All costs are shown in January 2007 dollars
- 20 year book/economic life (levelization period) for base and retrofitted plants
- Capital and operating cost escalation rate of 1.87% per year compounded
- Coal escalation rate of 2.35% per year compounded
- All plants are assumed to operate at constant capacity factors (85% for PC and 80% for IGCC) throughout the period of study
- Retrofitting can be done without shutdown and tie-ins can be made during normally scheduled outages
- All retrofitting occurs at the end of the year in time for startup at the beginning of the next year. The initial plant starts full operation at the beginning of the first year (time zero) and the Year 1 retrofit occurs at the end of the first year for startup at the beginning of the second year. The Year 20 retrofit occurs at the end of the 20^{th} year for start-up at the beginning of the 21^{st} year
- The LCOE was calculated for all PC Cases (with and without CO_2 capture) using investor owned utility (IOU) low risk project economic factors
- The LCOE was calculated for all IGCC Cases (with and without CO_2 capture) using investor owned utility (IOU) high risk project economic factors
- The LCOE values for all Cases (PC and IGCC) exclude the cost of CO_2 transport, storage, and monitoring

Chart 1 - Present Value Calculations for Pulverized Coal Plant Cases

Chart 1 CARBON DIOXIDE CAPTURE READY COAL POWER PLANTS DCF STUDY 2/6/2008

Economic Assumptions and Calculations

Supercritical Pulverized Coal Plants

Assumptions: IOU Low Risk

Economic :Life:	20	Years
Capital Charge Factor	16.4	% for a 20-Year Levelization Period
Escalation Rate:	1.87%	per year Both Capital and O&M excluding fuel
Escalation Rate:	2.35%	per year Coal
Discount Rate:	0.0879	per year
Plant Capacity factor	85.0%	

Costs for Transportation, Storage, and Monitoring of CO_2 are not included in this DCF study

Capitalization		Percent	Rate
	Debt	50%	0.09
	Bonds	0%	0.05
	Equity	50%	0.12
	Total	100%	

Tax Effects		
	Federal	34%
	State	6%
	Property	-1%
	Insurance	-1%
	Net	38%

Year	Value	Escalation Factor	Discount Factor	Present Value Amount	Escalation Factor	Present Value Amount
0	1.000	1.000	1.000	1.000	1.000	1.000
1	1.000	1.019	0.919	0.936	1.023	0.941
2	1.000	1.038	0.845	0.877	1.048	0.885
3	1.000	1.057	0.777	0.821	1.072	0.833
4	1.000	1.077	0.714	0.769	1.097	0.783
5	1.000	1.097	0.656	0.720	1.123	0.737
6	1.000	1.118	0.603	0.674	1.149	0.693
7	1.000	1.138	0.554	0.631	1.176	0.652
8	1.000	1.160	0.510	0.591	1.204	0.614
9	1.000	1.181	0.468	0.553	1.232	0.577
10	1.000	1.204	0.431	0.518	1.261	0.543
11	1.000	1.226	0.396	0.485	1.291	0.511
12	1.000	1.249	0.364	0.454	1.321	0.481
13	1.000	1.272	0.334	0.426	1.352	0.452
14	1.000	1.296	0.307	0.398	1.384	0.425
15	1.000	1.320	0.283	0.373	1.416	0.400
16	1.000	1.345	0.260	0.349	1.450	0.377
17	1.000	1.370	0.239	0.327	1.484	0.354
18	1.000	1.396	0.219	0.306	1.519	0.333
19	1.000	1.422	0.202	0.287	1.554	0.314
20	1.000	1.449	0.185	0.269	1.591	0.295
				11.767		12.201
Levelizing Factor		1.162			1.209	

Chart 2 - Present Value Calculations for IGCC Plant Cases

Chart 2 CARBON DIOXIDE CAPTURE READY COAL POWER PLANTS DCF STUDY 2/12/2008

Economic Assumptions and Calculations

Integrated Coal Gasification Combined Cycle Plants

Assumptions: IOU High Risk

Economic :Life:	20	Years	
Capital Charge Factor	**17.5**	% for a 20-Year Levelization Period	
Escalation Rate:	1.87%	per year	Both Capital and O&M excluding fuel
Escalation Rate:	2.35%	per year	Coal
Discount Rate:	0.0967	per year	
Plant Capacity factor	80.0%		

Costs for Transportation, Storage, and Monitoring of CO_2 are not included in this DCF study

Capitalization		Percent	Rate
	Debt	45%	0.11
	Bonds	0%	0.05
	Equity	55%	0.12
	Total	100%	

Tax Effects		
	Federal	34%
	State	6%
	Property	-1%
	Insurance	-1%
	Net	38%

Year	Value	Escalation Factor	Discount Factor	Present Value Amount	Escalation Factor	Present Value Amount
0	1.000	1.000	1.000	1.000	1.000	1.000
1	1.000	1.019	0.912	0.929	1.023	0.933
2	1.000	1.038	0.831	0.863	1.048	0.871
3	1.000	1.057	0.758	0.801	1.072	0.813
4	1.000	1.077	0.691	0.744	1.097	0.759
5	1.000	1.097	0.630	0.692	1.123	0.708
6	1.000	1.118	0.575	0.642	1.149	0.661
7	1.000	1.138	0.524	0.597	1.176	0.617
8	1.000	1.160	0.478	0.554	1.204	0.575
9	1.000	1.181	0.436	0.515	1.232	0.537
10	1.000	1.204	0.397	0.478	1.261	0.501
11	1.000	1.226	0.362	0.444	1.291	0.468
12	1.000	1.249	0.330	0.413	1.321	0.436
13	1.000	1.272	0.301	0.383	1.352	0.407
14	1.000	1.296	0.275	0.356	1.384	0.380
15	1.000	1.320	0.250	0.331	1.416	0.355
16	1.000	1.345	0.228	0.307	1.450	0.331
17	1.000	1.370	0.208	0.285	1.484	0.309
18	1.000	1.396	0.190	0.265	1.519	0.288
19	1.000	1.422	0.173	0.246	1.554	0.269
20	1.000	1.449	0.158	0.229	1.591	0.251
				11.075		11.469
Levelizing Factor		1.157			1.202	

PULVERIZED COAL PLANT ECONOMICS

Chart 3 shows the capital costs for the base PC BAU and PC Capture-Ready plants, as well as the additional capital required to retrofit the plant for CO_2 capture. The PV capital costs were determined for the retrofit plant as a function of time for the first 20 years of plant operation. The PV (2007$) capital cost of the retrofit is calculated by adding the **initial plant capital cost** (Case 1—PC BAU and 3—PC CR) to the **present values of the additional retrofit costs** for Case 7—PC BAU retrofit and 5—PC CR retrofit. All values are presented in 2007 dollars. The PV of the retrofit plant capital cost is graphed versus the year of retrofit. The retrofit PC plant capital costs in dollars per kilowatt ($/kW) of net electrical capacity (retrofit plant capacity) versus the year of retrofit is presented in Chart 4.

Chart 5 shows the PC base plants' operating costs for fuel and non-fuel components, as well as the additional operating costs associated with the retrofit to make the plants CO_2 capture capable. The PV annual operating costs were determined for the fuel and non-fuel production costs for the retrofit plants as a function of retrofit year for the first 20 years of plant operation. These values were calculated by escalating the after-retrofit costs into the future and then discounting them as described previously. Tables and graphs are presented showing the fuel and non-fuel operating costs for the retrofit plants versus year of retrofit.

Chart 6 shows the levelized cost of electricity (LCOE) for retrofit PC plants as a function of the year of retrofit. The LCOE decreases as the year of retrofit increases because of the time value of money.

The cost of electricity for each of the first 20 years of operation was calculated for retrofit of both PC plants. An example of the calculation method for one year (retrofit occurring in year 10) is presented in Chart 7. For each year prior to retrofit, the LCOE equals the base plant costs levelized over a 20 year time period (summing the levelized capital and operating costs and dividing by the plant net annual output). After retrofitting, the LCOE is increased due to the additional capital and operating expenses and plant derating. The 20-year average LCOE for retrofit in year 10 is calculated by summing the levelized capital and O&M costs over the 20 year period and dividing by the total megawatthours generated during the 20 year period. This method is repeated for each possible year of retrofit. Chart 8 is a summary of the 20-year averages based on the year of retrofit to CO_2 capture. The 20-year average LCOEs are graphed to display the trends for the two retrofit scenarios.

Analysis of Chart 8 reveals that if retrofit to CO_2 capture is desired or required in the early years following the startup of the base plants, the CO_2 capture-ready plant (Cases 3/5) will produce lower cost electricity than the business-as-usual plant (Cases 1/7). The cost advantage in the early years of operation for the capture-ready plant is directly attributable to the sharp decrease in net electrical output of the business-as-usual plant when retrofitted (31% reduction or 1,274,000 MWh per year).

Conclusion: If retrofit to CO_2 capture is required or desired before 10 years from the date of plant completion, then the PC Capture-ready plant is more economical.

Chart 3 - PC Plant Capital Costs

Chart 3 **CARBON DIOXIDE CAPTURE READY COAL POWER PLANTS DCF STUDY** 2/6/2008

Present Value of SC PC Capital Costs

Pulverized Coal Plants

			MW	Jan 2007 1000$
	Case 1	Business-as-usual SC PC Plant	550.15	$866,391
	Δ Case 7	Business-as-usual Retrofit for CO_2 Capture	-171.15	$598,509
1+Δ7		Combined =	379	$1,464,901
	Case 3	Capture-ready SC PC Plant	550.15	$1,110,786
	Δ Case 5	Capture-ready Retrofit for CO_2 Capture	-4.155	$457,287
3+Δ5		Combined=	545.995	$1,568,073

Initial Cost Difference Case 3 over Case 1 = $244,395

Retrofit Cost Difference Δ Case 5 over Δ Case 7 = $141,223

Present Value Analysis of Capital Costs for Retrofitted Startup at End of Year. (millions of 2007 dollars)

	Cases 1+Δ7	Cases 3+Δ5	
Year	P.V. 1+Δ7	P.V. 3+Δ5	
0	1,465	1,568	Initial Plant Startup - Time Zero
1	1,427	1,539	
2	1,391	1,512	
3	1,358	1,486	
4	1,327	1,462	
5	1,297	1,440	
6	1,270	1,419	
7	1,244	1,399	
8	1,220	1,381	
9	1,198	1,364	
10	1,177	1,348	
11	1,157	1,333	
12	1,138	1,319	
13	1,121	1,305	
14	1,105	1,293	
15	1,090	1,281	
16	1,076	1,271	
17	1,062	1,260	
18	1,050	1,251	
19	1,038	1,242	
20	1,027	1,234	

Example:		
Year 1	$866,391	Case 1
	$598,509	Δ Case 7
	0.936	PV Factor
	$560,439	PV Δ Case 7
	$1,426,830	PV Cases 1+Δ7

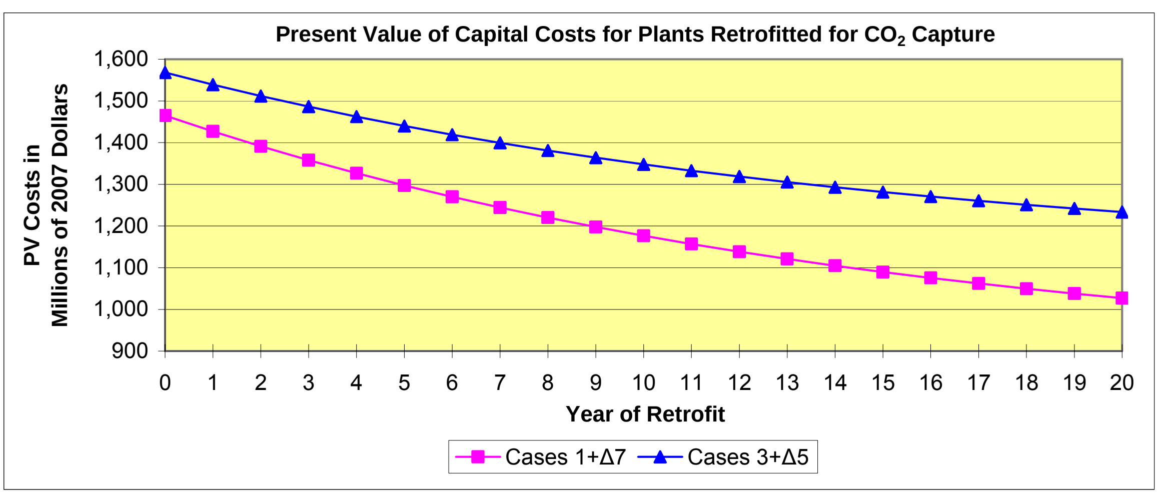


Chart 4 - PC Plant Capital Costs ($/kW)

Chart 4 **CARBON DIOXIDE CAPTURE READY COAL POWER PLANTS DCF STUDY** 2/6/2008

Present Value of SC PC Capital Costs per kW

Pulverized Coal Plants

			MW	Jan 2007 1000$	$/kW
Case 1	Business-as-usual SC PC Plant		550.2	$866,391	$1,575
Δ Case 7	Business-as-usual Retrofit for CO2 Capture		-171.2	$598,509	
		Combined =	379.0	$1,464,901	$3,865
Case 3	Capture-ready SC PC Plant		550.2	$1,110,786	$2,019
Δ Case 5	Capture-ready Retrofit for CO2 Capture		-4.2	$457,287	
		Combined=	546.0	$1,568,073	$2,872

Present Value Analysis of Capital Costs for Retrofitted Startup at End of Year. (2007 $/kW 2007)

Year	Cases 1+Δ7 P.V. 1+Δ7	Cases 3+Δ5 P.V. 3+Δ5	
0	3,865	2,872	Initial Plant Startup - Time Zero
1	3,765	2,819	
2	3,671	2,769	
3	3,583	2,722	
4	3,500	2,678	
5	3,423	2,637	
6	3,351	2,599	
7	3,283	2,563	
8	3,219	2,529	
9	3,160	2,498	
10	3,104	2,469	
11	3,052	2,441	
12	3,004	2,415	
13	2,958	2,391	
14	2,915	2,368	
15	2,875	2,347	
16	2,838	2,327	
17	2,803	2,308	
18	2,770	2,291	
19	2,739	2,275	
20	2,710	2,259	

Example:		
Year 1	$866,391	Case 1
	$598,509	Δ Case 7
	0.936	PV Factor
	$560,439	PV Δ Case 7
	$1,426,830	PV Cases 1+Δ7
	379	MW
	$3,765	$/kW

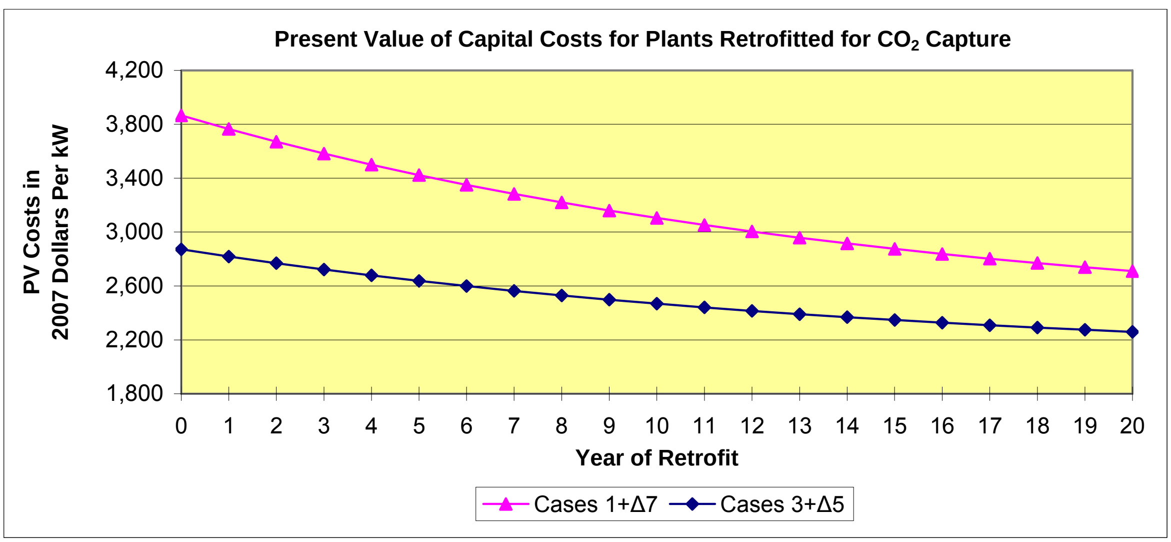


Chart 5 - PC Plant Production Costs

Chart 5 **CARBON DIOXIDE CAPTURE READY COAL POWER PLANTS DCF STUDY** 2/6/2008

Present Value of SC PC Production Costs

				MW	Jan 2007 1000$
Pulverized Coal Plants					
	Case 1	Business-as-usual SC PC Plant		550.15	
			Operating & Maintenance=		$22,575
			Consumables=		$11,225
			By-Product Credits=		$0
			Fuel Costs=		$64,479
			Subtotal Production=		$98,279
	Δ Case 7	Business-as-usual Retrofit for CO2 Capture		-171.15	
			Operating & Maintenance=		$11,613
			Consumables=		$5,897
			By-Product Credits=		$0
			Fuel Costs=		$0
			Subtotal Production=		$17,510
			Combined =	379	$115,789
	Case 3	Capture-ready SC PC Plant		550.15	
			Operating & Maintenance=		$22,573
			Consumables=		$11,225
			By-Product Credits=		$0
			Fuel Costs=		$64,479
			Subtotal Production=		$98,277
	Δ Case 5	Capture-ready Retrofit for CO2 Capture		-4.155	
			Operating & Maintenance=		$13,347
			Consumables=		$9,775
			By-Product Credits=		$0
			Fuel Costs=		$27,490
			Subtotal Production=		$50,612
			Combined =	545.995	$148,889

Production Cost Difference Case 3 over Case 1	-$2
Retrofit Cost Difference Δ Case 5 over Δ Case 7	-$33,102
Total Production Cost Difference Case 1+Δ7 over 3+Δ5	-$33,099

Present Value Analysis of Production Costs for Retrofitted Startup at End of Year. (millions of 2007 dollars)

Present Value Analysis of Production Costs

	Cases 1+Δ7	Cases 3+Δ5
Year	P.V. 1+Δ7	P.V. 3+Δ5
0	51.3	56.9
1	48.0	53.3
2	45.0	49.9
3	42.1	46.7
4	39.4	43.8
5	36.9	41.0
6	34.6	38.4
7	32.4	35.9
8	30.3	33.6
9	28.4	31.5
10	26.6	29.5
11	24.9	27.6
12	23.3	25.9
13	21.8	24.2
14	20.4	22.7
15	19.1	21.2
16	17.9	19.9
17	16.8	18.6
18	15.7	17.4
19	14.7	16.3
20	13.8	15.3

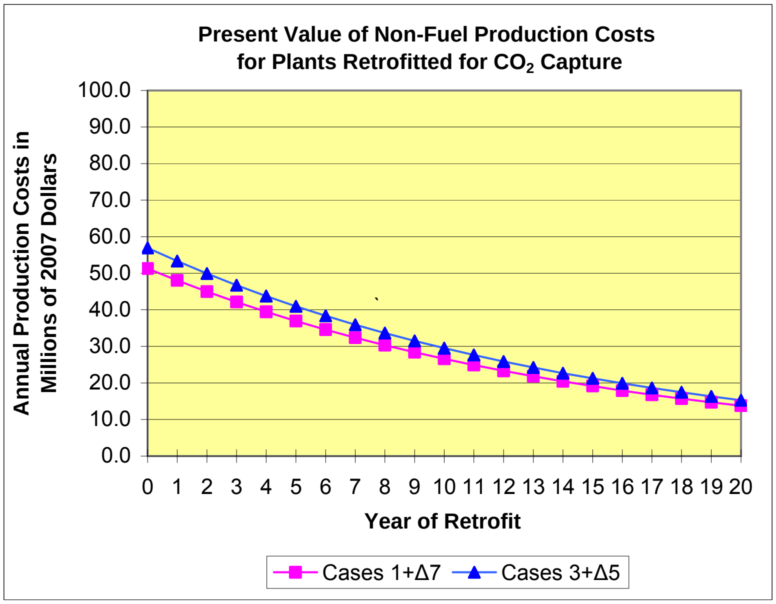


Chart 5 - PC Plant Production Costs continued

Chart 5 continued 2/6/2008

CARBON DIOXIDE CAPTURE READY COAL POWER PLANTS DCF STUDY

Present Value of SC PC Production Costs continued

Present Value Analysis of Production Costs for Retrofitted Startup at End of Year. (millions of 2007 dollars)

Present Value Analysis of Fuel Costs

	Cases 1+Δ7	Cases 3+Δ5
Year	P.V. 1+Δ7	P.V. 3+Δ5
0	64.5	92.0
1	60.7	86.5
2	57.1	81.4
3	53.7	76.6
4	50.5	72.0
5	47.5	67.8
6	44.7	63.8
7	42.1	60.0
8	39.6	56.4
9	37.2	53.1
10	35.0	50.0
11	32.9	47.0
12	31.0	44.2
13	29.2	41.6
14	27.4	39.1
15	25.8	36.8
16	24.3	34.6
17	22.8	32.6
18	21.5	30.7
19	20.2	28.8
20	19.0	27.1

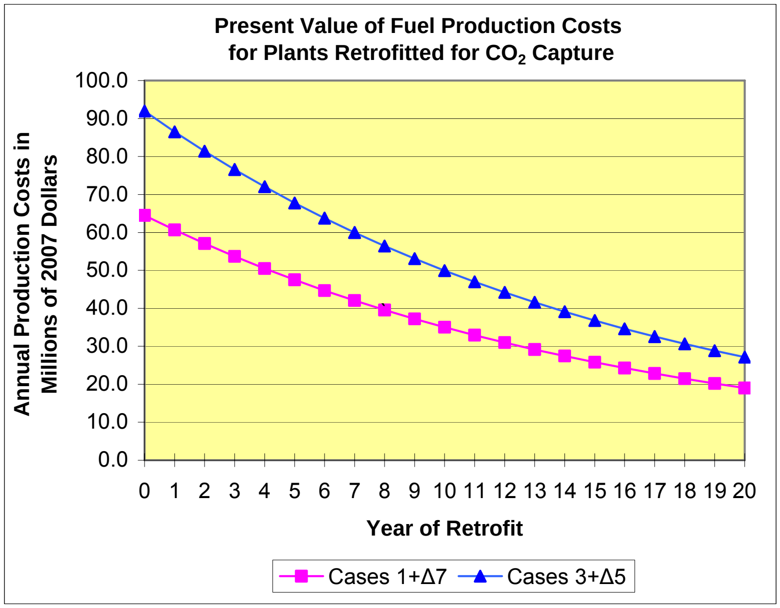


Chart 6 - PC Plant Levelized Cost of Electricity (LCOE)

Chart 6 **CARBON DIOXIDE CAPTURE READY COAL POWER PLANTS DCF STUDY** 2/6/2008

20 Year Levelized Cost of SC PC Electricity (COE)

				MW	Jan 2007 1000$
Pulverized Coal Plants					
	Case 1	Business-as-usual SC PC Plant		550.15	
			Capital Cost		$866,391
			Non Fuel Production Cost		$33,800 per year
			Fuel Production Cost		$64,479 per year
	Δ Case 7	Business-as-usual Retrofit for CO2 Capture		-171.15	
			Capital Cost		$598,509
			Non Fuel Production Cost		$17,510 per year
			Fuel Production Cost		$0 per year
	Case 3	Capture-ready SC PC Plant		550.15	
			Capital Cost		$1,110,786
			Non Fuel Production Cost		$33,798 per year
			Fuel Production Cost		$64,479 per year
	Δ Case 5	Capture-ready Retrofit for CO2 Capture		-4.155	
			Capital Cost		$457,287
			Non Fuel Production Cost		$23,122 per year
			Fuel Production Cost		$27,490 per year

Capital Charge Factor= 0.164
20 Year General Levelizing Factor = 1.162
20 Year Fuel Levelizing Factor = 1.209

Production Cases 1+Δ7 = 2,822,034 MWh
Cases 3+Δ5 = 4,065,479 MWh

Levelized Cost of Electricity (COE)

	Cases 1+Δ7	Cases 3+Δ5
Year	P.V. 1+Δ7	P.V. 3+Δ5
0	0.1339	0.1069
1	0.1287	0.1030
2	0.1238	0.0994
3	0.1192	0.0961
4	0.1150	0.0929
5	0.1110	0.0900
6	0.1072	0.0872
7	0.1037	0.0846
8	0.1003	0.0821
9	0.0972	0.0798
10	0.0943	0.0777
11	0.0916	0.0756
12	0.0890	0.0737
13	0.0866	0.0719
14	0.0844	0.0703
15	0.0823	0.0687
16	0.0803	0.0672
17	0.0784	0.0659
18	0.0767	0.0646
19	0.0750	0.0633
20	0.0735	0.0622

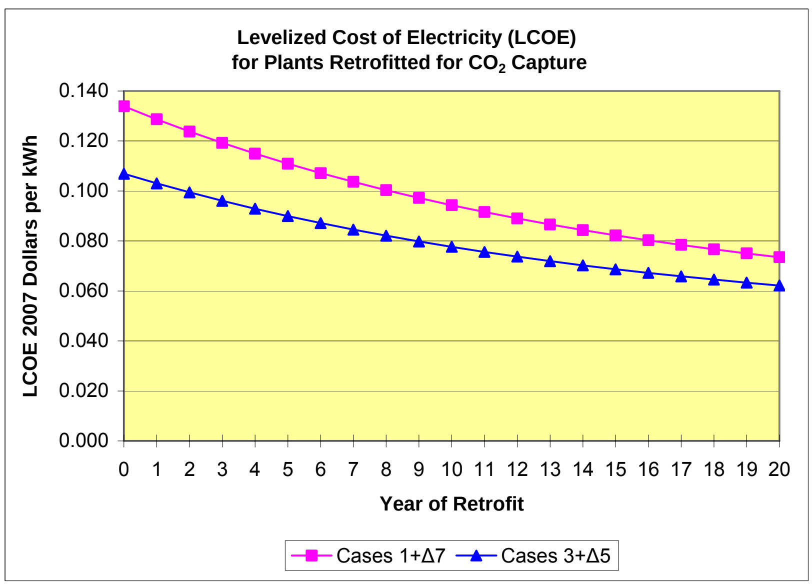


Chart 7 - Example 20-Year Average LCOE Calculation for PC Plant

Chart 7 **CARBON DIOXIDE CAPTURE READY COAL POWER PLANTS DCF STUDY** 2/6/2008

2007 Cost of Electricity (COE) By Year of Operation

Pulverized Coal Plants				Jan 2007 1000$	
Case 1	Business-as-usual SC PC Plant		550 MW		
		Capital Cost		$866,391	
		Production Cost		$33,800	per year
		Fuel Cost		$64,479	per year
Δ Case 7	Business-as-usual Retrofit for CO2 Capture		-171 MW		
		Capital Cost		$598,509	
		Production Cost		$17,510	per year
		Fuel Cost		$0	per year
Case 3	Capture-ready SC PC Plant		550 MW		
		Capital Cost		$1,110,786	
		Production Cost		$33,798	per year
		Fuel Cost		$64,479	per year
Δ Case 5	Capture-ready Retrofit for CO2 Capture		-4 MW		
		Capital Cost		$457,287	
		Production Cost		$23,122	per year
		Fuel Cost		$27,490	per year
	Capital Charge Factor=	0.1640	Retrofit at End of Year =	10	
	20 Year General Levelizing Factor =	1.1619	General PV Factor=	0.5183	
	20 Year Fuel Levelizing Factor =	1.2087	Fuel PV Factor=	0.5431	
Production	Case 1 =	4,096,417 MWh	Cases 1+Δ7 =	2,822,034 MWh	
	Case 3 =	4,096,417 MWh	Cases 3+Δ5 =	4,065,479 MWh	

Cases 1+Δ7					Cases 3+Δ5			
Levelized Cap. Chrgs	Levelized PV Prod	Annual Prod MWh	Levelized COE	Year of Retrofit	Levelized Cap. Chrgs	Levelized PV Prod	Annual Prod MWh	Levelized COE
142,088	117,208	4,096,417	0.0633	0	182,169	117,206	4,096,417	0.0731
142,088	117,208	4,096,417	0.0633	1	182,169	117,206	4,096,417	0.0731
142,088	117,208	4,096,417	0.0633	2	182,169	117,206	4,096,417	0.0731
142,088	117,208	4,096,417	0.0633	3	182,169	117,206	4,096,417	0.0731
142,088	117,208	4,096,417	0.0633	4	182,169	117,206	4,096,417	0.0731
142,088	117,208	4,096,417	0.0633	5	182,169	117,206	4,096,417	0.0731
142,088	117,208	4,096,417	0.0633	6	182,169	117,206	4,096,417	0.0731
142,088	117,208	4,096,417	0.0633	7	182,169	117,206	4,096,417	0.0731
142,088	117,208	4,096,417	0.0633	8	182,169	117,206	4,096,417	0.0731
142,088	117,208	4,096,417	0.0633	9	182,169	117,206	4,096,417	0.0731
142,088	117,208	4,096,417	0.0633	10	182,169	117,206	4,096,417	0.0731
192,961	73,229	2,822,034	0.0943	11	221,038	94,654	4,065,479	0.0777
192,961	73,229	2,822,034	0.0943	12	221,038	94,654	4,065,479	0.0777
192,961	73,229	2,822,034	0.0943	13	221,038	94,654	4,065,479	0.0777
192,961	73,229	2,822,034	0.0943	14	221,038	94,654	4,065,479	0.0777
192,961	73,229	2,822,034	0.0943	15	221,038	94,654	4,065,479	0.0777
192,961	73,229	2,822,034	0.0943	16	221,038	94,654	4,065,479	0.0777
192,961	73,229	2,822,034	0.0943	17	221,038	94,654	4,065,479	0.0777
192,961	73,229	2,822,034	0.0943	18	221,038	94,654	4,065,479	0.0777
192,961	73,229	2,822,034	0.0943	19	221,038	94,654	4,065,479	0.0777
192,961	73,229	2,822,034	0.0943	20	221,038	94,654	4,065,479	0.0777
3,350,496	1,904,366	69,184,509	0.0760	Year 1 through 20	4,032,072	2,118,592	81,618,957	0.0754
	5,254,861					6,150,664		

Months Penalty for Retrofitting Case 1 = 0

In above table 0 = Startup at Time Zero, 1=First Operating Year, 20 =20th Operating Year, Totals do not include Time Zero Values

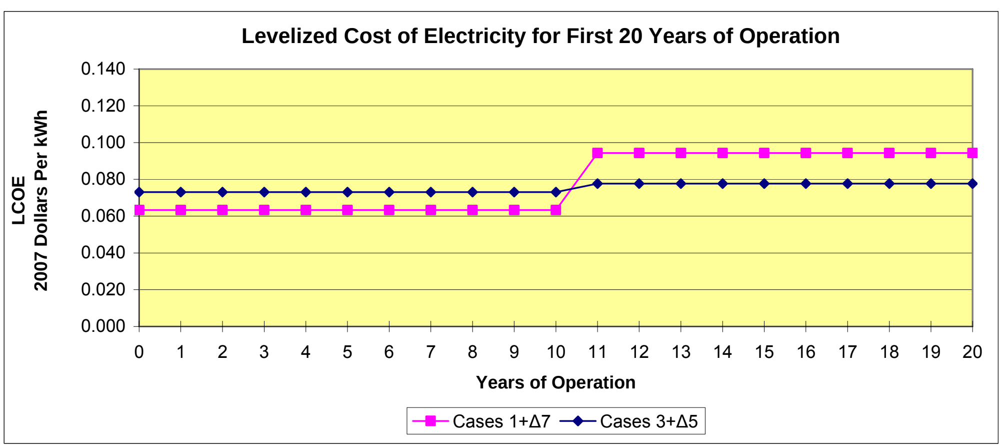
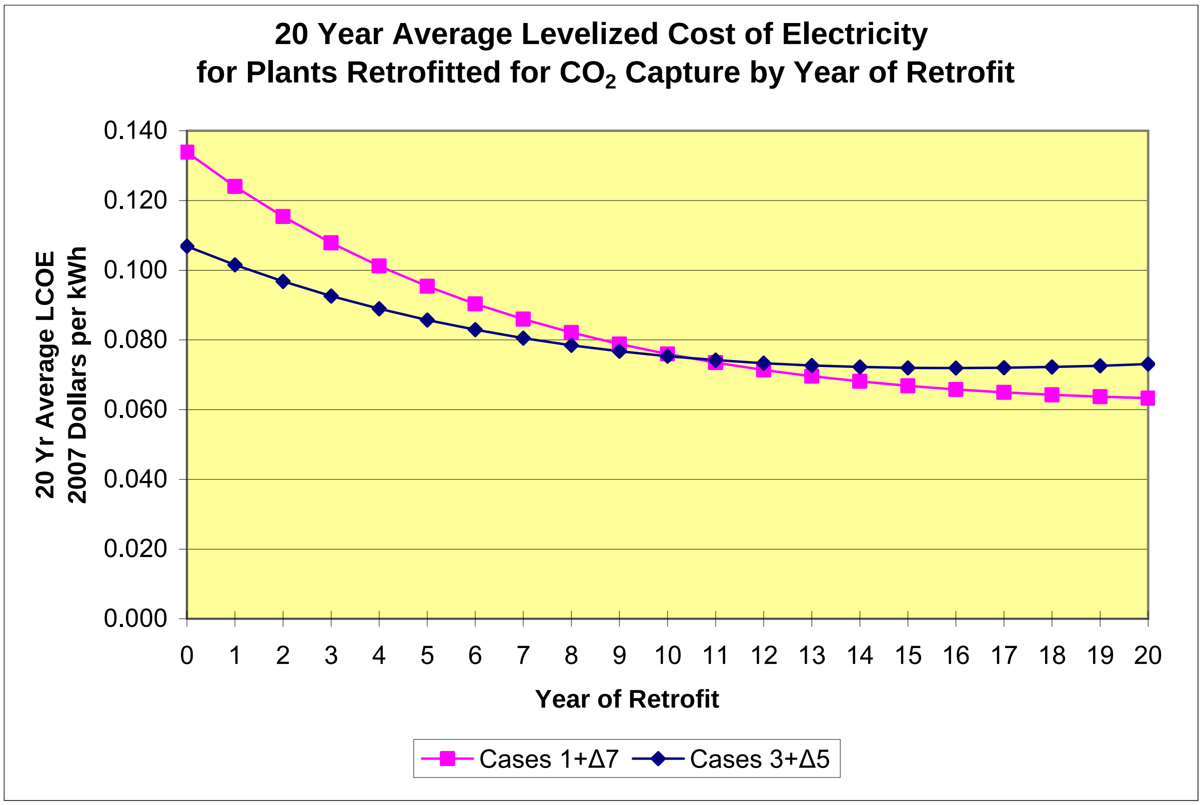


Chart 8 - 20-Year Average LCOE for PC Plants

Chart 8 — CARBON DIOXIDE CAPTURE READY COAL POWER PLANTS DCF STUDY — 2/6/2008

20 Year Average 2007 LCOE for SC PC by Year of Retrofit

Retrofit Year	Cases 1+Δ7	Cases 3+Δ5	Cases Diff
0	0.1339	0.1069	0.0270
1	0.1240	0.1015	0.0225
2	0.1154	0.0968	0.0186
3	0.1078	0.0926	0.0152
4	0.1012	0.0889	0.0123
5	0.0954	0.0857	0.0097
6	0.0904	0.0829	0.0074
7	0.0860	0.0805	0.0054
8	0.0821	0.0785	0.0036
9	0.0788	0.0768	0.0020
10	0.0760	0.0754	0.0006
11	0.0735	0.0742	-0.0007
12	0.0714	0.0733	-0.0019
13	0.0696	0.0727	-0.0031
14	0.0681	0.0722	-0.0041
15	0.0668	0.0720	-0.0052
16	0.0658	0.0719	-0.0061
17	0.0649	0.0720	-0.0071
18	0.0642	0.0722	-0.0080
19	0.0637	0.0726	-0.0089
20	0.0633	0.0731	-0.0098



INTEGRATED GASIFICATION COMBINED CYCLE PLANT ECONOMICS

Chart 9 shows the capital costs for the base IGCC BAU and IGCC Capture-Ready plants, as well as the additional capital required to retrofit the plant for CO_2 capture. The PV capital costs were determined for the retrofit plant as a function of time for the first 20 years of plant operation. The PV (2007$) capital cost of the retrofit is calculated by adding the capital cost of the initial plant Cases 2 (IGCC BAU) and 4 (IGCC CR) to t**he present values of the additional costs of retrofitting** to Cases 8 (IGCC BAU retrofit) and 6 (IGCC CR retrofit). All values are presented in 2007 dollars. The PV of the retrofit plant capital cost is graphed versus the year of retrofit. The retrofit IGCC plant capital costs in dollars per kilowatt ($/kW) of net electrical capacity (retrofit plant capacity) versus the year of retrofit is presented in Chart 10.

Chart 11 shows the IGCC base plants' operating costs for fuel and non-fuel components, as well as the additional operating costs associated with the retrofit to make the plants CO_2 capture capable. The PV annual operating costs were determined for the fuel and non-fuel production costs for the retrofit plants as a function of retrofit year for the first 20 years of plant operation. These values were calculated by escalating the after-retrofit costs into the future and then discounting them as described previously. Tables and graphs are presented showing the fuel and non-fuel operating costs for the retrofit plants versus year of retrofit.

Chart 12 shows the levelized cost of electricity (LCOE) for retrofit IGCC plants as a function of the year of retrofit. The LCOE decreases as the year of retrofit increases because of the time value of money.

The cost of electricity for each of the first 20 years of operation was calculated for retrofit of both IGCC plants. An example of the calculation method for one year (retrofit occurring in year 10) is presented in Chart 13. For each year prior to retrofit, the LCOE equals the base plant costs levelized over a 20 year time period (summing the levelized capital and operating costs and dividing by the plant net annual output). After retrofitting, the LCOE is increased due to the additional capital and operating expenses and plant derating. The 20-year average LCOE for retrofit in year 10 is calculated by summing the levelized capital and O&M costs over the 20 year period and dividing by the total MWhs generated during the 20 year period. This method is repeated for each possible year of retrofit. Chart 14 is a summary of all the 20-year averages based on the year of retrofit to CO_2 capture. The 20-year average LCOEs are graphed to display the trends for the two retrofit scenarios.

Analysis of Chart 14 reveals that if retrofit to CO_2 capture is desired or required in the early years following the startup of the base plants, the CO_2 capture-ready plant (Cases 4/6) will produce lower cost electricity than the business-as-usual plant (Cases 2/8). The cost difference between the capture-ready and BAU retrofit IGCC plants is not as dramatic as for the PC plants and this is due primarily to similar penalties for net output for the two retrofit IGCC plants.

Conclusion: If retrofit to CO_2 capture is required or desired before 8 years from the date of plant completion, there is limited economic advantage in using the IGCC Capture-ready plant design. Since the capital costs, operating costs, and net plant capacity are similar for the BAU and capture-ready designs, the LCOE's are similar.

Chart 9 - IGCC Plant Capital Costs

Chart 9 — **CARBON DIOXIDE CAPTURE READY COAL POWER PLANTS DCF STUDY** — 2/12/2008

Present Value of IGCC Capital Costs

IGCC Plants

			MW	Jan 2007 1000$
	Case 2	Business-as-usual IGCC Plant	623.37	$1,080,166
	Δ Case 8	Business-as-usual Retrofit for CO2 Capture	-123.04	$237,785
2+Δ8		Combined =	500.33	$1,317,951
	Case 4	Capture-ready IGCC Plant	623.37	$1,146,914
	Δ Case 6	Capture-ready Retrofit for CO2 Capture	-105.13	$123,949
4+Δ6		Combined=	518.24	$1,270,863

Initial Cost Difference Case 4 over Case 2 = $66,748

Retrofit Cost Difference Δ Case 6 over Δ Case 8 = $113,836

Present Value Analysis of Capital Costs for Retrofitted Startup at End of Year. (millions of 2007 dollars)

Year	Cases 2+Δ8 P.V. 2+Δ8	Cases 4+Δ6 P.V. 4+Δ6	
0	1,318	1,271	Initial Plant Startup - Time Zero
1	1,301	1,262	
2	1,285	1,254	
3	1,271	1,246	
4	1,257	1,239	
5	1,245	1,233	
6	1,233	1,227	
7	1,222	1,221	
8	1,212	1,216	
9	1,203	1,211	
10	1,194	1,206	
11	1,186	1,202	
12	1,178	1,198	
13	1,171	1,194	
14	1,165	1,191	
15	1,159	1,188	
16	1,153	1,185	
17	1,148	1,182	
18	1,143	1,180	
19	1,139	1,177	
20	1,135	1,175	

Example:		
Year 1	$1,080,166	Case 2
	$237,785	Δ Case 8
	0.929	PV Factor
	$220,875	PV Δ Case 8
	$1,301,042	PV Cases 2+Δ8

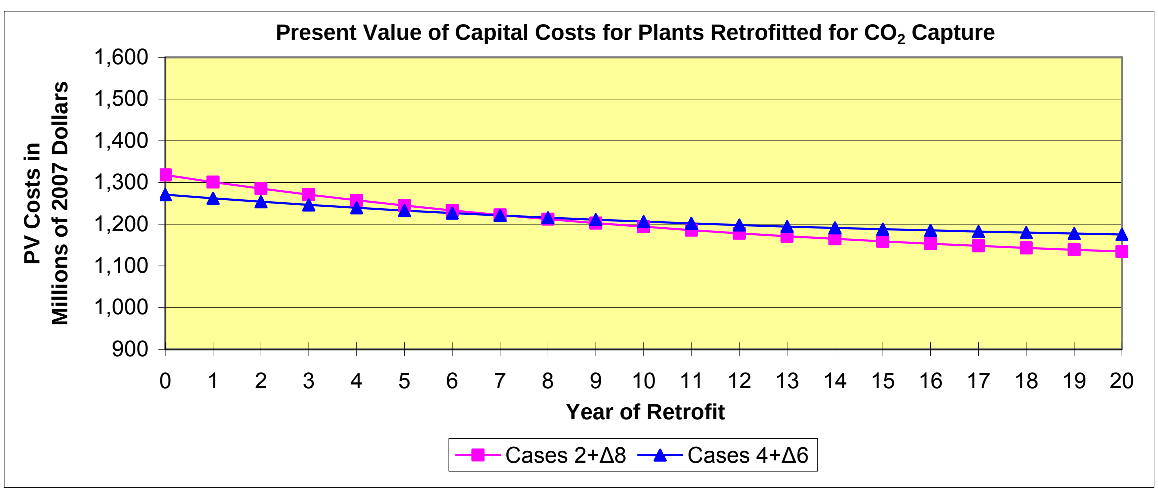


Chart 10 - IGCC Plant Capital Costs ($/kW)

Chart 10 **CARBON DIOXIDE CAPTURE READY COAL POWER PLANTS DCF STUDY** 2/12/2008

Present Value of IGCC Capital Costs per kW

IGCC Plants

		MW	Jan 2007 1000$	$/kW
Case 2	Business-as-usual IGCC Plant	623.4	$1,080,166	$1,733
Δ Case 8	Business-as-usual Retrofit for CO2 Capture	-123.0	$237,785	
	Combined =	500.3	$1,317,951	$2,634
Case 4	Capture-ready IGCC Plant	623.4	$1,146,914	$1,840
Δ Case 6	Capture-ready Retrofit for CO2 Capture	-105.1	$123,949	
	Combined=	518.2	$1,270,863	$2,452

Present Value Analysis of Capital Costs for Retrofitted Startup at End of Year. (2007 $/kW 2007)

Year	Cases 2+Δ8 P.V. 2+Δ8	Cases 4+Δ6 P.V. 4+Δ6	
0	2,634	2,452	Initial Plant Startup - Time Zero
1	2,600	2,435	
2	2,569	2,419	
3	2,540	2,405	
4	2,513	2,391	
5	2,488	2,378	
6	2,464	2,367	
7	2,442	2,356	
8	2,422	2,346	
9	2,404	2,336	
10	2,386	2,327	
11	2,370	2,319	
12	2,355	2,312	
13	2,341	2,305	
14	2,328	2,298	
15	2,316	2,292	
16	2,305	2,287	
17	2,295	2,281	
18	2,285	2,276	
19	2,276	2,272	
20	2,268	2,268	

Example: Year 1		
	$1,080,166	Case 2
	$237,785	Δ Case 8
	0.929	PV Factor
	$220,875	PV Δ Case 8
	$1,301,042	PV Cases 2+Δ8
	500.33	MW
	$2,600	$/kW

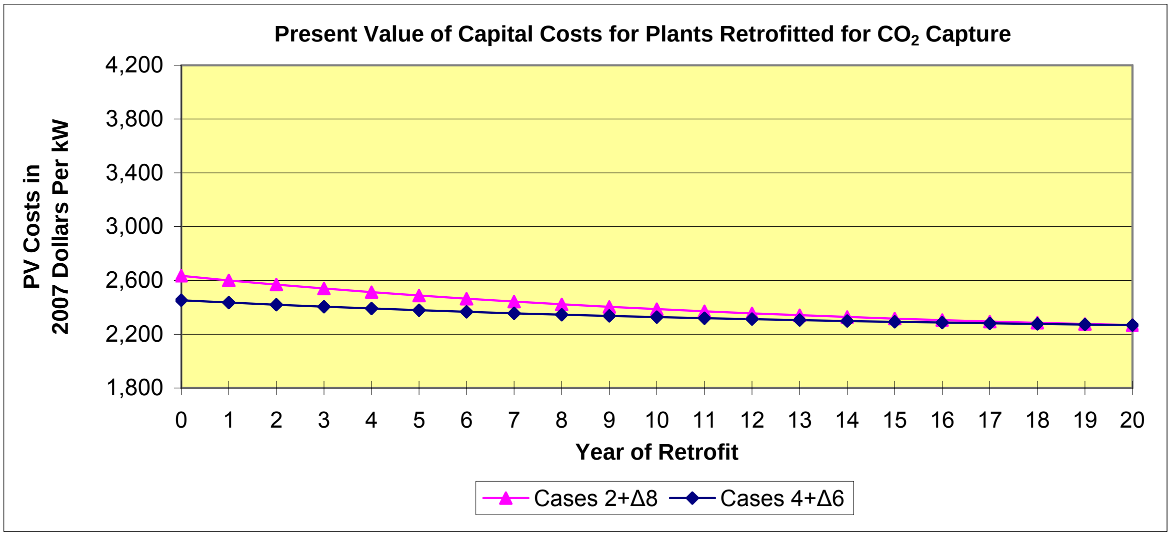


Chart 11 - IGCC Plant Production Costs

Chart 11 **CARBON DIOXIDE CAPTURE READY COAL POWER PLANTS DCF STUDY** 2/12/2008

Present Value of IGCC Production Costs

IGCC Plants			MW	Jan 2007 1000$
Case 2	Business-as-usual IGCC Plant		623.37	
		Operating & Maintenance=		$44,299
		Consumables=		$5,353
		By-Product Credits=		$0
		Fuel Costs=		$68,449
		Subtotal Production=		$118,100
Δ Case 8	Business-as-usual Retrofit for CO2 Capture		-123.04	
		Operating & Maintenance=		$3,583
		Consumables=		$1,048
		By-Product Credits=		$0
		Fuel Costs=		$0
		Subtotal Production=		$4,631
		Combined =	500.33	$122,731
Case 4	Capture-ready IGCC Plant		623.37	
		Operating & Maintenance=		$48,192
		Consumables=		$5,849
		By-Product Credits=		$0
		Fuel Costs=		$68,449
		Subtotal Production=		$122,489
Δ Case 6	Capture-ready Retrofit for CO2 Capture		-105.13	
		Operating & Maintenance=		$0
		Consumables=		$876
		By-Product Credits=		$0
		Fuel Costs=		$2,061
		Subtotal Production=		$2,937
		Combined =	518.24	$125,426

Production Cost Difference Case 4 over Case 2	$4,389
Retrofit Cost Difference Δ Case 6 over Δ Case 8	$1,694
Total Production Cost Difference Case 2+Δ8 over 4+Δ6	-$2,695

Present Value Analysis of Production Costs for Retrofitted Startup at End of Year. (millions of 2007 dollars)

Present Value Analysis of Production Costs

Year	Cases 2+Δ8 P.V. 2+Δ8	Cases 4+Δ6 P.V. 4+Δ6
0	54.3	54.9
1	50.4	51.0
2	46.8	47.4
3	43.5	44.0
4	40.4	40.9
5	37.5	38.0
6	34.9	35.3
7	32.4	32.8
8	30.1	30.4
9	27.9	28.3
10	26.0	26.3
11	24.1	24.4
12	22.4	22.7
13	20.8	21.0
14	19.3	19.6
15	18.0	18.2
16	16.7	16.9
17	15.5	15.7
18	14.4	14.6
19	13.4	13.5
20	12.4	12.6

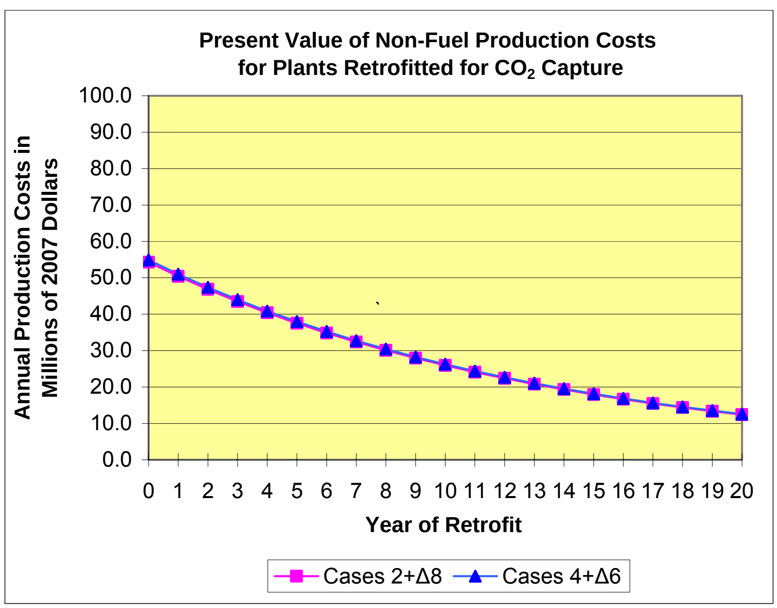


Chart 11 - IGCC Plant Production Costs continued

Chart 11 continued 2/12/2008

CARBON DIOXIDE CAPTURE READY COAL POWER PLANTS DCF STUDY

Present Value of IGCC Production Costs continued

Present Value Analysis of Production Costs for Retrofitted Startup at End of Year. (millions of 2007 dollars)

Present Value Analysis of Fuel Costs

	Cases 2+Δ8	Cases 4+Δ6
Year	P.V. 2+Δ8	P.V. 4+Δ6
0	68.4	70.5
1	63.9	65.8
2	59.6	61.4
3	55.6	57.3
4	51.9	53.5
5	48.5	49.9
6	45.2	46.6
7	42.2	43.5
8	39.4	40.6
9	36.8	37.9
10	34.3	35.3
11	32.0	33.0
12	29.9	30.8
13	27.9	28.7
14	26.0	26.8
15	24.3	25.0
16	22.7	23.3
17	21.1	21.8
18	19.7	20.3
19	18.4	19.0
20	17.2	17.7

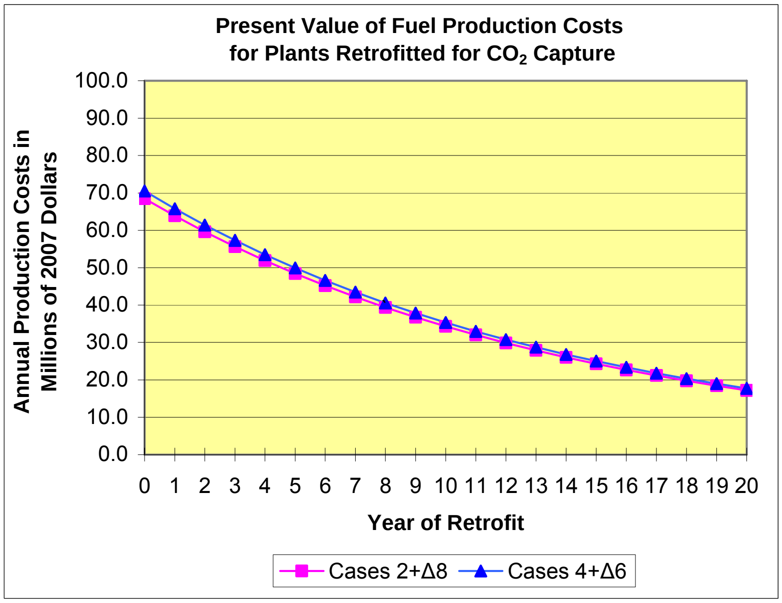


Chart 12 - IGCC Plant Levelized Cost of Electricity (LCOE)

Chart 12 **CARBON DIOXIDE CAPTURE READY COAL POWER PLANTS DCF STUDY** 2/12/2008

20 Year Levelized Cost of IGCC Electricity (COE)

			MW	Jan 2007 1000$	
IGCC Plants					
Case 2	Business-as-usual IGCC Plant		623.37		
		Capital Cost		$1,080,166	
		Non Fuel Production Cost		$49,652	per year
		Fuel Production Cost		$68,449	per year
Δ Case 8	Business-as-usual Retrofit for CO2 Capture		-123.04		
		Capital Cost		$237,785	
		Non Fuel Production Cost		$4,631	per year
		Fuel Production Cost		$0	per year
Case 4	Capture-ready IGCC Plant		623.37		
		Capital Cost		$1,146,914	
		Non Fuel Production Cost		$54,041	per year
		Fuel Production Cost		$68,449	per year
Δ Case 6	Capture-ready Retrofit for CO2 Capture		-105.13		
		Capital Cost		$123,949	
		Non Fuel Production Cost		$876	per year
		Fuel Production Cost		$2,061	per year

Capital Charge Factor=	0.175
20 Year General Levelizing Factor =	1.157
20 Year Fuel Levelizing Factor =	1.202

Production	Cases 2+Δ8 =	3,506,313 MWh
	Cases 4+Δ6 =	3,631,826 MWh

Levelized Cost of Electricity (COE)

Year	Cases 2+Δ8 P.V. 2+Δ8	Cases 4+Δ6 P.V. 4+Δ6
0	0.1072	0.1021
1	0.1035	0.0988
2	0.1000	0.0958
3	0.0968	0.0930
4	0.0939	0.0904
5	0.0911	0.0880
6	0.0885	0.0858
7	0.0861	0.0837
8	0.0839	0.0817
9	0.0818	0.0799
10	0.0799	0.0782
11	0.0781	0.0766
12	0.0764	0.0751
13	0.0749	0.0738
14	0.0734	0.0725
15	0.0721	0.0713
16	0.0708	0.0702
17	0.0697	0.0692
18	0.0686	0.0682
19	0.0676	0.0673
20	0.0666	0.0665

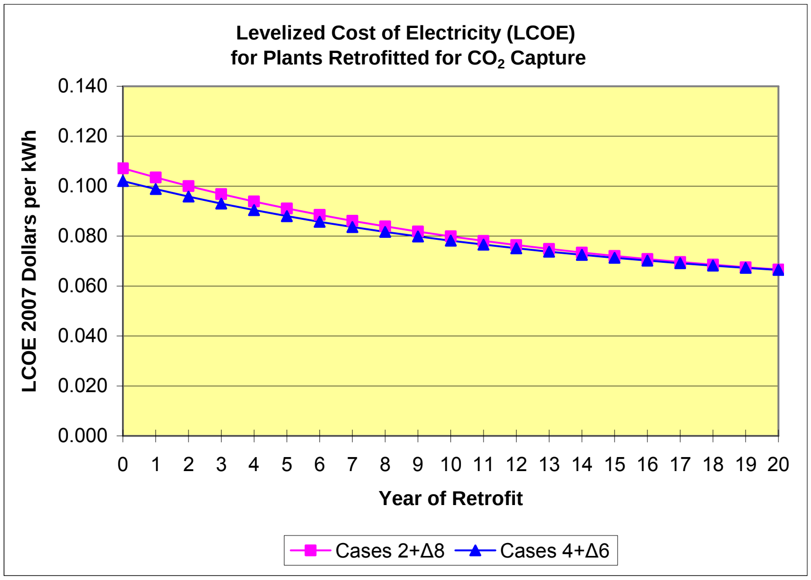


Chart 13 - Example 20-Year Average LCOE Calculation for IGCC Plants

Chart 13 **CARBON DIOXIDE CAPTURE READY COAL POWER PLANTS DCF STUDY** 2/12/2008

2007 Cost of Electricity (COE) By Year of Operation

IGCC Plants				Jan 2007 1000$	
Case 2	Business-as-usual IGCC Plant		623 MW		
		Capital Cost		$1,080,166	
		Production Cost		$49,652	per year
		Fuel Cost		$68,449	per year
Δ Case 8	Business-as-usual Retrofit for CO2 Capture		-123 MW		
		Capital Cost		$237,785	
		Production Cost		$4,631	per year
		Fuel Cost		$0	per year
Case 4	Capture-ready IGCC Plant		623 MW		
		Capital Cost		$1,146,914	
		Production Cost		$54,041	per year
		Fuel Cost		$68,449	per year
Δ Case 6	Capture-ready Retrofit for CO2 Capture		-105 MW		
		Capital Cost		$123,949	
		Production Cost		$876	per year
		Fuel Cost		$2,061	per year
	Capital Charge Factor=	0.1750	Retrofit at End of Year =	10	
	20 Year General Levelizing Factor =	1.1568	General PV Factor=	0.4782	
	20 Year Fuel Levelizing Factor =	1.2020	Fuel PV Factor=	0.5011	
Production	Case 2 =	4,368,577 MWh	Cases 2+Δ8 =	3,506,313 MWh	
	Case 4 =	4,368,577 MWh	Cases 4+Δ6 =	3,631,826 MWh	

Cases 2+Δ8					Cases 4+Δ6			
Levelized Cap. Chrgs	Levelized PV Prod	Annual Prod MWh	Levelized COE	Year of Retofit	Levelized Cap. Chrgs	Levelized PV Prod	Annual Prod MWh	Levelized COE
189,029	139,714	4,368,577	0.0753	0	200,710	144,791	4,368,577	0.0791
189,029	139,714	4,368,577	0.0753	1	200,710	144,791	4,368,577	0.0791
189,029	139,714	4,368,577	0.0753	2	200,710	144,791	4,368,577	0.0791
189,029	139,714	4,368,577	0.0753	3	200,710	144,791	4,368,577	0.0791
189,029	139,714	4,368,577	0.0753	4	200,710	144,791	4,368,577	0.0791
189,029	139,714	4,368,577	0.0753	5	200,710	144,791	4,368,577	0.0791
189,029	139,714	4,368,577	0.0753	6	200,710	144,791	4,368,577	0.0791
189,029	139,714	4,368,577	0.0753	7	200,710	144,791	4,368,577	0.0791
189,029	139,714	4,368,577	0.0753	8	200,710	144,791	4,368,577	0.0791
189,029	139,714	4,368,577	0.0753	9	200,710	144,791	4,368,577	0.0791
189,029	139,714	4,368,577	0.0753	10	200,710	144,791	4,368,577	0.0791
208,929	71,261	3,506,313	0.0799	11	211,083	72,854	3,631,826	0.0782
208,929	71,261	3,506,313	0.0799	12	211,083	72,854	3,631,826	0.0782
208,929	71,261	3,506,313	0.0799	13	211,083	72,854	3,631,826	0.0782
208,929	71,261	3,506,313	0.0799	14	211,083	72,854	3,631,826	0.0782
208,929	71,261	3,506,313	0.0799	15	211,083	72,854	3,631,826	0.0782
208,929	71,261	3,506,313	0.0799	16	211,083	72,854	3,631,826	0.0782
208,929	71,261	3,506,313	0.0799	17	211,083	72,854	3,631,826	0.0782
208,929	71,261	3,506,313	0.0799	18	211,083	72,854	3,631,826	0.0782
208,929	71,261	3,506,313	0.0799	19	211,083	72,854	3,631,826	0.0782
208,929	71,261	3,506,313	0.0799	20	211,083	72,854	3,631,826	0.0782
3,979,580	2,109,751	78,748,896	0.0773	Year 1 through 20	4,117,929	2,176,447	80,004,029	0.0787
	6,089,331					6,294,376		

Months Penalty for Retrofitting Case 2 = 0

In above table 0 = Startup at Time Zero, 1=First Operating Year, 20 =20th Operating Year, Totals do not include Time Zero Values

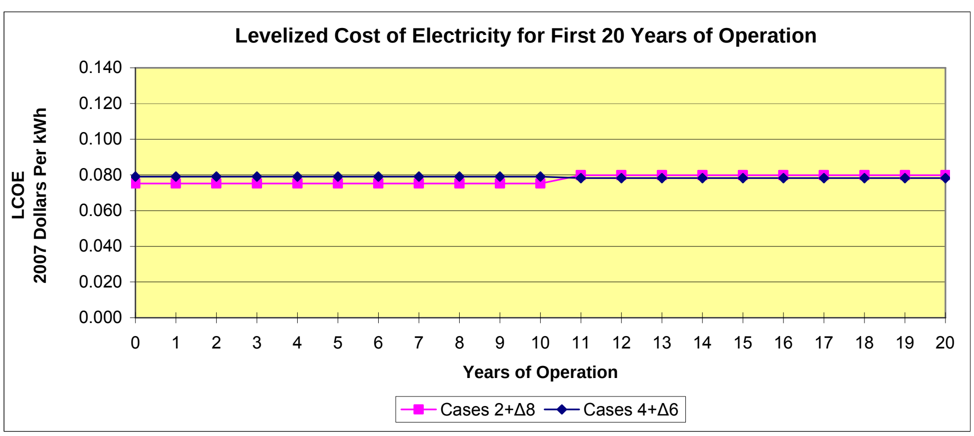
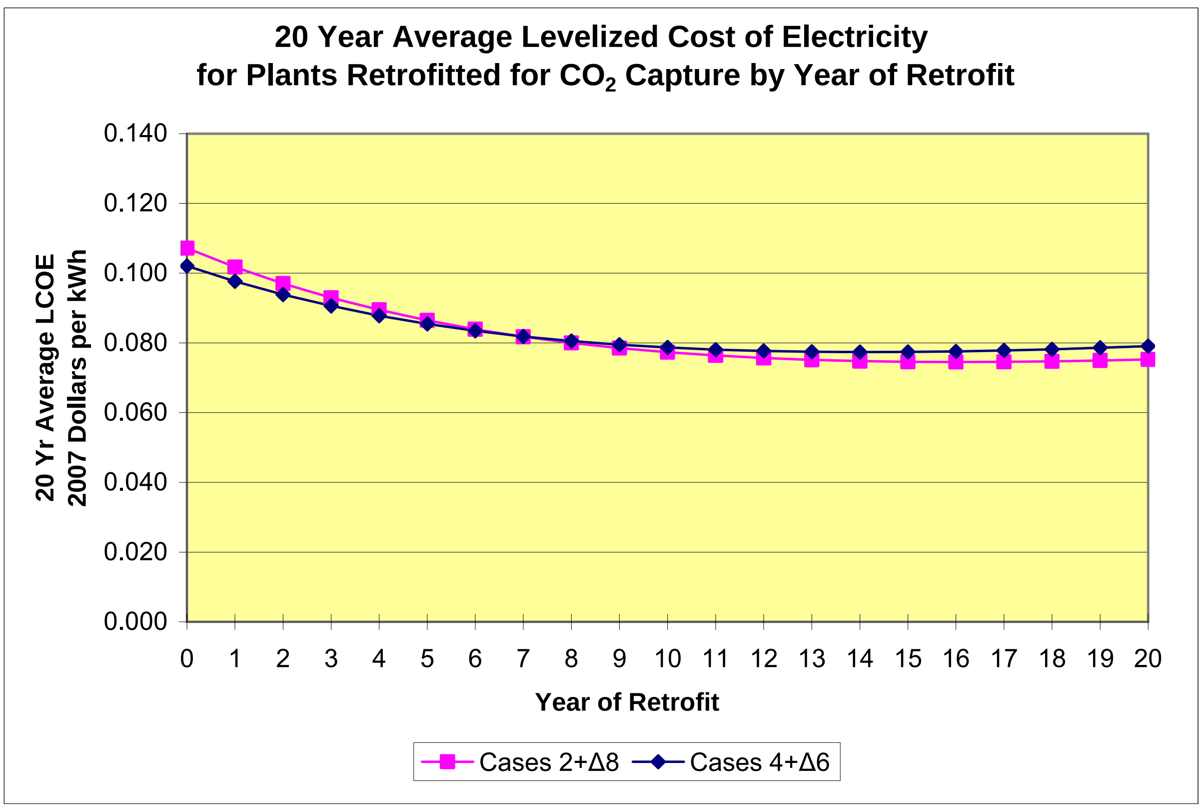


Chart 14 - 20-Year Average LCOE for IGCC Plants

Chart 14 **CARBON DIOXIDE CAPTURE READY COAL POWER PLANTS DCF STUDY** 2/12/2008

20 Year Average 2007 LCOE for IGCC by Year of Retrofit

Retrofit Year	Cases 2+Δ8	Cases 4+Δ6	Cases Diff
0	0.1072	0.1021	0.0051
1	0.1017	0.0977	0.0041
2	0.0970	0.0939	0.0032
3	0.0930	0.0906	0.0024
4	0.0895	0.0878	0.0016
5	0.0865	0.0855	0.0010
6	0.0839	0.0835	0.0004
7	0.0818	0.0819	-0.0001
8	0.0800	0.0805	-0.0006
9	0.0785	0.0795	-0.0010
10	0.0773	0.0787	-0.0013
11	0.0764	0.0781	-0.0017
12	0.0757	0.0777	-0.0020
13	0.0751	0.0774	-0.0023
14	0.0748	0.0774	-0.0026
15	0.0746	0.0774	-0.0028
16	0.0745	0.0776	-0.0030
17	0.0746	0.0778	-0.0033
18	0.0747	0.0782	-0.0035
19	0.0749	0.0786	-0.0037
20	0.0753	0.0791	-0.0038



CONCLUSIONS:

- A 550 MW Supercritical PC power plant which has been designed and built for future CO_2 capture (Case 3 PC Capture-Ready) is economically **more attractive** than a conventional plant (Case 1 PC Business-as-usual) if CO_2 capture is either desired or required **within the first 10 years of the plants operation**. The conventional, business-as-usual, plant is economically more attractive if retrofit is to occur after the first 10 years of plant operation. The main reason for this advantage of the Capture-Ready plant in the early years is that a conventional plant's net electrical output is reduced by about 31% when retrofitted for CO_2 capture, whereas the plant designed for future CO_2 capture does not experience the same power output reduction.

- A 623 MW IGCC plant designed for future CO_2 capture (Case 4 IGCC capture-ready) has a limited economic advantage over a conventional plant (Case 2 IGCC business-as-usual) if CO_2 capture will be either desired or required within the first 7 years of the plants operation. Either design is acceptable if retrofitting is expected after 7 years.