NATIONAL ENERGY TECHNOLOGY LABORATORY

Eliminating the Derate of Carbon Capture Retrofits

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ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

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FINAL REPORT

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LIST OF ACRONYMS AND ABBREVIATIONS

AACE	Association for the Advancement of Cost Engineering
acfm	Actual cubic foot per minute
AEO	Annual Energy Outlook
AGR	Acid gas removal
AQCS	Air quality control systems
AR	As Received
ASU	Air separation unit
BACT	Best available control technology
BEC	Bare erected cost
BFD	Block flow diagram
BFW	Boiler feed water
Btu	British thermal unit
Btu/h	British thermal unit per hour
Btu/kWh	British thermal unit per kilowatt hour
Btu/lb	British thermal unit per pound
CA	California
CBIGCC	Coal and biomass to power in integrated gasification combined cycle
CCF	Capital Charge Factor
CCS	Carbon Capture and Sequestration
CF	Capacity factor
CFM	Cubic feet per minute
CFR	Code of Federal Regulations
CGE	Cold gas efficiency
CH_4	Methane
cm	Centimeter
CO_2	Carbon dioxide
CO_{2e}	Carbon dioxide equivalent
COE	Cost of electricity
CoP	ConocoPhillips
COS	Carbonyl sulfide
CRP	Conservation Reserve Program
CRT	Cathode ray tube
CT	Combustion turbine
CTG	Combustion Turbine-Generator
CWT	Cold water temperature
DCS	Distributed control system
Dia.	Diameter
DOE	Department of Energy
EAF	Equivalent availability factor
E-Gas™	ConocoPhillips gasifier technology
EIA	Energy Information Administration

EPA	Environmental Protection Agency
EPC	Engineer/Procure/Construct
EPCM	Engineering/Procurement/Construction Management
EPRI	Electric Power Research Institute
FGD	Flue gas desulfurization
FOAK	First of a kind
ft	Foot, Feet
FW	Feedwater
gal	Gallon
GDP	Gross domestic product
GHG	Greenhouse gas
gpm	Gallons per minute
GT	Gas turbine
GW	Gigawatt
GWP	Global Warming Potential
h	Hour
H_2	Hydrogen
Hg	Mercury
HHV	Higher heating value
hp	Horsepower
HP	High pressure
HRSG	Heat recovery steam generator
HVAC	Heating, ventilating, and air conditioning
IGVs	Inlet guide vanes
IGCC	Integrated gasification combined cycle
IOU	Investor-owned utility
IP	Intermediate pressure
ISO	International Standards Organization
kg/GJ	Kilogram per gigajoule
kg/h	Kilogram per hour
kJ	Kilojoules
kJ/kg	Kilojoules per kilogram
KO	Knockout
kPa	Kilopascal absolute
kV	Kilovolt
kW	Kilowatt
kWe	Kilowatts electric
kWh	Kilowatt-hour
kWt	Kilowatts thermal
LAER	Lowest Achievable Emission Rate
lb	Pound
lb/h	Pounds per hour
lb/MMBtu	Pounds per million British thermal units

lb/MWh	Pounds per megawatt hour
LCOE	Levelized cost of electricity
LF_{Fn}	Levelization factor for category n fixed operating cost
LF_{Vn}	Levelization factor for category n variable operating cost
LHV	Lower heating value
LNB	Low NO_x burner
LP	Low pressure
m	Meters
MM$	Millions of Dollars
m/min	Meters per minute
m^3/min	Cubic meter per minute
MDEA	Methyldiethanolamine
MHz	Megahertz
MMBtu	Million British thermal units (also shown as 10^6 Btu)
MMBtu/h	Million British thermal units (also shown as 10^6 Btu) per hour
MPa	Megapascals
Mpg	Miles per gallon
MW	Megawatt
MWe	Megawatts electric
MWh	Megawatt-hour
net-MWh	Net megawatt-hour
NERC	North American Electric Reliability Council
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NGSC	Natural gas simple cycle
NOx	Oxides of nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review
NREL	National Renewable Energy Laboratory
O&M	Operation and maintenance
OC_{Fn}	Category n fixed operating cost for the initial year of operation
OFA	Over fire air
PC	Pulverized coal
PM	Particulate matter
PM_{10}	Particulate matter measuring 10 μm or less
POTW	Publicly Owned Treatment Works
ppm	Parts per million
ppmd	Parts per million, dry
ppmv	Parts per million volume
PRB	Powder River Basin coal region
PSFM	Power systems financial model
psia	Pounds per square inch absolute
psig	Pounds per square inch gage

R&D	Research and Development
RDS	Research and Development Solutions, LLC
SCR	Selective catalytic reduction
SGS	Sour gas shift
SO_2	Sulfur dioxide
STG	Steam turbine generator
TASC	Total as spent capital
TGTU	Tail gas treating unit
Tonne	Metric Ton (1000 kg)
TPC	Total plant cost
TPD	Tons per day
TPH	Tons per hour
TPI	Total plant investment
TS&M	Transport, storage and monitoring
USDA	United States Department of Agriculture
vol%	Volume percent
VWO	Valves wide open
wt%	Weight percent
$/AR ton	Dollars per As Received ton
$/dry ton	Dollars per dry ton
$/kW	Dollars per kilowatt
$/MMBtu	Dollars per million British thermal units
$/MMkJ	Dollars per million kilojoule
$/MWh	Dollars per Megawatt-hour
$/ton	Dollars per ton

EXECUTIVE SUMMARY

Upcoming challenges for the power generation industry will combine the need to build new capacity to meet ever increasing demand as well as to implement carbon mitigation strategies on new and existing capacity. New and advanced power plant designs will help increase efficiency and allow for the integration and optimization of designs incorporating new environmental control processes. Even with the development of these novel technologies, overcoming logistic and economic problems with retrofitting these advanced technologies will be challenging. One of the more significant issues pertains to the large parasitic power load required for appreciable levels of carbon capture. Post-combustion capture has been shown to reduce the net plant efficiency of an equivalent plant without capture by 30 percent or more. Yet, post-combustion amine scrubbing is anticipated to be the most viable near-term option for reducing CO_2 emissions from existing coal plants. This study attempts to quantify different power replacement options for existing PC boilers to reduce the effects caused by additional auxiliary steam and power requirements of the amine-based CO_2 removal process and the off-design operation of the existing plant.

In addition to cost and performance concerns, traditional impediments to plant retrofits are considered such as projected plant downtime, plant layout and footprint, reuse of equipment or resources, and permitting concerns. While individual retrofit options are highly plant-specific and therefore subject to unique optimization pathways, each of the proposed cases attempts to leverage the specific technologies or configurations to minimize or avoid some combination of these problems. A first look at the cases in this study (Exhibit ES-1 Study Matrix) reveals promise in the proposed methods for regenerating lost power. Furthermore, results in this study suggest that future optimization can provide even more attractive solutions.

Exhibit ES-1 Study Matrix

Objective	Case	Fuel Type	Retrofitted Plant Arrangement	Net Retrofit Flue Gas CO_2 Capture %	Capture Strategy
Retrofit Baseline	0	Illinois #6	Existing PC only, w/o makeup steam or power	90%	Amine
Greenfield NGSC Plant Generating all Lost Steam & Power	1	Natural Gas	New GE 6FA w/flue gas routed to CDR	90%	Amine
	2	Natural Gas	New GE 7FA w/flue gas routed to CDR	90%	Amine

Case 0 is designed to establish the raw consequences of CO_2 removal retrofits. This case highlights the costs to retrofit and the effects on net power generation due to increased auxiliary loads, off-design steam turbine operation, amine regeneration steam extraction, etc. Cases 1 and 2 represent a CO_2 removal retrofit augmented with a natural gas simple cycle (NGSC) to make up the lost power and to generate steam for the amine regeneration process. A 6FA turbine is used in Case 1 and a 7FA is used in Case 2, providing the auxiliaries (steam and power) for the CO_2 removal process. A summary of the results from these cases is presented in Exhibit ES-2.

The study design basis chose to restrict the total amount of power generated by the auxiliary plants to less than 110 percent of the original plant rating so that there would be no need to expand the existing transmission and distribution (T&D) system. Where power generation and steam generation of the NGSC do not exactly match the requirements of the amine system (as seems to often be the case) duct firing and measures to reduce the total auxiliary power generation are required and result in retrofits with sub-optimal efficiencies. Natural Gas Combined Cycles (NGCC) may provide more flexibility in steam to power generation and would enable more thermodynamically optimized retrofits. However, this would be at the expense of higher cost and may produce more power than the existing T&D system can handle.

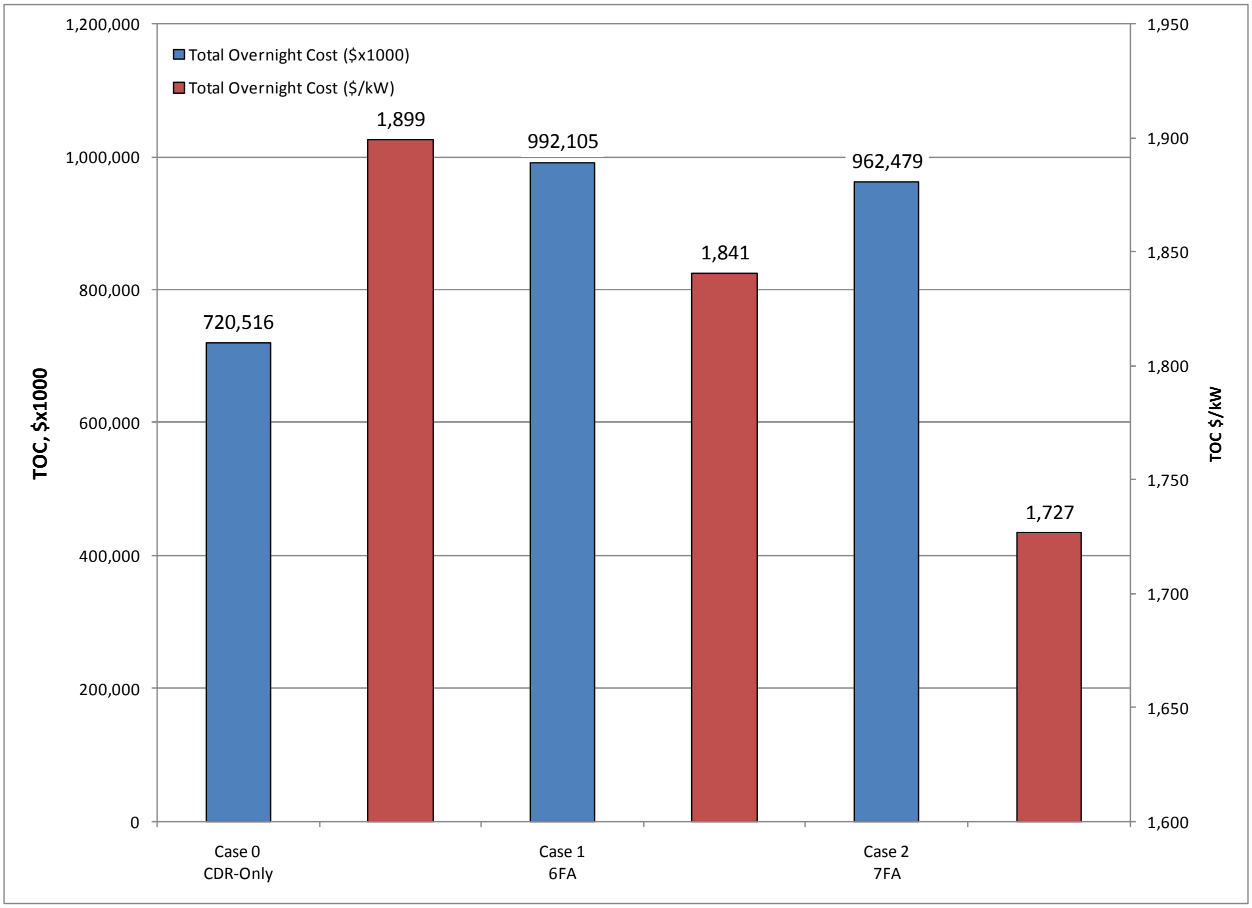
Exhibit ES-2 Results Summary

	Case 0 CDR-Only	Case 1 6FA	Case 2 7FA
Gross Power Output (kW_e)	467,600	657,500	668,500
Auxiliary Power Requirement (kW_e)	88,180	118,490	111,080
Net Power Output (kW_e)	379,420	539,010	557,420
Coal Flowrate (lb/hr)	437,378	437,378	437,378
Natural Gas Flowrate (MMBtu/hr)	0	2,761	1,797
HHV Thermal Input (kW_{th})	1,495,381	2,304,465	2,022,075
Net Plant HHV Efficiency (%)	25.4%	23.4%	27.6%
Net Plant HHV Heat Rate (Btu/kW-hr)	13,448	14,588	12,378
Raw Water Withdrawal, gpm	8,158	12,520	10,903
Raw Water Consumption, gpm	6,266	9,556	8,334
LCA GHG Emissions (lb/MWh_{gross})	390	367	330
LCA GHG Emissions (lb/MWh_{net})	481	448	396
SO_2 Emissions (lb/MWh_{gross})	0.019	0.022	0.024
NOx Emissions (lb/MWh_{gross})	0.787	0.568	0.559
PM Emissions (lb/MWh_{gross})	0.146	0.101	0.099
Hg Emissions (lb/MWh_{gross})	1.29E-05	8.87E-06	8.72E-06
Cost Values			
Total Plant Cost ($x1000)	574,859	774,879	758,364
Owner's Costs ($x1000)	145,657	217,227	204,115
Total Overnight Cost ($x1000)	720,516	992,105	962,479
Total Overnight Cost ($/kW)	1,899	1,841	1,727
FYCOE ($/MWh)	85.4	104.4	87.9
LCOE ($/MWh)	108.3	132.4	111.5

Effects on Costs

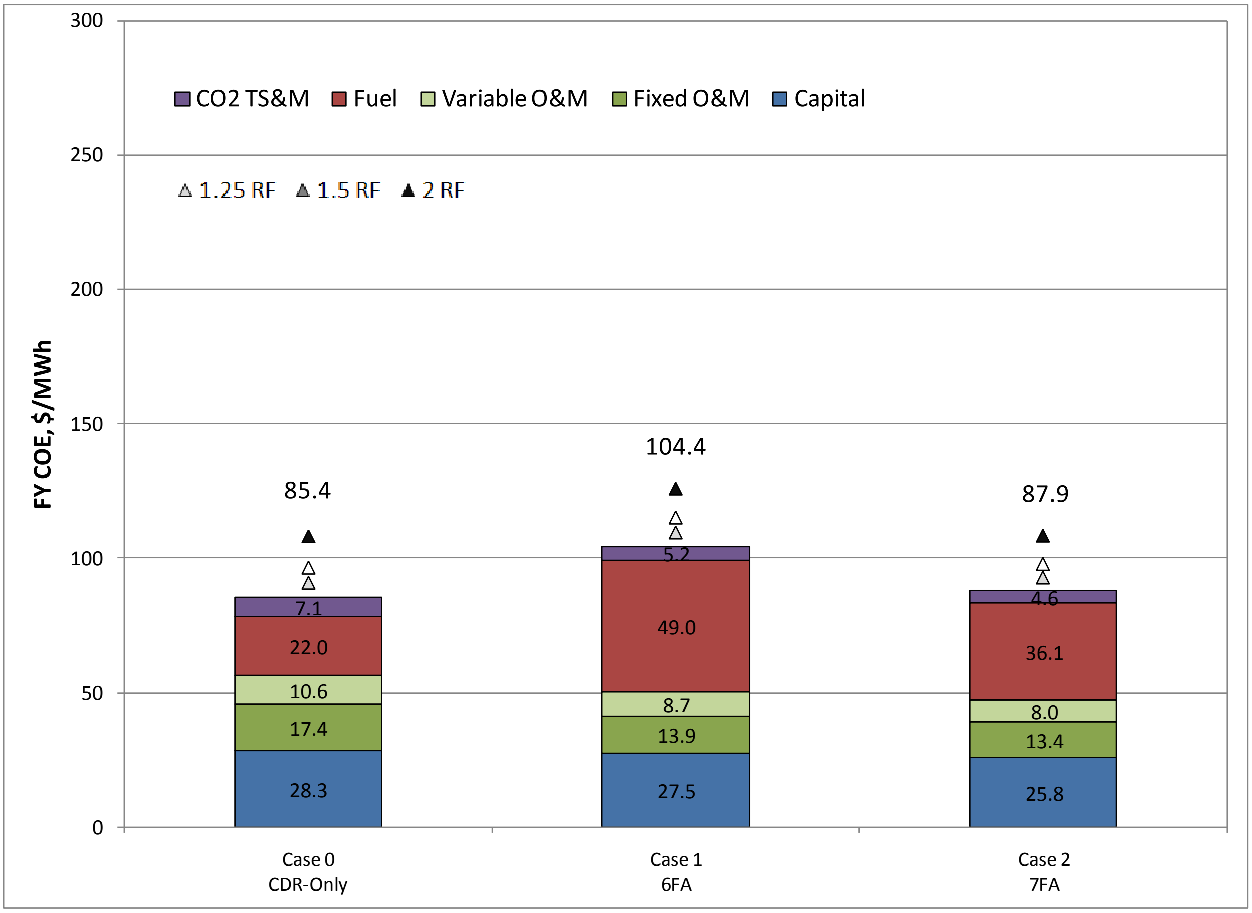
The simultaneous retrofit of CO_2 removal technology and dedicated auxiliary steam and power generation provides significant additional opportunities to lower costs and increase plant efficiency compared to a stand alone CO_2 removal retrofit. It is difficult for retrofits to perform as well and be less expensive than greenfield designs because minimal process optimization and economies of scale can be realized once the design and construction of the main plant has been completed. All cases in this study assume a fully depreciated base plant, to be representative of the older existing plants which may be considering such a retrofit. The capital costs of the retrofit, using total overnight cost as a metric, are shown in Exhibit ES-3. The base case in this study (Case 0 – CO_2 removal only) shows an incremental increase in COE of 85.4 mills/kWh and in capital cost (using total overnight cost per post-retrofit net kW of generation as a metric) of $1,899/kW or a total of $721M. Similar economics for greenfield plants with and without CO_2 removal show a increase in COE of 50.2 mills/kWh, $1,614/kW and an absolute cost increase of $887M [1]. The Case 0 retrofit is cheaper in absolute terms because it treats 30 percent less flue gas than the greenfield cases, but is more expensive on a per kW basis compared to the greenfield cases generating 550 MW due to loss of economies of scale and an additional steam turbine derate due to off design operation. The more promising combustion turbine auxiliary plant retrofit combination (Case 2) has a COE of 87.9 mills/kWh and total overnight cost (TOC) of $1,727/kW or $962MM. For the combustion turbine cases, fuel costs are a large proportion of the COE suggesting that improvements in efficiency would be especially beneficial to this configuration to reduce the amount of natural gas used.

Exhibit ES-3 Capital Costs



The COEs shown in Exhibit ES-4 include retrofit contingencies applied to appropriate equipment to represent the added costs associated with any retrofit difficulty (close-in construction premiums, etc.) compared to a similar baseline for greenfield costs. Retrofits with more equipment, complexity, and downtime may be more susceptible to installation or construction problems, so the true price of the retrofit may be better represented by applying a larger retrofit contingency. The CT auxiliary plant retrofits result in a competitive cost of electricity, even without further optimization, and the range of COEs when varying the retrofit factors suggests that several of these solutions could help decrease the cost of CO_2 removal retrofit.

Exhibit ES-4 FY COE Breakdown



Opportunities for cost improvements come from reusing existing equipment such as the stack, flue gas ducting, and existing electrical transmission infrastructure. Also, the assumption of simultaneously installing a dedicated auxiliary plant allows the flexibility to locate the CO_2 removal process to minimize costs. This alleviates some concern with the steam turbine extraction steam piping and allows designs to minimize duct installation costs and also return the treated flue gas to the existing stack.

Effects on Performance

A greenfield PC plant designed with CO_2 removal technology is approximately 30 percent less efficient than an analogous non-capture plant. For cases where this CO_2 removal technology is added as a retrofit after the initial design and construction, as is the case in this analysis, the net output reduction can be even greater depending on how amine regeneration steam is extracted from the existing steam turbine. A 34 percent reduction in non-capture plant efficiency is observed in the Case 0 retrofit when extracting steam equally from all low pressure steam turbine trains, which by design is likely the least efficient extraction method from a thermodynamic standpoint. This worst case scenario reflected in Case 0 helps to identify and bound opportunities to recover or prevent some of the losses associated with CO_2 removal retrofit. In addition to improving efficiency, the addition of the auxiliary plant allows for additional output. However, existing electrical transmission equipment, and likely everything downstream of the electrical generator, is designed for the original power output but may still have additional margin which could be leveraged to decrease the cost of total power generation. The natural gas cases result in more efficient and lower cost auxiliary power, driving down the total electricity cost as more auxiliary power is generated, provided the existing T&D infrastructure can accommodate the additional load. As an added benefit, the addition of the CO_2 removal process would likely satisfy any New Source Review, with the accompanying SOx, PM, and NOx removal required for the amine scrubbing, eliminating another potential impediment to augmenting an existing plant's output.

Auxiliary Power and Steam Optimization

Optimization of the auxiliary plant size to match the desired CO_2 removal installation and particular plant capacity would allow for efficiency gains. The MEA process implemented in this study removes 90 percent of the CO_2 from the flue gas generated by a 550 MW PC plant (pre-retrofit) and requires ~1,400 MMBtu/h of steam for solvent regeneration and ~55 MW of auxiliary power for Case 0, equating to a steam to power ratio of 7.3. For treating a given flue gas stream, the steam requirements scale with the amount of CO_2 captured, and the power scales based on the gas volume to be treated. The simple cycle combustion turbine plants have a fixed electrical output and available sensible heat for recovery, which results in a steam to power ratio of 1.5 according to the heat recovery assumptions made in this study. This ratio was adjusted by burning natural gas, similar to a duct firing configuration, to augment the steam production in Case 1. However, this reduces the efficiency of a simple cycle combustion turbine moreso than a combined cycle plant, which could recover a greater amount of higher quality heat, minimizing the opportunity cost of directly using natural gas in a less efficient duct burner.

In this study, the NGSC combustion turbine exhaust was used to produce as much steam at the minimum pressure necessary to minimize the amount of duct firing required to meet the CDR steam demands. Utilizing a full combined cycle as the basis for the auxiliary power plants may allow for higher efficiency and more flexible steam production. It will also allow most if not all natural gas to be used in a higher efficiency Brayton cycle. In a combined cycle, all steam produced will be of the highest quality possible and can first be expanded down to the conditions required for amine regeneration to generate additional power. This may permit the use of a smaller gas turbine design because of the additional power generated by the steam produced in the bottoming cycle, decreasing cost. Several approaches for optimization have been identified as a result of this study, either targeting or maximizing the power output or matching the required CO_2 removal auxiliary steam requirement. For a given plant which is interested in repowering or increasing its output, the former approach may make sense based on projected demand or growth. Matching the steam requirement is likely the more cost effective option as it leverages more of the existing equipment and infrastructure and requires minimal additional investment.

Additional Power Generation

For a plant to simultaneously add CO_2 removal and increase its overall output, additional capacity is required to offset or replace the steam and power diverted to the CO_2 removal process as well as to generate the desired power. The efficiencies of the proposed auxiliary plants could all be improved if their steam cycles were optimized, making use of the higher quality steam. The increased cost of a high temperature steam turbine in the auxiliary plant may be offset by the increased efficiency, which would also reduce the marginal cost of generating electricity. For the combustion turbine cases, the additional natural gas that is burned to adjust the steam to power ratio reduces the efficiency below that of simple cycle operation. Adding a combined cycle would fully take advantage of the chemical energy in the natural gas feedstock by generating higher quality steam in a more efficiency cycle and also to largely remove constraints on steam to power ratios imposed by simple cycle designs.

Adding a larger natural gas auxiliary plant could lead to a cost effective solution, largely because the additional low-carbon natural gas power is more efficient and lower cost than coal-generated power. Examples or perturbations of the modeled cases could include a larger combustion turbine auxiliary plant, similar to Cases 1 or 2 except with a full combined cycle HRSG and steam turbine added to generate power. For a 6FA turbine, this may add ~$60MM for a ~40 MW increase in power (~$1,500/kW), and for a 7FA, ~$120MM for a ~90 MW increase (~$1,300/kW), based on the differences between the simple cycle and combined cycle plant's published costs in the Gas Turbine World 2009 GTW Handbook [2]. Multiple turbine trains or larger turbines could also be considered to capture some economies of scale for the combined cycle portion of the plant. Further study with cases designed around these other repowering options could more precisely quantify the effects of adding additional power.

Matching Steam Generation

The general basis from the cases presented in this study is to avoid the inefficiencies associated with extracting steam from the existing steam turbine, while making up all lost power required to run the CO_2 capture and compression equipment.

Sensible heat left in the flue gas of the natural gas system is responsible for generating the regeneration steam. The sensible energy in the exhaust of the 7FA is well matched to the MEA based CO_2 removal process required to capture 90 percent of the emissions from the combined plant flue gas. For the 6FA case, with roughly half the capacity, additional duct firing with natural gas is required to meet the steam requirements of the CO_2 removal process. With the premise of matching the low pressure steam requirement, both of these cases make only one quality of steam, sent directly to the CO_2 removal process in a dedicated closed loop. So even though sensible heat is recovered from the flue gas, both these auxiliary plants contribute energy closer to the simple cycle efficiency rather than that of combined cycle operation. Even in this sub-optimal operation, Case 2 in this study shows that a combined combustion turbine retrofit can be cost competitive to add additional output to an existing plant.

Conclusions

Ultimately the cases presented in this report demonstrate viable opportunities to improve the attractiveness of a CO_2 retrofit. The cases considered in this study were heavily guided by the principle of replacing the steam required for the CO_2 removal process and eliminating any off design derate of the existing generating equipment. Excess power generation is possible and possibly preferred but it was beyond the scope of this study to optimize the effects of additional power generation. Follow-on optimization, considering such things as inclusion of Rankine cycles in the auxiliary plants, expanding existing T&D systems, and even surveying plant operators, could lower the technical and cost barriers for similar fleet wide modifications.

The discrete nature of the choices available for eliminating the derate of carbon capture retrofits requires examination of multiple strategies for each technology option before an optimal configuration can be identified. Furthermore, optimization is highly likely to be site dependent.

Recognizing potential for future optimization of this approach, results here still suggest that small, on-site, low-carbon auxiliary plants to regenerate power lost to CO_2 retrofits are a viable complement to amine based retrofits.

1. INTRODUCTION

1.1 STUDY BACKGROUND

The power generation industry potentially has multiple carbon mitigation strategies at its disposal. Where each strategy is employed will be determined by plant-specific economics. Furthermore, it is likely that many plants may benefit by employing multiple strategies to the fullest extent possible, or until they become cost-prohibitive. One of the most promising state of the art technologies for significant levels of carbon mitigation is amine-based post combustion capture. By leveraging the existing equipment in the power plant fleet, retrofitting these plants may provide cost-effective carbon mitigation.

However, retrofitting existing plants with new equipment required for amine-based post combustion carbon capture requires very high auxiliary power loads for the carbon capture and compression equipment, in addition to steam loads required for amine regeneration. Installing amine-based capture equipment on an existing PC plant results in a power deficit that must be overcome, especially if large-scale carbon capture initiatives are to succeed. There are a number of options for replacing this lost power and it is important to gain a thorough understanding of how each of these options compare to one another in terms of thermodynamic performance and economic feasibility.

It is very likely that in the short term it may be most economic for power generation facilities with lower capacity factors to increase power production to replenish the power taken from the grid to run CCS equipment, and this should not be ignored. However, increasing the capacity factor of existing plants depends largely on economics and may only provide limited make-up power as CCS retrofits increase to meet currently proposed carbon regulations.

1.2 PROJECT OBJECTIVES

This activity examines multiple options to compensate for the auxiliary loads associated with a newly-installed, amine-based, carbon dioxide (CO_2) removal (CDR) process that would have otherwise been used to generate power prior to retrofit. The focus will be on determining the best use of fuel resources for replacing this lost power generation. Dedicated steam and power production for the CDR process will be generated using natural gas fired combustion turbines. In addition, thermodynamic performance and economic feasibility of the different configurations will be evaluated and life cycle analyses will be performed to compare the overall costs and performance of different combined CO_2 management strategies.

In order to gain an understanding of the GHG effects of required plant operations lying outside of the classical plant boundary, the system studies presented in this report were performed using a limited life cycle GHG analysis. The life cycle boundaries were defined specifically to include technical, economic, and environmental information on feedstock (natural gas or coal) production, transport, and environmental effects. Life cycle emissions not included in this analysis include, but are not limited to, those associated with the plant construction, worker transport emissions, and emissions associated with plant maintenance.

Additional analysis of the integration of the CO_2 capture retrofit and the replacement power generation will be performed to evaluate benefits or concerns that may arise during the implementation of such a project: specifically space requirements, additional piping and duct work, recycling or combining of flue gas for treatment, and retrofit downtime.

The specific objectives of this study were to:

1. Complete a system study for each of the cases outlined in Exhibit 1-1 to identify and quantify performance consequences of retrofitting an existing plant with amine-based carbon capture;
2. Compare the net lifecycle carbon reduction after retrofit and installation of auxiliary plants;
3. Assess the relative space requirements for each strategy;
4. Propose alternative arrangements that may have technical promise based on the findings of this study.

Exhibit 1-1 Case Matrix

Objective	Case	Fuel Type	Retrofitted Plant Arrangement	Net Retrofit Flue Gas CO_2 Capture %	Capture Strategy
Retrofit Baseline	0	Illinois #6	Existing PC only, w/o makeup steam or power	90%	Amine
Greenfield NGSC Plant Generating all Lost Steam & Power	1	Natural Gas	New GE 6FA w/flue gas routed to CDR	90%	Amine
	2	Natural Gas	New GE 7FA w/flue gas routed to CDR	90%	Amine

2. GENERAL EVALUATION BASIS

This study is designed to assess technical and economic impacts of offsetting the increased steam and power auxiliaries associated with retrofitting CDR process to an existing PC plant firing Illinois #6.

For each of the auxiliary plant types and plant configurations in this study, a process simulation was developed and used to generate material and energy balances. The material and energy balances were used as the basis for generating the capital and operating cost estimates. Ultimately, a first year (FY) cost of electricity (COE) was calculated for each of the cases and is reported as the revenue requirement figure-of-merit.

The balance of this section provides details on the site characteristics, natural gas, and coal characteristics and costs, life cycle boundary description, study environmental targets, assumed capacity factor, raw water withdrawal, cost estimating methodology, and a description of each major process system.

2.1 SITE CHARACTERISTICS

The site location considered in this study is a generic Midwestern site using Illinois #6 with an assumed adequate local supply of hybrid poplar. Ambient conditions are shown in Exhibit 2-1 and site characteristics are shown in Exhibit 2-2 [3,4].

Exhibit 2-1 Site Ambient Conditions, Midwestern, Illinois #6 Coal

Average Elevation, ft	0
Barometric Pressure, psia	14.696
Design Ambient Temperature, Dry Bulb, °F	59
Design Ambient Temperature, Wet Bulb, °F	51.5
Design Ambient Relative Humidity, %	60

Exhibit 2-2 General Site Characteristics

Location	Retrofit
Topography	Level
Size, acres	300
Transportation	Rail
Ash Disposal	Off Site
Water	Municipal (50%)/ Groundwater (50%)
Access	Land locked, having also access by rail and highway

The following design parameters are considered site-specific, and are not quantified for this study. Allowances for normal conditions and construction are included in the cost estimates.

- Flood plain considerations.
- Existing soil/site conditions.
- Water discharges and reuse.
- Rainfall/snowfall criteria.
- Seismic design.
- Buildings/enclosures.
- Fire protection.
- Local code height requirements.
- Noise regulations – Impact on site and surrounding area.

2.2 COAL CHARACTERISTICS AND COST

The existing PC plant being retrofitted is assumed to fire Illinois #6 Bituminous coal, whose composition is shown in Exhibit 2-3 [5]. The coal mercury concentration used for this study did not come from Reference 4, but rather was determined from the Environmental Protection Agency's (EPA) Information Collection Request (ICR) database. The ICR database reports Illinois #6 bituminous coal as having an average Hg concentration of 0.09 ppm (dry) and a standard deviation of 0.06 ppm. The mercury value in Exhibit 2-3 is the mean plus one standard deviation, or 0.15 ppm (dry).

Exhibit 2-3 Design Coal Analysis

Rank	**Bituminous**	
Seam	**Illinois No. 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	100.0	100.0
HHV, Btu/lb	11,666	13,126
LHV, Btu/lb	11,252	12,712
Ultimate Analysis (weight %)		
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 (Note A)	6.88	7.75
Total	100.00	100.00
Ash Mineral Analysis (weight %)		
Silica	45.0	
Aluminum Oxide	18.0	
Titanium Dioxide	1.0	
Iron Oxide	20.0	
Calcium Oxide	7.0	
Magnesium Oxide	1.0	
Sodium Oxide	0.6	
Potassium Oxide	1.9	

Phosphorus Pentoxide	0.2	
Sulfur Trioxide	3.5	
Barium Oxide	0.00	
Strontium Oxide	0.00	
Manganese Dioxide	0.00	
Unknown	1.8	
Trace Components (ppmd)		
Mercury (Note B)	---	0.15

Notes: A. By Difference
B. Mercury value is the mean plus one standard deviation using EPA's ICR data

The Power Systems Financial Model (PSFM) was used to derive the CCFs and LFs for this study. The PSFM requires that all cost inputs have a consistent cost year basis. Because the capital and operating cost estimates are in June 2007 dollars, the fuel costs must also be in June 2007 dollars. The LF assumes a three percent nominal escalation rate. The retrofit construction duration is five years for IGCC/PC plants and three years for NGCC plants resulting in assumed start dates of 2012 (IGCC/PC) and 2010 (NGCC). The CDR-only retrofit was assumed to have a a construction duration of three years resulting in the same startup date and financial assumptions as the combined combustion turbine auxiliary plant retrofits.

The coal cost used in this study is $1.55/GJ ($1.64/MMBtu) (2007 cost of coal in June 2007 dollars). This cost was determined using the following information from the EIA 2008 AEO:

- The 2007 minemouth cost of Illinois No. 6 in 2006 dollars, $32.66/tonne ($29.63/ton), was obtained from Supplemental Table 112 of the EIA's 2008 AEO for eastern interior high-sulfur bituminous coal.
- The cost of Illinois No. 6 coal was escalated to 2007 dollars using the gross domestic product (GDP) chain-type price index from AEO 2008, resulting in a price of $33.67/tonne ($30.55/ton) [6].
- Transportation costs for Illinois No. 6 were estimated to be 25 percent of the minemouth cost based on the average transportation rate of the respective coals to the surrounding regions [7]. The final delivered costs for Illinois No. 6 coal used in the calculations is $42.09/tonne ($38.18/ton) or $1.55/GJ ($1.64/MMBtu). (Note: The Illinois No. 6 coal cost of $1.6366/MMBtu was used in calculations, but only two decimal places are shown in the report.)

2.3 NATURAL GAS CHARACTERISTICS

Natural gas is used in the cases 1 and 2 auxiliary plant, and its composition is presented in Exhibit 2-4 [8].

Exhibit 2-4 Natural Gas Composition

Component		Volume Percentage
Methane	CH_4	93.1
Ethane	C_2H_6	3.2
Propane	C_3H_8	0.7
n-Butane	C_4H_{10}	0.4
Carbon Dioxide	CO_2	1.0
Nitrogen	N_2	1.6
	Total	100.0

	LHV	HHV
kJ/kg	47,454	52,581
MJ/scm	34.71	38.46
Btu/lb	20,410	22,600
Btu/scf	932	1,032

Note: Fuel composition is normalized and heating values are calculated

The first year cost of natural gas used in this study is $6.21/MMkJ ($6.55/MMBtu) (2007 cost of natural gas in 2007 dollars). The cost was determined using the following information from the EIA's 2008 AEO:

- The 2007 East North Central region delivered cost of natural gas to electric utilities in 2006 dollars, \$231.47/1000 m^3 (\$6.55/1000 ft^3), was obtained from the AEO 2008 reference case Table 108 and converted to an energy basis, $6.02/MMkJ ($6.35/MMBtu).

- The 2007 cost was escalated to 2007 dollars using the GDP chain-type price index from AEO 2008, resulting in a delivered 2007 price in 2007 dollars of $6.21/MMkJ ($6.55/MMBtu) [6]. (Note: The natural gas cost of $6.5478/MMBtu was used in calculations, but only two decimal places are shown in the report.)

2.4 ENVIRONMENTAL TARGETS

The environmental targets for the study were considered on a technology- and fuel-specific basis. In setting the environmental targets a number of factors were considered, including current emission regulations, regulation trends, results from recent permitting activities, and the status of current best available control technology (BACT). The existing emissions from the PC plant remain constant or are reduced in every case in this study, due to the deep flue gas cleanup required for amine-scrubbine based CO_2 removal, but when combined, the emissions should most precisely be compared to a weighted average of the different technology and energy inputs being combined.

The current federal regulation governing new fossil-fuel fired electric utility steam generating units is the New Source Performance Standards (NSPS) as amended in June 2007 and shown in Exhibit 2-5. This represents the minimum level of control that would be required for a new fossil energy plant [9].

The new NSPS standards apply to units with the capacity to generate greater than 73 MW of power by burning fossil fuels, as well as cogeneration units that sell more than 25 MW of power and more than one-third of their potential output capacity to any utility power distribution system. In cases where both an emission limit and a percent reduction are presented, the unit has the option of meeting one or the other. All limits with the unit pounds per megawatt hour (lb/MWh) are based on gross power output.

Exhibit 2-5 Standards of Performance for Electric Utility Steam Generating Units Built, Reconstructed, or Modified After February 28, 2005

Pollutant	New Units		Reconstructed Units		Modified Units	
	Emission Limit	% Reduction	Emission Limit (lb/MMBtu)	% Reduction	Emission Limit (lb/MMBtu)	% Reduction
PM	0.015 lb/MMBtu	99.9	0.015	99.9	0.015	99.97
SO_2	1.4 lb/MWh	95	0.15	95	0.15	90
NO_x	1.0 lb/MWh	N/A	0.11	N/A	0.15	N/A

Other regulations that could affect emissions limits from a new plant include the New Source Review (NSR) permitting process and Prevention of Significant Deterioration (PSD). The NSR process requires installation of emission control technology meeting either BACT determinations for new sources being located in areas meeting ambient air quality standards (attainment areas), or Lowest Achievable Emission Rate (LAER) technology for sources being located in areas not meeting ambient air quality standards (non-attainment areas). The Clean Air Act authorizes EPA to establish regulations to prevent significant deterioration of air quality due to emissions of any pollutant for which a national ambient air quality standard (NAAQS) has been promulgated. Environmental area designation varies by county and can be established only for a specific site location. Based on the EPA Green Book Non-attainment Area Map relatively few areas in the Western U.S. are classified as "non-attainment" so the plant site for this study was assumed to be in an attainment area [10].

In addition to federal regulations, state and local jurisdictions can impose even more stringent regulations on a new facility. However, since each new plant has unique environmental requirements, it was necessary to apply some judgment in setting the environmental targets for this study.

Mercury

The Clean Air Mercury Rule (CAMR) issued on March 15, 2005 established NSPS limits for mercury (Hg) emissions from new PC-fired power plants. These rules were vacated by court action on February 8, 2008, and the final resolution of these rules is unknown. Even though the rules are vacated, the CAMR emission limits are included for reference only and shown in Exhibit 2-6.

Exhibit 2-6 NSPS Mercury Emission Limits

Coal Type / Technology	Hg Emission Limit
Bituminous	20×10^{-6} lb/MWh
Subbituminous (wet units)	66×10^{-6} lb/MWh
Subbituminous (dry units)	97×10^{-6} lb/MWh
Lignite	175×10^{-6} lb/MWh
Coal refuse	16×10^{-6} lb/MWh
IGCC	20×10^{-6} lb/MWh

Design Targets

The environmental targets for combustion cases were established using a presumed BACT as shown in Exhibit 2-7.

Exhibit 2-7 Environmental Targets

Pollutants	Environmental Target	NSPS Limit[1]	Type of Technology
Filterable PM	0.013 lb/MMBtu	0.015 lb/MMBtu	Fabric Filter
SO_2	0.132 lb/MMBtu	1.4 lb/MWh (0.105 lb/MMBtu)	Low-Sulfur Fuel and Dry FGD or Low-Sulfur Fuel
NOx	0.07 lb/MMBtu	1.0 lb/MWh (0.075 lb/MMBtu)	LNB's, OFA and SCR

[1] The values in parenthesis are calculated using the lowest efficiency plant heat rate for the applicable technology limit (CO_2 capture cases, PC as described).

[2] CAMR limits were vacated on February 8, 2008 by court action.

The environmental target represents the maximum allowable emissions for any of the combustion cases. In some cases actual emissions are less than the target. For example, the CO_2 capture cases require a polishing scrubber to reduce sulfur dioxide (SO_2) concentrations to less than 10 parts per million volume (ppmv). In those cases the SO_2 emissions are substantially less than the environmental target.

BACT was applied to the NGCC cases and the resulting emissions compared to NSPS limits. The NGCC environmental targets were chosen based on reasonably obtainable limits given the control technologies employed and are presented in Exhibit 2-8.

Exhibit 2-8 Environmental Targets for NGCC Cases

Pollutant	Environmental Target	40 CFR Part 60, Subpart KKKK Limits	Control Technology
NO_x	2.5 ppmv @ 15% O_2	15 ppmv @ 15% O_2	Low NO_x burners and SCR
SO_2	Negligible	0.9 lb/MWh (0.134 lb/MMBtu)[1]	Low sulfur content fuel
Particulate Matter (Filterable)	N/A	N/A	N/A

[1] Assumes a heat rate of 6,719 Btu/kWh from the NGCC non-capture case.

Published vendor literature indicates that 25 ppmv NO_x at 15 percent O_2 is achievable using natural gas and DLN technology [11,12]. The application of SCR with 90 percent efficiency further reduces NO_x emissions to 2.5 ppmv, which was selected as the environmental target.

For the purpose of this study, natural gas was assumed to contain a negligible amount of sulfur compounds, and therefore generate negligible sulfur emissions. The EPA defines pipeline natural gas as containing >70 percent methane by volume or having a gross calorific value (GCV) of between 35.4 and 40.9 MJ/Nm^3 (950 and 1,100 Btu/scf) and having a total sulfur content of less than 13.7 mg/Nm^3 (0.6 gr/100 scf) [13]. Assuming a sulfur content equal to the EPA limit for pipeline natural gas, resulting SO_2 emissions for the two NGCC cases in this study would be approximately 21 tonnes/yr (23.2 tons/yr) at 85 percent CF or 0.00084 kg/GJ (0.00195 lb/MMBtu). Thus, for the purpose of this study, SO_2 emissions were considered negligible.

The pipeline natural gas was assumed to contain no particulate matter (PM) and no mercury resulting in no emissions of either.

2.5 LIFE CYCLE GHG ASSUMPTIONS

All GHG emissions reported in this study are based on a limited "cradle-to-gate" life cycle analysis. The emissions include anthropogenic CO_2 discharged through the plant stack, as well as GHG emissions associated with the production, processing, and transportation of the fuels. The analysis ends at the plant busbar and does not consider CO_2 sequestration losses. The GHG emissions presented in this report are on the life cycle basis as presented in this section, which includes the effect of other GHGs.

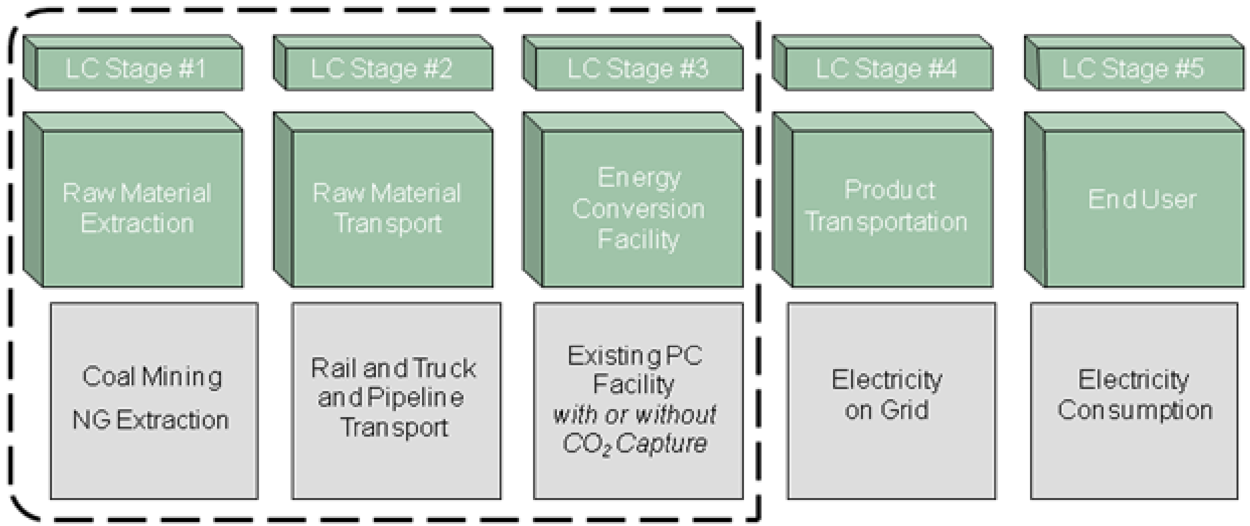
Many activities producing GHGs were included in the life cycle analysis, but the analysis still does not produce what might be considered a full life cycle. The following factors are not included in the life cycle boundary:

- Emissions from plant construction
- Fluctuations from plant start-up and shut-down

- Transmission losses
- Emissions associated with power delivery
- Emissions associated with the end user

Exhibit 2-9 illustrates the study life cycle stages. Plant life cycle stages 1-3 are considered. Excluded are stages 4 and 5 involving the transportation of the electricity product and activities of the end user.

Exhibit 2-9 Plant Life Cycle Stages



The limited life cycle emissions totals presented in this report are meant to be viewed as plant "snapshots" during normal, steady-state operation. The components of the limited life cycle analysis are described in more detail in the following sections.

2.5.1 Stack Emissions

Carbon in the fuel is converted to CO_2 via combustion and discharged to the atmosphere through the plant stack. Only fossil fuel-based carbon is considered to be anthropogenic and therefore counted towards the GHG emissions.

2.5.2 Coal Production

GHG emissions from coal production differ depending on coal type and mining method. In this study it is assumed that the bituminous coal is recovered from an underground mine and that no methane recovery is achieved. The GHG emission assumptions are summarized in Exhibit 2-10.

Exhibit 2-10 Assumptions for Coal Production GHG Emissions

Parameter	Value
CO_2 Mining Emissions[1]	43.5 lb CO_2/ton mined
N_2O Mining Emissions[1]	0.00069 lb CO_{2e}/ton mined
CH_4 Mining Emissions[2, 3]	243 lb CO_{2e}/ton

[1] GREET ver. 1.8b [2] Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 1999-2003, EPA Publication: EPA 430-K-04-003 [3] Kirchgessner, et. al., An Improved Inventory of Methane Emissions from Coal Mining in the United States

2.5.3 Coal Handling and Transportation

The mined coal contains in-situ methane, 95 percent of which is assumed to de-gas in the handling and storage process. The transportation emissions are based on rail transport using diesel-fueled locomotives. The GHG emission assumptions for coal handling and transport are summarized in Exhibit 2-11.

Exhibit 2-11 Assumptions for Coal Handling and Transportation GHG Emissions

Parameter	Value
In-Situ CH_4 Content[1]	60.4 lb CO_{2e} /ton
De-gas Rate	95%
Transport Distance	200 miles
Transport Energy Intensity[2]	370 Btu/ton-mile
Combustion Emissions (Diesel)[2]	
CO_2	77,632 g/MMBtu
CH_4	3.94 g/MMBtu
N_2O	2.0 g/MMBtu
Fuel Production Emissions[2]	
CO_2	13,320 g/MMBtu
CH_4	106.6 g/MMBtu
N_2O	0.22 g/MMBtu

[1] Kirchgessner, et. al., An Improved Inventory of Methane Emissions from Coal Mining in the United States
[2] Based on EPA's AP-42 document. Used in GREET to calculate fuel combustion emissions for upstream activities.

2.5.4 Natural Gas Acquisition

The boundaries for the life cycle analysis of natural gas begin with the acquisition of natural gas, in this case assumed to be from domestic sources. This stage of the analysis includes consideration of the construction materials and installation requirements for the natural gas wells, well operation including extraction, oil/gas separation, dehydration, acid gas removal (sweetening), and compression, ending with a natural gas product ready for pipeline transport. The GHG emissions associated with this stage of natural gas use are presented in Exhibit 2-12, based on an ongoing NETL life cycle analysis study for NGCC power plants [14]. These scaling parameters were constructed based on five extraction technologies used in the U.S. The majority of greenhouse gas, carbon monoxide, nitrogen oxide, and volatile organic compounds emissions are due to the combustion of natural gas required for natural gas extraction processing operations. The majority of sulfur oxide (SO_x) emissions are associated with well operations and are attributable to the upstream electricity consumed by gas extraction from Barnett Shale.

Wells in the Barnett Shale region are close to metropolitan areas and use electrically-powered compressors instead of gas-powered compressors, which results in lower operating costs and reduces the noise associated with extraction operations.

Exhibit 2-12 Assumptions for Domestic NG Acquisition GHG Emissions

GHG Emissions	kg/kg NG	Kg CO_2e /kg NG
CO_2	1.07E-01	1.07E-01
N2O	2.81E-07	8.38E-05
CH_4	1.67E-03	4.17E-02
SF6	3.78E-15	8.61E-11

2.5.5 Natural Gas Transport

For the domestic natural gas pathway, the boundary for natural gas transport begins with the receipt of natural gas from a natural gas extraction and processing site, includes an assumed 900 miles of pipeline transport, and ends with the delivery of natural gas to the NGSC facility [14]. The majority of emissions in this stage come from material and fuel inputs for pipeline transport, but a significant amount of GHG emission, especially when compared on an equivalent CO_2 basis, come from fugitive methane emissions. The assumptions for natural gas transport GHG emissions are shown in Exhibit 2-13.

Exhibit 2-13 Assumptions for Domestic NG Transport GHG Emissions

GHG Emissions	kg/kg NG	Kg CO_2e /kg NG
CO_2	1.07E-01	1.07E-01
N2O	2.81E-07	8.38E-05
CH_4	1.67E-03	4.17E-02
SF6	3.78E-15	8.61E-11

2.6 CO_2 PURITY SPECIFICATIONS

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. In the cases using sequestration, the CO_2 must be purified and pressurized prior to leaving the plant for sequestration. The following table lists the CO_2 conditions for which the CO_2 will be supplied at the "plant gate".

Exhibit 2-14 CO_2 Transport Specifications

	Design Condition (Remote EOR)
Pipeline material	carbon steel
Compression pressure (psia)	2214.71
CO_2	>95 vol%
Water	(0.015 vol%)
N_2	<4 vol%
O_2	<40 ppmv
Ar	< 10 ppmv

NH_3	<10 ppmv
CO	< 10 ppmv
Hydrocarbons	<5 vol%
H_2S	<1.3 vol%
CH_4	<0.8 vol%
H_2	uncertain
SO_2	<40 ppmv
NOx	uncertain

2.7 CAPACITY FACTOR

The capacity factor used in this study is 85 percent for all cases. This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore capacity factor and availability are equal. The capacity factor is the same as that used in previous studies for PC systems with CO_2 capture and is based on input from the North American Electric Reliability Council (NERC) and their work on the Generating Availability Data System (GADS).

NERC defines an equivalent availability factor (EAF), which is essentially a measure of the plant capacity factor assuming there is always a demand for the output. The EAF accounts for planned and scheduled derated hours as well as seasonal derated hours. As such, the EAF matches our definition of capacity factor.

The average EAF for coal-fired plants in the 400-599 MW size range was 84.9 percent in 2004 and averaged 83.9 percent from 2000 to 2004. Given that many of the plants in this size range are older, the EAF was rounded up to 85 percent and that value was used as the PC plant CF.

The addition of CO_2 capture to each technology was assumed not to impact the CF. This assumption was made to enable a comparison based on the impact of capital and variable operating costs only. Any reduction in assumed CF would further increase the COE for the CO_2 capture cases.

2.8 RAW WATER WITHDRAWAL AND CONSUMPTION

A water balance was performed for each case on the major water consumers in the process. The total water demand for each subsystem was determined and internal recycle water available from various sources like boiler feed water (BFW) blowdown and condensate flue gas (in CO_2 capture cases) was applied to offset the water demand. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is the water removed from the ground or diverted from a surface-water source for use in the plant. Raw water consumption is also accounted for as the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products, or otherwise not returned to the water source it was withdrawn from.

Raw water makeup was assumed to be provided 50 percent by a publicly owned treatment works (POTW) and 50 percent from groundwater. Raw water withdrawal is defined as the water metered from a raw water source and used in the plant processes for any and all purposes, such as cooling tower makeup, BFW makeup, slurry preparation makeup, ash handling makeup, syngas humidification, quench system makeup, and FGD system makeup. The difference between withdrawal and process water returned to the source is consumption. Consumption represents the net impact of the process on the water source.

BFW blowdown and a portion of the sour water stripper blowdown were assumed to be treated and recycled to the cooling tower. The cooling tower blowdown and the balance of the SWS blowdown streams were assumed to be treated and 90 percent returned to the water source with the balance sent to the ash ponds for evaporation.

The largest consumer of raw water in all cases is cooling tower makeup. It was assumed that all cases utilized a mechanical draft, evaporative cooling tower, and all process blowdown streams were assumed to be treated and recycled to the cooling tower. The design ambient wet bulb temperature of 11 °C (51.5 °F) (Exhibit 2-1) was used to achieve a cooling water temperature of 16 °C (60 °F) using an approach of 5 °C (8.5 °F). The cooling water range was assumed to be 11 °C (20 °F). The cooling tower makeup rate was determined using the following [15]:

- Evaporative losses of 0.8 percent of the circulating water flow rate per 10 °F of range
- Drift losses of 0.001 percent of the circulating water flow rate
- Blowdown losses were calculated as follows:
    - Blowdown Losses = Evaporative Losses / (Cycles of Concentration - 1)

      Where cycles of concentration is a measure of water quality, and a mid-range value of 4 was chosen for this study.

The water balances presented in subsequent sections include the water demand of the major water consumers within the process, the amount provided by internal recycle, the amount of raw water withdrawal by difference, the amount of process water returned to the source and the raw water consumption, again by difference.

2.9 COST ESTIMATING METHODOLOGY

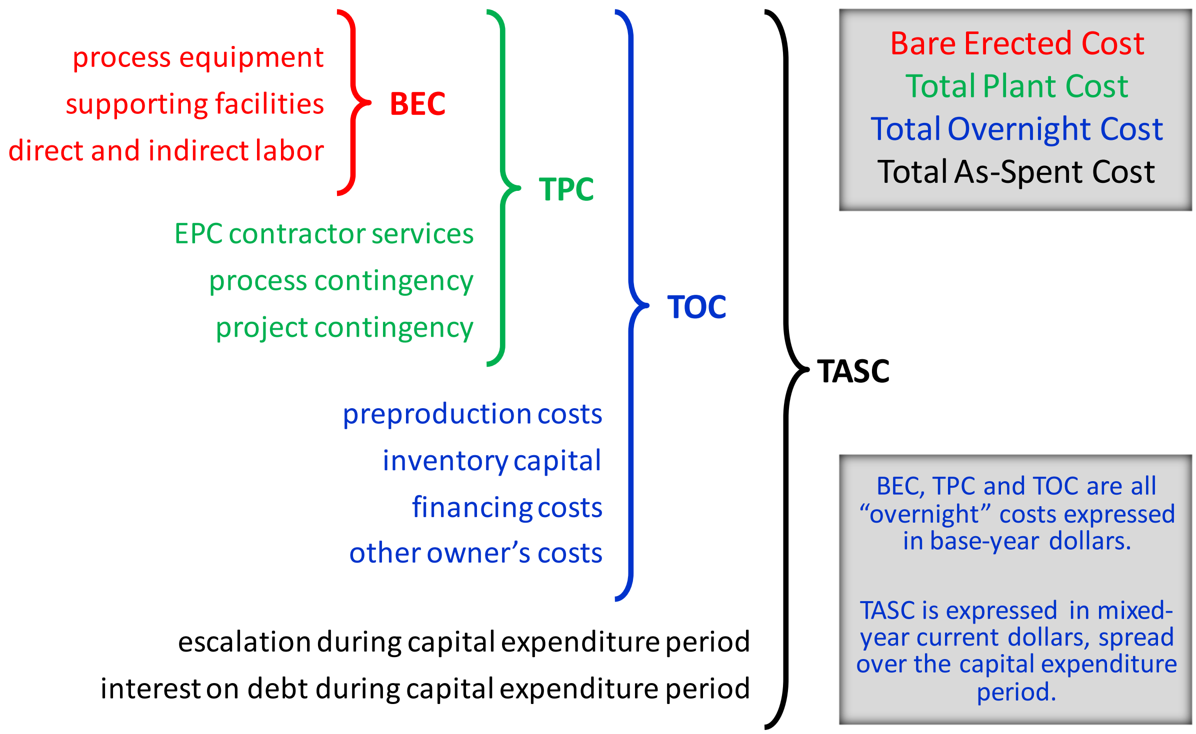
The estimating methodology for capital costs, operations and maintenance costs, and CO_2 TS&M costs are described below. The finance structure, basis for the discounted cash flow analysis, and first-year COE cost calculations are also described.

2.9.1 Capital Costs

As illustrated in Exhibit 2-15, this study reports capital cost at four levels: Bare Erected Cost (BEC), Total Plant Cost (TPC), Total Overnight Cost (TOC) and Total As-spent Capital (TASC). BEC, TPC and TOC are "overnight" costs and are expressed in "base-year" dollars. The base year is the first year of capital expenditure, which for this study is assumed to be 2007. TASC is expressed in mixed-year, current-year dollars over the entire capital expenditure period, which is assumed to last five years for coal plants (2007 to 2012).

The BEC comprises the cost of process equipment, on-site facilities and infrastructure that support the plant (e.g., shops, offices, labs, road), and the direct and indirect labor required for its construction and/or installation. The cost of EPC services and contingencies is not included in BEC. BEC is an overnight cost expressed in base-year (2007) dollars.

Exhibit 2-15 Capital Cost Levels and their Elements



The TPC comprises the BEC plus the cost of services provided by the engineering, procurement and construction (EPC) contractor and project and process contingencies. EPC services include: detailed design, contractor permitting (i.e., those permits that individual contractors must obtain to perform their scopes of work, as opposed to project permitting, which is not included here), and project/construction management costs. TPC is an overnight cost expressed in base-year (2007) dollars.

The TOC comprises the TPC plus owner's costs. TOC is an "overnight" cost, expressed in base-year (2007) dollars and as such does not include escalation during construction or interest during construction. TOC is an overnight cost expressed in base-year (2007) dollars.

The TASC is the sum of all capital expenditures as they are incurred during the capital expenditure period including their escalation. TASC also includes interest during construction. Accordingly, TASC is expressed in mixed, current-year dollars over the capital expenditure period.

Cost Estimate Basis and Classification

The TPC and Operation and Maintenance (O&M) costs for each of the cases in the study were scaled from existing cost quotes for similar plants. Recommended Practice 18R-97 of the Association for the Advancement of Cost Engineering International (AACE) describes a Cost Estimate Classification System as applied in Engineering, Procurement and Construction for the process industries [16].

Most techno-economic studies completed by NETL feature cost estimates intended for the purpose of a "Feasibility Study" (AACE Class 4). Exhibit 2-16 describes the characteristics of an AACE Class 4 Cost Estimate. Cost estimates in this study have an expected accuracy range of -15 percent/+30 percent.

Exhibit 2-16 Features of an AACE Class 4 Cost Estimate

Project Definition	Typical Engineering Completed	Expected Accuracy
1 to 15%	Plant capacity, block schematics, indicated layout, process flow diagrams for main process systems, and preliminary engineered process and utility equipment lists	-15% to -30% on the low side, and +20% to +50% on the high side

The capital costs for each cost account were reviewed by comparing individual accounts across all cases and to the baseline cases which were used as a cost basis to ensure an accurate representation of the relative cost differences between the cases and accounts. All capital costs are presented as "overnight costs" expressed in June 2007 dollars. The dollar values have been held at June 2007 to allow direct comparison with earlier results. Significant pricing fluctuations have occurred between June 2007 and March 2009. A retrospective look suggests that pricing for these commodities peaked in mid 2008 and generally declined during the latter parts of 2008 into 2009. While some pricing is still currently declining, based on published information, pricing at the end of 2008 remains higher than June 2007 values.

System Code-of-Accounts

The costs are grouped according to a process/system oriented code of accounts. This type of code-of-account structure has the advantage of grouping all reasonably allocable components of a system or process, so they are included within the specific system account. (This would not be the case had a facility, area, or commodity account structure been chosen instead).

Non-CO_2 Capture Plant Maturity

The case estimates provided include technologies at different commercial maturity levels. The estimates for the non-CO_2-capture portion of the plants represent well-developed commercial technology or "nth plants."

CO_2 Removal Plant Maturity

While the post-combustion technology for the PC plants has been practiced at smaller scale, it has never been practiced at a scale equivalent to that required in this study. There are domestic amine-based CO_2 capture systems operating on coal-derived flue gas at scales ranging from 150-800 tons per day (TPD) [17]. The plants in this study will capture an average 16,000 TPD of CO_2. Consequently the CO_2 capture cases are treated as FOAK.

Contracting Strategy

The estimates are based on an 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.

In a traditional lump sum EPC contract, the Contractor assumes all risk for performance, schedule, and cost. As a result of current market conditions, EPC contractors appear more reluctant to assume that overall level of risk. The current trend appears to be a modified EPC approach where much of the risk remains with the Owner. Where Contractors are willing to accept the risk in EPC type lump-sum arrangements, it is reflected in the project cost. In today's market, Contractor premiums for accepting these risks, particularly performance risk, can be substantial and increase the overall project costs dramatically.

The 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 and absorbs higher project management costs, the risks become reduced with time, as there is better scope definition at the time of contract award(s).

Estimate Scope

The estimates represent a complete power plant facility on a generic site. The plant boundary limit is defined as the total plant facility within the "fence line" including coal receiving and water supply system, but terminating at the high voltage side of the main power transformers. TS&M cost is not included in the reported capital cost or O&M costs, but is treated separately and added to the COE.

Capital Cost Assumptions

Key equipment costs for each of the cases were calibrated to reflect recent quotations and/or purchase orders for other ongoing in-house power or process projects. These include, but are not limited to, the following equipment:

- Econamine CO_2 Capture Process
- Circulating Water Pumps and Drivers
- Cooling Towers
- Main Transformers
- CT Auxiliary Plants

Other key estimate considerations include the following:

- Labor costs are based on Midwest, Merit Shop. Costs would need to be re-evaluated for projects at different locations or for projects employing union labor.
- The estimates are based on a competitive bidding environment, with adequate skilled craft labor available locally.
- Labor is based on a 50-hour work-week (5-10s). No additional incentives such as per-diems or bonuses have been included to attract craft labor.
- While not included at this time, labor incentives may ultimately be required to attract and retain skilled labor depending on the amount of competing work in the region, and the availability of skilled craft in the area at the time the projects proceed to construction. Current indications are that regional craft shortages are likely over the next several years. The types and amounts of incentives will vary based on project location and timing relative to other work. The cost impact resulting from an inadequate local work force can be significant.

- The site is considered to be Seismic Zone 1, relatively level, and free from hazardous materials, archeological artifacts, or excessive rock. Soil conditions are considered adequate for spread footing foundations. The soil bearing capability is assumed adequate such that piling is not needed to support the foundation loads.
- Costs are limited to within the "fence line," terminating at the high voltage side of the main power transformers.
- Engineering and Construction Management were estimated as 10 percent of bare erected cost.
- All capital costs are presented as "Overnight Costs" in June 2007 dollars. Escalation to period-of-performance is specifically excluded.

Price Fluctuations

A significant change in power plant cost occurred in recent years due to the significant increases in the pricing of equipment and bulk materials. This estimate includes these increases. All vendor quotes used to develop these estimates were received within the last two years.

Cross-comparisons

In all technology comparison studies, the relative differences in costs are often more significant than the absolute level of TPC. This requires cross-account comparison between technologies to review the consistency of the direction of the costs. As noted above, the capital costs were reviewed and compared across all of the cases, accounts, and technologies to ensure that a consistent representation of the relative cost differences is reflected in the estimates.

In performing such a comparison, it is important to reference the technical parameters for each specific item, as these are the basis for establishing the costs. Scope or assumption differences can quickly explain any apparent anomalies. There are a number of cases where differences in design philosophy occur. For example:

- Different amounts of duct firing were required to meet the CDR steam requirements for the two combustion turbine auxiliary plants, affecting efficiency and the size of the CO_2 capture plant required to capture the resulting emissions.

Exclusions

The capital cost estimate includes all anticipated costs for equipment and materials, installation labor, professional services (Engineering and Construction Management), and contingency. The following items are excluded from the capital costs:

All taxes, with the exception of payroll and property taxes (property taxes are included with the fixed O&M costs)

Site specific considerations – including, but not limited to, seismic zone, accessibility, local regulatory requirements, excessive rock, piles, laydown space, etc.

Labor incentives in excess of 5-10s

Additional premiums associated with an EPC contracting approach

Contingency

Both the project contingency and process contingency costs represent costs that are expected to be spent in the development and execution of the project that 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.

Project Contingency

Project contingencies were added to each of the capital accounts to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Each bare erected cost account was evaluated against the level of estimate detail, field experience, and the basis for the equipment pricing to define project contingency.

The capital cost estimates associated with the plant designs in this study were derived from various sources which include prior conceptual designs and actual design and construction of both process and power plants.

The Association for the Advancement of Cost Engineering (AACE) International recognizes five classes of estimates. On the surface, the level of project definition of the cases evaluated in this study would appear to fall under an AACE International Class 5 Estimate, associated with less than 2 percent project definition, and based on preliminary design methodology. However, the study cases are actually more in line with the AACE International Class 4 Estimate, which is associated with equipment factoring, parametric modeling, historical relationship factors, and broad unit cost data.

Based on the AACE International contingency guidelines as presented in NETL's "Quality Guidelines for Energy System Studies," it would appear that the overall project contingencies for the subject cases should be in the range of 30 to 40 percent [18]. However, we believe these to be too high when the basis for the cost numbers is considered. The costs have been extrapolated from an extensive database of project costs (estimated, quoted, and actual), based on both conceptual and detailed designs for the various technologies. This information has been used to calibrate the costs in the current studies, thus improving the quality of the overall estimates. As such, the overall project contingencies should be more in the lower portion of 15 to 20 percent range with the capture cases being higher than the non-capture cases.

Process Contingency

As shown in Exhibit 2-17, AACE International Recommended Practice 16R-90 provides guidelines for estimating process contingency based on EPRI philosophy [19].

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies have been applied to the estimates as follows:

CO_2 Removal System – 20 percent on all capture cases - post-combustion process unproven at commercial scale for power plant applications

Instrumentation and Controls – 5 percent on all capture cases

Exhibit 2-17 AACE Guidelines for Process Contingency

Technology Status	Process Contingency (% of Associated Process Capital)
New concept with limited data	40+
Concept with bench-scale data	30-70
Small pilot plant data	20-35
Full-sized modules have been operated	5-20
Process is used commercially	0-10

All contingencies included in the TPC, both project and process, represent costs that are expected to be spent in the development and execution of the project.

Owner's Costs

Exhibit 2-19 explains the estimation method for owner's costs. With some exceptions, the estimation method follows guidelines in Sections 12.4.7 to 12.4.12 of AACE International Recommended Practice No. 16R-90 [19]. The Electric Power Research Institute's "Technical Assessment Guide (TAG®) – Power Generation and Storage Technology Options" also has guidelines for estimating owner's costs. The EPRI and AACE guidelines are very similar. In instances where they differ, this study has sometimes adopted the EPRI approach.

Interest during construction and escalation during construction are not included as owner's costs but are factored into the COE and are included in TASC. These costs vary based on the capital expenditure period and the financing scenario. Ratios of TASC/TOC determined from the PSFM are used to account for escalation and interest during construction. Given TOC, TASC can be determined from the ratios given in Exhibit 2-18.

Exhibit 2-18 TASC/TOC Factors

Finance Structure	IOU High Risk	IOU Low Risk
TASC/TOC	1.140	1.134

Exhibit 2-19 Owner's Costs Included in TOC

Owner's Cost	Estimate Basis
Prepaid Royalties	Any technology royalties are assumed to be included in the associated equipment cost, and thus are not included as an owner's cost.
Preproduction (Start-Up) Costs	• 6 months operating labor • 1 month maintenance materials at full capacity • 1 month non-fuel consumables at full capacity • 1 month waste disposal • 25% of one month's fuel cost at full capacity • 2% of TPC Compared to AACE 16R-90, this includes additional costs for operating labor (6 months versus 1 month) to cover the cost of training the plant operators, including their participation in startup, and involving them occasionally during the design and construction. AACE 16R-90 and EPRI TAG® differ on the amount of fuel cost to include; this estimate follows EPRI.
Working Capital	Although inventory capital (see below) is accounted for, no additional costs are included for working capital.
Inventory Capital	• 0.5% of TPC for spare parts • 60 day supply (at full capacity) of fuel. Not applicable for natural gas. • 60 day supply (at full capacity) of non-fuel consumables (e.g., chemicals and catalysts) that are stored on site. Does not include catalysts and adsorbents that are batch replacements such as WGS, COS, and SCR catalysts and activated carbon. AACE 16R-90 does not include an inventory cost for fuel, but EPRI TAG® does.
Land	• $3,000/acre (300 acres for IGCC and PC, 100 acres for NGSC)
Financing Cost	• 2.7% of TPC This financing cost (not included by AACE 16R-90) covers the cost of securing financing, including fees and closing costs but not including interest during construction (or AFUDC). The "rule of thumb" estimate (2.7% of TPC) is based on a 2008 private communication with a capital services firm.
Other Owner's Costs	• 15% of TPC This additional lumped cost is not included by AACE 16R-90 or EPRI TAG®. The "rule of thumb" estimate (15% of

Owner's Cost	Estimate Basis
	TPC) is based on a 2009 private communication with WorleyParsons. Significant deviation from this value is possible as it is very site and owner specific. The lumped cost includes: − Preliminary feasibility studies, including a Front-End Engineering Design (FEED) study − Economic development (costs for incentivizing local collaboration and support) − Construction and/or improvement of roads and/or railroad spurs outside of site boundary − Legal fees − Permitting costs − Owner's engineering (staff paid by owner to give third-party advice and to help the owner oversee/evaluate the work of the EPC contractor and other contractors) − Owner's contingency (Sometimes called "management reserve", these are funds to cover costs relating to delayed startup, fluctuations in equipment costs, unplanned labor incentives in excess of a five-day/ten-hour-per-day work week. Owner's contingency is NOT a part of project contingency.) This lumped cost does NOT include: − EPC Risk Premiums (Costs estimates are based on an Engineering Procurement Construction Management approach utilizing multiple subcontracts, in which the owner assumes project risks for performance, schedule and cost) − Transmission interconnection: the cost of interconnecting with power transmission infrastructure beyond the plant busbar. − Taxes on capital costs: all capital costs are assumed to be exempt from state and local taxes. − Unusual site improvements: normal costs associated with improvements to the plant site are included in the bare erected cost, assuming that the site is level and requires no environmental remediation. Unusual costs associated with the following design parameters are excluded: flood plain considerations, existing soil/site conditions, water discharges and reuse, rainfall/snowfall criteria, seismic design, buildings/enclosures, fire protection, local code height requirements, noise regulations.
Initial Cost for Catalysts and Chemicals	• All initial fills not included in BEC
Taxes & Insurance	• 2% of TPC (Fixed O&M Cost)

2.9.2 Operations and Maintenance Costs

The production costs or operating costs and related maintenance expenses (O&M) pertain to those charges associated with O&M the power plants over their expected life. These costs include:

- Operating labor
- Maintenance – material and labor
- Administrative and support labor
- Consumables
- Fuel
- Waste disposal
- Co-product or by-product credit (that is, a negative cost for any by-products sold)

There are two components of O&M costs; fixed O&M, which is independent of power generation, and variable O&M, which is proportional to power generation.

Operating Labor

Operating labor cost was determined based on the number of operators required for each specific case. The average base labor rate used to determine annual cost is $34.65/hour (hr). The associated labor burden is estimated at 30 percent of the base labor rate. Taxes and insurance are included as fixed O&M costs totaling 2 percent of the TPC.

Maintenance Material and Labor

Maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost. This represents a weighted analysis in which the individual cost relationships were considered for each major plant component or section.

Administrative and Support Labor

Labor administration and overhead charges are assessed at a rate of 25 percent of the burdened O&M labor.

Consumables

The cost of consumables, including fuel, was determined on the basis of individual rates of consumption, the unit cost of each specific consumable commodity, and the plant annual operating hours.

Quantities for major consumables such as fuel were taken from technology-specific heat and mass balance diagrams developed for each plant application. Other consumables were evaluated on the basis of the quantity required using reference data.

The quantities for initial fills and daily consumables were calculated on a 100 percent operating capacity basis. The annual cost for the daily consumables was then adjusted to incorporate the annual plant operating basis, or CF.

Initial fills of the consumables, fuels and chemicals, are different from the initial chemical loadings (such as reactor catalyst), which are included with the equipment pricing in the capital cost.

Waste Disposal

Waste quantities and disposal costs were determined similarly to the consumables. In this study fly ash and bottom ash from the PC plant are considered a waste with a disposal cost of $17.89/tonne ($16.23/ton).

Co-Products and By-Products (Other than CO_2)

By-product quantities were also determined similarly to the consumables. However, due to the variable marketability of these by-products (bottom ash; fly ash co-mingled with FGD products) no credit was taken for potential saleable value.

It should be noted that by-product credits and/or disposal costs could potentially be an additional determining factor in the choice of technology for some companies and in selecting some sites. A high local value of the product can establish whether or not added capital should be included in the plant costs to produce a particular co-product. Ash is a potential by-product in certain markets and would have potential marketability. However, as stated above, since in these cases the fly ash contains mercury from carbon injection and FGD byproducts, it was assumed to be a waste material rather than a saleable byproduct.

2.9.3 CO_2 Transport, Storage and Monitoring

For those cases that feature carbon sequestration, the capital and operating costs for CO_2 TS&M were independently estimated by NETL. Those costs were converted to a TS&M COE increment that was added to the plant COE.

CO_2 TS&M was modeled based on the following assumptions:

- CO_2 is supplied to the pipeline at the plant fence line at a pressure of 15.3 MPa (2,215 psia). The CO_2 product gas composition varies in the cases presented, but is expected to meet the specification described in Exhibit 2-20 [20]. A glycol dryer located near the mid-point of the compression train is used to meet the moisture specification.
- The CO_2 is transported 80 km (50 miles) via pipeline to a geologic sequestration field for injection into a saline formation.
- The CO_2 is transported and injected as a SC fluid in order to avoid two-phase flow and achieve maximum efficiency [21]. The pipeline is assumed to have an outlet pressure (above the SC pressure) of 8.3 MPa (1,200 psia) with no recompression along the way. Accordingly, CO_2 flow in the pipeline was modeled to determine the pipe diameter that results in a pressure drop of 6.9 MPa (1,000 psi) over an 80 km (50 mile) pipeline length [22]. (Although not explored in this study, the use of boost compressors and a smaller pipeline diameter could possibly reduce capital costs for sufficiently long pipelines.) The diameter of the injection pipe will be of sufficient size that frictional losses during injection are minimal and no booster compression is required at the well-head in order to achieve an appropriate down-hole pressure, with hydrostatic head making up the difference between the injection and reservoir pressure.

Exhibit 2-20 CO_2 Pipeline Specification

Parameter	Units	Parameter Value
Inlet Pressure	MPa (psia)	15.3 (2,215)
Outlet Pressure	MPa (psia)	10.4 (1,515)
Inlet Temperature	°C (°F)	35 (95)
N_2 Concentration	ppmv	< 300
O_2 Concentration	ppmv	< 40
Ar Concentration	ppmv	< 10
H_2O Concentration	ppmv	< 150

- The saline formation is at a depth of 1,236 m (4,055 ft) and has a permeability of 22 millidarcy (md) (22 μm2) and formation pressure of 8.4 MPa (1,220 psig) [23]. This is considered an average storage site and requires roughly one injection well for each 9,360 tonnes (10,320 short tons) of CO_2 injected per day [23]. The assumed aquifer characteristics are tabulated in Exhibit 2-21.

Exhibit 2-21 Deep Saline Aquifer Specification

Parameter	Units	Base Case
Pressure	MPa (psi)	8.4 (1,220)
Thickness	m (ft)	161 (530)
Depth	m (ft)	1,236 (4,055)
Permeability	md (μm2)	22 (22)
Pipeline Distance	Km (miles)	80 (50)
Injection Rate per Well	Tonne (ton) CO_2/day	9,360 (10,320)

The cost metrics utilized in this study provide a best estimate of TS&M costs for a "favorable" sequestration project, and may vary significantly based on variables such as terrain to be crossed by the pipeline, reservoir characteristics, and number of land owners from which sub-surface rights must be acquired. Raw capital and operating costs are derived from detailed cost metrics found in the literature, escalated to June 2007-year dollars using appropriate price indices. These costs were then verified against values quoted by industrial sources where possible. Where regulatory uncertainty exists or costs are undefined, such as liability costs and the acquisition of underground pore volume, analogous existing policies were used for representative cost scenarios.

The following subsections describe the sources and methodology used for each metric.

TS&M Capital Costs

TS&M capital costs include both a 20 percent process contingency and 30 percent project contingency.

In several areas, such as Pore Volume Acquisition, Monitoring, and Liability, cost outlays occur over a longer time period, up to 100 years. In these cases a capital fund is established based on the net present value of the cost outlay, and this fund is then levelized similar to the other costs.

Transport Costs

CO_2 transport costs are broken down into three categories: pipeline costs, related capital expenditures, and O&M costs.

Pipeline costs are derived from data published in the Oil and Gas Journal's (O&GJ) annual Pipeline Economics Report for existing natural gas, oil, and petroleum pipeline project costs from 1991 to 2003. These costs are expected to be analogous to the cost of building a CO_2 pipeline, as noted in various studies [21, 23, 24]. The University of California performed a regression analysis to generate cost curves from the O&GJ data: (1) Pipeline Materials, (2) Direct Labor, (3) Indirect Costs, and (4) Right-of-way acquisition, with each represented as a function of pipeline length and diameter [24]. These cost curves were escalated to the June 2007 year dollars used in this study.

Related capital expenditures were based on the findings of a previous study funded by DOE/NETL, Carbon Dioxide Sequestration in Saline Formations – Engineering and Economic Assessment [23]. This study utilized a similar basis for pipeline costs (O&GJ Pipeline cost data up to the year 2000) but added a CO_2 surge tank and pipeline control system to the project.

Transport O&M costs were assessed using metrics published in a second DOE/NETL sponsored report entitled Economic Evaluation of CO_2 Storage and Sink Enhancement Options [21]. This study was chosen due to the reporting of O&M costs in terms of pipeline length, whereas the other studies mentioned above either (a) do not report operating costs, or (b) report them in absolute terms for one pipeline, as opposed to as a length- or diameter-based metric.

Storage Costs

Storage costs were divided into five categories: (1) Site Screening and Evaluation, (2) Injection Wells, (3) Injection Equipment, (4) O&M Costs, and (5) Pore Volume Acquisition. With the exception of Pore Volume Acquisition, all of the costs were obtained from Economic Evaluation of CO_2 Storage and Sink Enhancement Options [21]. These costs include all of the costs associated with determining, developing, and maintaining a CO_2 storage location, including site evaluation, well drilling, and the capital equipment required for distributing and injecting CO_2.

Pore Volume Acquisition costs are the costs associated with acquiring rights to use the sub-surface volume where the CO_2 will be stored, i.e., the pore space in the geologic formation. These costs were based on recent research by Carnegie Mellon University, which examined existing sub-surface rights acquisition as it pertains to natural gas storage [25]. The regulatory uncertainty in this area combined with unknowns regarding the number and type (private or government) of property owners, require a number of "best engineering judgment" decisions to be made. In this study it was assumed that long-term lease rights were acquired from the property owners in the projected CO_2 plume growth region for a nominal fee, and that an annual "rent" was paid when the plume reached each individual acre of their property for a period of up to 100 years from the injection start date. The present value of the life cycle pore volume costs are assessed at a 10 percent discount rate and a capital fund is set up to pay for these costs over the 100 year rent scenario.

Liability Protection

Liability Protection addresses the fact that if damages are caused by injection and long-term storage of CO_2, the injecting party may bear financial liability. Several types of liability protection schemes have been suggested for CO_2 storage, including Bonding, Insurance, and Federal Compensation Systems combined with either tort law (as with the Trans-Alaska Pipeline Fund), or with damage caps and preemption, as is used for nuclear energy under the Price Anderson Act [26]. However, at present, a specific liability regime has yet to be dictated either at a Federal or (to our knowledge) State level. However, certain state governments have enacted legislation which assigns liability to the injecting party, either in perpetuity (Wyoming) or until ten years after the cessation of injection operations, pending reservoir integrity certification, at which time liability is turned over to the state (North Dakota and Louisiana) [27, 28, 29]. In the case of Louisiana, a trust fund totaling five million dollars is established over the first ten years (120 months) of injection operations for each injector. This fund is then used by the state for CO_2 monitoring and, in the event of an at-fault incident, damage payments.

Liability costs assume that a bond must be purchased before injection operations are permitted in order to establish the ability and good will of an injector to address damages where they are deemed liable. A figure of five million dollars was used for the bond based on the Louisiana fund level. This bond level may be conservatively high, in that the Louisiana fund covers both liability and monitoring, but that fund also pertains to a certified reservoir where injection operations have ceased, having a reduced risk compared to active operations. The bond cost was not escalated.

Monitoring Costs

Monitoring costs were evaluated based on the methodology set forth in the International Energy Agency (IEA) Greenhouse Gas (GHG) R&D Programme's Overview of Monitoring Projects for Geologic Storage Projects report [30]. In this scenario, operational monitoring of the CO_2 plume occurs over thirty years (during plant operation) and closure monitoring occurs for the following fifty years (for a total of eighty years). Monitoring is via electromagnetic (EM) survey, gravity survey, and periodic seismic survey; EM and gravity surveys are ongoing while seismic survey occurs in years 1, 2, 5, 10, 15, 20, 25, and 30 during the operational period, then in years 40, 50, 60, 70, and 80 after injection ceases.

2.9.4 Finance Structure, Discounted Cash Flow Analysis, and COE

The global economic assumptions are listed in Exhibit 2-22.

Finance structures were chosen based on the assumed type of developer/owner (investor-owned utility (IOU) or independent power producer) and the assumed risk profile of the plant being assessed (low-risk or high-risk). For this study the owner/developer was assumed to be an IOU and all cases were categorized as high risk. Exhibit 2-23 describes the low-risk IOU and high-risk IOU finance structures that are assumed for this type of study. These finance structures were recommended in a 2008 NETL report based on interviews with project developers/owners, financial organizations and law firms [31].

Exhibit 2-22 Global Economic Assumptions

Parameter	Value
TAXES	
Income Tax Rate	38% (Effective 34% Federal, 6% State)
Capital Depreciation	20 years, 150% declining balance
Investment Tax Credit	0%
Tax Holiday	0 years
CONTRACTING AND FINANCING TERMS	
Contracting Strategy	Engineering Procurement Construction Management (owner assumes project risks for performance, schedule and cost)
Type of Debt Financing	Non-Recourse (collateral that secures debt is limited to the real assets of the project)
Repayment Term of Debt	15 years
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
ANALYSIS TIME PERIODS	
Capital Expenditure Period	5 Years
Operational Period	30 years
Economic Analysis Period (used for IRROE)	35 Years (capital expenditure period plus operational period)
TREATMENT OF CAPITAL COSTS	
Capital Cost Escalation During Capital Expenditure Period (nominal annual rate)	3.6%[1]
Distribution of Total Overnight Capital over the Capital Expenditure Period (before escalation)	5-Year Period: 10%, 30%, 25%, 20%, 15%
Working Capital	zero for all parameters
% of Total Overnight Capital that is Depreciated	100% *(this assumption introduces a very small error even if a substantial amount of TOC is actually non-depreciable)*
ESCALATION OF OPERATING REVENUES AND COSTS	
Escalation of COE (revenue), O&M Costs, and Fuel Costs (nominal annual rate)	3.0%[2]

[1] A nominal average annual rate of 3.6 percent is assumed for escalation of capital costs during construction. This rate is equivalent to the nominal average annual escalation rate for process plant construction costs between 1947 and 2008 according to the *Chemical Engineering* Plant Cost Index.

[2] An average annual inflation rate of 3.0 percent is assumed. This rate is equivalent to the average annual escalation rate between 1947 and 2008 for the U.S. Department of Labor's Producer Price Index for Finished Goods, the so-called "headline" index of the various Producer Price Indices. (The Producer Price Index for the Electric Power Generation Industry may be more applicable, but that data does not provide a long-term historical perspective since it only dates back to December 2003.)

Exhibit 2-23 Financial Structure for Investor Owned Utility High and Low Risk Projects

Type of Security	% of Total	Current (Nominal) Dollar Cost	Weighted Current (Nominal) Cost	After Tax Weighted Cost of Capital
Low Risk				
Debt	50	4.5%	2.25%	
Equity	50	12%	6%	
Total			8.25%	7.39%
High Risk				
Debt	45	5.5%	2.475%	
Equity	55	12%	6.6%	
Total			9.075%	8.13%

DCF Analysis and Cost of Electricity

The NETL Power Systems Financial Model (PSFM) is a nominal-dollar[3] (current dollar) discounted cash flow (DCF) analysis tool. As explained below, the PSFM was used to calculate COE[4] in two ways: a COE and a levelized COE (LCOE). To illustrate how the two are related, COE solutions are shown in Exhibit 2-24 for a generic pulverized coal (PC) power plant and a generic natural gas combined cycle (NGCC) power plant, each with carbon capture and sequestration installed.

- The **COE** is the revenue received by the generator per net megawatt-hour during the power plant's first year of operation, *assuming that the COE escalates thereafter at a nominal annual rate equal to the general inflation rate, i.e., that it remains constant in real terms over the operational period of the power plant*. To calculate the COE, the PSFM was used to determine a "base-year" (2007) COE that, when escalated at an assumed nominal annual general inflation rate of 3 percent[5], provided the stipulated internal rate of return on equity over the entire economic analysis period (capital expenditure period plus thirty years of operation). The COE solutions are shown as curved lines in the upper portion of Exhibit 2-24 for a PC power plant and a NGCC power plant. Since this analysis assumes that COE increases over the economic analysis period at the nominal annual general inflation rate, it remains constant in real terms and the first-year COE is equivalent to the base-year COE when expressed in base-year (2007) dollars.

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[3] Since the analysis takes into account taxes and depreciation, a nominal dollar basis is preferred to properly reflect the interplay between depreciation and inflation.

[4] For this calculation, "cost of electricity" is somewhat of a misnomer because from the power plant's perspective it is actually the "price" received for the electricity generated to achieve the stated IRROE. However, since the price paid for generation is ultimately charged to the end user, from the customer's perspective it is part of the cost of electricity.

[5] This nominal escalation rate is equal to the average annual inflation rate between 1947 and 2008 for the U.S. Department of Labor's Producer Price Index for Finished Goods. This index was used instead of the Producer Price Index for the Electric Power Generation Industry because the Electric Power Index only dates back to December 2003 and the Producer Price Index is considered the "headline" index for all of the various Producer Price Indices.

- The **LEVELIZED COE** is the revenue received by the generator per net megawatt-hour during the power plant's first year of operation, *assuming that the COE escalates thereafter at a nominal annual rate of 0 percent, i.e., that it remains constant in nominal terms over the operational period of the power plant.* This study reports LCOE on a current-dollar basis over thirty years. "Current dollar" refers to the fact that levelization is done on a nominal, rather than a real, basis[6]. "Thirty-years" refers to the length of the operational period assumed for the economic analysis. To calculate the LCOE, the PSFM was used to calculate a base-year COE that, when escalated at a nominal annual rate of 0 percent, provided the stipulated return on equity over the entire economic analysis period. For the example PC and NGCC power plant cases, the LCOE solutions are shown as horizontal lines in the upper portion of Exhibit 2-24.

Exhibit 2-24 also illustrates the relationship between COE and the assumed developmental and operational timelines for the power plants. As shown in the lower portion of Exhibit 2-24, the capital expenditure period is assumed to start in 2007 for all cases in this report. All capital costs included in this analysis, including project development and construction costs, are assumed to be incurred during the capital expenditure period. Coal-fueled plants are assumed to have a capital expenditure period of five years and natural gas-fueled plants are assumed to have a capital expenditure period of three years. Since both types of plants begin expending capital in the base year (2007), this means that the analysis assumes that they begin operating in different years: 2012 for coal plants and 2010 for natural gas plants in this study (see Volume 3c for cost and performance of NGCC plants). In this study, the existing plant is assumed to be paid off and so the capital expenditure is determined by the auxiliary plant being retrofitted, or defaulted to three years. Note that, according to the *Chemical Engineering* Plant Cost Index, June-2007 dollars are nearly equivalent to January-2010 dollars.

In addition to the capital expenditure period, the economic analysis considers thirty years of operation.

Since 2007 is the first year of the capital expenditure period, it is also the base year for the economic analysis. Accordingly, it is convenient to report the results of the economic analysis in base-year (June 2007) dollars, except for TASC, which is expressed in mixed-year, current dollars over the capital expenditure period.

Consistent with our nominal-dollar discounted cash flow methodology, the COEs shown on Exhibit 2-24 are expressed in current dollars. However, they can also be expressed in constant, base year dollars (June 2007) as shown in Exhibit 2-25 by adjusting them with the assumed nominal annual general inflation rate (3 percent).

Exhibit 2-25 illustrates the same information as in Exhibit 2-24 for a PC plant with CCS only on a constant 2007 dollar basis. With an assumed nominal COE escalation rate equal to the rate of inflation, the COE line now becomes horizontal and the LCOE decreases at a rate of 3 percent per year.

[6] For this current-dollar analysis, the LCOE is uniform in current dollars over the analysis period. In contrast, a constant-dollar analysis would yield an LCOE that is uniform in constant dollars over the analysis period.

Exhibit 2-24 Illustration of COE Solutions using DCF Analysis

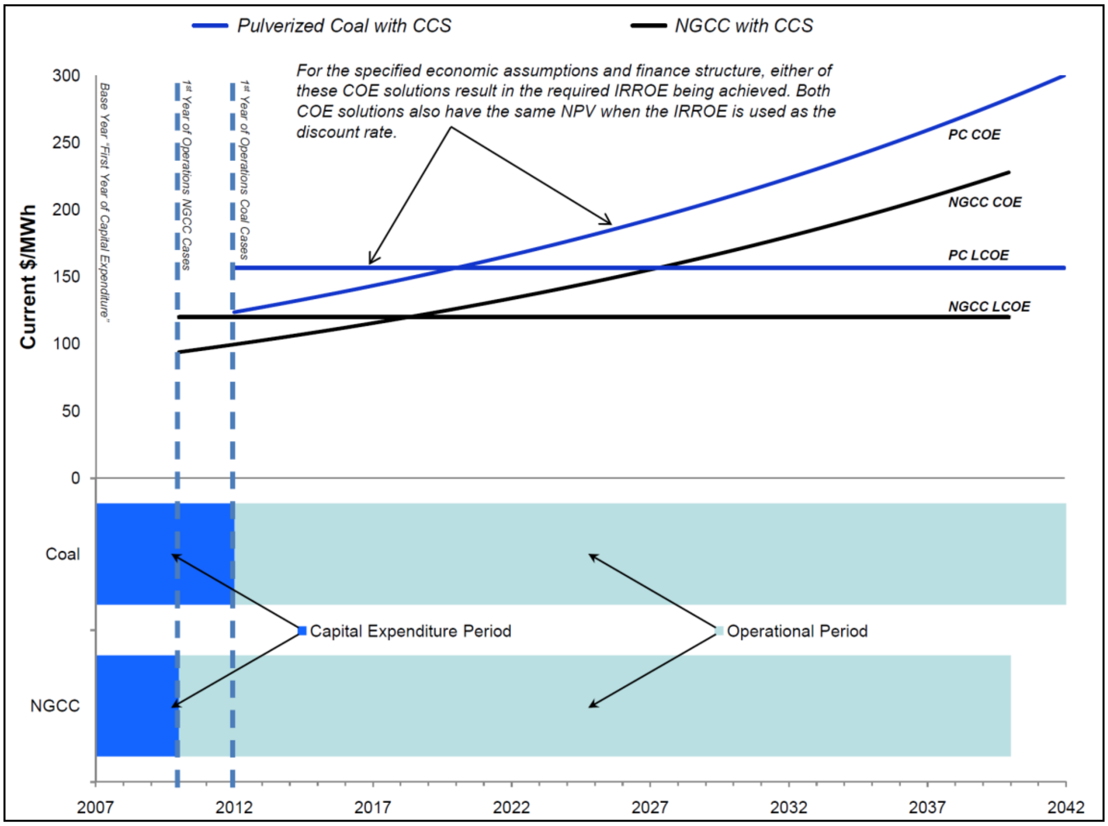
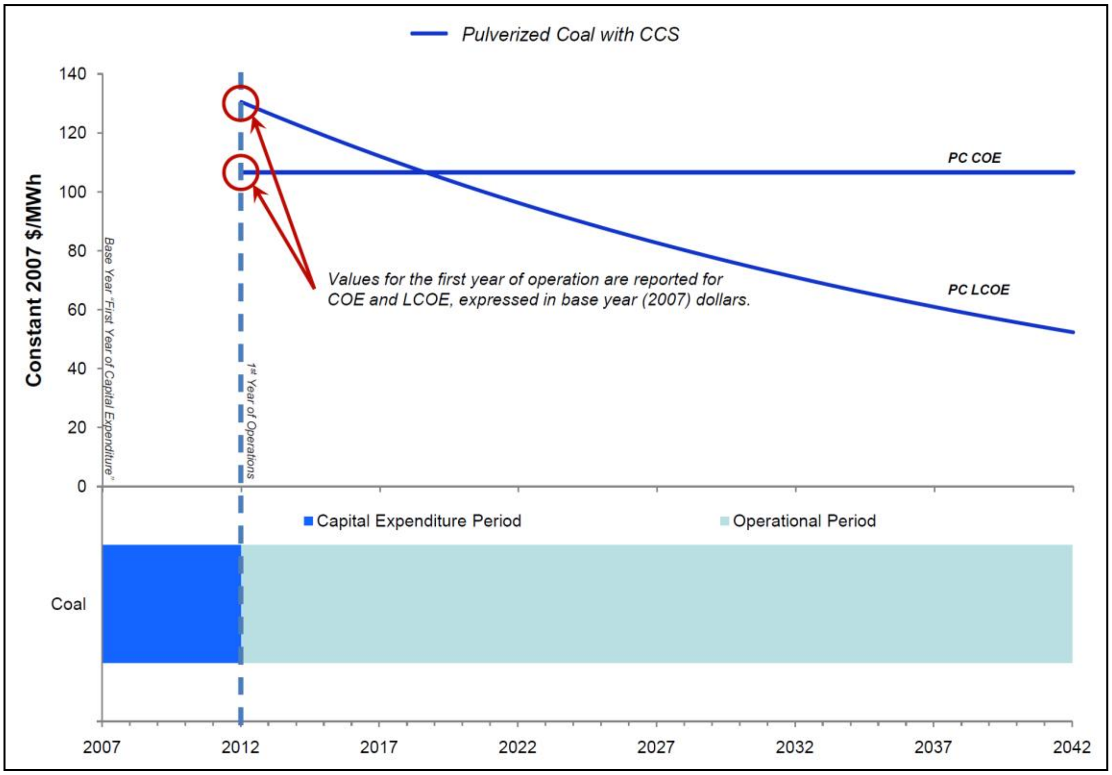


Exhibit 2-25 PC with CCS in Current 2007 Dollars



Estimating COE with Capital Charge Factors

For scenarios that adhere to the global economic assumptions listed in Exhibit 2-22 and utilize one of the finance structures listed in Exhibit 2-23, the following simplified equation can be used to estimate COE as a function of TOC, fixed O&M, variable O&M (including fuel), capacity factor and net output. The equation requires the application of one of the capital charge factors (CCF) listed in Exhibit 2-26. These CCFs are valid only for the global economic assumptions listed in Exhibit 2-22, the stated finance structure, and the stated capital expenditure period.

Exhibit 2-26 Capital Charge Factors for COE Equation

Finance Structure	High Risk IOU	Low Risk IOU
Capital Charge Factor (CCF)	0.1243	0.1165

All factors in the COE equation are expressed in base-year dollars. The base year is the first year of capital expenditure, which for this study is assumed to be 2007. As shown in Exhibit 2-22, all factors (COE, O&M and fuel) are assumed to escalate at a nominal annual general inflation rate of 3.0 percent. Accordingly, all first-year costs (COE and O&M) are equivalent to base-year costs when expressed in base-year (2007) dollars.

$$COE = \frac{\begin{matrix} first\ year \\ capital\ charge \end{matrix} + \begin{matrix} first\ year \\ fixed\ operating \\ costs \end{matrix} + \begin{matrix} first\ year \\ variable\ operating \\ costs \end{matrix}}{\begin{matrix} annual\ net\ megawatt\ hours \\ of\ power\ generated \end{matrix}}$$

$$COE = \frac{(CCF)(TOC) + OC_{FIX} + (CF)(OC_{VAR})}{(CF)(MWH)}$$

where:

COE =	revenue received by the generator ($/MWh, equivalent to mills/kWh) during the power plant's first year of operation (*but expressed in base-year dollars*), assuming that the COE escalates thereafter at a nominal annual rate equal to the general inflation rate, i.e., that it remains constant in real terms over the operational period of the power plant.
CCF =	capital charge factor taken from Exhibit 2-26 that matches the applicable finance structure and capital expenditure period
TOC =	total overnight capital, *expressed in base-year dollars*
OC_{FIX} =	the sum of all fixed annual operating costs, *expressed in base-year dollars*
OC_{VAR} =	the sum of all variable annual operating costs, including fuel at 100 percent capacity factor, *expressed in base-year dollars*
CF =	plant capacity factor, assumed to be constant over the operational period
MWH =	annual net megawatt-hours of power generated at 100 percent capacity factor

3. SYSTEM DESCRIPTIONS

System descriptions for the major process areas included in this study are described in this section. A base plant configuration with modifications to the configuration is described in Section 4.

3.1 COAL AND SORBENT RECEIVING, PREPARATION, AND STORAGE

The function of this 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 at the outlet of the coal storage silos.

The coal is delivered to the site by 100-car unit trains comprised of 91 tonne (100 ton) rail cars. The unloading is done by a trestle bottom dumper, which unloads the coal into two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 8 cm x 0 (3" x 0) coal from the feeder is discharged onto a belt conveyor. Two conveyors with an intermediate transfer tower are assumed to convey the coal to the coal stacker, which transfer the coal to either the long-term storage pile or to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

The reclaimer loads the coal into two vibratory feeders located in the reclaim hopper under the pile. The feeders transfer the coal onto a belt conveyor that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3 cm x 0 (1¼" x 0) by the crusher. A conveyor then transfers the coal to a transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of three silos. Two sampling systems are supplied: the as-received sampling system and the as-fired sampling system. Data from the analyses are used to support the reliable and efficient operation of the plant.

Limestone is delivered to the site using 23 tonne (25 ton) trucks. The trucks empty into a below grade hopper where a feeder transfers the limestone to a conveyor for delivery to the storage pile. Limestone from the storage pile is transferred to a reclaim hopper and conveyed to a day bin

3.2 COAL FEED

The crushed Illinois No. 6 bituminous coal is fed through feeders to each of the mills (pulverizers), where its size is reduced to approximately 72 percent passing 200 mesh and less than 0.5 percent remaining on 50 mesh [32]. The PC exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls using air supplied by the PA fans.

3.3 STEAM GENERATOR AND ANCILLARIES

The steam generator for the plants is a once-through, spiral-wound, Benson-boiler, wall-fired, balanced draft type unit with a water-cooled, dry bottom furnace. It includes a superheater, reheater, economizer, and air heater.

For the purposes of this study, it is assumed that the power plant is designed to be operated as a base-loaded 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. It is assumed for the purposes of this study that the power plant is designed for operation as a base-load unit.

3.3.1 Scope

The steam generator comprises the following:

- Once-through type steam generator
- Startup circuit, including integral separators
- Water-cooled furnace, dry bottom
- Two-stage superheater
- RH
- OFA system
- Economizer
- Spray type desuperheater
- Soot blower system
- Air preheaters (Ljungstrom type)
- Coal feeders and pulverizers
- Low NO_x Coal burners and light oil ignitors/ warmup system
- Forced draft (FD) fans
- Primary air (PA) fans
- Induced draft (ID) fans

The steam generator operates as follows:

3.3.2 Feedwater and Steam

The feedwater (FW) enters the bottom header of the economizer and passes upward through the economizer tube bank, through stringer tubes, which support the primary superheater, and discharges to the economizer outlet headers. From the outlet headers, water flows to the furnace hopper inlet headers via external downcomers. Water then flows upward through the furnace hopper and furnace wall tubes. From the furnace, water flows to the steam water separator. During low load operation (operation below the Benson point), the water from the separator is returned to the economizer inlet with the boiler recirculating pump. Operation at loads above the Benson point is once through.

Steam flows from the separator through the furnace roof to the convection pass enclosure walls, primary superheater, through the first stage of water attemperation, to the furnace platens. From the platens, the steam flows through the second stage of attemperation and then to the intermediate superheater. The steam then flows to the final superheater and on to the outlet pipe terminal. During rapid load changes, two stages of spray attemperation are used to provide tight temperature control in all high temperature sections.

Steam returning from the turbine passes through the primary reheater surface, then through crossover piping containing inter-stage attemperation. The crossover piping feeds the steam to the final reheater banks and then out to the turbine. Inter-stage attemperation is used to provide outlet temperature control during load changes.

3.3.3 Air and Combustion Products

Combustion air from the 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 PC to the burners is supplied by the PA fans.

The fuel/air mixture flows to the fuel nozzles at upper 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 and flow to the SCR reactor, fabric filter, ID fan, FGD system, and stack.

3.3.4 Ash Removal

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. The hoppers are of welded steel construction, lined with 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 description of the balance of the bottom ash handling system is presented in Section 3.10. The steam generator incorporates fly ash hoppers under the economizer outlet and air heater outlet.

3.3.5 Burners

A typical boiler from the existing plant employs approximately 24 to 36 nozzles arranged at multiple elevations for 100 percent coal. Each burner is designed at a low NO_x configuration, with staging of the coal combustion to minimize NO_x formation. In addition, OFA nozzles are provided to further stage combustion and thereby minimize NO_x formation.

Oil-fired pilot torches are provided for each coal burner for ignition, warm-up and flame stabilization at startup and low loads.

3.3.6 Air Preheaters

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

3.3.7 Soot Blowers

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 HP 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.

3.3.8 Auxiliary Plant HRSG/Boiler

The steam required for the CDR retrofit process can be directly satisfied by a concurrent auxiliary plant retrofit, recovering heat to generate steam in a HRSG or boiler, depending on the configuration. If a natural gas turbine is used to generate additional power, significant amounts of sensible heat can be extracted from the exhaust using a HRSG. The steam pressure levels generated in the HRSG would be determined by process needs and identifying suitable and cost effective uses. Conceivably, this HRSG could be used to augment the main steam flow for the base plant, taking advantage of existing design margins in the existing steam turbine, but at the cost of added complexity, downtime for installation, and cost. For the combustion turbine auxiliary plants, the HRSG was used only to provide steam to the CDR process, which would all be installed together. If the sensible heat in the flue gas is insufficient to provide the necessary heat, duct firing in the HRSG or a supplemental boiler (burning natural gas coal) may be added to avoid taking extraction from the existing steam turbine.

3.4 NO_X CONTROL SYSTEM

The plant is designed to achieve the environmental target of 0.07 lb NOx/MMBtu. Two measures are taken to reduce the NO_x. The first is a combination of LNBs and the introduction of staged OFA in the boiler. The LNBs and OFA reduce the emissions to about 0.5 lb/MMBtu.

The second measure taken to reduce the NO_x emissions is the installation of an SCR system prior to the air heater. SCR uses ammonia and a catalyst to reduce NO_x to N_2 and H_2O. The SCR system consists of three subsystems: reactor vessel, ammonia storage and injection, and gas flow control. The SCR system is designed for 86 percent reduction with 2 ppmv ammonia slip at the end of the catalyst life. This design, along with the LNBs, achieves the emission limit of 0.07 lb/MMBtu. The SCR capital costs are included with the boiler costs, as is the cost for the initial load of catalyst.

3.4.1 SCR Operation

The reactor vessel is designed to allow proper retention time for the ammonia to contact the NO_x in the boiler exhaust gas. Ammonia is injected into the gas immediately prior to entering the reactor vessel. The catalyst contained in the reactor vessel enhances the reaction between the ammonia and the NO_x in the gas. Catalysts consist of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. The operating range for vanadium/titanium-based catalysts is 260 °C (500 °F) to 455 °C (850 °F). The boiler is equipped with economizer bypass to provide FG to the reactors at the desired temperature during periods of low flow rate, such as low load operation. Also included with the reactor vessel is soot-blowing equipment used for cleaning the catalyst.

The ammonia storage and injection system consists of the unloading facilities, bulk storage tank, vaporizers, dilution air skid, and injection grid.

The FG flow control consists of ductwork, dampers, and flow straightening devices required to route the boiler exhaust to the SCR reactor and then to the air heater. The economizer bypass and associated dampers for low load temperature control are also included.

3.5 PARTICULATE CONTROL

The fabric filter (or baghouse) consists of two separate single-stage, in-line, multi-compartment units. Each unit is of high (0.9-1.5 m/min [3-5 ft/min]) air-to-cloth ratio design with a pulse-jet on-line cleaning system. The ash is collected on the outside of the bags, which are supported by steel cages. The dust cake is removed by a pulse of compressed air. The bag material is polyphenylensulfide (PPS) with intrinsic Teflon Polytetrafluoroethylene (PTFE) coating [33]. The bags are rated for a continuous temperature of 180 °C (356 °F) and a peak temperature of 210 °C (410 °F). Each compartment contains a number of gas passages with filter bags, and heated ash hoppers supported by a rigid steel casing. The fabric filter is provided with necessary control devices, inlet gas distribution devices, insulators, inlet and outlet nozzles, expansion joints, and other items as required.

3.6 MERCURY REMOVAL

Mercury removal is based on a coal Hg content of 0.15 ppmd. The environmental target for Hg is listed in Section 2.4. The combination of pollution control technologies used in the PC plants, SCR, fabric filters and FGD, result in significant co-benefit capture of mercury. The SCR promotes the oxidation of elemental mercury, which in turn enhances the mercury removal capability of the fabric filter and FGD unit. The mercury co-benefit capture is assumed to be 90 percent for this combination of control technologies as described in Section 2.4. Co-benefit capture alone is sufficient to meet current NSPS mercury limits so no activated carbon injection is included.

3.7 FLUE GAS DESULFURIZATION

The FGD system is a wet limestone forced oxidation positive pressure absorber non-reheat unit, with wet-stack, and gypsum production. The function of the FGD system is to scrub the boiler exhaust gases to remove the SO_2 prior to release to the environment, or entering into the Carbon Dioxide Removal (CDR) facility. Sulfur emission target is 0.085lb/MMBtu for all cases.

SO_2 content of the scrubbed gases must be further reduced to approximately 10 ppmv to minimize formation of amine heat stable salts (HSS) during the CO_2 absorption process. The CDR unit includes a polishing scrubber to reduce the FG SO_2 concentration from about 44 ppmv at the FGD exit to the required 10 ppmv prior to the CDR absorber. The scope of the FGD system is from the outlet of the ID fans to CDR process inlet. The system description is divided into three sections:

- Limestone Handling and Reagent Preparation
- FGD Scrubber
- Byproduct Dewatering

3.7.1 <u>Reagent Preparation System</u>

The function of the limestone reagent preparation system is to grind and slurry the limestone delivered to the plant. The scope of the system is from the day bin up to the limestone feed system. The system is designed to support continuous baseload operation.

Operation Description - Each day bin supplies a 100 percent capacity ball mill via a weigh feeder. The wet ball mill accepts the limestone and grinds the limestone to 90 to 95 percent passing 325 mesh (44 microns). Water is added at the inlet to the ball mill to create limestone slurry. The reduced limestone slurry is then discharged into a mill slurry tank. Mill recycle pumps, two per tank, pump the limestone water slurry to an assembly of hydrocyclones and distribution boxes. The slurry is classified into several streams, based on suspended solids content and size distribution.

The hydrocyclone underflow with oversized limestone is directed back to the mill for further grinding. The hydrocyclone overflow with correctly sized limestone is routed to a reagent storage tank. Reagent distribution pumps direct slurry from the tank to the absorber module.

3.7.2 FGD Scrubber

The FG exiting the air preheater section of the boiler passes through one of two parallel fabric filter units, then through the ID fans, and into the one 100 percent capacity absorber module. The absorber module is designed to operate with counter-current flow of gas and reagent. Upon entering the bottom of the absorber vessel, the gas stream is subjected to an initial quenching spray of reagent. The gas flows upward through the spray zone, which provides enhanced contact between gas and reagent. Multiple spray elevations with header piping and nozzles maintain a consistent reagent concentration in the spray zone. Continuing upward, the reagent-laden gas passes through several levels of moisture separators. These consist of chevron-shaped vanes that direct the gas flow through several abrupt changes in direction, separating the entrained droplets of liquid by inertial effects. The scrubbed FG exits at the top of the absorber vessel and is routed to the plant stack or CDR process.

The scrubbing slurry falls to the lower portion of the absorber vessel, which contains a large inventory of liquid. Oxidation air is added to promote the oxidation of calcium sulfite contained in the slurry to calcium sulfate (gypsum). Multiple agitators operate continuously to prevent settling of solids and enhance mixture of the oxidation air and the slurry. Recirculation pumps recirculate the slurry from the lower portion of the absorber vessel to the spray level. Spare recirculation pumps are provided to ensure availability of the absorber.

The absorber chemical equilibrium is maintained by continuous makeup of fresh reagent, and blowdown of byproduct solids via the bleed pumps. A spare bleed pump is provided to ensure availability of the absorber. The byproduct solids are routed to the byproduct dewatering system. The circulating slurry is monitored for pH and density.

This FGD system is designed for wet stack operation. Scrubber bypass or reheat, which may be utilized at some older facilities to ensure the exhaust gas temperature is above the saturation temperature, is not employed in this reference plant design because new scrubbers have improved mist eliminator efficiency, and detailed flow modeling of the flue interior enables the placement of gutters and drains to intercept moisture that may be present and convey it to a drain. Consequently, raising the exhaust gas temperature above the FGD discharge temperature of 57 °C (135 °F) (non-CO_2 capture cases) or 32 °C (89 °F) (CO_2 capture cases) is not necessary.

3.7.3 Byproduct Dewatering

The function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber modules. The dewatering process selected for this plant is gypsum dewatering producing wallboard grade gypsum. The scope of the system is from the bleed pump discharge connections to the gypsum storage pile.

Operation Description - The recirculating reagent in the FGD absorber vessel accumulates dissolved and suspended solids on a continuous basis as byproducts from the SO_2 absorption process. Maintenance of the quality of the recirculating slurry requires that a portion be withdrawn and replaced by fresh reagent. This maintenance is accomplished on a continuous basis by the bleed pumps pulling off byproduct solids and the reagent distribution pumps supplying fresh reagent to the absorber.

Gypsum (calcium sulfate) is produced by the injection of oxygen into the calcium sulfite produced in the absorber tower sump. The bleed from the absorber contains approximately 20 wt. percent gypsum. The absorber slurry is pumped by an absorber bleed pump to a primary dewatering hydrocyclone cluster. The primary hydrocyclone performs two process functions. The first function is to dewater the slurry from 20 wt. percent to 50 wt. percent solids. The second function of the primary hydrocyclone is to perform a $CaCO_3$ and $CaSO_4•2H_2O$ separation. This process ensures a limestone stoichiometry in the absorber vessel of 1.10 and an overall limestone stoichiometry of 1.05. This system reduces the overall operating cost of the FGD system. The underflow from the hydrocyclone flows into the filter feed tank, from which it is pumped to a horizontal belt vacuum filter. Two 100-percent filter systems are provided for redundant capacity.

Hydrocyclones

The hydrocyclone is a simple and reliable device (no moving parts) designed to increase the slurry concentration in one step to approximately 50 wt. percent. This high slurry concentration is necessary to optimize operation of the vacuum belt filter.

The hydrocyclone feed enters tangentially and experiences centrifugal motion so that the heavy particles move toward the wall and flow out the bottom. Some of the lighter particles collect at the center of the cyclone and flow out the top. The underflow is thus concentrated from 20 wt. percent at the feed to 50 wt. percent.

Multiple hydrocyclones are used to process the bleed stream from the absorber. The hydrocyclones are configured in a cluster with a common feed header. The system has two hydrocyclone clusters, each with five 15 cm (6 inch) diameter units. Four cyclones are used to continuously process the bleed stream at design conditions, and one cyclone is spare.

Cyclone overflow and underflow are collected in separate launders. The overflow from the hydrocyclones still contains about 5 wt. percent solids, consisting of gypsum, fly ash, and limestone residues and is sent back to the absorber. The underflow of the hydrocyclones flows into the filter feed tank from where it is pumped to the horizontal belt vacuum filters.

Horizontal Vacuum Belt Filters

The secondary dewatering system consists of horizontal vacuum belt filters. The pre-concentrated gypsum slurry (50 wt, percent) is pumped to an overflow pan through which the slurry flows onto the vacuum belt. As the vacuum is pulled, a layer of cake is formed. The cake is dewatered to approximately 90 wt. percent solids as the belt travels to the discharge. At the discharge end of the filter, the filter cloth is turned over a roller where the solids are dislodged from the filter cloth. This cake falls through a chute onto the pile prior to the final byproduct uses. The required vacuum is provided by a vacuum pump. The filtrate is collected in a filtrate tank that provides surge volume for use of the filtrate in grinding the limestone. Filtrate that is not used for limestone slurry preparation is returned to the absorber.

3.8 CARBON DIOXIDE RECOVERY FACILITY

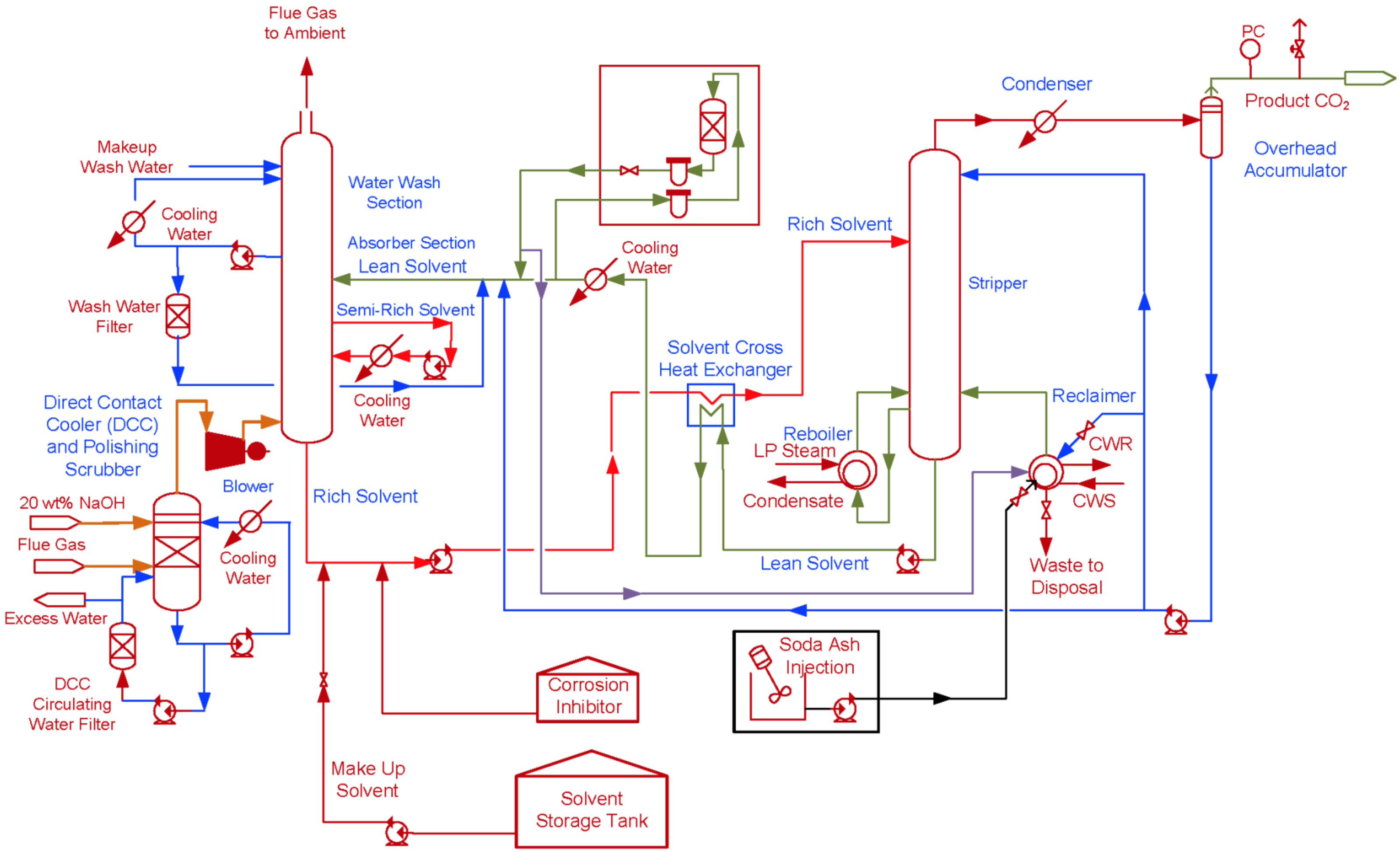
A CDR facility is used in all cases to remove 90 percent of the CO_2 in the desulfurized FG, exiting both the main plant and any auxiliary plants, purify it, and compress it to a SC condition. The FG exiting the FGD unit contains about 1 percent more CO_2 than the raw FG because of the CO_2 liberated from the limestone in the FGD absorber vessel. The CDR is comprised of the FG supply, SO_2 polishing, CO_2 absorption, solvent stripping and reclaiming, and CO_2 compression and drying.

The CO_2 absorption/stripping/solvent reclaim process is based on the Fluor Econamine FG Plus^{SM} technology [34, 35]. A typical flowsheet is shown in Exhibit 3-1. The Econamine FG Plus process uses a formulation of MEA and a proprietary corrosion inhibitor to recover CO_2 from the flue gas. This process is designed to recover high-purity CO_2 from LP streams that contain oxygen, such as flue gas from coal-fired power plants, GT exhaust gas, and other waste gases. The Econamine process used in this study differs from previous studies, including the 2003 IEA study, [36] in the following ways:

- The complexity of the control and operation of the plant is significantly decreased
- Solvent consumption is decreased
- Hard to dispose waste from the plant is greatly reduced

The above are achieved at the expense of a slightly higher steam requirement in the stripper (3,556 kJ/kg) [1,530 Btu/lb] versus 3,242 kJ/kg [1,395 Btu/lb] used in the IEA study) [37].

Exhibit 3-1 Fluor Econamine FG Plus[SM] Typical Flow Diagram



SO_2 Polishing and FG Cooling and Supply

To minimize the accumulation of HSS, the incoming flue gas must have an SO_2 concentration of 10 ppmv or less. The gas exiting the FGD system passes through an SO_2 polishing step to achieve this objective. The polishing step consists of a non-plugging, low-differential-pressure, spray-baffle-type scrubber using a 20 wt% solution of sodium hydroxide (NaOH). A removal efficiency of about 75 percent is necessary to reduce SO_2 emissions from the FGD outlet to 10 ppmv as required by the Econamine process. The polishing scrubber proposed for this application has been demonstrated in numerous industrial applications throughout the world and can achieve removal efficiencies of over 95 percent if necessary.

The polishing scrubber also serves as the flue gas cooling system. Cooling water from the PC plant is used to reduce the flue gas temperature to below the adiabatic saturation temperature resulting in a reduction of the flue gas moisture content. Flue gas is cooled beyond the CO_2 absorption process requirements to 32°C (90°F) to account for the subsequent temperature increase of about 17°C (30°F) in the flue gas blower. Downstream from the Polishing Scrubber flue gas pressure is boosted in the FG Blowers by approximately 0.014 MPa (2 psi) to overcome pressure drop in the CO_2 absorber tower.

Circulating Water System

Cooling water is provided from the PC plant CWS and returned to the PC plant cooling tower. The CDR facility requires a significant amount of cooling water for flue gas cooling, water wash cooling, absorber intercooling, reflux condenser duty, reclaimer cooling, the lean solvent cooler, and CO_2 compression interstage cooling. The cooling water requirements for the CDR facility in the two PC capture cases range from 1,173,350-1,286,900 lpm (310,000-340,000 gpm), which greatly exceeds the PC plant cooling water requirement of 643,450-757,000 lpm (170,000-200,000 gpm).

CO_2 Absorption Section

The cooled flue gas enters the bottom of the CO_2 Absorber and flows up through the tower countercurrent to a stream of lean MEA-based solvent. Approximately 90 percent of the CO_2 in the feed gas is absorbed into the lean solvent, and the rest leaves the top of the absorber section and flows into the water wash section of the tower. The lean solvent enters the top of the absorber section, absorbs the CO_2 from the FG and leaves the bottom of the absorber with the absorbed CO_2. The FG Plus process also includes solvent intercooling. The semi-rich solvent is extracted from the column, cooled using cooling water, and returned to the absorber section just below the extraction point. The CO_2 carrying capacity of the solvent is increased at lower temperature, which reduces the solvent circulation rate.

Water Wash Section

The purpose of the Water Wash section is to minimize solvent losses due to mechanical entrainment and evaporation. The flue gas from the top of the CO_2 Absorption section is contacted with a re-circulating stream of water for the removal of most of the lean solvent. The scrubbed gases, along with unrecovered solvent, exit the top of the wash section for discharge to the atmosphere via the vent stack. The water stream from the bottom of the wash section is collected on a chimney tray. A portion of the water collected on the chimney tray spills over to the absorber section as water makeup for the amine with the remainder pumped via the Wash Water Pump, cooled by the Water Wash Cooler, and recirculated to the top of the CO_2 Absorber. The wash water level is maintained by wash water makeup.

<u>Rich/Lean Amine Heat Exchange System</u>

The rich solvent from the bottom of the CO_2 Absorber is preheated by the lean solvent from the Solvent Stripper in the Lean/Rich Cross Exchanger. The heated rich solvent is routed to the Solvent Stripper for removal of the absorbed CO_2. The stripped solvent from the bottom of the Solvent Stripper is pumped via the Lean Solvent Pump to the Lean Solvent Cooler. A slipstream of the lean solvent is then sent through the Amine Filter Package to prevent buildup of contaminants in the solution. The filtered lean solvent is mixed with the remaining lean solvent from the Lean Solvent Cooler and sent to the CO_2 Absorber, completing the circulating solvent circuit.

<u>Solvent Stripper</u>

The purpose of the Solvent Stripper is to separate the CO_2 from the rich solvent feed exiting the bottom of the CO_2 Absorber. The rich solvent is collected on a chimney tray below the bottom packed section of the Stripper and routed to the Reboiler where the rich solvent is heated by steam, stripping the CO_2 from the solution. Steam is provided from the crossover pipe between the IP and LP sections of the steam turbine and is 0.5 MPa (74 psia) and 152°C (306°F) for the two PC cases. The hot wet vapor from the top of the stripper containing CO_2, steam, and solvent vapor, is partially condensed in the Reflux Condenser by cross exchanging the hot wet vapor with cooling water. The partially condensed stream then flows to the Reflux Drum where the vapor and liquid are separated. The uncondensed CO_2-rich gas is then delivered to the CO_2 product compressor. The condensed liquid from the Reflux Drum is pumped via the Reflux Pump where a portion of condensed overhead liquid is combined with the lean solvent entering the CO_2 Absorber. The rest of the pumped liquid is routed back to the Solvent Stripper as reflux, which aids in limiting the amount of solvent vapors entering the stripper overhead system.

<u>Solvent Reclaimer</u>

The low temperature reclaimer technology is a recent development for the FG Plus technology. A small slipstream of the lean solvent is fed to the Solvent Reclaimer for the removal of high-boiling nonvolatile impurities including HSS, volatile acids and iron products from the circulating solvent solution. Reclaiming occurs in two steps, the first is an ion-exchange process. There is a small amount of degradation products that cannot be removed via ion-exchange, and a second atmospheric pressure reclaiming process is used to remove the degradation products. The solvent reclaimer system reduces corrosion, foaming and fouling in the solvent system. The reclaimed solvent is returned to the Solvent Stripper and the spent solvent is pumped via the Solvent Reclaimer Drain Pump to the Solvent Reclaimer Drain Tank for disposal. The quantity of spent solvent is greatly reduced from the previously used thermal reclaimer systems.

<u>Steam Condensate</u>

Steam condensate from the Solvent Stripper Reclaimer accumulates in the Solvent Reclaimer Condensate Drum and is level controlled to the Solvent Reboiler Condensate Drum. Steam condensate from the Solvent Stripper Reboilers is also collected in the Solvent Reboiler

Condensate Drum and returned to the steam cycle between BFW heaters 4 and 5 via the Solvent Reboiler Condensate Pumps.

Corrosion Inhibitor System

A proprietary corrosion inhibitor is intermittently injected into the CO_2 Absorber rich solvent bottoms outlet line. This additive is to help control the rate of corrosion throughout the CO_2 recovery plant system.

Gas Compression and Drying System

In the compression section, the CO_2 is compressed to 15.3 MPa (2,215 psia) by a six-stage centrifugal compressor. The discharge pressures of the stages were balanced to give reasonable power distribution and discharge temperatures across the various stages as shown in Exhibit 3-2.

Exhibit 3-2 CO_2 Compressor Interstage Pressures

Stage	Outlet Pressure, MPa (psia)
1	0.36 (52)
2	0.78 (113)
3	1.71 (248)
4	3.76 (545)
5	8.27 (1,200)
6	15.3 (2,215)

Power consumption for this large compressor was estimated assuming a polytropic efficiency of 86 percent and a mechanical efficiency of 98 percent for all stages. During compression to 15.3 MPa (2,215 psia) in the multiple-stage, intercooled compressor, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The virtually moisture-free SC CO_2 stream is delivered to the plant battery limit as sequestration ready. CO_2 TS&M costs were estimated and included in LCOE and COE using the methodology described in Section 2.7.

Several alternatives to rejecting the heat of CO_2 compression to cooling water were investigated in a separate study [[38]]. The first alternative consisted of using a portion of the heat to pre-heat BFW while the remaining heat was still rejected to cooling water. This configuration resulted in an increase in efficiency of 0.3 percentage points (absolute). The second alternative modified the CO_2 compression intercooling configuration to enable integration into a LiBr-H_2O absorption refrigeration system, where water is the refrigerant. In the CO_2 compression section, the single intercooler between each compression stage was replaced with one kettle reboiler and two counter current shell and tube heat exchangers. The kettle reboiler acts as the generator that rejects heat from CO_2 compression to the LiBr-H_2O solution to enable the separation of the refrigerant from the brine solution. The second heat exchanger rejects heat to the cooling water. The evaporator heat exchanger acts as the refrigerator and cools the CO_2 compression stream by vaporizing the refrigerant. Only five stages of CO_2 compression were necessary for Approach 2. The compression ratios were increased from the reference cases to create a compressor outlet temperature of at least 200°F to maintain a temperature gradient of 10°F in the kettle reboiler. This configuration resulted in an efficiency increase of 0.1 percentage points (absolute).

It was concluded that the small increase in efficiency did not justify the added cost and complexity of the two configurations and hence they were not incorporated into the base design.

3.9 POWER GENERATION

3.9.1 Steam Turbine

The steam turbine is designed for long-term operation (90 days or more) at MCR with throttle control valves 95 percent open. It is also capable of a short-term 5 percent OP/VWO condition (16 hours).

The steam turbine is a tandem compound type, consisting of HP-IP-two LP (double flow) sections enclosed in three casings, designed for condensing single reheat operation, and equipped with non-automatic extractions and four-flow exhaust. The turbine drives a hydrogen-cooled generator. The turbine has DC motor-operated lube oil pumps, and main lube oil pumps, which are driven off the turbine shaft [39]. The exhaust pressure is 50.8 cm (2 in) Hg in the single pressure condenser. There are eight extraction points. The condenser is two-shell, transverse, single pressure with divided waterbox for each shell.

Turbine bearings are lubricated by a CL, water-cooled pressurized oil system. Turbine shafts are sealed against air in-leakage or steam blowout using a labyrinth gland arrangement connected to a LP steam seal system. The generator stator is cooled with a CL water system consisting of circulating pumps, shell and tube or plate and frame type heat exchangers, filters, and deionizers, all skid-mounted. The generator rotor is cooled with a hydrogen gas recirculation system using fans mounted on the GRS.

Operation Description - The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system. Main steam from the boiler passes through the stop valves and control valves and enters the turbine. The steam initially enters the turbine near the middle of the HP span, flows through the turbine, and returns to the boiler for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the two LP sections. The steam divides into four paths and flows through the LP sections exhausting downward into the condenser.

The turbine is designed to operate at constant inlet steam pressure over the entire load range.

3.9.2 Combustion Turbine

The turbines considered in this study are the F Class turbines with an ISO base rating of 171.7 MW for the 7FA and 77.1 MW for the 6FA when firing natural gas in the simple cycle configuration. The resulting heat rate is approximately 9360 Btu/kWh for the 7FA and 9760 Btu/kWh for the 6FA [40,41]. These machines are axial flow, single spool, constant speed unit, with variable IGVs, and dry LNB combustion system.

Each CTG is provided with inlet air filtration systems; inlet silencers; lube and control oil systems including cooling; electric motor starting systems; acoustical enclosures including heating and ventilation; control systems including supervisory, fire protection, and fuel systems. No back up fuel was envisioned for this project.

The CTG is typically supplied in several fully shop-fabricated modules, complete with all mechanical, electrical, and control systems required for CTG operation. Site CTG installation involves module interconnection and linking CTG modules to the plant systems. The CTG package scope of supply for combined cycle application, while project specific, does not vary much from project-to-project. A typical scope of supply is presented in Exhibit 3-3.

Exhibit 3-3 Combustion Turbine Typical Scope of Supply

System	System Scope
ENGINE ASSEMBLY	Coupling to Generator, Dry Chemical Exhaust Bearing Fire Protection System, Insulation Blankets, Platforms, Stairs and Ladders
Engine Assembly with Bedplate	Variable IGV System, Compressor, Bleed System, Purge Air System, Bearing Seal Air System, Combustors, Dual Fuel Nozzles, Turbine Rotor Cooler
Walk-in acoustical enclosure	HVAC, Lighting, and LP CO_2 Fire Protection System
MECHANICAL PACKAGE	HVAC, Lighting, Air Compressor for Pneumatic System, LP CO_2 Fire Protection System
Lubricating Oil System and Control Oil System	Lube Oil Reservoir, Accumulators, 2x100% AC Driven Oil Pumps, DC Emergency Oil Pump with Starter, 2x100% Oil Coolers, Duplex Oil Filter, Oil Temperature and Pressure Control Valves, Oil Vapor Exhaust Fans and Demister, Oil Heaters, Oil Interconnect Piping (SS and CS), Oil System Instrumentation, Oil for Flushing and First Filling
ELECTRICAL PACKAGE	HVAC, Lighting, AC and DC Motor Control Centers, Generator Voltage Regulating Cabinet, Generator Protective Relay Cabinet, DC Distribution Panel, Battery Charger, Digital Control System with Local Control Panel (all control and monitoring functions as well as data logger and sequence of events recorder), Control System Valves and Instrumentation Communication link for interface with plant DCS Supervisory System, Bentley Nevada Vibration Monitoring System, LP CO_2 Fire Protection System, Cable Tray and Conduit Provisions for Performance Testing including Test Ports, Thermowells, Instrumentation and DCS interface cards
INLET AND EXHAUST SYSTEMS	Inlet Duct Trash Screens, Inlet Duct and Silencers, Self Cleaning Filters, Hoist System For Filter Maintenance, Evaporative Cooler System, Exhaust Duct Expansion Joint, Exhaust Silencers Inlet and Exhaust Flow, Pressure and Temperature Ports and Instrumentation
FUEL SYSTEMS	
N. Gas System	Gas Valves Including Vent, Throttle and Trip Valves, Gas Filter/Separator, Gas Supply Instruments and Instrument Panel
STARTING SYSTEM	Enclosure, Starting Motor or Static Start System, Turning Gear and Clutch Assembly, Starting Clutch, Torque Converter
GENERATOR	Static or Rotating Exciter (Excitation transformer to be included for a static system), Line Termination Enclosure with CTs, VTs, Surge Arrestors, and Surge Capacitors, Neutral Cubicle with CT, Neutral Tie Bus, Grounding Transformer, and Secondary Resistor, Generator Gas Dryer, Seal Oil System (including Defoaming Tank, Reservoir, Seal Oil Pump, Emergency Seal Oil Pump, Vapor Extractor, and Oil Mist Eliminator), Generator Auxiliaries Control Enclosure, Generator Breaker, Iso-Phase bus connecting generator and breaker, Grounding System Connectors
Generator Cooling	Totally Enclosed Water-to-Air-Cooled (TEWAC) System (including circulation system, interconnecting piping and controls), or Hydrogen Cooling System (including H_2 to Glycol and Glycol to Air heat exchangers, liquid level detector circulation system, interconnecting piping and controls)

System	System Scope
MISCELLANEOUS	Interconnecting Pipe, Wire, Tubing and Cable Instrument Air System Including Air Dryer On Line and Off Line Water Wash System LP CO_2 Storage Tank Drain System Drain Tanks Coupling, Coupling Cover and Associated Hardware

The generators would typically be provided with the CT package. The generators are assumed to be 24 kV, 3-phase, 60 hertz, constructed to meet American National Standards Institute (ANSI) and National Electrical Manufacturers Association (NEMA) standards for turbine-driven synchronous generators. The generator is TEWAC, complete with excitation system, cooling, and protective relaying.

3.10 BALANCE OF PLANT

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

Condensate

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser and the LP FW heaters. Each system consists of one main condenser; two variable speed electric motor-driven vertical condensate pumps each sized for 50 percent capacity; one gland steam condenser; four LP heaters; and one deaerator with storage tank.

Condensate is delivered to a common discharge header through two 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 downstream of the gland steam condenser to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

LP FW heaters 1 through 4 are 50 percent capacity, parallel flow, and are located in the condenser neck. All remaining FW heaters are 100 percent capacity shell and U-tube heat exchangers. Each LP FW heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP FW heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Pneumatic level control valves control normal drain levels in the heaters. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Pneumatic level control valves control dump line flow.

Feedwater

The function of the FW system is to pump the FW from the deaerator storage tank through the HP FW heaters to the economizer. One turbine-driven BFW pump sized at 100 percent capacity is provided to pump FW through the HP FW heaters. One 25 percent motor-driven BFW pump is provided for startup. The pumps are provided with inlet and outlet isolation valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by automatic recirculation valves, which are a combination check valve in the main line and in the bypass, bypass control valve, and flow sensing element. The suction of the boiler feed pump is equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each HP FW heater is provided with inlet/outlet isolation valves and a full capacity bypass. FW heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Pneumatic level control valves control normal drain level in the heaters. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

The deaerator is a horizontal, spray tray type with internal direct contact stainless steel (SS) vent condenser and storage tank. The boiler feed pump turbine is driven by main steam up to 60 percent plant load. Above 60 percent load, extraction from the IP turbine exhaust provides steam to the boiler feed pump steam turbine.

<u>Main and Reheat Steam</u>

The function of the main steam system is to convey main steam from the boiler 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 boiler reheater and from the boiler reheater outlet to the IP turbine stop valves.

Main steam exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve and is routed in a single line feeding the HP turbine. A branch line off the IP turbine exhaust feeds the boiler feed water pump turbine during unit operation starting at approximately 60 percent load.

Cold reheat steam exits the HP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler reheater. Hot reheat steam exits the boiler reheater through a motor-operated gate valve and is routed to the IP turbine. A branch connection from the cold reheat piping supplies steam to FW heater 7.

<u>Extraction Steam</u>

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- HP turbine exhaust (cold reheat)
- IP turbine extraction
- LP turbine extraction

The turbine is protected from overspeed on turbine trip, from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disc non-return valves located in all extraction lines except the lines to the LP FW heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

<u>Circulating Water System</u>

It is assumed that the plant is serviced by a public water facility and has access to groundwater for use as makeup cooling water with minimal pretreatment. All filtration and treatment of the circulating water are conducted on site. A mechanical draft, wood frame, counter-flow cooling tower is provided for the circulating water heat sink. Two 50 percent CWPs are provided. The CWS provides cooling water to the condenser, the auxiliary cooling water system, and the CDR facility in capture cases.

The auxiliary cooling water system is a closed loop system. Plate and frame heat exchangers with circulating water as the cooling medium are provided. This system provides cooling water to the lube oil coolers, turbine generator, boiler feed pumps, etc. All pumps, vacuum breakers, air release valves, instruments, controls, etc. are included for a complete operable system.

The CDR system in the capture cases requires a substantial amount of cooling water that is provided by the PC plant CWS. The additional cooling load imposed by the CDR is reflected in the significantly larger CWPs and cooling tower in those cases.

Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing of the fly ash and bottom ash produced on a daily basis by the boiler. The scope of the system is from the baghouse hoppers, air heater and economizer hopper collectors, and bottom ash hoppers to the hydrobins (for bottom ash) and truck filling stations (for fly ash). The system is designed to support short-term operation at the 5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

The fly ash collected in the baghouse and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using LP air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the boiler is fed into a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. From the clinker grinders the bottom ash is sluiced to hydrobins for dewatering and offsite removal by truck.

Ash from the economizer hoppers and pyrites (rejected from the coal pulverizers) is conveyed using water to the economizer/pyrites transfer tank. This material is then sluiced on a periodic basis to the hydrobins.

Ducting and Stack

One stack is provided with a single fiberglass-reinforced plastic (FRP) liner. The stack is constructed of reinforced concrete. The stack is 152 m (500 ft) high for adequate particulate dispersion.

Waste Treatment/Miscellaneous Systems

An onsite water treatment facility treats all runoff, cleaning wastes, blowdown, and backwash to within the U.S. EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals. Waste treatment equipment is housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge dewatering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes, and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system, dry lime feeder, lime slurry tank, slurry tank mixer, and lime slurry feed pumps.

The oxidation system consists of an air compressor, which injects air through a sparger pipe into the second-stage neutralization tank. The flocculation tank is fiberglass with a variable speed agitator. A polymer dilution and feed system is also provided for flocculation. The clarifier is a plate-type, with the sludge pumped to the dewatering system. The sludge is dewatered in filter presses and disposed offsite. Trucking and disposal costs are included in the cost estimate. The filtrate from the sludge dewatering is returned to the raw waste sump.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water are provided. A storage tank provides a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

Buildings and Structures

Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Fuel oil pump house
- Guard house
- Boiler building
- Coal crusher building
- Runoff water pump house
- Administration and service building
- Continuous emissions monitoring building
- Industrial waste treatment building
- Makeup water and pretreatment building
- Pump house and electrical equipment building
- FGD system buildings

3.11 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, required foundations, and standby equipment.

3.12 INSTRUMENTATION AND CONTROL

An integrated plant-wide control and monitoring DCS is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor and keyboard units. The monitor/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 provide 99.5 percent 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 implemented as supervised manual, with operator selection of modular automation routines available.

4. CASE RESULTS

Section 4.1 covers the base case plant with a fixed coal feed retrofit with CDR with steam extraction throttled from the IP-LP crossover, providing a base/worst-case scenario for off-design operation of an existing plant after retrofit by extracting steam evenly from all LP steam turbine trains. Section 4.2 covers the two cases using an auxiliary natural gas combustion turbine to generate power and with a HRSG generating steam for the CDR process in a dedicated closed loop. The sections are organized analogously for the three basic configurations as follows:

- Process Description provides an overview of the technology operation.
- Key Assumptions is a summary of study and modeling assumptions.
- Sparing Philosophy.
- Performance Results provide the main modeling results including the performance summary, environmental performance, carbon balance, sulfur balance, water balance, energy balance and mass and energy balance diagrams.
- Equipment Lists provide an itemized list of major equipment with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provide a summary of capital and operating costs.

4.1 RETROFIT BASELINE CASE 0

4.1.1 Process Description

For the baseline retrofit case, a post combustion MEA CO_2 removal process is used to treat the flue gas from an existing subcritical PC boiler plant, which is based on the NETL Bituminous Baseline Study Case 9 plant configuration.

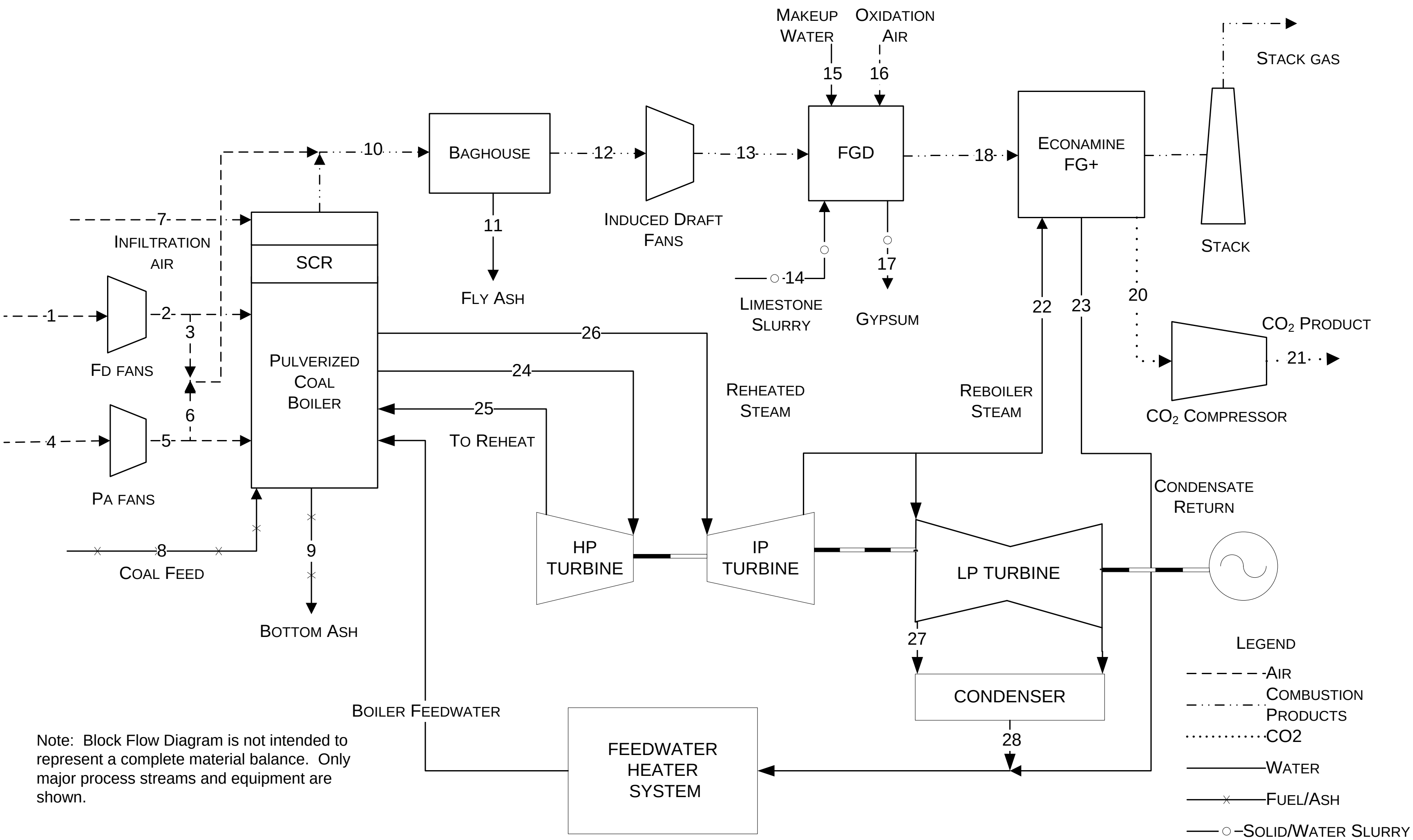
The coal feed is assumed to be unchanged after the retrofit, so the increased auxiliary loads due to CO_2 retrofit reduce the net plant output. The addition of the CDR process after the sulfur removal and before the flue gas exits the stack causes ripple effects to the design conditions of the plant. Additional ID fans are included in the MEA account to generate enough head to push the flue gas through the MEA absorber. A new stack was considered to reduce the amount of downtime required for new construction, but the necessity of alterations to the steam cycle, in order to provide the large steam auxiliaries for the CDR process, should provide ample opportunity to lay new ducting and reconnect the existing stack. The flow to the stack is reduced enough to eliminate the need for a new stack, offsetting the reduced buoyancy due to the lower temperature, cleaner, flue gas with the removal of 90 percent of the CO_2.

In this section the base case subcritical PC process with CO_2 capture retrofit is described. The system description follows the BFD in Exhibit 4-1 and stream numbers reference the same exhibit. The tables in Exhibit 4-2 provide process data for the numbered streams in the BFD.

Coal and PA are introduced into the boiler through the wall-fired burners. Additional combustion air, including the OFA, is provided by the FD fans. The boiler operates at a slight negative pressure so air leakage is into the boiler, and the infiltration air is accounted along with the Ljungstrom air preheater leakages from the FD and PA fan outlet streams to the boiler exhaust.

FG exits the boiler through the SCR reactor and is cooled to 169 °C (337 °F) in the combustion air preheater before passing through a fabric filter for particulate removal. An ID fan increases the FG temperature to 181 °C (357 °F) and provides the motive force for the FG to pass through the FGD unit. FGD inputs and outputs include makeup water, oxidation air, limestone slurry and product gypsum. The clean, saturated FG exiting the FGD unit passes to the retrofitted CDR facility described in Section 3.8, producing a product CO_2 stream and a flue gas exiting the stack.

Exhibit 4-1 Case 0 Block Flow Diagram, Subcritical Unit with CO_2 Capture Retrofit



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Exhibit 4-2 Case 0 Stream Table, Subcritical Unit with CO_2 Capture Retrofit

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
V-L Mole Fraction														
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450	0.1450	0.0000
H_2	0.0000	0.0000	0.0000	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	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870	0.0870	1.0000
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324	0.7324	0.0000
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247	0.0247	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	51,695	51,695	1,538	15,880	15,880	2,178	1,195	0	0	72,745	0	72,745	72,745	2,497
V-L Flowrate (kg/hr)	1,491,773	1,491,773	44,387	458,257	458,257	62,864	34,480	0	0	2,163,663	0	2,163,663	2,163,663	44,980
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	198,391	3,848	15,390	15,390	0	0	20,076
Temperature (°C)	15	19	19	15	25	25	15	15	15	169	15	169	182	15
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.10
Enthalpy (kJ/kg)[A]	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	327.40	---	308.96	322.83	---
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	0.8	---	0.8	0.8	---
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	29.743	---	29.743	29.743	---
V-L Flowrate (lb_{mol}/hr)	113,969	113,969	3,391	35,010	35,010	4,803	2,634	0	0	160,375	0	160,375	160,375	5,504
V-L Flowrate (lb/hr)	3,288,796	3,288,796	97,858	1,010,284	1,010,284	138,592	76,015	0	0	4,770,061	0	4,770,061	4,770,061	99,164
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	437,378	8,482	33,929	33,929	0	0	44,261
Temperature (°F)	59	66	66	59	78	78	59	59	59	337	59	337	360	59
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.4	14.7	14.2	15.4	15.0
Enthalpy (Btu/lb)[A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	140.8	---	132.8	138.8	---
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	0.050	---	0.049	0.052	---

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 4-2 Case 0 Stream Table, Subcritical Unit with CO2 Capture (Continued)

	15	16	17	18	19	20	21	22	23	24	25	26	27	28
V-L Mole Fraction														
Ar	0.0000	0.0128	0.0000	0.0081	0.0108	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0005	0.0004	0.1351	0.0179	0.9961	0.9985	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	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	0.0062	0.9996	0.1537	0.0383	0.0039	0.0015	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.0000	0.7506	0.0000	0.6793	0.9013	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.2300	0.0000	0.0238	0.0316	0.0000	0.0000	0.0000	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	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	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	10,543	742	190	79,256	59,730	9,671	9,648	34,591	34,591	93,448	85,525	85,525	42,129	43,063
V-L Flowrate (kg/hr)	189,929	21,531	3,429	2,285,020	1,682,701	424,642	424,223	623,173	623,173	1,683,490	1,540,758	1,540,758	758,957	775,792
Solids Flowrate (kg/hr)	0	0	31,031	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	181	58	58	32	21	35	296	151	566	363	566	38	40
Pressure (MPa, abs)	0.10	0.31	0.10	0.10	0.10	0.16	15.27	0.51	0.90	16.65	4.28	3.90	0.01	1.69
Enthalpy (kJ/kg)[A]	-46.80	191.62	---	301.42	93.86	19.49	-211.71	3,054.40	636.27	3,472.33	3,120.82	3,594.06	2,143.55	167.21
Density (kg/m^3)	1,003.1	2.4	---	1.1	1.1	2.9	795.9	2.0	916.0	47.7	15.7	10.3	0.1	993.1
V-L Molecular Weight	18.015	29.029	---	28.831	28.172	43.908	43.971	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	23,243	1,635	419	174,729	131,682	21,321	21,270	76,261	76,261	206,017	188,551	188,551	92,877	94,938
V-L Flowrate (lb/hr)	418,721	47,467	7,559	5,037,607	3,709,720	936,175	935,252	1,373,860	1,373,860	3,711,459	3,396,791	3,396,791	1,673,214	1,710,328
Solids Flowrate (lb/hr)	0	0	68,412	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	357	136	136	89	69	95	564	304	1,050	686	1,050	101	103
Pressure (psia)	14.7	45.0	14.9	14.9	14.7	23.5	2,214.5	73.5	130.0	2,415.0	620.5	565.5	1.0	245.0
Enthalpy (Btu/lb)[A]	-20.1	82.4	---	129.6	40.4	8.4	-91.0	1,313.2	273.5	1,492.8	1,341.7	1,545.2	921.6	71.9
Density (lb/ft^3)	62.622	0.149	---	0.067	0.070	0.184	49.684	0.122	57.183	2.977	0.983	0.643	0.004	61.999

A - Reference conditions are 32.02 F & 0.089 PSIA

4.1.2 Key System Assumptions

System assumptions for Case 0, subcritical PC with CDR retrofit, are compiled in Exhibit 4-3.

Exhibit 4-3 Subcritical PC Plant Study Configuration Matrix

	Case 0
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/566 (2400/1050/1050)
Coal	Illinois No. 6
Condenser pressure, mm Hg (in Hg)	50.8 (2)
Boiler Efficiency, %	88
Cooling water to condenser, °C (ºF)	16 (60)
Cooling water from condenser, °C (ºF)	27 (80)
Stack temperature, °C (°F)	32 (89)
SO_2 Control	Wet Limestone Forced Oxidation
FGD Efficiency, % (A)	98 (B, C)
NO_x Control	LNB w/OFA and SCR
SCR Efficiency, % (A)	86
Ammonia Slip (end of catalyst life), ppmv	2
Particulate Control	Fabric Filter
Fabric Filter efficiency, % (A)	99.8
Ash Distribution, Fly/Bottom	80% / 20%
Mercury Control	Co-benefit Capture
Mercury removal efficiency, % (A)	90
CO_2 Control	Econamine
Overall CO_2 Capture (A)	90.2%
CO_2 Sequestration	Off-site Saline Formation

A. Removal efficiencies are based on the FG content
B. An SO_2 polishing step is included to meet more stringent SOx content limits in the FG (< 10 ppmv) to reduce formation of amine HSS during the CO_2 absorption process
C. SO_2 exiting the post-FGD polishing step is absorbed in the CO_2 capture process making stack emissions negligible

Balance of Plant – Case 0

The balance of plant assumptions are common to all cases and are presented in Exhibit 4-4.

Exhibit 4-4 Balance of Plant Assumptions

Cooling system	Recirculating Wet Cooling Tower
Fuel and Other storage	
Coal	30 days
Ash	30 days
Gypsum	30 days
Limestone	30 days
Plant Distribution Voltage	
Motors below 1 hp	110/220 volt
Motors between 1 hp and 250 hp	480 volt
Motors between 250 hp and 5,000 hp	4,160 volt
Motors above 5,000 hp	13,800 volt
Steam and GT generators	24,000 volt
Grid Interconnection voltage	345 kV
Water and Waste Water	
Makeup Water	The water supply is 50 percent from a local POTW and 50 percent from groundwater, and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and DI water is drawn from municipal sources.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 cubic meters per day (1,500 gallons per day)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown will be treated for chloride and metals, and discharged.

4.1.3 Sparing Philosophy

Single trains are used throughout the design with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- One dry-bottom, wall-fired PC subcritical boiler (1 x 100 percent)
- Two SCR reactors (2 x 50 percent)
- Two single-stage, in-line, multi-compartment fabric filters (2 x 50 percent)
- One wet limestone forced oxidation positive pressure absorber (1 x 100 percent)
- One steam turbine (1 x 100 percent)
- Two parallel Econamine CO_2 absorption systems, with each system consisting of two absorbers, strippers and ancillary equipment (2 x 50 percent)

4.1.4 Performance Results

The plant produces a net output of 379 MWe at a net plant efficiency of 25.4 percent (HHV basis). Overall performance for the plant is summarized in Exhibit 4-5, which includes auxiliary power requirements.

Exhibit 4-5 Case 0 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Steam Turbine Power	467,600
Gas Turbine Power	-
TOTAL POWER, kWe	**467,600**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	450
Pulverizers	2,970
Sorbent Handling & Reagent Preparation	970
Ash Handling	570
Primary Air Fans	1,390
Forced Draft Fans	1,780
Induced Draft Fans	8,640
SCR	50
Baghouse	70
Wet FGD	3,180
Econamine FG Plus Auxiliaries	15,900
CO_2 Compression	34,700
Miscellaneous Balance of Plant[1]	2,000
Steam Turbine Auxiliaries	400
Gas Turbine Auxiliaries	-
Condensate Pumps	490
Circulating Water Pumps	8,070
Ground Water Pumps	730
Cooling Tower Fans	4,180
Transformer Losses	1,640
TOTAL AUXILIARIES, kWe	**88,180**
NET POWER, kWe	**379,420**
Net Plant Efficiency, % (HHV)	25.4%
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	14,188 (13,448)
CONDENSER COOLING DUTY, GJ/hr (10^6 Btu/hr)	1,450 (1,375)
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)	198,391 (437,378)
Thermal Input, kWt	1,495,381
Raw Water Withdrawal, m^3/min (gpm)	30.5 (8,052)
Raw Water Consumption, m^3/min (gpm)	23.4 (6,184)

Notes:
1. HHV of As Received Illinois No. 6 coal is 27,135 kJ/kg (11,666 Btu/lb)
2. Boiler feed pumps are turbine driven
3. Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and PM were presented in Section 2.4. A summary of the plant air emissions for Case 0 is presented in Exhibit 4-6.

Exhibit 4-6 Case 0 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% CF	kg/MWh (lb/MWh)
SO_2	0.001 (0.002)	29 (32)	0.008 (.02)
NOx	0.030 (0.070)	1,206 (1,330)	0.346 (.764)
Particulates	0.006 (0.013)	224 (247)	0.064 (.142)
Hg	4.91E-7 (1.14E-6)	0.020 (0.022)	5.66E-6 (1.25E-5)
CO_2	8.8 (20.4)	350,758 (386,645)	101 (222)
CO_2[1]			124 (274)

[1] CO_2 emissions based on net power instead of gross power

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

NO_x emissions from the base plant are controlled to about 0.5 $lb/10^6$ Btu through the use of LNBs and OFA. An SCR unit is used to further reduce the NO_x concentration by 86 percent to 0.07 $lb/10^6$ Btu.

Particulate emissions from the base plant are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.8 percent.

Co-benefit capture results in a 90 percent reduction of mercury emissions from the base plant. CO_2 emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 4-7. The carbon input to the plant consists of carbon in the coal, carbon in the air, and carbon in the limestone reagent used in the FGD. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO_2 through the stack but also leaves as gypsum.

Exhibit 4-7 Case 0 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	126,464 (278,805)	**Stack Gas**	12,856 (28,343)
Natural Gas	-	**Gypsum**	213 (469)
Air (CO_2)	274 (605)	**CO_2 Product**	115,706 (255,089)
Limestone	2,037 (4,491)		
Total	**128,776 (283,901)**	**Total**	**128,776 (283,901)**

Exhibit 4-8 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum and sulfur emitted in the stack gas.

Exhibit 4-8 Case 0 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	4,973 (10,963)	**Gypsum**	4,873 (10,743)
		Stack Gas	2 (4)
		Econamine HSS	97 (215)
Total	**4,973 (10,963)**	**Total**	**4,973 (10,963)**

Exhibit 4-9 shows the water balance for Case 0. Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is re-used as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a surface-water source for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from groundwater. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for any and all purposes, such as FDG makeup, BFW makeup, and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source.

Exhibit 4-9 Case 0 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Withdrawal, m^3/min (gpm)	Process Water Discharge, m^3/min (gpm)	Raw Water Consumption, m^3/min (gpm)
Econamine	0.10 (28)	0.0 (0)	0.10 (28)	0.00 (0)	0.10 (28)
FGD Makeup	3.92 (1036)	0.0 (0)	3.92 (1,036)	0.00 (0)	3.92 (1,036)
BFW Makeup	0.28 (74)	0.0 (0)	0.28 (74)	0.00 (0)	0.28 (74)
Cooling Tower Makeup	31.8 (8,411)	5.23 (1,391)	26.6 (7,020)	7.16 (1,892)	19.21 (5,128)
Total	**36.1 (9,549)**	**5.26 (1,391)**	**30.9 (8,158)**	**7.16 (1,892)**	**23.72 (6,266)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case 0 PC boiler, the flue gas cleanup, and steam cycle as shown in Exhibit 4-11 and Exhibit 4-12.

An overall plant energy balance is provided in tabular form in Exhibit 4-10. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-5) is calculated by multiplying the power out by a generator efficiency of 98.6 percent.

Exhibit 4-10 Case 0 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,383 (5,102)	4.5 (4.3)		5,388 (5,107)
Air		60.1 (56.9)		60.0 (56.9)
Raw Water Withdrawal		114.7 (108.7)		114.7 (108.7)
Limestone		0.23 (0.22)		0.23 (0.22)
Auxiliary Power			317 (301)	317 (301)
Totals	**5,383 (5,102)**	**179.4 (170.0)**	**317 (301)**	**5,880 (5,573)**
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash		0.5 (0.4)		0.5 (0.4)
Fly Ash + FGD Ash		1.9 (1.8)		1.9 (1.8)
Flue Gas		158 (150)		158 (150)
Condenser		1,450 (1,375)		1,450 (1,375)
CO_2		-90 (-85)		-90 (-85)
Cooling Tower Blowdown		52.5 (49.8)		52.5 (49.8)
Econamine Losses		2,549 (2,416)		2,549 (2,416)
ST Off-Design Loss		35 (33)		35 (33)
Process Losses*		38.9 (36.8)		38.9 (36.8)
Power			1,683 (1,596)	1,683 (1,596)
Totals	**0 (0)**	**4,197 (3,978)**	**1,683 (1,596)**	**5,880 (5,573)**

* Process losses are estimated to match the heat input to the plant. Process losses include losses from: turbines, gas cooling, etc.

Exhibit 4-11 Case 0 Heat and Mass Balance, Subcritical PC Boiler with CO_2 Capture

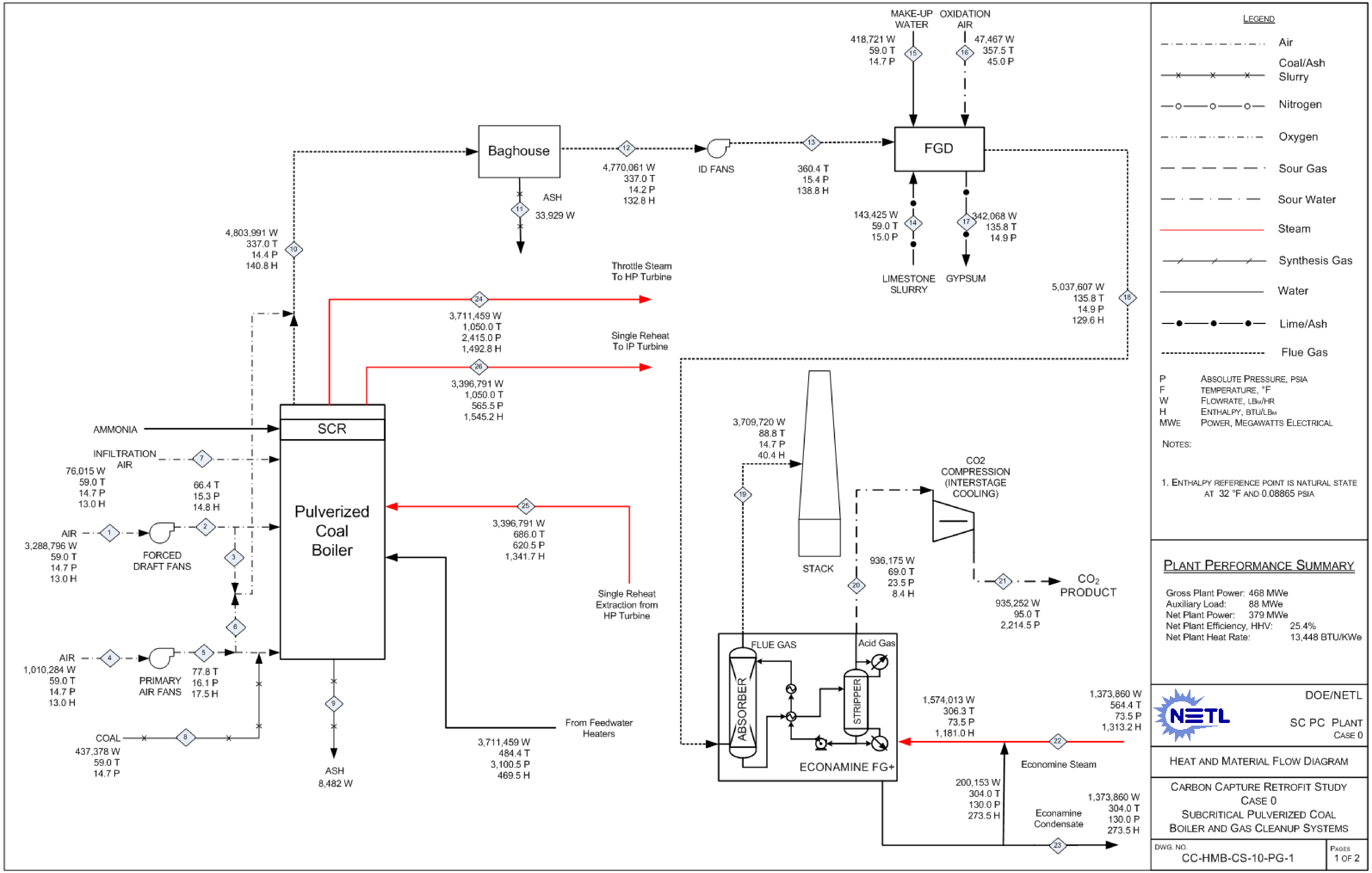
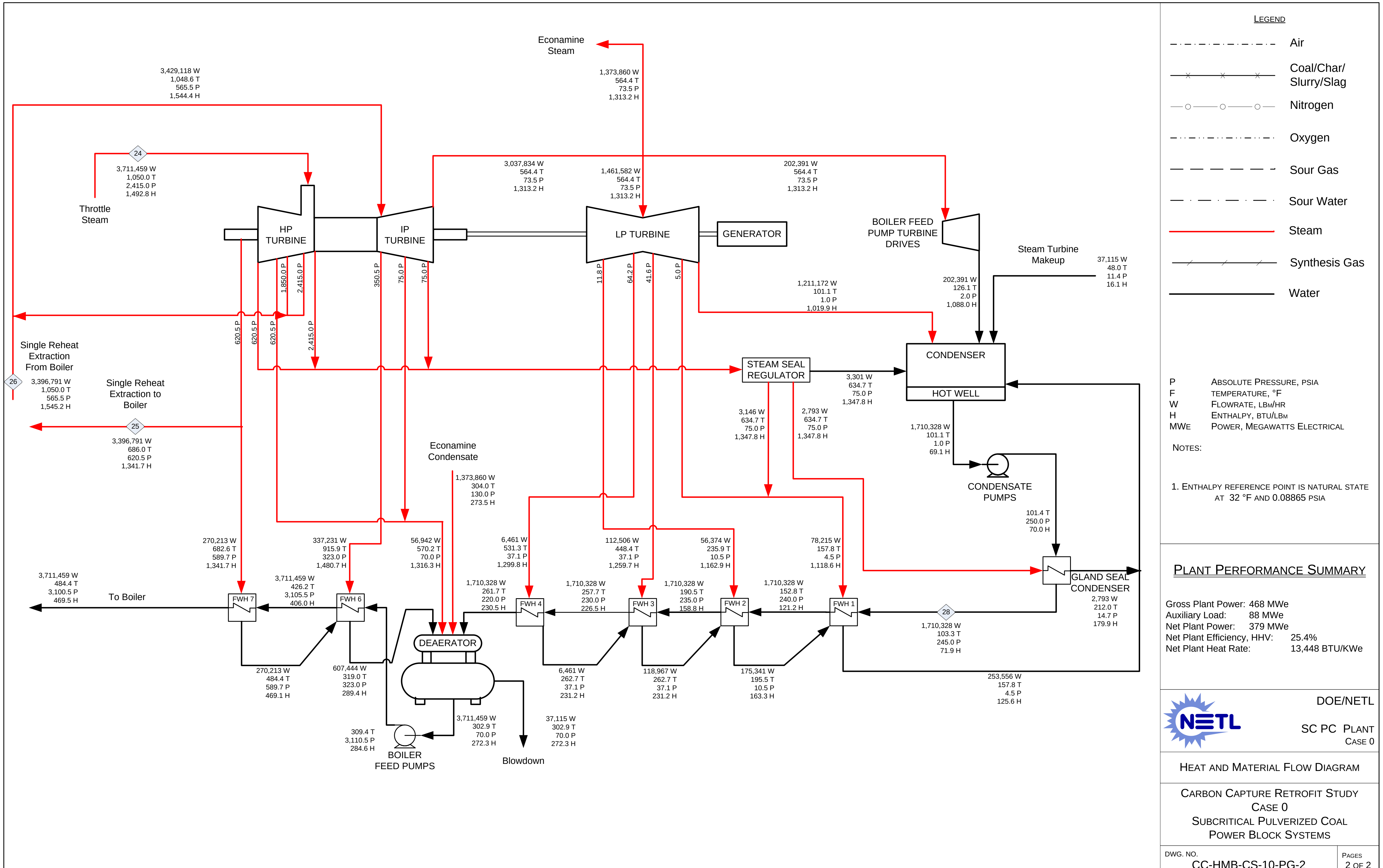


Exhibit 4-12 Case 0 Heat and Mass Balance, Subcritical Steam Cycle



4.1.5 Major Equipment List

Major equipment items for the subcritical PC plant with CDR retrofit are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.1.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 5B CARBON DIOXIDE RECOVERY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Econamine FG Plus	Amine-based CO2 capture technology	1,256,904 kg/h (2,771,000 lb/h) 20.6 wt % CO2 concentration	2	0
2	Econamine Condensate Pump	Centrifugal	13,098 lpm @ 52 m H2O (3,460 gpm @ 170 ft H2O)	1	1
3	CO2 Compressor	Integrally geared, multi-stage centrifugal	233,179 kg/h @ 15.3 MPa (514,073 lb/h @ 2,215 psia)	2	0

ACCOUNT 7 HRSG, DUCTING & STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 4.9 m (16 ft) diameter	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	810,100 lpm @ 30 m (214,000 gpm @ 100 ft)	2	1
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 / 4516 GJ/hr (4280 MMBtu/hr) heat duty	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 430 MVA, 3-ph, 60 Hz	1	0
2	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 96 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 14 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.1.6 Cost Estimating

The cost estimating methodology was described previously in Section 2.6. Exhibit 4-13 shows the total plant capital cost summary organized by cost account and Exhibit 4-14 shows a more detailed breakdown of the capital costs along with owner's costs, TOC and TASC. Exhibit 4-15 shows the initial and annual O&M costs.

The estimated TOC of the subcritical PC boiler CDR retrofit is $1,899/kW. The FY COE for Case 0 is 85.4 mills/kWh.

Exhibit 4-13 Case 0 Total Plant Cost Summary

Client: USDOE/NETL **Report Date**: 2010-Aug-20
Project: Eliminating the Derate of Carbon Capture Retrofits

TOTAL PLANT COST SUMMARY

Case: Case 0 - SubCritical PC w/ CO2 Capture Retrofit
Plant Size: 379.4 MW,net **Estimate Type:** Conceptual **Cost Base (Jun)** 2007 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
2	COAL & SORBENT PREP & FEED	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
3	FEEDWATER & MISC. BOP SYSTEMS	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4	PC BOILER	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
5	FLUE GAS CLEANUP	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
5B	CO_2 REMOVAL & COMPRESSION	$200,957	$0	$61,254	$0	$0	**$262,212**	$25,071	$46,260	$66,709	**$400,251**	$1,055
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Other	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 6	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK	$10,270	$1,019	$7,181	$0	$0	**$18,470**	$1,752	$0	$2,380	**$22,603**	$60
8	STEAM TURBINE GENERATOR	$4,470	$0	$2,204	$0	$0	**$6,674**	$561	$0	$1,085	**$8,320**	$22
9	COOLING WATER SYSTEM	$7,492	$3,983	$7,334	$0	$0	**$18,809**	$1,509	$0	$2,524	**$22,842**	$60
10	ASH/SPENT SORBENT HANDLING SYS	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
11	ACCESSORY ELECTRIC PLANT	$8,129	$7,608	$21,544	$0	$0	**$37,282**	$3,391	$0	$5,369	**$46,041**	$121
12	INSTRUMENTATION & CONTROL	$8,974	$0	$9,099	$0	$0	**$18,072**	$1,639	$904	$2,532	**$23,147**	$61
13	IMPROVEMENTS TO SITE	$2,626	$1,509	$5,291	$0	$0	**$9,426**	$930	$0	$2,071	**$12,428**	$33
14	BUILDINGS & STRUCTURES	$0	$15,731	$15,552	$0	$0	**$31,283**	$2,828	$0	$5,117	**$39,227**	$103
	TOTAL COST	**$242,918**	**$29,851**	**$129,460**	**$0**	**$0**	**$402,228**	**$37,680**	**$47,164**	**$87,787**	**$574,859**	**$1,515**

Exhibit 4-14 Case 0 Total Plant Cost Details

	Client:	USDOE/NETL							**Report Date**: 2010-Aug-20			
	Project:	Eliminating the Derate of Carbon Capture Retrofits										
				TOTAL PLANT COST SUMMARY								
	Case:	Case 0 - SubCritical PC w/ CO2 Capture Retrofit										
	Plant Size:	379.4 MW,net		**Estimate Type:**		Conceptual		**Cost Base (Jun)**	2007	($x1000)		
Acct		**Equipment**	**Material**	**Labor**		**Sales**	**Bare Erected**	**Eng'g CM**	**Contingencies**		**TOTAL PLANT COST**	
No.	**Item/Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Tax**	**Cost $**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**
5B	CO_2 REMOVAL & COMPRESSION											
5B.1	CO_2 Removal System	$177,428	$0	$53,873	$0	$0	$231,301	$22,114	$46,260	$59,935	$359,610	$948
5B.2	CO_2 Compression & Drying	$23,530	$0	$7,382	$0	$0	$30,911	$2,956	$0	$6,773	$40,641	$107
	SUBTOTAL 5B.	**$200,957**	**$0**	**$61,254**	**$0**	**$0**	**$262,212**	**$25,071**	**$46,260**	**$66,709**	**$400,251**	**$1,055**
6	COMBUSTION TURBINE/ACCESSORIES											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
7.2	HRSG Accessories	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$1,385	$0	$825	$0	$0	$2,210	$193	$0	$360	$2,763	$7
7.4	Stack	$8,885	$0	$5,199	$0	$0	$14,083	$1,356	$0	$1,544	$16,983	$45
7.9	Duct & Stack Foundations	$0	$1,019	$1,158	$0	$0	$2,177	$204	$0	$476	$2,857	$8
	SUBTOTAL 7.	**$10,270**	**$1,019**	**$7,181**	**$0**	**$0**	**$18,470**	**$1,752**	**$0**	**$2,380**	**$22,603**	**$60**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
8.2	Turbine Plant Auxiliaries	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
8.3	Condenser & Auxiliaries	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
8.4	Steam Piping	$4,470	$0	$2,204	$0	$0	$6,674	$561	$0	$1,085	$8,320	$22
8.9	TG Foundations	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 8.	**$4,470**	**$0**	**$2,204**	**$0**	**$0**	**$6,674**	**$561**	**$0**	**$1,085**	**$8,320**	**$22**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$5,913	$0	$1,841	$0	$0	$7,754	$476	$0	$545	$8,775	$23
9.2	Circulating Water Pumps	$794	$0	$60	$0	$0	$853	$72	$0	$93	$1,018	$3
9.3	Circ.Water System Auxiliaries	$297	$0	$40	$0	$0	$337	$32	$0	$37	$406	$1
9.4	Circ.Water Piping	$0	$2,356	$2,284	$0	$0	$4,640	$434	$0	$761	$5,835	$15
9.5	Make-up Water System	$253	$0	$337	$0	$0	$590	$57	$0	$97	$744	$2
9.6	Component Cooling Water Sys	$236	$0	$187	$0	$0	$423	$40	$0	$69	$533	$1
9.9	Circ.Water System Foundations & Structures	$0	$1,627	$2,585	$0	$0	$4,212	$398	$0	$922	$5,532	$15
	SUBTOTAL 9.	**$7,492**	**$3,983**	**$7,334**	**$0**	**$0**	**$18,809**	**$1,509**	**$0**	**$2,524**	**$22,842**	**$60**

Exhibit 4-14 Case 0 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date**: 2010-Aug-20
Project: Eliminating the Derate of Carbon Capture Retrofits
TOTAL PLANT COST SUMMARY
Case: Case 0 - SubCritical PC w/ CO2 Capture Retrofit
Plant Size: 379.4 MW,net **Estimate Type:** Conceptual **Cost Base (Jun)** 2007 ($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Cyclone Ash Letdown	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	HGCU Ash Letdown	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.7	Ash Transport & Feed Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 10.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
11.2	Station Service Equipment	$3,656	$0	$1,201	$0	$0	$4,858	$454	$0	$398	$5,710	$15
11.3	Switchgear & Motor Control	$4,204	$0	$714	$0	$0	$4,918	$456	$0	$537	$5,911	$16
11.4	Conduit & Cable Tray	$0	$2,635	$9,113	$0	$0	$11,748	$1,137	$0	$1,933	$14,818	$39
11.5	Wire & Cable	$0	$4,973	$9,600	$0	$0	$14,573	$1,228	$0	$2,370	$18,171	$48
11.6	Protective Equipment	$269	$0	$916	$0	$0	$1,185	$116	$0	$130	$1,431	$4
11.7	Standby Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11.8	Main Power Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11.9	Electrical Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 11.	**$8,129**	**$7,608**	**$21,544**	**$0**	**$0**	**$37,282**	**$3,391**	**$0**	**$5,369**	**$46,041**	**$121**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$462	$0	$277	$0	$0	$739	$70	$37	$127	$972	$3
12.7	Distributed Control System Equipment	$4,665	$0	$815	$0	$0	$5,480	$508	$274	$626	$6,888	$18
12.8	Instrument Wiring & Tubing	$2,528	$0	$5,015	$0	$0	$7,544	$643	$377	$1,285	$9,848	$26
12.9	Other I & C Equipment	$1,318	$0	$2,991	$0	$0	$4,310	$418	$215	$494	$5,437	$14
	SUBTOTAL 12.	**$8,974**	**$0**	**$9,099**	**$0**	**$0**	**$18,072**	**$1,639**	**$904**	**$2,532**	**$23,147**	**$61**

Exhibit 4-14 Case 0 Total Plant Cost Details (Continued)

	Client:	USDOE/NETL							**Report Date**: 2010-Aug-20			
	Project:	Eliminating the Derate of Carbon Capture Retrofits										
				TOTAL PLANT COST SUMMARY								
	Case:	Case 0 - SubCritical PC w/ CO2 Capture Retrofit										
	Plant Size:	379.4 MW,net		**Estimate Type:**		Conceptual			**Cost Base (Jun)**	2007	($x1000)	
Acct		**Equipment**	**Material**	**Labor**		**Sales**	**Bare Erected**	**Eng'g CM**	**Contingencies**		**TOTAL PLANT COST**	
No.	**Item/Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Tax**	**Cost $**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$44	$883	$0	$0	$927	$92	$0	$204	$1,223	$3
13.2	Site Improvements	$0	$1,465	$1,820	$0	$0	$3,285	$324	$0	$722	$4,331	$11
13.3	Site Facilities	$2,626	$0	$2,589	$0	$0	$5,215	$514	$0	$1,146	$6,874	$18
	SUBTOTAL 13.	**$2,626**	**$1,509**	**$5,291**	**$0**	**$0**	**$9,426**	**$930**	**$0**	**$2,071**	**$12,428**	**$33**
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
14.2	Turbine Building	$0	$13,173	$12,277	$0	$0	$25,450	$2,294	$0	$4,162	$31,905	$84
14.3	Administration Building	$0	$626	$662	$0	$0	$1,287	$117	$0	$211	$1,615	$4
14.4	Circulation Water Pumphouse	$0	$87	$69	$0	$0	$156	$14	$0	$25	$195	$1
14.5	Water Treatment Buildings	$0	$464	$423	$0	$0	$887	$80	$0	$145	$1,112	$3
14.6	Machine Shop	$0	$419	$281	$0	$0	$700	$62	$0	$114	$876	$2
14.7	Warehouse	$0	$284	$284	$0	$0	$568	$51	$0	$93	$712	$2
14.8	Other Buildings & Structures	$0	$232	$197	$0	$0	$429	$38	$0	$70	$538	$1
14.9	Waste Treating Building & Str.	$0	$448	$1,358	$0	$0	$1,806	$171	$0	$297	$2,274	$6
	SUBTOTAL 14.	**$0**	**$15,731**	**$15,552**	**$0**	**$0**	**$31,283**	**$2,828**	**$0**	**$5,117**	**$39,227**	**$103**
	TOTAL COST	**$242,918**	**$29,851**	**$129,460**	**$0**	**$0**	**$402,228**	**$37,680**	**$47,164**	**$87,787**	**$574,859**	**$1,515**

Exhibit 4-14 Case 0 Total Plant Cost Details (Continued)

	Client:	USDOE/NETL								**Report Date**: 2010-Aug-20			
	Project:	Eliminating the Derate of Carbon Capture Retrofits											
				TOTAL PLANT COST SUMMARY									
	Case:	Case 0 - SubCritical PC w/ CO2 Capture Retrofit											
	Plant Size:	379.4 MW,net		**Estimate Type:**	Conceptual					**Cost Base (Jun)** 2007	($x1000)		
Acct		**Equipment**	**Material**	**Labor**		**Sales**	**Bare Erected**	**Eng'g CM**	**Contingencies**		**TOTAL PLANT COST**		
No.	**Item/Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Tax**	**Cost $**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**	
	TOTAL COST	**$242,918**	**$29,851**	**$129,460**	**$0**	**$0**	**$402,228**	**$37,680**	**$47,164**	**$87,787**	**$574,859**	**$1,515**	
	Owner's Costs												
	Preproduction Costs												
	6 Months All Labor										$7,892	$21	
	1 Month Maintenance Materials										$1,410	$4	
	1 Month Non-fuel Consumables										$1,273	$3	
	1 Month Waste Disposal										$251	$1	
	25% of 1 Months Fuel Cost at 100% CF										$1,524	$4	
	2% of TPC										$11,497	$30	
	Total										**$23,848**	**$63**	
	Inventory Capital												
	60 day supply of fuel and consumables at 100% CF										$14,357	$38	
	0.5% of TPC (spare parts)										$2,874	$8	
	Total										**$17,231**	**$45**	
	Initial Cost for Catalyst and Chemicals										$1,929	$5	
	Land										$900	$2	
	Other Owner's Costs										$86,229	$227	
	Financing Costs										$15,521	$41	
	Total Overnight Costs (TOC)										**$720,516**	**$1,899**	
	TASC Multiplier								(IOU, high-risk, 35 year)		1.140		
	Total As-Spent Cost (TASC)										**$821,389**	**$2,165**	

Exhibit 4-15 Case 0 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2007
Case 0 - SubCritical PC w/ CO2 Capture Retrofit					Heat Rate-net (Btu/kWh):	13,448
					MWe-net:	379
					Capacity Factor:	85%
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/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	10.7		10.7			
Foreman	1.0		1.0			
Lab Tech's, etc.	2.0		2.0			
TOTAL-O.J.'s	15.7		15.7			
					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost					$6,195,129	$16.33
Maintenance Labor Cost					$9,589,083	$25.27
Administrative & Support Labor					$3,946,053	$10.40
Property Taxes and Insurance					$29,345,843	$77.34
TOTAL FIXED OPERATING COSTS					**$49,076,108**	**$129.345**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$14,383,625**	**0.00509**
Consumables	Consumption		Unit	Initial Fill		
	Initial Fill	/Day	Cost	Cost		
Water (/1000 gallons)	0	5,797	1.08	**$0**	**$1,945,562**	**$0.00069**
Chemicals						
MU & WT Chem.(lbs)	0	28,063	0.17	$0	$1,506,843	$0.00053
Limestone (ton)	0	531	21.63	$0	$3,564,849	$0.00126
Carbon (Mercury Removal) (lb)	0	0	1.05	$0	$0	$0.00000
MEA Solvent (ton)	794	1.13	2,249.89	$1,787,399	$786,285	$0.00028
NaOH (tons)	56	5.61	433.68	$24,338	$755,093	$0.00027
H2SO4 (tons)	54	5.36	138.78	$7,432	$230,578	$0.00008
Corrosion Inhibitor	0	0	0.00	$109,887	$5,233	$0.00000
Activated Carbon (lb)	0	1,345	1.05	$0	$438,365	$0.00016
Ammonia (19% NH3) ton	0	79	129.80	$0	$3,161,256	$0.00112
Subtotal Chemicals				**$1,929,055**	**$10,448,503**	**$0.00370**
Other						
Supplemental Fuel (MBtu)	0	0	0.00	$0	$0	$0.00000
SCR Catalyst (m3)	w/equip.	0.33	5,775.94	$0	$590,782	$0.00021
Emission Penalties	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$590,782**	**$0.00021**
Waste Disposal						
Fly Ash (ton)	0	407	16.23	$0	$2,048,977	$0.00073
Bottom Ash (ton)	0	102	16.23	$0	$512,244	$0.00018
Subtotal-Waste Disposal				**$0**	**$2,561,222**	**$0.00091**
By-products & Emissions						
Gypsum (tons)	0	821	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$0**	**$29,929,694**	**$0.01059**
Coal (ton)	0	5,249	38.19	**$200,416**	**$62,179,108**	**$0.02201**

4.2 COMBUSTION TURBINE AUXILIARY PLANTS CASES 1 AND 2

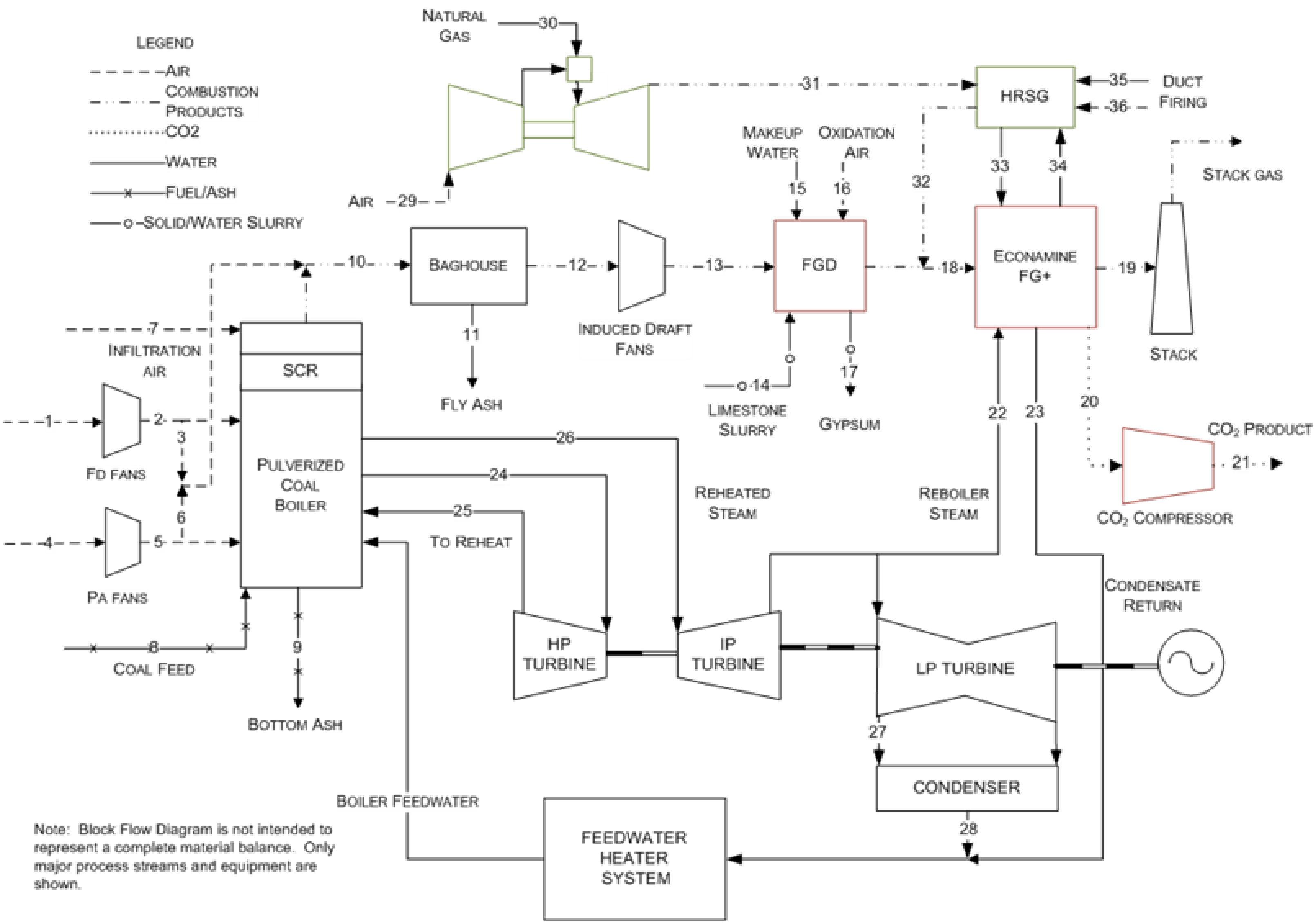
4.2.1 Process Description

Starting from the base case retrofit, Cases 1 and 2 examine the effects of reducing the amount of extracted steam from the existing steam cycle due to CDR retrofit and of repowering the plant back to its original output using a combustion turbine-based auxiliary plant. The additional steam and power from the auxiliary plants will be routed to the main retrofitted plant, as will the flue gas to permit a single CDR for both the retrofitted and auxiliary plants to achieve overall 90 percent reduction in stack emissions.

The maximum repowering of the overall plant is limited by the generation capacity of the individual turbines. The 7FA auxiliary plant achieves the full 550MW repowering, but the 6FA plant is only able to achieve 539 MW. For this application, the combustion turbines exhaust at higher pressures, 15.2 psia, similar to combined cycle operation, in order to provide adequate head through the downstream equipment. Heat is recovered from the combustion turbine exhaust to satisfy as much of the CDR steam requirements as possible, with additional duct firing as necessary. This steam is routed in a closed loop directly to the CDR, simplifying the CDR retrofit by avoiding the extraction of large amounts of steam from the existing steam cycle and piping it to the necessary equipment. Also, the cooled combustion turbine exhaust can be similarly routed to the CDR facility. In this way, the CDR can be placed without regard to the location of the existing steam turbine and can minimize the amount of duct work to route the flue gas streams for CO_2 removal.

The Case 1 and 2 configurations can be viewed as minimal and maximum repowering, respectively, using a combustion turbine auxiliary plant. The 6FA combustion turbine provides enough power and offsets enough steam to almost fully repower the existing plant to its pre-retrofit output after fully satisfying the CDR steam demand by additional duct firing. The 7FA configuration is able to repower the combined retrofitted plant to the original capacity without duct firing. To produce all the CDR steam in the 7FA auxiliary plant, additional heat input would be required to generate steam and increase the steamto power ratio of the auxiliary plant, but this would result in increased plant output, so was not implemented for these comparisons. The configuration presented here repowers to the original 550 MW, partly to compare two different CT configurations with similar outputs and to minimize the natural gas usage while still fully repowering. This results in Case 2 requiring a small amount of LP steam extraction from the existing steam cycle. The reduction in efficiency in the case with lower gas turbine capacity, partly replaced by increased duct firing, indicates that this configuration is not the best use for natural gas. Duct firing would be more economical if it was used in a reheat steam cycle or for high quality steam generation.

Exhibit 4-16 Case 1 and 2 Block Flow Diagram, CT Auxiliary Plant



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Exhibit 4-17 Case 1 Stream Table, 6FA Auxiliary Plant

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	51,695	51,695	1,538	15,880	15,880	2,178	1,195	0	0	72,745	0	72,745
V-L Flowrate (kg/hr)	1,491,773	1,491,773	44,387	458,257	458,257	62,864	34,480	0	0	2,163,663	0	2,163,663
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	198,391	3,848	15,390	15,390	0
Temperature (°C)	15	19	19	15	25	25	15	15	15	169	15	169
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10
Enthalpy (kJ/kg)[A]	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	327.40	---	308.96
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	0.8	---	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	29.743	---	29.743
V-L Flowrate (lb_{mol}/hr)	113,969	113,969	3,391	35,010	35,010	4,803	2,634	0	0	160,375	0	160,375
V-L Flowrate (lb/hr)	3,288,796	3,288,796	97,858	1,010,284	1,010,284	138,592	76,015	0	0	4,770,061	0	4,770,061
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	437,378	8,482	33,929	33,929	0
Temperature (°F)	59	66	66	59	78	78	59	59	59	337	59	337
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.4	14.7	14.2
Enthalpy (Btu/lb)[A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	140.8	---	132.8
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	0.050	---	0.049

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 4-17 Case 1 Stream Table, 6FA Auxiliary Plant (Continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0087	0.0000	0.0000	0.0128	0.0000	0.0084	0.0106	0.0000	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.1450	0.0000	0.0000	0.0005	0.0004	0.1063	0.0135	0.9950	0.9985	0.0000	0.0000	0.0000
H_2O	0.0870	1.0000	1.0000	0.0062	0.9996	0.1444	0.0383	0.0050	0.0015	1.0000	1.0000	1.0000
N_2	0.7324	0.0000	0.0000	0.7506	0.0000	0.6980	0.8833	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0247	0.0000	0.0000	0.2300	0.0000	0.0429	0.0543	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0021	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	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	72,745	2,497	10,543	742	190	132,272	104,523	12,717	12,673	0	0	93,448
V-L Flowrate (kg/hr)	2,163,663	44,980	189,929	21,531	3,429	3,775,271	2,946,309	558,029	557,225	0	0	1,683,490
Solids Flowrate (kg/hr)	0	20,076	0	0	31,031	0	0	0	0	0	0	0
Temperature (°C)	182	15	15	181	58	128	32	21	35	296	151	566
Pressure (MPa, abs)	0.11	0.10	0.10	0.31	0.10	0.10	0.10	0.16	15.27	0.51	0.90	16.65
Enthalpy (kJ/kg)[A]	322.83	---	-46.80	191.62	---	365.40	93.78	20.64	-211.71	3,054.40	637.40	3,472.33
Density (kg/m^3)	0.8	---	1,003.1	2.4	---	0.9	1.1	2.9	795.9	2.0	915.7	47.7
V-L Molecular Weight	29.743	---	18.015	29.029	---	28.542	28.188	43.880	43.971	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	160,375	5,504	23,243	1,635	419	291,610	230,435	28,037	27,938	0	0	206,017
V-L Flowrate (lb/hr)	4,770,061	99,164	418,721	47,467	7,559	8,323,048	6,495,499	1,230,244	1,228,471	0	0	3,711,459
Solids Flowrate (lb/hr)	0	44,261	0	0	68,412	0	0	0	0	0	0	0
Temperature (°F)	360	59	59	357	136	262	89	69	95	564	304	1,050
Pressure (psia)	15.4	15.0	14.7	45.0	14.9	14.9	14.7	23.5	2,214.5	74.0	130.0	2,415.0
Enthalpy (Btu/lb)[A]	138.8	---	-20.1	82.4	---	157.1	40.3	8.9	-91.0	1,313.2	274.0	1,492.8
Density (lb/ft^3)	0.052	---	62.622	0.149	---	0.055	0.070	0.184	49.684	0.123	57.167	2.977

Exhibit 4-17 Case 1 Stream Table, 6FA Auxiliary Plant (Continued)

	25	26	27	28	29	30	31	32	33	34	35	36
V-L Mole Fraction												
Ar	0.0000	0.0000	0.0000	0.0000	0.0092	0.0000	0.0089	0.0087	0.0000	0.0000	0.0000	0.0092
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000	0.9310	0.0000
C_2H_6	0.0000	0.0000	0.0000	0.0000	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0320	0.0000
C_3H_8	0.0000	0.0000	0.0000	0.0000	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0070	0.0000
C_4H_{10}	0.0000	0.0000	0.0000	0.0000	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0040	0.0000
CO_2	0.0000	0.0000	0.0000	0.0000	0.0003	0.0100	0.0375	0.0633	0.0000	0.0000	0.0100	0.0003
H_2O	1.0000	1.0000	1.0000	1.0000	0.0099	0.0000	0.0810	0.1305	1.0000	1.0000	0.0000	0.0099
N_2	0.0000	0.0000	0.0000	0.0000	0.7732	0.0160	0.7454	0.7260	0.0000	0.0000	0.0160	0.7732
O_2	0.0000	0.0000	0.0000	0.0000	0.2074	0.0000	0.1272	0.0715	0.0000	0.0000	0.0000	0.2074
SO_2	0.0000	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	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	85,525	85,525	77,031	77,965	25,885	958	26,871	53,016	50,195	50,195	2,247	23,833
V-L Flowrate (kg/hr)	1,540,758	1,540,758	1,387,731	1,404,566	746,976	16,601	763,577	1,490,251	904,285	904,285	38,933	687,741
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	363	566	38	39	15	25	589	236	152	139	25	15
Pressure (MPa, abs)	4.28	3.90	0.01	1.69	0.10	3.10	0.11	0.10	0.51	0.48	0.10	0.10
Enthalpy (kJ/kg)[A]	3,120.82	3,594.06	2,025.27	165.23	30.23	16.51	777.77	463.51	2,746.79	583.57	50.99	30.23
Density (kg/m^3)	15.7	10.3	0.1	993.3	1.2	23.4	0.4	0.7	2.7	926.9	0.7	1.2
V-L Molecular Weight	18.015	18.015	18.015	18.015	28.857	17.328	28.416	28.109	18.015	18.015	17.328	28.857
V-L Flowrate (lb_{mol}/hr)	188,551	188,551	169,824	171,884	57,068	2,112	59,241	116,880	110,662	110,662	4,953	52,542
V-L Flowrate (lb/hr)	3,396,791	3,396,791	3,059,423	3,096,538	1,646,800	36,600	1,683,400	3,285,441	1,993,608	1,993,608	85,832	1,516,210
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	686	1,050	101	102	59	77	1,093	456	306	282	77	59
Pressure (psia)	620.5	565.5	1.0	245.0	14.7	450.0	15.2	14.7	73.5	70.0	14.7	14.7
Enthalpy (Btu/lb)[A]	1,341.7	1,545.2	870.7	71.0	13.0	7.1	334.4	199.3	1,180.9	250.9	21.9	13.0
Density (lb/ft^3)	0.983	0.643	0.004	62.011	0.076	1.459	0.026	0.042	0.169	57.867	0.044	0.076

Exhibit 4-18 Case 2 Stream Table, 7FA Auxiliary Plant

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	51,695	51,695	1,538	15,880	15,880	2,178	1,195	0	0	72,745	0	72,745
V-L Flowrate (kg/hr)	1,491,773	1,491,773	44,387	458,257	458,257	62,864	34,480	0	0	2,163,663	0	2,163,663
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	198,391	3,848	15,390	15,390	0
Temperature (°C)	15	19	19	15	25	25	15	15	15	169	15	169
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10
Enthalpy (kJ/kg)[A]	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	327.40	---	308.96
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	0.8	---	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	29.743	---	29.743
V-L Flowrate (lb_{mol}/hr)	113,969	113,969	3,391	35,010	35,010	4,803	2,634	0	0	160,375	0	160,375
V-L Flowrate (lb/hr)	3,288,796	3,288,796	97,858	1,010,284	1,010,284	138,592	76,015	0	0	4,770,061	0	4,770,061
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	437,378	8,482	33,929	33,929	0
Temperature (°F)	59	66	66	59	78	78	59	59	59	337	59	337
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.4	14.7	14.2
Enthalpy (Btu/lb)[A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	140.8	---	132.8
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	0.050	---	0.049
	A - Reference conditions are 32.02 F & 0.089 PSIA											

Exhibit 4-18 Case 2 Stream Table, 7FA Auxiliary Plant(Continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0087	0.0000	0.0000	0.0128	0.0000	0.0085	0.0103	0.0000	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.1450	0.0000	0.0000	0.0005	0.0004	0.0942	0.0114	0.9942	0.9985	0.0000	0.0000	0.0000
H_2O	0.0870	1.0000	1.0000	0.0062	0.9996	0.1236	0.0383	0.0058	0.0015	1.0000	1.0000	1.0000
N_2	0.7324	0.0000	0.0000	0.7506	0.0000	0.7069	0.8588	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0247	0.0000	0.0000	0.2300	0.0000	0.0668	0.0812	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0021	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	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	72,745	2,497	10,543	742	190	136,858	112,656	11,674	11,624	25,125	25,125	93,448
V-L Flowrate (kg/hr)	2,163,663	44,980	189,929	21,531	3,429	3,921,445	3,183,599	512,004	511,102	452,633	452,633	1,683,490
Solids Flowrate (kg/hr)	0	20,076	0	0	31,031	0	0	0	0	0	0	0
Temperature (°C)	182	15	15	181	58	126	32	21	35	296	151	566
Pressure (MPa, abs)	0.11	0.10	0.10	0.31	0.10	0.10	0.10	0.16	15.27	0.51	0.90	16.65
Enthalpy (kJ/kg)[A]	322.83	---	-46.80	191.62	---	328.30	93.54	21.44	-211.71	3,054.40	636.27	3,472.33
Density (kg/m^3)	0.8	---	1,003.1	2.4	---	0.9	1.1	2.9	795.9	2.0	916.0	47.7
V-L Molecular Weight	29.743	---	18.015	29.029	---	28.653	28.259	43.860	43.971	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	160,375	5,504	23,243	1,635	419	301,721	248,364	25,736	25,626	55,391	55,391	206,017
V-L Flowrate (lb/hr)	4,770,061	99,164	418,721	47,467	7,559	8,645,307	7,018,635	1,128,775	1,126,788	997,885	997,885	3,711,459
Solids Flowrate (lb/hr)	0	44,261	0	0	68,412	0	0	0	0	0	0	0
Temperature (°F)	360	59	59	357	136	258	89	69	95	564	304	1,050
Pressure (psia)	15.4	15.0	14.7	45.0	14.9	14.9	14.7	23.5	2,214.5	73.5	130.0	2,415.0
Enthalpy (Btu/lb)[A]	138.8	---	-20.1	82.4	---	141.1	40.2	9.2	-91.0	1,313.2	273.5	1,492.8
Density (lb/ft^3)	0.052	---	62.622	0.149	---	0.055	0.071	0.184	49.684	0.122	57.183	2.977

Exhibit 4-18 Case 2 Stream Table, 7FA Auxiliary Plant(Continued)

	25	26	27	28	29	30	31	32	33	34
V-L Mole Fraction										
Ar	0.0000	0.0000	0.0000	0.0000	0.0092	0.0000	0.0089	0.0089	0.0000	0.0000
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0000	0.0000	0.0000	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0000	0.0000	0.0000	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0000	0.0000	0.0000	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.0000	0.0000	0.0003	0.0100	0.0381	0.0381	0.0000	0.0000
H_2O	1.0000	1.0000	1.0000	1.0000	0.0099	0.0000	0.0822	0.0822	1.0000	1.0000
N_2	0.0000	0.0000	0.0000	0.0000	0.7732	0.0160	0.7449	0.7449	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.2074	0.0000	0.1260	0.1260	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
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	85,525	85,525	52,371	53,306	55,455	2,086	57,602	57,602	18,284	18,284
V-L Flowrate (kg/hr)	1,540,758	1,540,758	943,480	960,315	1,600,274	36,151	1,636,425	1,636,425	329,394	329,394
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	363	566	38	39	15	25	607	222	152	139
Pressure (MPa, abs)	4.28	3.90	0.01	1.69	0.10	3.10	0.11	0.11	0.51	0.48
Enthalpy (kJ/kg)[A]	3,120.82	3,594.06	2,029.96	166.36	30.23	16.51	801.26	365.83	2,746.79	583.57
Density (kg/m^3)	15.7	10.3	0.1	993.2	1.2	23.4	0.4	0.7	2.7	926.9
V-L Molecular Weight	18.015	18.015	18.015	18.015	28.857	17.328	28.409	28.409	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	188,551	188,551	115,459	117,519	122,258	4,600	126,991	126,991	40,310	40,310
V-L Flowrate (lb/hr)	3,396,791	3,396,791	2,080,018	2,117,132	3,528,000	79,700	3,607,700	3,607,700	726,189	726,189
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	686	1,050	101	103	59	77	1,125	432	306	282
Pressure (psia)	620.5	565.5	1.0	245.0	14.7	450.0	15.2	15.2	73.5	70.0
Enthalpy (Btu/lb)[A]	1,341.7	1,545.2	872.7	71.5	13.0	7.1	344.5	157.3	1,180.9	250.9
Density (lb/ft^3)	0.983	0.643	0.004	62.004	0.076	1.459	0.025	0.045	0.169	57.867

4.2.2 Key System Assumptions

System assumptions for Cases 1 and 2, retrofitted PC plant with CT auxiliary plant and CO_2 capture, are compiled in Exhibit 4-19.

Exhibit 4-19 Retrofitted PC Plant CT Aux Plant Configuration Matrix

	Case 1	Case 2
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/566 (2400/1050/1050)	16.5/566/566 (2400/1050/1050)
Coal	Illinois No. 6	Illinois No. 6
Condenser pressure, mm Hg (in Hg)	50.8 (2)	50.8 (2)
Boiler Efficiency, %	88	88
Cooling water to condenser, °C (ºF)	16 (60)	16 (60)
Cooling water from condenser, °C (ºF)	27 (80)	27 (80)
Stack temperature, °C (°F)	32 (89)	32 (89)
SO_2 Control	Wet Limestone Forced Oxidation	Wet Limestone Forced Oxidation
FGD Efficiency, % (A)	98 (B, C)	98 (B, C)
NO_x Control	LNB w/OFA and SCR	LNB w/OFA and SCR
SCR Efficiency, % (A)	86	86
Ammonia Slip (end of catalyst life), ppmv	2	2
Particulate Control	Fabric Filter	Fabric Filter
Fabric Filter efficiency, % (A)	99.8	99.8
Ash Distribution, Fly/Bottom	80% / 20%	80% / 20%
Mercury Control	Co-benefit Capture	Co-benefit Capture
Mercury removal efficiency, % (A)	90	90
CO_2 Control	Econamine	Econamine
Overall CO_2 Capture (A)	90.2%	90.2%
CO_2 Sequestration	Off-site Saline Formation	Off-site Saline Formation
Aux Plant Combustion Turbine	6FA	7FA
CT Output, MW	75.8	171.1
CT Heat Rate, BTU/kWh (HHV)	10,882	10,496

A. Removal efficiencies are based on the FG content
B. An SO_2 polishing step is included to meet more stringent SOx content limits in the FG (< 10 ppmv) to reduce formation of amine HSS during the CO_2 absorption process
C. SO_2 exiting the post-FGD polishing step is absorbed in the CO_2 capture process making stack emissions negligible

Balance of Plant – Cases 1 and 2

The balance of plant assumptions are common to all cases and are presented in Exhibit 4-20.

Exhibit 4-20 Balance of Plant Assumptions

Cooling system	Recirculating Wet Cooling Tower
Fuel and Other storage	
Coal	30 days
Natural Gas	Pipeline supply at 3.1 MPa (450 psia) and 38°C (100°F)
Ash	30 days
Gypsum	30 days
Limestone	30 days
Plant Distribution Voltage	
Motors below 1 hp	110/220 volt
Motors between 1 hp and 250 hp	480 volt
Motors between 250 hp and 5,000 hp	4,160 volt
Motors above 5,000 hp	13,800 volt
Steam and GT generators	24,000 volt
Grid Interconnection voltage	345 kV
Water and Waste Water	
Makeup Water	The water supply is 50 percent from a local POTW and 50 percent from groundwater, and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and DI water is drawn from municipal sources.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 cubic meters per day (1,500 gallons per day)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown will be treated for chloride and metals, and discharged.

4.2.3 Sparing Philosophy

Single trains are used throughout the design with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- One F class CTGs (1 x 100 percent)
- One HRSGs with duct burners, self supporting stacks and SCR systems (1 x 100 percent)
- One STG (1 x 100 percent)
- Two parallel Econamine CO_2 absorption systems, with each system consisting of two absorbers, strippers and ancillary equipment (2 x 50 percent)

4.2.4 Performance Results

The Case 1 plant repowers the existing plant, with CDR retrofit to 539 MWe at a net plant efficiency of 23.4 percent (HHV basis) and the Case 2 plant to 557 MW at an efficiency of 27.6 percent. Overall performance for these plants is summarized in Exhibit 4-21, which includes auxiliary power requirements.

Exhibit 4-21 Cases 1 and 2 Plant Performance Summaries

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	Case 1	Case 2
Steam Turbine Power	577,800	497,300
Gas Turbine Power	79,700	171,200
TOTAL POWER, kWe	**657,500**	**668,500**
AUXILIARY LOAD SUMMARY, kWe		
Coal Handling and Conveying	450	450
Pulverizers	2,970	2,970
Sorbent Handling & Reagent Preparation	970	970
Ash Handling	570	570
Primary Air Fans	1,390	1,390
Forced Draft Fans	1,780	1,780
Induced Draft Fans	8,640	8,640
SCR	60	60
Baghouse	70	70
Wet FGD	3,180	3,180
Econamine FG Plus Auxiliaries	25,800	26,300
CO_2 Compression	45,590	41,820
Miscellaneous Balance of Plant[1]	2,500	2,500
Steam Turbine Auxiliaries	400	400
Gas Turbine Auxiliaries	700	700
Condensate Pumps	890	610
Circulating Water Pumps	12,740	10,490
Ground Water Pumps	1,120	940
Cooling Tower Fans	6,620	5,450
Transformer Losses	2,050	1,790
TOTAL AUXILIARIES, kWe	**118,490**	**111,080**
NET POWER, kWe	**539,010**	**557,420**
Net Plant Efficiency, % (HHV)	23.4%	27.6%
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	15,391 (14,588)	13,059 (12,378)
CONDENSER COOLING DUTY, GJ/hr (10^6 Btu/hr)	2,589 (2,451)	1,762 (1,670)
CONSUMABLES		
As-Received Coal Feed, kg/hr (lb/hr)	198,391 (437,378)	198,391 (437,378)
Natural Gas Feed, kg/hr (lb/hr)	55,534 (122,432)	36,151 (79,700)
Thermal Input, kWt	2,304,465	2,022,075
Raw Water Withdrawal, m^3/min (gpm)	47.4 (12,520)	41.3 (10,903)
Raw Water Consumption, m^3/min (gpm)	36.2 (9,556)	31.5 (8,334)

Notes:
1. HHV of As Received Illinois No. 6 coal is 27,135 kJ/kg (11,666 Btu/lb)
2. Boiler feed pumps are turbine driven
3. Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and PM were presented in Section 2.4. A summary of the plant air emissions for Cases 1 and 2 are presented in Exhibit 4-23 and Exhibit 4-24, respectively.

Exhibit 4-22 Case 1 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% CF	kg/MWh (lb/MWh)
SO_2	0.001 (0.002)	50 (55)	0.010 (0.022)
NOx	0.020 (0.048)	1,262 (1,391)	0.258 (0.568)
Particulates	0.002 (0.0042)	224 (247)	0.046 (0.101)
Hg	3.191E-7 (7.42E-7)	0.020 (0.022)	4.02E-6 (8.87E-6)
CO_2	7.5 (17.3)	460,728 (507,866)	94 (207)
CO_2[1]			115 (253)

[1] CO_2 emissions based on net power instead of gross power

Exhibit 4-23 Case 2 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% CF	kg/MWh (lb/MWh)
SO_2	0.001 (0.002)	54 (59)	0.011 (.024)
NOx	0.023 (0.054)	1,262 (1,391)	0.254 (.559)
Particulates	0.002 (0.0048)	224 (247)	0.045 (.099)
Hg	3.63E-7 (8.45E-7)	0.020 (0.022)	3.96E-6 (8.72E-6)
CO_2	7.8 (18.1)	422,593 (465,829)	85 (187)
CO_2[1]			102 (224)

[1] CO_2 emissions based on net power instead of gross power

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

NO_x emissions from the base plant are controlled to about 0.5 $lb/10^6$ Btu through the use of LNBs and OFA. An SCR unit is used for both the base plant and auxiliary combustion turbine exhaust to further reduces the NO_x concentration to 0.07 $lb/10^6$ Btu.

Particulate emissions from the base plant are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.8 percent.

Co-benefit capture results in a 90 percent reduction of mercury emissions from the base plant. CO_2 emissions represent the uncontrolled discharge from the process.

The carbon balance for these plants are shown in Exhibit 4-24 and Exhibit 4-25. The carbon input to the plant consists of carbon in the coal, carbon in the air, and carbon in the limestone reagent used in the FGD. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO_2 through the stack but also leaves as gypsum.

Exhibit 4-24 Case 1 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	126,464 (278,805)	**Stack Gas**	16,887 (37,229)
Natural Gas	40,122 (88,431)	**FGD Product**	213 (469)
Air (CO_2)	470 (1,036)	**CO_2 Product**	151,983 (335,064)
FGD Reagent	2,037 (4,491)		
Total	169,083 (372,763)	**Total**	169,083 (372,763)

Exhibit 4-25 Case 2 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	126,464 (278,805)	**Stack Gas**	15,489 (34,148)
Natural Gas	26,112 (57,566)	**FGD Product**	213 (469)
Air (CO_2)	492 (1,085)	**CO_2 Product**	139,403 (307,330)
FGD Reagent	2,037 (4,491)		
Total	155,105 (341,948)	**Total**	155,105 (341,948)

Exhibit 4-26 and Exhibit 4-27 show the sulfur balances for these plants. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum and sulfur emitted in the stack gas.

Exhibit 4-26 Case 1 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	4,973 (10,963)	**FGD Product**	4,873 (10,743)
		Stack Gas	3 (7)
		Econamine Polishing Scrubber/HSS	96 (212)
		CO_2 Product	0 (0)
Total	4,973 (10,963)	**Total**	4,973 (10,963)

Exhibit 4-27 Case 2 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	4,973 (10,963)	**FGD Product**	4,873 (10,743)
		Stack Gas	4 (8)
		Econamine Polishing Scrubber/HSS	96 (211)
		CO_2 Product	0 (0)
Total	4,973 (10,963)	**Total**	4,973 (10,963)

Exhibit 4-28 and Exhibit 4-29 show the water balances for Case 1 and 2, respectively. Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is re-used as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a surface-water source for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from groundwater. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for any and all purposes, such as FDG makeup, BFW makeup, and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source.

Exhibit 4-28 Case 1 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Withdrawal, m^3/min (gpm)	Process Water Discharge, m^3/min (gpm)	Raw Water Consumption, m^3/min (gpm)
Econamine	0.14 (36)	0.0 (0)	0.14 (36)	0.00 (0)	0.14 (36)
FGD Makeup	3.92 (1,036)	0.0 (0)	3.92 (1036)	0.00 (0)	3.92 (1,036)
BFW Makeup	0.28 (74)	0.0 (0)	0.28 (74)	0.00 (0)	0.28 (74)
Cooling Tower	49.9 (13,178)	6.83 (1804)	43.1 (11,374)	11.22 (2,964)	31.84 (8,410)
Total	**54.2 (14,324)**	**6.83 (1,804)**	**47.4 (12,520)**	**11.22 (2,964)**	**36.18 (9,556)**

Exhibit 4-29 Case 2 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Withdrawal, m^3/min (gpm)	Process Water Discharge, m^3/min (gpm)	Raw Water Consumption, m^3/min (gpm)
Econamine	0.13 (33)	0.0 (0)	0.13 (33)	0.00 (0)	0.13 (33)
FGD Makeup	3.92 (1036)	0.0 (0)	3.92 (1036)	0.00 (0)	3.92 (1,036)
BFW Makeup	0.28 (74)	0.0 (0)	0.28 (74)	0.00 (0)	0.28 (74)
Cooling Tower	41.1 (10,848)	6.08 (1605)	35.0 (9,242)	9.23 (2,440)	25.75 (6,803)
Total	**45.4 (11,991)**	**6.08 (1605)**	**39.3 (10,386)**	**9.23 (2440)**	**30.08 (7,946)**

<u>Heat and Mass Balance Diagrams</u>

A heat and mass balance diagrams are shown for the PC boiler, the flue gas cleanup including CDR facility, steam cycle, and auxiliary plants as shown in Exhibit 4-32 and Exhibit 4-33 for Case 1 and in Exhibit 4-34 and Exhibit 4-35 for Case 2.

Overall plant energy balances are provided in tabular form in Exhibit 4-30 and Exhibit 4-31. The power out is the steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by a generator efficiency of 98.6 percent.

Exhibit 4-30 Case 1 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,383 (5,102)	4.5 (4.3)		5,388 (5,107)
Natural Gas	2,913 (2,761)	1.9 (1.8)		2,915 (2,763)
Air		103.4 (98.0)		103.4 (98.0)
Raw Water Withdrawal		178.3 (169.0)		178.3 (169.0)
Lime		0.23 (0.22)		0.23 (0.22)
Auxiliary Power			427 (404)	427 (404)
Totals	**8,296 (7,863)**	**288.4 (273.3)**	**427 (404)**	**9,011 (8,541)**
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash		0.5 (0.4)		0.5 (0.4)
Fly Ash + FGD Ash		1.9 (1.8)		1.9 (1.8)
Flue Gas		249 (236)		249 (236)
Condenser		2,586 (2,451)		2,586 (2,451)
CO_2		-118 (-112)		-118 (-112)
Cooling Tower Blowdown		83.3 (79.0)		83.3 (79.0)
Econamine Losses		3,823 (3,623)		3,823 (3,623)
Process Losses*		19 (18)		19 (18)
Power			2,367 (2,243)	2,367 (2,243)
Totals	**0 (0)**	**6,644 (6,297)**	**2,367 (2,243)**	**9,011 (8,541)**

* Process losses are estimated to match the heat input to the plant. Process losses include losses from: turbines, gas cooling, etc.

Exhibit 4-31 Case 2 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,383 (5,102)	4.5 (4.3)		5,388 (5,107)
Natural Gas	1,896 (1,797)	1.3 (1.2)		1,897 (1,798)
Air		108.4 (102.7)		108.4 (102.7)
Raw Water Withdrawal		147.9 (140.2)		147.9 (140.2)
Lime		0.23 (0.22)		0.23 (0.22)
Auxiliary Power			400 (379)	400 (379)
Totals	**8,010 (7,592)**	**262.3 (248.6)**	**400 (379)**	**7,942 (7,527)**
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash		0.5 (0.4)		0.5 (0.4)
Fly Ash + FGD Ash		1.9 (1.8)		1.9 (1.8)
Flue Gas		268 (254)		268 (254)
Condenser		1,762 (1,670)		1,762 (1,670)
CO_2		-108 (-103)		-108 (-103)
Cooling Tower Blowdown		68.6 (65.0)		68.6 (65.0)
Econamine Losses		3,495 (3,313)		3,495 (3,313)
ST Off-Design Loss		27 (25)		27 (25)
Process Losses*		21 (20)		21 (20)
Power			2,407 (2,281)	2,407 (2,281)
Totals	**0 (0)**	**5,535 (5,246)**	**2,407 (2,281)**	**7,942 (7,527)**

* Process losses are estimated to match the heat input to the plant. Process losses include losses from: turbines, gas cooling, etc.

Exhibit 4-32 Case 1 Heat and Mass Balance, Auxiliary 6FA CT Plant

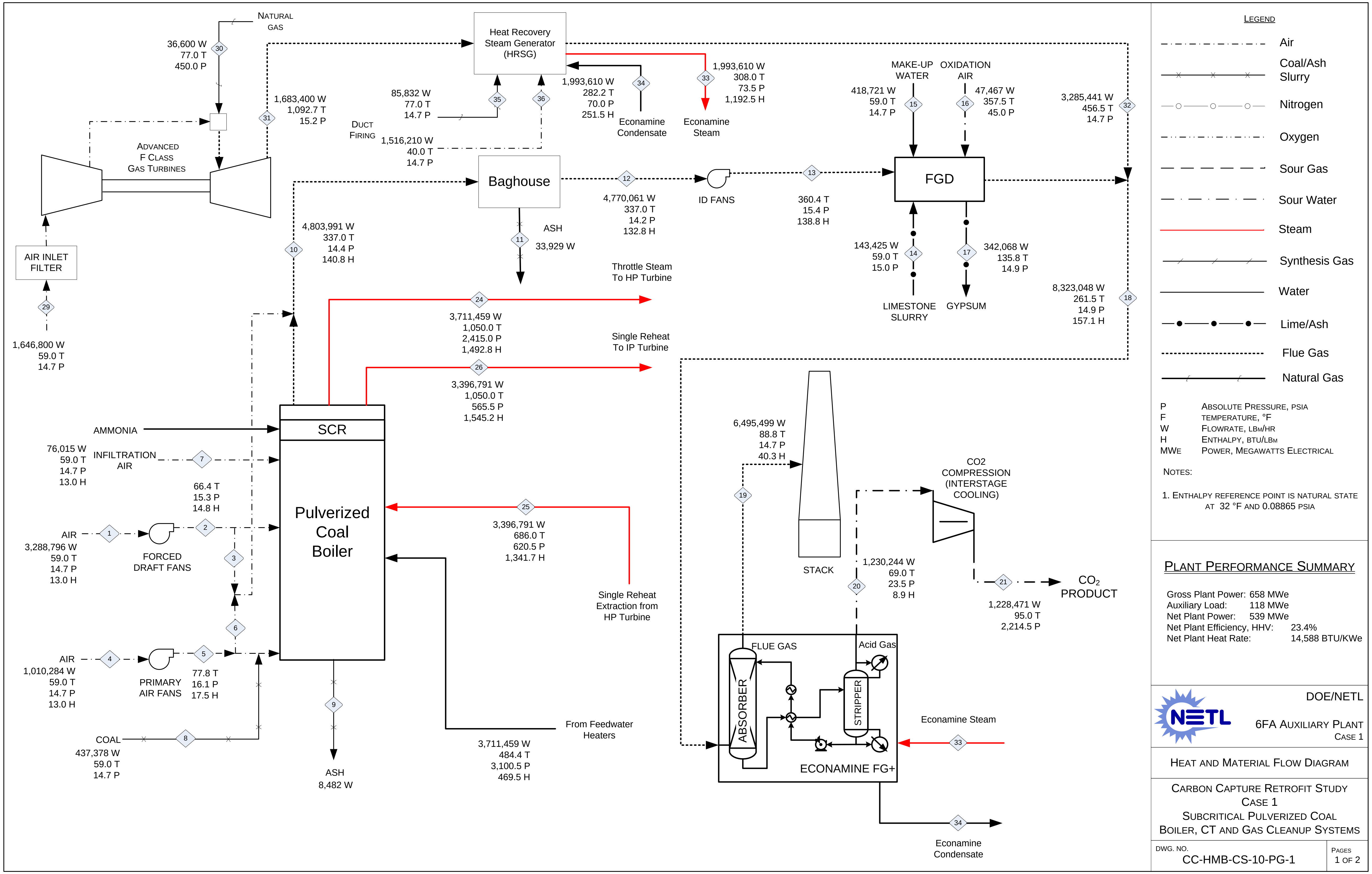


Exhibit 4-33 Case 1 Heat and Mass Balance, Subcritical Steam Cycle

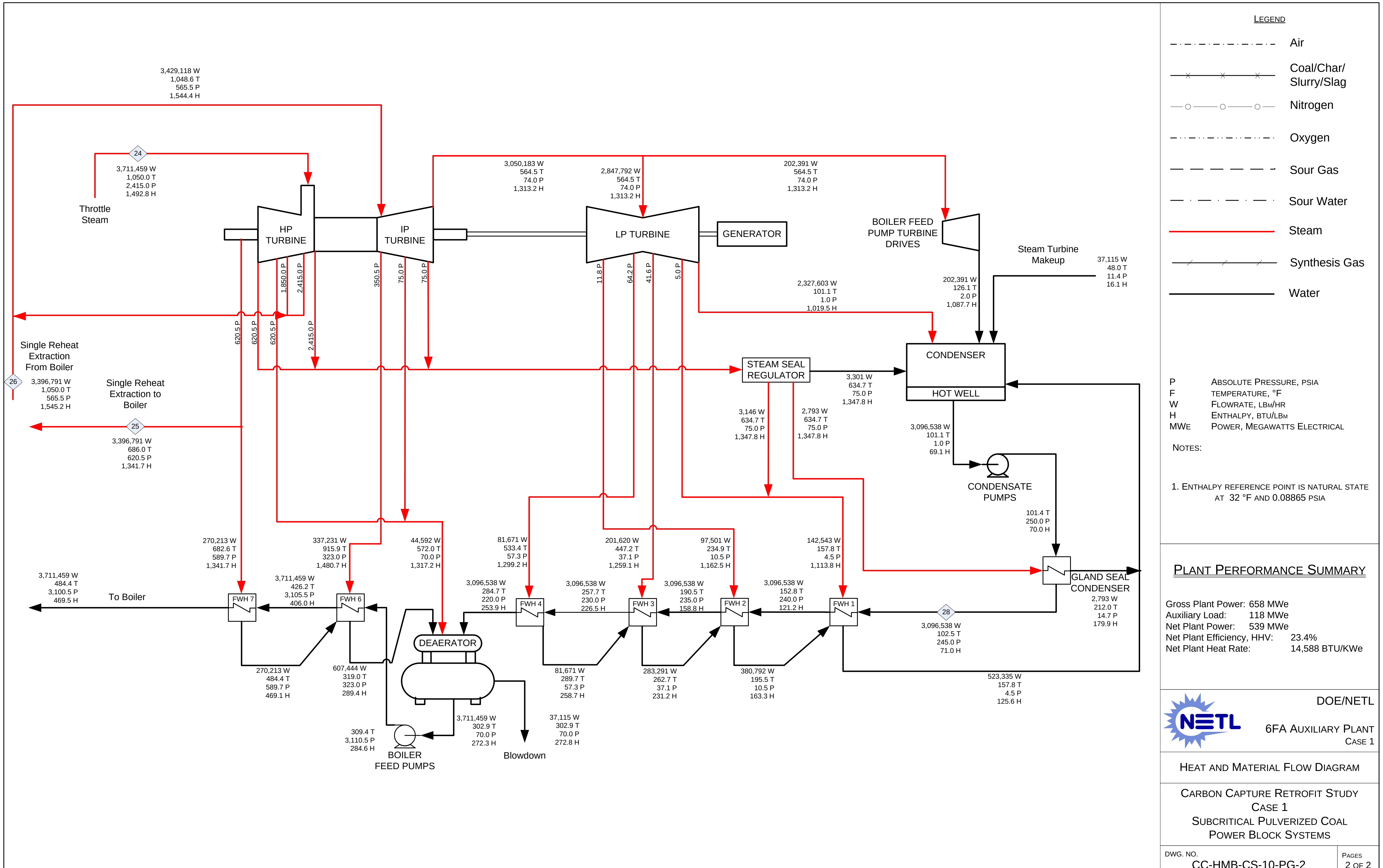


Exhibit 4-34 Case 2 Heat and Mass Balance, Auxiliary 7FA CT Plant

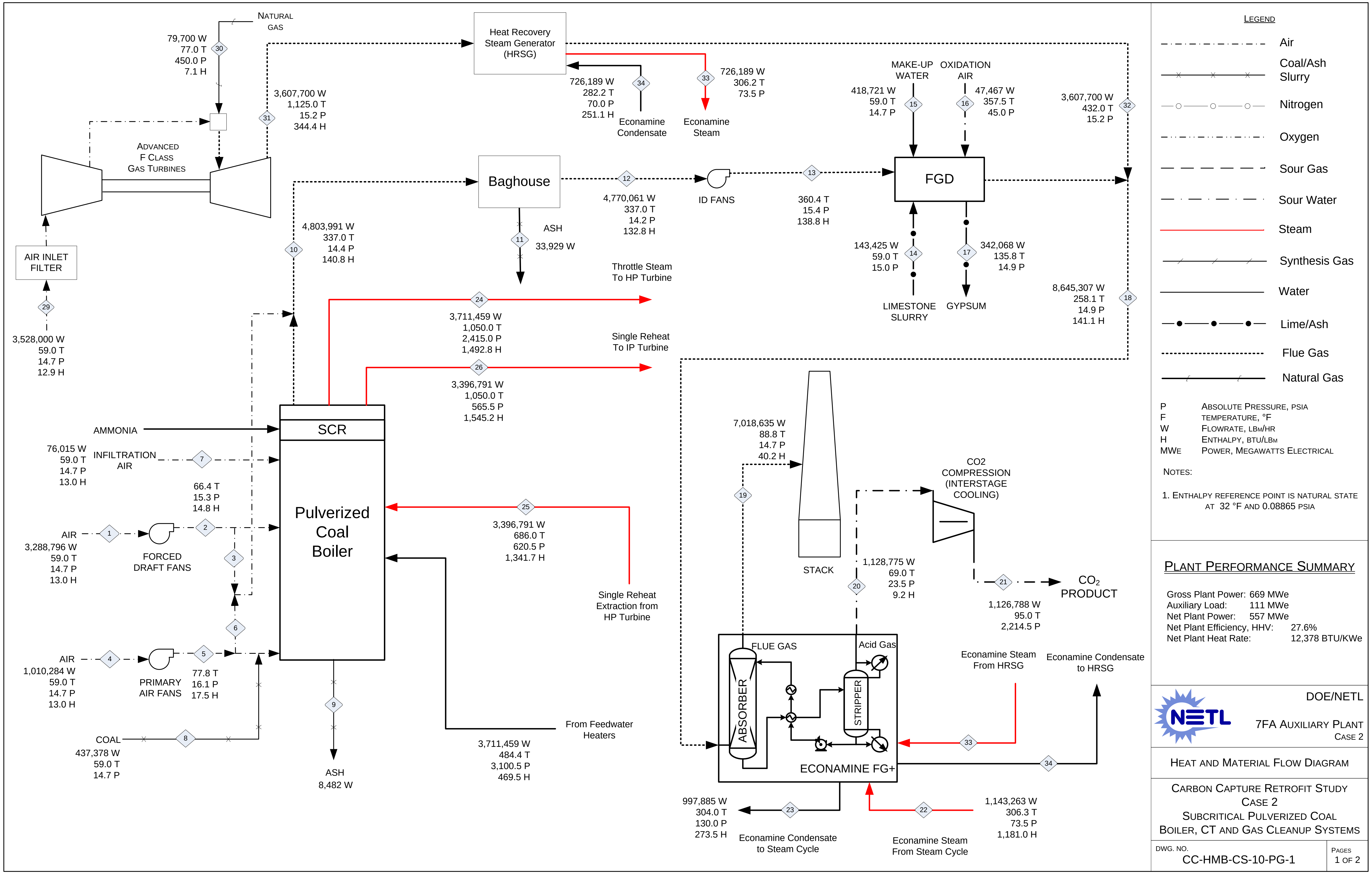
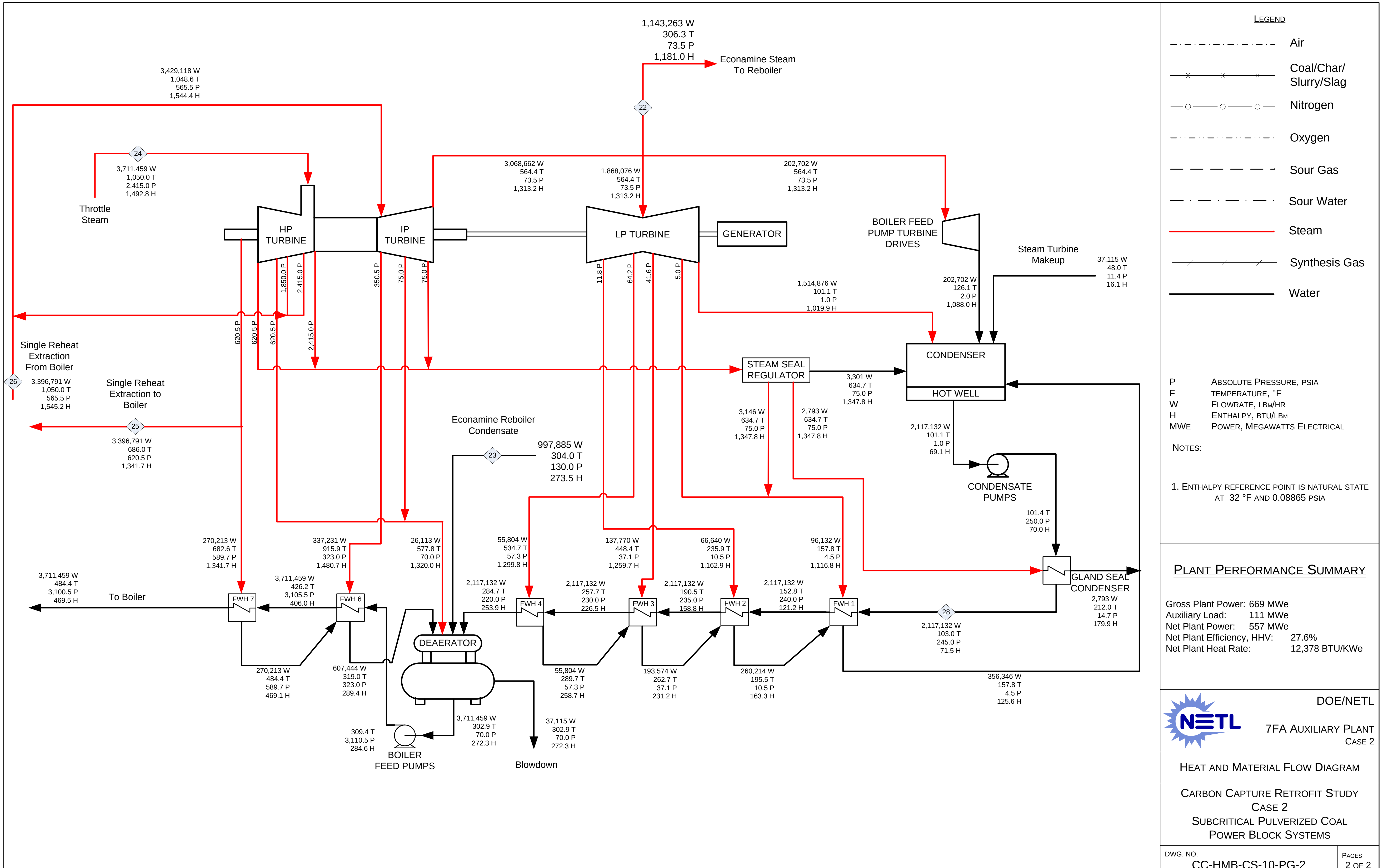


Exhibit 4-35 Case 2 Heat and Mass Balance, Subcritical Steam Cycle



4.2.5 Major Equipment List

Major equipment items for the additional required equipment for the CDR and auxiliary plant retrofits are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.1.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

CASE 1 EQUIPMENT LIST

ACCOUNT 3 FEEDWATER AND ANCILLARY EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,112,911 liters (294,000 gal)	2	0
2	Condensate Pumps	Vertical canned	25,741 lpm @ 213 m H2O (6,800 gpm @ 700 ft H2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	1,852,018 kg/hr (4,083,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	31,040 lpm @ 2,591 m H2O (8,200 gpm @ 8,500 ft H2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	9,085 lpm @ 2,591 m H2O (2,400 gpm @ 8,500 ft H2O)	1	0
6	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
7	Fuel Oil System	No. 2 fuel oil for light off	1,135,624 liter (300,000 gal)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H2O (5,500 gpm @ 100 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	13,438 lpm @ 18 m H2O (3,550 gpm @ 60 ft H2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	5,375 lpm @ 268 m H2O (1,420 gpm @ 880 ft H2O)	5	1
16	Filtered Water Pumps	Stainless steel, single suction	2,120 lpm @ 49 m H2O (560 gpm @ 160 ft H2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	2,040,337 liter (539,000 gal)	1	0
18	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	757 lpm (200 gpm)	1	1
19	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

ACCOUNT 5B CARBON DIOXIDE RECOVERY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Econamine FG Plus	Amine-based CO_2 capture technology	1,256,904 kg/h (2,771,000 lb/h) 20.6 wt % CO_2 concentration	2	0
2	Econamine Condensate Pump	Centrifugal	13,098 lpm @ 52 m H_2O (3,460 gpm @ 170 ft H_2O)	1	1
3	CO_2 Compressor	Integrally geared, multi-stage centrifugal	233,179 kg/h @ 15.3 MPa (514,073 lb/h @ 2,215 psia)	2	0

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	6FA w/ dry low-NOx burner	76 MW	1	0
2	Gas Turbine Generator	TEWAC	80 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0

ACCOUNT 7 HRSG, DUCTING & STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 4.9 m (16 ft) diameter	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	1,287,000 lpm @ 30 m (340,000 gpm @ 100 ft)	2	1
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 / 7164 GJ/hr (6790 MMBtu/hr) heat duty	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 430 MVA, 3-ph, 60 Hz	1	0
2	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 96 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 14 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

CASE 2 EQUIPMENT LIST

ACCOUNT 3 FEEDWATER AND ANCILLARY EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,112,911 liters (294,000 gal)	2	0
2	Condensate Pumps	Vertical canned	17,791 lpm @ 213 m H2O (4,700 gpm @ 700 ft H2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	1,852,018 kg/hr (4,083,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	31,040 lpm @ 2,591 m H2O (8,200 gpm @ 8,500 ft H2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	9,085 lpm @ 2,591 m H2O (2,400 gpm @ 8,500 ft H2O)	1	0
6	Auxiliary Boiler	Shop fabricated, water tube	331,122 kg/hr, 0.5 MPa, 152°C (730,000 lb/hr, 74 psig, 306°F)	1	0
7	Fuel Oil System	No. 2 fuel oil for light off	1,135,624 liter (300,000 gal)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H2O (5,500 gpm @ 100 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	12,605 lpm @ 18 m H2O (3,330 gpm @ 60 ft H2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	5,035 lpm @ 268 m H2O (1,330 gpm @ 880 ft H2O)	5	1
16	Filtered Water Pumps	Stainless steel, single suction	4,845 lpm @ 49 m H2O (1,280 gpm @ 160 ft H2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	4,637,129 liter (1,225,000 gal)	1	0
18	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	6,170 lpm (1,630 gpm)	1	1
19	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

ACCOUNT 5B CARBON DIOXIDE RECOVERY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Econamine FG Plus	Amine-based CO2 capture technology	2,156,832 kg/h (4,755,000 lb/h) 14.5 wt % CO2 concentration	2	0
2	Econamine Condensate Pump	Centrifugal	15,558 lpm @ 52 m H2O (4,110 gpm @ 170 ft H2O)	1	1
3	CO2 Compressor	Integrally geared, multi-stage centrifugal	280,934 kg/h @ 15.3 MPa (619,353 lb/h @ 2,215 psia)	2	0

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	7FA w/ dry low-NOx burner	171 MW	1	0
2	Gas Turbine Generator	TEWAC	190 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0

ACCOUNT 7 HRSG, DUCTING & STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.7 m (22 ft) diameter	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	1,059,900 lpm @ 30 m (280,000 gpm @ 100 ft)	2	1
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 / 5898 GJ/hr (5590 MMBtu/hr) heat duty	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 450 MVA, 3-ph, 60 Hz	1	0
2	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 121 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 18 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.2.6 Cost Estimating

The cost estimating methodology was described previously in Section 2.6. Exhibit 4-36 shows the total plant capital cost summary organized by cost account and Exhibit 4-37 shows a more detailed breakdown of the capital costs along with owner's costs, TOC and TASC for Case 1. Exhibit 4-38 shows the initial and annual O&M costs for Case 1.

Exhibit 4-39 shows the total plant capital cost summary organized by cost account and Exhibit 4-40 shows a more detailed breakdown of the capital costs along with owner's costs, TOC and TASC for Case 2. Exhibit 4-41 shows the initial and annual O&M costs for Case 2.

The estimated TOC of the Case 1 6FA auxiliary plant retrofit is $1,841/kW and of the Case 2 7FA auxiliary plant retrofit is $1,727/kW. The FY COE for Case 1 is 104.4 mills/kWh and for Case 2 is 87.9 mills/kWh.

Exhibit 4-36 Case 1 Total Plant Cost Summary

Client: USDOE/NETL **Report Date:** 2010-Jul-23
Project: Eliminating the Derate of Carbon Capture Retrofits
TOTAL PLANT COST SUMMARY
Case: Case 1 - 6FA Auxiliary Plant
Plant Size: 539.0 MW,net **Estimate Type:** Conceptual **Cost Base (Jun)** 2007 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
2	COAL & SORBENT PREP & FEED	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
3	FEEDWATER & MISC. BOP SYSTEMS	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4	PC BOILER	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
5	FLUE GAS CLEANUP	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
5B	CO_2 REMOVAL & COMPRESSION	$237,287	$0	$72,328	$0	$0	**$309,615**	$29,603	$54,623	$78,768	**$472,609**	$877
6	COMBUSTION TURBINE/ACCESSORIES	$24,342	$232	$1,793	$0	$0	**$26,368**	$2,238	$0	$2,912	**$31,517**	$58
7	HRSG, DUCTING & STACK	$17,548	$1,019	$11,514	$0	$0	**$30,082**	$2,765	$0	$4,274	**$37,121**	$69
8	STEAM TURBINE GENERATOR	$20,781	$284	$6,258	$0	$0	**$27,323**	$1,456	$0	$2,262	**$31,040**	$58
9	COOLING WATER SYSTEM	$15,470	$7,645	$14,175	$0	$0	**$37,290**	$3,514	$0	$5,529	**$46,333**	$86
10	ASH/SPENT SORBENT HANDLING SYS	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
11	ACCESSORY ELECTRIC PLANT	$10,832	$9,268	$26,122	$0	$0	**$46,221**	$4,205	$0	$6,628	**$57,055**	$106
12	INSTRUMENTATION & CONTROL	$9,493	$0	$9,626	$0	$0	**$19,120**	$1,734	$956	$2,679	**$24,488**	$45
13	IMPROVEMENTS TO SITE	$2,801	$1,610	$5,645	$0	$0	**$10,057**	$992	$0	$2,210	**$13,259**	$25
14	BUILDINGS & STRUCTURES	$0	$25,161	$23,857	$0	$0	**$49,018**	$4,422	$0	$8,016	**$61,456**	$114
	TOTAL COST	**$338,554**	**$45,219**	**$171,320**	**$0**	**$0**	**$555,094**	**$50,928**	**$55,579**	**$113,278**	**$774,879**	**$1,438**

Exhibit 4-37 Case 1 Total Plant Cost Details

	Client:	USDOE/NETL								**Report Date:**	2010-Jul-23	
	Project:	Eliminating the Derate of Carbon Capture Retrofits										
					TOTAL PLANT COST SUMMARY							
	Case:	Case 1 - 6FA Auxiliary Plant										
	Plant Size:	539.0 MW,net		**Estimate Type:**		Conceptual			**Cost Base (Jun)**	2007	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5B	CO_2 REMOVAL & COMPRESSION											
5B.1	CO_2 Removal System	$209,504	$0	$63,612	$0	$0	$273,115	$26,112	$54,623	$70,770	$424,621	$788
5B.2	CO_2 Compression & Drying	$27,783	$0	$8,716	$0	$0	$36,499	$3,491	$0	$7,998	$47,988	$89
	SUBTOTAL 5B.	**$237,287**	**$0**	**$72,328**	**$0**	**$0**	**$309,615**	**$29,603**	**$54,623**	**$78,768**	**$472,609**	**$877**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$24,342	$0	$1,553	$0	$0	$25,895	$2,198	$0	$2,809	$30,903	$57
6.2	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Combustion Turbine Foundations	$0	$232	$240	$0	$0	$473	$40	$0	$102	$615	$1
	SUBTOTAL 6.	**$24,342**	**$232**	**$1,793**	**$0**	**$0**	**$26,368**	**$2,238**	**$0**	**$2,912**	**$31,517**	**$58**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$10,655	$0	$1,383	$0	$0	$12,038	$1,050	$0	$1,963	$15,051	$28
7.2	Duct Burner	$6,527	$0	$3,885	$0	$0	$10,412	$908	$0	$1,698	$13,018	$24
7.3	Ductwork	$2,137	$0	$1,272	$0	$0	$3,410	$297	$0	$556	$4,263	$8
7.4	Stack	$8,885	$0	$5,199	$0	$0	$14,083	$1,356	$0	$1,544	$16,983	$32
7.9	Duct & Stack Foundations	$0	$1,019	$1,158	$0	$0	$2,177	$204	$0	$476	$2,857	$5
	SUBTOTAL 7.	**$17,548**	**$1,019**	**$11,514**	**$0**	**$0**	**$30,082**	**$2,765**	**$0**	**$4,274**	**$37,121**	**$69**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$12,462	$0	$1,559	$0	$0	$14,021	$705	$0	$806	$15,532	$29
8.2	Turbine Plant Auxiliaries	$91	$0	$194	$0	$0	$284	$14	$0	$16	$314	$1
8.3	Condenser & Auxiliaries	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8.4	Steam Piping	$8,228	$0	$4,057	$0	$0	$12,285	$702	$0	$1,358	$14,345	$27
8.9	TG Foundations	$0	$284	$449	$0	$0	$733	$35	$0	$81	$849	$2
	SUBTOTAL 8.	**$20,781**	**$284**	**$6,258**	**$0**	**$0**	**$27,323**	**$1,456**	**$0**	**$2,262**	**$31,040**	**$58**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$11,789	$0	$3,671	$0	$0	$15,460	$1,478	$0	$1,694	$18,632	$35
9.2	Circulating Water Pumps	$2,122	$0	$159	$0	$0	$2,281	$193	$0	$247	$2,721	$5
9.3	Circ.Water System Auxiliaries	$594	$0	$79	$0	$0	$673	$64	$0	$74	$811	$2
9.4	Circ.Water Piping	$0	$4,708	$4,563	$0	$0	$9,271	$868	$0	$1,521	$11,659	$22
9.5	Make-up Water System	$496	$0	$662	$0	$0	$1,158	$111	$0	$190	$1,459	$3
9.6	Component Cooling Water Sys	$471	$0	$374	$0	$0	$845	$80	$0	$139	$1,064	$2
9.9	Circ.Water System Foundations & Structures	$0	$2,937	$4,667	$0	$0	$7,604	$719	$0	$1,665	$9,988	$19
	SUBTOTAL 9.	**$15,470**	**$7,645**	**$14,175**	**$0**	**$0**	**$37,290**	**$3,514**	**$0**	**$5,529**	**$46,333**	**$86**

Exhibit 4-37 Case 1 Total Plant Cost Details (Continued)

	Client:	USDOE/NETL							**Report Date:**	2010-Jul-23		
	Project:	Eliminating the Derate of Carbon Capture Retrofits										
				TOTAL PLANT COST SUMMARY								
	Case:	Case 1 - 6FA Auxiliary Plant										
	Plant Size:	539.0 MW,net		**Estimate Type:**		Conceptual			**Cost Base (Jun)**	2007	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Cyclone Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.3	HGCU Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Recovery Equipment	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.7	Ash Transport & Feed Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 10.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$544	$0	$88	$0	$0	$633	$59	$0	$52	$743	$1
11.2	Station Service Equipment	$4,412	$0	$1,450	$0	$0	$5,862	$548	$0	$481	$6,891	$13
11.3	Switchgear & Motor Control	$5,073	$0	$862	$0	$0	$5,935	$550	$0	$649	$7,134	$13
11.4	Conduit & Cable Tray	$0	$3,180	$10,997	$0	$0	$14,178	$1,373	$0	$2,333	$17,883	$33
11.5	Wire & Cable	$0	$6,001	$11,585	$0	$0	$17,587	$1,482	$0	$2,860	$21,928	$41
11.6	Protective Equipment	$270	$0	$917	$0	$0	$1,187	$116	$0	$130	$1,433	$3
11.7	Standby Equipment	$532	$0	$12	$0	$0	$545	$50	$0	$59	$654	$1
11.8	Main Power Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11.9	Electrical Foundations	$0	$86	$210	$0	$0	$296	$28	$0	$65	$389	$1
	SUBTOTAL 11.	**$10,832**	**$9,268**	**$26,122**	**$0**	**$0**	**$46,221**	**$4,205**	**$0**	**$6,628**	**$57,055**	**$106**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$489	$0	$293	$0	$0	$782	$74	$39	$134	$1,029	$2
12.7	Distributed Control System Equipment	$4,935	$0	$863	$0	$0	$5,798	$537	$290	$662	$7,287	$14
12.8	Instrument Wiring & Tubing	$2,675	$0	$5,306	$0	$0	$7,981	$680	$399	$1,359	$10,420	$19
12.9	Other I & C Equipment	$1,395	$0	$3,165	$0	$0	$4,559	$442	$228	$523	$5,752	$11
	SUBTOTAL 12.	**$9,493**	**$0**	**$9,626**	**$0**	**$0**	**$19,120**	**$1,734**	**$956**	**$2,679**	**$24,488**	**$45**

Exhibit 4-37 Case 1 Total Plant Cost Details (Continued)

	Client:	USDOE/NETL							**Report Date**:	2010-Jul-23		
	Project:	Eliminating the Derate of Carbon Capture Retrofits										
					TOTAL PLANT COST SUMMARY							
	Case:	Case 1 - 6FA Auxiliary Plant										
	Plant Size:	539.0 MW,net		**Estimate Type:**	Conceptual			**Cost Base (Jun)**	2007	($x1000)		
Acct		**Equipment**	**Material**	**Labor**		**Sales**	**Bare Erected**	**Eng'g CM**	**Contingencies**		**TOTAL PLANT COST**	
No.	**Item/Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Tax**	**Cost $**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$47	$942	$0	$0	$989	$98	$0	$217	$1,304	$2
13.2	Site Improvements	$0	$1,563	$1,941	$0	$0	$3,505	$346	$0	$770	$4,620	$9
13.3	Site Facilities	$2,801	$0	$2,762	$0	$0	$5,564	$548	$0	$1,222	$7,334	$14
	SUBTOTAL 13.	**$2,801**	**$1,610**	**$5,645**	**$0**	**$0**	**$10,057**	**$992**	**$0**	**$2,210**	**$13,259**	**$25**
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$9,232	$8,118	$0	$0	$17,350	$1,559	$0	$2,836	$21,746	$40
14.2	Turbine Building	$0	$13,238	$12,338	$0	$0	$25,577	$2,305	$0	$4,182	$32,064	$59
14.3	Administration Building	$0	$631	$667	$0	$0	$1,299	$118	$0	$212	$1,629	$3
14.4	Circulation Water Pumphouse	$0	$105	$83	$0	$0	$188	$17	$0	$31	$236	$0
14.5	Water Treatment Buildings	$0	$562	$513	$0	$0	$1,075	$97	$0	$176	$1,347	$2
14.6	Machine Shop	$0	$422	$284	$0	$0	$706	$63	$0	$115	$884	$2
14.7	Warehouse	$0	$286	$287	$0	$0	$573	$52	$0	$94	$719	$1
14.8	Other Buildings & Structures	$0	$234	$199	$0	$0	$433	$39	$0	$71	$542	$1
14.9	Waste Treating Building & Str.	$0	$451	$1,367	$0	$0	$1,818	$173	$0	$299	$2,289	$4
	SUBTOTAL 14.	**$0**	**$25,161**	**$23,857**	**$0**	**$0**	**$49,018**	**$4,422**	**$0**	**$8,016**	**$61,456**	**$114**
	TOTAL COST	**$338,554**	**$45,219**	**$171,320**	**$0**	**$0**	**$555,094**	**$50,928**	**$55,579**	**$113,278**	**$774,879**	**$1,438**

Exhibit 4-37 Case 1 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 2010-Jul-23
Project: Eliminating the Derate of Carbon Capture Retrofits
TOTAL PLANT COST SUMMARY
Case: Case 1 - 6FA Auxiliary Plant
Plant Size: 539.0 MW,net **Estimate Type:** Conceptual **Cost Base (Jun)** 2007 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
	TOTAL COST	**$338,554**	**$45,219**	**$171,320**	**$0**	**$0**	**$555,094**	**$50,928**	**$55,579**	**$113,278**	**$774,879**	**$1,438**
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$11,246	$21
	1 Month Maintenance Materials										$1,602	$3
	1 Month Non-fuel Consumables										$1,590	$3
	1 Month Waste Disposal										$251	$0
	25% of 1 Months Fuel Cost at 100% CF										$1,524	$3
	2% of TPC										$15,498	$29
	Total										**$31,710**	**$59**
	Inventory Capital											
	60 day supply of fuel and consumables at 100% CF										$41,068	$76
	0.5% of TPC (spare parts)										$3,874	$7
	Total										**$44,943**	**$83**
	Initial Cost for Catalyst and Chemicals										$2,521	$5
	Land										$900	$2
	Other Owner's Costs										$116,232	$216
	Financing Costs										$20,922	$39
	Total Overnight Costs (TOC)										**$992,105**	**$1,841**
	TASC Multiplier								(IOU, high-risk, 33 year)		1.078	
	Total As-Spent Cost (TASC)										**$1,069,490**	**$1,984**

Exhibit 4-38 Case 1 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2007
Case 1 - 6FA Auxiliary Plant					Heat Rate-net (Btu/kWh):	14,588
					MWe-net:	539
					Capacity Factor:	85%
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/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	13.0		13.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	2.0		2.0			
TOTAL-O.J.'s	18.0		18.0			
					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost					$7,102,696	$13.18
Maintenance Labor Cost					$10,890,273	$20.20
Administrative & Support Labor					$4,498,242	$8.35
Property Taxes and Insurance					$33,346,235	$61.87
TOTAL FIXED OPERATING COSTS					**$55,837,446**	**$103.593**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$16,335,410**	**0.00407**
Consumables	Consumption		Unit	Initial Fill		
	Initial Fill	/Day	Cost	Cost		
Water (/1000 gallons)	0	10,567	1.08	**$0**	**$3,546,087**	**$0.00088**
Chemicals						
MU & WT Chem.(lbs)	0	51,150	0.17	$0	$2,746,454	$0.00068
Limestone (ton)	0	531	21.63	$0	$3,564,849	$0.00089
Carbon (Mercury Removal) (lb)	0	0	1.05	$0	$0	$0.00000
MEA Solvent (ton)	1,044	1.48	2,249.89	$2,347,800	$1,032,801	$0.00026
NaOH (tons)	43	4.32	433.68	$18,746	$581,606	$0.00014
H2SO4 (tons)	70	7.03	138.78	$9,762	$302,872	$0.00008
Corrosion Inhibitor	0	0	0.00	$144,338	$6,873	$0.00000
Activated Carbon (lb)	0	1,767	1.05	$0	$575,833	$0.00014
Ammonia (19% NH3) ton	0	80	129.80	$0	$3,218,844	$0.00080
Subtotal Chemicals				**$2,520,647**	**$12,030,131**	**$0.00300**
Other						
Supplemental Fuel (MBtu)	0	0	0.00	$0	$0	$0.00000
SCR Catalyst (m3)	w/equip.	0.36	5,775.94	$0	$641,596	$0.00016
Emission Penalties	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$641,596**	**$0.00016**
Waste Disposal						
Fly Ash (ton)	0	407	16.23	$0	$2,048,977	$0.00051
Bottom Ash (ton)	0	102	16.23	$0	$512,244	$0.00013
Subtotal-Waste Disposal				**$0**	**$2,561,222**	**$0.00064**
By-products & Emissions						
Gypsum (tons)	0	821	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$0**	**$35,114,446**	**$0.00875**
Coal (ton)	0	5,249	38.19	**$200,416**	**$62,179,108**	**$0.01549**
Natural Gas (MMBtu)	0	66,257	6.55	**$433,839**	**$134,598,502**	**$0.03354**

Exhibit 4-39 Case 2 Total Plant Cost Summary

	Client:	USDOE/NETL							Report Date:	2010-Jul-23		
	Project:	Eliminating the Derate of Carbon Capture Retrofits										
				TOTAL PLANT COST SUMMARY								
	Case:	Case 2 - 7FA Auxiliary Plant										
	Plant Size:	557.4 MW,net	Estimate Type:	Conceptual					Cost Base (Jun)	2007	($x1000)	
Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
1	COAL & SORBENT HANDLING	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
2	COAL & SORBENT PREP & FEED	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
3	FEEDWATER & MISC. BOP SYSTEMS	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4	PC BOILER	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
5	FLUE GAS CLEANUP	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
5B	CO_2 REMOVAL & COMPRESSION	$225,117	$0	$68,619	$0	$0	**$293,736**	$28,085	$51,822	$74,728	**$448,371**	$804
6	COMBUSTION TURBINE/ACCESSORIES	$41,790	$399	$3,079	$0	$0	**$45,268**	$3,842	$0	$4,999	**$54,109**	$97
7	HRSG, DUCTING & STACK	$11,022	$1,019	$7,629	$0	$0	**$19,670**	$1,857	$0	$2,576	**$24,103**	$43
8	STEAM TURBINE GENERATOR	$21,966	$310	$6,464	$0	$0	**$28,740**	$1,560	$0	$2,386	**$32,686**	$59
9	COOLING WATER SYSTEM	$11,894	$6,038	$11,171	$0	$0	**$29,104**	$2,485	$0	$4,041	**$35,629**	$64
10	ASH/SPENT SORBENT HANDLING SYS	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
11	ACCESSORY ELECTRIC PLANT	$12,017	$10,353	$29,071	$0	$0	**$51,441**	$4,679	$0	$7,384	**$63,503**	$114
12	INSTRUMENTATION & CONTROL	$9,815	$0	$9,952	$0	$0	**$19,767**	$1,792	$988	$2,769	**$25,317**	$45
13	IMPROVEMENTS TO SITE	$2,792	$1,605	$5,626	$0	$0	**$10,022**	$989	$0	$2,202	**$13,213**	$24
14	BUILDINGS & STRUCTURES	$0	$25,151	$23,848	$0	$0	**$48,999**	$4,420	$0	$8,013	**$61,432**	$110
	TOTAL COST	**$336,412**	**$44,875**	**$165,459**	**$0**	**$0**	**$546,747**	**$49,709**	**$52,810**	**$109,099**	**$758,364**	**$1,360**

Exhibit 4-40 Case 2 Total Plant Cost Details

Client: USDOE/NETL **Report Date:** 2010-Jul-23
Project: Eliminating the Derate of Carbon Capture Retrofits
TOTAL PLANT COST SUMMARY
Case: Case 2 - 7FA Auxiliary Plant
Plant Size: 557.4 MW,net **Estimate Type:** Conceptual **Cost Base (Jun)** 2007 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5B	CO_2 REMOVAL & COMPRESSION											
5B.1	CO_2 Removal System	$198,759	$0	$60,350	$0	$0	$259,109	$24,773	$51,822	$67,141	$402,844	$723
5B.2	CO_2 Compression & Drying	$26,358	$0	$8,269	$0	$0	$34,627	$3,312	$0	$7,588	$45,527	$82
	SUBTOTAL 5B.	**$225,117**	**$0**	**$68,619**	**$0**	**$0**	**$293,736**	**$28,085**	**$51,822**	**$74,728**	**$448,371**	**$804**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$41,790	$0	$2,666	$0	$0	$44,457	$3,774	$0	$4,823	$53,054	$95
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$399	$413	$0	$0	$812	$68	$0	$176	$1,055	$2
	SUBTOTAL 6.	**$41,790**	**$399**	**$3,079**	**$0**	**$0**	**$45,268**	**$3,842**	**$0**	**$4,999**	**$54,109**	**$97**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$18,292	$0	$2,375	$0	$0	$20,667	$1,802	$0	$3,370	$25,839	$46
7.2	Duct Burner	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$2,137	$0	$1,272	$0	$0	$3,410	$297	$0	$556	$4,263	$8
7.4	Stack	$8,885	$0	$5,199	$0	$0	$14,083	$1,356	$0	$1,544	$16,983	$30
7.9	Duct & Stack Foundations	$0	$1,019	$1,158	$0	$0	$2,177	$204	$0	$476	$2,857	$5
	SUBTOTAL 7.	**$11,022**	**$1,019**	**$7,629**	**$0**	**$0**	**$19,670**	**$1,857**	**$0**	**$2,576**	**$24,103**	**$43**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$13,639	$0	$1,706	$0	$0	$15,344	$802	$0	$918	$17,064	$31
8.2	Turbine Plant Auxiliaries	$99	$0	$212	$0	$0	$311	$16	$0	$18	$345	$1
8.3	Condenser & Auxiliaries	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8.4	Steam Piping	$8,228	$0	$4,057	$0	$0	$12,285	$702	$0	$1,358	$14,345	$26
8.9	TG Foundations	$0	$310	$490	$0	$0	$800	$40	$0	$92	$932	$2
	SUBTOTAL 8.	**$21,966**	**$310**	**$6,464**	**$0**	**$0**	**$28,740**	**$1,560**	**$0**	**$2,386**	**$32,686**	**$59**

Exhibit 4-40 Case 2 Total Plant Cost Details (Continued)

Client:	USDOE/NETL	**Report Date:**	2010-Jul-23
Project:	Eliminating the Derate of Carbon Capture Retrofits		
	TOTAL PLANT COST SUMMARY		
Case:	Case 2 - 7FA Auxiliary Plant		
Plant Size:	557.4 MW,net **Estimate Type:** Conceptual	**Cost Base (Jun)**	2007 ($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$9,186	$0	$2,860	$0	$0	$12,046	$893	$0	$1,023	$13,961	$25
9.2	Circulating Water Pumps	$1,487	$0	$112	$0	$0	$1,599	$135	$0	$173	$1,907	$3
9.3	Circ.Water System Auxiliaries	$462	$0	$62	$0	$0	$524	$50	$0	$57	$631	$1
9.4	Circ.Water Piping	$0	$3,666	$3,553	$0	$0	$7,218	$676	$0	$1,184	$9,078	$16
9.5	Make-up Water System	$392	$0	$524	$0	$0	$917	$88	$0	$151	$1,155	$2
9.6	Component Cooling Water Sys	$366	$0	$291	$0	$0	$658	$62	$0	$108	$828	$1
9.9	Circ.Water System Foundations & Structures	$0	$2,372	$3,769	$0	$0	$6,142	$581	$0	$1,345	$8,067	$14
	SUBTOTAL 9.	**$11,894**	**$6,038**	**$11,171**	**$0**	**$0**	**$29,104**	**$2,485**	**$0**	**$4,041**	**$35,629**	**$64**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Cyclone Ash Letdown	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	HGCU Ash Letdown	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.7	Ash Transport & Feed Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 10.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$584	$0	$95	$0	$0	$679	$63	$0	$56	$797	$1
11.2	Station Service Equipment	$4,931	$0	$1,620	$0	$0	$6,551	$612	$0	$537	$7,700	$14
11.3	Switchgear & Motor Control	$5,668	$0	$963	$0	$0	$6,632	$615	$0	$725	$7,971	$14
11.4	Conduit & Cable Tray	$0	$3,554	$12,288	$0	$0	$15,842	$1,534	$0	$2,606	$19,982	$36
11.5	Wire & Cable	$0	$6,706	$12,945	$0	$0	$19,651	$1,656	$0	$3,196	$24,503	$44
11.6	Protective Equipment	$270	$0	$918	$0	$0	$1,188	$116	$0	$130	$1,434	$3
11.7	Standby Equipment	$564	$0	$13	$0	$0	$577	$53	$0	$63	$693	$1
11.8	Main Power Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11.9	Electrical Foundations	$0	$93	$229	$0	$0	$322	$31	$0	$71	$423	$1
	SUBTOTAL 11.	**$12,017**	**$10,353**	**$29,071**	**$0**	**$0**	**$51,441**	**$4,679**	**$0**	**$7,384**	**$63,503**	**$114**

Exhibit 4-40 Case 2 Total Plant Cost Details (Continued)

	Client:	USDOE/NETL								**Report Date:**	2010-Jul-23		
	Project:	Eliminating the Derate of Carbon Capture Retrofits											
					TOTAL PLANT COST SUMMARY								
	Case:	Case 2 - 7FA Auxiliary Plant											
	Plant Size:	557.4 MW,net		**Estimate Type:**	Conceptual					**Cost Base (Jun)**	2007	($x1000)	
Acct		**Equipment**	**Material**	**Labor**		**Sales**	**Bare Erected**	**Eng'g CM**	**Contingencies**		**TOTAL PLANT COST**		
No.	**Item/Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Tax**	**Cost $**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**	
12	INSTRUMENTATION & CONTROL												
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0	
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0	
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0	
12.4	Other Major Component Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
12.5	Signal Processing Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0	
12.6	Control Boards,Panels & Racks	$505	$0	$303	$0	$0	$808	$76	$40	$139	$1,064	$2	
12.7	Distributed Control System Equipment	$5,102	$0	$892	$0	$0	$5,994	$556	$300	$685	$7,534	$14	
12.8	Instrument Wiring & Tubing	$2,766	$0	$5,486	$0	$0	$8,252	$703	$413	$1,405	$10,773	$19	
12.9	Other I & C Equipment	$1,442	$0	$3,272	$0	$0	$4,713	$457	$236	$541	$5,947	$11	
	SUBTOTAL 12.	**$9,815**	**$0**	**$9,952**	**$0**	**$0**	**$19,767**	**$1,792**	**$988**	**$2,769**	**$25,317**	**$45**	
13	IMPROVEMENTS TO SITE												
13.1	Site Preparation	$0	$47	$938	$0	$0	$985	$98	$0	$217	$1,300	$2	
13.2	Site Improvements	$0	$1,558	$1,935	$0	$0	$3,492	$345	$0	$767	$4,604	$8	
13.3	Site Facilities	$2,792	$0	$2,753	$0	$0	$5,544	$546	$0	$1,218	$7,309	$13	
	SUBTOTAL 13.	**$2,792**	**$1,605**	**$5,626**	**$0**	**$0**	**$10,022**	**$989**	**$0**	**$2,202**	**$13,213**	**$24**	
14	BUILDINGS & STRUCTURES												
14.1	Boiler Building	$0	$9,233	$8,120	$0	$0	$17,353	$1,560	$0	$2,837	$21,749	$39	
14.2	Turbine Building	$0	$13,235	$12,335	$0	$0	$25,570	$2,305	$0	$4,181	$32,056	$58	
14.3	Administration Building	$0	$631	$667	$0	$0	$1,298	$118	$0	$212	$1,628	$3	
14.4	Circulation Water Pumphouse	$0	$104	$82	$0	$0	$186	$17	$0	$30	$233	$0	
14.5	Water Treatment Buildings	$0	$557	$507	$0	$0	$1,064	$96	$0	$174	$1,334	$2	
14.6	Machine Shop	$0	$422	$284	$0	$0	$706	$63	$0	$115	$883	$2	
14.7	Warehouse	$0	$286	$287	$0	$0	$573	$52	$0	$94	$718	$1	
14.8	Other Buildings & Structures	$0	$234	$199	$0	$0	$433	$39	$0	$71	$542	$1	
14.9	Waste Treating Building & Str.	$0	$450	$1,367	$0	$0	$1,817	$173	$0	$298	$2,288	$4	
	SUBTOTAL 14.	**$0**	**$25,151**	**$23,848**	**$0**	**$0**	**$48,999**	**$4,420**	**$0**	**$8,013**	**$61,432**	**$110**	
	TOTAL COST	**$336,412**	**$44,875**	**$165,459**	**$0**	**$0**	**$546,747**	**$49,709**	**$52,810**	**$109,099**	**$758,364**	**$1,360**	

Exhibit 4-40 Case 2 Total Plant Cost Details (Continued)

	Client:	USDOE/NETL									Report Date: 2010-Jul-23		
	Project:	Eliminating the Derate of Carbon Capture Retrofits											
		TOTAL PLANT COST SUMMARY											
	Case:	Case 2 - 7FA Auxiliary Plant											
	Plant Size:	557.4 MW,net		Estimate Type:		Conceptual				Cost Base (Jun)	2007	($x1000)	
Acct		**Equipment**	**Material**	**Labor**		**Sales**	**Bare Erected**	**Eng'g CM**	**Contingencies**		**TOTAL PLANT COST**		
No.	**Item/Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Tax**	**Cost $**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**	
	TOTAL COST	**$336,412**	**$44,875**	**$165,459**	**$0**	**$0**	**$546,747**	**$49,709**	**$52,810**	**$109,099**	**$758,364**	**$1,360**	
	Owner's Costs												
	Preproduction Costs												
	6 Months All Labor										$11,201	$20	
	1 Month Maintenance Materials										$1,591	$3	
	1 Month Non-fuel Consumables										$1,430	$3	
	1 Month Waste Disposal										$251	$0	
	25% of 1 Months Fuel Cost at 100% CF										$1,524	$3	
	2% of TPC										$15,167	$27	
	Total										**$31,164**	**$56**	
	Inventory Capital												
	60 day supply of fuel and consumables at 100% CF										$31,715	$57	
	0.5% of TPC (spare parts)										$3,792	$7	
	Total										**$35,507**	**$64**	
	Initial Cost for Catalyst and Chemicals										$2,313	$4	
	Land										$900	$2	
	Other Owner's Costs										$113,755	$204	
	Financing Costs										$20,476	$37	
	Total Overnight Costs (TOC)										**$962,479**	**$1,727**	
	TASC Multiplier								(IOU, high-risk, 33 year)		1.078		
	Total As-Spent Cost (TASC)										**$1,037,553**	**$1,861**	

Exhibit 4-41 Case 2 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES						Cost Base (Jun):	2007
Case 2 - 7FA Auxiliary Plant						Heat Rate-net (Btu/kWh):	12,378
						MWe-net:	557
						Capacity Factor:	85%
OPERATING & MAINTENANCE LABOR							
Operating Labor							
Operating Labor Rate(base):	34.65	$/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	13.0		13.0				
Foreman	1.0		1.0				
Lab Tech's, etc.	2.0		2.0				
TOTAL-O.J.'s	18.0		18.0				
						Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost						$7,102,696	$12.74
Maintenance Labor Cost						$10,819,224	$19.41
Administrative & Support Labor						$4,480,480	$8.04
Property Taxes and Insurance						$33,015,945	$59.23
TOTAL FIXED OPERATING COSTS						**$55,418,345**	**$99.419**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost						**$16,228,836**	**0.00391**
Consumables	Consumption Initial Fill	Consumption /Day	Unit Cost	Initial Fill Cost			
Water (/1000 gallons)	0	7,850	1.08	**$0**		**$2,634,434**	**$0.00063**
Chemicals							
MU & WT Chem.(lbs)	0	38,000	0.17	$0		$2,040,376	$0.00049
Limestone (ton)	0	531	21.63	$0		$3,564,849	$0.00086
Carbon (Mercury Removal) (lb)	0	0	1.05	$0		$0	$0.00000
MEA Solvent (ton)	957	1.36	2,249.89	$2,153,478		$947,278	$0.00023
NaOH (tons)	42	4.21	433.68	$18,262		$566,606	$0.00014
H2SO4 (tons)	65	6.45	138.78	$8,954		$277,802	$0.00007
Corrosion Inhibitor	0	0	0.00	$132,391		$5,233	$0.00000
Activated Carbon (lb)	0	1,727	1.05	$0		$562,618	$0.00014
Ammonia (19% NH3) ton	0	82	129.80	$0		$3,284,888	$0.00079
Subtotal Chemicals				**$2,313,085**		**$11,249,651**	**$0.00271**
Other							
Supplemental Fuel (MBtu)	0	0	0.00	$0		$0	$0.00000
SCR Catalyst (m3)	w/equip.	0.39	5,775.94	$0		$699,725	$0.00017
Emission Penalties	0	0	0.00	$0		$0	$0.00000
Subtotal Other				**$0**		**$699,725**	**$0.00017**
Waste Disposal							
Fly Ash (ton)	0	407	16.23	$0		$2,048,977	$0.00049
Bottom Ash (ton)	0	102	16.23	$0		$512,244	$0.00012
Subtotal-Waste Disposal				**$0**		**$2,561,222**	**$0.00062**
By-products & Emissions							
Gypsum (tons)	0	821	0.00	$0		$0	$0.00000
Subtotal By-Products				**$0**		**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$0**		**$33,373,869**	**$0.00804**
Coal (ton)	0	5,249	38.19	**$200,416**		**$62,179,108**	**$0.01498**
Natural Gas (MMBtu)	0	43,132	6.55	**$282,418**		**$87,620,071**	**$0.02111**

4.3 LIFE CYCLE GHG ANALYSIS

The lifecycle GHG emissions for each of the cases was calculated using the procedure and assumptions described in Section 2.5 and displayed in Exhibit 4-42 with tabular breakdowns in Exhibit 4-43, shown on a CO_2 equivalents basis. Emissions for all cases increase when considering the complete life cycle of the fuels.

Exhibit 4-42 LCA GHG Emissions Comparison

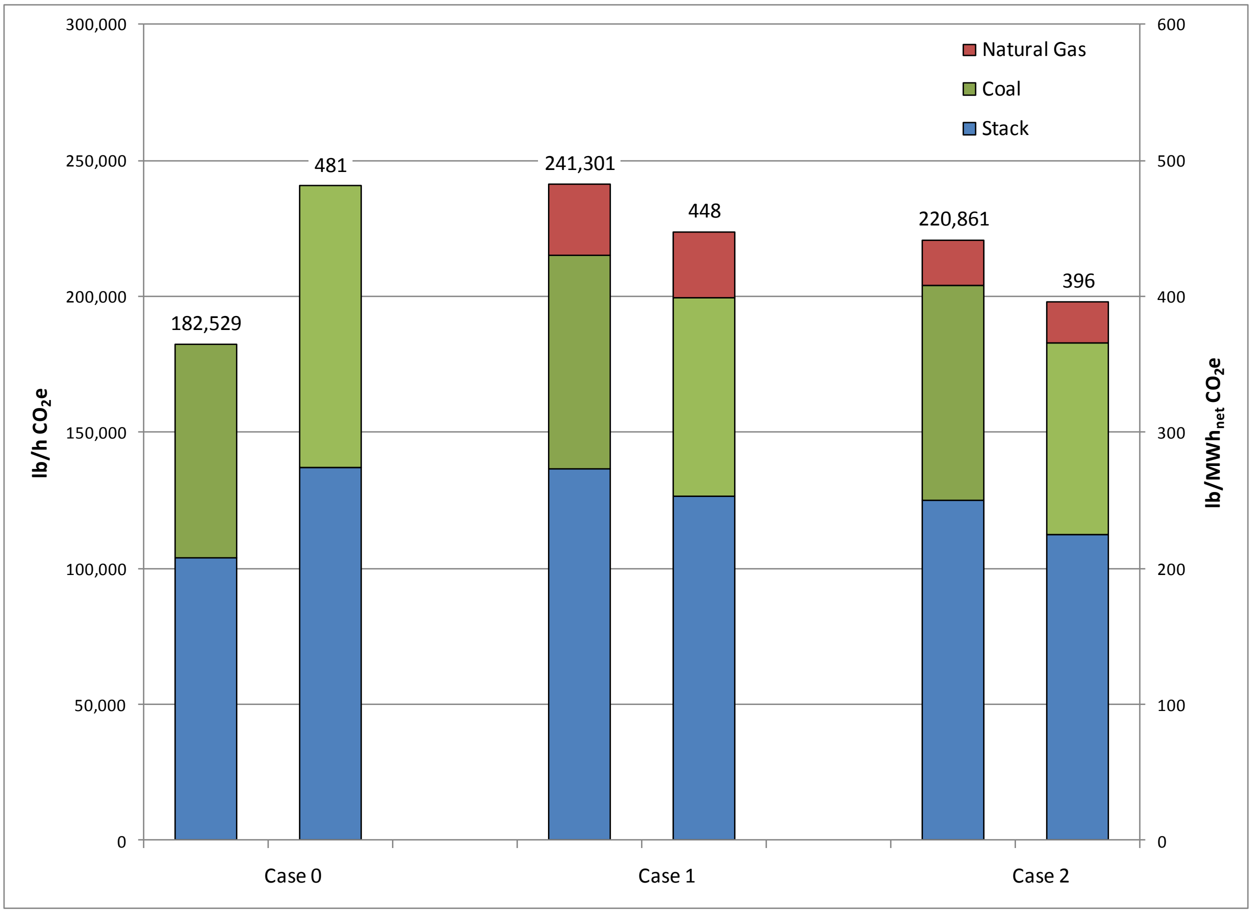


Exhibit 4-43 LCA GHG Emissions

Case	Stage 1 & 2		Stage 3		Total	
	Coal	NG	Combustion	CCS		
	lb/h CO_2e	lb/h CO_2e	lb/h CO_2e	lb/h CO_2e	lb/h CO_2e	lb/MWh$_{net}$ CO_2e
0	78,676	-	1,039,105	-935,252	182,529	481
1	78,676	26,212	1,364,884	-1,228,471	241,301	448
2	78,676	17,063	1,295,597	-1166109	220,861	396

4.4 ECONOMIC RESULTS

The following sections present the economic results of the study to compare the contributing effects of different CDR retrofit and auxiliary plant options. The effects on cost of electricity are examined for combustion turbine auxiliary plants using natural gas. Decisions on CDR retrofit solutions will take account the economic metrics presented below as well as space considerations, site specific integration issues, and the prevailing carbon management legislation and policies.

4.4.1 Cost of Electricity

Capital costs are shown in Exhibit 4-44 and a COE breakdown for each case is presented in Exhibit 4-45. The additional capital cost component for a CDR process added to a 550MW greenfield subcritical PC plant, using similar assumptions, increases the TOC by $887M, or approximately, $1614/kW [1]. The Case 0 retrofit to the existing base plant costs $721M or $1,899/kW for a case with a fixed coal flow resulting in only 379MW net power. The Case 0 CDR is cheaper in absolute terms because it treats a 30 percent smaller flue gas stream, but is more expensive on a per kW basis due to loss of economies of scale and an additional steam turbine off design derate. The more promising combustion turbine auxiliary plant retrofit combination (Case 2) has a COE of 87.9 mills/kWh and total overnight cost (TOC) of $1,727/kW or $962MM. Fuel costs are a large proportion of the COE suggesting that improvements in efficiency would be especially beneficial to these configurations.

Exhibit 4-44 Capital Costs

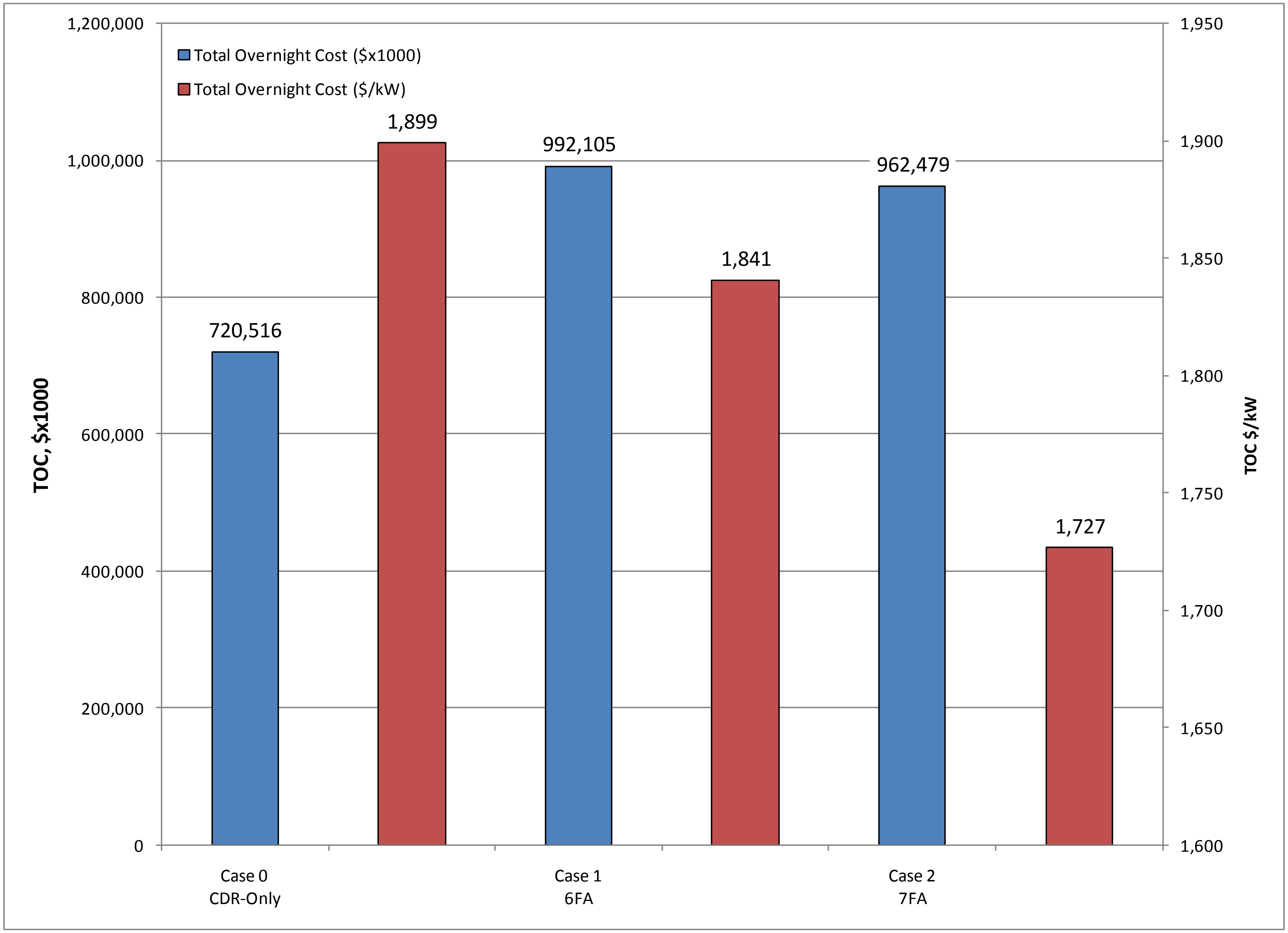
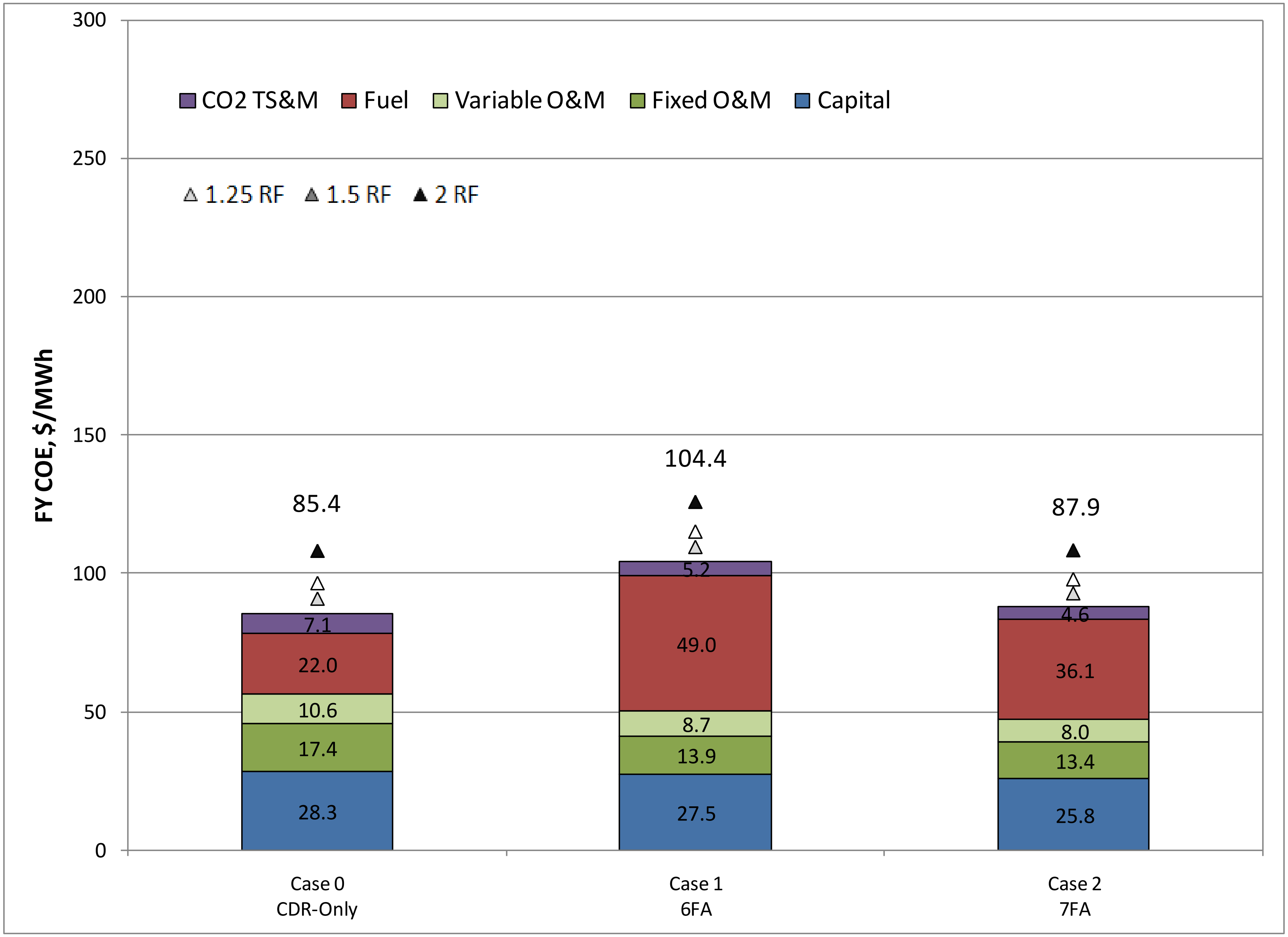
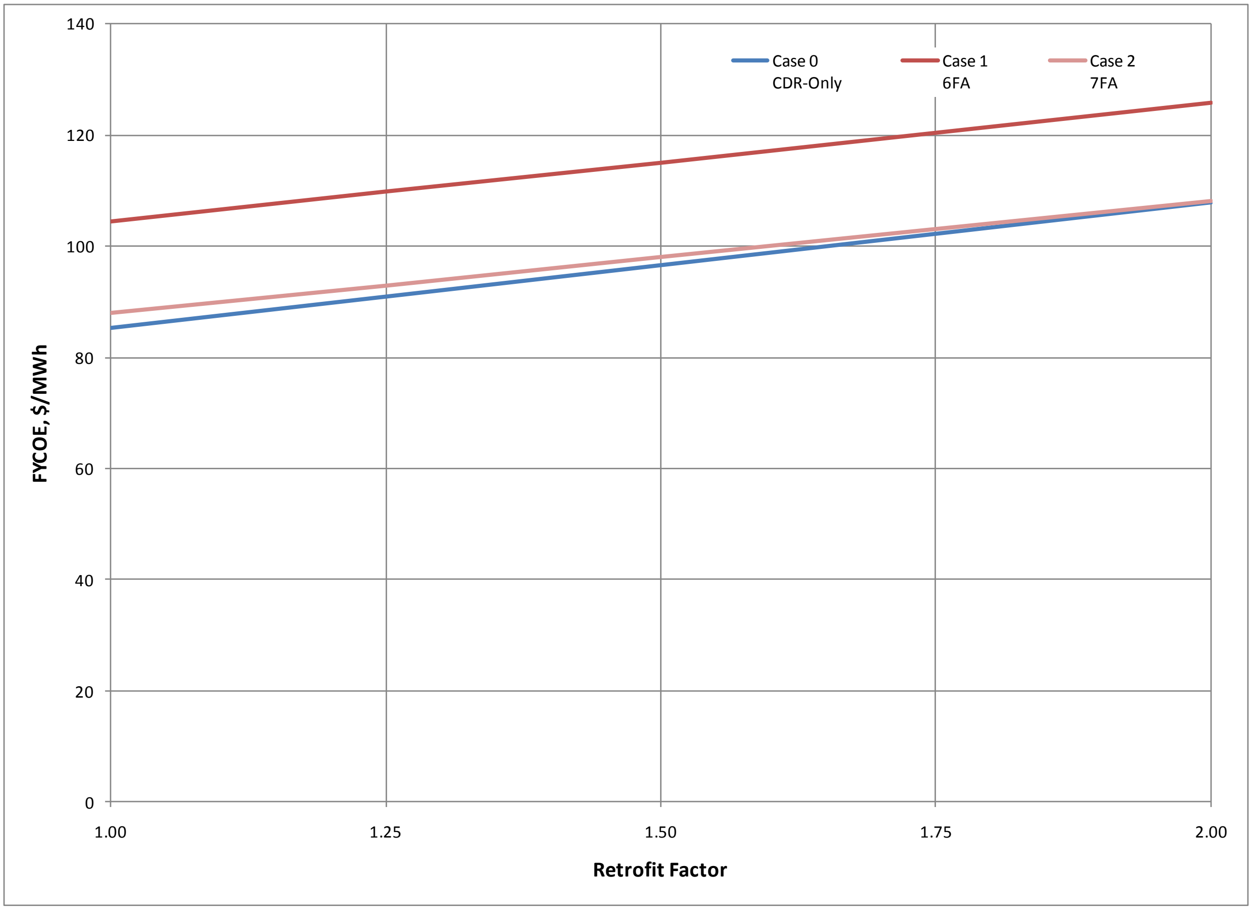


Exhibit 4-45 FY COE Breakdown



Retrofit factors were meant to adjust the equipment costs to account for additional complexities and integration of installing this equipment to an existing plant. The retrofit cases with larger capital cost components are affected more by a given change to the retrofit factor, which is applied to the TPC. The relative order of slopes for the cases, from highest to lowest, is the base CDR only retrofit, then the 6FA and 7FA auxiliary plant retrofits. This adjustment to the TPC typically covers cost increases over a greenfield installation due to site space and layout limitations, connecting to the existing plant, and potential changes to construction sequence, methods of construction, or labor costs. Lost revenue due to plant downtime also affects retrofit costs, which motivates decisions like a new stack to minimize the amount of downtime required to tie in the new CDR system. More circuitous piping or ductwork and space saving arraingments such as vertical construction or stacking of vessels would increase cost of the equipment. Labor costs are higher than for greenfield construction due to limited staging and storage areas, necessitating additional steps for transporting, storing, positioning, and installing equipment. The true cost of a given plant retrofit will be higher than the base installation cost, and likely to be within the range of sensitivities to the retrofit factor, based on site specific characteristics and the complexity of the retrofit. More detailed engineering and historical evidence of other retofit work completed at the same plant would be help refine the applicable retrofit factor for any proposed projects. Sensitivities to the retrofit factor, ranging from 1.25 to 2, are shown in Exhibit 4-46 and displayed visually in the COE exhibit.

Exhibit 4-46 Retrofit Factor Sensitivity



Fuel costs are a large contributer to the overall COE, and natural gas prices can be volatile, so an analysis was performed to demonstrate the sensitivity of COE for the natural gas combustion turbine cases to the price of natural gas, in Exhibit 4-47. The best combustion turbine case breaks even with the Case 0 CDR-only retrofit at $6.81/MMBtu – at equal or higher natural gas prices, the base case would be more cost effective than the combined Case 2 7FA combustion turbine auxiliary plant retrofit.

Exhibit 4-47 Natural Gas Price Sensitivity

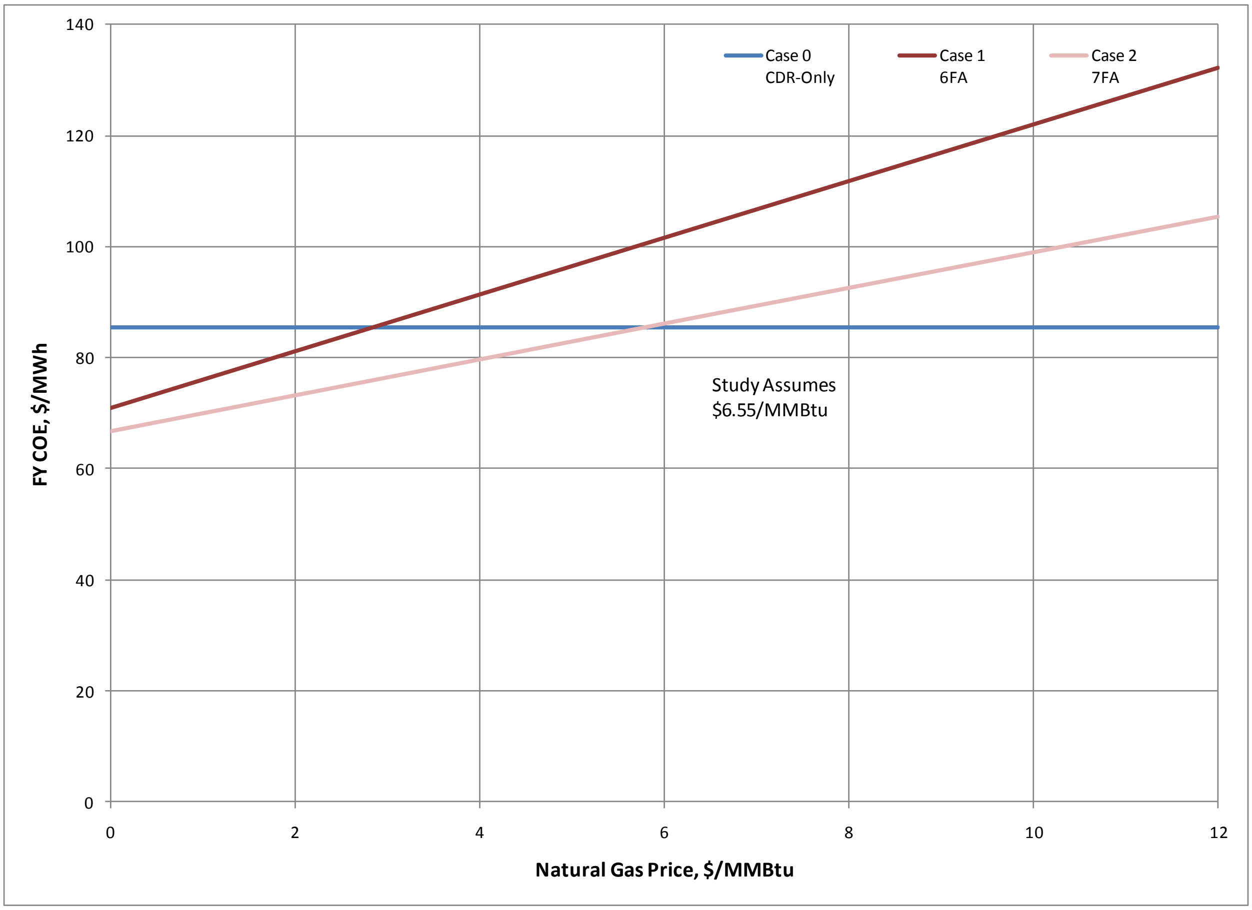
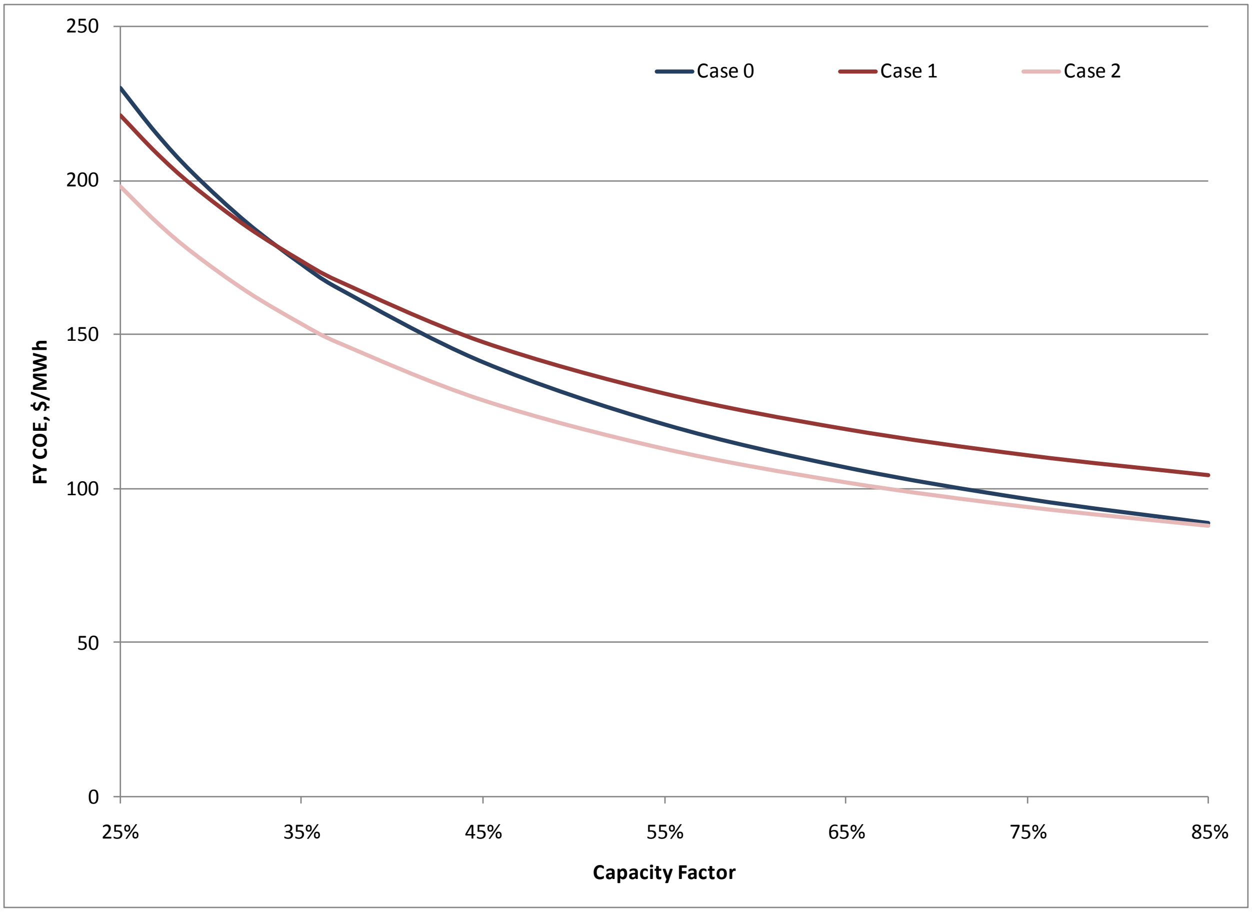


Exhibit 4-48 shows the COE as a function of the plant capacity factor. The natural gas cases have a small capital cost component and a higher fuel cost when the plant is operating; thus they are less affected by reductions to the plant output. Cases with relatively higher capital investment must operate at a high capacity factor in order to recover the initial costs.

Exhibit 4-48 Capacity Factor Sensitivity

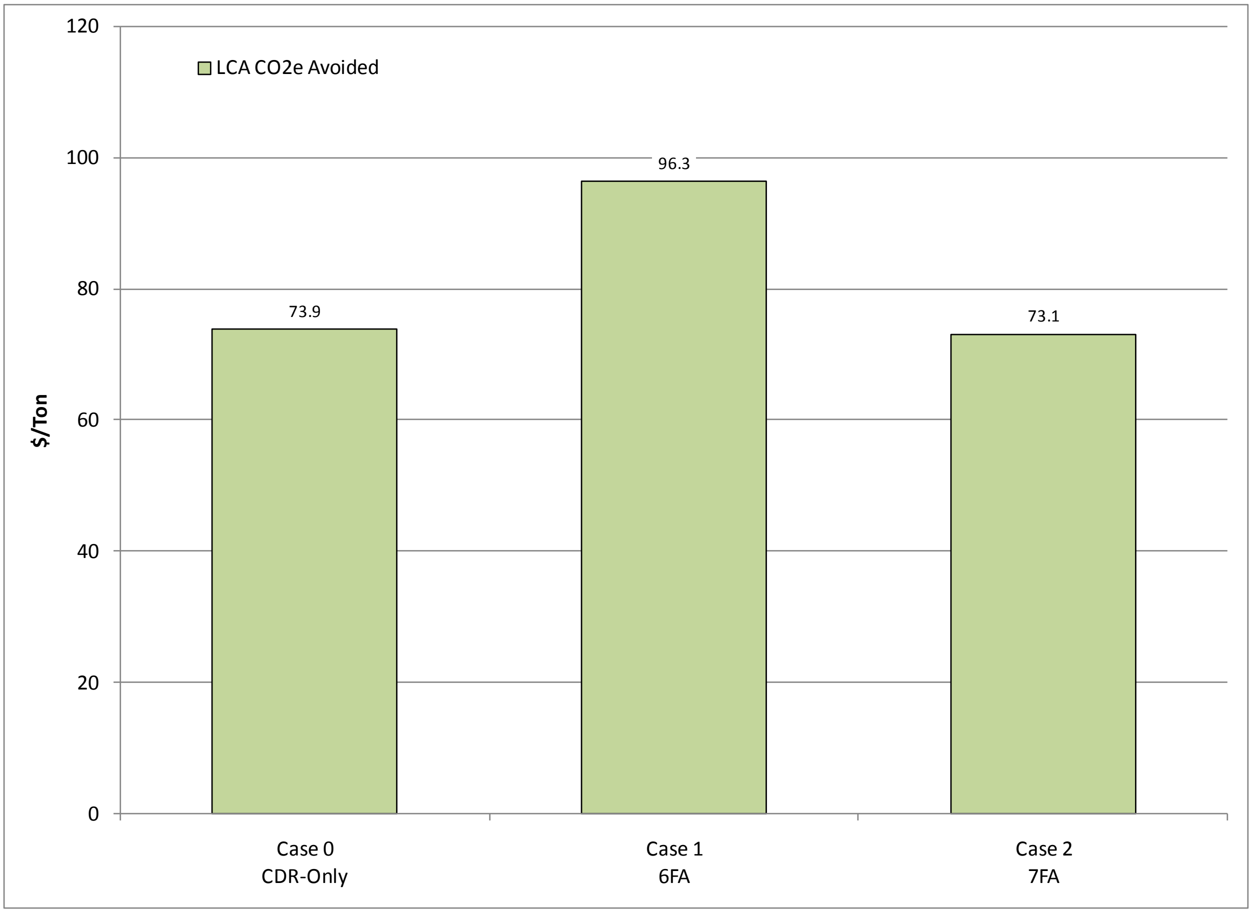


4.4.2 <u>GHG Tax Implications</u>

To reduce emissions of GHGs, legislation must be passed that mandates such reductions because capturing carbon dioxide from power plants will raise the cost of electricity compared to analogous plants without carbon capture. A cap-and-trade scenario or GHG tax may be two feasible options for regulating emissions. In the case of a GHG tax, plant stack emissions or LCA emissions would be taxed according to a certain rate (ex. \$/ton CO_2e). GHG taxes could also extend beyond the plant to consider the life cycle emissions from coal mining and natural gas extraction. Taxes accumulated prior to the plant gate by mining companies would be passed along to the power plant, most likely in the form of higher fuel prices. Consequently, the production cost of electricity would increase.

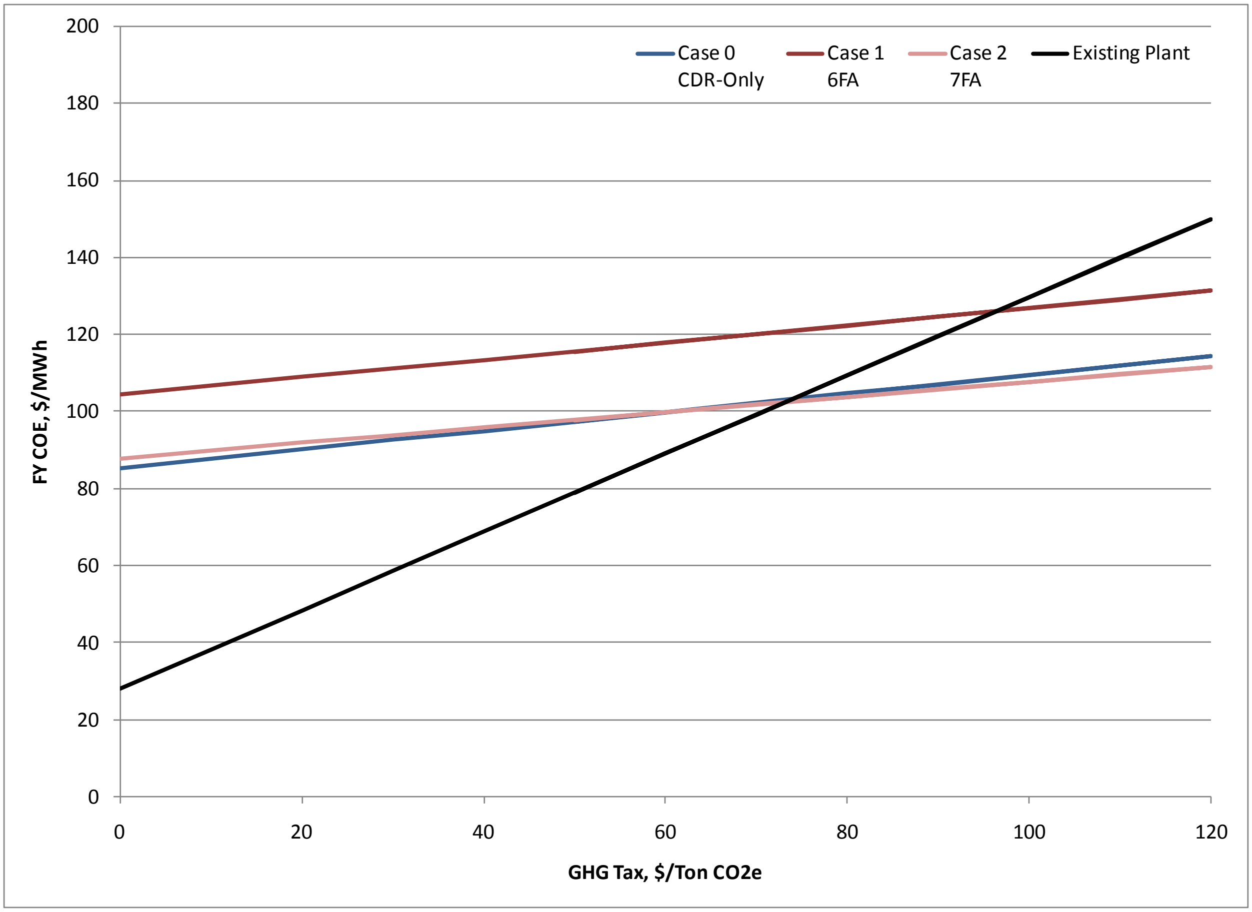
Exhibit 4-49 shows cost of avoiding GHG emissions for each of the retrofit options compared the the existing plant. This exhibit will provide insight into the required GHG tax that will begin to motivate measures to reduce emissions. Exhibit 4-50 shows the increase in COE in a GHG tax economy for the different cases and auxiliary plants. This metric compares the additional costs to retrofit and operate the CDR process and auxiliary plant, assuming the existing plant is paid off. All cases are compared to the pre-retrofit plant emitting 1,888 lb/MWh$_{net}$ of anthropotgenic CO_2 from the stack and a total of 2,030 lb/MWh$_{net}$ LCA CO_2e. The Case 2 natural gas auxiliary plant retrofit has a low cost of avoidance due to the low carbon fuel and the high efficiency.

Exhibit 4-49 Cost of CO_2 Avoided



The different emissions and COE profiles results in varying responses to a sensitivity analysis on an imposed cost of carbon emissions. As the cost of CO_2 emissions increases, the natural gas cases become more competitive due to its inherent low carbon intensity and high efficiency.

Exhibit 4-50 FY COE vs. GHG Tax



5. ISSUES WITH RETROFITING CDR AND AUXILIARY PLANTS

5.1 AUXILIARY POWER AND STEAM GENERATION

Auxiliary plants were designed to repower an existing 550 MW PC plant when CDR retrofit is added. Two main benefits to be investigated in such a configuration would be the reuse of electrical generation and distribution capacity already existing at the plant, along with the demand, and to maintain operation of the existing steam turbine at conditions that are as close to original design conditions as possible. The electrical auxiliaries, associated with adding CDR and for the larger overall gross plant size, are offset by power generated by the natural gas combustion turbine. Combustion turbines have inherently low carbon emissions and can be sited and built more readily and quickly. The existing electrical generation and distribution equipment was assumed to have a design margin to support steam turbine operation at valves wide open and 5 percent over-pressure, corresponding to a 10 percent increase in generating load.

Each auxiliary plant was modeled and costed as its own stand alone plant. Having a dedicated plant for generating the required power and steam should reduce the complexity of the CDR retrofit, as the only streams crossing between the existing plant and the auxiliary plant boundaries are the two flue gas streams that are combined to be treated in the CDR process. For all cases with an auxiliary plant, the CDR system and the auxiliary plants are envisioned to be retrofitted and installed as a single project. Assuming the different space requirements for the different plants can be met, this allows for the most compact and cost effective retrofit and integration arrangement. The CDR system would be located as close to the existing flue gas duct work as possible, to minimize any additional pressure drop and reduce the amount of ductwork required. The steam from the auxiliary plant would be generated close to the reboiler equipment where it would be used, in a closed loop system, returning the condensate to the auxiliary plant.

Additionally, if a stand alone auxiliary plant is used to power the CO_2 removal process, the auxiliary plant will have to be running whenever CO_2 is being captured. For retrofit on a baseload generating plant, the auxiliary plant will be required to run similar to a baseload plant, but in the case of the CT auxiliary plant, with a higher cost of fuel and marginal cost for power, and in the case of the auxiliary boiler, a newly financed boiler rolled into the cost of generation. The dispatch of this combined or integrated plant will have to be adjusted to account for this change in overall generating costs, but in a carbon constrained world, adding CO_2 removal will also likely increase the dispatch priority of the retrofitted plant.

5.2 CDR RETROFIT STEAM EXTRACTION

Steam required for the CDR process, mainly for MEA regeneration, is heat that could have otherwise been used to generate power. If a steam cycle is designed to satisfy this steam demand through extraction, the output should decrease proportional to the enthalpy of the steam, at a given gross ST efficiency. The base Case 0 retrofit uses steam extraction from the existing turbine, taking 45 percent of the IP-LP crossover steam, reducing the steam turbine output by 19 percent. The steam requirements and sources for all the cases are compared in Exhibit 5-1.

Exhibit 5-1 CDR Steam Requirements

	Case 0	Case 1	Case 2
CO_2 Captured, lb/h	934,677	1,227,716	1,126,096

CDR Steam Demand, MMBtu/h	1,429	1,877	1,721
Steam Extraction, MMBtu/h	1,429	0	1,037
Steam Extraction, % of IP-LP Crossover Flow	45%	0	33%
ST Gross Output, MW	468	578	497
Total ST Derate, %	19%	0	14%

In addition to the lost power from the lower steam flow, if the CDR is installed after the initial design, as a retrofit, the ST will be running at off-design conditions. This compounds the reduction in power by reducing the efficiency of the affected turbine sections and contributes to the total ST derate, as described in Section 5.3.

5.3 CDR RETROFIT OFF-DESIGN DERATE

Using the subcritical PC plant, modeled as Case 9 of the NETL Bituminous Baseline study, as a basis, the Case 0 retrofit plant holds the coal feed constant while adding CDR to treat the flue gas. This reduces the plant output by 162 MW split between steam extraction (106 MW equivalent) and increased auxiliary loads (55 MW) as seen in Exhibit 5-2.

When retrofitting a CDR process and extracting the required steam from an existing steam cycle, such as in Case 0, certain portions of the steam turbine must be retrofitted to accommodate these demands. For the presented throttled IP-LP crossover extraction scheme, a throttling valve, along with the associated flanges, spool pieces, and piping, will be installed to extract the desired steam. The LP turbine section may also need to have the turbine blades and casing replaced to accommodate the reduced flow. The derate for adding a CDR, extracting 45 percent of the LP steam flow, is compared in Exhibit 5-2 to show the effects of running the LP section at off-design conditions.

Exhibit 5-2 CDR Retrofit Derate

	Existing PC BB Case 9	Case 0 No Derate	Case 0
ST Power, MW	583	477	467
Auxiliary Load, MW	33	88	88
Net Power, MW	550	388	379
Efficiency %	36.8	26.0	25.4
Coal Flow, lb/hr	437,378	437,378	437,378
ST Off-design Derate, %			1.9

The additional base case off-design steam turbine derate was calculated using the ratio of the total steam turbine gross output for their reference throttled LP turbine CDR retrofit and the greenfield plant with CDR (1.9 percent derate in gross steam turbine efficiency) from the Lucquiaud et al study, which was tested against published data from the IEA GHG study done by a collaboration between Alstom Power, Mitsui Babcock, Flour, and Imperial College [42, 43]. The 1.9 percent reduction in steam turbine efficiency corresponds to the 0.9 percent additional LHV efficiency penalty. The linear decrease in steam turbine efficiency for the throttled LP extraction configuration serve as a basis for reduction in overall steam turbine efficiency as reboiler regeneration steam is offset with steam from an auxiliary boiler, converging to zero derate when no steam is extracted.

In considering the possible benefits of generating CDR process reboiler steam from an auxiliary plant, it was assumed that Case 0 was utilizing both LP trains throttled to achieve the desired extraction steam. When meeting the auxiliary steam requirements using steam extraction, the throttled extraction is the worst case scenario. By using the throttled extraction configuration as the base retrofit, a continuous steam turbine derate can be used to bound the benefits of incremental reductions in steam extraction from the main steam cycle. For the different auxiliary plant configurations, as more of the steam is supplied from the auxiliary plant (or changing to a lower energy penalty solvent), the throttled turbine completely eliminates any off-design ST derate, returning the turbine to its original design conditions. Turning off one of the two LP sections, in a cluted LP turbine configuration, offers the least flexibility as less steam is extracted because the one running LP section is already at full capacity, with no off-design derate, and any additional steam would not be able to be used in the clutched non-operating LP turbine section.

Significant changes to the steam flow of an existing steam cycle also affect the performance of the condenser. The condenser is designed for a given approach to the cooling water temperature for cooling a particularly sized turbine exhaust flow. When this flow is reduced, the same condenser heat exchange surface would have the potential to achieve even lower condenser pressures and temperatures. This could help offset the reduced output due to reduced steam flow and off design operation. The temperature approach of the condenser would be expected to decrease proportionally to the reduction in exhaust flow, after accounting for any change in heat transfer coefficient due to the change in exhaust velocity. In Case 0, where approximately half of the LP steam is extracted, the existing condenser temperature approach could be reduced from 20F to 10F, ignoring changes to the heat transfer coefficient, which results in condenser conditions of 90F and 0.70 psia. Additional study on the heat transfer coefficient and limits of condener operation for retrofit applications is recommended to more accurately determine the range of condenser pressures that should be considered for sensitivities to these cases.

5.4 RETROFIT AUXILIARY PLANT COSTING

The costs for the additional equipment required for the CDR retrofit and the auxiliary plants were scaled costs estimates based on the Bituminous Baseline base cases as well as other costs developed as part of baseline series [1]. The auxiliary plant combustion turbine prices were scaled from Gas Turbine World Handbook turnkey budget prices for simple cycle 6FA and 7FA turbines [2]. The additional number of plant workers required for each CDR and auxiliary plant installation was scaled based on the total additional equipment costs. The additional or marginal costs of electricity after retrofit were calculated based on the capital costs of the additional retrofitted CDR and auxiliary plant combined with the combined plant's O&M costs, including the maintenance of existing equipment, coal for the existing plant, etc. This assumes or simulates an existing plant that is paid off (or a sunk cost) and is consider adding such a retrofit and could compare such a marginal price to the required CO_2 credit, for instance, which would make such an investment economically attractive.

A retrofit factor was added to the additional plant costs to account for the complexity and limitations of applying a retrofit to an existing running plant. A retrofit factor was applied to the baseline costs presented in the costs sheets to account for the integration, depending on specifics of the existing plant, such as space, accessibility, downtime, and other difficult-to-quantify peculiarities associated with these unplanned additions to an existing plant. Each prospective plant considering such a retrofit may have a different retrofit factor to account for site specific factors, and could affect the desirability of these retrofit options.

5.5 SPACE REQUIREMENTS

The CDR retrofit and different auxiliary plant options each have their own specific concerns with space requirements that could affect the configurations of the plant and could ultimately prevent a given plant from even considering one option or the other. Very generally, for the combustion turbine cases the natural gas fuel must be accessible from the existing site, or else additional infrastructure will be required. Combustion turbines have relatively small footprints and thus can be located at a larger proportion of existing sites. Typical coal plants frequently have a buffer zone surrounding the plant to prevent noise and pollution from reaching local residents, but would conceivably contribute to the available land for a CDR retrofit and combustion turbine. In comparison, particular plants with space concerns could be restricted to the lower space requirement solutions or could solve these problems by purchasing adjacent land, increasing the integration costs and moving towards the results based on the higher retrofit factor sensitivities.

For each auxiliary plant, the important space restrictions were calculated based on the pertinent parameters for each technology and fuel type. The 6FA turbine requires an approximate area of 95x66 ft while the 7FA requires 180x75 ft. Natural gas is piped directly to the site, which will have to be laid out thoughtfully, but no additional fuel storage is required for the Case 1 and 2 retrofits.

5.6 STACK REQUIREMENTS AND FLUE GAS PRESSURE

Changes in stack draft losses due to the altered stack gas is a combination of the static pressure change due to the change in density and the dynamic pressure change due to the change in flow and thus velocity of the stack gas. Even though a large portion of the CO_2 in the stack gas is removed in these cases, the larger capacity with the auxiliary plant and the associated increase in stack emissions increases the overall gas flow and velocity of the exiting stack gas. For this study, it was assumed that a new stack would be built in concert with the CDR and auxiliary plant retrofit to minimize downtime to the existing plant. A specific plant's operating profile could motivate re-using an existing stack, in which case an analysis similar to the stack loss calculations, shown in Exhibit 5-3, would be required. The increased stack gas velocity increases the dynamic pressure losses by up to 0.05 psi. The static frictional forces are directly proportional to the density of the stack gas, and the height of the stack, designed to be 500ft, which is unchanged assuming the existing stack is reusable. The reduced temperature of the the stack gas after CO_2 removal increases the pressure slightly and increases the static pressure losses, but by less than 0.02 psi. The lower temperature flue gas temperature exiting the CDR process eliminates an additional 0.013 psi of natural buoyancy of the exhaust, for all the cases. The total increased losses are less than 0.068 psi. The cleaner flue gas and higher velocities indicate that the existing stack height is suitable for whatever existing regulatory environment and given dispersion modeling existed before the retrofit, not necessitating a new stack. Any additional losses are overcome by the the head generated by the retrofitted CDR system and accompanying blowers.

Exhibit 5-3 Retrofit Stack Losses

	Stack Temp (F)	Volumetric Flow (ft3/h)	Dynamic Pressure Loss (psi)	Static Pressure Loss (psi)	Bouyancy Effect (psi)	Pressure Loss Increase (psi)
Pre-retrofit	135	75,425,804	0.039	0.232	-0.033	-
Case 0	89	52,700,578	0.020	0.244	-0.020	0.005
Case 1	89	92,222,636	0.062	0.245	-0.020	0.047
Case 2	89	105,707,556	0.082	0.245	-0.020	0.068

By ranking the magnitudes of the different stack losses, different strategies are qualitatively addressed to outline the effects on the stack gas delivery and dispersion after retrofit. The biggest contributor to the additional losses is from the dynamic pressure losses; although unnecessary, a wider stack would counteract these concerns by reducing the stack gas velocity closer to the original 80 ft/s design point, while not reducing the dispersion below the original stack design. The second largest effect comes from the static pressure due to the increased density of the gas acting along the height of the stack; a shorter stack would reduce the static losses and could be a viable solution once new detailed dispersion modeling was performed that could leverage the cleaner, more highly treated flue gas. Presumably, fewer pollutants would allow for a shorter stack with less dispersion without adverse environmental effects. Finally the decreased buoyancy stack effect could be counteracted by reheating the flue gas but would likely be limited by the amount of available waste heat in the plant.

6. CONCLUSIONS

The base case in this study, the CO_2 removal only retrofit Case 0, shows an incremental COE of 85.4 mills/kWh and capital costs (using total overnight cost as a metric) of $1,899/kW or a total of $721M. Compare that to the BB results where a greenfield PC plant with CO_2 removal COE is 109.6 mills/kWh and costing $3,610/kW or $1,985M total and without capture, 59.4 mills/kWh and costing $1,996/kW or $1,098M total, that results in a difference of 50.2 mills/kWh, $1,604/kW and an absolute cost difference of $887M.

Exhibit 6-1 Results Summary

	Case 0 CDR-Only	Case 1 6FA	Case 2 7FA
Gross Power Output (kW_e)	467,600	657,500	668,500
Auxiliary Power Requirement (kW_e)	88,180	118,490	111,080
Net Power Output (kW_e)	379,420	539,010	557,420
Coal Flowrate (lb/hr)	437,378	437,378	437,378
Natural Gas Flowrate (MMBtu/hr)	0	2,761	1,797
HHV Thermal Input (kW_{th})	1,495,381	2,304,465	2,022,075
Net Plant HHV Efficiency (%)	25.4%	23.4%	27.6%
Net Plant HHV Heat Rate (Btu/kW-hr)	13,448	14,588	12,378
Raw Water Withdrawal, gpm	8,158	12,520	10,903
Raw Water Consumption, gpm	6,266	9,556	8,334
LCA GHG Emissions (lb/MWh_{gross})	390	367	330
LCA GHG Emissions (lb/MWh_{net})	481	448	396
SO_2 Emissions (lb/MWh_{gross})	0.019	0.022	0.024
NOx Emissions (lb/MWh_{gross})	0.787	0.568	0.559
PM Emissions (lb/MWh_{gross})	0.146	0.101	0.099
Hg Emissions (lb/MWh_{gross})	1.29E-05	8.87E-06	8.72E-06
Cost Values			
Total Plant Cost ($x1000)	574,859	774,879	758,364
Owner's Costs ($x1000)	145,657	217,227	204,115
Total Overnight Cost ($x1000)	720,516	992,105	962,479
Total Overnight Cost ($/kW)	1,899	1,841	1,727
FYCOE ($/MWh)	85.4	104.4	87.9
LCOE ($/MWh)	108.3	132.4	111.5

The objective of this study is to examine the performance, environmental response, and economics of retrofitting CDR to existing PC plants and the effects of retrofitting an additional auxiliary plant to satisfy the additional steam and electrical auxiliaries which would reduce the output of the post-retrofit plant. Two sizes of combustion turbine installations.

The performance and economic results, summarized in Exhibit 6-1, show that there are several competitive options for retrofitting CDR. Conclusions based on these economic results include:

- A maximally sized combustion turbine auxiliary plant provides the lowest cost option for fully repowering a CDR retrofitted plant. The increased auxiliary plant costs are relatively small compared to the associated CDR retrofit, but any possible cost reductions compared to the base CDR retrofit-only are minimal.

- The combustion turbine configurations are attractive because theay have high efficiencies and lowest stack emissions, mainly because of the clean, low carbon natural gas fuel and high efficiency turbines.

The overall combined net efficiencies of the retrofitted plants are not simply a combination of the efficiencies of the base plant plus the auxiliary plant. Additional inefficiencies still remain and are related to such things as existing steam turbine derate, unrecoverable heat contained in vented flue gas and other process design considerations. For the combustion turbine cases, the most basic trend indicates that as duct firing increases, without recovering high level heat, the efficiency of the combined plants decreases. This implies that the efficiency of these retrofit options increases as combustion turbine size increases. It can be seen that the larger turbine also lowers the cost of electricity. However, in deciding on an auxiliary combustion turbine size, the main considerations are the gross power output and the steam production. Without an increase in regional power demand the turbine size ideally would be chosen so that there is minimal unused power generation capacity from the plant, while meeting the steam requirements of the CDR

The MEA process implemented in this study removes 90 percent of the CO_2 from the flue gas generated by a 550MW PC plant (pre-retrofit) and requires ~1,400 MMBtu/h of steam for solvent regeneration and ~55 MW of auxiliary power for Case 0, equating to a steam to power ratio of 7.3. The off-design derate of Case 0 increases the amount of power required to repower to the original output and thus decreases the required steam to power ratio. For treating a given flue gas stream, the steam requirements scale with the amount of CO_2 captured, and the power scales based on the gas volume to be treated. Thus, treating a more dilute flue gas stream, as in the case of mixed PC boiler and CT exhaust, decreases the required steam to power ratio. Because boiler and turbines are available in a wide range of sizes, the boilers in cases 3 and 4 can be paired with an appropriately sized backpressure letdown turbine to exactly meet these steam and power requirements. The simple cycle combustion turbine plants, on the other hand, have a fixed electrical output and available sensible heat for recovery, which results in a steam to power ratio of 1.5 according to the heat recovery assumptions made in this study. Case 2 demonstrates a scenario where only a portion of the CDR steam demand is met, limited by the excess power output from the larger 7FA combustion turbine. The steam to power ratio was adjusted by burning natural gas, similar to a duct firing configuration, to augment the steam production in Case 1. However, this reduces the efficiency of a simple cycle combustion turbine moreso than a combined cycle plant, which could recover a greater amount of higher quality heat, minimizing the opportunity cost of directly using natural gas in a less efficient duct burner.

For a given plant which is interested in repowering or increasing its output, the former approach may make sense based on projected demand or growth. Matching the steam requirement is likely the more cost effective option as it leverages more of the existing equipment and infrastructure and requires minimal additional investment.

Additional Power Generation

For a plant to simultaneously add CO_2 removal and increase its overall output, additional capacity is required to offset or replace the steam and power diverted to the CO_2 removal process as well as to generate the desired power. The efficiencies of the proposed auxiliary plants could all be improved if their steam cycles were optimized, making use of the higher quality steam. The increased cost of a high temperature steam turbine in the auxiliary plant may be offset by the increased efficiency, which would also reduce the marginal cost of generating electricity. For the combustion turbine cases, the additional natural gas that is burned to adjust the steam to power ratio reduces the efficiency below that of simple cycle operation. Adding a combined cycle would fully take advantage of the chemical energy in the natural gas feedstock by generating higher quality steam in a more efficiency cycle and also to largely remove constraints on steam to power ratios imposed by simple cycle designs.

Typically, duct firing with natural gas is used to create high temperature steam or reheat to maximize high quality steam flowrates and increase the efficiency of the steam cycle. This configuration using natural gas to create additional low quality steam for the reboiler does not fully take advantage of the natural gas and decreases the net efficiency of the combined plants. Duct firing is not preferred if natural gas could instead be used in a combustion turbine. While the additional capital costs are small for a duct-firing configuration, the natural gas would be better used to power the largest combustion turbine that could be accommodated at the plant, limited by either power demand or other plant considerations. Challenges exist when trying to match both the power and steam production required by a PC plant retrofitted with an amine-based CDR because of fixed combustion turbine designs.

Adding a larger natural gas auxiliary plant could lead to a cost effective solution, largely because the additional low-carbon natural gas power is more efficient and lower cost than coal-generated power. Examples or perturbations of the modeled cases could include a larger combustion turbine auxiliary plant, similar to Cases 1 or 2 except with a full combined cycle HRSG and steam turbine added to generate power. For a 6FA turbine, this may add ~$60MM for a ~40MW increase in power (~$1,500/kW), and for a 7FA, ~$120MM for a ~90MW increase (~$1,300/kW), based on the differences between the simple cycle and combined cycle plant's published costs in the Gas Turbine World 2009 GTW Handbook [40]. Multiple turbine trains or larger turbines could also be considered to capture some economies of scale for the combined cycle portion of the plant.

Matching Steam Generation

The general basis from the cases presented in this study is to avoid the inefficiencies associated with extracting steam from the existing steam turbine, while making up all lost power required to run the CO_2 capture and compression equipment.

Sensible heat left in the flue gas of the combustion processestem is responsible for generating the regeneration steam. The sensible energy in the exhaust of the 7FA is well matched to the MEA based CO_2 removal process required to capture 90 percent of the emissions from the combined plant flue gas. For the 6FA case, with roughly half the capacity, additional duct firing with natural gas is required to meet the steam requirements of the CO_2 removal process. With the premise of matching the low pressure steam requirement, both of these cases make only the required quality of steam, sent directly to the CO_2 removal process in a dedicated closed loop. So even though sensible heat is recovered from the flue gas, both these auxiliary plants contribute energy closer to the simple cycle efficiency rather than that of combined cycle operation. Even in this sub-optimal operation, Case 2 in this study shows that a combined combustion turbine retrofit can be cost competitive to add additional output to an existing plant.

The final determinations for a CDR repowering retrofit would go beyond the baseline technoeconomic parameters quantified in this study to consider space requirements, permitting, additional electrical demand, and reliability.

7. FUTURE WORKS

7.1 ALTERNATIVE CDR STEAM

If the additional power generated from the auxiliary plants to repower the overall plant is not emphasized, the major tradeoff in this study becomes offsetting the CDR steam requirement to allow the existing steam turbine to run closer to full design conditions. This could be accomplished by a stand alone direct fired reboiler for the CDR plant. This not only repurposes the previously extracted steam to generate power but also reduces the off-design derate of the steam turbine. Any number of fuels could be considered but the installation of this small heat plant would leverage the existing steam turbine equipment for little more than the price of the fuel. A first-order analysis, ignoring the cost of any required equipment, shows that using natural gas to meet the CDR reboiler heat duty for Case 0 would cost $9,400/hr using natural gas and $2,300/hr using coal, to eliminate the 9MW off-design derate. This tradeoff seems competitive, and further analysis may be warranted to explore this simple but possibly cost effective compromise.

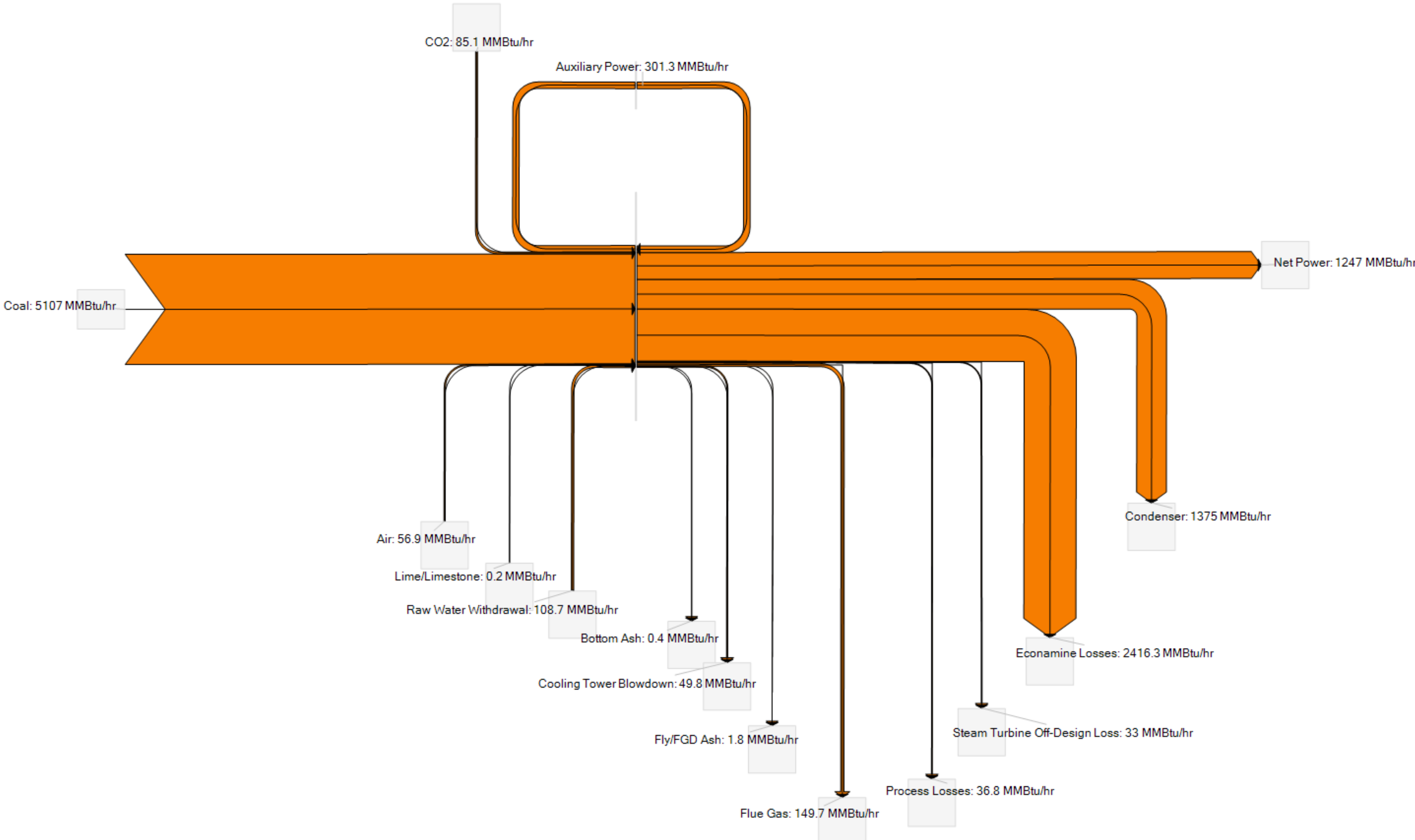
7.2 CARBON CAPTURE LEVELS

As part of the design basis for this study, 90 percent capture of all carbon fuel inputs had to be captured in the CDR retrofit, including from the auxiliary plant. Because of the different emissions profiles of the auxiliary plants, this results in differing CO_2 emission intensities. An alternative basis would require equivalent LCA GHG emissions from all plants or even equivalent stack emissions normalized to net power output. If a normalized stack emission target is imposed, the combustion turbine cases would have a similar benefit due to the low carbon intensity of the fuel, reducing the cost of electricity and making it a more attractive retrofit option. All these scenarios have potential to inform the policy landscape and compare possible routes to reducing carbon emissions in a fair and equitable way.

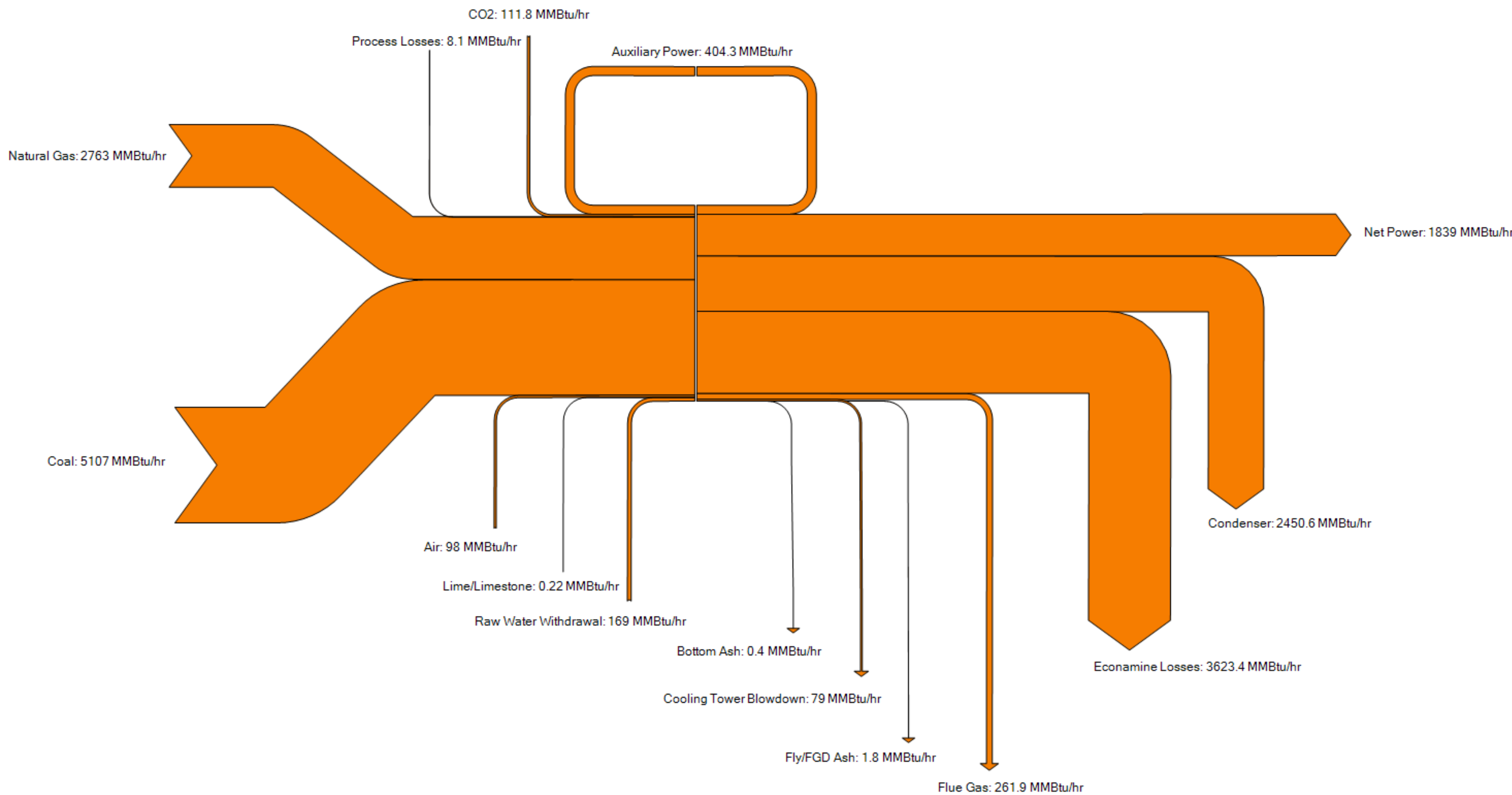
APPENDIX A

SANKEY DIAGRAMS

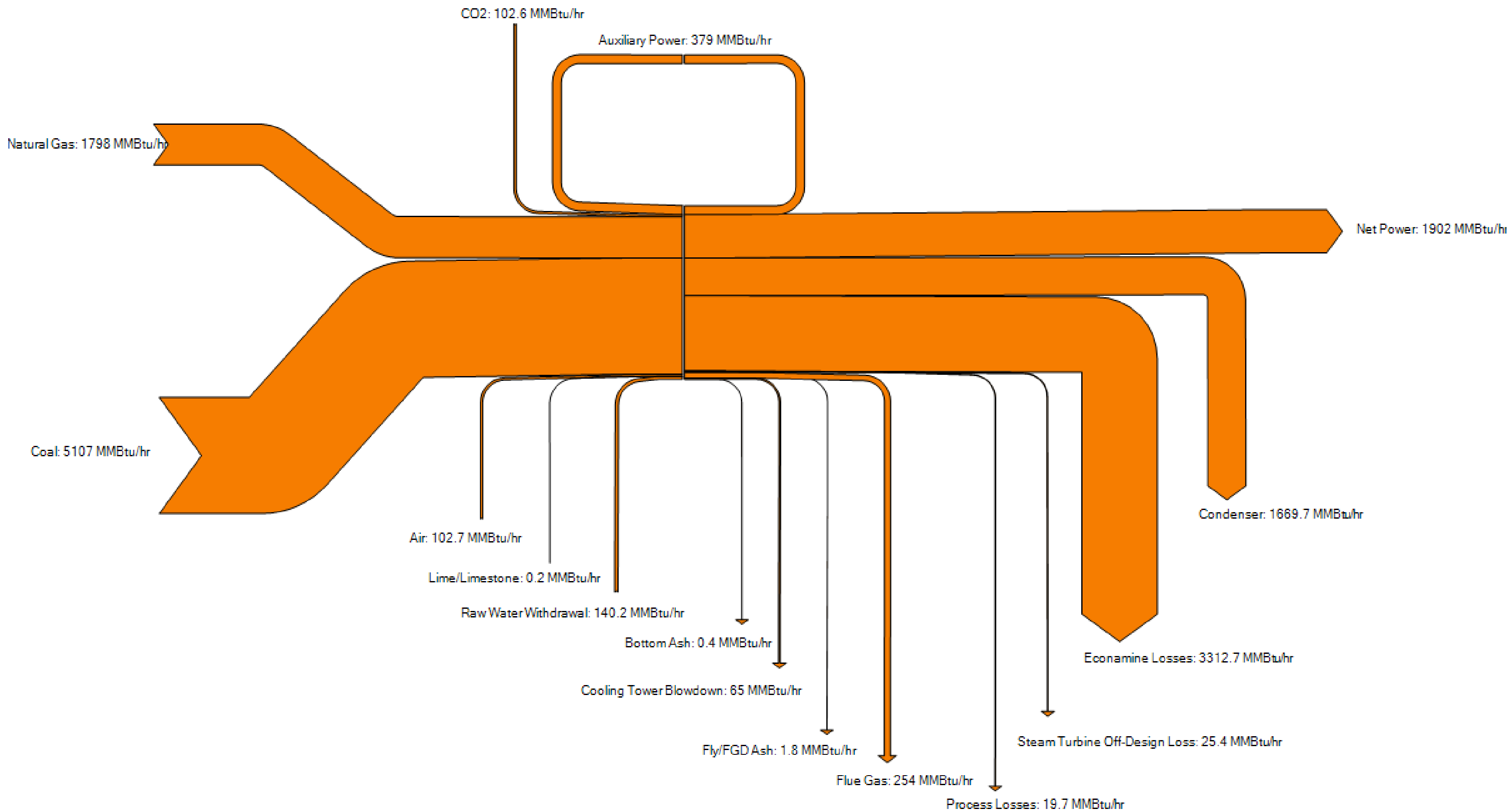
Appendix A- 1 Case 0 Sankey Diagram



Appendix A- 2 Case 1 Sankey Diagram



Appendix A- 3 Case 2 Sankey Diagram



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