

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS



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ACRONYMS AND ABBREVIATIONS

AACE	AACE International (formerly the Association for the Advancement of Cost Engineering)	CHP	Combined heat and power
AC	Alternating current	CL	Closed-loop
acfm	Actual cubic feet per minute	cm	Centimeter
ACI	Activated carbon injection	CM	Construction management
ADA-ES	Advanced Emissions Solutions, Inc.	CO	Carbon monoxide
AF	Availability factor	CO ₂	Carbon dioxide
AGR	Acid gas removal	COE	Cost of electricity
ANSI	American National Standards Institute	CS	Carbon steel
Ar	Argon	CT	Combustion turbine or current transformer
Aspen	Aspen Plus®	CTG	Combustion turbine-generator
atm	Atmosphere (14.696 psi)	CWP	Circulating water pump
Aux	Auxiliary	CWS	Circulating water system
BACT	Best available control technology	CWT	Cold water temperature
BAU	Business as usual	DC	Direct current
BDL	Blowdown losses	DCS	Distributed control system
BEC	Bare erected cost	DI	De-ionized
BFD	Block flow diagram	DLN	Dry low NOx
BFW	Boiler feedwater	DOE	Department of Energy
BOP	Balance of plant	DSI	Dry sorbent injection
Btu	British thermal unit	EAF	Equivalent availability factor
Btu/kWh	British thermal units per kilowatt hour	EGU	Electric generating unit
Btu/lb	British thermal units per pound	EIA	Energy Information Administration
Btu/scf	British thermal units per standard cubic foot	EMF	Emission modification factors
C ₂ H ₆	Ethane	EPA	Environmental Protection Agency
C ₃ H ₈	Propane	EPC	Engineering, procurement, and construction
C ₄ H ₁₀	Butane	EPCC	Engineering, procurement, and construction cost
CaSO ₄	Calcium sulfate	ESP	Electrostatic precipitator
CCF	Capital charge factor	ESPA	Energy Sector Planning and Analysis
CCS	Carbon capture and storage	FD	Forced draft
CCSI	Carbon Capture Simulation Initiative	FE	Fossil Energy
CCUS	Carbon capture, utilization, and storage	FGD	Flue gas desulfurization
CF	Capacity factor	FO	Fuel oil
CH ₄	Methane	FRP	Fiberglass-reinforced plastic
CH ₄ S	Mercaptan	ft	Foot, feet
		FW	Feedwater
		GADS	Generating Availability Data System
		gal	Gallon

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GE	General Electric	kg/m ³	Kilogram per cubic meter
GHG	Greenhouse gas	kgmol	Kilogram mole
GJ	Gigajoule	kJ	Kilojoule
GJ/hr	Gigajoules per hour	kJ/kg	Kilojoules per kilogram
gpm	Gallons per minute	km	Kilometer
gr/100 scf	Grains per one hundred standard cubic feet	KO	Knockout
Gt	Gigatonne	kV	Kilovolt
h, hr	Hour	kW, kWe	Kilowatt electric
H.O.	Home office	kWh	Kilowatt-hour
H ₂	Hydrogen	kWt	Kilowatt thermal
H ₂ O	Water	LAER	Lowest Achievable Emission Rate
H ₂ S	Hydrogen sulfide	lb	Pound
H ₂ SO ₄	Sulfuric acid	lb/ft ³	Pound per cubic foot
HCl	Hydrochloric acid	lb/hr	Pounds per hour
Hg	Mercury	lb/MMacf	Pounds per actual cubic feet
HHV	Higher heating value	lb/MMBtu	Pounds per million British thermal units
Hnd	Handling	lbm	Pounds mass
hp	Horsepower	lbmole/hr	Pound moles per hour
HP	High pressure	lb/MWh	Pounds per megawatt hour
hr	hour	lb/TBtu	Pounds per trillion British thermal units
HRCC	Heat rate with carbon capture	LDT	Letdown turbine
HRSG	Heat recovery steam generator	LHV	Lower heating value
HSS	Heat stable salts	LiBr	Lithium bromide
HVAC	Heating, ventilating, and air conditioning	LNB	Low NOx burner
HWT	Hot water temperature	LP	Low pressure
Hz	Hertz	lpm	Liters per minute
I&C	Instrumentation and control	m	Meter
I/O	Input/output	M	Thousand
ICR	Information Collection Request	MM	Million
ID	Induced draft	m/min	Meters per minute
IEA	International Energy Agency	m ³ /min	Cubic meters per minute
IEEE	Institute of Electrical and Electronics Engineers	MATS	Mercury and Air Toxics Standards
IGV	Inlet guide vane	MCR	Maximum continuous rating
in Hg	Inches of mercury	MESA	Mission Execution and Strategic Analysis
IOU	Investor-owned utility	mg/Nm ³	Milligrams per normal cubic meter
IP	Intermediate pressure	mi	Mile
IPM	Integrated Planning Model	MJ/scm	Megajoule per standard cubic meter
IRROE	Internal rate of return on equity	mm Hg	Millimeters of mercury
ISO	International Organization for Standardization	MM	Million
kg/GJ	Kilograms per gigajoule		
kg/hr	Kilograms per hour		

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MMacf	Million actual cubic feet	POTW	Publicly owned treatment works
MMBtu	Million British thermal units		
MMBtu/hr	Million British thermal units per hour	ppm	Parts per million
MPa	Megapascal	ppmdb	Parts per million, dry basis
MVA	Mega volt-amps	ppmv	Parts per million volume
MW	Megawatt	ppmvd	Parts per million volume, dry
MWe	Megawatt electric	ppmwd	Parts per million weight, dry
MWh	Megawatt-hour	PPS	Polyphenylsulfide
N ₂	Nitrogen	PSD	Prevention of significant deterioration
N/A	Not applicable	PSFM	Power Systems Financial Model
NaOH	Sodium hydroxide	psi	Pounds per square inch
NCF	Net capacity factor	psia	Pound per square inch absolute
NEMA	National Electrical Manufacturers Association	psig	Pound per square inch gage
NERC	North American Electric Reliability Corporation	PSP	Projected sales price
NETL	National Energy Technology Laboratory	PTFE	Teflon (Polytetrafluoroethylene)
NG	Natural gas	QGESS	Quality Guidelines for Energy System Studies
NGCC	Natural gas combined cycle	Qty	Quantity
NGSC	Natural gas simple cycle	RCF	Retrofit contingency factor
NH ₃	Ammonia	RD&D	Research, development, and demonstration
Nm ³	Normal cubic meter	RET	Retrofit
NOAK	Nth-of-a-kind	RH	Reheater
NO	Nitrogen oxide	RO	Reverse osmosis
NOx	Oxides of nitrogen	scf	Standard cubic feet
NSPS	New Source Performance Standards	scfm	Standard cubic feet per minute
NSR	New Source Review	SCR	Selective catalytic reduction
NTNU	Norwegian University of Science and Technology	SO ₂	Sulfur dioxide
O ₂	Oxygen	SO ₃	Sulfur trioxide
O&M	Operation and maintenance	SOx	Oxides of sulfur
O-H	Overhead	SS	Stainless steel
OFA	Overfire air	ST	Steam turbine
OP/VWO	Over pressure/valve wide open	STG	Steam turbine generator
PA	Primary air	SubC	Subcritical
PAC	Powdered activated carbon	Syngas	Synthetic gas
PAS	PAS, Inc.	T&D	Transmission and distribution
PC	Pulverized coal	T&S	Transport and storage
PCC	Post-combustion capture	TASC	Total as-spent cost
p.f.	Power factor	TEG	Triethylene glycol
ph	phase	TEWAC	Totally Enclosed Water-to-Air Cooled
PM	Particulate matter	tonne	Metric ton (1,000 kg)
		TOC	Total overnight cost

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TPC	Total plant cost	\$	U.S. Dollar
TR	Transformer	\$/kW	Dollars per kilowatt
U.S.	United States	\$/MMBtu	Dollars per million British thermal units
V	Volt		
V-L	Vapor liquid portion of stream (excluding solids)	\$MM	Millions of dollars
		°C	Degrees Celsius
VT	Voltage transformer	°F	Degrees Fahrenheit
WG	Water gauge	%	Percent
wt%	Weight percent	5-10s	Fifty-hour work weeks
yr	Year		

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EXECUTIVE SUMMARY

The upcoming challenge for the power generation industry will be meeting ever increasing demand (which requires building new capacity), while simultaneously reducing greenhouse gas emissions from existing sources (to meet regulations under the Clean Power Plan). [1] New and advanced carbon capture technologies may help increase efficiency and reduce the derate experienced when retrofitting existing power plants with amine-based carbon capture and storage (CCS) systems. Even with the development of these novel technologies, overcoming logistical and economic problems of retrofitting the existing fleet will be challenging. Older, higher emitting plants face the prospect of having to add new, expensive gas cleanup equipment or shutting down operations. One of the more significant issues pertains to the reduction in net power output (derate) due to the large parasitic power load required for appreciable levels of carbon capture. Post-combustion capture (PCC) has been shown to reduce the net plant efficiency of an equivalent plant without capture by 20 percent or more. Yet, post-combustion amine scrubbing is anticipated to be the most viable near-term technology for reducing carbon dioxide (CO₂) emissions from existing coal plants. This study attempts to quantify auxiliary load replacement options for existing pulverized coal (PC) boilers to reduce the effects caused by steam and power requirements of the CCS systems and the resulting derated output of the existing plant.

In addition to cost and performance concerns, traditional impediments to plant retrofits exist, such as projected plant downtime during construction, plant layout and footprint restrictions, reuse of equipment or resources, and permitting requirements. While individual retrofit options are highly plant-specific and, therefore, subject to unique optimization pathways, each of the proposed cases in this study attempts to examine the most promising configurations for each repowering technology. The study case matrix is presented in Exhibit ES-1. A range of auxiliary plant technologies and configurations were explored in the previous version of this study. [2] This report update incorporates several modifications to the study assumptions and case matrix. The results from this study show that combined heat and power (CHP) repowering can make up the lost power due to retrofitting an existing subcritical PC plant with CCS while reducing the overall cost of electricity (COE) relative to a CCS-only retrofit.

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Exhibit ES-1. Study matrix

Objective	Case	Existing ST Extraction	Duct Firing	CO ₂ Capture Criteria ^A	Auxiliary Plant Arrangement
Retrofit Baseline	0	As Required	None	90% from PC flue gas	N/A
Retrofit with NGSC CHP Repowering	1	None	None	90% from PC flue gas	NGSC Auxiliary Plant with a hypothetically sized CT, no carbon capture
Retrofit with NGCC CHP Repowering	2	None	None	90% from PC flue gas	NGCC Auxiliary Plant with (2x) GE 7FA CTs, no carbon capture

^AAll cases have a nominal 90 percent removal rate from the PC plant flue gas based on the total feedstock minus unburned carbon in ash. The rate of CO₂ capture from the flue gas in the Cansolv systems varies. An explanation for the difference is provided in Section 2.4.3. All cases include pipeline transportation for offsite CO₂ storage.

A summary of the performance and environmental results from these cases is presented in Exhibit ES-2. A summary of the cost results is presented in Exhibit ES-3. The existing plant values are included in the tables for comparison. Several study assumptions were established that provide context for the results and conclusions provided in this report. These assumptions include the following:

- The retrofitted CCS facility only treats the flue gas emitted from the PC boiler. CO₂ is not removed from the exhaust gas emitted by the auxiliary CHP plants.
- The existing transmission and distribution (T&D) grid infrastructure is capable of accepting all electrical generation produced in excess of the generation previously produced by the existing plant.
- The plant is in an area where no regional T&D restrictions exist that limit the sale of the excess generation.
- The CHP auxiliary plants are sized such that the entire thermal demand of the retrofitted CCS facility is met by steam raised by the auxiliary CHP plant without duct firing or steam extraction from the existing steam turbine.
- A natural gas simple cycle (NGSC) CHP auxiliary plant is based on a hypothetically sized combustion turbine (CT). It does not represent an “off the shelf,” commercially available model from any specific turbine manufacturer.
- Financing of the CCS facility (and for Case 1 and Case 2, the associated CHP auxiliary plant) is only applicable to the retrofit equipment and does not include any remaining capital repayment obligations on the existing plant. Retrofit equipment costs are amortized over a three-year construction period and a 30-year plant lifetime.

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Exhibit ES-2. Performance summary and environmental profile

Parameter	Combined Plant Performance			
	Existing Plant	Retrofit Baseline	Auxiliary Repowering	
	Baseline B11A [3]	Case 0 No CHP	Case 1 NGSC CHP	Case 2 NGCC CHP
Gross Power Output (MWe)	581	501	811	1,148
Auxiliary Power Requirement (MWe)	31	76	81	88
Net Power Output (MWe)	550	425	730	1,060
Coal Flow rate (lb/hr)	412,005	411,949	412,005	412,005
Natural Gas Flow rate (lb/hr)	N/A	N/A	100,984	185,484
HHV Thermal Input (kWt)	1,408,630	1,408,440	2,074,494	2,631,664
Net Plant HHV Efficiency (%)	39.0%	30.2%	35.2%	40.3%
Net Plant HHV Heat Rate (Btu/kWh)	8,740	11,301	9,700	8,468
Raw Water Withdrawal (gpm)	5,538	6,711	8,212	9,392
Process Water Discharge (gpm)	1,137	1,545	1,882	2,148
Raw Water Consumption (gpm)	4401	5,166	6,330	7,244
Overall CO ₂ Capture	90%	90%	71%	60%
CO ₂ Emissions (lb/MMBtu)	204	20	52	66
CO ₂ Emissions (lb/MWh-gross)	1,683	195	453	516
CO ₂ Emissions (lb/MWh-net)	1,779	230	503	559
SO ₂ Emissions (lb/MMBtu)	0.085	0.000	0.000	0.000
SO ₂ Emissions (lb/MWh-gross)	0.700	0.000	0.003	0.003
NO _x Emissions (lb/MMBtu)	0.083	0.073	0.058	0.047
NO _x Emissions (lb/MWh-gross)	0.700	0.700	0.511	0.366
PM Emissions (lb/MMBtu)	0.011	0.009	0.007	0.006
PM Emissions (lb/MWh-gross)	0.090	0.090	0.065	0.046
Hg Emissions (lb/TBtu)	0.363	0.313	0.246	0.194
Hg Emissions (lb/MWh-gross)	3.00E-06	3.00E-06	2.15E-06	1.52E-06

Contingencies are needed for retrofit capital charges to reflect the added costs associated with any typical retrofit project (limited space resulting in construction premiums, insufficient laydown area, long tie-in connections, etc.) compared to a similar baseline for greenfield costs. In this study, the retrofit contingencies were not included in the total plant cost (TPC) estimates summarized in Exhibit ES-3. Instead, a retrofit contingency factor (RCF) of 1.1 was applied to the total overnight capital (TOC) component of the COE based on the simplified

method described in the August 2013 Quality Guidelines for Energy System Studies (QGESS) document “Estimating Plant Costs Using Retrofit Difficulty Factors.” [4] The RCF was calculated as a weighted average of the retrofit total plant cost premiums using the high contingency values applied to greenfield equipment costs scaled for retrofitting to an existing subcritical PC plant. [4]

Exhibit ES-3. Cost summary for all cases

Parameter	Combined Plant Costs ^A			
	Existing Plant	Retrofit Baseline	Auxiliary Repowering	
	Baseline B11A [3]	Case 0 No CHP	Case 1 NGSC CHP	Case 2 NGCC CHP
Total Plant Cost (2011\$/kW)	N/A	1,743	1,192	983
Bare Erected Cost	N/A	1,241	872	735
Home Office Expenses	N/A	114	79	66
Project Contingency	N/A	254	77	53
Process Contingency	N/A	135	164	130
Total Overnight Cost (2011\$MM)	N/A	898	1,057	1,268
Total Overnight Cost (2011\$/kW)	N/A	2,111	1,448	1,196
Owner's Costs (2011\$/kW)	N/A	367	256	213
TOC including RCF (2011\$MM)	N/A	987	1,162	1,394
TOC including RCF (2011\$/kW)	N/A	2,322	1,593	1,315
Total As-Spent Cost (2011\$/kW)	N/A	2,276	1,561	1,289
TASC including RCF (2011\$/kW)	N/A	2,503	1,717	1,418
COE (\$/MWh) (excluding T&S)	44.2	103.3	84.6	73.6
Capital Costs	0.0	34.6	23.7	19.6
Fixed Costs	9.3	19.0	12.2	9.1
Variable Costs	9.2	16.4	10.1	7.4
Fuel Costs	25.7	33.2	38.5	37.5
COE (\$/MWh) (including T&S)	44.2	113.6	90.6	77.7
CO₂ T&S Costs	N/A	10.3	6.0	4.1

^AAll costs are on a net output basis (\$/kW, \$/MWh) representing the costs spread over the combined plant (retrofitted existing plant plus CHP plant if applicable).

EFFECTS ON PERFORMANCE

A greenfield, subcritical PC plant with CO₂ removal technology as part of its original design has a net plant efficiency of 31 percent on a higher heating value (HHV) basis, approximately 20 percent less efficient than an analogous non-capture plant having a net plant efficiency of 39 percent. [3] For cases where CO₂ removal technology is added as a retrofit after the initial power plant design and construction, as is the case in this study, the net output reduction can be even greater depending on how amine regeneration steam is extracted from the existing

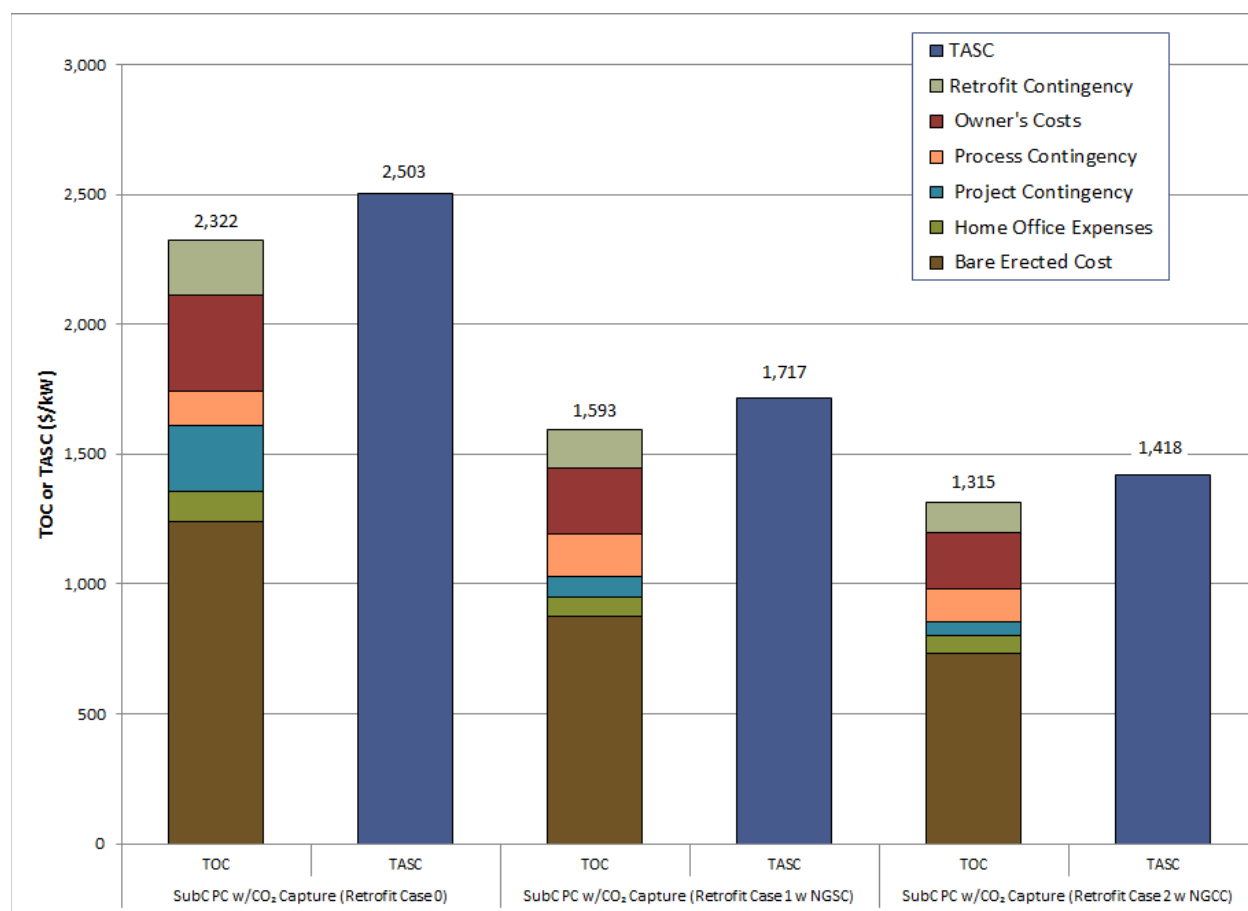
steam turbine. In the likely worst case, a 23 percent reduction from the non-capture plant efficiency is observed in the Case 0 retrofit when extracting steam equally from all low-pressure steam turbine trains (by design is likely the least efficient extraction method from a thermodynamic standpoint, especially in cases with multiple low pressure (LP) steam turbine sections). This worst-case scenario reflected in Case 0 helps to identify and bound opportunities to recover or prevent some of the losses associated with CO₂ removal retrofit. Including an auxiliary CHP plant provides an opportunity to reduce the impact to overall plant efficiency while also allowing for the potential increase of net combined power plant electrical output, beyond that of the 550 MWe existing (non-capture) subcritical PC plant.

Without restrictions on transmission capacity, the cases that include a CHP component have higher efficiencies than Case 0 as a result of the surplus power generated and sold by the higher cycle efficiency CHP plants. The high-capacity natural gas combined cycle (NGCC) CHP facility in Case 2 not only offsets the efficiency penalty of the CO₂ removal retrofit, it realizes a higher plant efficiency than the existing non-capture plant.

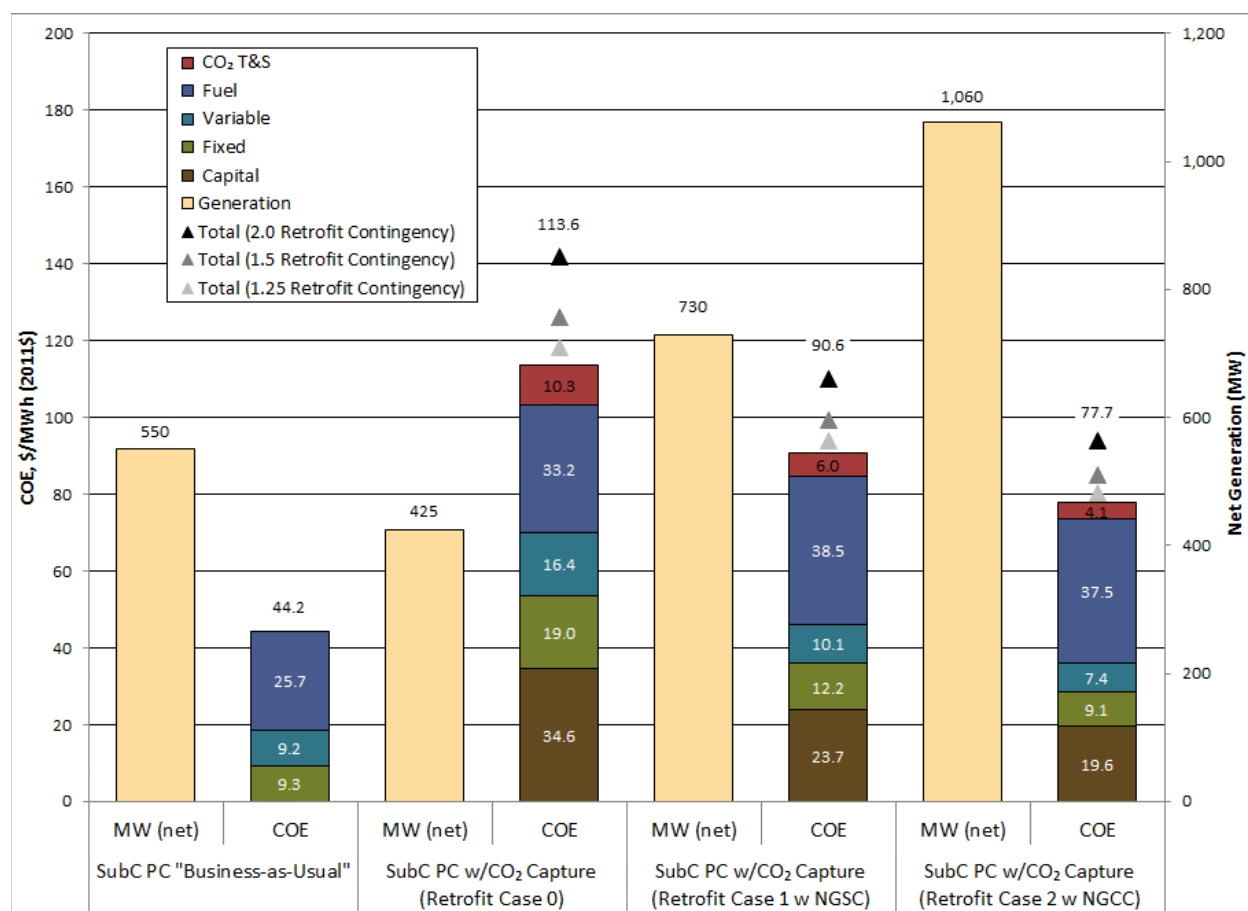
EFFECTS ON COSTS

The simultaneous retrofit of CO₂ 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 CO₂ removal retrofit. As a rule, CO₂ capture retrofit of an existing plant will not perform as well as a greenfield plant originally designed to meet the objectives of the retrofit because plant processes cannot be optimized in the same way after the design and construction of the main plant has been completed. Incorporating an auxiliary CHP plant into the retrofit design reduces the number and extent of disruptions of (presumably) previously optimized systems of the existing non-capture plant and allows for minimal impact to the performance of the base plant.

All cases in this study assume a fully depreciated base plant, to be representative of the older existing plants in the domestic coal fleet that may be considering such a retrofit. The capital costs of the retrofit, using total overnight cost (\$/kW net output of combined plant) as a metric, are shown in Exhibit ES-4.

Exhibit ES-4. Capital costs

The COE for each case is shown in Exhibit ES-5. The COE is expressed in terms of post-retrofit costs, which include the current plant operation and maintenance (O&M) costs and additional costs associated with the retrofit project (i.e., annualized capital costs plus all fixed and variable operating costs of the CCS equipment, including any fuel costs for operating the CHP plant) at the full net output capacity of the combined plant. The COE and net capacity for the existing subcritical PC plant are included for comparison. The COE includes only the ongoing O&M costs (i.e., non-capital) associated with the existing, fully depreciated plant.

Exhibit ES-5. COE breakdown

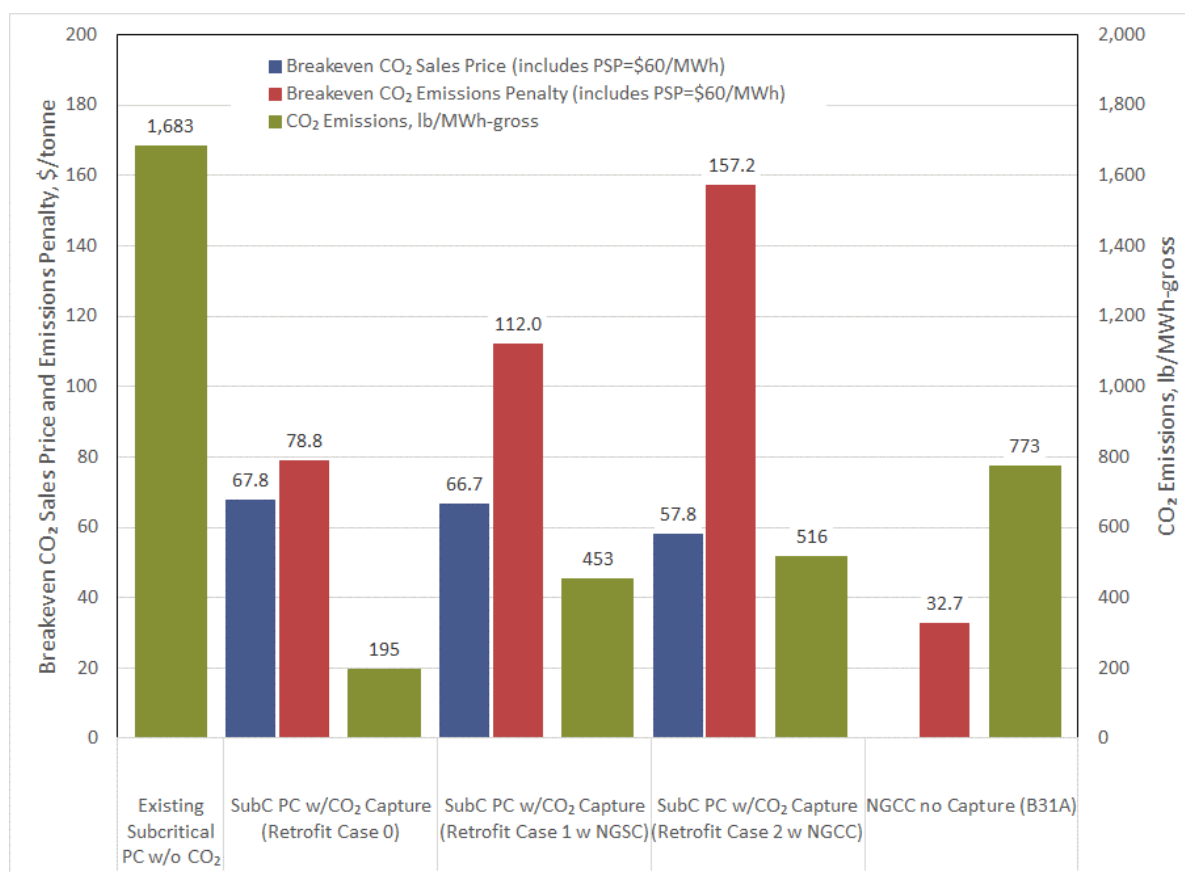
The base case in this study (Case 0 – CCS-only retrofit) shows a post-retrofit COE of \$113.6/MWh and capital cost (using TOC per post-retrofit net kW of generation as a metric) of \$2,322/kW or a total of \$987 million. The Case 0 retrofit scenario is more cost effective on a COE (\$143.5/MWh) and TOC (\$4,267/kW) basis than a 550 MW-net greenfield subcritical PC plant with CCS and identical environmental controls [3] despite the lower net plant output of 425 MW-net.

Providing additional capital to replace the lost generation through CHP auxiliary repowering improves the retrofit economics relative to Case 0. In Case 1 and Case 2, the net electrical generation is greater than the original 550 MW-net. The additional electrical generation acts to dilute the increased capital costs in the COE calculation for these cases. Inherent to the results for Case 1 and Case 2 is the avoidance of the negative economic impacts incurred by duct firing, significant T&D grid modifications, and off-design operation of the existing steam turbine. Costs associated with any of the above diminish the attractiveness of CHP repowering.

The COEs shown for cases 0, 1, and 2 in Exhibit ES-5 include retrofit contingencies that represent the added costs associated with any typical retrofit project (limited space resulting in construction premiums, insufficient laydown area, long tie-in connections, etc.) compared

to a similar baseline for greenfield costs. The base COEs are calculated assuming an RCF of 1.1 applied to the capital component of the COE. [4] Sensitivities for higher retrofit contingencies are presented above each COE breakdown bar. 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. Each of these cases would have a different configuration and site-specific retrofit contingencies; for example, the cases with no steam extraction from the existing turbine, Case 1 and Case 2, would have lower contingencies compared to the case with the increased complexity of steam extraction (Case 0). The range of COEs when varying the retrofit contingencies suggests that several of these solutions could help decrease the cost of a CO₂ capture retrofit.

The breakeven CO₂ sales price (at plant gate) and breakeven CO₂ emissions penalty relative to a fully depreciated, existing PC plant provide additional insight into the economics of PC retrofits. Exhibit ES-6 shows these values for each of the PC retrofit scenarios considered as well as the emissions for each case. The breakeven parameters are explained in more detail in Section 2.7.4. The values in Exhibit ES-6 include an annual charge/credit for the makeup/excess capacity under/over the existing plant net generation in each case at a projected sales price (PSP) for electricity of \$60/MWh. In the base case results presented, the breakeven CO₂ sales price decreases as the net power generated by each case increases due to the increase in credit for excess power sales, but the breakeven CO₂ emissions penalty increases as the net power generated increases due to the increase in uncontrolled emissions from the natural gas-fired auxiliary plants.

Exhibit ES-6. Breakeven CO₂ sales price and emissions penalties

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 co-locate the CO₂ removal process to minimize costs. This may allow for more optimal routing of steam turbine extraction steam piping in Case 0. The potential exists to reuse the existing stack, but a new stack is costed for all cases to eliminate the ducting from the new CCS retrofit to the old stack and to compare all auxiliary plant cases on a consistent basis.

CONCLUSIONS

Ultimately, the cases presented in this report demonstrate viable opportunities to improve the attractiveness of a CO₂ retrofit by using various alternatives to make up the retrofit derate. Installing alternative sources of steam and power allows for the design to minimize the piping and ducting complexity as well as increase the output of the plant. Under the right circumstances, with low natural gas prices, these combined retrofits can also lower the cost of generating electricity relative to a greenfield plant with CCS.

Specific observations and conclusions from these results include the following:

- Providing the auxiliary steam and power requirements of a retrofitted CCS facility from the existing steam turbine generator is the lowest up-front capital investment option

on an absolute dollar TOC basis including retrofit contingency (\$987 MM). However, the performance derate of the steam turbine makes this the least attractive long-term option on a COE basis (\$113.6/MWh).

- Supplying auxiliary electrical power and steam with CT-based CHP technologies can more than offset the losses in net plant output that would otherwise be incurred. In doing so, the long-term project economics are improved on a COE basis at the expense of higher up-front capital investment.
- Of the retrofit options examined, repowering a retrofitted PC plant with an NGCC CHP plant provides the most favorable long-term economics (\$77.7/MWh), driven primarily by the addition of high-efficiency, low-cost generation.

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. Recognizing the potential for future optimization of this approach, the results here suggest that small, on-site, low-carbon auxiliary plants to produce steam and power lost to CO₂ retrofits are a viable complement to amine-based CCS retrofits assuming no T&D constraints for utilizing the additional output.

1 INTRODUCTION

1.1 STUDY BACKGROUND

The power generation industry potentially has multiple carbon mitigation strategies at its disposal, including carbon dioxide (CO₂) utilization, CO₂ sequestration, increased use of renewable energy, and improved efficiency. Where each strategy is employed will be determined by regulations and plant-specific economics. Furthermore, it is likely that many plants may benefit by employing multiple strategies. For example, a plant may exhaust efficiency improvement options before proceeding to a post-combustion CO₂ capture process. One of the most promising near-term technologies for significant levels of carbon mitigation is amine-based post-combustion capture (PCC) followed by geologic sequestration.

The existing fleet of coal-fueled power plants represents nearly a century of investment and options that allow leveraging of these assets so that they may provide cost-effective carbon mitigation. However, retrofitting existing plants with new equipment required for amine-based PCC requires high auxiliary power loads for the carbon capture and compression equipment, in addition to steam demands for amine regeneration. Installing amine-based capture equipment on an existing pulverized coal (PC) plant results in a power deficit that must be overcome—especially if large-scale carbon capture, utilization, and storage (CCUS) initiatives are to succeed. There are a number of options for replacing this lost power; the purpose of this study is to advance the understanding of how these options compare to one another in terms of thermodynamic performance and economic feasibility. The original publication of this study [2] examined combustion turbine (CT) options for meeting the steam and power requirements of the carbon capture and storage (CCS) process in a scenario where exporting excess power is limited to 110 percent of the original generation. This updated version of the study examines options without a constraint on exporting excess power.

In addition to unit-level impacts (e.g., decreased export power available for sale), wide deployment of PCC systems would result in an overall decrease of aggregate capacity capable of supplying power to the grid. It is very likely that in the short term it may be most cost-effective for power generation facilities with lower capacity factors to increase power production to replenish the power lost from the grid due to its use to run CCS equipment at the retrofitted unit. 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 applicable carbon regulations.

1.2 PROJECT OBJECTIVES

This report examines multiple options to compensate for the auxiliary loads associated with operating a newly-installed, amine-based, PCC process that would have otherwise been used to generate power prior to retrofit. The focus of this study is to establish baseline performance and cost estimates incurred as a result of an integrated (steam and power) retrofit of the amine-based PCC process into the steam cycle of an existing 550 MWe subcritical PC facility and to compare two alternate plant configurations that utilize externally

supplied steam and power to meet all capture system auxiliary loads. All cases include retrofitting the existing plant with the Shell Cansolv CCS process and gas compression train detailed in the National Energy Technology Laboratory (NETL) Bituminous Baseline Report. [3]

1.3 STUDY APPROACH

Three capture system retrofit options were investigated as part of this study. One option (Case 0) is the retrofit of the capture system to an existing PC plant (described in detail in Section 4 of this report) where the capture system is “integrated” into the existing facility. In this option, all energy needs of the capture system (steam and electric power) are supplied by “extraction” from the existing plant (i.e., steam is extracted from the existing steam cycle, electricity that would otherwise be sold as product is diverted from export to the grid). The existing plant is “derated” due to the reduced net plant output and inefficiencies that result from operating the existing steam cycle with different (i.e., lower) energy flows than originally designed. As this option is to serve as the basis for comparison, no attempt is made to mitigate the derate by replacing any of the lost energy streams resulting from the retrofit.

In addition to the integrated retrofit option, two alternative plant configurations were evaluated that externally supply the required steam and power for the retrofitted capture system with natural gas (NG)-fueled combined heat and power (CHP) systems. Both alternatives are summarized here and described in detail in Section 4 of this report.

The first of these alternatives (Case 1) represents the addition of a new natural gas simple cycle (NGSC) plant where power is provided through a CT coupled to an electricity generator (combustion turbine-generator (CTG)); the required steam is generated through the recovery of heat from the turbine exhaust.^a Based on the thermodynamics of the CT, the CHP system is sized such that steam of the necessary quantities and conditions to satisfy the capture process heat demands is raised in a heat recovery steam generator (HRSG). As a result, the CT electrical output exceeds the auxiliary load of the capture plant and it is assumed that excess power can be readily exported to the grid.

The second alternative (Case 2) represents the addition of a new natural gas combined cycle (NGCC) plant where the bottoming cycle of the combined cycle is specifically designed to supply the steam demand of the capture system and the various pressure sections of the steam turbine (ST) are sized for the balance of the energy recovered from the combustion turbine exhaust gas. This alternative includes a two-on-one configuration (two CTGs and one steam turbine-generator (STG)). The addition of a second CT provides additional exhaust heat to raise high pressure (HP), intermediate pressure (IP), and low pressure (LP) steam for a subcritical Rankine bottoming cycle with process steam extractions to supply the capture process.

As a result of the significant thermal energy required by the capture process, in both alternatives the resulting power^b generated by the auxiliary CHP plant is greatly in excess of

^a Case 1 is comparable to the NETL Recovery Act: Petra Nova Parish Holdings: W. A. Parish Post-Combustion CO₂ Capture and Sequestration Project. [49]

^b Due to the discrete sizing of commercial combustion turbine offerings, a hypothetical combustion turbine having a capacity of approximately 9 percent greater than that of the General Electric (GE) state-of-the-art 2013 F-class was

the demand of the associated capture facility and more than offsets the total losses incurred in Case 0. The result is that in both alternatives the post retrofit combined capacity of the combined plant (retrofit PC plant plus new CHP plant) is greater than the pre-retrofit existing PC plant.

It should be noted that a number of simplifying assumptions underlie this analysis including but not limited to:

- NGSC plant sized such that all steam requirements could be fully met through heat recovery from the exhaust of a single CT and no duct-firing is required.
- Excess power generation could be readily accepted by existing transmission and distribution (T&D) infrastructure at the facility battery limits. New inside battery limits equipment associated with the addition of the CTGs for Case 1 and Case 2 and CTG for Case 2 are required and included in the respective analyses.
- Capture of 90% of the CO₂ in the treated stream of flue gas from the PC plant and no treatment or capture of CO₂ from the exhaust gas of the CTGs from either Case 1 or 2.

The analysis approach, including assumptions and details related to each plant configuration, are described further in the corresponding report sections.

The balance of this report is organized as follows:

- Section 2 provides the basis for technical, environmental, and cost evaluations
- Section 3 describes the existing PC plant systems
- Section 4 describes the retrofitted systems
- Section 5 provides performance and economic case results
- Section 6 provides results analysis
- Section 7 provides study conclusions
- Section 8 provides recommendations for future works

A summary of plant configurations considered in this report is presented in Exhibit 1-1.

considered for Case 1 to match the capture system steam demand. For Case 2, the NGCC design includes two GE 2013 F-class turbines.

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Exhibit 1-1. Case descriptions

Objective	Case	Existing ST Extraction	Duct Firing	CO ₂ Capture Criteria ^A	Auxiliary Plant Arrangement
Retrofit Baseline	0	As Required	None	90% from PC flue gas	N/A
Retrofit with NGSC CHP Repowering	1	None	None	90% from PC flue gas	NGSC Auxiliary Plant with a hypothetically sized CT, no carbon capture
Retrofit with NGCC CHP Repowering	2	None	None	90% from PC flue gas	NGCC Auxiliary Plant with (2x) GE 7FA CTs, no carbon capture

^AAll cases have a nominal 90 percent removal rate from the PC plant flue gas based on the total feedstock minus unburned carbon in ash. The rate of CO₂ capture from the flue gas in the Cansolv systems varies. An explanation for the difference is provided in Section 2.4.3. All cases sequester the CO₂ offsite.

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 an amine-based, PCC process to an existing PC plant firing Illinois No. 6 coal. For each of the plant configurations analyzed in this report an Aspen Plus® (Aspen) model was developed and used to generate material and energy balances, which were, in turn, used to provide a design basis for items in the major equipment list. The equipment list and material balances were used as the basis for generating the capital and operating cost estimates. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgment. Capital and operating costs were estimated by WorleyParsons based on simulation results and through scaled estimates from previous design/build projects. Ultimately, a 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 discusses the design basis common to all technologies, as well as environmental targets and cost assumptions used in the study. Technology specific design criteria are covered in subsequent sections.

2.1 SITE CHARACTERISTICS

The existing PC plant considered in this report is assumed to be located at a generic plant site in Midwestern United States, with site characteristics and ambient conditions as presented in Exhibit 2-1 and Exhibit 2-2. The ambient conditions are the same as International Organization for Standardization (ISO) conditions.

Exhibit 2-1. Site characteristics

Parameter	Value
Location	Greenfield, Midwestern U.S.
Topography	Level
Size (Pulverized Coal), acres	300
Transportation	Rail or Highway
Ash Disposal	Off-Site
Water	50% Municipal and 50% Ground Water

Exhibit 2-2. Site ambient conditions

Parameter	Value
Elevation, ft	0
Barometric Pressure, MPa (psia)	0.101 (14.696)
Average Ambient Dry Bulb Temperature, °C (°F)	15 (59)
Average Ambient Wet Bulb Temperature, °C (°F)	10.8 (51.5)
Design Ambient Relative Humidity, %	60
Cooling Water Temperature, °C (°F) ^A	15.6 (60)
Air composition based on published psychrometric data, mass %	
N ₂	75.055
O ₂	22.998
Ar	1.280
H ₂ O	0.616
CO ₂	0.050
Total	100.00

^AThe cooling water temperature is the cooling tower cooling water exit temperature. This is set to 8.5°F above ambient wet bulb conditions in ISO cases.

The land area assumes that 30 acres are occupied by the plant proper and the balance provides a buffer of approximately 0.25 mi to the fence line with sufficient unused acreage to construct an auxiliary plant for repowering purposes.

In all cases, it was assumed that the PC plant steam turbine is enclosed in a turbine building and the boiler is enclosed in a boiler building. The CTs in the auxiliary plants are not enclosed.

The following design parameters are considered site-specific and are not quantified for this report. 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
- Local code height requirements
- Noise regulations – Impact on site and surrounding area
- Other localized environmental concerns
- Weather delays

2.2 COAL CHARACTERISTICS

The design coal is Illinois No. 6 with characteristics presented in Exhibit 2-3. The coal properties are from the January 2012 revision of the Quality Guidelines for Energy System Studies (QGESS) document "Detailed Coal Specifications." [5]

Exhibit 2-3. Design coal

Rank	Bituminous	
Seam	Illinois No. 6 (Herrin)	
Source	Old Ben Mine	
Proximate Analysis (weight %) ^A		
	As Received	Dry
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	100.00	100.00
Sulfur	2.51	2.82
HHV, kJ/kg (Btu/lb)	27,113 (11,666)	30,506 (13,126)
LHV, Btu/lb (Btu/lb)	26,151 (11,252)	29,544 (12,712)
Ultimate Analysis (weight %)		
	As Received	Dry
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen ^B	6.88	7.75
Total	100.00	100.00

^AThe proximate analysis assumes sulfur as volatile matter.

^BBy difference.

The Power Systems Financial Model (PSFM) was used to derive the capital charge factors (CCFs) for this report. [6] The PSFM requires that all cost inputs have a consistent cost-year basis. Because the capital and operating cost estimates are in June 2011 dollars, the fuel costs must also be in June 2011 dollars.

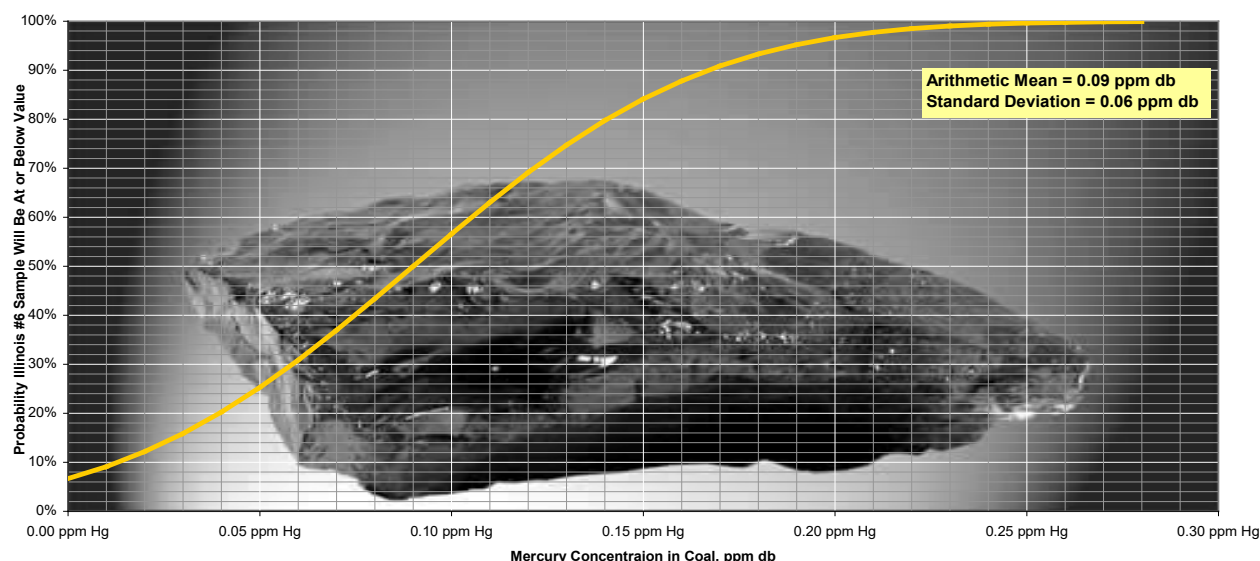
Assumed fuel price is \$2.78/GJ (\$2.94/MMBtu) for Illinois No. 6 coal, on a higher heating value (HHV) basis, delivered to the Midwest, and in 2011 United States (U.S.) dollars.^c

The mercury content of 34 samples of Illinois No. 6 coal has an arithmetic mean value of 0.09 ppmwd with standard deviation of 0.06 based on coal samples shipped by Illinois mines. [7] Hence, as illustrated in Exhibit 2-4, there is a 50 percent probability that the mercury

^c As specified in the November 2012 QGESS document on "Fuel Prices for Selected Feedstocks in NETL Studies." [50]

content in the Illinois No. 6 coal would not exceed 0.09 ppmwd. The coal mercury content for this report was assumed to be 0.15 ppmwd for all PC cases, which corresponds to the mean plus one standard deviation and encompasses about 84 percent of the samples. It was further assumed that all the coal mercury (Hg) enters the gas phase and none leaves with the bottom ash. [8]

Exhibit 2-4. Probability distribution of mercury concentration in the Illinois No. 6 coal



2.3 NATURAL GAS CHARACTERISTICS

Natural gas is utilized as the fuel in the NGSC and NGCC CHP auxiliary plants in Case 1 and Case 2, and its composition is presented in Exhibit 2-5. The natural gas properties are from the January 2012 revision of the QGESS document "Specification for Selected Feedstocks" [9] with the addition of methanethiol (mercaptan). [10]

Assumed fuel price is \$5.81/GJ (\$6.13/MMBtu) for natural gas, on an HHV basis, delivered to the Midwest, and in 2011 U.S. dollars.^d

^d As specified in the November 2012 QGESS document on "Fuel Prices for Selected Feedstocks in NETL Studies." [50]

Exhibit 2-5. Natural gas composition

Component		Volume Percentage
Methane	CH ₄	93.1
Ethane	C ₂ H ₆	3.2
Propane	C ₃ H ₈	0.7
<i>n</i> -Butane	C ₄ H ₁₀	0.4
Carbon Dioxide	CO ₂	1.0
Nitrogen	N ₂	1.6
Methanethiol ^A	CH ₄ S	5.75x10 ⁻⁶
	Total	100.00
	LHV	HHV
kJ/kg (Btu/lb)	47,454 (20,410)	52,581 (22,600)
MJ/scm (Btu/scf)	34.71 (932)	38.46 (1,032)

^AThe sulfur content of natural gas is primarily composed of added methanethiol (mercaptan (CH₄S)) with trace levels of hydrogen sulfide (H₂S). [10]

Note: Fuel composition is normalized and heating values are calculated.

2.4 ENVIRONMENTAL TARGETS

Environmental targets were established for each of the technologies as follows:

- Mercury (Hg) and hydrochloric acid (HCl) limits were set by the March 2013 update to the Utility Mercury and Air Toxics Standards (MATS) for PC technologies. [11], [12], [13]
- Particulate matter (PM), sulfur dioxide (SO₂), and nitrogen oxide (NO_x) limits were set by the February 2013 update to the New Source Performance Standards (NSPS) for PC and NGCC technologies. [13], [14]

The regulations divide the coal types into low rank and non-low rank based on their heating value. Coals with an HHV of greater than 8,300 Btu per pound (Btu/lb) on a moist, mineral-matter free basis are considered non-low rank. Therefore, Illinois No. 6 coal, with an HHV (moist, mineral-matter free) of 12,900 Btu/lb, is considered a non-low rank coal.

The emission limits imposed by MATS and NSPS that apply to each technology in this report are provided in Exhibit 2-6.

Exhibit 2-6. MATS and NSPS emission limits for PM, HCl, SO₂, NO_x, and Hg

Pollutant ^A	PC (lb/MWh-gross)	NGCC (lb/MWh-gross)
SO ₂	1.00	0.90
NO _x	0.70	0.43
PM (Filterable)	0.09	N/A
Hg	3x10 ⁻⁶	N/A
HCl	0.010	N/A

^ACO emissions may be considered in future revisions of this report, if necessary.

These new regulations apply to PC and NGCC technologies that begin construction after May 3, 2011. Furthermore, these regulations state that: [13], [15]

Fossil fuel is defined as natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Electric utility steam generating units (EGU) are defined as a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Fossil fuel-fired means an EGU that is capable of combusting more than 25 MW of fossil fuels. To be capable of combusting fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; or oil storage facilities).

Coal-fired electric utility steam generating units are defined as an EGU and meet the definition of "fossil fuel-fired," which is that it burns coal for more than 10 percent of the average annual heat input during any three consecutive calendar years or for more than 15 percent of the annual heat input during any one calendar year.

Unit designed for low-rank virgin coal subcategory is defined as any coal-fired EGU that is designed to burn, and that is burning, non-agglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed for coal $\geq 8,300$ Btu/lb subcategory is defined as any coal-fired EGU that is not a coal-fired EGU in the "unit designed for low rank virgin coal" subcategory.

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 best available control technology (BACT) determinations for new sources being in areas meeting ambient air quality standards (attainment areas), or Lowest Achievable Emission Rate (LAER) technology for sources being in areas not meeting ambient air quality standards (non-attainment areas). Environmental area designation varies by county and can be established only for a specific site location. Based on the Environmental Protection Agency (EPA) Green Book Non-attainment Area Map relatively few areas in Midwestern United States are classified as "non-attainment," so the plant site for this report was assumed to be in an attainment area. [14]

In addition to federal regulations, state and local jurisdictions can impose even more stringent regulations on a new facility. If each configuration described in the three cases considered in this report were to be subject to the normal permitting process it is possible (and perhaps likely) that emissions limits would be more aggressive than the applicable NSPS. However, for

the objective of this report, the applicable NSPS is viewed to be a reasonable assumption for setting plant environmental control system attributes and is a consistent approach with similar studies, both internal and external to NETL.

2.4.1 Pulverized Coal

This study considers an existing subcritical PC unit that is assumed to include emission control technologies that meet current NSPS for all cases. It is further assumed that because the pre-retrofit is fully compliant with current NSPS, any modifications to the existing PC unit would not affect its permitting status (i.e., even if modifications would subject the existing PC plant to the NSR or PSD processes, no additional control technologies for criteria or hazardous air pollutants would be required). Exhibit 2-7 provides the emissions limits for PC plants as well as a summary of the control technology utilized to satisfy the limits.

Exhibit 2-7. Environmental targets for PC cases

Pollutant	PC (lb/MWh-gross)	Control Technology
SO ₂	1.00	Wet limestone scrubber
NO _x	0.70	Low NO _x burners, overfire air and SCR
PM (Filterable)	0.09	Fabric filter
Hg	3x10 ⁻⁶	Co-benefit capture, dry sorbent injection ^A , activated carbon injection
HCl	0.010	SO ₂ surrogate ^B

^ALimits sulfur trioxide (SO₃) levels and their detrimental effects on activated carbon injection (see Section 3.5).

^BSO₂ may be utilized as a surrogate for HCl measurement if the EGU utilizes wet FGD. [16]

This study did not seek to quantify the removal efficiency of non-CO₂ or SO₂ pollutants from the addition of downstream flue gas cleanup (e.g., Cansolv). Additional information from Shell Cansolv is required in order to model changes in lb/MWh-gross emission rates of these pollutants. As a consequence, it is assumed that the pre-retrofit environmental performance for these pollutants is maintained after the retrofit.

For the existing plant, it was assumed that low NO_x burners (LNB) and staged overfire air (OFA) would limit NO_x emissions to 0.5 lb/MMBtu and that selective catalytic reduction (SCR) technology would be 83-85 percent efficient. By adjusting the ammonia flow rate in the SCR, the NO_x emissions limit was able to be met exactly. The Cansolv process is expected to remove additional NO₂ from the flue gas, but the exact amount was not quantified in this study, so the pre-retrofit environmental NO_x emissions is assumed to be maintained after the retrofit.

For the existing plant, the wet limestone scrubber was assumed to be 98 percent efficient, which results in SO₂ emissions below the NSPS SO₂ limit even for the comparatively high sulfur concentration of the Illinois No. 6 coal. Current technology allows wet flue gas desulfurization (FGD) removal efficiencies in excess of 99 percent, but based on NSPS requirements, such high removal efficiency is not necessary. After retrofit, the Cansolv

process removes the remaining SO₂ from the flue gas via the pre-scrubber, effectively reducing the SO₂ emissions to 0 lb/MWe.

For the existing plant, the fabric filter was assumed to be capable of achieving an efficiency of greater than 99.9 percent. As this design efficiency was approximately 99.9 percent for each case, the modeled efficiency was estimated in order to meet the PM emissions limit exactly, but the actual emission level is assumed to be lower. As a consequence, it is assumed that the pre-retrofit environmental performance for particulate removal is maintained even at the lower gross MWe generation value after the retrofit.

For the existing plant, the mercury removal efficiency required to meet the emission limit is approximately 97 percent in each case. It was assumed that the total mercury removal rate resulting from the combination of pollution control technologies used (SCR, dry sorbent injection (DSI), activated carbon injection (ACI), fabric filters, and FGD) would meet the limit exactly. DSI is required to limit the effects of SO₃ on Hg capture due to the high sulfur content of the coal in this study. Section 3.5 provides a detailed discussion regarding mercury removal and the various systems involved. The impact of the Cansolv CO₂ removal system on the mercury emission level would require additional information and was considered beyond the scope of this study, and the emission values were assumed to continue to meet the limit after retrofit.

2.4.2 Combustion Turbine

Due to the size of the combustion turbines and the associated electricity generated, this study assumes that the NG-fueled CHP auxiliary plants for both Case 1 and Case 2 meet the definition of an EGU and the applicable NSPS for new NG-fueled EGUs are required to be met. Exhibit 2-8 provides the emissions limits for combustion turbine plants as well as a summary of the control technology utilized to satisfy the limits.

Exhibit 2-8. Environmental targets for CT cases

Pollutant	CT (lb/MWh-gross)	Control Technology
SO ₂	0.90	Low sulfur content fuel
NO _x	0.43	Dry low NO _x burners and SCR
PM (Filterable)	N/A	N/A
Hg	N/A	N/A
HCl	N/A	N/A

The cases including auxiliary CHP plants were designed to achieve approximately 1.0 ppmvd NO_x emissions (referenced to 15 percent oxygen (O₂)) through the use of a dry low NO_x (DLN) burner in the CTG—the DLN burners are a low NO_x design and reduce the emissions to about 9 ppmvd [17] (assumed to be approximately 98 percent nitrogen oxide (NO) and referenced to 15 percent O₂)—and an SCR. [18]

While a state-of-the-art 2013 F-class CT alone produces NO_x emissions below the limit shown in Exhibit 2-8, an SCR was included as it is routinely required as BACT for NG-fueled EGUs under EPA's PSD program. The SCR system is designed for 90 percent NO reduction while firing natural gas.

The total sulfur content of natural gas is typically limited by contract terms and industry practice to between 0.25 and 1.00 gr/100 scf with the average total sulfur content being 0.34 gr/100 scf. [10] For the purpose of this report, the natural gas was assumed to contain the average value of total sulfur of 0.34 gr/100 scf (4.71×10^{-4} lb-S/MMBtu). It was also assumed that the added mercaptan (CH₄S) was the sole contributor of sulfur to the natural gas. The mercaptan concentration of the natural gas was provided in Exhibit 2-5 as 5.75×10^{-6} mol% (7.06×10^{-4} lb-CH₄S/MMBtu).

If the natural gas contained 1.00 gr-S/100 scf, the SO₂ emissions for the non-capture case would be 0.018 lb/MWh-gross.

The pipeline natural gas was assumed to contain no PM, Hg, or HCl, resulting in zero emissions.

2.4.3 Carbon Dioxide

On August 3, 2015, the EPA finalized carbon pollution standards for new, modified, and reconstructed power plants under the authority of the Clean Air Act Section 111(b). The regulations propose emission limits of 1,000 lb CO₂/MW-gross (1,030 lb CO₂/MWh-net) for base load and 120 lb CO₂/MMBtu for non-base load NG-fired units. Under the final regulation, determination must be made whether newly constructed CHP stationary combustion turbines are classified as base load or non-base load units considering their operation relative to the EPA defined "electric sales threshold" as mentioned in the rule. [19]

Each case assumes that CO₂ capture is only applied to the flue gas of the existing coal-fired PC plant. The CO₂ capture plant design treats 100 percent of the flue gas exiting the FGD system and achieves 90 percent capture of the CO₂ in the treated stream. For the carbon mass balance, the study assumes that all the combusted carbon in the flue gas exiting the PC boiler is CO₂ and accounts for other processes where carbon dioxide is generated (i.e., CO₂ evolution from the FGD system and activated carbon added for mercury removal). Therefore, the net result for each case is a 90 percent reduction in the CO₂ emission rate (mass/time) compared to the pre-retrofit (uncontrolled) existing coal-fired PC plant. No CO₂ capture is applied to the exhaust of the NG-fueled CHP plants in either of the alternative cases. Emission results reported in Section 5 include uncaptured CO₂ emissions exiting the PC plant stack as well as uncontrolled CO₂ emissions exiting the auxiliary plant stack.

2.5 CAPACITY FACTOR

2.5.1 Capacity Factor Assumptions

Availability is the percent of time during a specific period that a generating unit is capable of producing electricity. This report assumes that the pre-retrofit plant is dispatched any time it is available and is capable of generating the nameplate capacity when online. Therefore, the

capacity factor (CF) and availability are equal. It is assumed that the retrofitted plant and associated auxiliary plant in each case in this study would be dispatched in the same manner. The operating period selected is also important. The calculations assume that the capacity factor and availability are constant over the life of the plant, but actual operation may require that a plant have a higher peak availability to counter lower availability in the first several years of operation.

2.5.2 Existing Plant Data

The North American Electric Reliability Council (NERC) Generating Availability Data System [20] (GADS) provides information on existing plants (e.g., Generating Analysis Reports, Generating Availability Reports, Generating Unit Statistical Brochure, and Historical Availability Statistics). These data for coal plants (e.g., PC technology) include average availability and plant capacity factor data, by fuel type and plant capacity.

The GADS database provides data on many plant operating characteristics. Three metrics are used in this report to evaluate existing plant availability and capacity factors: net capacity factor (NCF), availability factor (AF), and equivalent availability factor (EAF). The metrics can be defined by the following equations.

$$NCF = \frac{NAG}{PH * \left(\frac{GMC - CU}{Aux} \right)}$$

Where:

NAG – Net actual generation

PH – Number of hours a unit was in the active state

GMC – Gross maximum capacity

CU – Capacity utilized for unit station service

Aux – Auxiliaries

$$AF = \frac{PH - (POH + FOH + MOH)}{PH}$$

Where:

POH – Planned outage hours

FOH – Forced outage hours

MOH – Maintenance outage hours

$$EAF = \frac{(PH - (POH + FOH + MOH)) - (EUDH + EPDH + ESEDH)}{PH}$$

Where:

EUDH – Equivalent un-planned derated hours

EPDH – Equivalent planned derated hours

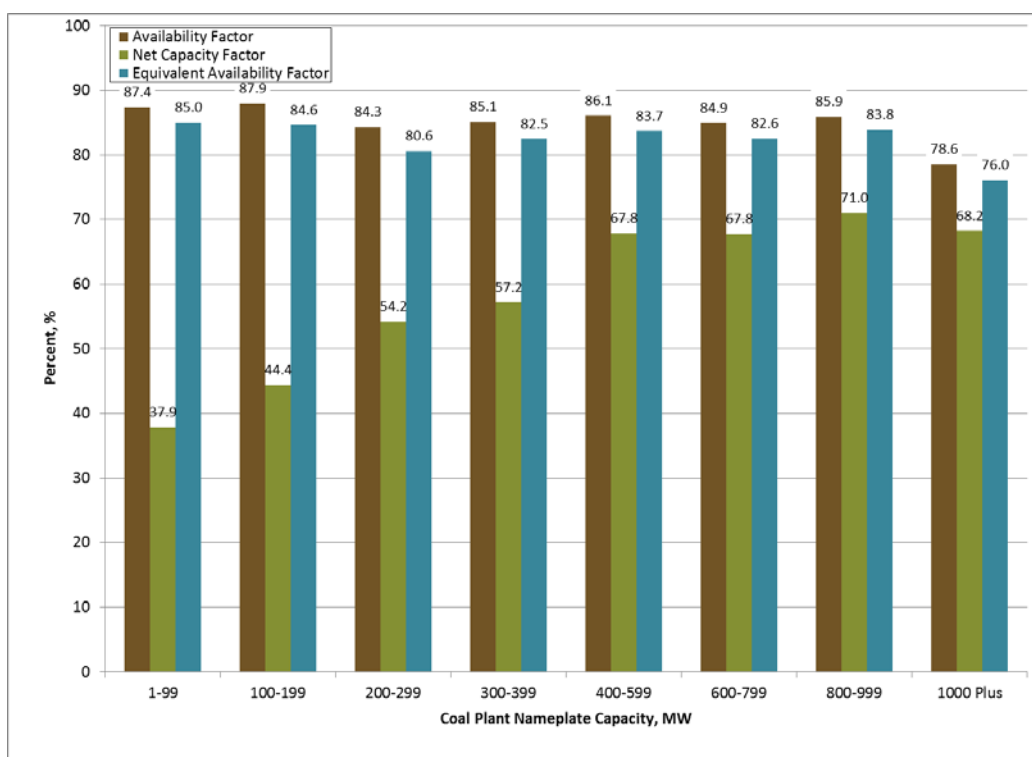
ESEDH – Equivalent seasonal derated hours

The EAF is essentially a measure of the plant CF, 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 this report's definition of CF.

2.5.3 Capacity Factor for Coal Units Without Carbon Capture

Exhibit 2-9 presents GADS coal unit availability and capacity factor data for generating plants in 2011. In order to provide perspective on these metrics over time, Exhibit 2-10 presents the same metrics averaged over the period 2007-2011. The number of generating units included in the 2011 data is presented in Exhibit 2-11.

Exhibit 2-9. Coal plant availability and capacity factor data for units reporting in 2011



ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Exhibit 2-10. Coal plant availability and CF average data over the period 2007-2011

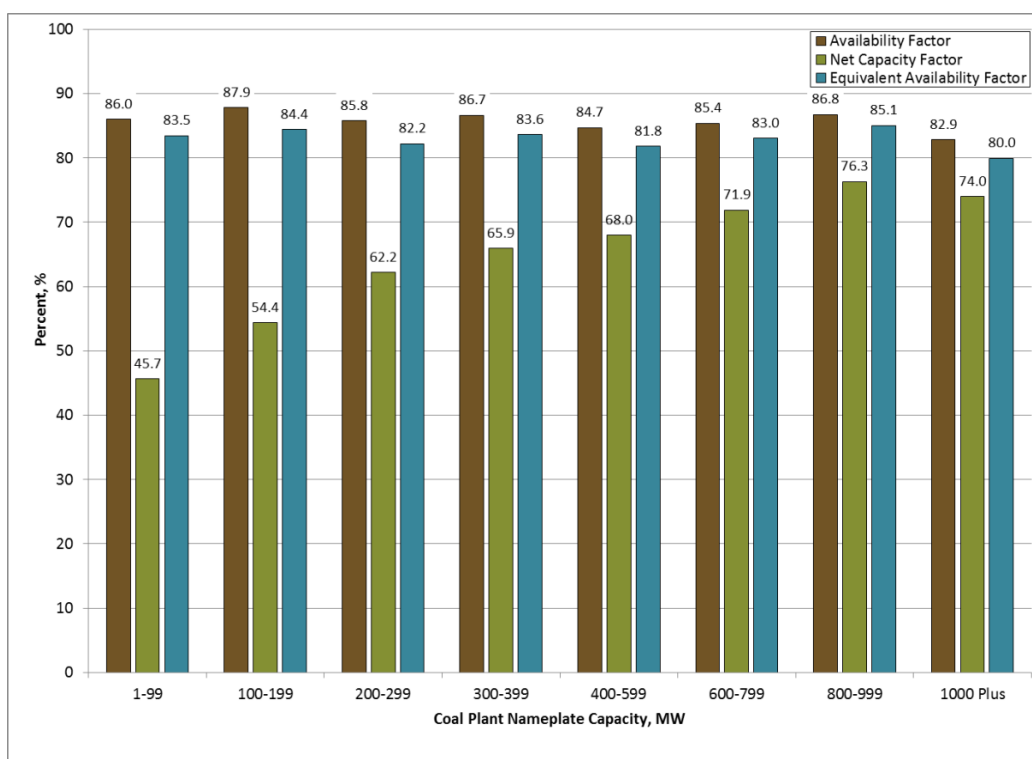
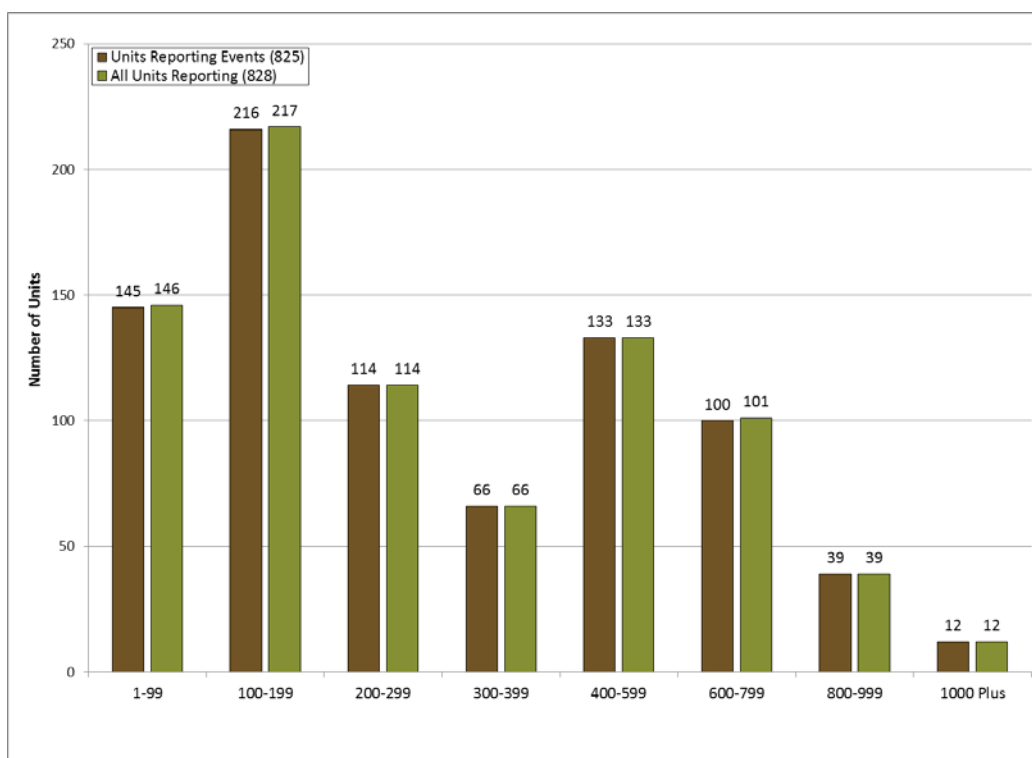


Exhibit 2-11. Number of coal units included in the 2011 data

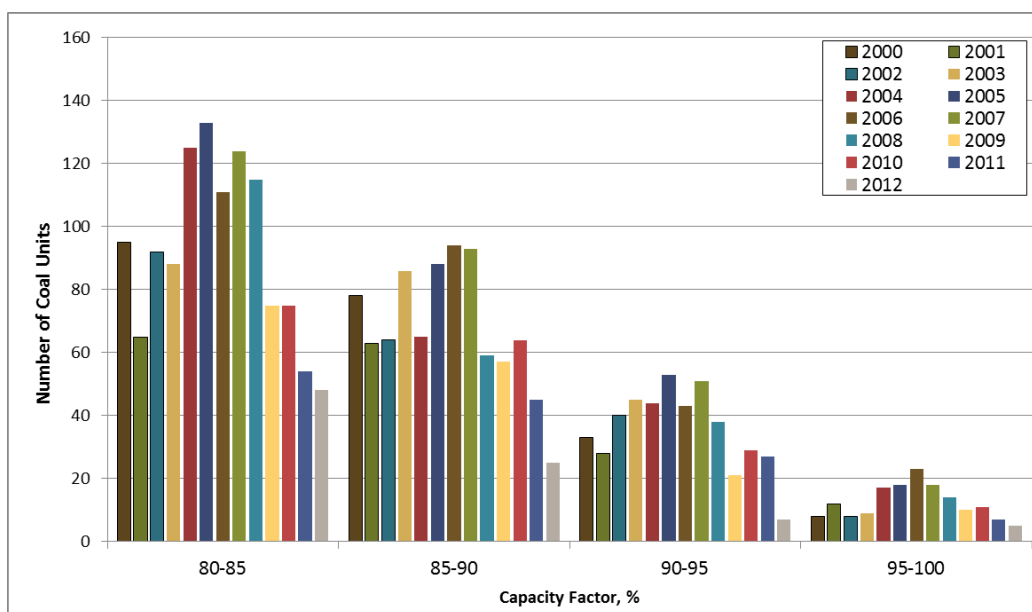


The net output of the pre-retrofit PC plant is 550 MW. The average EAF for coal-fired plants in the 400-599 MW size range was 83.7 percent in 2011 and averaged 81.8 percent from 2007-2011. The average net capacity factor for these units is less than 70 percent, which reflects the demand and how the plants were dispatched.

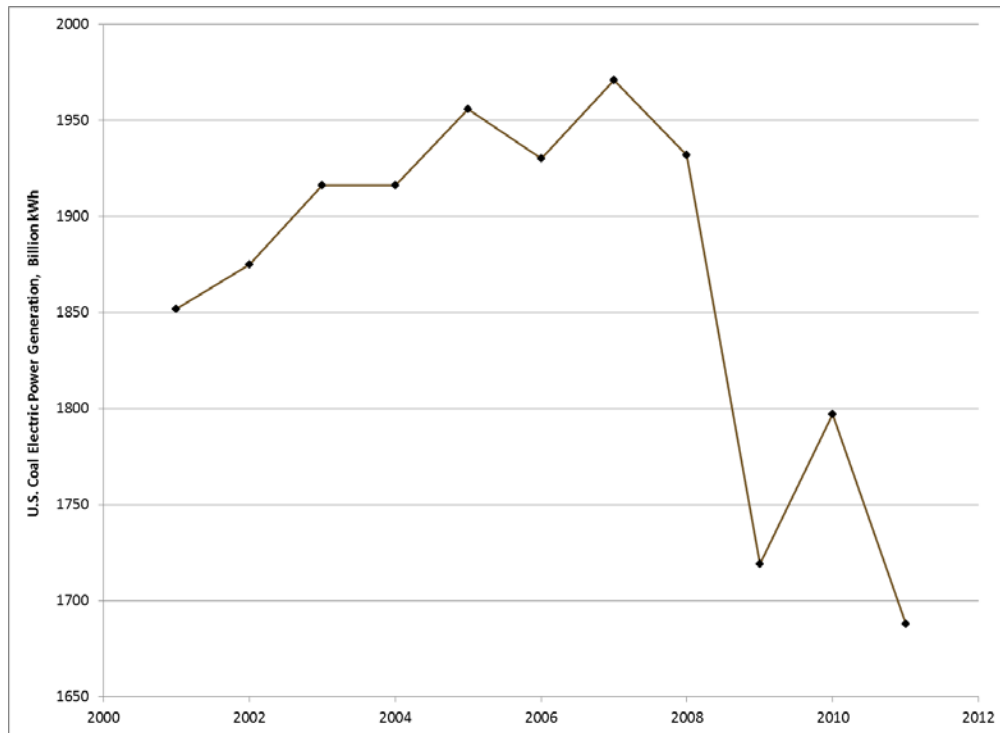
While the assumption for this report is that a unit will be dispatched when it is available, it is useful to have perspective on the ability of coal units to achieve high capacity factors. The Ventyx Velocity Suite [21] database provides data on individual unit performance.

Exhibit 2-12 presents data on the number of units that achieved greater than 80 percent capacity factor in a given year for each year from 2000 through 2012.

Exhibit 2-12. Number of coal units reporting capacity factors greater than 80%



The 2006-2007 peak in the number of units operating with a given capacity factor is related to the U.S. coal electricity demand. Exhibit 2-13 presents Energy Information Administration (EIA) data [22] on electricity generation that shows a peak in 2007.

Exhibit 2-13. U.S. coal electricity power generation

The GADS data show an average coal unit availability greater than 80 percent and the individual unit data from Ventyx Velocity show that up to 162 coal units have operated in a given year with capacity factors greater than 85 percent. The current study costs are based on mature plant technology. Based on a review of the available data, an 85 percent capacity factor is selected for the PC coal units.

2.5.4 Capacity Factor for Natural Gas Auxiliary Plants

Similar data as used for PC plants were reviewed for NGCC plants. The GADS database shows an average availability of 87.8 percent for 160 combined cycle plants in 2011. The data over the last ten years show an availability of ~ 90 percent for each year. The average availability from 1980 to 1995 ranged from 80-90 percent. Based on this data and the fact that the CHP plants are designed to provide the auxiliary power and steam for the capture system, an 85 percent capacity factor is selected for the natural gas auxiliary plants to match that of the retrofitted PC plant.

2.5.5 Capacity Factor for Plants with Carbon Capture

The addition of carbon capture adds extra equipment to the power plant. Preliminary reliability analyses show small reductions in reliability if the reliability of the base plant components is kept constant. [3] A solvent-based carbon capture technology is used in this report in all cases. The capture and CO₂ compression technologies have commercial operating experience with demonstrated ability for high reliability. Given the use of commercial technology, albeit at smaller scale, the assumption is made that the capacity

factors for a given plant with and without carbon capture are the same. Thus, the capacity factor for retrofitted plants with capture is 85 percent.

In their Annual Energy Outlook 2013, EIA projected a capacity factor of 85 percent for new advanced coal with capture and 87 percent for new advanced coal without capture.

2.6 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 feedwater (BFW) blowdown and condensate from flue gas (in CO₂ 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 municipal 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 from which it was withdrawn.

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 all purposes, such as cooling tower makeup, BFW makeup, ash handling 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 was assumed to be treated and recycled to the cooling tower. The cooling tower blowdown was 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 utilize mechanical draft, evaporative cooling towers, and all process blowdown streams were assumed to be treated and recycled to the cooling towers. The design ambient wet bulb temperature of 11°C (51.5°F) (Exhibit 2-1 and Exhibit 2-2) 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: [23]

- Evaporative losses of 0.8 percent of the circulating water flow rate per 5.6°C (10°F) of range
- Drift losses of 0.001 percent of the circulating water flow rate
- Blowdown losses (BDL) were calculated as follows:

$$BDL = \frac{EL}{CC - 1}$$

Where:

EL – Evaporative Losses

CC – Cycles of concentration

The cycles of concentration are a measure of water quality and a mid-range value of four was chosen for this report.

The water balances presented in subsequent sections are representative of the retrofitted PC plant and auxiliary plant combined. They 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.

2.7 COST ESTIMATING METHODOLOGY

Detailed information pertaining to topics such as contracting strategy; engineering, procurement, and construction (EPC) contractor services; estimation of capital cost contingencies; owner's costs; cost estimate scope; economic assumptions; finance structures; and cost of electricity, are available in the April 2011 revision of the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance." [24] Select portions are repeated in this report for completeness.

Capital Costs:

The capital cost estimates documented in this report reflect an uncertainty range of -15 percent/+30 percent, consistent with AACE International (AACE) Class 4 cost estimates (i.e., feasibility study) [24, 25, 26], based on the level of engineering design performed. In all cases, the report intends to represent the next commercial offering, and relies on vendor cost estimates for component technologies. It also applies process contingencies at the appropriate subsystem levels in an attempt to account for expected but undefined costs (a challenge for emerging technologies).

Costs of Mature Technologies and Designs:

The cost estimates for plant designs that only contain fully mature technologies, which have been widely deployed at commercial scale (e.g., PC and combustion turbine-based power plants without CO₂ capture), reflect nth-of-a-kind (NOAK) on the technology commercialization maturity spectrum. The costs of such plants have dropped over time due to learning by doing and risk reduction benefits that result from serial deployments as well as from continuing research and development.

Costs of Emerging Technologies and Designs:

The cost estimates for plant designs that include technologies that are not yet fully mature (e.g., any plant with CO₂ capture) use the same cost estimating methodology as for the mature plant designs, which does not fully account for the unique cost premiums associated with the initial, complex integrations of emerging technologies in a commercial application. Thus, it is anticipated that initial deployments of the capture plants may incur costs higher than those reflected within this report.

Other Factors:

Actual reported project costs for all the plant types are also expected to deviate from the cost estimates in this report due to project- and site-specific considerations (e.g., contracting strategy, local labor costs, seismic conditions, water quality, financing parameters, local environmental concerns, and weather delays) that may make construction costlier. Such variations are not captured by the reported cost uncertainty.

Future Cost Trends:

Continuing research, development, and demonstration (RD&D) is expected to result in designs that are more advanced than those assessed by this report, leading to costs that are lower than those estimated herein.

2.7.1 Capital Costs

As illustrated in Exhibit 2-14, this report defines capital cost at five levels: BEC, EPCC, TPC, TOC, and TASC. BEC, EPCC, TPC, and TOC are overnight costs and are expressed in base-year dollars. The base year is the first year of capital expenditure.

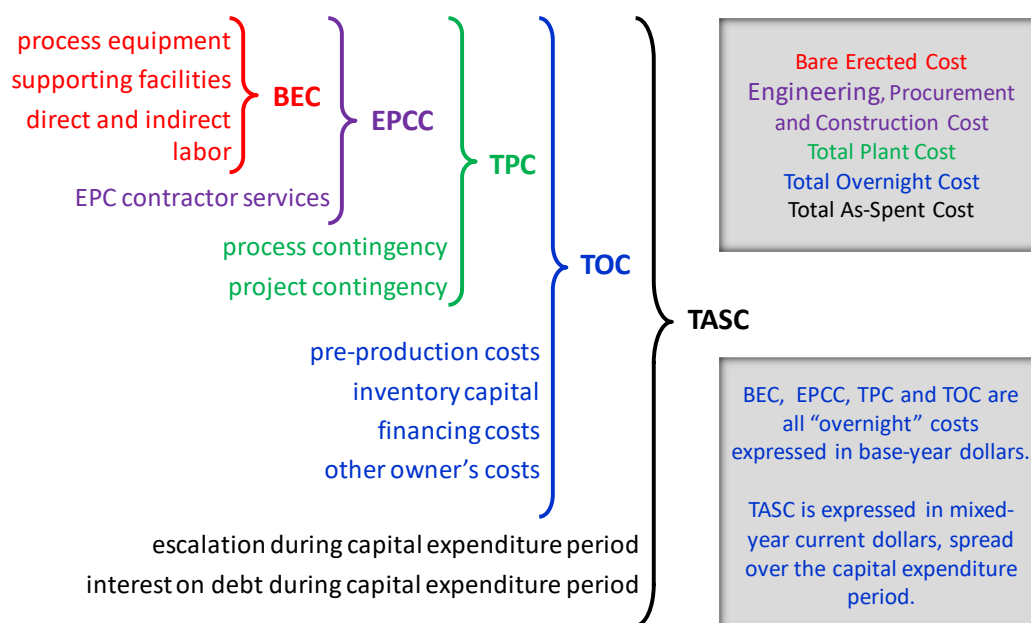
The Bare Erected Cost (BEC) comprises the cost of process equipment, on-site facilities, and infrastructure that support the plant (e.g., shops, offices, labs, and roads), and the direct and indirect labor required for its construction and/or installation. The cost of EPC services and contingencies are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

The Engineering, Procurement and Construction Cost (EPCC) comprises the BEC plus the cost of services provided by the EPC contractor. 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. EPCC is an overnight cost expressed in base-year dollars.

The Total Plant Cost (TPC) comprises the EPCC plus project and process contingencies. TPC is an overnight cost expressed in base-year dollars.

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

The Total As-Spent Cost (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, which is assumed in most NETL studies to last five years for coal plants and three years for natural gas plants. In the case of PC plant retrofits, the period of construction is assumed to be three years.

Exhibit 2-14. Capital cost levels and their elements

2.7.1.1 Cost Estimate Basis and Classification

The TPC and operation and maintenance (O&M) costs for each of the cases in the study are scaled cost estimates using cost references provided by WorleyParsons from an in-house database and conceptual estimating models. The reference costs were calibrated using a combination of adjusted vendor-furnished and actual cost data from recent design projects.

2.7.1.2 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 in the specific system account. This would not be the case had a facility, area, or commodity account structure been chosen instead.

2.7.1.3 Estimate Scope

The capital cost estimates represent the complete construction and operation of retrofitted CCS and auxiliary CHP facilities for an existing PC power plant located 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. For all cases evaluated, it is assumed that the existing plant is fully depreciated and there are no ongoing capital costs for any plant components other than those required to facilitate the retrofit of the different configurations. Systems associated with the existing PC plant that do not require modification are listed in the individual plant cost detail tables but have no associated costs. However, the costs associated with continuing operations of the existing plant (overhead, labor, maintenance materials, consumables, fuels, etc.) are included in developing the COE for the retrofitted plant.

Costs associated with pipeline transport of the captured CO₂ and storage site infrastructure (transport and storage (T&S)) are not included in the reported capital cost or O&M costs, but are combined into a single, separate component of COE. Section 4 describes in greater detail the scope of capital requirements considered for each case with a summary provided in Exhibit 4-1. More detailed descriptions of each of the items is provided in the sections referenced within the table. Specific costs associated with the individual sub-accounts identified in Exhibit 4-1 can be found in the capital cost estimate sheets for the corresponding cases presented in Section 5.

2.7.1.4 Capital Cost Assumptions

The reference costs used to develop the capital cost estimates for each plant were developed using WorleyParsons in-house database and conceptual estimating models for each of the specific technologies. This database and the respective models are maintained by WorleyParsons as part of a commercial power plant design base of experience for similar equipment in the company's range of power and process projects. A reference bottom-up estimate for each major component provides the basis for the estimating models.

Other key estimate considerations include the following:

- Labor costs are based on Midwest, Merit Shop. The estimating models are based on U.S. Gulf Coast and the labor has been factored to Midwest. The basis for the factors is the PAS, Inc. (PAS) "Merit Shop Wage & Benefit Survey," which is published annually. Based on the data provided in PAS, WorleyParsons used the weighted average payroll plus fringe rate for a standard craft distribution as developed for the estimating models. PAS presents information for eight separate regions. For this report, Region 5 (IL, IN, MI, MN, OH, and WI) was selected.
- 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 diem allowances or bonuses have been included to attract craft labor. While not included, 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.
- A retrofit contingency factor of 1.1 is applied to the TOC within the COE calculations in each case to account for site-specific uncertainties, which cannot be directly accounted for in the capital cost estimates. [4] The factor was calculated as a weighted average retrofit TPC premium using the high contingency values applied to greenfield equipment costs scaled for retrofitting to an existing subcritical PC plant. [4]
- 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.

- Engineering and Construction Management are estimated at 8-10 percent of BEC. These costs consist of all home office engineering and procurement services as well as field construction management costs. Site staffing generally includes a construction manager, resident engineer, scheduler, and personnel for project controls, document control, materials management, site safety, and field inspection.

2.7.1.5 Price Fluctuations

While developing the reference cost estimates, the prices of equipment and bulk materials fluctuated substantially. Some reference quotes pre-dated the 2011 year cost basis while others were received post-2011. All vendor quotes used to develop these reference estimates were adjusted to June 2011 dollars accounting for the price fluctuations. Price indices, e.g., the Chemical Engineering Plant Cost Index [27] and the Gross Domestic Product Chain-type Price Index [28], were used as needed for these adjustments. While these overall indices are nearly constant, it should be noted that the cost of individual equipment types may still deviate from the June 2011 reference point.

2.7.1.6 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.

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.

2.7.1.7 Process Contingency

The following process contingency was applied to the estimates in this report:

- Cansolv CO₂ Removal System – 20 percent on all cases – PCC process unproven at commercial scale for power plant applications
- Steam Piping – 10 percent for Case 0 – unanticipated process issues from the integration between the steam turbine and Cansolv system
- Instrumentation and Controls – 5 percent on the PC capture Case 0 – integration issues

2.7.1.8 Owner's Costs

One example of what could be included in the owner's costs are switch yard costs. Switch yard costs are dependent on voltage, configuration, number of breakers, layout, and air-insulated versus gas-insulated. As a rule of thumb, a 345-kV switchyard (air-insulated, ring bus) would cost roughly \$850,000 per breaker.

Additional details and explanation of owner's costs are available in the April 2011 revision of the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance." [24]

2.7.2 Operation and Maintenance Costs

The production costs, or O&M costs, pertain to those charges associated with operating and maintaining the retrofitted power plants over their expected life. The O&M costs included in this report reflect the summation of ongoing O&M costs associated with the continual operation of the PC plant prior to retrofit and the additional O&M costs incurred after retrofit. These costs include the following:

- Operating labor
- Maintenance – material and labor
- Administrative and support labor
- Consumables
- Fuel
- Waste disposal
- Co-product or by-product credit (i.e., 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. Taxes and insurance are included as fixed O&M costs, totaling two percent of the TPC.

2.7.2.1 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 \$39.70/hour. The associated labor burden is estimated at 30 percent of the base labor rate.

2.7.2.2 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.

2.7.2.3 Administrative and Support Labor

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

2.7.2.4 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 and sorbent 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, which are included with the equipment pricing in the capital cost.

2.7.2.5 Waste Disposal

Waste quantities and disposal costs were determined/evaluated similarly to the consumables. In this report, fly ash and bottom ash from the PC plant are considered a waste with a disposal cost of \$27.80/tonne (\$25.11/ton).

2.7.2.6 Co-Products and By-Products

By-product quantities were also determined similarly to the consumables. However, due to the variable marketability of these by-products, specifically gypsum and sulfur, no credit was taken for their potential salable 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 if added capital should be included in the plant costs to produce a particular co-product. Ash is a potential by-product in certain markets; however, due to the activated carbon injection in the PC plant, the fly ash may not be marketable. As stated above, the ash is considered a waste in this report with a concomitant disposal cost.

2.7.3 CO₂ Transport and Storage

The cost of CO₂ T&S in a deep saline formation is estimated using the Fossil Energy (FE)/NETL CO₂ Transport Cost Model and the FE/NETL CO₂ Saline Storage Cost Model. Additional detail on development of these costs is available in the May 2014 revision of the QGESS document "Carbon Dioxide Transport and Storage Costs in NETL Studies." [29]

T&S costs are reported as first-year costs in \$/tonne of CO₂, increasing at a nominal rate of 3 percent per year, consistent with the general inflation rate assumed in NETL's energy system studies. From the perspective of the CO₂ source (e.g., a power plant or other energy conversion facility), these costs are treated as a disposal cost for each tonne of CO₂ captured during the assumed 30-year operational period. From the pipeline and storage site's perspective, this cost represents the first-year break-even price that must be charged across the 30-year operational period to cover all costs and provide the required internal rate of return on equity (IRROE). All costs are reported in 2011 dollars.

The FE/NETL CO₂ Transport Cost Model provides cost estimates for the construction and operation of a dedicated pipeline for transporting CO₂ from a CO₂ source to a CO₂ storage site. The pipeline is assumed to be buried in the shallow subsurface and the CO₂ along the pipeline is assumed to be at the temperature of the surrounding soil, typically about 10°C (50°F). The CO₂ entering the pipeline at the plant gate is assumed to be at a pressure of 15.2 MPa (2,200

psig) and exiting the pipeline at the storage site at a pressure of 8.3 MPa (1,200 psig). At these pressures, CO₂ is a liquid at temperatures from approximately -18°C (-0.4°F) to 31°C (88°F).

It is further assumed that the pipeline is 100 km long (62.1 mi) and transports 3.2 million tonnes of CO₂ each year on average or approximately 8,770 tonnes per day on average. The pipeline is designed to operate at 80 percent of its maximum mass flow capacity, so the design maximum daily mass flow rate of CO₂ is about 10,960 tonnes/day. The model determines the smallest standard diameter pipe that can transport this mass flow of CO₂ the required distance without boosting the pressure. The model also determines the smallest standard diameter pipe that can transport this mass flow of CO₂ the required distance assuming boost pumps are placed at equal intervals along the pipeline to boost the pressure from 1,200 psig to 2,200 psig. The model then determines which of these configurations (no boost pumps, one boost pump, two boost pumps, or three boost pumps, etc.) is least expensive. The capital and operating costs used in the model were taken from the open literature. The capital costs for the pipeline are based on capital costs for natural gas pipelines reported in the *Oil and Gas Journal* with adjustments for the higher pressures used in CO₂ pipelines.

The financial parameters used in the FE/NETL CO₂ Transport Cost Model are the following:

- Debt to equity ratio: 50%/50%
- Nominal interest rate on debt: 4.5%/year
- Nominal IRROE: 12%
- Escalation rate: 3%
- Tax rate: 38%
- Project contingency factor of 15%

The FE/NETL CO₂ Transport Cost Model determines the first-year break-even price that needs to be charged to transport the CO₂ in order to cover all costs including the minimum return on equity. The model uses a weighted average cost of capital methodology in determining the first-year break-even CO₂ price. From the perspective of the CO₂ source, the break-even price is also the minimum cost of transporting CO₂. Transport costs are estimated to be \$2.24/tonne in 2011 dollars.

Storage costs are based on the FE/NETL CO₂ Saline Storage Cost Model. This model provides detailed cost estimates for the injection and monitoring of CO₂ under U.S. EPA regulations for Class VI injection wells as well as monitoring and reporting requirements under Subpart RR of the Greenhouse Gas Reporting Rule.

Inputs to the FE/NETL CO₂ Saline Storage Cost Model that have a significant influence on cost include financial parameters, the timelines for the various stages of storage and important activities occurring in each stage. The financial parameters include:

- Debt to equity ratio: 45%/55%
- Nominal interest rate on debt: 5.5%/year

- Nominal IRROE: 12%
- Escalation rate: 3%
- Financial responsibility requirements for post-injection site care and site closure are met by pre-funding a modified trust fund over the period of injection operations
- Project contingency factor of 15% and process contingency factor of 20%

In the FE/NETL CO₂ Saline Storage Cost Model, the sequestration process is divided into six stages. The timelines and important activities impacting costs for these stages are as follows:

- Regional evaluation and initial site selection: 1 year
- Site characterization: 3 years; four sites undergo site characterization with one successful site selected; pore space rights are leased
- Permitting: 2 years; drill, test and complete injection wells
- Operations: 30 years; installation of buildings, surface equipment, monitoring wells and other monitoring equipment; compliance with permit requirements; fund modified trust fund to cover financial responsibility requirements for post-injection site care and site closure
- Post-injection site care and site closure: 50 years; continue monitoring, verification, and accounting per permit; costs are covered by storage site operator's trust fund
- Long-term stewardship: (This stage is not explicitly included in the model.) The possible financial implication of long-term stewardship is included in the model as a state-sponsored trust fund that the storage operator pays into during operations

Due to the variances in the geologic formations that make up saline formations across the United States, region-specific storage and monitoring costs are developed to correspond to the plant locations used in NETL techno-economic studies of energy conversion facilities. Results from the FE/NETL CO₂ Saline Storage Cost Model for storage and monitoring costs were aligned with the NETL studies by taking four generic plant locations and overlaying them with possible sequestration basins from the cost model resulting in the following pairings:

- Midwest plant location – Illinois Basin
- Texas plant location – East Texas Basin
- North Dakota plant location – Williston Basin
- Montana plant location – Powder River Basin

CO₂ storage supply-cost curves were developed for each of the four basins of interest with the resulting cost for each basin at 25 gigatonnes (Gt) of potential storage shown in Exhibit 2-15. Choosing this point on the supply-cost curves provides a conservative estimate of the storage cost since many decades, if not more than a century, will pass before 25 Gt of CO₂ is stored in any of the four individual basins. For example, 25 Gt of storage would be sufficient for 125 GW of coal power with 90 percent CO₂ capture operating over 30 years.

The far-right column of Exhibit 2-15 shows the total T&S costs used in NETL system studies for each plant location rounded to the nearest whole dollar. Only the \$11/tonne value is used in this volume of the baseline study report since all cases are in the Midwest.

Exhibit 2-15. CO₂ transport and storage costs

Plant Location	Basin	Transport (2011 \$/tonne)	Storage Cost at 25 Gt (2011 \$/tonne)	T&S Value for System Studies ^A (2011 \$/tonne)
Midwest	Illinois	2.24	8.69	11
Texas	East Texas		8.83	11
North Dakota	Williston		13.95	16
Montana	Powder River		21.81	24

^AThe sum of transport and storage costs is rounded to the nearest dollar.

2.7.4 Cost of Electricity and Other Metrics

The primary cost metric used in this study is the COE, which is the revenue received by the generator per net megawatt-hour during the power plant's first year of operation after the retrofit equipment is installed. It is assumed that the existing PC plant has been fully paid off, and the only capital outlays required are for the CCS process (which includes the removal technology process equipment, a CO₂ compression train, and any modification to the existing plant required to accommodate the retrofitted technology) and the CHP auxiliary plants. Ongoing fuel costs, as well as fixed and variable O&M, and additional consumables for the existing plant are included in the cost of electricity calculations. The owner/developer was assumed to be an investor-owned utility (IOU), and the retrofitted capital costs were assumed to have financial structures consistent with high-risk projects and three-year capital expenditure periods to get a capital charge factor (CCF) of 0.111. This is consistent with the greenfield capture NGCC cases in the NETL baseline study. [3] The CCF times the TOC equals the annual capital charges included in COE calculations. A retrofit contingency factor of 1.1 is also applied to the TOC within the COE calculations in each case to account for site-specific uncertainties, which cannot be directly accounted for in the capital cost estimates. [4]

For retrofit cases, the equation for the calculating the COE is:

$$COE = \frac{[RCF * CCF * TOC_{RET}(\frac{\$}{yr}) + O\&M_{BAU}(\frac{\$}{yr} @ CF) + added\ O\&M_{RET}(\frac{\$}{yr} @ CF)]}{MWh_{RET}(\frac{MWh}{yr} @ CF)}$$

Where:

RCF – Retrofit contingency factor

CCF – Capital charge factor

TOC – Total overnight cost of retrofit case

RET – After retrofit

CF – Capacity factor after retrofit

O&M – Fixed O&M + Variable O&M + Fuel

BAU – Business as usual (aka existing plant)

MWh_{RET} – Annual net generation after retrofit, MWh/yr

The breakeven CO₂ sales price, formerly known as the cost of CO₂ captured in the referenced reports, is the price at which the revenue generated by selling the recovered CO₂ equals the costs of recovering it. If the price a plant would receive by selling CO₂ is greater than the breakeven sales price, then the plant has an economic incentive to install the capture system and sell the CO₂ for revenue. The costs of recovering the CO₂ include capital expenditures, fixed and variable O&M increases, fuel cost changes, and makeup/excess power charges/credits. The cost or credit for any difference between the existing power plant annual net generation and the after retrofit annual net generation is included in each case at a projected sales price (PSP) for electricity of \$60/MWh.

For retrofit cases, the equation for the calculating the breakeven CO₂ sales price is:

Breakeven of CO₂ Sales Price =

$$\frac{\left[\text{PSP} \left(\frac{\$}{\text{MWh}} \right) * \text{Lost MWh} \left(\frac{\text{MWh}}{\text{yr}} @ \text{CF} \right) + \text{RCF} * \text{CCF} * \text{TOC}_{RET} \left(\frac{\$}{\text{yr}} \right) + \text{Incremental O\&M} \left(\frac{\$}{\text{yr}} @ \text{CF} \right) \right]}{\text{CO}_2 \text{ Captured} \left(\frac{\text{tonne}}{\text{yr}} @ \text{CF} \right)}$$

Where:

BAU – Business as usual (aka existing plant)

RET – After retrofit

PSP – Projected sales price of electricity, \$/MWh

Lost MWh = $MWh_{BAU} - MWh_{RET}$

MWh_{BAU} – Annual net generation for non-capture/BAU, MWh/yr

MWh_{RET} – Annual net generation for RET, MWh/yr

Note – when this excess power is generated this value becomes a credit (negative) and reduces the value of the numerator

CF – Capacity factor

RCF – Retrofit contingency factor

CCF – Capital charge factor

TOC – Total overnight cost of retrofit case

Incremental O&M – O&M Costs associated with retrofit, \$/yr

= (Fixed O&M + Variable O&M + Fuel)_{BAU} - (Fixed O&M + Variable O&M + Fuel)_{RET}

CO₂ Captured = CO₂ captured, tonne/yr

The breakeven CO₂ emissions penalty, formerly known as the cost of CO₂ avoided in the referenced reports, is the cost of reducing emissions at which the penalty for not reducing the emissions is equal to the costs. If the price of allowances or fines for emissions is higher than this value then there is an economic incentive for adding the capture system. The costs of recovering the CO₂ include capital expenditures, fixed and variable O&M increases, fuel cost changes, T&S, and makeup power charges.

For retrofit cases, the equation for the calculating the breakeven CO₂ emissions penalty is:

Breakeven of CO₂ Emissions Penalty =

$$\frac{PSP\left(\frac{\$}{\text{MWh}}\right) * \text{lost MWh} \left(\frac{\text{MWh}}{\text{yr}} @ CF\right) + RCF * CCF * TOC_{RET} \left(\frac{\$}{\text{yr}}\right) + \text{Incremental O\&M} \left(\frac{\$}{\text{yr}} @ CF\right) + \text{T\&S Costs} \left(\frac{\$}{\text{yr}} @ CF\right)}{\left(\text{MWh}_{BAU} \left(\frac{\text{MWh}}{\text{yr}} @ CF\right) * CO_2 \text{Emissions}_{BAU} \left(\frac{\text{tonne}}{\text{MWh}_{BAU}}\right) - \text{MWh}_{RET} \left(\frac{\text{MWh}}{\text{yr}} @ CF\right) * CO_2 \text{Emissions}_{RET} \left(\frac{\text{tonne}}{\text{MWh}_{RET}}\right)\right)}$$

Where:

BAU – Business as usual (aka existing plant)

RET – After retrofit

PSP – Projected sales price of electricity, \$/MWh

Lost MWh = MWh_{BAU} - MWh_{RET}

MWh_{BAU} – Annual net generation for non-capture/BAU, MWh/yr

MWh_{RET} – Annual net generation for RET, MWh/yr

Note – when this excess power is generated this value becomes a credit (negative) and reduces the value of the numerator

CF – Capacity factor

RCF – Retrofit contingency factor

CCF – Capital charge factor

TOC – Total overnight cost of retrofit case

Incremental O&M – O&M Costs associated with retrofit, \$/yr

= (Fixed O&M + Variable O&M + Fuel)_{BAU} - (Fixed O&M + Variable O&M + Fuel)_{RET}

T&S Costs – Costs for transport and storage of captured CO₂, \$/yr

CO₂ Emissions – CO₂ emissions, tonne/yr

For a PC coal plant retrofitted with CCS, the business as usual, non-capture plant used to calculate the breakeven CO₂ sales price and emissions penalty is a fully depreciated, subcritical PC plant without capture. Case B11A from the NETL Bituminous Baseline Report [3] serves as this reference plant for the calculations.

3 EXISTING PULVERIZED COAL RANKINE CYCLE PLANT

Three retrofit options for a generic existing PC-fired Rankine cycle power plant^e were evaluated. The plant system descriptions of the existing PC plant are based on Case B11A in NETL Bituminous Baseline Report. [3]

The design employs a single unit configuration (i.e., one boiler supplying steam to one STG) that comprises a conventional PC steam generator firing Illinois No. 6 coal and a steam turbine. The net generating capacity of the existing PC plant is 550 MW-net.

Steam conditions for the existing PC plant were selected to be subcritical to reflect the prevalence of these units within the existing PC plant fleet. The following single-reheat steam conditions for this study are 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F).

Each of the retrofit cases examined have process areas that are associated with the existing PC plant, such as coal receiving and storage, emissions control technologies, and power generation. Detailed descriptions of these process areas are largely similar across the cases and are presented in this section for general background information. Aspects and performance features of these sections that are relevant to the individual cases are discussed in subsequent sections of this report.

3.1 COAL, ACTIVATED CARBON, AND SORBENT RECEIVING AND STORAGE

The function of the Coal Receiving and Storage system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to and including the slide gate valves at the outlet of the coal storage silos. The system is designed to support short-term operation at the 5 percent over pressure/valves wide open (OP/VWO) condition (16 hours) and long-term operation of 90 days or more at the maximum continuous rating (MCR).

The scope of the sorbent receiving and storage system includes truck roadways, turnarounds, unloading hoppers, conveyors, and the day storage bin.

Operation Description – The coal is delivered to the site by 100-car unit trains comprising 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 transfers the coal to either the long-term storage pile or to the reclaim area. The conveyors pass under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor, which transfers the coal to the coal surge bin located in the crusher tower. The coal

^e The retrofitted plant is a variant of Case B11B and the existing plant is Case B11A, without capital costs, from NETL Bituminous Baseline Report. [3]

is reduced in size to 2.5 cm x 0 (1" x 0) by the coal crushers. The coal is then transferred by conveyor to the transfer tower. In the transfer tower the coal is routed to the tripper that loads the coal into one of the six boiler silos.

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.

Non-halogenated PAC is delivered to the site using 18-tonne (20-ton) trucks. The trucks pneumatically unload into a storage silo where a feeder hopper transfers the PAC to a screw feeder that conveys the PAC into the drop tube. PAC is fed through the drop tube directly into the eductor suction port. The carbon is transferred from the eductor suction port through the piping system and injected through a distribution of lances across the flue gas ductwork upstream of the baghouse. [30]

Hydrated lime is delivered and distributed in a manner very similar to that of the PAC: the sorbent is contained in the main storage silo and fed to a weigh hopper for conveying through transport piping to the sorbent distribution manifold upstream of the air preheater.

3.2 STEAM GENERATOR AND ANCILLARIES

The steam generator is a drum-type, wall-fired, balanced draft, natural circulation, totally enclosed dry bottom furnace, with superheater, reheater, economizer, and air preheater.

The combustion system is equipped with LNBs and OFA. It is assumed for the purposes of this report that the power plant is designed for operation as a base-load unit but with some consideration for daily or weekly cycling.

3.2.1 Scope

The steam generator includes the following:

- Drum-type evaporator
- Water-cooled furnace, dry bottom
- Two-stage superheater
- Reheater (RH)
- Low NO_x coal burners and light oil igniters/warm-up system
- Economizer
- Spray type desuperheater
- Soot blower system
- Air preheaters (Ljungstrom type)
- Coal feeders and pulverizers
- OFA system
- Forced draft (FD) fans
- Primary air (PA) fans
- Induced draft (ID) fans

The following subsections describe the operation of the steam generator.

3.2.2 Feedwater and Steam

Feedwater (FW) enters the economizer, recovers heat from the combustion gases exiting the steam generator, and then passes to the boiler drum, from where it is distributed to the water wall circuits enclosing the furnace. After passing through the lower and upper furnace circuits and steam drum in sequence, the steam passes through the convection enclosure circuits to the primary superheater and then to the secondary superheater.

The steam then exits the steam generator en route to the HP turbine. Steam from the HP turbine returns to the steam generator as cold reheat and returns to the IP turbine as hot reheat.

3.2.3 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. This air is heated in the Ljungstrom type air preheaters to permit drying of the PC, and a portion of the air from the PA fans bypasses the air preheaters to be used for regulating the outlet coal/air temperature leaving the mills.

The coal and air mixture flows to the coal nozzles at various elevations of the furnace. The hot combustion products rise to the top of the boiler and pass through the superheater and reheater sections. The gases then pass through the economizer and air preheater. The gases exit the steam generator at this point and flow to the SCR reactor, DSI manifold, ACI manifold, fabric filter, ID fan, FGD system, and stack.

3.2.4 Fuel 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. [31] The coal 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.

3.2.5 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 3.8. The steam generator incorporates fly ash hoppers under the economizer outlet and air preheater outlet.

3.2.6 Burners

A boiler of this capacity employs approximately 24 to 36 coal nozzles arranged at multiple elevations. Each burner is designed as 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.

3.2.7 Dry Sorbent Injection

The hydrated lime injection manifold is located directly before the air preheaters. This SO₃ control system is discussed in detail in Section 3.5.

3.2.8 Air Preheaters

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

3.2.9 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 NO_x CONTROL SYSTEM

The plant is designed to achieve the environmental target of 0.70 lb/MWh-gross. 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 nitrogen (N₂) and water (H₂O). The SCR system consists of three subsystems: reactor vessel, ammonia storage and injection, and gas flow control. The SCR system is designed for 83-85 percent reduction with 2 ppmv ammonia slip at the end of the catalyst life.

SCR Operation Description – The reactor vessel is designed and operated such that there is adequate 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 an economizer bypass to provide flue gas 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 flue gas 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.

3.4 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. [32] 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 several 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.

The use of ACI and DSI increases the calcium content of the fly ash and adds an additional burden to the fabric filter. The addition of calcium is not expected to increase the leaching of trace metals from the fly ash significantly. The ACI and DSI systems increase the total amount of particulate matter by approximately 26 percent.

Fly ash from bituminous-fired plants (Class F fly ash) is sometimes sold for use as filler material in concrete mixtures. The use of Class F fly ash for concrete manufacture is not as common as the use of Class C fly ash (from high-calcium-containing coals); the latter is more valuable as a replacement for Portland cement in concrete mixtures. Class F fly ash must have a low unburned carbon content to be used in cement mixtures. The inclusion of activated carbon and hydrated lime (or, rather, the calcium sulfate (CaSO_4) reaction product) will render the fly ash unsuitable for use in concrete mixtures.

3.5 MERCURY REMOVAL^f

Mercury removal is partially achieved through flue gas reactions between mercury and available halogens and carbon.

Halogens in the coal, primarily chlorine, influence the fraction of oxidized mercury that is formed as the flue gas passes through the SCR and air preheater. Therefore, the overall mercury removal in control devices such as fabric filters and wet scrubbers is also influenced

^f Much of the text, descriptions, and images within this section were sourced, with permission, from a quote provided by Advanced Emissions Solutions, Inc. (ADA-ES) to NETL, unless otherwise noted. The information relates to a mercury control system designed by ADA-ES. The quote also provided all images credited to them.

by halogens in the coal (concentrations of chlorine greater than 500 ppmv do not appear to have any additional impact on the rate of mercury oxidation). [33]

The presence of an SCR can impact the amount of SO_3 or sulfuric acid (H_2SO_4) that is present in the flue gas. Sulfuric acid can impact the ability of unburned carbon to adsorb mercury. Based on the assumptions and design bases of the PC cases in this study, the estimated SO_3 concentration at the inlet of the air preheater, without mitigation, is 59 ppmvd. At these levels, low mercury removal is expected from either unburned carbon or added activated carbon. Therefore, dry sorbent injection is included in the PC plant designs in order to reduce the SO_3 levels to approximately 2 ppmvd, as discussed in Section 3.5.1.

The rate of mercury oxidation is also affected by the ammonia concentration. Since the SCR is operated more aggressively for NO_x control, the ammonia levels increase and the fraction of oxidized mercury decreases. [34]

Unburned carbon can act as a catalyst to promote mercury oxidation as well as to adsorb mercury. In general, sufficient unburned carbon is present at plants firing bituminous coals such that one or both of these factors will have a significant influence on the overall mercury removal achieved in the system. [35]

The presence of unburned carbon and/or activated carbon on the fabric filter surface, in combination with relatively high levels of hydrogen halides (e.g., HCl) in the flue gas, is expected to result in high levels of oxidized mercury exiting the fabric filter. Oxidized mercury is water soluble and should be readily removed in the wet scrubber. Depending on the chemistry in the scrubber, some of the captured mercury may be reduced back to the relatively insoluble elemental form, which will then be re-emitted from the scrubber. The control systems employed in this study minimize the amount of mercury entering the scrubber, which reduces the risk of exceeding the emission limit. Even with low levels entering the scrubber, there is a risk of periodic spikes in mercury at the stack if mercury collected and concentrated in a recirculating scrubber is released. However, to a large extent, the periodic surges can be managed through careful operations and, because the regulations specify a 30- or 90-day averaging period, the impact of the surges on compliance can be minimized.

EPA used a statistical method to calculate the Hg co-benefit capture from units using a “best demonstrated technology” approach, which for bituminous coals was considered to be a combination of a fabric filter and an FGD system. The statistical analysis resulted in a co-benefit capture estimate of 86.7 percent with an efficiency range of 83.8 to 98.8 percent. [36] EPA’s documentation for their Integrated Planning Model (IPM) provides mercury emission modification factors (EMF) based on 190 combinations of boiler types and control technologies. The EMF is simply one minus the removal efficiency.

For PC boilers (as opposed to cyclones, stokers, fluidized beds, and others) with a fabric filter, SCR and wet FGD, the EMF is 0.1, which corresponds to a removal efficiency of 90 percent; [37] the average reduction in total Hg emissions developed from EPA’s Information Collection Request (ICR) data on U.S. coal-fired boilers using bituminous coal, fabric filters, and wet FGD is 98 percent. [38] The referenced sources bound the co-benefit Hg capture for bituminous coal units employing SCR, a fabric filter, and a wet FGD system between 83.8 and 98 percent.

It was assumed that the co-benefit potential of the equipment utilized in the PC cases of this report is 90 percent, as it is near the mid-point of the previously mentioned range, and it also matches the value used by EPA in their IPM.

The potential co-benefit capture of the systems utilized in the PC cases does not satisfy the requirements of the mercury emission limit, therefore, a cost and performance estimate was obtained from ADA-ES, which stated that ACI and DSI would be required.

Location of the DSI relative to the air preheater impacts the mercury removal efficiency of the ACI system. The mercury limit is assumed to be achievable with a DSI location downstream of the air preheater; however, the upstream location of the air preheater allows for a lower flue gas outlet temperature from the air preheater, which improves plant performance as well as increases the carbon efficiency by up to 25 percent.

3.5.1 Dry Sorbent Injection

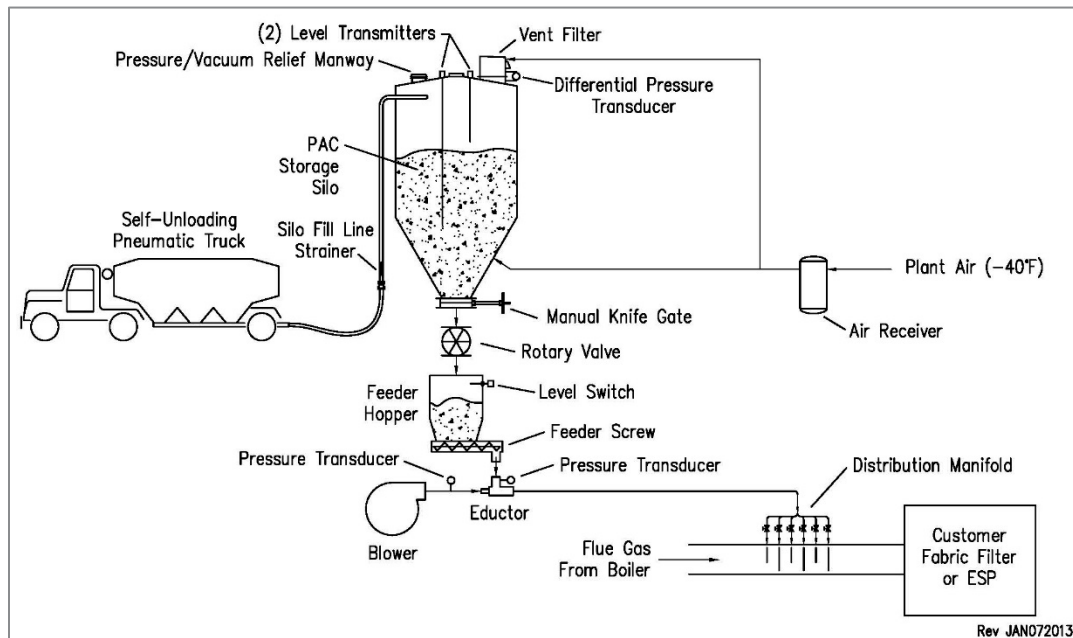
Illinois No. 6 coal contains relatively high levels of sulfur (2.82 wt%). ADA-ES estimated that nominally 36 ppmvd of SO_3 will be present at the outlet of the air preheater resulting from coal combustion and oxidation across the SCR.

SO_3 can be detrimental to the effectiveness of both unburned carbon and activated carbon for mercury control, as evidenced by the results from a testing program conducted at the Mercury Research Center. The test using an electrostatic precipitator (ESP)-configured system with an ACI rate of 10 lb/MMacf upstream of the air preheater, which showed that at SO_3 levels above 20 ppm, less than 50 percent mercury removal was achieved. At SO_3 levels above 10 and 3 ppm, less than 70 and 80 percent mercury removal was achieved, respectively. [39]

Hydrated lime injection was selected for SO_3 control and located upstream of the air preheater, which allows the air preheater to operate at a lower downstream flue gas temperature (143°C (290°F)) and increases the overall plant efficiency compared to a system with no DSI or DSI downstream of the air preheater. Without SO_3 mitigation, the downstream flue gas temperature must be maintained above the acid dew point temperature (approximately 169°C (337°F)).

Operation Description – The DSI and ACI injection systems are nearly identical; therefore, the description provided below pertains to both systems.

As shown in Exhibit 3-1, the DSI system is based on dilute-phase, pneumatic conveying of hydrated lime at a metered rate from a bulk storage silo to the flue gas ductwork where it mixes with the flue gas and reacts with the SO_3 to form CaSO_4 , which is captured in the fabric filter.

Exhibit 3-1. Typical injection process flow diagram

Used with permission from ADA-ES

The hydrated lime is delivered in 40,000-lb batches by self-unloading pneumatic trucks. The hydrated lime is unloaded from the truck via an on-board compressor into the dry, welded-steel storage silo where the displaced air is vented through a silo vent filter. The hydrated lime level in the silo is measured by system instrumentation. A combination of compressed air fluidization valves and nozzles is used to pulse compressed air, promoting mass flow of the hydrated lime out of the silo chisel-type cone.

Fluidized hydrated lime is then transferred from the silo by a rotary valve into the feeder hopper where it is temporarily stored until conveyed by the screw feeder into the drop tube. The speed of the screw feeder determines the feed rate into the drop tube. Hydrated lime is fed through the drop tube directly into the eductor suction port.

Motive air, provided by low-pressure blowers and fed into the eductors, produces a vacuum at the suction port. This helps draw the hydrated lime and air into the mixing zone directly downstream of the eductor discharge. The hydrated lime is transported through the piping system and is distributed to an array of injection lances specifically designed to disperse the hydrated lime across the cross section of the flue gas ductwork upstream of the air preheater.

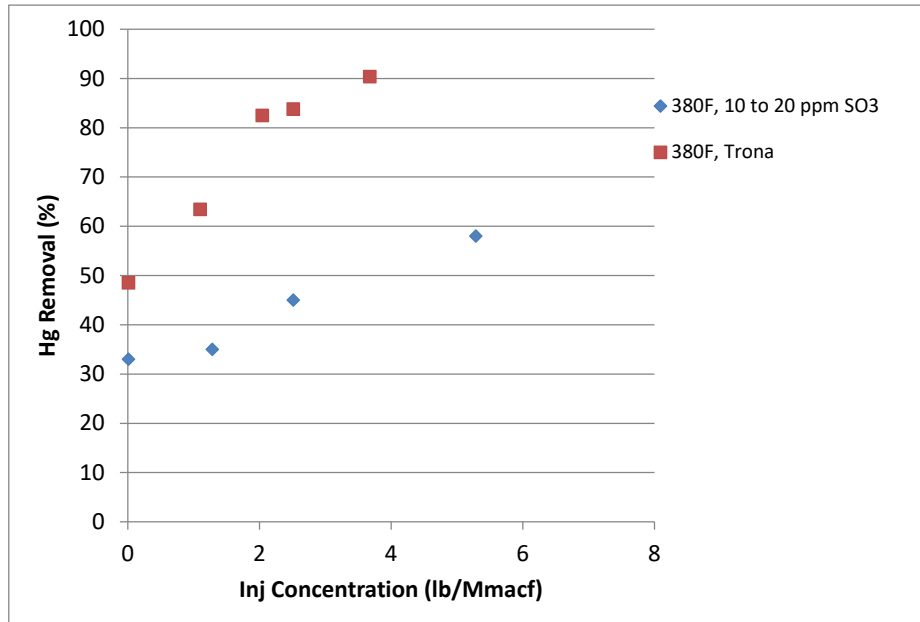
The DSI system is monitored and controlled by the distributed control system (DCS) to adjust to varying demand.

3.5.2 Activated Carbon Injection

ADA-ES conducted a mercury control trial using ACI and trona-based DSI on a unit with an installed fabric filter and high (greater than 20 ppm) levels of SO₃ in the flue gas. For this test, the flue gas temperature was 193°C (380°F). Results from this test are presented in Exhibit 3-2 and indicate that high mercury removal can be achieved when alkaline materials are present

with activated carbon on a bag surface (improved performance is expected at lower temperatures).

Exhibit 3-2. Mercury removal across a fabric filter during a high-sulfur bituminous test



Used with permission from ADA-ES

In order to meet the mercury emission limit, PAC is injected at a rate of approximately 2.7 lb/MMacf. The injection manifold is located directly before the baghouse. [30]

Operation Description – The ACI system’s injection manifold is located directly upstream of the fabric filter and is otherwise identical to that of the DSI system and is described in Section 3.5.1.

3.6 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 SO₂ prior to release to the environment or entering into the CCS facility. Sulfur removal efficiency is 98 percent in the FGD unit for all cases. The SO₂ content of the scrubbed gases must be further reduced to approximately 1 ppmv to minimize formation of amine heat stable salts (HSS) during the CO₂ absorption process. The CCS unit includes a polishing scrubber to reduce the flue gas SO₂ concentration from about 37 ppmv at the FGD exit to the required level prior to the CCS absorber. The scope of the FGD system is from the outlet of the ID fans to the CCS process inlet. The system description is divided into three sections:

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

3.6.1 Limestone Handling and Reagent Preparation System

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 base load 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.

3.6.2 FGD Scrubber

The flue gas 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 flue gas exits at the top of the absorber vessel and is routed to the plant stack or CCS 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. The flue gas exiting the FGD unit contains about 1 percent more CO₂ than the raw flue gas because of the CO₂ liberated from the limestone in the FGD absorber vessel.

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 56°C (133°F) is not necessary.

3.6.3 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 SO₂ absorption process. Maintenance of the quality of the recirculating slurry requires that a portion be withdrawn and replaced by fresh reagent. This 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% 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% to 50 wt% solids. The second function of the primary hydrocyclone is to perform a CaCO₃ and CaSO₄•2H₂O 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.

3.6.3.1 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%. 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% at the feed to 50 wt%.

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% 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.

3.6.3.2 Horizontal Vacuum Belt Filters

The secondary dewatering system consists of horizontal vacuum belt filters. The pre-concentrated gypsum slurry (50 wt%) 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% 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.

3.7 POWER GENERATION

The existing 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 direct current (DC) motor-operated lube oil pumps, and main lube oil pumps, which are driven off the turbine shaft. [40] The exhaust pressure is 50.8 cm (2 inch) Hg in the single pressure condenser. There are seven extraction points. The condenser is two-shell, transverse, single pressure with divided waterbox for each shell.

Turbine bearings are lubricated by a closed-loop (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 generator rotor shaft.

Operation Description – The turbine is designed to operate at constant inlet steam pressure over the entire load range. 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 at 16.5 MPa/566°C (2,400 psig/1,050°F). 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 at 566°C (1,050°F). 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 last stages of the LP sections operate as condensing turbines with an exit liquid fraction ranging from 9.2 percent to 9.5 percent.

3.8 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.

3.8.1 Condensate

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator and through 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, 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 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.

3.8.2 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.

3.8.3 Main and Reheat Steam

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.

3.8.4 Extraction Steam

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

- From HP turbine extraction to heater 7
- From IP turbine extraction to heater 6 and the deaerator (heater 5)
- From LP turbine extraction to heaters 1, 2, 3, and 4

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.

3.8.5 Circulating Water System

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 circulating water pumps (CWPs) are provided. The circulating water system (CWS) provides cooling water to the condenser and to the auxiliary cooling water system.

The auxiliary cooling water system is a CL 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.

3.8.6 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, along with the hydrated lime and activated carbon injected for mercury control (discussed in Section 3.5). 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.

As mentioned in Section 3.4, the use of ACI and DSI increases the calcium content of the fly ash and adds an additional burden to the fabric filter. The addition of calcium is not expected to increase the leaching of trace metals from the fly ash significantly. The ACI and DSI systems increase the total amount of particulate matter by approximately 26 percent.

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.

3.8.7 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.

3.8.8 Waste Treatment/Miscellaneous Systems

An onsite water treatment facility treats all runoff, cleaning wastes, blowdown, and backwash. It is anticipated that the treated water will be suitable for discharge into existing systems and be within the EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals.

The waste treatment system is minimal and consists, primarily, of neutralization and oil/water separators (along with the associated pumps, piping, etc.).

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.

3.8.9 Buildings and Structures

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

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

3.9 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.

3.10 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.

3.11 PERFORMANCE SUMMARY METRICS

This section details the methodologies of several metrics reported in the performance summaries.

3.11.1 Steam Generator Efficiency

The steam generator efficiency is equal to the amount of heat transferred in the boiler divided by the thermal input provided by the coal. This calculation is represented by the equation:

$$SGE = \frac{BH}{CH}$$

Where:

SGE – Steam generator efficiency

BH – Boiler thermal output

CH – Coal thermal input

The heat transferred in the boiler is provided by the Aspen models, and the thermal input of the coal is the product of the coal feed rate and the heating value of the coal.

3.11.2 Steam Turbine Efficiency

The steam turbine efficiency is calculated by taking the steam turbine power produced and dividing it by the difference between the thermal input and thermal consumption. This calculation is represented by the equation:

$$STE = \frac{STP}{(TI - TC)}$$

Where:

STE – Steam turbine efficiency

STP – Steam turbine power

TI – Thermal input

TC – Thermal consumption

The thermal input is considered to be the main steam.

The thermal consumption is only present in the capture cases. It is the enthalpy difference between the streams extracted for the capture and CO₂ dryer systems and the condensate returned to the condenser (steam extraction – condensate return).

3.11.3 Steam Turbine Heat Rate

The steam turbine heat rate is calculated by taking the inverse of the steam turbine efficiency. This calculation is represented by the equation:

$$STHR = \frac{1}{STE} * 3,412$$

Where:

STHR – Steam turbine heat rate, Btu/kWh

STE – Steam turbine efficiency, fraction

4 RETROFITTED SYSTEMS

The cases in this study examine three different options for retrofitting the existing PC plant described in Section 3 with a CO₂ capture facility. The following sections provide descriptions of the cumulative installed capital in the three cases. Many of the retrofitted systems described are included in each of the three cases (e.g., Cansolv process), while others are included in a subset of the cases. Exhibit 4-1 provides a summary of the major capital items considered for each retrofit option and identifies in which section of the report a description of the particular item can be found. The sub-account categories correspond to the categories included in the cost estimates provided in Section 5.

Exhibit 4-1. Summary of retrofitted capital

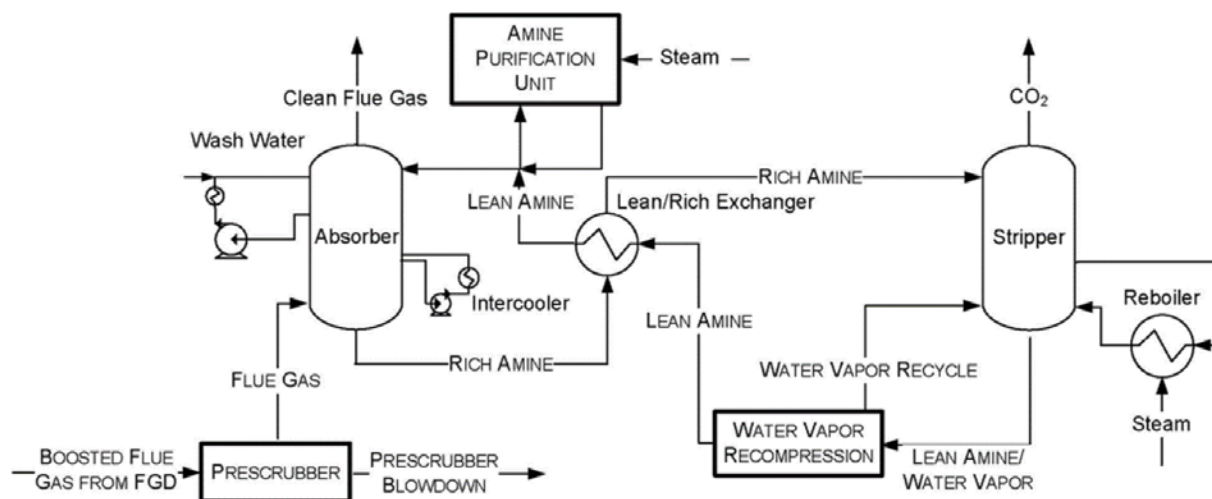
Retrofitted Capital Item	Case 0 CCS Retrofit-Only	Case 1 NGSC CHP	Case 2 NGCC CHP	Section(s)
Sub-Account 3 – Feedwater & Misc. BOP Systems				
FW, makeup, etc. systems for HRSG		•	•	4.9.1 and 4.9.2
Sub-Account 5b – CO₂ Removal & Compression				
Cansolv process	•	•	•	4.1
CO ₂ compression/drying train	•	•	•	4.1
Letdown turbine (LDT) addition	•			4.9.3
Sub-Account 6 – Combustion Turbine & Accessories				
Combustion turbine(s) generator		•	•	4.5
Sub-Account 7 – HRSG, Ducting & Stack				
PC plant ducting and stack	•	•	•	4.2
HRSG with SCR		•	•	4.6 and 4.7
Sub-Account 8 – Steam Turbine Generator				
Steam bottoming cycle			•	4.8
Existing ST extraction piping	•			4.9.3
HRSG steam piping		•	•	4.6
Sub-Account 9 – Cooling Water System				
Auxiliary wet cooling tower	•	•	•	4.9.4
Sub-Account 11 – Accessory Electric Plant				
Addition for CO ₂ capture system auxiliary loads	•	•	•	4.10
Addition for CT auxiliary loads		•	•	4.10
Sub-Account 12 – Instrumentation & Control				
CHP plant I&C additions		•	•	4.11
Misc. I&C	•	•	•	4.11
Sub-Account 13 – Improvements to Site				
Site prep, facilities & improvements	•	•	•	
Sub-Account 14 – Buildings & Structures				
Water treatment, waste & circ. buildings	•	•	•	
CT building		•	•	
ST building			•	

4.1 CARBON DIOXIDE CAPTURE FACILITY⁹

A carbon dioxide capture facility designed to remove 90 percent of the CO₂ in the treated flue gas stream is retrofitted in all cases evaluated. The facility captures the CO₂ and then purifies it and compresses it to a supercritical condition. The flue gas exiting the FGD unit contains about 1 percent more CO₂ than the raw flue gas because of the CO₂ liberated from the limestone in the FGD absorber vessel. The carbon capture system comprises the pre-scrubber, CO₂ absorber, CO₂ stripper, and absorbent purification unit.

The CO₂ recovery process is based on data provided to NETL by Shell Cansolv in 2012. A typical flowsheet is shown in Exhibit 4-2. This process is designed to recover high-purity CO₂ from LP streams that contain oxygen, such as flue gas from coal-fired power plants, CT exhaust gas, and other waste gases.

Exhibit 4-2. Cansolv CO₂ capture process typical flow diagram



4.1.1 Pre-scrubber Section

The flue gas from the FGD section is sent through a booster fan to drive the gas through downstream equipment starting with the pre-scrubber inlet cooling section. The cooler is operated as a direct contact cooler that saturates and sub-cools the flue gas. Saturation and sub-cooling are beneficial to the system as they improve the amine absorption capacity, thus reducing amine circulation rate. After the cooling section, the flue gas is scrubbed with caustic in the pre-scrubber sulfur polishing section. This step reduces the SO₂ concentration entering the CO₂ absorber column to 1 ppmv and reduces the NO₂ concentration by 50 percent.

⁹ Much of the text and descriptions within this section were sourced, with permission, from data provided by Shell Cansolv to NETL, unless otherwise noted. The information relates to a CO₂ removal system designed by Shell Cansolv.

4.1.2 CO₂ Absorber Section

The Cansolv CO₂ absorber is a single, rectangular, acid resistant, brick-lined concrete structure containing SS packing.

There are four packing sections in the Cansolv absorber. The first three are used for CO₂ absorption, and the final section is a water-wash section. This specific absorber geometry and design provides several cost advantages over more traditional column configurations while maintaining equivalent or elevated performance. The flue gas enters the absorber and flows counter-current to the Cansolv solvent. Approximately 90 percent of the inlet CO₂ is absorbed into the lean solvent, and the remaining CO₂ exits the main absorber section and enters the water-wash section of the absorber. Prior to entering the bottom packing section, hot amine is collected, removed, and pumped through a heat exchanger to provide intercooling and limit water losses. The cooled amine is then sent back to the absorber just above the final packing section.

The water-wash section at the top of the absorber is used to remove volatiles or entrained amine from the flue gas, as well as to condense and retain water in the system. The wash water is removed from the bottom of the wash section, pumped through a heat exchanger, and is then re-introduced at the top of the wash section. This wash water is made up of recirculated wash water as well as water condensed from the flue gas. The flue gas treated in the water-wash section is then routed to a newly constructed stack for discharge to the atmosphere.

4.1.3 Amine Regeneration Section

The rich amine is collected at the bottom of the absorber and pumped through a rich/lean heat exchanger where heat from the lean amine is exchanged with the rich amine. The Cansolv rich/lean solvent heat exchanger is an SS plate and frame type with a 5°C (8.5°F) approach temperature. Additional options for heat integration in the Cansolv system include a second heat exchanger after the rich/lean solvent heat exchanger where low-pressure steam condensate from the regenerator reboiler or intermediate-pressure steam condensate from the amine purification section may be used to further pre-heat the rich solvent. The rich amine continues and enters the stripper near the top of the column. The stripper is an SS vessel using structured SS packing. The regenerator reboiler uses low-pressure steam to produce water vapor that flows upwards, counter-current to the rich amine flowing downwards, and removes CO₂ from the amine. The Cansolv regenerator reboiler is an SS plate and frame type with a 3°C (5°F) approach temperature. Lean amine is collected in the stripper bottoms and flows to a flash vessel where water vapor is released. The water vapor is then recompressed and recycled to the bottom of the stripper to continue stripping CO₂. The lean amine is then pumped through the same rich/lean heat exchanger to exchange heat from the lean amine to the rich amine and continues on to the lean amine tank.

The water vapor and stripped CO₂ flow up the stripper where they are contacted with recycled reflux to condense a portion of the vapor. The remaining gas continues to the condenser where it is partially condensed. The two-phase mixture then flows to a reflux accumulator where the CO₂ product gas is separated and sent to the CO₂ compressor at

approximately 30 psia, and the remaining water is collected and returned to the stripper as reflux.

The flow of steam to the regenerator reboiler is proportional to the rich amine flow to the stripper; however, the flow of low-pressure steam is also dependent on the stripper top temperature. For the steady-state case described here, the low-pressure steam requirement for the reboiler only is calculated as approximately 1,100 Btu/lb CO₂ for the Cansolv process, which is typically satisfied by extracting steam from the crossover pipe between the IP and LP sections of a steam turbine.

4.1.4 Amine Purification Section

The purpose of the amine purification section is to remove a portion of the HSS as well as ionic and non-ionic amine degradation products. The Cansolv amine purification process is performed in batch.

4.1.4.1 Ion Exchange

The HSS form due to residual amounts of NO₂ and SO₂ in the flue gas. The acids formed by the oxidative degradation of the amine, as well as through reactions with NO₂ and SO₂, neutralize a portion of the amine making it inactive to further CO₂ absorption. Therefore, excess HSS are removed via an ion exchange (resin bed contained within a column).

4.1.4.2 Thermal Reclaimer

The ionic and non-ionic amine degradation products are removed in the thermal reclaimer by distilling a slipstream—taken from the treated amine exiting the ion exchanger—under vacuum conditions to separate the water and amine. This process leaves the non-ionic degradation products in the bottom, which are pumped to a storage tank, diluted and cooled with process water, and then disposed. A portion of the condensed amine and water is returned to the absorber column with the rest being sent to the lean amine tank.

4.2 DUCTING AND STACK

Additional ducting and a new stack are provided for the existing PC plant. The stack is sized for the post-retrofit flue gas flow rate and includes a single FRP liner. The stack is constructed of reinforced concrete. The stack is 152 m (500 ft) high for adequate dispersion of the exhaust gas.

4.3 CO₂ COMPRESSION AND DRYING SYSTEM

A CO₂ compression and drying system is included in all retrofit cases evaluated. The compression system was modeled based on vendor supplied data, similar in design to that presented in the Carbon Capture Simulation Initiative's (CCSI) paper "Centrifugal Compressor Simulation User Manual." [41] The design was assumed to be an eight-stage, front-loaded centrifugal compressor with stage discharge pressures presented in Exhibit 4-3.

Exhibit 4-3. CO₂ compressor interstage pressures

Stage	Outlet Pressure, MPa (psia)	Stage Pressure Ratio
1	0.44 (64)	2.23
2	0.92 (133)	2.14
3	1.72 (250)	1.90
4	3.04 (441)	1.78
5	4.80 (696)	1.59
6	6.97 (1,011)	1.53
7	10.36 (1,502)	1.49
8	15.27 (2,215)	1.48

Power consumption for this large compressor was estimated assuming a polytropic efficiency of 89 percent and a mechanical efficiency of 97 percent for the first seven stages and a polytropic efficiency of 91 percent for the final stage.

Intercooling is included for each stage with the first three stages including water knockout. There is no aftercooler included in this design.

A triethylene glycol (TEG) dehydration unit is included between stages 4 and 5, operating at 3.03 MPa (439 psia), to reduce the moisture concentration of the CO₂ stream to 300 ppmw. The dryer was designed based on a paper published by the Norwegian University of Science and Technology (NTNU) [42] titled "Conditioning of CO₂ Coming from a CO₂ Capture Process for Transport and Storage Purposes."

In an absorption process, such as in a TEG dehydration unit, the gas containing water flows up through a column while the TEG flows downward. The solvent binds the water by physical absorption; water is more soluble in the solvent than in other components of the gas mixture. The dried gas exits at the top of the column, while the solvent rich in water exits at the bottom. After depressurization to around atmospheric pressure, the solvent is regenerated by heating it and passing it through a regeneration column where the water is boiled off. Depending on configuration, a TEG unit can reduce water concentrations to below 10 ppm. [43]

Several alternatives to rejecting the heat of CO₂ compression to cooling water were investigated in a separate study. [44] 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 net plant efficiency of 0.3 percentage points (absolute). The second alternative modified the CO₂ compression intercooling configuration to enable integration into a LiBr-H₂O absorption refrigeration system, where water is the refrigerant. In the CO₂ 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 CO₂ compression to the LiBr-H₂O 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 CO₂ compression stream by vaporizing the refrigerant.

Only five stages of CO₂ compression were necessary for Approach 2. The compression ratios were increased from the reference cases to create a compressor outlet temperature of at least 93°C (200°F) to maintain a temperature gradient of 6°C (10°F) in the kettle reboiler. This configuration resulted in a net plant efficiency increase of 0.1 percentage points (absolute).

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

4.4 NATURAL GAS SUPPLY SYSTEM

Addition of natural gas supply system is only required for Case 1 and Case 2. It was assumed that a natural gas main with adequate capacity is in close proximity (within 16 km [10 mi]) to the site fence line and that a branch line is available for use at the site. For the purposes of this report it was also assumed that the gas will be delivered to the plant custody transfer point at 3.0 MPa (435 psig) and 38°C (100°F), which matches the state-of-the-art 2013 F-class fuel system requirements. Hence, neither a pressure reducing station with gas preheating (to prevent moisture and hydrocarbon condensation), nor a fuel booster compressor is required.

4.5 COMBUSTION TURBINE GENERATOR

A single combustion turbine generator is required for Case 1 and two CTGs are required for Case 2. Performance of the CTGs in Case 1 and Case 2 are representative of the state-of-the-art 2013 F-class turbines with an ISO base rating of 211 MW when firing natural gas. [17] In order to meet the capture system steam demand for Case 1, the base rating of the CTG was artificially increased by approximately 9 percent (ISO base rating increased to 230 MW).

Each CTG is an axial flow, single spool, constant speed unit equipped with inlet air filtration systems, inlet silencers, variable inlet guide vanes (IGV), and a dry low NO_x (DLN) combustion system. The CTGs also include 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 these cases.

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 4-4.

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Exhibit 4-4. 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 Inlet Guide Vane 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
Engine Assembly	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
NG Fuel Systems	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	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)
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

Electrical generators are provided with the CT package. The generators are assumed to be 24 kV, 3-phase, 60 Hz, constructed to meet American National Standards Institute (ANSI) and National Electrical Manufacturers Association (NEMA) standards for turbine-driven

synchronous generators. The generator is totally enclosed water-to-air-cooled (TEWAC), complete with excitation system, cooling, and protective relaying.

4.6 HEAT RECOVERY STEAM GENERATOR

A single HRSG is required for Case 1 and two HRSGs are required for Case 2. All HRSGs are configured with HP, IP, and LP steam drums. The economizer sections heat feed water in both cases and for Case 2 heats condensate in separate tube bundles. The HRSG tubes are typically composed of bare surface and/or finned tubing or pipe material. The high-temperature portions are type P91 or P22 ferritic alloy material; the low-temperature portions (less than 399°C [750°F]) are carbon steel (CS). The HRSG evaporator sections in Case 1 send 2.9 MPa (319 psia) HP steam at 217°C (423°F) to the Cansolv thermal reclaimer, 1.7 MPa (247 psia) IP steam at 204°C (400°F) to the TEG CO₂ dryer, and 0.5 MPa (73.5 psia) LP steam at 152°C (306°F) to the Cansolv regenerator reboiler.

The HRSG in Case 2 also includes superheater, reheater, and economizer sections. HP steam passes to the superheater section for heating to 566°C (1,050°F). The IP steam from the drum is superheated to 482°C (900°F) and mixed the HP turbine exhaust before being reheated to 566°C (1,050°F). The combined flows are admitted into the IP section of the steam turbine. The LP drum provides steam to the LP turbine.

Each HRSG exhausts directly to a dedicated stack (separate from the new stack for the CO₂ capture system), which is fabricated from CS plate materials and lined with Type 409 SS. The stack for each case is assumed to be 46 m (150 ft) high, and the cost is included in the HRSG account.

4.7 NOX CONTROL SYSTEM

Two measures are taken to reduce NO_x formation from the natural gas CHP auxiliary plants. The first is a DLN burner in the CTG. The DLN burners are a low NO_x design and reduce the emissions to about 9 ppmvd [17] (assumed to be approximately 98 percent NO and referenced to 15 percent O₂).

While a state-of-the-art 2013 F-class CT alone produces NO_x emissions below the limits described in Section 2.4, an SCR was included under a presumption that SCR would be required as BACT to comply with PSD requirements.

The SCR uses ammonia and a catalyst to reduce NO to N₂ and H₂O. The SCR system consists of a reactor, and ammonia supply and storage system. The SCR system is designed for 90 percent reduction while firing natural gas. [18]

Operation Description – The SCR reactor is in the flue gas path inside the HRSG between the HP and IP sections. The SCR reactor is equipped with one catalyst layer consisting of catalyst modules stacked in line on a supporting structural frame. The SCR reactor has space for installation of an additional layer. Ammonia is injected into the gas immediately prior to entering the SCR reactor. The ammonia injection grid is arranged into several sections and consists of multiple pipes with nozzles. The ammonia flow rate into each injection grid section is controlled taking into account imbalances in the flue gas flow distribution across

the HRSG. The catalyst contained in the reactor enhances the reaction between the ammonia and the NO_x in the gas. The catalyst consists of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. The optimum inlet flue gas temperature range for the catalyst is 260°C (500°F) to 343°C (650°F).

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

4.8 STEAM TURBINE IN COMBINED CYCLE

Only Case 2 adds a new steam turbine as a bottoming cycle of the NGCC.

The steam turbine included in the Case 2 NGCC CHP auxiliary plant consists of an HP section, an IP section, and a double-flow LP section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single span, opposed-flow casing, with the double-flow LP section in a separate casing.

Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 16.5 MPa/566°C (2,400 psig/1,050°F). The steam initially enters the turbine near the middle of the HP span, flows through the turbine, and is combined with steam from the IP superheater before being returned to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 4.2 MPa/566°C (608 psia/1,050°F). After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. A branch line equipped with combined stop/intercept valves conveys LP steam from the HRSG LP drum to a tie-in at the cross-over line. The steam divides into two paths and flows through the LP sections exhausting downward into the condenser. Process steam extractions are taken from the HP turbine exhaust to supply heat to the Cansolv CO₂ capture facility thermal reclaimer and CO₂ dehydration unit. Process steam for the Cansolv regenerator column reboiler is taken from the LP IP turbine exhaust. Process condensate is returned to the steam cycle condenser.

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 modern positive pressure variable clearance shaft sealing design arrangement connected to a LP steam seal system. The open-air-cooled generator produces power at 24 kV. A static, transformer type exciter is provided. The STG is controlled by a triple-redundant microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, color monitor/operator interfacing, datalink interfaces to the balance-of-plant DCS and incorporates on-line repair capability.

4.9 WATER AND STEAM SYSTEMS

4.9.1 New Condensate System

Case 2 requires a dedicated condensate system for the steam bottoming cycle. The function of the condensate system in Case 2 is to pump condensate from the condenser hotwell to the

deaerator, through the gland steam condenser, and the low-temperature economizer section in the HRSG.

The system consists of one main condenser, two 50 percent capacity, motor-driven vertical multistage condensate pumps (total of two pumps for the plant), one gland steam condenser, condenser air removal vacuum pumps, condensate polisher, and a low-temperature tube bundle in the HRSG.

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 to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

4.9.2 Feedwater

Dedicated FW systems are required for both Case 1 and Case 2.

The function of the FW system is to pump the various FW streams from the deaerator storage tank in the HRSG to the respective steam drums. One 100 percent capacity motor-driven feed pump is provided per each HRSG. The FW pumps are equipped with an interstage takeoff to provide IP and LP FW. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

4.9.3 Steam System

Modifications to the existing steam piping system of Case 0 are required to satisfy the heat requirements for the Cansolv regenerator reboiler, reclaimer, and CO₂ dryer in Case 0. Significant modifications are required to the IP/LP crossover piping to enable extraction of a large proportion of the steam flow for the regenerator reboiler. A throttling arrangement, where a backpressure control valve is used to maintain the discharge pressure of the existing IP turbine section is installed as well as the extraction piping. [45] The steam pressure at the IP/LP crossover is greater than the steam pressure required by Cansolv process. A letdown turbine is included as part of the retrofit in Case 0 to allow for some recovery of the lost power associated with the extraction at higher pressure than is required to meet the steam conditions of the CO₂ capture process. The addition of the letdown turbine to recover energy from the extracted steam as its pressure is reduced to that required for the solvent regeneration system partially mitigates the derate.

In Case 1, low pressure steam exits the HRSG low pressure evaporator section through motor-operated stop/check valves and motor-operated gate valves and is carried to the Cansolv regenerator reboiler. Intermediate and high-pressure steam exit their respective evaporator sections through motor-operated stop/check valves and motor-operated gate valves and are carried to the Cansolv thermal reclaimer and CO₂ dryer reboiler, respectively.

In Case 2 main, intermediate, and low-pressure steam exits the HRSG superheater section through motor-operated stop/check valves and motor-operated gate valves. The main steam is routed to the HP turbine stop valve. The intermediate steam is combined with the HP turbine exhaust and is conveyed through a motor-operated isolation gate valve to the HRSG reheater and from the HRSG reheater outlet through a motor-operated gate valve to the IP turbines. The low-pressure steam is combined with the IP turbine exhaust and is conveyed through a motor-operated isolation gate valve to the LP turbines.

4.9.4 Circulating Water System

A new CWS is constructed, in addition to the existing PC plant CWS, in all cases to supply additional cooling water to condense the steam turbine exhaust steam (Case 2), for the auxiliary cooling system, and for the retrofitted CO₂ capture facility. The system consists of two 50 percent capacity vertical CWP's (total of two pumps for the plant), a mechanical draft evaporative cooling tower, and interconnecting piping.

The significant quantity of steam turbine extraction in Case 0 for the acid gas removal (AGR) stripper reboiler frees up cooling capacity in the existing cooling tower. The available capacity can be used to partially supply the additional cooling demands created by the AGR. The existing PC plant CWS piping network is expanded in this case to service the AGR process.

The auxiliary cooling system in Case 1 and Case 2 is a CL system. Plate and frame heat exchangers with circulating water as the cooling medium are provided. The system provides cooling water to the following systems:

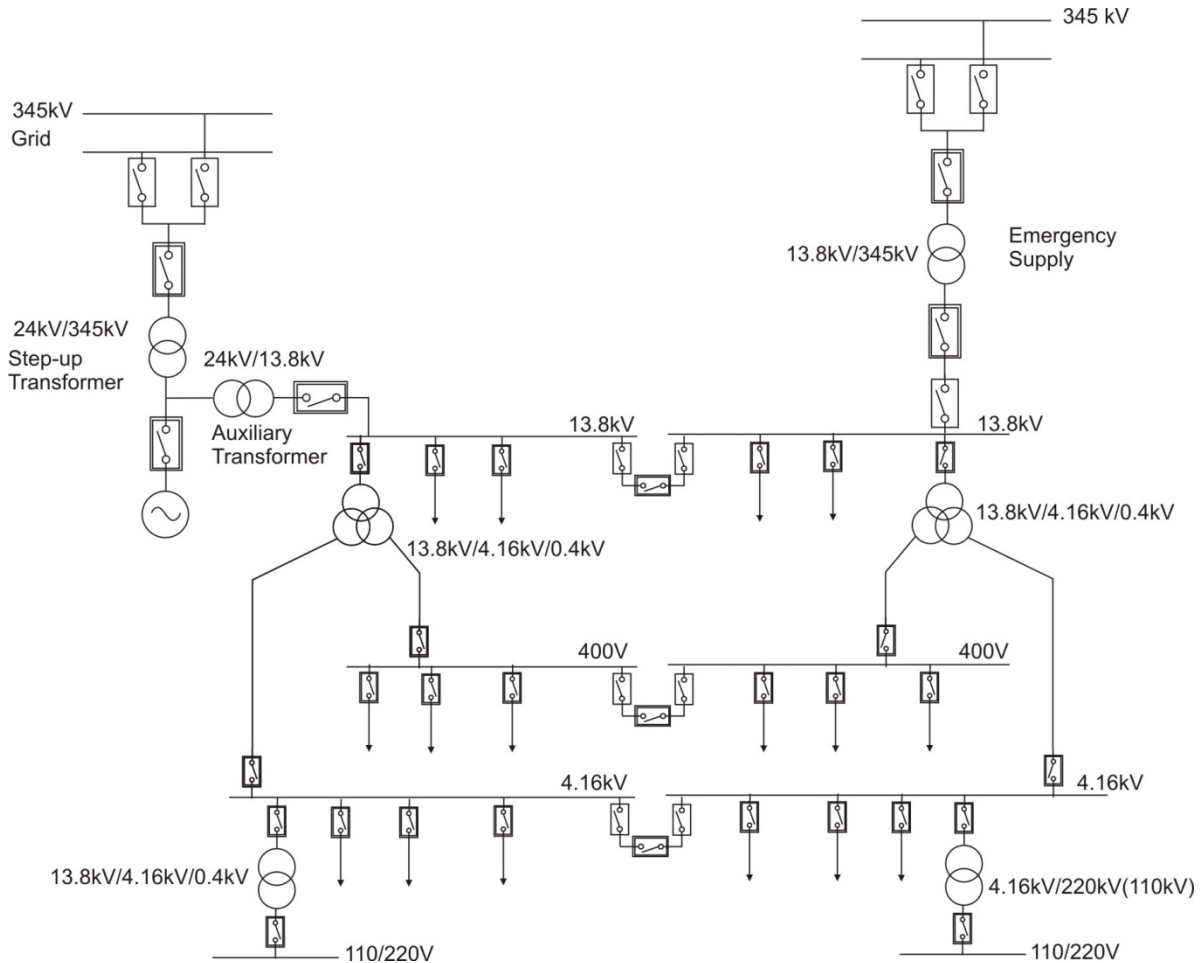
1. CTG lube oil coolers
2. CTG air coolers
3. STG lube oil coolers (Case 2 only)
4. STG hydrogen coolers (Case 2 only)
5. BFW pumps
6. Air compressors
7. Generator seal oil coolers (as applicable)
8. Sample room chillers
9. Blowdown coolers
10. Condensate extraction pump-motor coolers

The steam turbine condenser in Case 2 is a single pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

4.10 ACCESSORY ELECTRIC PLANT

When adding carbon capture and compression systems to an existing plant, the increased parasitic electrical loads can be diverted either from the existing generator (as is necessary for Case 0) or, if available, from a new electrical generator (as in Case 1 and Case 2). The actual configuration will depend on the capabilities of the existing plant and the optimizations that are possible based on the existing design capacity margins. Power flow and short circuit studies would need to be performed with the added electrical loads to determine if the operating levels are within the parameters of the existing electrical distribution equipment. However, regardless of any extra capacity in the existing plant, retrofitting currently available technologies to capture 90 percent of the plants CO₂ emissions will more than double the electrical auxiliary loads for the entire plant. In most circumstances, the resulting increase in auxiliary load will exceed normal design margins and alterations and additional equipment will be required (e.g., new bus and transformers) to provide power for export to the grid and for process auxiliaries.

Exhibit 4-5 shows a simplified single line diagram for a thermal power plant identifying the typical elements that would need to be addressed when considering necessary upgrades to existing infrastructure. Depending on the specific plant type some additional elements may exist.

Exhibit 4-5. Simplified single line diagram of the existing PC plant

For the baseline case (Case 0) of only retrofitting the CO₂ capture process to an existing plant, gross power output from the steam turbine decreases due to steam extraction, the auxiliary loads increase significantly, and substantially less net power is available for export. As a result, it is assumed that no replacement of the generation step up transformers is required for Case 0. However, due to the significant increase in total plant auxiliary loads (increase from 31 MW to 76 MW), substantial modifications are necessary to the plant auxiliary system. If this auxiliary load increase was small (within the 20 percent design margin, the typical industry standard, Institute of Electrical and Electronics Engineers (IEEE) C57.116 IEEE Guide for Transformers Directly Connected to Generators), it would be conceivable to utilize the existing auxiliary distribution system, consisting of the plant buses and auxiliary transformers. But because of the substantial CCS auxiliary loads, Case 0 would require substantial modifications to the plant auxiliary system, including additional auxiliary and low voltage transformers, and modifications (tapping) of the existing or upgraded isolated phase (isophase) bus. The isophase bus would need to be analyzed based on its existing ratings to determine if adequate capacity exists to accommodate the auxiliary load increases and additional short circuit current contribution.

The CO₂ capture process auxiliary load can be connected to the existing system or to a completely new system as shown in the simplified single line diagram in Exhibit 4-6. Adding auxiliary loads to the existing system would be expected to overload the equipment, requiring the replacement of the equipment specified in Exhibit 4-7. For each case, a new system was sized and costed to avoid any inapplicable assumptions to the existing electrical equipment.

Exhibit 4-6. Single line diagram for CO₂ capture and compression system-only retrofit

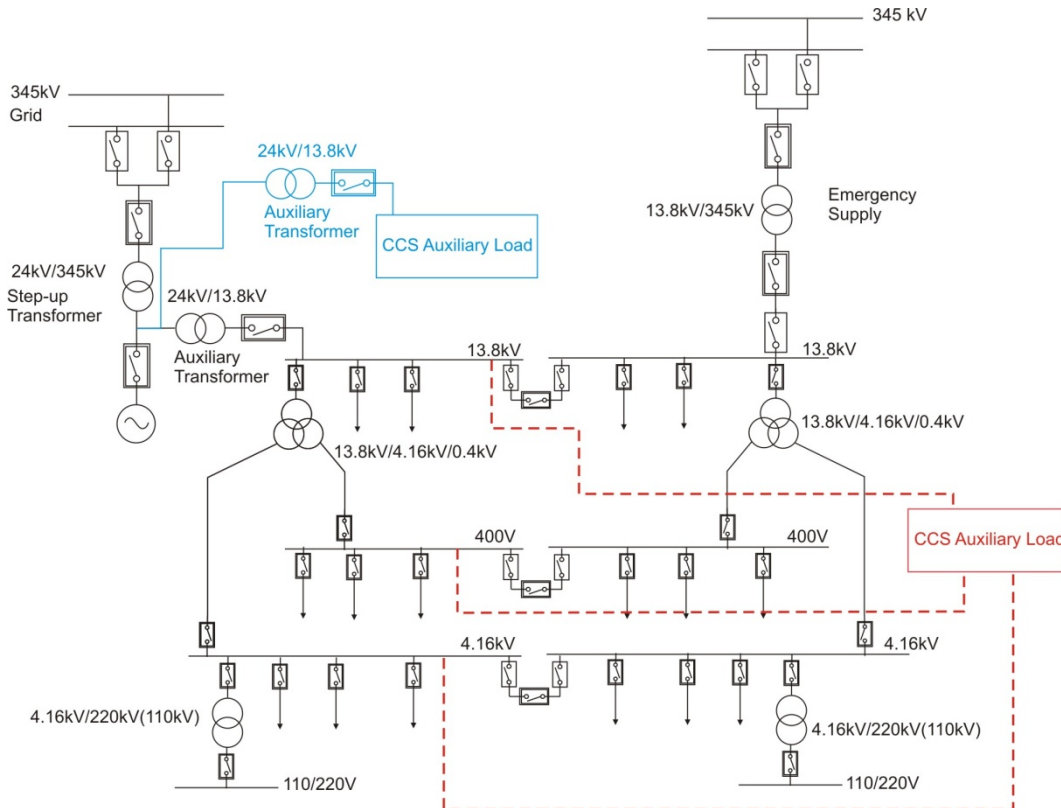


Exhibit 4-7. Electrical equipment options for CO₂ capture and compression-only retrofit

Adding to existing system	Replacement of the existing equipment: • Auxiliary TR • 3-winding TR • Switchgear
Building a new system	New equipment: • Auxiliary TR • 3-winding TR • Switchgear • Protection • Measuring devices

4.11 INSTRUMENTATION AND CONTROL

All cases include the addition of major process instrumentation; input/output (I/O) signal wiring, conduit, and junction boxes, etc. are included within the equipment package for the CO₂ capture and compression system. Additional control room hardware is included in each case to handle the integration of additional I/O points as well as an expansion of the existing plant control programming. Case 1 and Case 2 include additional equipment associated with the construction of the natural gas CHP auxiliary plant.

4.12 BALANCE OF PLANT

All cases include site improvement costs as well as buildings and structures costs as needed for the new capture system. Case 1 and Case 2 include additional costs that are associated with the CHP auxiliary plants. The costs are based on corresponding case account items in the NETL Bituminous Baseline Report. [3]

4.13 PERFORMANCE SUMMARY METRICS

This section details the methods used to calculate several metrics reported in the performance summaries of the cases incorporating CHP auxiliary plants.

Combustion Turbine Efficiency

The combustion turbine efficiency is calculated by taking the CT power produced and dividing it by the thermal input to the turbines. This calculation is represented by the equation:

$$CTE = \frac{CTP}{TI}$$

Where:

CTE – Combustion turbine efficiency

CTP – Combustion turbine power

TI – Thermal input to turbines

The thermal input is calculated by taking the natural gas feed rate and multiplying it by the heating value of the natural gas and converting it to kW.

Steam Turbine Efficiency

The steam turbine efficiency for the NGCC CHP auxiliary plant included in Case 2 is calculated as described in Section 3.11.

Steam Turbine Heat Rate

The steam turbine heat rate for the NGCC CHP auxiliary plant included in Case 2 is calculated as described in Section 3.11.

5 CASE RESULTS

The cost and performance results for each retrofit scenario are presented in this section.

The major assumption updates from previous study [2] are as follows:

- A new advanced amine post-combustion capture (PCC) system with lower steam regeneration energy and electrical auxiliaries, but higher capital cost, is included in the study. Cost and performance of the system is based on new 2012 vendor quotes. (Section 4.1)
- Only the flue gas emitted from the existing PC plant is treated with CO₂ capture system equipment. No CO₂ capture is applied to the exhaust from the NG-fired CHP systems in Case 1 or Case 2.
- Steam extraction for the existing PC plant is at the subcritical steam turbine IP-LP crossover. The steam conditions differ from prior NETL studies where the steam extraction conditions matched the steam pressure requirements of the CO₂ capture system amine regenerator.
- A letdown turbine is used to recover work from the crossover steam, expanding to the required 75 psia steam quality for the CCS process in Case 0. (Section 4.9.3 and Section 6.1.1)
- The restriction on total power generation of 110% of the existing generation was removed. Electrical grid T&D infrastructure of sufficient capacity is assumed to be present, capable, and amenable to exporting the surplus power produced in Case 1 and Case 2.
- The sizes of the CHP auxiliary plants in Case 1 and Case 2 are determined by the steam demands of the CO₂ capture system retrofitted PC plant (i.e., sufficient heat recovery in the combustion turbine exhaust). Case 1 was sized such that a single CTG could provide the required amount of steam. No duct firing is used in either case.
- The approach to sizing the CHP auxiliary plants resulted in substantial excess electrical output (compared to the auxiliary load requirements of the CO₂ capture system) from the CTG. Existing electrical grid T&D infrastructure of sufficient capacity is assumed to be present, capable, and amenable to exporting the surplus power produced in Case 1 and Case 2.

The case results are organized by the following section titles:

- *Process Description* provides an overview of the technology.
- *Key System Assumptions* provides a summary of study and modeling assumptions.
- *Sparing Philosophy* provides the number of trains for the new equipment.
- *Performance Results* provides the main modeling results, including the performance summary, environmental performance, carbon balance, sulfur balance, water balance, energy balance, and mass and energy balance diagrams.

- *Major Equipment List* provides an itemized list of major equipment with account codes that correspond to the cost accounts in the Cost Estimating section.
- *Cost Estimating* provides a summary of capital and operating costs.

5.1 RETROFIT CASE 0 – BASELINE

Case 0 represents a “base case” retrofit of a subcritical PC process with CO₂ capture where the CO₂ capture system is “integrated” into the existing steam cycle. For this baseline retrofit case, a post-combustion advanced amine CO₂ removal process (see Section 4.1) is used to treat 100 percent of the flue gas from an existing subcritical PC boiler plant, which is based on the NETL Bituminous Baseline Report Case B11A plant configuration. [3] The steam and electrical utilities required to operate the CCS facility are supplied by extracting IP steam from the existing steam cycle and diverting generator output from the grid, effectively reducing the net output available for sale from the existing PC plant.

In this retrofit case, the coal feed (and corresponding steam production) is assumed to be essentially unchanged after the retrofit, so the diverted steam and increased auxiliary loads due to CO₂ capture system retrofit reduce both the gross and net plant electricity output. A small reduction in the coal flow rate was required in the model to retain the steam design conditions after the steam diversion. Other required modifications include additional ID fans to push the flue gas through the absorber, a letdown turbine to capture some of the lost energy due to steam extraction, and a new stack sized to handle the reduced volumetric flow of flue gas. A new stack also allows for a single, less complex tie-in point to the existing flue gas duct work and reduces the facility downtime due to connection of the CO₂ capture facility during construction.

The main steam flow rate and conditions of Case 0 are the same as the existing plant. The Case 0 coal flow rate is reduced from the existing plant coal flow rate of 412,005 lb/hr to compensate for the slight reduction in boiler reheat steam mass flow resulting from the Cansolv reclaiming steam extraction requirement. As a result of the reduced coal flow, the existing steam reheat temperature of 566°C (1,050°F) is maintained in Case 0.

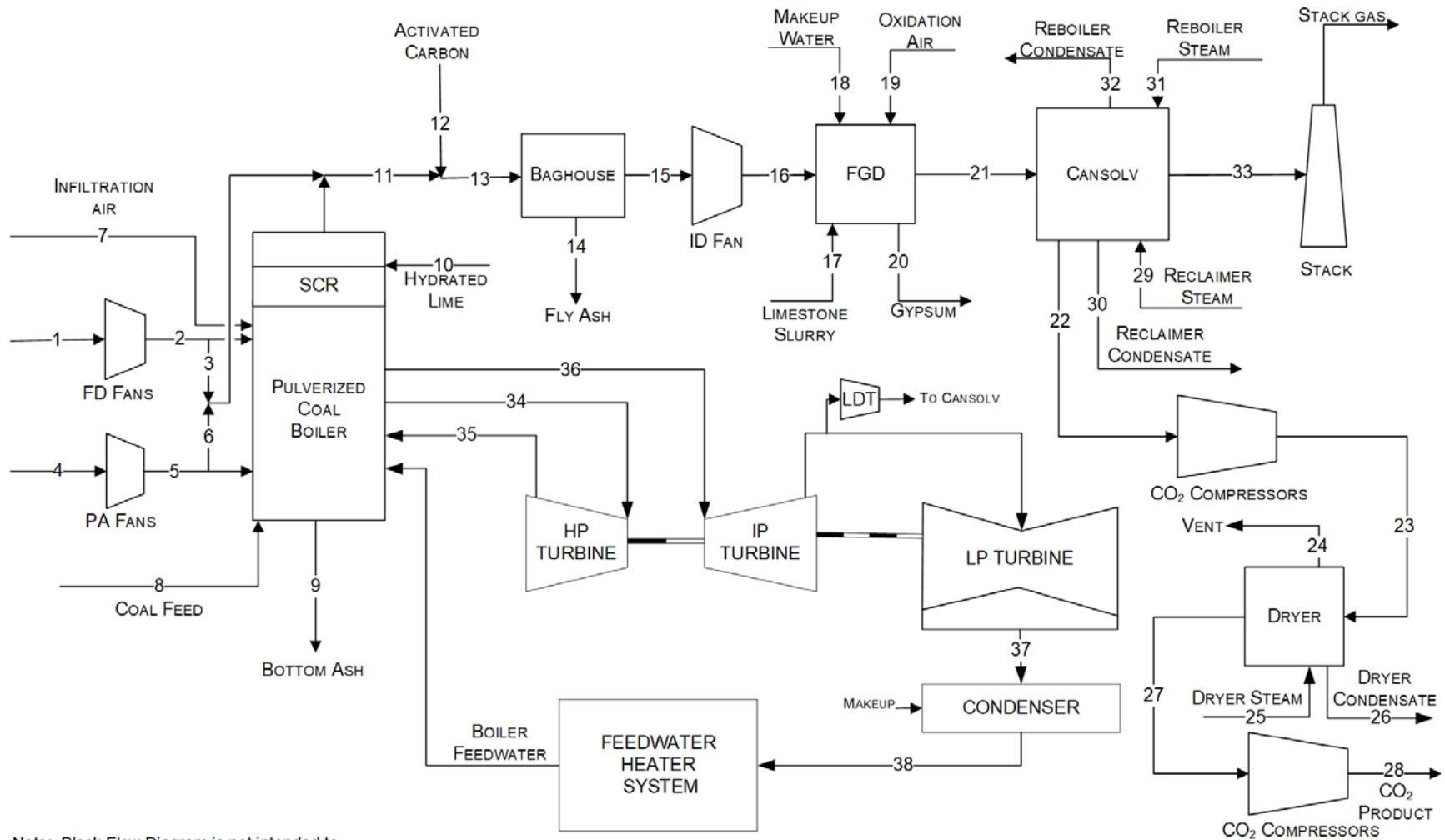
5.1.1 Process Description

The plant configuration for Case 0 is illustrated in the block flow diagram (BFD) Exhibit 5-1 and the material and energy data are presented in the tables in Exhibit 5-2.

Coal feed 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 goes into the boiler, and the infiltration air is accounted for as an additional stream. Ljungstrom air preheater leakages from the FD and PA fan outlet streams are accounted by adding the flows to the boiler exhaust.

Flue gas exits the boiler through the SCR reactor where ammonia is injected to reduce NO_x compounds, followed by hydrated lime injection for the reduction of SO₃. It then passes through the combustion air preheater (where the air preheater leakages are introduced) and is cooled to 143°C (289°F) before PAC is injected for mercury reduction. The flue gas then

passes through a fabric filter for particulate removal. An ID fan increases the flue gas temperature to 153°C (308°F) and provides the motive force for the flue gas to pass through the FGD unit. FGD inputs and outputs include makeup water, oxidation air, limestone slurry and product gypsum. The clean, saturated flue gas exiting the FGD unit passes to the Cansolv CO₂ capture system, then on to the plant stack and is discharged to the atmosphere. Since the Cansolv facility process description was provided in Section 4.1, it is not repeated here.

Exhibit 5-1. Case 0 block flow diagram, subcritical unit with CO₂ capture

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

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Exhibit 5-2. Case 0 stream table, subcritical unit with capture

	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	0.0000	0.0088	0.0000	0.0088	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1376	0.0000	0.1376	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 ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0000	0.0831	0.0000	0.0831	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7345	0.0000	0.7345	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0340	0.0000	0.0340	0.3333
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0020	0.0000	0.0020	0.6667
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg _{mole} /hr)	51,524	51,524	1,526	15,828	15,828	2,178	1,125	0	0	0	72,220	0	72,220	3
V-L Flowrate (kg/hr)	1,486,833	1,486,833	44,037	456,740	456,740	62,859	32,475	0	0	0	2,144,785	0	2,144,785	164
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	186,857	3,624	3,766	18,261	109	18,370	18,370
Temperature (°C)	15	19	19	15	25	25	15	15	149	27	143	27	143	143
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	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	0.00	0.00	0.00	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,114.05	97.18	-13,306.82	-2,399.44	3.40	-2,399.31	-2,632.09
Density (kg/m ³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	---	0.9	---	0.9	1.5
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	---	29.698	---	29.698	53.376
V-L Flowrate (lb _{mole} /hr)	113,592	113,592	3,364	34,894	34,894	4,802	2,481	0	0	0	159,219	0	159,219	7
V-L Flowrate (lb/hr)	3,277,905	3,277,905	97,085	1,006,938	1,006,938	138,581	71,596	0	0	0	4,728,442	0	4,728,442	362
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	411,949	7,989	8,302	40,259	240	40,499	40,499
Temperature (°F)	59	66	66	59	78	78	59	59	300	80	289	80	289	289
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.4	14.7	14.4	14.7	14.4	14.4
Steam Table Enthalpy (Btu/lb) ^A	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-908.9	41.8	-5,720.9	-1,031.6	1.5	-1,031.5	-1,131.6
Density (lb/ft ³)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	---	0.053	---	0.053	0.096

^ASteam table reference conditions are 32.02°F and 0.089 psia.

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm.

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Exhibit 5-2. Case 0 stream table, subcritical unit with capture (continued)

	15	16	17	18	19	20	21	22	23	24	25	26
V-L Mole Fraction												
Ar	0.0088	0.0088	0.0000	0.0000	0.0092	0.0000	0.0082	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.1376	0.1376	0.0000	0.0000	0.0003	0.0001	0.1288	0.9824	0.9977	0.0503	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
H ₂ O	0.0831	0.0831	1.0000	1.0000	0.0099	0.9999	0.1451	0.0176	0.0023	0.9497	1.0000	1.0000
N ₂	0.7345	0.7345	0.0000	0.0000	0.7732	0.0000	0.6854	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0340	0.0340	0.0000	0.0000	0.2074	0.0000	0.0325	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0020	0.0020	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 _{mole} /hr)	72,217	72,217	2,394	9,596	764	177	78,258	9,235	9,093	15	12	12
V-L Flowrate (kg/hr)	2,144,621	2,144,621	43,124	172,882	22,039	3,183	2,257,913	402,201	399,657	291	211	211
Solids Flowrate (kg/hr)	0	0	18,464	0	0	28,637	0	0	0	0	0	0
Temperature (°C)	143	153	15	27	167	56	56	29	29	29	476	203
Pressure (MPa, abs)	0.10	0.11	0.10	0.11	0.31	0.10	0.10	0.20	3.03	3.03	2.42	1.70
Steam Table Enthalpy (kJ/kg) ^A	274.35	285.60	---	111.65	184.48	---	286.09	42.52	-6.01	137.66	3,408.95	863.91
AspenPlus Enthalpy (kJ/kg) ^B	-2,397.30	-2,386.05	- 14,995.75	- 15,964.53	56.67	- 12,481.91	-2,940.24	-8,972.02	-8,974.91	- 15,221.54	- 12,571.34	- 15,116.38
Density (kg/m ³)	0.8	0.9	1,003.6	992.3	2.4	833.1	1.1	3.5	63.3	372.2	7.1	861.8
V-L Molecular Weight	29.697	29.697	18.015	18.015	28.857	18.018	28.852	43.553	43.950	19.322	18.015	18.015
V-L Flowrate (lb _{mole} /hr)	159,212	159,212	5,277	21,156	1,684	389	172,530	20,359	20,048	33	26	26
V-L Flowrate (lb/hr)	4,728,080	4,728,080	95,073	381,139	48,588	7,017	4,977,847	886,702	881,093	642	465	465
Solids Flowrate (lb/hr)	0	0	40,707	0	0	63,134	0	0	0	0	0	0
Temperature (°F)	289	308	59	80	332	133	133	85	85	85	888	397
Pressure (psia)	14.2	15.2	15.0	15.7	45.0	14.7	14.7	28.7	439.4	439.4	350.5	247.3
Steam Table Enthalpy (Btu/lb) ^A	118.0	122.8	---	48.0	79.3	---	123.0	18.3	-2.6	59.2	1,465.6	371.4
AspenPlus Enthalpy (Btu/lb) ^B	-1,030.7	-1,025.8	-6,447.0	-6,863.5	24.4	-5,366.3	-1,264.1	-3,857.3	-3,858.5	-6,544.1	-5,404.7	-6,498.9
Density (lb/ft ³)	0.052	0.055	62.650	61.950	0.153	52.009	0.067	0.216	3.953	23.235	0.446	53.800

^ASteam table reference conditions are 32.02°F and 0.089 psia.

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm.

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Exhibit 5-2. Case 0 stream table, subcritical unit with capture (continued)

	27	28	29	30	31	32	33	34	35	36	37	38
V-L Mole Fraction												
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0103	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.9993	0.9993	0.0000	0.0000	0.0000	0.0000	0.0163	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
H ₂ O	0.0007	0.0007	1.0000	1.0000	1.0000	1.0000	0.0671	1.0000	1.0000	1.0000	1.0000	1.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.8652	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0410	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
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 _{mole} /hr)	9,078	9,078	69	69	22,881	22,881	61,992	87,854	81,932	81,932	49,456	50,523
V-L Flowrate (kg/hr)	399,366	399,366	1,246	1,246	412,206	412,206	1,728,909	1,582,720	1,476,027	1,476,027	890,965	910,188
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	29	40	355	215	368	151	41	566	355	566	38	39
Pressure (MPa, abs)	2.89	15.27	4.28	2.20	1.13	0.51	0.10	16.65	4.28	4.19	0.01	2.04
Steam Table Enthalpy (kJ/kg) ^A	-5.92	-205.59	3,098.44	921.65	3,192.60	635.95	151.94	3,473.89	3,098.44	3,593.58	1,981.35	163.34
AspenPlus Enthalpy (kJ/kg) ^B	-8,970.17	-9,169.84	-	-	-	-	-794.65	-	-	-	-	-
Density (kg/m ³)	59.9	789.2	16.0	846.4	3.9	916.3	1.1	47.7	16.0	11.1	0.1	993.6
V-L Molecular Weight	43.991	43.991	18.015	18.015	18.015	18.015	27.889	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mole} /hr)	20,014	20,014	152	152	50,444	50,444	136,670	193,686	180,629	180,629	109,032	111,384
V-L Flowrate (lb/hr)	880,451	880,451	2,747	2,747	908,759	908,759	3,811,592	3,489,300	3,254,082	3,254,082	1,964,242	2,006,622
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	85	104	671	419	694	304	107	1,050	671	1,050	101	101
Pressure (psia)	419.4	2,214.7	620.5	319.0	164.3	73.5	14.7	2,414.7	620.5	608.1	1.0	295.5
Steam Table Enthalpy (Btu/lb) ^A	-2.5	-88.4	1,332.1	396.2	1,372.6	273.4	65.3	1,493.5	1,332.1	1,545.0	851.8	70.2
AspenPlus Enthalpy (Btu/lb) ^B	-3,856.5	-3,942.3	-5,538.2	-6,474.0	-5,497.7	-6,596.9	-341.6	-5,376.8	-5,538.2	-5,325.3	-6,018.5	-6,800.1
Density (lb/ft ³)	3.737	49.267	1.000	52.840	0.244	57.202	0.068	2.975	1.000	0.692	0.004	62.028

^ASteam table reference conditions are 32.02°F and 0.089 psia.

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm.

5.1.2 Key System Assumptions

System assumptions for Case 0, subcritical PC with CCS retrofit, are compiled in Exhibit 5-3. The balance of plant assumptions for Case 0 are presented in Exhibit 5-4.

Exhibit 5-3. Subcritical PC plant retrofit baseline study configuration matrix

Parameter	Case 0
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/566 (2,400/1,050/1,050)
Coal	Illinois No. 6
Condenser Pressure, mm Hg (in Hg)	50.8 (2)
Boiler Efficiency, HHV %	89
Cooling Water to Condenser, °C (°F)	16 (60)
Cooling Water from Condenser, °C (°F)	27 (80)
Stack Temperature, °C (°F)	56 (133)
SO ₂ Control	Wet Limestone Forced Oxidation
FGD Efficiency ^A , %	98 ^{B,C}
NO _x Control	LNB w/OFA, SCR, and Polishing Scrubber
SCR Efficiency ^A , %	83
Ammonia Slip (end of catalyst life), ppmv	2
Particulate Control	Fabric Filter
Fabric Filter Efficiency ^A , %	99.9
Ash Distribution, Fly/Bottom	80%/20%
SO ₃ Control	DSI
Mercury Control	Co-benefit Capture and ACI
CO ₂ Control	Cansolv (PC plant flue gas only)
Carbon Capture Efficiency ^A	90%
CO ₂ Sequestration	Off-site Saline Formation

^ARemoval efficiencies are based on the flue gas content.

^BAn SO₂ polishing step is included to meet more stringent oxides of sulfur (SO_x) content limits in the flue gas (~1 ppmv) to reduce formation of amine HSS during the CO₂ absorption process.

^CSO₂ exiting the post-FGD polishing step is absorbed in the CO₂ capture process making stack emissions negligible.

Exhibit 5-4. Case 0 balance of plant assumptions

Parameter	Value
Cooling System	Recirculating Wet Cooling Tower
Fuel and Other Storage	
Coal	30 days
Ash	30 days
Gypsum	30 days
Limestone	30 days
Hydrated lime	30 days
Activated carbon	30 days
Plant Distribution Voltage	
Motors below 1 hp	110/220 V
Motors between 1 hp and 250 hp	480 V
Motors between 250 hp and 5,000 hp	4,160 V
Motors above 5,000 hp	13,800 V
Steam and CT generators	24,000 V
Grid interconnection voltage	345 kV
Water and Wastewater	
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.

5.1.3 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 PCC plant design consists of the following major subsystem: one amine CO₂ absorption system consisting of an absorber, stripper, and ancillary equipment (1 x 100 percent) and two CO₂ compression systems (2 x 50 percent).

5.1.4 Case 0 – Performance Results

The plant produces a net output of 425 MWe at a net plant efficiency of 30.2 percent (HHV basis). Overall performance for the plant is summarized in Exhibit 5-5. Exhibit 5-6 provides a detailed breakdown of the auxiliary power requirements.

Exhibit 5-5. Case 0 plant performance summary

Performance Summary	
Existing Steam Turbine Power, MWe	484
Letdown Turbine Power, MWe	17
Total Gross Power, MWe	501
CO ₂ Capture/Removal Auxiliaries, kWe	13,300
CO ₂ Compression, kWe	29,180
Balance of Plant, kWe	33,683
Total Auxiliaries, MWe	76
Net Power, MWe	425
HHV Net Plant Efficiency (%)	30.2%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,924 (11,301)
LHV Net Plant Efficiency (%)	31.3%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,501 (10,900)
HHV Boiler Efficiency, %	89.1%
LHV Boiler Efficiency, %	92.4%
Steam Turbine Cycle Efficiency, %	51.2%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,027 (6,660)
Condenser Duty, GJ/hr (MMBtu/hr)	1,620 (1,536)
As-Received Coal Feed, kg/hr (lb/hr)	186,857 (411,949)
Limestone Sorbent Feed, kg/hr (lb/hr)	18,464 (40,707)
HHV Thermal Input, kWt	1,408,440
LHV Thermal Input, kWt	1,358,457
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.060 (15.8)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.046 (12.1)
Excess Air, %	20.9%

Exhibit 5-6. Case 0 plant power summary

Power Summary	
Existing Steam Turbine Power, MWe	484
Letdown Turbine Power, MWe	17
Total Gross Power, MWe	501
Auxiliary Load Summary	
Coal Handling and Conveying, kWe	440
Pulverizers, kWe	2,800
Sorbent Handling & Reagent Preparation, kWe	890
Ash Handling, kWe	650
Primary Air Fans, kWe	1,390
Forced Draft Fans, kWe	1,770
Induced Draft Fans, kWe	6,940
SCR, kWe	50
Activated Carbon Injection, kWe	23
Dry Sorbent Injection, kWe	90
Baghouse, kWe	90
Wet FGD, kWe	2,950
CO ₂ Capture/Removal Auxiliaries, kWe	13,300
CO ₂ Compression, kWe	29,180
Miscellaneous Balance of Plant ^{A,B} , kWe	2,000
Steam Turbine Auxiliaries, kWe	400
Condensate Pumps, kWe	680
Circulating Water Pumps, kWe	6,610
Ground Water Pumps, kWe	610
Cooling Tower Fans, kWe	3,420
Transformer Losses, kWe	1,880
Total Auxiliaries, MWe	76
Net Power, MWe	425

^ABoiler feed pumps are turbine driven.

^BIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads.

5.1.4.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case 0 is presented in Exhibit 5-7. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 5-7. Case 0 air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year) ^A	kg/MWh (lb/MWh)
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.031 (0.073)	1,185 (1,307)	0.318 (0.700)
Particulate	0.004 (0.009)	152 (168)	0.041 (0.090)
Hg	1.35E-7 (3.13E-7)	0.005 (0.006)	1.36E-6 (3.00E-6)
CO ₂ ^B	9 (20)	330,338 (364,135)	88 (195)
CO ₂ ^C	-	-	104 (230)
	mg/Nm ³		
Particulate Concentration ^{D,E}	12.65		

^ACalculations based on an 85 percent capacity factor.

^BCO₂ emissions based upon gross power.

^CCO₂ emissions based on net power.

^DConcentration of particles in the flue gas after the baghouse.

^ENormal conditions given at 32°F and 14.696 psia.

SO₂ emissions 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 SO₂ emissions are further reduced to 1 ppmv using a sodium hydroxide (NaOH)-based polishing scrubber in the CCS facility. The remaining low concentration of SO₂ is essentially completely removed in the CCS absorber vessel resulting in very low SO₂ emissions.

NO_x emissions are controlled to about 0.5 lb/MMBtu using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 83 percent to 0.08 lb/MMBtu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and wet FGD) is 96.8 percent.

CO₂ emissions represent controlled emissions by the retrofitted CO₂ capture facility.

The carbon balance for the plant is shown in Exhibit 5-8. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon that is not captured for geologic storage, leaves the plant mostly as CO₂ through the stack; however, the PAC is captured in the fabric filter and some leaves as gypsum.

Exhibit 5-8. Case 0 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	119,111 (262,596)	Stack Gas	12,108 (26,693)
Air (CO ₂)	272 (599)	FGD Product	179 (394)
PAC	109 (240)	Baghouse	109 (240)
FGD Reagent	1,874 (4,130)	CO ₂ Product	108,961 (240,218)
		CO ₂ Dryer Vent	9 (20)
		CO ₂ Knockout	0 (0)
Total	121,365 (267,565)	Total	121,365 (267,565)

Exhibit 5-9 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, sulfur emitted in the stack gas, and sulfur removed in the polishing scrubber.

Exhibit 5-9. Case 0 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	4,683 (10,325)	FGD Product	4,525 (9,976)
		Stack Gas	0 (0)
		Polishing Scrubber and Solvent Reclaiming	92 (204)
		Baghouse	66 (145)
Total	4,683 (10,325)	Total	4,683 (10,325)

Exhibit 5-10 shows the water balance for Case 0. Water demand, withdrawal, and consumption are discussed in Section 2.6.

Exhibit 5-10. Case 0 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
FGD Makeup	3.60 (952)	–	3.60 (952)	–	3.60 (952)
CO ₂ Drying	–	–	–	0.00 (1)	0.00 (-1)
Capture System Makeup	0.02 (4)	–	0.02 (4)	–	0.02 (4)
Deaerator Vent	–	–	–	0.05 (14)	-0.05 (-14)
Condenser Makeup	0.32 (85)	–	0.32 (85)	–	0.32 (85)
BFW Makeup	0.32 (85)	–	0.32 (85)	–	0.32 (85)
Cooling Tower	25.74 (6,801)	4.28 (1,131)	21.46 (5,670)	5.79 (1,529)	15.67 (4,140)
FGD Dewatering	–	1.86 (491)	-1.86 (-491)	–	-1.86 (-491)
CO ₂ Capture Recovery	–	2.11 (558)	-2.11 (-558)	–	-2.11 (-558)
CO ₂ Compression KO	–	0.04 (11)	-0.04 (-11)	–	-0.04 (-11)
BFW Blowdown	–	0.27 (71)	-0.27 (-71)	–	-0.27 (-71)
Total	29.69 (7,842)	4.28 (1,131)	25.40 (6,711)	5.85 (1,545)	19.56 (5,166)

5.1.4.2 Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case 0 PC boiler and gas cleanup systems in Exhibit 5-11 and the PC plant steam cycle in Exhibit 5-12.

An overall plant energy balance is provided in tabular form in Exhibit 5-13. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-5) is calculated by multiplying the power out by a generator efficiency of 98.5 percent. A Sankey diagram is presented in Exhibit 5-14, illustrating the flow of energy into and out of the plant.

Exhibit 5-11. Case 0 heat and mass balance, subcritical PC boiler with CO₂ capture

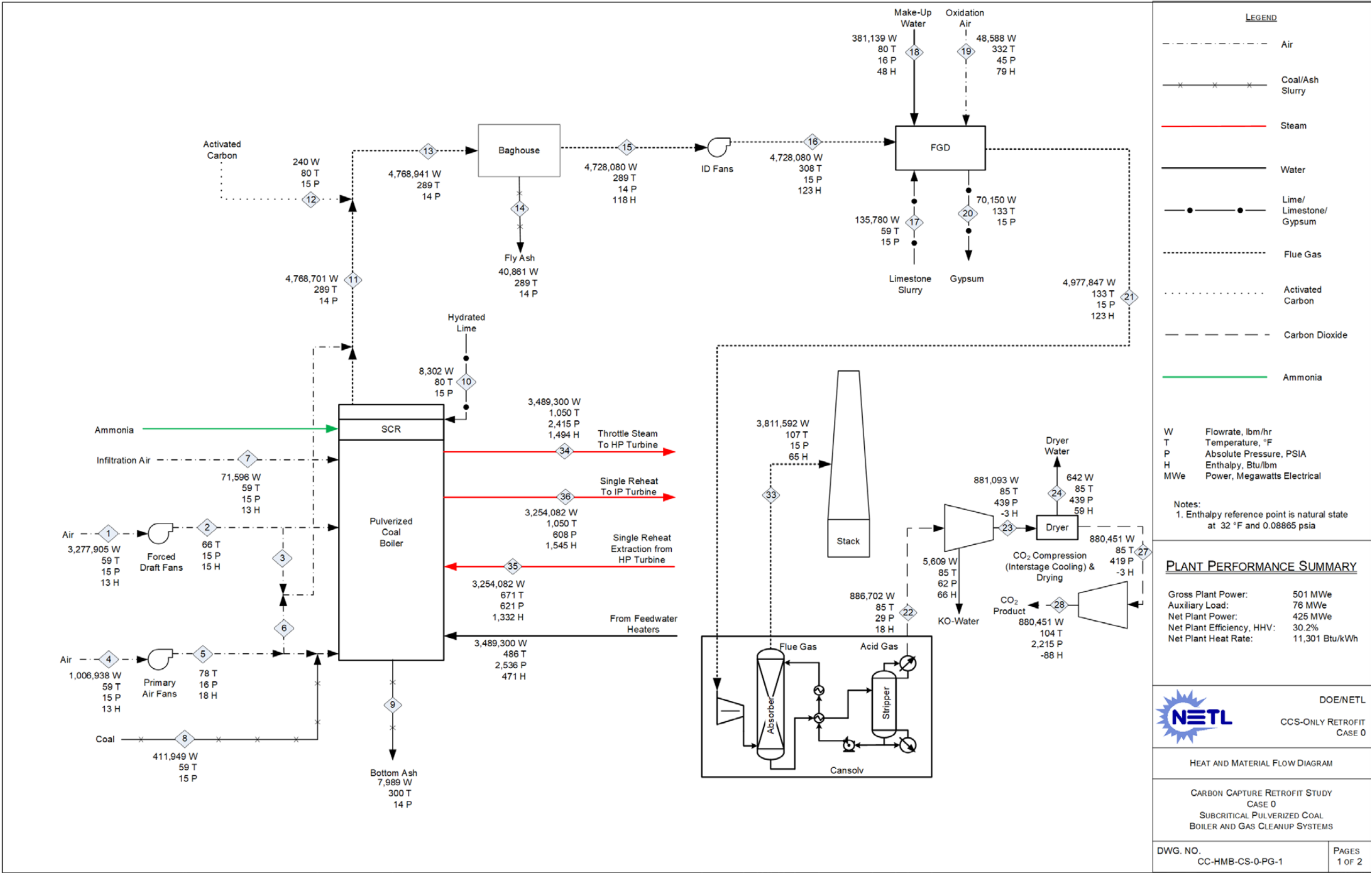
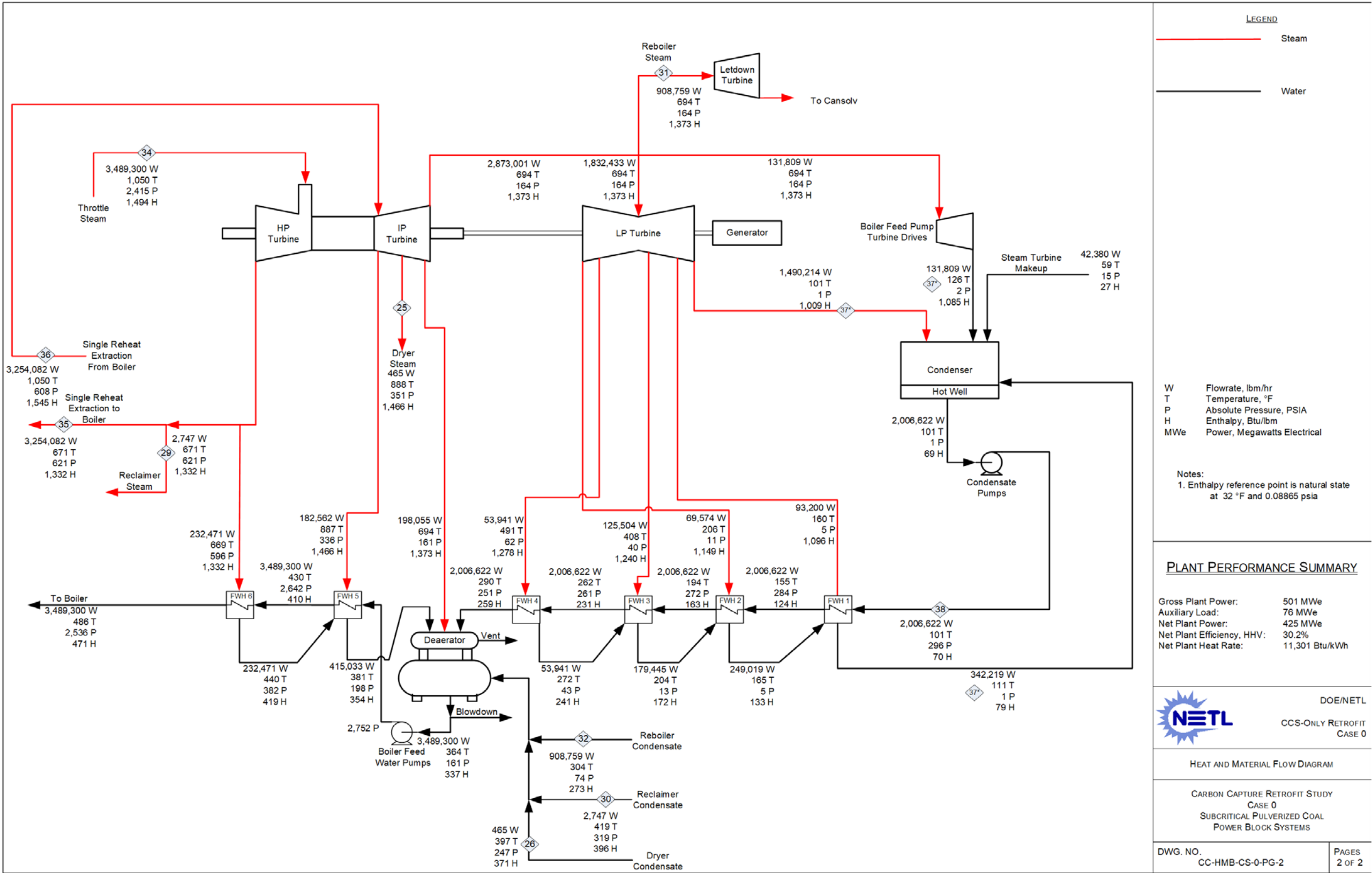


Exhibit 5-12. Case 0 heat and mass balance, subcritical steam cycle



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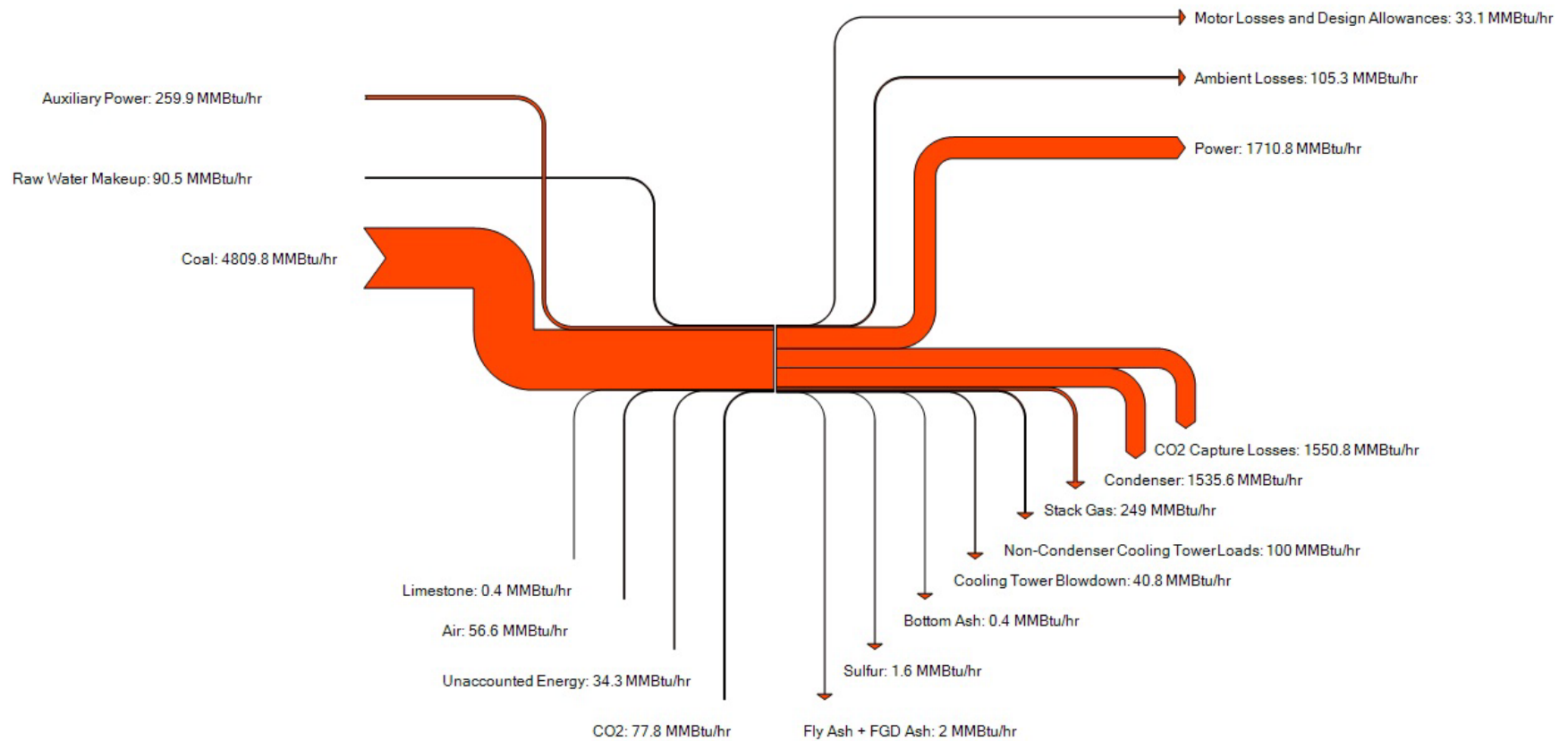
Exhibit 5-13. Case 0 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,070 (4,806)	4.2 (4.0)	–	5,075 (4,810)
Air	–	59.7 (56.6)	–	59.7 (56.6)
Raw Water Makeup	–	95.5 (90.5)	–	95.5 (90.5)
Limestone	–	0.40 (0.38)	–	0.40 (0.38)
Auxiliary Power	–	–	274 (260)	274 (260)
TOTAL	5,070 (4,806)	159.9 (151.5)	274 (260)	5,504 (5,217)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	0.4 (0.4)	–	0.4 (0.4)
Fly Ash + FGD Ash	–	2.1 (2.0)	–	2.1 (2.0)
Stack Gas	–	263 (249)	–	263 (249)
Sulfur	1.7 (1.6)	0.0 (0.0)	–	1.7 (1.6)
Motor Losses and Design Allowances	–	–	35 (33)	35 (33)
Condenser	–	1,620 (1,536)	–	1,620 (1,536)
Miscellaneous Non-Condenser Cooling Tower Loads	–	105 (100)	–	105 (100)
CO ₂	–	-82.1 (-77.8)	–	-82.1 (-77.8)
Cooling Tower Blowdown	–	43.0 (40.8)	–	43.0 (40.8)
CO ₂ Capture Losses	–	1,636 (1,551)	–	1,636 (1,551)
<i>Ambient Losses^A</i>	–	111.1 (105.3)	–	111.1 (105.3)
Power	–	–	1,805 (1,711)	1,805 (1,711)
TOTAL	1.7 (1.6)	3,699 (3,506)	1,840 (1,744)	5,541 (5,252)
Unaccounted Energy ^B	–	-36 (-34)	–	-36 (-34)

^AAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers.

^BBy difference.

Exhibit 5-14. Case 0 Sankey diagram



5.1.5 Case 0 – Major Equipment List

Equipment lists showing the major retrofitted equipment items for Case 0 are shown in the following tables. The major equipment list is not intended to be all-inclusive of required modifications but rather to identify key equipment items and applicable design conditions. The account identifications (e.g., Account 5B: Carbon Dioxide Recovery) in the equipment list correspond to the account numbers used in the cost estimates in Section 5.1.6. 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 0 – Account 5B: Carbon Dioxide Recovery

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Cansolv	Amine-based CO ₂ capture technology	2,484,000 kg/hr (5,476,000 lb/hr) 19.6 wt% CO ₂ concentration	1	0
2	Letdown Turbine	Commercially available	19 MW, 1 MPa @ 288 °C (74 psig @ 551 °F)	1	0
3	Letdown Turbine Generator	Commercially available	20 MVA @ 24 kV (1 p.f. @ 60 Hz)	1	0
4	Cansolv LP Condensate Pump	Centrifugal	8,593 lpm @ 1 m H ₂ O (2,270 gpm @ 4 ft H ₂ O)	1	1
5	Cansolv IP Condensate Pump	Centrifugal	5 lpm @ 3.7 m H ₂ O (1 gpm @ 12 ft H ₂ O)	1	1
6	CO ₂ Dryer	Triethylene glycol	Inlet: 105.0 m ³ /min (3,715 acfm) @ 3.0 MPa (439 psia) Outlet: 2.9 MPa (419 psia) Water Recovered: 291 kg/hr (642 lb/hr)	1	0
7	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	219,585 kg/hr @ 15.3 MPa (484,103 lb/hr @ 2,215 psia)	2	0

Case 0 – Account 7: Ducting and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 5.0 m (17 ft) diameter	1	0

Case 0 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	323,000 lpm @ 30 m (47,000 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/ 1060 GJ/hr (1000 MMBtu/hr) heat duty	1	0

Case 0 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 500 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 16 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 83 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 12 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case 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 black and white)	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

5.1.6 Case 0 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 5-15 shows a detailed breakdown of the capital costs including the major equipment items identified in Section 5.1.5 as well as other capital expenditures required to facilitate the retrofit. The costs for the additional equipment required for the CCS retrofit were scaled from the NETL Bituminous Baseline Report cases as well as other costs developed as part of baseline series. [3, 46] Exhibit 5-16 identifies owner's costs, along with the TOC and TASC; Exhibit 5-17 shows the initial and annual O&M costs; and Exhibit 5-18 shows the COE breakdown.

The estimated TPC of the subcritical PC boiler with retrofitted CO₂ capture and no auxiliary plant repowering is \$1,743/kW. Process contingency represents 7.8 percent of the TPC and project contingency represents 14.5 percent. The COE is \$113.6/MWh.

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Exhibit 5-15. Case 0 total plant cost details (without retrofit contingency)

Case:		0	– Subcritical PC w/CCS Retrofit				Estimate Type:			Conceptual	
Plant Size (MW,net):		425					Cost Base:			Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost (excluding RCF)	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1 Coal & Sorbent Handling											
1.1	Coal Receive & Unload	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.2	Coal Stackout & Reclaim	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.3	Coal Conveyors	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.4	Other Coal Handling	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.5	Sorbent Receive & Unload	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.6	Sorbent Stackout & Reclaim	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.7	Sorbent Conveyors	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.8	Other Sorbent Handling	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.9	Coal & Sorbent Hnd. Foundations	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2 Coal & Sorbent Prep & Feed											
2.1	Coal Crushing & Drying	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2.2	Coal Conveyor to Storage	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2.5	Sorbent Prep Equipment	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2.6	Sorbent Storage & Feed	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2.9	Coal & Sorbent Feed Foundation	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3 Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3.2	Water Makeup & Pretreating	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3.3	Other Feedwater Subsystems	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3.4	Service Water Systems	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3.5	Other Boiler Plant Systems	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3.6	FO Supply Sys & Nat Gas	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3.7	Waste Treatment Equipment	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3.8	Misc. Equip. (Cranes, Air Comp., Comm.)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0

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Case:		0	– Subcritical PC w/CCS Retrofit				Estimate Type:		Conceptual		
Plant Size (MW,net):		425					Cost Base:		Jun 2011		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost (excluding RCF)	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
	Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4 Boiler & Accessories											
4.1	PC Boiler & Accessories	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.2	SCR	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.5	Primary Air System	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.6	Secondary Air System	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.8	Major Component Rigging	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.9	Boiler Foundations	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A Gas Cleanup & Piping											
5A.1	Absorber Vessels & Accessories	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A.2	Other FGD	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A.3	Bag House & Accessories	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A.4	Other Particulate Removal Materials	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A.5	Gypsum Dewatering System	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A.6	Mercury Removal System	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5B CO ₂ Removal & Compression											
5B.1	CO ₂ Removal System	\$150,883	\$55,166	\$117,856	\$0	\$323,904	\$27,912	\$55,825	\$72,572	\$480,213	\$1,129
5B.2	CO ₂ Compression & Drying	\$44,547	\$6,682	\$14,667	\$0	\$65,897	\$6,590	\$0	\$14,497	\$86,984	\$205
5B.3	CO ₂ Removal System Let Down Turbine	\$10,011	\$0	\$1,147	\$0	\$11,158	\$1,116	\$0	\$1,227	\$13,501	\$32
	Subtotal	\$205,441	\$61,848	\$133,670	\$0	\$400,958	\$35,618	\$55,825	\$88,297	\$580,698	\$1,366
7 HRSG, Ducting, & Stack											
7.3	PC Plant Ductwork	\$8,538	\$0	\$5,390	\$0	\$13,928	\$1,393	\$0	\$2,298	\$17,619	\$41
7.4	PC Plant Stack	\$10,133	\$0	\$5,889	\$0	\$16,022	\$1,602	\$0	\$1,762	\$19,387	\$46
7.9	PC Plant Duct & Stack Foundations	\$0	\$1,051	\$1,248	\$0	\$2,300	\$230	\$0	\$506	\$3,036	\$7
	Subtotal	\$18,672	\$1,051	\$12,527	\$0	\$32,250	\$3,225	\$0	\$4,566	\$40,041	\$94
8 Steam Turbine Generator											
8.1	Steam TG & Accessories	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0

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Case:		0	– Subcritical PC w/CCS Retrofit				Estimate Type:		Conceptual		
Plant Size (MW,net):		425					Cost Base:		Jun 2011		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost (excluding RCF)	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
8.2	Turbine Plant Auxiliaries	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
8.3	Condenser & Auxiliaries	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
8.4	Steam Piping	\$10,088	\$0	\$4,089	\$0	\$14,177	\$1,418	\$1,418	\$2,339	\$19,352	\$46
8.9	TG Foundations	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$10,088	\$0	\$4,089	\$0	\$14,177	\$1,418	\$1,418	\$2,339	\$19,352	\$46
9 Cooling Water System											
9.1	Cooling Towers	\$5,254	\$0	\$1,625	\$0	\$6,880	\$688	\$0	\$757	\$8,324	\$20
9.2	Circulating Water Pumps	\$1,066	\$0	\$68	\$0	\$1,134	\$113	\$0	\$125	\$1,372	\$3
9.3	Circ. Water System Auxiliaries	\$323	\$0	\$43	\$0	\$366	\$37	\$0	\$40	\$443	\$1
9.4	Circ. Water Piping	\$0	\$3,982	\$3,606	\$0	\$7,588	\$759	\$0	\$1,252	\$9,599	\$23
9.5	Make-up Water System	\$205	\$0	\$264	\$0	\$469	\$47	\$0	\$77	\$593	\$1
9.6	Component Cooling Water Sys.	\$263	\$0	\$202	\$0	\$466	\$47	\$0	\$77	\$589	\$1
9.9	Circ. Water Foundations & Structures	\$0	\$1,513	\$2,513	\$0	\$4,026	\$403	\$0	\$886	\$5,314	\$12
	Subtotal	\$7,112	\$5,495	\$8,320	\$0	\$20,928	\$2,093	\$0	\$3,214	\$26,234	\$62
10 Ash & Spent Sorbent Handling Systems											
10.6	Ash Storage Silos	\$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
10.9	Ash/Spent Sorbent Foundation	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
11 Accessory Electric Plant											
11.1	Generator Equipment	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
11.2	Station Service Equipment	\$3,905	\$0	\$1,309	\$0	\$5,215	\$521	\$0	\$430	\$6,166	\$15
11.3	Switchgear & Motor Control	\$4,483	\$0	\$779	\$0	\$5,261	\$526	\$0	\$579	\$6,366	\$15
11.4	Conduit & Cable Tray	\$0	\$3,074	\$9,931	\$0	\$13,005	\$1,301	\$0	\$2,146	\$16,451	\$39
11.5	Wire & Cable	\$0	\$5,853	\$10,462	\$0	\$16,315	\$1,632	\$0	\$2,692	\$20,639	\$49
11.6	Protective Equipment	\$317	\$0	\$1,099	\$0	\$1,416	\$142	\$0	\$156	\$1,713	\$4
11.7	Standby Equipment	\$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
11.9	Electrical Foundations	\$0	\$281	\$715	\$0	\$996	\$100	\$0	\$219	\$1,314	\$3
	Subtotal	\$8,705	\$9,208	\$24,295	\$0	\$42,208	\$4,221	\$0	\$6,222	\$52,650	\$124

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Case:		0	– Subcritical PC w/CCS Retrofit				Estimate Type:			Conceptual	
Plant Size (MW,net):		425					Cost Base:			Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost (excluding RCF)	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
12		Instrumentation & Control									
12.1	PC Control Equipment	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12.3	Steam Turbine Control	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12.5	Signal Processing Equipment	w/ 5B.1/.2	\$0	w/ 5B.1/.2	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12.6	Control Boards, Panels & Racks	w/ 5B.1/.2	\$0	w/ 5B.1/.2	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12.7	Distributed Control Sys. Equipment	w/ 5B.1/.2	\$0	w/ 5B.1/.2	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12.8	Instrument Wiring & Tubing	w/ 5B.1/.2	\$0	w/ 5B.1/.2	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12.9	Other I&C Equipment	\$1,574	\$0	\$3,645	\$0	\$5,220	\$522	\$261	\$600	\$6,603	\$16
	Subtotal	\$1,574	\$0	\$3,645	\$0	\$5,220	\$522	\$261	\$600	\$6,603	\$16
13		Improvements to Site									
13.1	Site Preparation	\$0	\$42	\$883	\$0	\$924	\$92	\$0	\$203	\$1,220	\$3
13.2	Site Improvements	\$0	\$1,378	\$1,820	\$0	\$3,198	\$320	\$0	\$704	\$4,222	\$10
13.3	Site Facilities	\$2,469	\$0	\$2,590	\$0	\$5,059	\$506	\$0	\$1,113	\$6,678	\$16
	Subtotal	\$2,469	\$1,419	\$5,293	\$0	\$9,182	\$918	\$0	\$2,020	\$12,120	\$29
14		Buildings & Structures									
14.1	Boiler Building	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
14.2	Steam Turbine Building	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
14.3	Administration Building	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
14.4	Circulation Water Pumphouse	\$0	\$110	\$87	\$0	\$197	\$20	\$0	\$54	\$270	\$1
14.5	Water Treatment Buildings	\$0	\$252	\$230	\$0	\$481	\$48	\$0	\$132	\$662	\$2
14.6	Machine Shop	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
14.7	Warehouse	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
14.8	Other Buildings & Structures	\$0	\$189	\$161	\$0	\$350	\$35	\$0	\$58	\$443	\$1
14.9	Waste Treating Building & Str.	\$0	\$447	\$1,356	\$0	\$1,803	\$180	\$0	\$297	\$2,281	\$5
	Subtotal	\$0	\$998	\$1,830	\$0	\$2,831	\$283	\$0	\$542	\$3,656	\$9
	Total	\$254,061	\$80,019	\$193,674	\$0	\$527,754	\$48,297	\$57,503	\$107,800	\$741,354	\$1,743

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Exhibit 5-16. Case 0 owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$3,658	\$9
1 Month Maintenance Materials	\$627	\$1
1 Month Non-fuel Consumables	\$770	\$2
1 Month Waste Disposal	\$0	\$0
25% of 1 Months Fuel Cost at 100% CF	\$0	\$0
2% of TPC	\$14,827	\$35
Total	\$19,882	\$47
Inventory Capital		
60 Day Supply of Fuel and Consumables at 100% CF	\$1,454	\$3
0.5% Of TPC (Spare Parts)	\$3,707	\$9
Total	\$5,161	\$12
Other Costs		
Initial Cost for Catalyst and Chemicals	\$0	\$0
Land	\$0	\$0
Other Owner's Costs	\$111,203	\$262
Financing Costs	\$20,017	\$47
Total Overnight Costs (TOC)	\$897,617	\$2,111
TOC Including Retrofit Contingency	\$987,379	\$2,322
TASC Multiplier (IOU, high-risk, 33 year)	1.078	
Total As-Spent Cost (TASC) including Retrofit Contingency	\$1,064,394	\$2,503

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Exhibit 5-17. Case 0 initial and annual operating and maintenance costs

Case:	0	– Subcritical PC w/ CCS Retrofit			Cost Base:	Jun 2011
Plant Size (MW _{net}):	425	Heat Rate-net (Btu/kWh):	11,301	Capacity Factor (%):	85	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		39.70	\$/hour	Skilled Operator:		2.0
Operating Labor Burden:		30.00	% of base	Operator:		11.3
Labor O-H Charge Rate:		25.00	% of labor	Foreman:		1.0
				Lab Techs, etc.:		2.0
				Total:		16.3
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$7,384,208	\$17.36
Maintenance Labor:					\$11,686,525	\$27.48
Administrative & Support Labor:					\$4,767,683	\$11.21
Property Taxes and Insurance:					\$36,389,354	\$85.57
Total:					\$60,227,770	\$141.63
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$16,732,405	\$5.28
Consumables						
	Consumption				Cost (\$)	
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	4,832	\$1.67	\$0	\$2,509,524	\$0.79
Makeup and Wastewater Treatment Chemicals (lbs):	0	23,390	\$0.27	\$0	\$1,943,632	\$0.61
Limestone (ton)	0	488	\$33.48	\$0	\$5,073,887	\$1.60
Hydrated Lime (ton)	0	100	\$155.00	\$0	\$4,791,024	\$1.51
Activated Carbon (ton)	0	3	\$1,255.00	\$0	\$1,120,336	\$0.35
CO ₂ Capture System Chemicals ^A			Proprietary		\$6,226,752	\$1.97
Triethylene Glycol (gal)	0	325	\$6.57	\$0	\$662,004	\$0.21
Ammonia (19% NH ₃ , ton)	0	73	\$330.00	\$0	\$7,516,022	\$2.37
SCR Catalyst (m ³)	0	0.33	\$8,938.80	\$0	\$908,532	\$0.29
Subtotal:				\$0	\$30,751,712	\$9.71
Waste Disposal						
Fly Ash (ton)	0	490	\$25.11	\$0	\$3,816,083	\$1.21
Bottom Ash (ton)	0	96	\$25.11	\$0	\$750,661	\$0.24
Amine Purification Unit Waste (ton)	0	21	\$0.00	\$0	\$0	\$0.00
Thermal Reclaimer Unit Waste (ton)	0	2	\$0.00	\$0	\$0	\$0.00
Prescrubber Blowdown Waste (ton)	0	46	\$0.00	\$0	\$0	\$0.00
Subtotal:				\$0	\$4,566,744	\$1.44
By-Products						
Gypsum (ton)	0	758	\$0.00	\$0	\$0	\$0.00
Subtotal:				\$0	\$0	\$0.00
Variable Operating Costs Total:				\$0	\$52,050,861	\$16.44
Fuel Cost						
Illinois Number 6 (ton):	0	4,943	\$68.54	\$0	\$105,118,810	\$33.20
Total:				\$0	\$105,118,810	\$33.20

^ACO₂ Capture System Chemicals includes Ion Exchange Resin, NaOH, and Cansolv Solvent.

Exhibit 5-18. Case 0 COE breakdown

Component	Value, \$/MWh	Percentage
Capital	34.6	30%
Fixed	19.0	17%
Variable	16.5	15%
Fuel	33.2	29%
Total (Excluding T&S)	103.3	N/A
CO ₂ T&S	10.3	9%
Total (Including T&S)	113.6	N/A

5.2 RETROFIT CASE 1 – NGSC CHP REPOWERING

Case 1 examines the costs and performance aspects of adding a comparatively high efficient auxiliary plant (NG-fueled CHP plant comprising a CTG followed by heat recovery from the turbine exhaust gas) to satisfy the energy demand of the retrofitted CO₂ capture plant. The addition of the CHP plant eliminates the need to divert steam from the existing steam cycle and electric power that would be supplied to the grid. Conceptually, Case 1 leaves the base PC plant largely unmodified (with the exception of ductwork and a new stack) and minimally impacts facility operations. The Case 1 analysis is intended to consider an “optimal” scenario for reducing the emissions from an existing PC plant and the CO₂ capture process is only applied to the flue gas of the coal plant. It is assumed that no CO₂ capture is required for the NG-fueled CHP plant. However, results are reported in the context of the cost and performance of the hybrid dual-fueled power plant.

The sizing of the CHP plant is dictated by the required steam flows it is intended to satisfy and the available waste heat in the combustion turbine exhaust gas. Based on the performance of commercially available combustion turbines, the recoverable energy in the exhaust gas of a single state-of-the-art 7FA turbine approaches (but does not completely satisfy) the steam demand required for a CO₂ capture system sized to achieve 90 percent capture of the CO₂ in the flue gas of the base PC plant.

The amount of recoverable energy in the state-of-the-art 7FA turbine exhaust at the design conditions is able to satisfy approximately 92 percent of the steam demand of the CO₂ capture plant. As a simplifying assumption for this study, a hypothetical turbine with performance characteristics equivalent to the state-of-the-art 7FA was assumed, which resulted in a CT with approximately 9 percent greater output. Other approaches to provide the additional required steam, including duct firing, were considered in the previous version of this study. [2] But without power transmission restrictions placed on the repowered facility, the CHP plant more than offsets the lost generation from Case 0 while at the same time meeting the entire CCUS facility utility steam demand without affecting the performance of the existing steam turbine or duct firing.

As the CHP plant is sized to satisfy the steam demand of the capture plant, the electricity output of today’s highly efficient CTGs greatly exceeds the auxiliary load of the CO₂ capture plant. The hypothetical turbine used for Case 1 has a simple cycle gross output of approximately 228 MWe (a single state-of-the-art 7FA has a simple cycle gross output of

approximately 211 MWe), well above the 42 MWe electric load of the CO₂ capture plant. The combination of the existing PC plant and the CHP auxiliary plant results in a significant increase in the net electricity generating capacity available for sale to the grid. The addition of the excess electricity generated by the CHP plant to the 550 MWe existing PC plant results in a facility with a combined net output of approximately 730 MWe.

5.2.1 Process Description

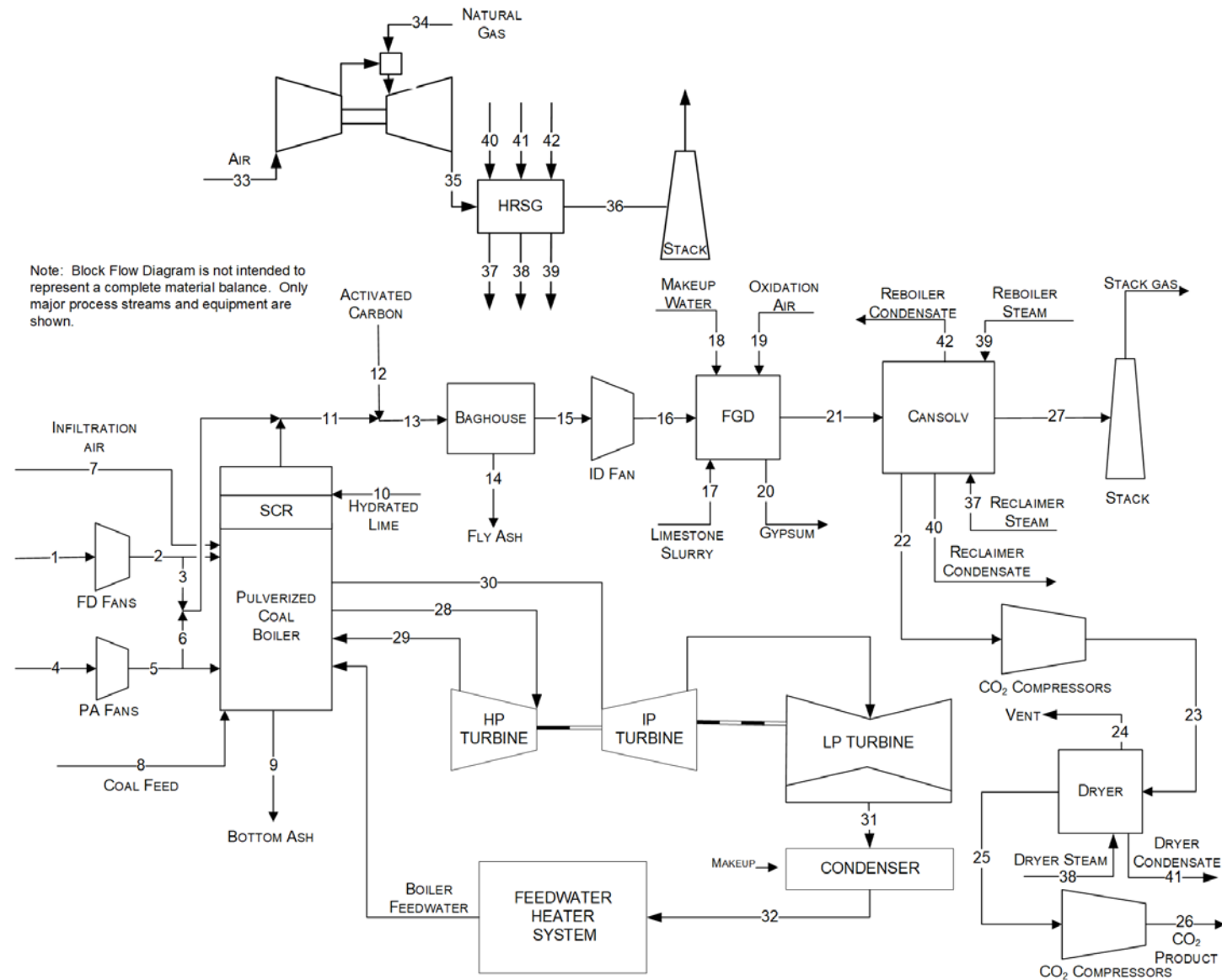
The system description follows the block flow diagram (BFD) shown in Exhibit 5-19 and the numbered streams correspond to the material and energy data presented in the tables in Exhibit 5-20.

The major processes of the existing PC plant are essentially the same as those described in Section 5.1.1 and are repeated here for convenience. Coal feed and primary air (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 goes into the boiler, and the infiltration air is accounted for as an additional stream. Ljungstrom air preheater leakages from the FD and PA fan outlet streams are accounted by adding the flows to the boiler exhaust.

Flue gas exits the boiler through the SCR reactor where ammonia is injected to reduce NO_x compounds, followed by hydrated lime injection for the reduction of SO₃. It then passes through the combustion air preheater (where the air preheater leakages are introduced) and is cooled to 143°C (289°F) before PAC is injected for mercury reduction. The flue gas then passes through a fabric filter for particulate removal. An ID fan increases the flue gas temperature to 153°C (308°F) and provides the motive force for the flue gas to pass through the FGD unit. FGD inputs and outputs include makeup water, oxidation air, limestone slurry and product gypsum. The clean, saturated flue gas exiting the FGD unit passes to the Cansolv CO₂ capture system, then on to the plant stack and is discharged to the atmosphere. Since the Cansolv facility process description was provided in Section 4.1, it is not repeated here.

The primary differences between Case 1 and Case 0 are 1) no modifications to the PC plant steam cycle and 2) the addition of the NG-fueled auxiliary plant. As a result of the minimal impact to the existing PC plant, performance is largely unaffected and the plant is assumed to continue to operate as it did prior to the retrofit, which is assumed to be the NETL Bituminous Baseline Report Case B11A plant configuration. [3]

In the NG-fueled simple cycle CHP auxiliary plant, air and natural gas are fed to the gas turbine combustors where combustion occurs. The resulting products of combustion flow through the expander section of the turbine. The turbine exhaust gas at 603°C (1,118°F) is routed through two HRSGs where steam is produced at the conditions required to meet the thermal needs of the CO₂ capture plant. Flue gas (stream 36) exiting each HRSG is routed to a dedicated stack at 164°C (327°F) for discharge to the atmosphere.

Exhibit 5-19. Case 1 block flow diagram, subcritical unit with NGSC CHP

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Exhibit 5-20. Case 1 stream table, subcritical unit with NGSC CHP

	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	0.0000	0.0088	0.0000	0.0088	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	0.0000	0.0000
CH ₄ S	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
C ₂ H 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	0.0000	0.0000
C ₃ H 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	0.0000	0.0000
C ₄ H 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	0.0000	0.0000
CO	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
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1376	0.0000	0.1376	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 ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0000	0.0831	0.0000	0.0831	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7345	0.0000	0.7345	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0340	0.0000	0.0340	0.3333
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0020	0.0000	0.0020	0.6667
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg _{mole} /hr)	51,530	51,530	1,526	15,829	15,829	2,179	1,126	0	0	0	72,228	0	72,228	3
V-L Flowrate (kg/hr)	1,486,986	1,486,986	44,042	456,787	456,787	62,866	32,480	0	0	0	2,145,013	0	2,145,013	164
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	186,882	3,624	3,766	18,264	109	18,372	18,372
Temperature (°C)	15	19	19	15	25	25	15	15	149	27	143	27	143	143
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	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	0.00	0.00	0.00	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,114.05	97.18	-13,306.82	-2,399.51	3.40	-2,399.39	-2,632.02
Density (kg/m ³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	---	0.9	---	0.9	1.5
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	---	29.698	---	29.698	53.376
V-L Flowrate (lb _{mole} /hr)	113,603	113,603	3,365	34,898	34,898	4,803	2,481	0	0	0	159,236	0	159,236	7
V-L Flowrate (lb/hr)	3,278,243	3,278,243	97,095	1,007,042	1,007,042	138,595	71,605	0	0	0	4,728,944	0	4,728,944	362
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	412,005	7,990	8,303	40,264	240	40,504	40,504
Temperature (°F)	59	66	66	59	78	78	59	59	300	80	289	80	289	289
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.4	14.7	14.4	14.7	14.4	14.4
Steam Table Enthalpy (Btu/lb) ^A	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-908.9	41.8	-5,720.9	-1,031.6	1.5	-1,031.6	-1,131.6
Density (lb/ft ³)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	---	0.053	---	0.053	0.096

^ASteam table reference conditions are 32.02°F and 0.089 psia.

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm.

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Exhibit 5-20. Case 1 stream table, subcritical unit with NGSC CHP (continued)

	15	16	17	18	19	20	21	22	23	24	25	26	27	28
V-L Mole Fraction														
Ar	0.0088	0.0088	0.0000	0.0000	0.0092	0.0000	0.0082	0.0000	0.0000	0.0000	0.0000	0.0000	0.0103	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	0.0000	0.0000
CH ₄ S	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
C ₂ H 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	0.0000	0.0000
C ₃ H 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	0.0000	0.0000
C ₄ H 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	0.0000	0.0000
CO	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
CO ₂	0.1376	0.1376	0.0000	0.0000	0.0003	0.0001	0.1288	0.9824	0.9977	0.0503	0.9993	0.9993	0.0163	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 ₂ O	0.0831	0.0831	1.0000	1.0000	0.0099	0.9999	0.1451	0.0176	0.0023	0.9497	0.0007	0.0007	0.0671	1.0000
N ₂	0.7345	0.7345	0.0000	0.0000	0.7732	0.0000	0.6854	0.0000	0.0000	0.0000	0.0000	0.0000	0.8652	0.0000
O ₂	0.0340	0.0340	0.0000	0.0000	0.2074	0.0000	0.0325	0.0000	0.0000	0.0000	0.0000	0.0000	0.0410	0.0000
SO ₂	0.0020	0.0020	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 _{mole} /hr)	72,225	72,225	2,394	9,596	764	177	78,267	9,236	9,095	15	9,080	9,080	61,998	87,854
V-L Flowrate (kg/hr)	2,144,849	2,144,849	43,130	172,875	22,042	3,183	2,258,155	402,256	399,711	291	399,420	399,420	1,729,078	1,582,720
Solids Flowrate (kg/hr)	0	0	18,467	0	0	28,641	0	0	0	0	0	0	0	0
Temperature (°C)	143	153	15	27	167	56	56	29	29	29	29	40	41	566
Pressure (MPa, abs)	0.10	0.11	0.10	0.11	0.31	0.10	0.10	0.20	3.03	3.03	2.89	15.27	0.10	16.65
Steam Table Enthalpy (kJ/kg) ^A	274.36	285.60	---	111.65	184.48	---	286.10	42.52	-6.01	137.66	-5.92	-205.59	151.94	3,473.89
AspenPlus Enthalpy (kJ/kg) ^B	-2,397.37	-2,386.13	-	-	56.67	-	-2,940.32	-	-	-	-	-	-794.66	-
Density (kg/m ³)	0.8	0.9	1,003.6	992.3	2.4	833.1	1.1	3.5	63.3	372.2	59.9	789.2	1.1	47.7
V-L Molecular Weight	29.697	29.697	18.015	18.015	28.857	18.018	28.852	43.553	43.950	19.322	43.991	43.991	27.889	18.015
V-L Flowrate (lb _{mole} /hr)	159,229	159,229	5,278	21,156	1,684	389	172,548	20,362	20,050	33	20,017	20,017	136,683	193,686
V-L Flowrate (lb/hr)	4,728,582	4,728,582	95,086	381,124	48,595	7,018	4,978,379	886,823	881,213	642	880,571	880,571	3,811,964	3,489,300
Solids Flowrate (lb/hr)	0	0	40,712	0	0	63,142	0	0	0	0	0	0	0	0
Temperature (°F)	289	308	59	80	332	133	133	85	85	85	85	104	107	1,050
Pressure (psia)	14.2	15.2	15.0	15.7	45.0	14.7	14.7	28.7	439.4	439.4	419.4	2,214.7	14.7	2,414.7
Steam Table Enthalpy (Btu/lb) ^A	118.0	122.8	---	48.0	79.3	---	123.0	18.3	-2.6	59.2	-2.5	-88.4	65.3	1,493.5
AspenPlus Enthalpy (Btu/lb) ^B	-1,030.7	-1,025.8	-6,447.0	-6,863.5	24.4	-5,366.3	-1,264.1	-3,857.3	-3,858.5	-6,544.1	-3,856.5	-3,942.3	-341.6	-5,376.8
Density (lb/ft ³)	0.052	0.055	62.650	61.950	0.153	52.011	0.067	0.216	3.953	23.235	3.737	49.267	0.068	2.975

^ASteam table reference conditions are 32.02°F and 0.089 psia.

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm.

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Exhibit 5-20. Case 1 stream table, subcritical unit with NGSC CHP (continued)

	29	30	31	32	33	34	35	36	37	38	39	40	41	42
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	0.0000	0.0000	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	0.0000	0.0000	0.0000	0.0000
CH ₄ S	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
C ₂ H ₆	0.0000	0.0000	0.0000	0.0000	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₃ H ₈	0.0000	0.0000	0.0000	0.0000	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0000	0.0000	0.0000	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	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
CO ₂	0.0000	0.0000	0.0000	0.0000	0.0003	0.0100	0.0391	0.0391	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 ₂ O	1.0000	1.0000	1.0000	1.0000	0.0099	0.0000	0.0841	0.0841	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.7732	0.0160	0.7442	0.7442	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.2074	0.0000	0.1238	0.1238	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 _{mole} /hr)	82,001	82,001	72,119	73,186	68,368	2,643	71,088	71,088	80	15	26,021	80	15	26,021
V-L Flowrate (kg/hr)	1,477,273	1,477,273	1,299,245	1,318,468	1,972,898	45,805	2,018,704	2,018,704	1,443	278	468,767	1,443	278	468,767
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	355	566	38	39	15	38	603	164	217	204	152	215	203	151
Pressure (MPa, abs)	4.28	4.19	0.01	2.04	0.10	3.10	0.10	0.10	2.20	1.70	0.51	2.11	1.64	0.49
Steam Table Enthalpy (kJ/kg) ^A	3,098.44	3,593.58	1,980.13	163.34	30.22	46.29	800.29	306.60	2,800.44	2,795.02	2,749.20	921.30	863.65	635.93
AspenPlus Enthalpy (kJ/kg) ^B	12,881.86	12,386.71	14,000.17	15,816.96	-97.57	4,462.93	-616.68	-1,110.37	13,179.85	13,185.28	13,231.10	15,058.99	15,116.65	15,344.37
Density (kg/m ³)	16.0	11.1	0.1	993.6	1.2	22.2	0.4	0.8	11.0	8.6	2.7	846.4	861.8	916.3
V-L Molecular Weight	18.015	18.015	18.015	18.015	28.857	17.328	28.397	28.397	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mole} /hr)	180,781	180,781	158,995	161,348	150,726	5,828	156,723	156,723	177	34	57,365	177	34	57,365
V-L Flowrate (lb/hr)	3,256,829	3,256,829	2,864,345	2,906,725	4,349,496	100,984	4,450,480	4,450,480	3,182	612	1,033,455	3,182	612	1,033,455
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	671	1,050	101	101	59	100	1,118	327	423	400	306	419	397	304
Pressure (psia)	620.5	608.1	1.0	295.5	14.7	450.0	15.1	15.1	319.0	247.3	73.5	306.2	237.4	70.6
Steam Table Enthalpy (Btu/lb) ^A	1,332.1	1,545.0	851.3	70.2	13.0	19.9	344.1	131.8	1,204.0	1,201.6	1,181.9	396.1	371.3	273.4
AspenPlus Enthalpy (Btu/lb) ^B	-5,538.2	-5,325.3	-6,019.0	-6,800.1	-41.9	-1,918.7	-265.1	-477.4	-5,666.3	-5,668.6	-5,688.3	-6,474.2	-6,499.0	-6,596.9
Density (lb/ft ³)	1.000	0.692	0.004	62.028	0.076	1.384	0.025	0.051	0.688	0.536	0.169	52.841	53.801	57.201

^ASteam table reference conditions are 32.02°F and 0.089 psia.

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm.

5.2.2 Key System Assumptions

System assumptions for Case 1, subcritical PC with CCS retrofit and NGSC CHP repowering, are compiled in Exhibit 5-21. The balance of plant assumptions for Case 1 are presented in Exhibit 5-22.

Exhibit 5-21. Subcritical PC plant with NGSC CHP study configuration matrix

Parameter	Case 1
Existing Subcritical PC Plant	
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/566 (2,400/1,050/1,050)
Coal	Illinois No. 6
Condenser Pressure, mm Hg (in Hg)	50.8 (2)
Boiler Efficiency, HHV %	89
Cooling Water to Condenser, °C (°F)	16 (60)
Cooling Water from Condenser, °C (°F)	27 (80)
Stack Temperature, °C (°F)	56 (133)
SO ₂ Control	Wet Limestone Forced Oxidation
FGD Efficiency ^A , %	98 ^{B,C}
NO _x Control	LNB w/OFA, SCR, and Polishing Scrubber
SCR Efficiency ^A , %	83
Ammonia Slip (end of catalyst life), ppmv	2
Particulate Control	Fabric Filter
Fabric Filter Efficiency ^A , %	99.9
Ash Distribution, Fly/Bottom	80%/20%
SO ₃ Control	DSI
Mercury Control	Co-benefit Capture and ACI
CO ₂ Control	Cansolv (PC plant flue gas only)
Carbon Capture Efficiency ^A	90%
CO ₂ Sequestration	Off-site Saline Formation
New Simple Cycle CHP Plant	
Auxiliary Plant Combustion Turbine	Hypothetical 7FA
CT Output, MW	230 (1x)
CT NO _x Control	LNB
CT SCR Efficiency ^A , %	90
CT Heat Rate, Btu/kWh (HHV)	9,896

^ARemoval efficiencies are based on the flue gas content.

^BAn SO₂ polishing step is included to meet more stringent SO_x content limits in the flue gas (~1 ppmv) to reduce formation of amine HSS during the CO₂ absorption process.

^CSO₂ exiting the post-FGD polishing step is absorbed in the CO₂ capture process making stack emissions negligible.

Exhibit 5-22. Case 1 balance of plant assumptions

Parameter	Value
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
Hydrated lime	30 days
Activated carbon	30 days
Plant Distribution Voltage	
Motors below 1 hp	110/220 V
Motors between 1 hp and 250 hp	480 V
Motors between 250 hp and 5,000 hp	4,160 V
Motors above 5,000 hp	13,800 V
Steam and CT generators	24,000 V
Grid interconnection voltage	345 kV
Water and Wastewater	
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.

5.2.3 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 PCC plant design consists of the following major subsystems:

- One amine CO₂ absorption system consisting of an absorber, stripper, and ancillary equipment (1 x 100%) and two CO₂ compression systems (2 x 50%).
- One NG-fueled auxiliary (combined heat and power) plant

- One hypothetically-sized F class CTG (1 x 100%)
- One three-pressure HRSGs with self-supporting stack and SCR system (1 x 100%)

5.2.4 Case 1 – Performance Results

The combined plant (existing PC plant plus excess power from auxiliary plant) produces a net output of 730 MWe and has an overall net plant efficiency of 35.2 percent (HHV basis). Overall performance for the plant is summarized in Exhibit 5-23. Exhibit 5-24 provides a detailed breakdown of the auxiliary power requirements.

Exhibit 5-23. Case 1 plant performance summary

Performance Summary	
Base Plant Steam Turbine Power, MWe	581
Auxiliary Combustion Turbine Power, MWe	230
Auxiliary Plant Steam Turbine Power, MWe	0
Total Gross Power, MWe	811
CO ₂ Capture/Removal Auxiliaries, kWe	13,300
CO ₂ Compression, kWe	29,180
Balance of Plant, kWe	38,484
Total Auxiliaries, MWe	81
Net Power, MWe	730
HHV Net Plant Efficiency, %	35.2%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,234 (9,700)
LHV Net Plant Efficiency, %	37.2%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,671 (9,166)
HHV Boiler Efficiency, %	89.1%
LHV Boiler Efficiency, %	92.4%
Base Plant Steam Turbine Cycle Efficiency, %	46.3%
Base Plant Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,774 (7,369)
Auxiliary Plant Combustion Turbine HHV Efficiency, %	34.5%
Auxiliary Plant Combustion Turbine LHV Efficiency, %	38.2%
Base Plant Condenser Duty, GJ/hr (MMBtu/hr)	2,362 (2,239)
Auxiliary Plant Condenser Duty, GJ/hr (MMBtu/hr)	0 (0)
As-Received Coal Feed, kg/hr (lb/hr)	186,882 (412,005)
Limestone Sorbent Feed, kg/hr (lb/hr)	18,467 (40,712)
Natural Gas Feed Flow, kg/hr (lb/hr)	45,805 (100,984)
HHV Thermal Input, kWt	2,074,494
LHV Thermal Input, kWt	1,960,332
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.043 (11.3)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.033 (8.7)
Excess Air, %	20.9%

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Exhibit 5-24. Case 1 plant power summary

Power Summary	
Base Plant Steam Turbine Power, MWe	581
Auxiliary Combustion Turbine Power, MWe	230
Auxiliary Plant Steam Turbine Power, MWe	0
Total Gross Power, MWe	811
PC Plant Auxiliary Load Summary	
Coal Handling and Conveying, kWe	440
Pulverizers, kWe	2,800
Sorbent Handling & Reagent Preparation, kWe	890
Ash Handling, kWe	650
Primary Air Fans, kWe	1,390
Forced Draft Fans, kWe	1,770
Induced Draft Fans, kWe	6,940
SCR, kWe	50
Activated Carbon Injection, kWe	23
Dry Sorbent Injection, kWe	90
Baghouse, kWe	90
Wet FGD, kWe	2,950
CO ₂ Capture/Removal Auxiliaries, kWe	13,300
CO ₂ Compression, kWe	29,180
Miscellaneous Balance of Plant ^{A,B} , kWe	2,000
Steam Turbine Auxiliaries, kWe	400
Condensate Pumps, kWe	990
Circulating Water Pumps, kWe	8,070
Ground Water Pumps, kWe	740
Cooling Tower Fans, kWe	4,170
Transformer Losses, kWe	2,130
NGSC CHP Plant Auxiliary Load Summary	
Feedwater Pumps, kWe	10
SCR, kWe	1
CO ₂ Capture/Removal Auxiliaries, kWe	0
Miscellaneous Balance of Plant ^B , kWe	500
Combustion Turbine Auxiliaries, kWe	700
Condensate Pumps, kWe	0
Circulating Water Pumps, kWe	0
Ground Water Pumps, kWe	0
Cooling Tower Fans, kWe	0
Transformer Losses, kWe	690
Total Auxiliaries, MWe	81
Net Power, MWe	730

^ABoiler feed pumps are turbine driven.

^BIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads.

5.2.4.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case 1 (inclusive of emissions from the auxiliary plant) is presented in Exhibit 5-25. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 5-25. Case 1 air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year) ^A	kg/MWh (lb/MWh)
SO ₂	0.000 (0.000)	7 (8)	0.001 (0.003)
NO _x	0.025 (0.058)	1,398 (1,541)	0.232 (0.511)
Particulate	0.003 (0.007)	177 (195)	0.029 (0.065)
Hg	1.06E-7 (2.46E-7)	0.006 (0.006)	9.75E-7 (2.15E-6)
CO ₂ ^B	22 (52)	1,240,372 (1,367,276)	205 (453)
CO ₂ ^C	-	-	228 (503)
mg/Nm ³			
Particulate Concentration ^{D,E}	14.66		

^ACalculations based on an 85 percent capacity factor.

^BCO₂ emissions based upon gross power.

^CCO₂ emissions based on net power instead of gross power.

^DConcentration of particles in the flue gas after the baghouse.

^ENormal conditions given at 32°F and 14.696 psia.

SO₂ emissions from the PC boiler 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 flue gas exiting the scrubber is vented through the plant stack.

NO_x emissions are controlled from the PC boiler to about 0.5 lb/MMBtu using LNBs and OFA. The CT is also equipped with LNBs. SCR units are used for both the PC boiler and auxiliary combustion turbine to further reduce the total plant NO_x concentration by 83 percent to 0.06 lb/MMBtu.

Particulate emissions from the PC boiler are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment on the PC boiler (SCR, ACI, fabric filter, DSI, and wet FGD) is 96.8 percent.

CO₂ emissions represent the combined emissions from the retrofitted PC plant and uncontrolled flue gas from the auxiliary plant.

The carbon balance for the plant is shown in Exhibit 5-26. The carbon input to the plant consists of carbon in the coal, natural gas, air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon in the air is not neglected here since the Aspen model accounts

for air components throughout. Carbon leaves the plant mostly as CO₂ through the PC boiler and auxiliary plant stacks; however, the PAC is captured in the fabric filter and some leaves as gypsum.

Exhibit 5-26. Case 1 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	119,128 (262,632)	Base Plant Stack Gas	12,109 (26,697)
Natural Gas	33,084 (72,939)	Aux Plant Stack Gas	33,354 (73,532)
Base Plant Air	272 (599)	FGD Product	179 (394)
Aux Plant Air	269 (594)	Baghouse	109 (240)
PAC	109 (240)	CO ₂ Product	108,976 (240,250)
		CO ₂ Dryer Vent	9 (20)
		CO ₂ Knockout	0 (0)
Total	154,736 (341,134)	Total	154,736 (341,134)

Exhibit 5-27 shows the sulfur balance for the plant. Sulfur input comes primarily from the sulfur in the coal with a negligible amount from the natural gas. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur captured in the fabric filter via hydrated lime, and sulfur emitted in the stack gas.

Exhibit 5-27. Case 1 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	4,684 (10,327)	FGD Product	4,526 (9,978)
Natural Gas	0 (1)	Base Plant Stack Gas	0 (0)
		Aux Plant Stack Gas	0 (1)
		Polishing Scrubber and Solvent Reclaiming	92 (204)
		Baghouse	66 (145)
Total	4,685 (10,328)	Total	4,685 (10,328)

Exhibit 5-28 shows the water balance for Case 1. Water demand, withdrawal, and consumption are discussed in Section 2.6.

Exhibit 5-28. Case 1 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
FGD Makeup	3.61 (952)	–	3.61 (952)	–	3.61 (952)
CO ₂ Drying	–	–	–	0.00 (1)	0.00 (-1)
Capture System Makeup	0.02 (4)	–	0.02 (4)	–	0.02 (4)
Deaerator Vent	–	–	–	0.05 (14)	-0.05 (-14)
Base Plant Condenser Makeup	0.32 (85)	–	0.32 (85)	–	0.32 (85)
BFW Makeup	0.32 (85)	–	0.32 (85)	–	0.32 (85)
HRSO Steam Loop	0.08 (21)	–	0.08 (21)	–	0.08 (21)
Condensate Makeup	0.08 (21)	–	0.08 (21)	–	0.08 (21)
Cooling Tower	31.43 (8,302)	4.36 (1,152)	27.06 (7,149)	7.07 (1,867)	20.00 (5,282)
FGD Dewatering	–	1.86 (491)	-1.86 (-491)	–	-1.86 (-491)
CO ₂ Capture Recovery	–	2.11 (558)	-2.11 (-558)	–	-2.11 (-558)
CO ₂ Compression KO	–	0.04 (11)	-0.04 (-11)	–	-0.04 (-11)
Base Plant BFW Blowdown	–	0.27 (71)	-0.27 (-71)	–	-0.27 (-71)
HRSO Blowdown	–	0.08 (21)	-0.08 (-21)	–	-0.08 (-21)
Total	35.45 (9,364)	4.36 (1,152)	31.09 (8,212)	7.13 (1,882)	23.96 (6,330)

5.2.4.2 Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case 1 PC boiler, the FGD unit, steam cycle, and auxiliary plant systems in Exhibit 5-29 and Exhibit 5-30.

An overall plant energy balance is provided in tabular form in Exhibit 5-31. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-23) is calculated by multiplying the power out by a generator efficiency of 98.5 percent. A Sankey diagram is presented in Exhibit 5-32, illustrating the flow of energy into and out of the plant.

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Exhibit 5-29. Case 1 heat and mass balance, subcritical PC boiler with CO₂ capture and NGSC CHP plant

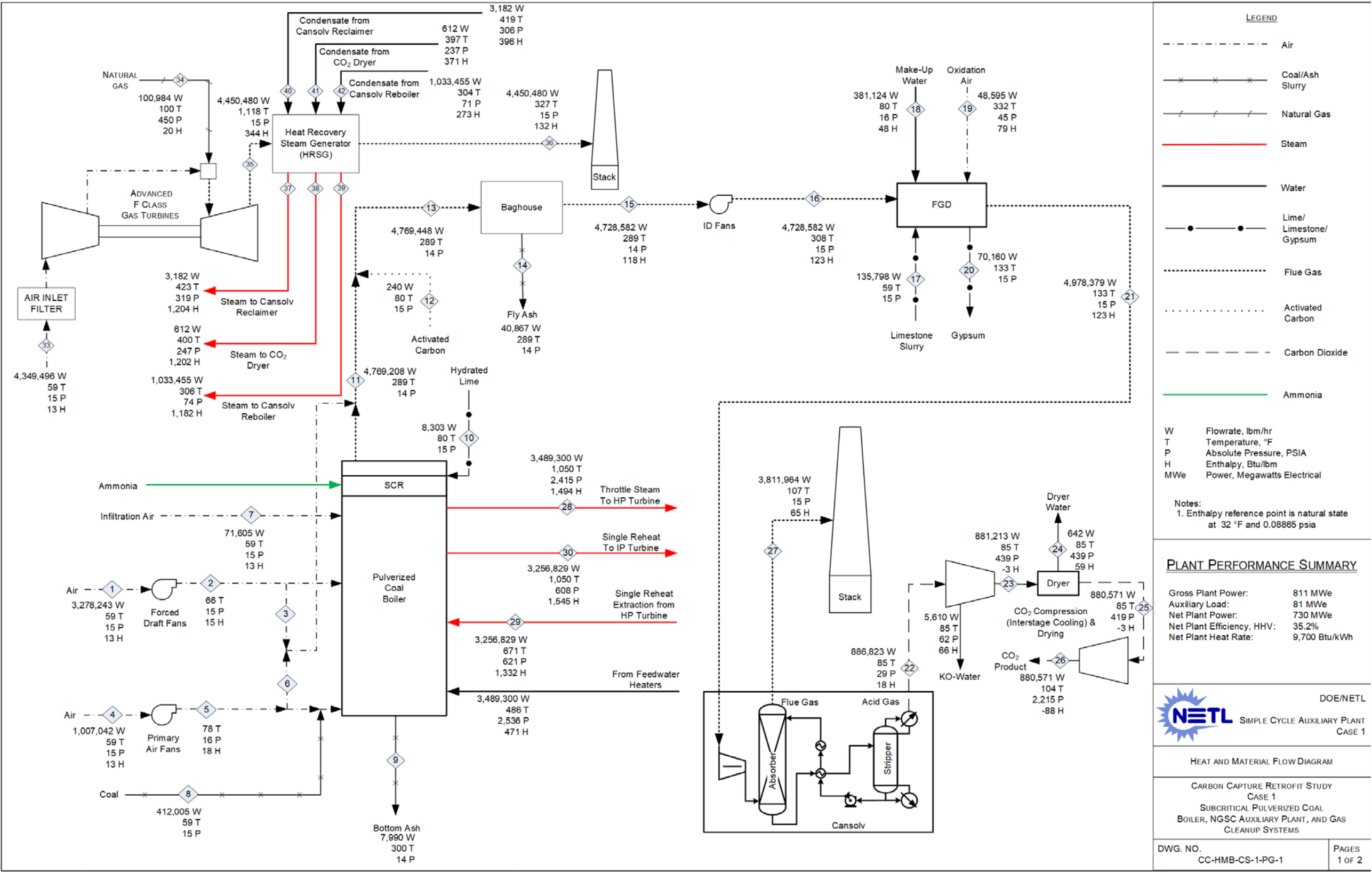
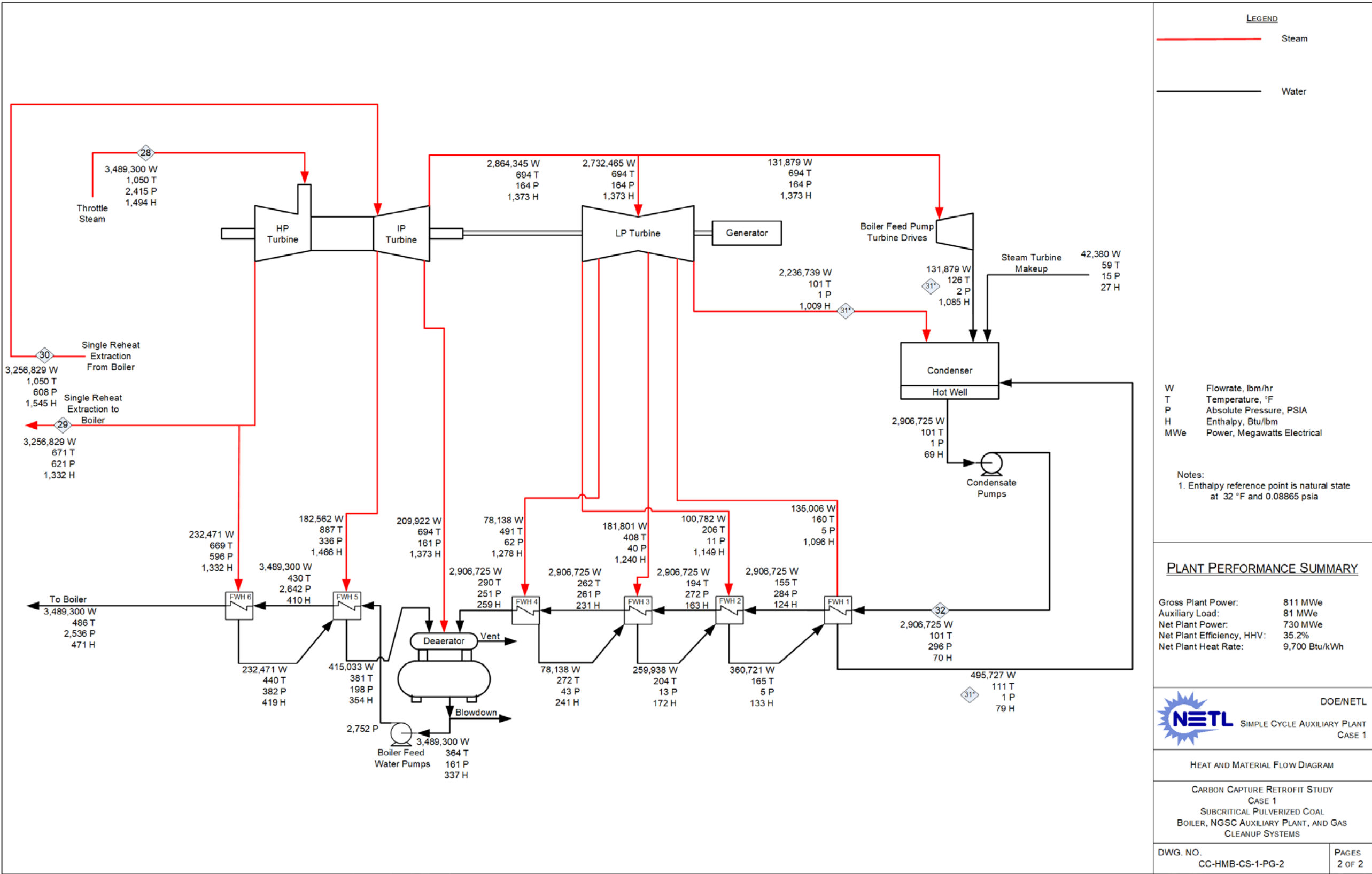


Exhibit 5-30. Case 1 heat and mass balance, subcritical steam cycle



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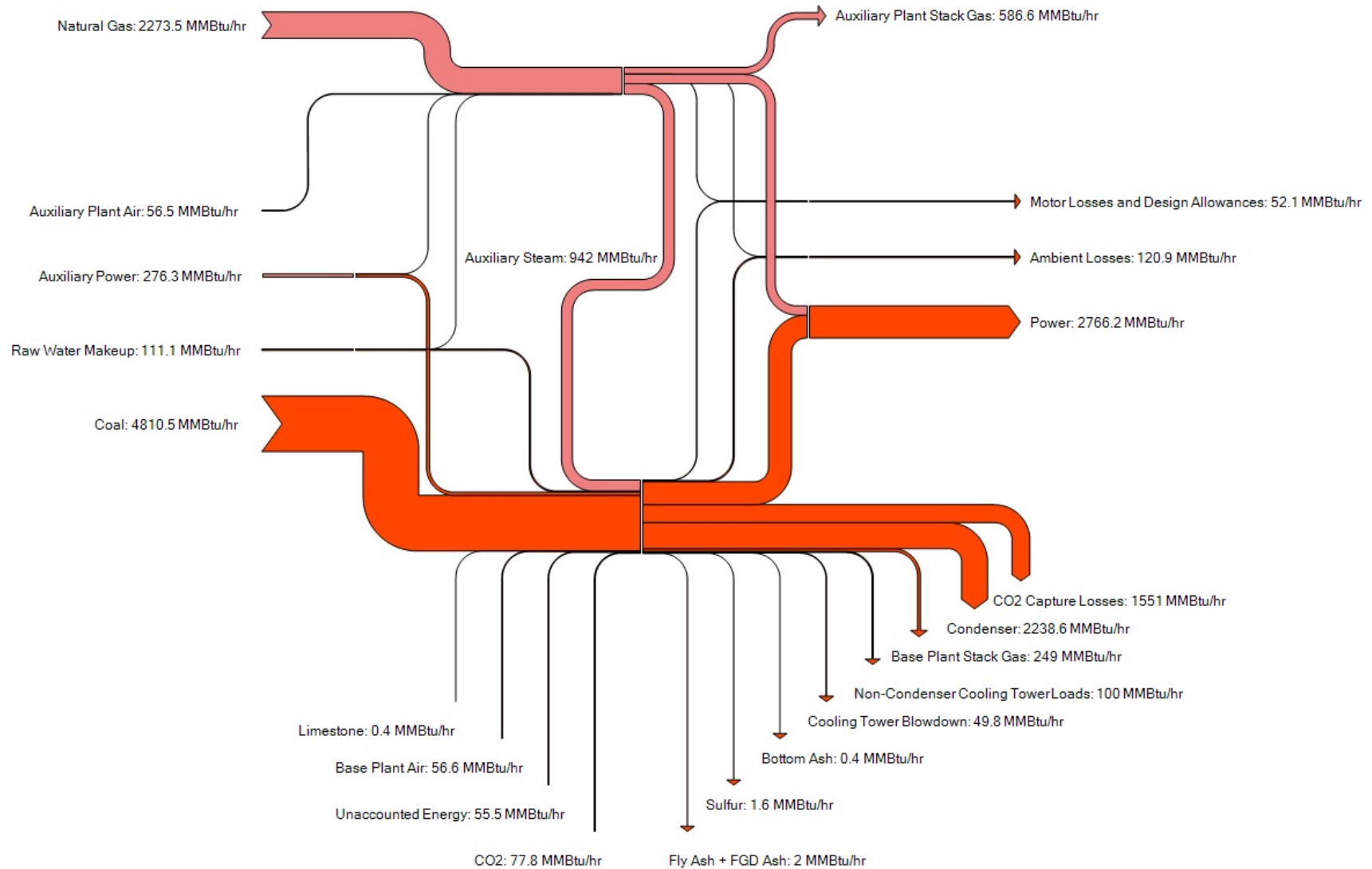
Exhibit 5-31. Case 1 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,071 (4,806)	4.2 (4.0)	–	5,075 (4,810)
Natural Gas	2,397 (2,272)	1.6 (1.5)	–	2,399 (2,274)
Base Plant Air	–	59.7 (56.6)	–	59.7 (56.6)
Aux Plant Air	–	59.6 (56.5)	–	59.6 (56.5)
Raw Water Makeup	–	117.2 (111.1)	–	117.2 (111.1)
Limestone	–	0.40 (0.38)	–	0.40 (0.38)
Auxiliary Power	–	–	291 (276)	291 (276)
TOTAL	7,468 (7,078)	242.8(230.1)	291 (276)	8,002 (7,585)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	0.4 (0.4)	–	0.4 (0.4)
Fly Ash + FGD Ash	–	2.1 (2.0)	–	2.1 (2.0)
Base Plant Stack Gas	–	263 (249)	–	263 (249)
Aux Plant Stack Gas	–	619 (587)	–	619 (587)
Sulfur	1.7 (1.6)	0.0 (0.0)	–	1.7 (1.6)
Motor Losses and Design Allowances	–	–	55 (52)	55 (52)
Base Plant Condenser	–	2,362 (2,239)	–	2,362 (2,239)
Aux Plant Condenser	–	–	–	0 (0)
Miscellaneous Non-Condenser Cooling Tower Loads	–	105 (100)	–	105 (100)
CO ₂	–	-82.1 (-77.8)	–	-82.1 (-77.8)
Cooling Tower Blowdown	–	52.5 (49.8)	–	52.5 (49.8)
CO ₂ Capture Losses	–	1,636 (1,551)	–	1,636 (1,551)
<i>Ambient Losses^A</i>	–	127.5 (120.9)	–	127.5 (120.9)
Power	–	–	2,919 (2,766)	2,919 (2,766)
TOTAL	1.7 (1.6)	5,086 (4,820)	2,919 (2,818)	8,061 (7,640)
Unaccounted Energy ^B	–	-59 (-55)	–	-59 (-55)

^AAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers.

^BBy difference.

Exhibit 5-32. Case 1 Sankey diagram



5.2.5 Case 1 – Major Equipment List

Equipment lists showing the major retrofitted equipment items for Case 0 are shown in the following tables. The major equipment list is not intended to be all-inclusive of required modifications but rather to identify key equipment items and applicable design conditions. The account identifications (e.g., Account 5B: Carbon Dioxide Recovery) in the equipment list correspond to the account numbers used in the cost estimates in Section 5.2.6. 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 – Account 3: Feedwater and Miscellaneous Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	627,000 liters (166,000 gal)	2	0
2	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 10 lpm @ 250 m H ₂ O (4 gpm @ 810 ft H ₂ O)	2	1
3	Raw Water Pumps	Stainless steel, single suction	100 lpm @ 20 m H ₂ O (32 gpm @ 60 ft H ₂ O)	2	1
4	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H ₂ O (40 gpm @ 160 ft H ₂ O)	2	1
5	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
6	Auxiliary Boiler (for startup)	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
7	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
8	Liquid Waste Treatment System		10 years, 24-hour storm	1	0
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1

Case 1 – Account 5B: Carbon Dioxide Recovery

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Cansolv	Amine-based CO ₂ capture technology	2,484,000 kg/hr (5,476,000 lb/hr) 19.6 wt % CO ₂ concentration	1	0
2	Cansolv LP Condensate Pump	Centrifugal	8,593 lpm @ 1 m H ₂ O (2,270 gpm @ 4 ft H ₂ O)	1	1
3	Cansolv IP Condensate Pump	Centrifugal	5 lpm @ 3.7 m H ₂ O (1 gpm @ 12 ft H ₂ O)	1	1

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Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
4	CO ₂ Dryer	Triethylene glycol	Inlet: 105.0 m ³ /min (3,715 acfm) @ 3.0 MPa (439 psia) Outlet: 2.9 MPa (419 psia) Water Recovered: 291 kg/hr (642 lb/hr)	1	0
5	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	219,615 kg/hr @ 15.3 MPa (484,169 lb/hr @ 2,215 psia)	2	0

Case 1 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	Hypothetical advanced F class w/ dry low-NOx burner	230 MW	1	0
2	Combustion Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0

Case 1 – Account 7: Ducting and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	PC Plant Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 5.0 m (17 ft) diameter	1	0
2	HRSB Stack	CS plate, type 409SS liner	46 m (150 ft) high x 6.3 m (21 ft) diameter	1	0
3	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	LP steam - 515,644 kg/hr, 0.5 MPa/152°C (1,136,800 lb/hr, 74 psig/306°F) IP steam - 305 kg/hr, 1.7 MPa/204°C (674 lb/hr, 247 psig/400°F) HP steam - 1,588 kg/hr, 2.2 MPa/217°C (3,500 lb/hr, 319 psig/423°F)	1	0
4	SCR Reactor	Space for spare layer	2,220,000 kg/hr (4,900,000 lb/hr)	1	0
5	SCR Catalyst	--	Space available for an additional catalyst layer	1 layer	0
6	Dilution Air Blowers	Centrifugal	6 m ³ /min @ 108 cm WG (210 scfm @ 42 in WG)	1	1
6	Ammonia Feed Pump	Centrifugal	1.3 lpm @ 90 m H ₂ O (0.3 gpm @ 300 ft H ₂ O)	1	1
7	Ammonia Storage Tank	Horizontal tank	18,000 liter (5,000 gal)	1	0

Case 1 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	323,000 lpm @ 30 m (85,000 gpm @ 100 ft)	2	1

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Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
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/ 1800 GJ/hr (1710 MMBtu/hr) heat duty	1	0

Case 1 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 16 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 85 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 13 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case 1 – 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 black and white)	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

5.2.6 Case 1 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. The costs for the additional equipment required for the CCS retrofit and the auxiliary plants were scaled from the NETL Bituminous Baseline Report cases as well as other costs developed as part of baseline series. [3, 46] Exhibit 5-33 shows a detailed breakdown of the capital costs; Exhibit 5-34 shows the owner's costs, along with the TOC, and TASC; Exhibit 5-35 shows the initial and annual O&M costs; and Exhibit 5-36 shows the COE breakdown.

The estimated TPC of the subcritical PC boiler with retrofitted CO₂ capture and NGSC CHP auxiliary repowering is \$1,192/kW. Process contingency represents 6.4 percent of the TPC and project contingency represents 13.8 percent. The COE is \$90.6/MWh.

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Exhibit 5-33. Case 1 total plant cost details (without retrofit contingency)

Case:		1	– Subcritical PC w/ NGSC CHP				Estimate Type:		Conceptual		
Plant Size (MW _{net}):		730					Cost Base:		Jun 2011		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost (excluding RCF)	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1 Coal & Sorbent Handling											
1.1	Coal Receive & Unload	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.2	Coal Stackout & Reclaim	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.3	Coal Conveyors	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.4	Other Coal Handling	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.5	Sorbent Receive & Unload	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.6	Sorbent Stackout & Reclaim	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.7	Sorbent Conveyors	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.8	Other Sorbent Handling	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.9	Coal & Sorbent Hnd. Foundations	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2 Coal & Sorbent Prep & Feed											
2.1	Coal Crushing & Drying	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2.2	Coal Conveyor to Storage	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2.5	Sorbent Prep Equipment	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2.6	Sorbent Storage & Feed	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2.9	Coal & Sorbent Feed Foundation	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3 Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$2,758	\$3,497	\$2,855	\$0	\$9,110	\$820	\$0	\$1,490	\$11,420	\$16
3.2	Water Makeup & Pretreating	\$64	\$7	\$33	\$0	\$103	\$9	\$0	\$22	\$134	\$0
3.3	Other Feedwater Subsystems	\$1,292	\$427	\$357	\$0	\$2,076	\$187	\$0	\$339	\$2,602	\$4
3.4	Service Water Systems	\$8	\$15	\$49	\$0	\$72	\$7	\$0	\$16	\$95	\$0
3.5	Other Boiler Plant Systems	\$52	\$19	\$44	\$0	\$116	\$10	\$0	\$19	\$145	\$0
3.6	Natural Gas, incl. pipeline	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3.7	Waste Treatment Equipment	\$22	\$0	\$13	\$0	\$35	\$3	\$0	\$8	\$46	\$0
3.8	Misc. Equip. (Cranes, Air Comp., Comm.)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$4,196	\$3,965	\$3,351	\$0	\$11,512	\$1,036	\$0	\$1,894	\$14,442	\$20

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Case:		1	– Subcritical PC w/ NGSC CHP				Estimate Type:			Conceptual	
Plant Size (MW,net):		730					Cost Base:			Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost (excluding RCF)	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
4				Boiler & Accessories							
4.1	PC Boiler & Accessories	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.2	SCR	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.5	Primary Air System	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.6	Secondary Air System	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.8	Major Component Rigging	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.9	Boiler Foundations	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A				Gas Cleanup & Piping							
5A.1	Absorber Vessels & Accessories	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A.2	Other FGD	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A.3	Bag House & Accessories	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A.4	Other Particulate Removal Materials	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A.5	Gypsum Dewatering System	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A.6	Mercury Removal System	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5B				CO ₂ Removal & Compression							
5B.1	CO ₂ Removal System	\$150,894	\$55,170	\$117,865	\$0	\$323,929	\$27,914	\$55,829	\$72,578	\$480,249	\$658
5B.2	CO ₂ Compression & Drying	\$44,551	\$6,683	\$14,668	\$0	\$65,902	\$6,590	\$0	\$14,498	\$86,991	\$119
5B.3	CO ₂ Removal System Let Down Turbine	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$195,445	\$61,852	\$132,533	\$0	\$389,831	\$34,505	\$55,829	\$87,076	\$567,240	\$777
6				Combustion Turbine & Accessories							
6.1	Combustion Turbine Generator	\$56,746	\$0	\$3,453	\$0	\$60,199	\$5,418	\$0	\$6,562	\$72,179	\$99
6.9	Combustion Turbine Foundations	\$0	\$478	\$517	\$0	\$996	\$90	\$0	\$217	\$1,303	\$2
	Subtotal	\$56,746	\$478	\$3,971	\$0	\$61,195	\$5,508	\$0	\$6,779	\$73,481	\$101
7				HRSG, Ducting, & Stack							
7.1	Heat Recovery Steam Generator	\$22,305	\$0	\$4,128	\$0	\$26,433	\$2,379	\$0	\$2,881	\$31,693	\$43
7.2	SCR System	\$898	\$377	\$526	\$0	\$1,802	\$162	\$0	\$295	\$2,259	\$3
7.3	HRSG, Duct & Stack Foundations	\$0	\$384	\$360	\$0	\$745	\$67	\$0	\$162	\$974	\$1
7.4	PC Plant Ductwork	\$8,539	\$0	\$5,390	\$0	\$13,929	\$1,393	\$0	\$2,298	\$17,620	\$24
7.5	PC Plant Stack	\$10,172	\$0	\$5,912	\$0	\$16,084	\$1,608	\$0	\$1,769	\$19,462	\$27

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Case:		1	– Subcritical PC w/ NGSC CHP				Estimate Type:		Conceptual		
Plant Size (MW,net):		730					Cost Base:		Jun 2011		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost (excluding RCF)	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
7.9	PC Plant Duct & Stack Foundations	\$0	\$1,055	\$1,253	\$0	\$2,309	\$231	\$0	\$508	\$3,047	\$4
	Subtotal	\$41,915	\$1,817	\$17,569	\$0	\$61,301	\$5,840	\$0	\$7,914	\$75,055	\$103
8 Steam Turbine Generator											
8.1	Steam TG & Accessories	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
8.2	Turbine Plant Auxiliaries	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
8.3	Condenser & Auxiliaries	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
8.4	Steam Piping	\$7,684	\$0	\$4,474	\$0	\$12,158	\$1,215.85	\$0	\$2,006	\$15,380	\$21
8.9	TG Foundations	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$7,684	\$0	\$4,474	\$0	\$12,158	\$1,216	\$0	\$2,006	\$15,380	\$21
9 Cooling Water System											
9.1	Cooling Towers	\$8,216	\$0	\$2,541	\$0	\$10,757	\$1,076	\$0	\$1,183	\$13,016	\$18
9.2	Circulating Water Pumps	\$1,657	\$0	\$106	\$0	\$1,762	\$176	\$0	\$194	\$2,132	\$3
9.3	Circ. Water System Auxiliaries	\$473	\$0	\$63	\$0	\$535	\$54	\$0	\$59	\$648	\$1
9.4	Circ. Water Piping	\$0	\$3,982	\$3,606	\$0	\$7,588	\$759	\$0	\$1,252	\$9,599	\$13
9.5	Make-up Water System	\$346	\$0	\$445	\$0	\$791	\$79	\$0	\$130	\$1,000	\$1
9.6	Component Cooling Water Sys.	\$385	\$0	\$296	\$0	\$681	\$68	\$0	\$112	\$862	\$1
9.9	Circ. Water Foundations & Structures	\$0	\$2,148	\$3,567	\$0	\$5,715	\$571	\$0	\$1,257	\$7,544	\$10
	Subtotal	\$11,077	\$6,130	\$10,623	\$0	\$27,830	\$2,783	\$0	\$4,188	\$34,801	\$48
10 Ash & Spent Sorbent Handling Systems											
10.6	Ash Storage Silos	\$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
10.9	Ash/Spent Sorbent Foundation	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
11 Accessory Electric Plant											
11.1	Generator Equipment	\$2,908	\$0	\$1,720	\$0	\$4,627	\$416	\$0	\$378	\$5,422	\$7
11.2	Station Service Equipment	\$3,999	\$0	\$344	\$0	\$4,343	\$391	\$0	\$355	\$5,088	\$7
11.3	Switchgear & Motor Control	\$4,921	\$0	\$855	\$0	\$5,775	\$520	\$0	\$630	\$6,925	\$9
11.4	Conduit & Cable Tray	\$0	\$2,572	\$7,408	\$0	\$9,980	\$898	\$0	\$1,632	\$12,510	\$17
11.5	Wire & Cable	\$0	\$8,264	\$4,699	\$0	\$12,962	\$1,167	\$0	\$2,119	\$16,248	\$22
11.6	Protective Equipment	\$0	\$722	\$2,506	\$0	\$3,228	\$291	\$0	\$352	\$3,871	\$5
11.7	Standby Equipment	\$78	\$0	\$73	\$0	\$152	\$14	\$0	\$17	\$182	\$0

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Case: 1		– Subcritical PC w/ NGSC CHP					Estimate Type: Conceptual				
Plant Size (MW,net): 730							Cost Base:		Jun 2011		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost (excluding RCF)	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
11.8	Main Power Transformers	\$7,679	\$0	\$117	\$0	\$7,797	\$702	\$0	\$850	\$9,348	\$13
11.9	Electrical Foundations	\$0	\$80	\$204	\$0	\$283	\$26	\$0	\$62	\$371	\$1
	Subtotal	\$19,585	\$11,637	\$17,925	\$0	\$49,147	\$4,423	\$0	\$6,394	\$59,965	\$82
12 Instrumentation & Control											
12.1	PC Control Equipment	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12.3	Steam Turbine Control	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12.4	Other Major Component Control	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12.5	Signal Processing Equipment	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12.6	Control Boards, Panels & Racks	\$93	\$0	\$57	\$0	\$151	\$14	\$0	\$25	\$189	\$0
12.7	Computer & Accessories	\$1,495	\$0	\$46	\$0	\$1,541	\$139	\$0	\$168	\$1,848	\$3
12.8	Instrument Wiring & Tubing	\$0	\$278	\$492	\$0	\$770	\$69	\$0	\$126	\$966	\$1
12.9	Other I&C Equipment	\$3,955	\$0	\$9,158	\$0	\$13,113	\$1,180	\$0	\$1,429	\$15,722	\$22
	Subtotal	\$5,544	\$278	\$9,752	\$0	\$15,575	\$1,402	\$0	\$1,748	\$18,724	\$26
13 Improvements to Site											
13.1	Site Preparation	\$0	\$68	\$1,441	\$0	\$1,509	\$136	\$0	\$329	\$1,974	\$3
13.2	Site Improvements	\$0	\$622	\$822	\$0	\$1,444	\$130	\$0	\$315	\$1,889	\$3
13.3	Site Facilities	\$1,270	\$0	\$1,332	\$0	\$2,603	\$234	\$0	\$567	\$3,404	\$5
	Subtotal	\$1,270	\$690	\$3,596	\$0	\$5,556	\$500	\$0	\$1,211	\$7,267	\$10
14 Buildings & Structures											
14.1	Combustion Turbine Building	\$0	\$220	\$116	\$0	\$336	\$30	\$0	\$55	\$421	\$1
14.2	Steam Turbine Building	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
14.3	Administration Building	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
14.4	Circulation Water Pumphouse	\$0	\$228	\$113	\$0	\$341	\$31	\$0	\$56	\$427	\$1
14.5	Water Treatment Buildings	\$0	\$486	\$443	\$0	\$928	\$84	\$0	\$152	\$1,1928	\$2
14.6	Machine Shop	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
14.7	Warehouse	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
14.8	Other Buildings & Structures	\$0	\$77	\$56	\$0	\$134	\$12	\$0	\$22	\$168	\$0
14.9	Waste Treating Building & Str.	\$0	\$303	\$541	\$0	\$844	\$76	\$0	\$138	\$1,058	\$1
	Subtotal	\$0	\$1,314	\$1,269	\$0	\$2,583	\$232	\$0	\$422	\$3,237	\$4
	Total	\$343,461	\$88,162	\$205,064	\$0	\$636,687	\$57,445	\$55,829	\$119,632	\$869,593	\$1,192

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Exhibit 5-34. Case 1 owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$5,524	\$8
1 Month Maintenance Materials	\$812	\$1
1 Month Non-fuel Consumables	\$885	\$1
1 Month Waste Disposal	\$0	\$0
25% of 1 Months Fuel Cost at 100% CF	\$2,548	\$3
2% of TPC	\$17,392	\$24
Total	\$27,161	\$37
Inventory Capital		
60 Day Supply of Fuel and Consumables at 100% CF	\$1,574	\$2
0.5% of TPC (spare parts)	\$4,348	\$6
Total	\$5,922	\$8
Other Costs		
Initial Cost for Catalyst and Chemicals	\$0	\$0
Land	\$0	\$0
Other Owner's Costs	\$130,439	\$179
Financing Costs	\$23,479	\$32
Total Overnight Costs (TOC)	\$1,056,593	\$1,448
TOC Including Retrofit Contingency	\$1,162,252	\$1,593
TASC Multiplier (IOU, high-risk, 33 year)	1.078	
Total As-Spent Cost (TASC) including Retrofit Contingency	\$1,252,908	\$1,717

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Exhibit 5-35. Case 1 initial and annual operating and maintenance costs

Case:	1	– Subcritical PC w/ NGSC CHP			Cost Base:	Jun 2011
Plant Size (MW,net):	730	Heat Rate-net (Btu/kWh):	9,700	Capacity Factor (%):	85	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		39.70	\$/hour	Skilled Operator:		3.0
Operating Labor Burden:		30.00	% of base	Operator:		13.3
Labor O-H Charge Rate:		25.00	% of labor	Foreman:		2.0
				Lab Techs, etc.:		3.0
				Total:		21.3
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$9,644,726	\$13.22
Maintenance Labor:					\$12,411,865	\$17.01
Administrative & Support Labor:					\$5,514,148	\$7.56
Property Taxes and Insurance:					\$38,954,121	\$53.38
Total:					\$66,524,861	\$91.16
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$18,617,798	\$3.43
Consumables						
	Consumption				Cost (\$)	
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	5,913	\$1.67	\$0	\$3,070,756	\$0.57
Makeup and Wastewater Treatment Chemicals (lbs):	0	28,621	\$0.27	\$0	\$2,378,308	\$0.44
Limestone (ton)	0	489	\$33.48	\$0	\$5,074,583	\$0.93
Hydrated Lime (ton)	0	100	\$155.00	\$0	\$4,791,516	\$0.88
Activated Carbon (ton)	0	3	\$1,255.00	\$0	\$1,120,454	\$0.21
CO ₂ Capture System Chemicals ^A			Proprietary		\$6,227,603	\$1.15
Triethylene Glycol (gal)	0	325	\$6.57	\$0	\$662,001	\$0.12
Ammonia (19% NH ₃ , ton)	0	73	\$330.00	\$0	\$7,482,280	\$1.38
SCR Catalyst (m ³)	0	0.40	\$8,938.80	\$0	\$1,116,698	\$0.21
Subtotal:				\$0	\$31,924,199	\$5.88
Waste Disposal						
Fly Ash (ton)	0	490	\$25.11	\$0	\$3,816,581	\$0.70
Bottom Ash (ton)	0	96	\$25.11	\$0	\$750,759	\$0.14
Amine Purification Unit Waste (ton)	0	21	\$0.00	\$0	\$0	\$0.00
Thermal Reclaimer Unit Waste (ton)	0	2	\$0.00	\$0	\$0	\$0.00
Prescrubber Blowdown Waste (ton)	0	46	\$0.00	\$0	\$0	\$0.00
Subtotal:				\$0	\$4,567,340	\$0.84
By-Products						
Gypsum (ton)	0	758	\$0.00	\$0	\$0	\$0.00
Subtotal:				\$0	\$0	\$0.00
Variable Operating Costs Total:				\$0	\$55,109,337	\$10.14
Fuel Cost						
Illinois Number 6 (ton):	0	4,944	\$68.54	\$0	\$105,133,176	\$19.35
Natural Gas (MMBtu):	0	54,652	\$6.13	\$0	\$103,939,761	\$19.13
Total:				\$0	\$209,072,937	\$38.48

^ACO₂ Capture System Chemicals includes Ion Exchange Resin, NaOH, and Cansolv Solvent.

Exhibit 5-36. Case 1 COE breakdown

Component	Value, \$/MWh	Percentage
Capital	23.7	26%
Fixed	12.2	14%
Variable	10.1	11%
Fuel	38.5	42%
Total (Excluding T&S)	84.6	N/A
CO ₂ T&S	6.0	7%
Total (Including T&S)	90.6	N/A

5.3 RETROFIT CASE 2 – NGCC CHP REPOWERING

Case 2 examines the costs and performance aspects of co-locating an NG-fueled combined cycle power plant that is specifically designed to satisfy the energy demand of the CO₂ capture plant and the bottoming cycle is designed around the balance of available thermal energy recoverable from the CT exhaust. The Case 2 analysis is also intended to consider a “bounding” scenario using highly efficient state-of-the-art F-class turbine technology in an NGCC CHP configuration, producing power and heat required for a solvent-based CO₂ capture process designed to achieve a 90 percent reduction of CO₂ emissions from an existing PC plant. Similar to Case 1, It is assumed that no CO₂ capture is required for the NGCC CHP plant. It should be noted that results are reported in the context of the cost and performance of the hybrid dual-fueled power plant.

The NGCC CHP evaluated in Case 2 differs from that in Case 1 in that it addresses the insufficient recoverable energy in the exhaust gas of commercially available F-Class technology that required the hypothetical sizing in Case 1. Case 2 overcomes the shortcoming using two 7FA combustion turbines and adds a steam bottoming cycle to produce power from the remaining recoverable energy (in excess of the requirements of the CO₂ capture system) in the CT exhaust. A brief discussion of the practicality of this assumption is discussed later in Section 6.1.4 of this report.

5.3.1 Process Description

The system description follows the BFD in Exhibit 5-37 and the numbered streams correspond to the material and energy data presented in the tables in Exhibit 5-38.

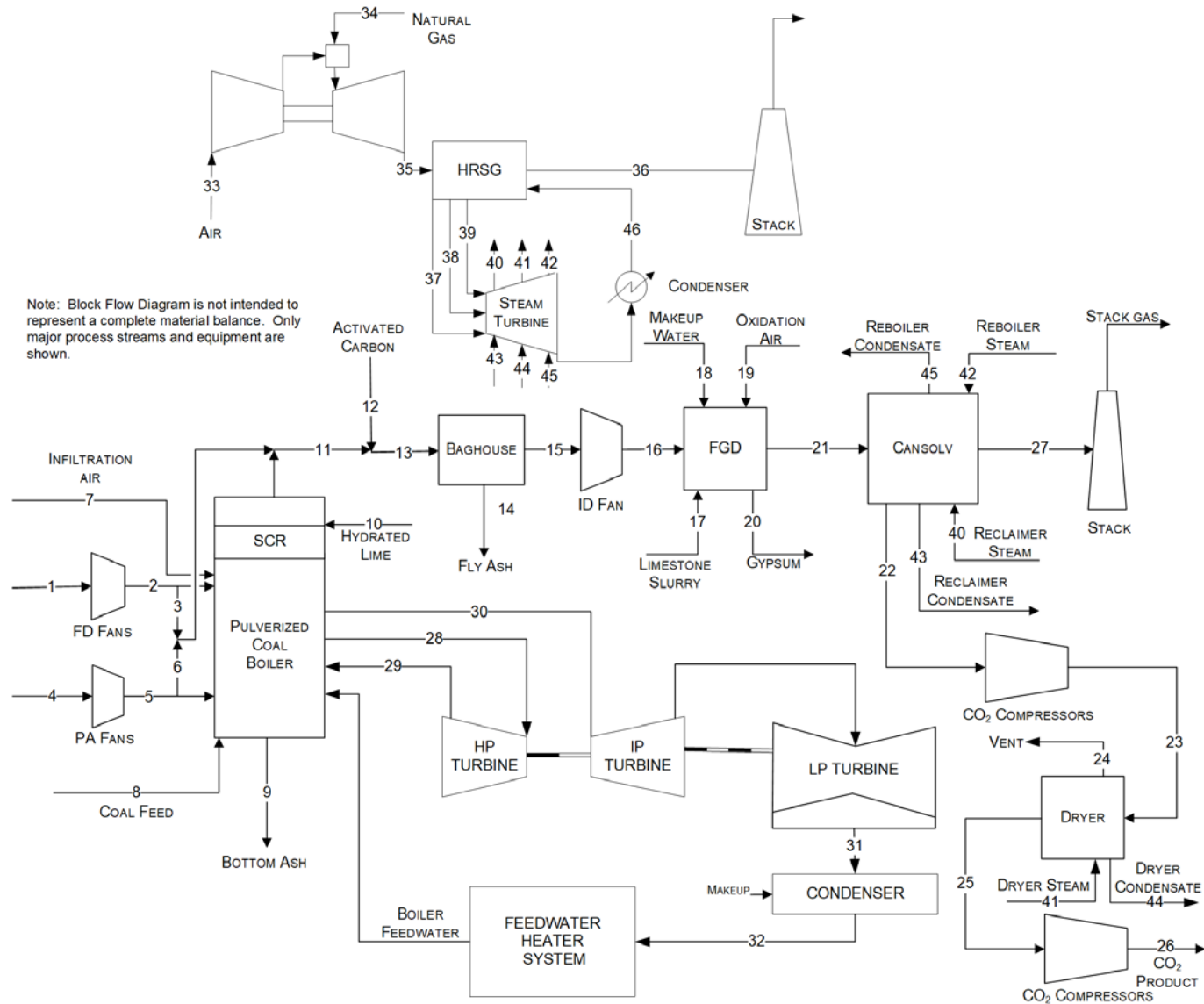
The major processes of the existing PC plant are essentially the same as those described in Section 5.1.1 and are repeated here for convenience. Coal feed and primary air (PA) are introduced into the boiler through the wall-fired burners. Additional combustion air, including the OFA, is provided by the FD fans. The boiler operates at a slight negative pressure so air leakage goes into the boiler, and the infiltration air is accounted for as an additional stream. Ljungstrom air preheater leakages from the FD and PA fan outlet streams are accounted by adding the flows to the boiler exhaust.

Flue gas exits the boiler through the SCR reactor where ammonia is injected to reduce NO_x compounds, followed by hydrated lime injection for the reduction of SO₃. It then passes

through the combustion air preheater (where the air preheater leakages are introduced) and is cooled to 143°C (289°F) before PAC is injected for mercury reduction. The flue gas then passes through a fabric filter for particulate removal. An ID fan increases the flue gas temperature to 153°C (308°F) and provides the motive force for the flue gas to pass through the FGD unit. FGD inputs and outputs include makeup water, oxidation air, limestone slurry and product gypsum. The clean, saturated flue gas exiting the FGD unit passes to the Cansolv CO₂ capture system, then on to the plant stack and is discharged to the atmosphere. The clean, saturated flue gas exiting the FGD unit passes to the Cansolv CO₂ capture system, then on to the plant stack and is discharged to the atmosphere. Since the Cansolv facility process description was provided in Section 4.1, it is not repeated here.

For Case 2 (as in Case 1), no modifications are made to the PC plant steam cycle. Case 2 differs from Case 1 in that an NGCC CHP auxiliary plant is added rather than the NG-fueled simple cycle CHP plant. Similar to Case 1, there is minimal impact to the existing PC plant, performance is largely unaffected and the plant is assumed to continue to operate as it did prior to the retrofit.

In the NGCC CHP auxiliary plant, natural gas is combusted and sent through the combustion turbines. Exhaust gas at 603°C (1,118°F) is routed through two HRSGs where utility steam is raised for the CCS facility. Flue gas is then routed to the HRSG stack at 116°C (242°F).

Exhibit 5-37. Case 2 block flow diagram, subcritical unit with NGCC CHP

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Exhibit 5-38. Case 2 stream table, subcritical unit with NGCC CHP

	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	0.0000	0.0088	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
CH ₄ S	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 ₂ H 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 ₃ H 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 ₄ H 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	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	0.0000	0.1376	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
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0000	0.0831	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7345	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0340	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0020	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	1.0000	0.0000
V-L Flowrate (kg _{mole} /hr)	51,530	51,530	1,526	15,829	15,829	2,179	1,126	0	0	0	72,228	0
V-L Flowrate (kg/hr)	1,486,986	1,486,986	44,042	456,787	456,787	62,866	32,480	0	0	0	2,145,013	0
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	186,882	3,624	3,766	18,264	109
Temperature (°C)	15	19	19	15	25	25	15	15	149	27	143	27
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
Steam Table Enthalpy (kJ/kg) ^A	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	- 2,114.05	97.18	- 13,306.82	-2,399.51	3.40
Density (kg/m ³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	---	0.9	---
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	---	29.698	---
V-L Flowrate (lb _{mole} /hr)	113,603	113,603	3,365	34,898	34,898	4,803	2,481	0	0	0	159,236	0
V-L Flowrate (lb/hr)	3,278,243	3,278,243	97,095	1,007,042	1,007,042	138,595	71,605	0	0	0	4,728,944	0
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	412,005	7,990	8,303	40,264	240
Temperature (°F)	59	66	66	59	78	78	59	59	300	80	289	80
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.4	14.7	14.4	14.7
Steam Table Enthalpy (Btu/lb) ^A	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-908.9	41.8	-5,720.9	-1,031.6	1.5
Density (lb/ft ³)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	---	0.053	---

^ASteam table reference conditions are 32.02°F and 0.089 psia.

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm.

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Exhibit 5-38. Case 2 stream table, subcritical unit with NGCC CHP (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0088	0.0000	0.0088	0.0088	0.0000	0.0000	0.0092	0.0000	0.0082	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
CH ₄ S	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 ₂ H 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 ₃ H 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 ₄ H 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	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	0.1376	0.0000	0.1376	0.1376	0.0000	0.0000	0.0003	0.0001	0.1288	0.9824	0.9977	0.0503
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
H ₂ O	0.0831	0.0000	0.0831	0.0831	1.0000	1.0000	0.0099	0.9999	0.1451	0.0176	0.0023	0.9497
N ₂	0.7345	0.0000	0.7345	0.7345	0.0000	0.0000	0.7732	0.0000	0.6854	0.0000	0.0000	0.0000
O ₂	0.0340	0.3333	0.0340	0.0340	0.0000	0.0000	0.2074	0.0000	0.0325	0.0000	0.0000	0.0000
SO ₂	0.0020	0.6667	0.0020	0.0020	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 _{mole} /hr)	72,228	3	72,225	72,225	2,394	9,596	764	177	78,267	9,236	9,095	15
V-L Flowrate (kg/hr)	2,145,013	164	2,144,849	2,144,849	43,130	172,875	22,042	3,183	2,258,155	402,256	399,711	291
Solids Flowrate (kg/hr)	18,372	18,372	0	0	18,467	0	0	28,641	0	0	0	0
Temperature (°C)	143	143	143	153	15	27	167	56	56	29	29	29
Pressure (MPa, abs)	0.10	0.10	0.10	0.11	0.10	0.11	0.31	0.10	0.10	0.20	3.03	3.03
Steam Table Enthalpy (kJ/kg) ^A	---	---	274.36	285.60	---	111.65	184.48	---	286.10	42.52	-6.01	137.66
AspenPlus Enthalpy (kJ/kg) ^B	-2,399.39	-2,632.02	-2,397.37	-2,386.13	-14,995.75	-15,964.53	56.67	-12,481.91	-2,940.32	-8,972.02	-8,974.91	-15,221.56
Density (kg/m ³)	0.9	1.5	0.8	0.9	1,003.6	992.3	2.4	833.1	1.1	3.5	63.3	372.2
V-L Molecular Weight	29.698	53.376	29.697	29.697	18.015	18.015	28.857	18.018	28.852	43.553	43.950	19.322
V-L Flowrate (lb _{mole} /hr)	159,236	7	159,229	159,229	5,278	21,156	1,684	389	172,548	20,362	20,050	33
V-L Flowrate (lb/hr)	4,728,944	362	4,728,582	4,728,582	95,086	381,124	48,595	7,018	4,978,379	886,823	881,213	642
Solids Flowrate (lb/hr)	40,504	40,504	0	0	40,712	0	0	63,142	0	0	0	0
Temperature (°F)	289	289	289	308	59	80	332	133	133	85	85	85
Pressure (psia)	14.4	14.4	14.2	15.2	15.0	15.7	45.0	14.7	14.7	28.7	439.4	439.4
Steam Table Enthalpy (Btu/lb) ^A	---	---	118.0	122.8	---	48.0	79.3	---	123.0	18.3	-2.6	59.2
AspenPlus Enthalpy (Btu/lb) ^B	-1,031.6	-1,131.6	-1,030.7	-1,025.8	-6,447.0	-6,863.5	24.4	-5,366.3	-1,264.1	-3,857.3	-3,858.5	-6,544.1
Density (lb/ft ³)	0.053	0.096	0.052	0.055	62.650	61.950	0.153	52.011	0.067	0.216	3.953	23.235

^ASteam table reference conditions are 32.02°F and 0.089 psia.

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm.

Exhibit 5-38. Case 2 stream table, subcritical unit with NGCC CHP (continued)

	25	26	27	28	29	30	31	32	33	34	35	36
V-L Mole Fraction												
Ar	0.0000	0.0000	0.0103	0.0000	0.0000	0.0000	0.0000	0.0000	0.0092	0.0000	0.0089	0.0089
CH ₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.9310	0.0000	0.0000
CH ₄ S	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 ₂ H ₆	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0320	0.0000	0.0000
C ₃ H ₈	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0070	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0040	0.0000	0.0000
CO	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	0.9993	0.9993	0.0163	0.0000	0.0000	0.0000	0.0000	0.0000	0.0003	0.0100	0.0391	0.0391
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
H ₂ O	0.0007	0.0007	0.0671	1.0000	1.0000	1.0000	1.0000	1.0000	0.0099	0.0000	0.0841	0.0841
N ₂	0.0000	0.0000	0.8652	0.0000	0.0000	0.0000	0.0000	0.0000	0.7732	0.0160	0.7442	0.7442
O ₂	0.0000	0.0000	0.0410	0.0000	0.0000	0.0000	0.0000	0.0000	0.2074	0.0000	0.1238	0.1238
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 _{mole} /hr)	9,080	9,080	61,998	87,854	82,001	82,001	72,119	73,186	125,541	4,855	130,538	130,538
V-L Flowrate (kg/hr)	399,420	399,420	1,729,078	1,582,720	1,477,273	1,477,273	1,299,245	1,318,468	3,622,750	84,134	3,706,884	3,706,884
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	29	40	41	566	355	566	38	39	15	38	603	116
Pressure (MPa, abs)	2.89	15.27	0.10	16.65	4.28	4.19	0.01	2.04	0.10	3.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	-5.92	-205.59	151.94	3,473.89	3,098.44	3,593.58	1,980.13	163.34	30.22	46.29	800.33	255.87
AspenPlus Enthalpy (kJ/kg) ^B	8,970.17	9,169.84	-794.66	12,506.41	12,881.86	12,386.71	14,000.17	15,816.96	-97.57	4,462.93	-616.98	-1,161.44
Density (kg/m ³)	59.9	789.2	1.1	47.7	16.0	11.1	0.1	993.6	1.2	22.2	0.4	0.9
V-L Molecular Weight	43.991	43.991	27.889	18.015	18.015	18.015	18.015	18.015	28.857	17.328	28.397	28.397
V-L Flowrate (lb _{mole} /hr)	20,017	20,017	136,683	193,686	180,781	180,781	158,995	161,348	276,771	10,704	287,786	287,786
V-L Flowrate (lb/hr)	880,571	880,571	3,811,964	3,489,300	3,256,829	3,256,829	2,864,345	2,906,725	7,986,797	185,484	8,172,281	8,172,281
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	85	104	107	1,050	671	1,050	101	101	59	100	1,118	242
Pressure (psia)	419.4	2,214.7	14.7	2,414.7	620.5	608.1	1.0	295.5	14.7	450.0	15.1	14.8
Steam Table Enthalpy (Btu/lb) ^A	-2.5	-88.4	65.3	1,493.5	1,332.1	1,545.0	851.3	70.2	13.0	19.9	344.1	110.0
AspenPlus Enthalpy (Btu/lb) ^B	-3,856.5	-3,942.3	-341.6	-5,376.8	-5,538.2	-5,325.3	-6,019.0	-6,800.1	-41.9	-1,918.7	-265.3	-499.3
Density (lb/ft ³)	3.737	49.267	0.068	2.975	1.000	0.692	0.004	62.028	0.076	1.384	0.025	0.056

^ASteam table reference conditions are 32.02°F and 0.089 psia.^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm.

Exhibit 5-38. Case 2 stream table, subcritical unit with NGCC CHP (continued)

	37	38	39	40	41	42	43	44	45	46
V-L Mole Fraction										
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	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
CH ₄ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₂ H ₆	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₃ H ₈	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	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
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 _{mole} /hr)	24,421	289	7,612	69	13	23,255	69	13	23,255	32,648
V-L Flowrate (kg/hr)	439,947	5,215	137,125	1,245	239	418,944	1,245	239	418,944	588,168
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	566	482	281	356	356	270	215	203	151	38
Pressure (MPa, abs)	16.65	4.28	0.51	4.28	4.28	0.51	2.11	1.64	0.49	0.01
Steam Table Enthalpy (kJ/kg) ^A	3,473.89	3,401.18	3,023.29	3,100.49	3,100.49	3,000.52	921.30	863.65	635.93	160.78
AspenPlus Enthalpy (kJ/kg) ^B	12,506.41	12,579.12	12,957.01	12,879.81	12,879.81	-12,979.77	-15,058.99	-15,116.65	-15,344.37	-15,819.51
Density (kg/m ³)	47.7	12.7	2.0	16.0	16.0	2.1	846.4	861.8	916.3	992.8
V-L Molecular Weight	18.015	18.015	18.015	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mole} /hr)	53,839	638	16,781	152	29	51,268	152	29	51,268	71,977
V-L Flowrate (lb/hr)	969,917	11,497	302,309	2,745	527	923,613	2,745	527	923,613	1,296,689
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	1,050	900	537	673	673	517	419	397	304	101
Pressure (psia)	2,414.7	620.5	73.5	620.5	620.5	73.5	306.2	237.4	70.6	1.0
Steam Table Enthalpy (Btu/lb) ^A	1,493.5	1,462.2	1,299.8	1,333.0	1,333.0	1,290.0	396.1	371.3	273.4	69.1
AspenPlus Enthalpy (Btu/lb) ^B	-5,376.8	-5,408.0	-5,570.5	-5,537.3	-5,537.3	-5,580.3	-6,474.2	-6,499.0	-6,596.9	-6,801.2
Density (lb/ft ³)	2.975	0.795	0.126	0.998	0.998	0.128	52.841	53.801	57.201	61.977

^ASteam table reference conditions are 32.02°F and 0.089 psia.^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm.

5.3.2 Key System Assumptions

System assumptions for Case 2, subcritical PC with CCS retrofit and NGCC CHP repowering, are compiled in Exhibit 5-39. The balance of plant assumptions for Case 2 are presented in Exhibit 5-40.

Exhibit 5-39. Subcritical PC plant with NGCC CHP study configuration matrix

Parameter	Case 1
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/566 (2,400/1,050/1,050)
Coal	Illinois No. 6
Condenser Pressure, mm Hg (in Hg)	50.8 (2)
Boiler Efficiency, HHV %	89
Cooling Water to Condenser, °C (°F)	16 (60)
Cooling Water from Condenser, °C (°F)	27 (80)
Stack Temperature, °C (°F)	56 (133)
SO ₂ Control	Wet Limestone Forced Oxidation
FGD Efficiency ^A , %	98 ^{B,C}
NO _x Control	LNB w/OFA, SCR, and Polishing Scrubber
SCR Efficiency ^A , %	83
Ammonia Slip (end of catalyst life), ppmv	2
Particulate Control	Fabric Filter
Fabric Filter Efficiency ^A , %	99.9
Ash Distribution, Fly/Bottom	80%/20%
SO ₃ Control	DSI
Mercury Control	Co-benefit Capture and ACI
CO ₂ Control	Cansolv (PC plant flue gas only)
Carbon Capture Efficiency ^A	90%
CO ₂ Sequestration	Off-site Saline Formation
Auxiliary Plant Combustion Turbine	7FA
CT Output, MW	211 (2x)
CT NO _x Control	LNB
CT SCR Efficiency ^A , %	90
CT Heat Rate, Btu/kWh (HHV)	9,898
Combined Cycle ST, MPa/°C/°C (psig/°F/°F)	16.5/566/566 (2400/1050/1050)
NGCC ST Output, MW	145
NGCC ST Exhaust Pressure, MPa (psia)	0.51 (73.5)

^ARemoval efficiencies are based on the flue gas content.

^BAn SO₂ polishing step is included to meet more stringent SO_x content limits in the flue gas (~1 ppmv) to reduce formation of amine HSS during the CO₂ absorption process.

^CSO₂ exiting the post-FGD polishing step is absorbed in the CO₂ capture process making stack emissions negligible.

Exhibit 5-40. Case 2 balance of plant assumptions

Parameter	Value
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
Hydrated lime	30 days
Activated carbon	30 days
Plant Distribution Voltage	
Motors below 1 hp	110/220 V
Motors between 1 hp and 250 hp	480 V
Motors between 250 hp and 5,000 hp	4,160 V
Motors above 5,000 hp	13,800 V
Steam and CT generators	24,000 V
Grid interconnection voltage	345 kV
Water and Wastewater	
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.

5.3.3 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 PCC plant design consists of the following major subsystems:

- One amine CO₂ absorption system consisting of an absorber, stripper, and ancillary equipment (1 x 100%) and two CO₂ compression systems (2 x 50%)
- One NG-fueled auxiliary (combined heat and power) plant
 - Two state-of-the-art 2013 F class CTGs (2 x 50%)
 - Two three-pressure HRSGs with self-supporting stacks and SCR systems (2 x 50%)
 - One three-pressure reheat, triple-admission STG (1 x 100%)

5.3.4 Case 2 – Performance Results

The combined plant (existing PC plant plus excess power from auxiliary plant) produces a net output of 1,148 MWe and has an overall net plant efficiency of 40.3 percent (HHV basis). Overall performance for the plant is summarized in Exhibit 5-41. Exhibit 5-42 provides a detailed breakdown of the auxiliary power requirements.

Exhibit 5-41. Case 2 plant performance summary

Performance Summary	
Base Plant Steam Turbine Power, MWe	581
Auxiliary Combustion Turbine Power, MWe	422
Auxiliary Plant Steam Turbine Power, MWe	145
Total Gross Power, MWe	1,148
CO ₂ Capture/Removal Auxiliaries, kWe	13,300
CO ₂ Compression, kWe	29,180
Balance of Plant, kWe	45,145
Total Auxiliaries, MWe	88
Net Power, MWe	1,060
HHV Net Plant Efficiency (%)	40.3%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,934 (8,468)
LHV Net Plant Efficiency (%)	43.0%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,364 (7,927)
HHV Boiler Efficiency, %	89.1%
LHV Boiler Efficiency, %	92.4%
Base Plant Steam Turbine Cycle Efficiency, %	46.3%
Base Plant Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,774 (7,369)
Auxiliary Plant Steam Turbine Cycle Efficiency, %	50.9%
Auxiliary Plant Combustion Turbine HHV Efficiency, %	34.5%
Auxiliary Plant Efficiency, %	45.7%
Auxiliary Plant Heat Rate, kJ/kWh (Btu/kWh)	7,882 (7,471)
Base Plant Condenser Duty, GJ/hr (MMBtu/hr)	2,362 (2,239)
Auxiliary Plant Condenser Duty, GJ/hr (MMBtu/hr)	557 (528)
As-Received Coal Feed, kg/hr (lb/hr)	186,882 (412,005)
Limestone Sorbent Feed, kg/hr (lb/hr)	18,467 (40,712)
Natural Gas Feed Flow, kg/hr (lb/hr)	84,134 (185,484)
HHV Thermal Input, kWt	2,631,664
LHV Thermal Input, kWt	2,463,805
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.034 (8.9)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.026 (6.8)
Excess Air, %	20.9%

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Exhibit 5-42. Case 2 plant power summary

Power Summary	
Base Plant Steam Turbine Power, MWe	581
Auxiliary Combustion Turbine Power, MWe	422
Auxiliary Plant Steam Turbine Power, MWe	145
Total Gross Power, MWe	1,148
PC Plant Auxiliary Load Summary	
Coal Handling and Conveying, kWe	440
Pulverizers, kWe	2,800
Sorbent Handling & Reagent Preparation, kWe	890
Ash Handling, kWe	650
Primary Air Fans, kWe	1,390
Forced Draft Fans, kWe	1,770
Induced Draft Fans, kWe	6,940
SCR, kWe	50
Activated Carbon Injection, kWe	23
Dry Sorbent Injection, kWe	90
Baghouse, kWe	90
Wet FGD, kWe	2,950
CO ₂ Capture/Removal Auxiliaries, kWe	13,300
CO ₂ Compression, kWe	29,180
Miscellaneous Balance of Plant ^{A,B} , kWe	2,000
Steam Turbine Auxiliaries, kWe	400
Condensate Pumps, kWe	990
Circulating Water Pumps, kWe	8,070
Ground Water Pumps, kWe	740
Cooling Tower Fans, kWe	4,170
Transformer Losses, kWe	2,130
NGCC CHP Plant Auxiliary Load Summary	
Feedwater Pumps, kWe	3,550
SCR, kWe	2
CO ₂ Capture/Removal Auxiliaries, kWe	0
CO ₂ Compression, kWe	0
Miscellaneous Balance of Plant ^B , kWe	500
Combustion Turbine Auxiliaries, kWe	700
Steam Turbine Auxiliaries, kWe	100
Condensate Pumps, kWe	130
Circulating Water Pumps, kWe	1,150
Ground Water Pumps, kWe	110
Cooling Tower Fans, kWe	600
Transformer Losses, kWe	1,720
Total Auxiliaries, MWe	88
Net Power, MWe	1,060

^ABoiler feed pumps are turbine driven.

^BIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads.

5.3.4.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case 2 (inclusive of emissions from auxiliary plant) is presented in Exhibit 5-43. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 5-43. Case 2 air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year) ^A	kg/MWh (lb/MWh)
SO ₂	0.000 (0.000)	13 (15)	0.002 (0.003)
NO _x	0.020 (0.047)	1,418 (1,563)	0.166 (0.366)
Particulate	0.003 (0.006)	177 (195)	0.021 (0.046)
Hg	8.35E-8 (1.94E-7)	0.006 (0.006)	6.89E-7 (1.52E-6)
CO ₂ ^B	28 (66)	2,001,816 (2,206,625)	234 (516)
CO ₂ ^C	-	-	254 (559)
mg/Nm³			
Particulate Concentration ^{D,E}	14.66		

^ACalculations based on an 85 percent capacity factor.

^BCO₂ emissions based upon gross power.

^CCO₂ emissions based on net power instead of gross power.

^DConcentration of particles in the flue gas after the baghouse.

^ENormal conditions given at 32°F and 14.696 psia.

SO₂ emissions from the PC boiler 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 flue gas exiting the scrubber is vented through the plant stack.

NO_x emissions are controlled from the PC boiler to about 0.5 lb/MMBtu using LNBs and OFA. The CTs are also equipped with LNBs. SCR units are used for both the PC boiler and auxiliary NGCC to further reduce the total plant NO_x concentration by 84 percent to 0.05 lb/MMBtu.

Particulate emissions from the PC boiler are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment on the PC boiler (SCR, ACI, fabric filter, DSI, and wet FGD) is 96.8 percent.

CO₂ emissions represent the combined emissions from the retrofitted PC plant and uncontrolled flue gas from the auxiliary plant.

The carbon balance for the plant is shown in Exhibit 5-44. The carbon input to the plant consists of carbon in the coal, natural gas, air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO₂ through the PC boiler and auxiliary plant stacks; however, the PAC is captured in the fabric filter and some leaves as gypsum.

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Exhibit 5-44. Case 2 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	119,128 (262,632)	Base Plant Stack Gas	12,109 (26,697)
Natural Gas	60,768 (133,971)	Aux Plant Stack Gas	61,263 (135,061)
Base Plant Air	272 (599)	FGD Product	179 (394)
Aux Plant Air	494 (1,090)	Baghouse	109 (240)
PAC	109 (240)	CO ₂ Product	108,976 (240,250)
		CO ₂ Dryer Vent	9 (20)
		CO ₂ Knockout	0 (0)
Total	182,645 (402,663)	Total	182,645 (402,663)

Exhibit 5-45 shows the sulfur balance for the plant. Sulfur input comes primarily from the sulfur in the coal with a negligible amount from the natural gas. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur captured in the fabric filter via hydrated lime, and sulfur emitted in the stack gas.

Exhibit 5-45. Case 2 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	4,684 (10,327)	FGD Product	4,526 (9,978)
Natural Gas	1 (2)	Base Plant Stack Gas	0 (0)
		Aux Plant Stack Gas	1 (2)
		Polishing Scrubber and Solvent Reclaiming	92 (204)
		Baghouse	66 (145)
Total	4,685 (10,329)	Total	4,685 (10,329)

Exhibit 5-46 shows the water balance for Case 2. Water demand, withdrawal, and consumption are discussed in Section 2.6.

Exhibit 5-46. Case 2 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
FGD Makeup	3.61 (952)	–	3.61 (952)	–	3.61 (952)
CO ₂ Drying	–	–	–	0.00 (1)	0.00 (-1)
Capture System Makeup	0.02 (4)	–	0.02 (4)	–	0.02 (4)
Deaerator Vent	–	–	–	0.05 (14)	-0.05 (-14)
Base Plant Condenser Makeup	0.32 (85)	–	0.32 (85)	–	0.32 (85)
BFW Makeup	0.32 (85)	–	0.32 (85)	–	0.32 (85)
HRSR Steam Loop	0.10 (26)	–	0.10 (26)	–	0.10 (26)
Condensate Makeup	0.10 (26)	–	0.10 (26)	–	0.10 (26)
Cooling Tower	35.89 (9,482)	4.38 (1,157)	31.51 (8,324)	8.07 (2,132)	23.44 (6,192)
FGD Dewatering	–	1.86 (491)	-1.86 (-491)	–	-1.86 (-491)
CO ₂ Capture Recovery	–	2.11 (558)	-2.11 (-558)	–	-2.11 (-558)
CO ₂ Compression KO	–	0.04 (11)	-0.04 (-11)	–	-0.04 (-11)
Base Plant BFW Blowdown	–	0.27 (71)	-0.27 (-71)	–	-0.27 (-71)
HRSR Blowdown	–	0.10 (26)	-0.10 (-26)	–	-0.10 (-26)
Total	39.93 (10,549)	4.38 (1,157)	35.55 (9,392)	8.13 (2,148)	27.42 (7,244)

5.3.4.2 Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case 2 PC boiler, the FGD unit, steam cycle, and auxiliary plant systems in Exhibit 5-47 and Exhibit 5-48.

An overall plant energy balance is provided in tabular form in Exhibit 5-49. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-41) is calculated by multiplying the power out by a generator efficiency of 98.5 percent. A Sankey diagram is presented in Exhibit 5-50 illustrating the flow of energy into and out of the plant.

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Exhibit 5-47. Case 2 heat and mass balance, subcritical PC boiler with CO₂ capture and NGCC CHP plant

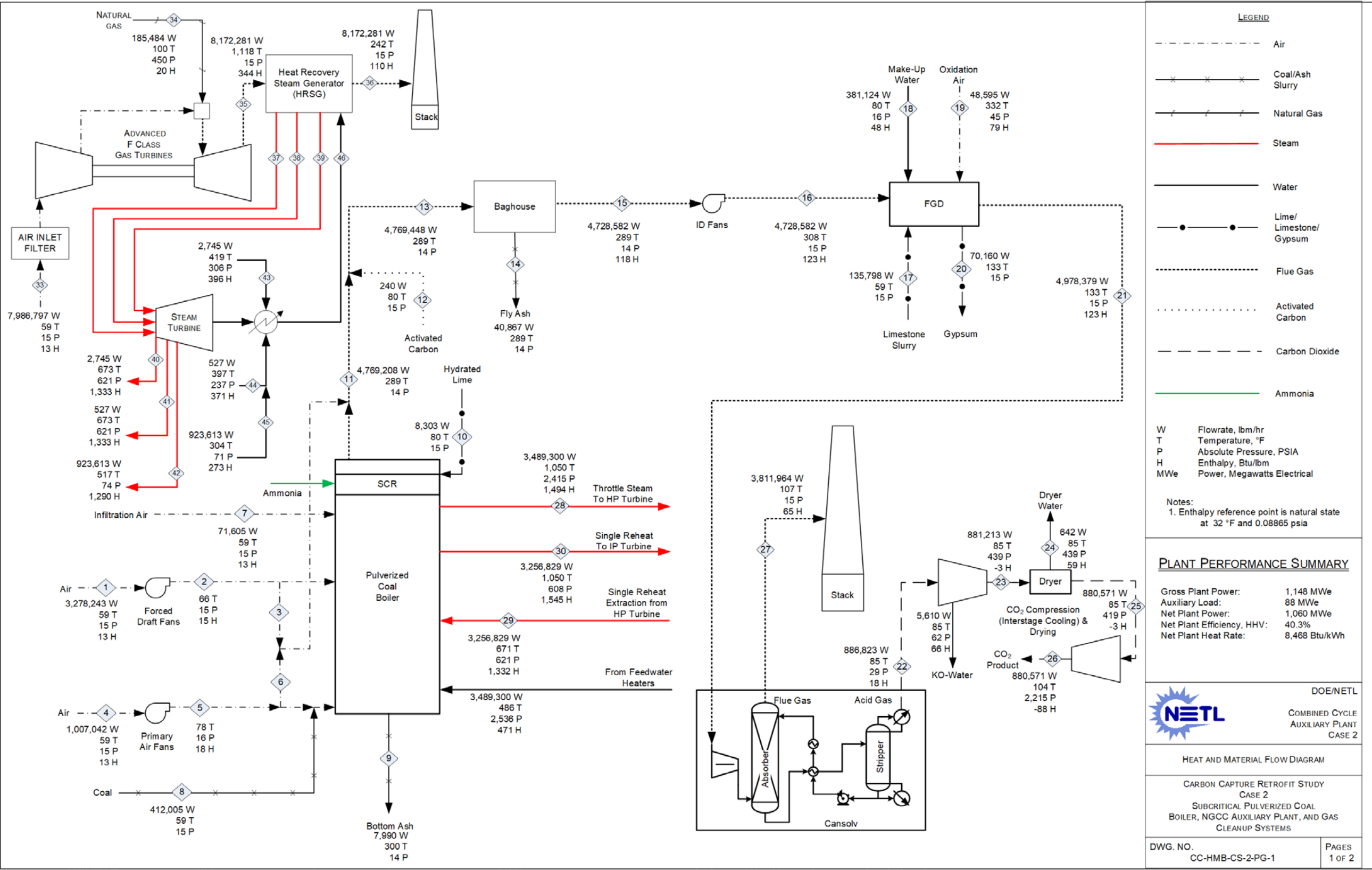
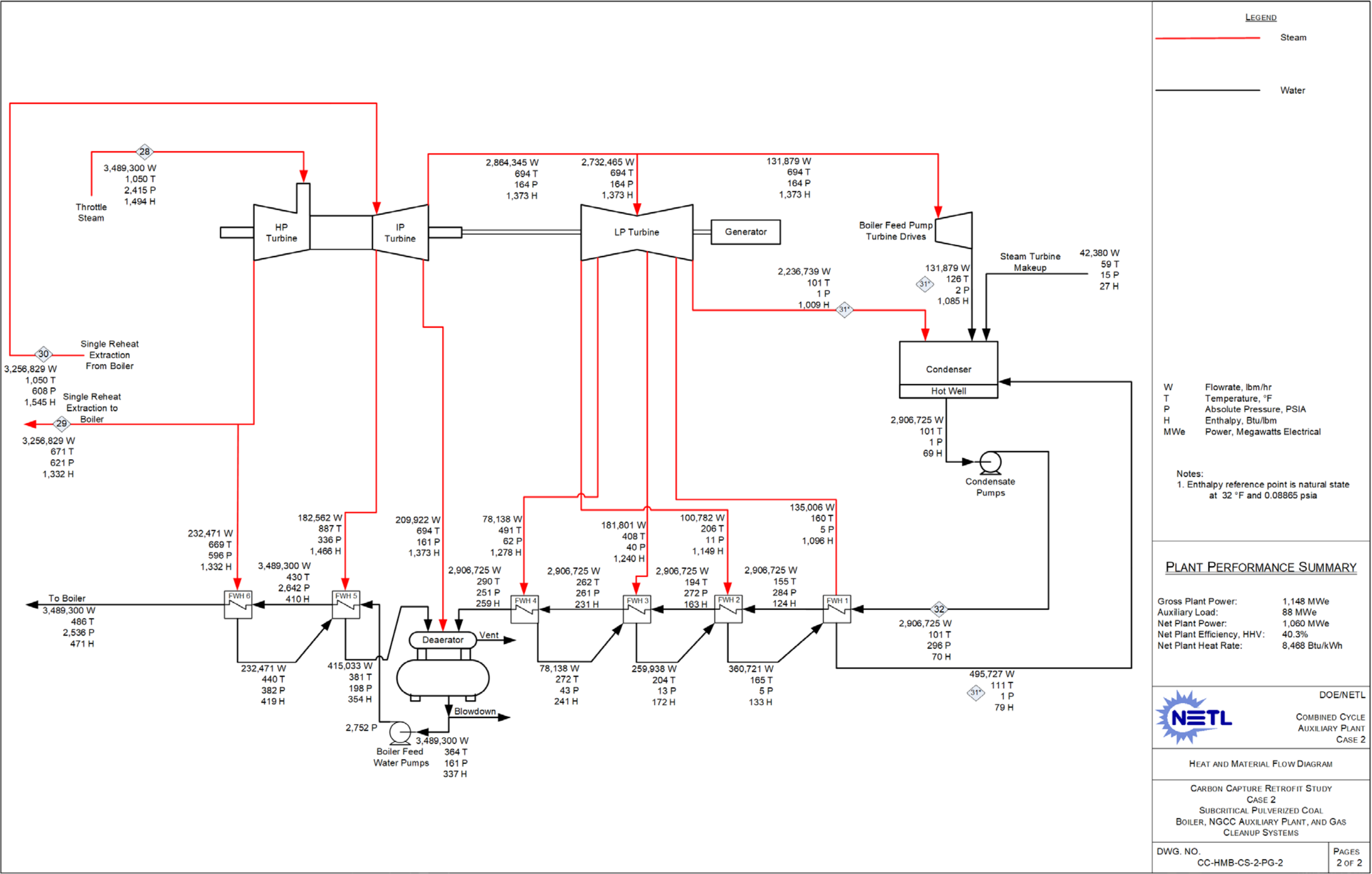


Exhibit 5-48. Case 2 heat and mass balance, subcritical steam cycle



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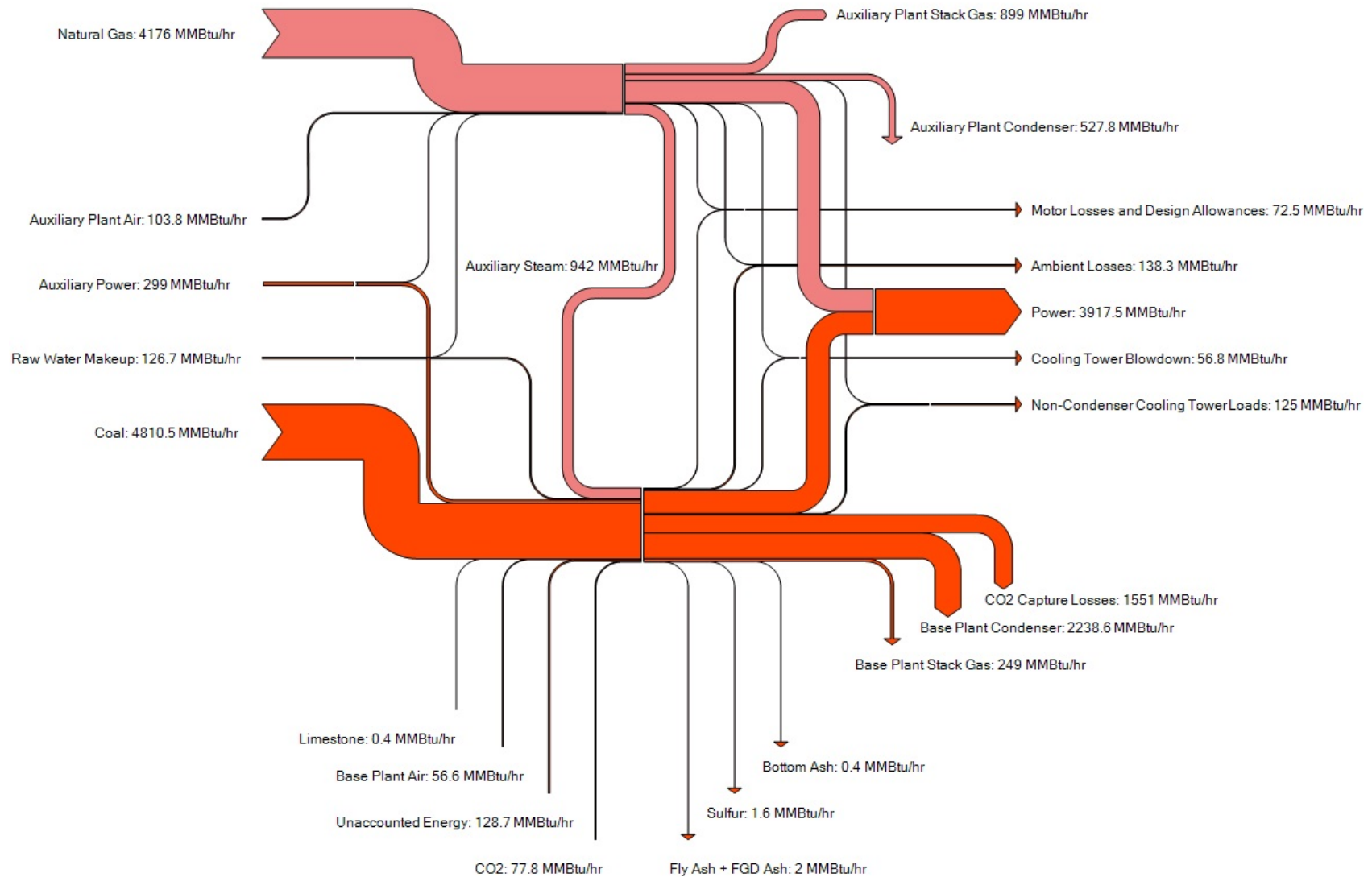
Exhibit 5-49. Case 2 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,071 (4,806)	4.2 (4.0)	–	5,075 (4,810)
Natural Gas	4,403 (4,173)	2.9 (2.8)	–	4,406 (4,176)
Base Plant Air	–	59.7 (56.6)	–	59.7 (56.6)
Aux Plant Air	–	109.5 (103.8)	–	109.5 (103.8)
Raw Water Makeup	–	133.7 (126.7)	–	133.7 (126.7)
Limestone	–	0.40 (0.38)	–	0.40 (0.38)
Auxiliary Power	–	–	315 (299)	315 (299)
TOTAL	9,474 (8,980)	310.5 (294.3)	315 (299)	10,100 (9,573)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	0.4 (0.4)	–	0.4 (0.4)
Fly Ash + FGD Ash	–	2.1 (2.0)	–	2.1 (2.0)
Base Plant Stack Gas	–	263 (249)	–	263 (249)
Aux Plant Stack Gas	–	948 (899)	–	948 (899)
Sulfur	1.7 (1.6)	0.0 (0.0)	–	1.7 (1.6)
Motor Losses and Design Allowances	–	–	76 (72)	76 (72)
Base Plant Condenser	–	2,362 (2,239)	–	2,362 (2,239)
Aux Plant Condenser	–	557 (528)	–	557 (528)
Miscellaneous Non-Condenser Cooling Tower Loads	–	132 (125)	–	132 (125)
CO ₂	–	-82.1 (-77.8)	–	-82.1 (-77.8)
Cooling Tower Blowdown	–	60.0 (56.8)	–	60.0 (56.8)
CO ₂ Capture Losses	–	1,636 (1,551)	–	1,636 (1,551)
<i>Ambient Losses^A</i>	–	145.9 (138.3)	–	145.9 (138.3)
Power	–	–	4,133 (3,917)	4,133 (3,917)
TOTAL	1.7 (1.6)	6,024 (5,710)	4,210 (3,990)	10,236 (9,702)
Unaccounted Energy ^B	–	-136 (-129)	–	-136 (-129)

^AAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers.

^BBy difference.

Exhibit 5-50. Case 2 Sankey diagram



5.3.5 Case 2 – Major Equipment List

Equipment lists showing the major retrofitted equipment items for Case 2 are shown in the following tables. The major equipment list is not intended to be all-inclusive of required modifications but rather to identify key equipment items and applicable design conditions. The account identifications (e.g., Account 5B: Carbon Dioxide Recovery) in the equipment list correspond to the account numbers used in the cost estimates in Section 5.3.6. 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 2 – Account 3: Feedwater and Miscellaneous Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	776,000 liters (205,000 gal)	2	0
2	Condensate Pumps	Vertical canned	5,430 lpm @ 70 m H ₂ O (1,430 gpm @ 240 ft H ₂ O)	2	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 4,100 lpm @ 2,500 m H ₂ O (1,080 gpm @ 8,210 ft H ₂ O)	2	1
4	Filtered Water Pumps	Stainless steel, single suction	IP water: 050 lpm @ 540 m H ₂ O (10 gpm @ 1,790 ft H ₂ O)	2	1
5	Filtered Water Tank	Vertical, cylindrical	LP water: 1,280 lpm @ 14.0 m H ₂ O (340 gpm @ 50 ft H ₂ O)	1	0
4	Auxiliary Boiler (for startup)	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m ³ /min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m ³ /min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 MMkJ/hr (13 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,200 lpm @ 20 m H ₂ O (1,400 gpm @ 70 ft H ₂ O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	2,600 lpm @ 20 m H ₂ O (700 gpm @ 60 ft H ₂ O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H ₂ O (40 gpm @ 160 ft H ₂ O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0

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Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
15	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

Case 2 – Account 5B: Carbon Dioxide Recovery

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Cansolv	Amine-based CO ₂ capture technology	2,484,000 kg/hr (5,476,000 lb/hr) 19.6 wt % CO ₂ concentration	1	0
2	Cansolv LP Condensate Pump	Centrifugal	8,593 lpm @ 1 m H ₂ O (2,270 gpm @ 4 ft H ₂ O)	1	1
3	Cansolv IP Condensate Pump	Centrifugal	5 lpm @ 3.7 m H ₂ O (1 gpm @ 12 ft H ₂ O)	1	1
4	CO ₂ Dryer	Triethylene glycol	Inlet: 105.0 m ³ /min (3,715 acfm) @ 3.0 MPa (439 psia) Outlet: 2.9 MPa (419 psia) Water Recovered: 291 kg/hr (642 lb/hr)	1	0
5	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	219,615 kg/hr @ 15.3 MPa (484,169 lb/hr @ 2,215 psia)	2	0

Case 2 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	State-of-the-art 2013 F-Class	210 MW	2	0
2	Combustion Turbine Generator	TEWAC	230 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

Case 2 – Account 7: Ducting and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	PC Plant Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 5.0 m (17 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 241,971 kg/hr, 16.5 MPa/566°C (533,454 lb/hr, 2,400 psig/1,050°F) Reheat steam - 243,774 kg/hr, 4.1 MPa/566°C (537,428 lb/hr, 593 psig/1,050°F)	2	0
3	SCR Reactor	Space for spare layer	2,040,000 kg/hr (4,490,000 lb/hr)	2	0
4	SCR Catalyst	--	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	10 m ³ /min @ 108 cm WG (190 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	1.2 lpm @ 90 m H ₂ O (0.3 gpm @ 300 ft H ₂ O)	2	1

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Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
7	Ammonia Storage Tank	Horizontal tank	33,000 liter (9,000 gal)	1	0
1	HRSO Stack	CS plate, type 409SS liner	46 m (150 ft) high x 8.1 m (27 ft) diameter	2	0

Case 2 – Account 8: Steam Turbine Generator

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	153 MW 16.5 MPa/566°C/566°C (2400 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	170 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	610 GJ/hr (580 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0
4	Steam Bypass	One per HRSO	50% steam flow @ design steam conditions	2	0

Case 2 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	438,000 lpm @ 30 m (116,000 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/ 2220 GJ/hr (2100 MMBtu/hr) heat duty	1	0

Case 2 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 230 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 160 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 16 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 8 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 1 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case 2 – 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 black and white)	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

5.3.6 Case 2 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. The costs for the additional equipment required for the CCS retrofit and the auxiliary plants were scaled from the NETL Bituminous Baseline Report cases as well as other costs developed as part of baseline series. [3, 46] Exhibit 5-51 shows a detailed breakdown of the capital costs; Exhibit 5-52 shows the owner's costs, along with the TOC, and TASC; Exhibit 5-53 shows the initial and annual O&M costs; and Exhibit 5-54 shows the COE breakdown.

The estimated TPC of the subcritical PC boiler with retrofitted CO₂ capture and NGCC CHP auxiliary repowering is \$983/kW. Process contingency represents 5.4 percent of the TPC and project contingency represents 13.2 percent. The COE is \$77.7/MWh.

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Exhibit 5-51. Case 2 total plant cost details (without retrofit contingency)

Case:		2	– Subcritical PC w/ NGCC CHP				Estimate Type:			Conceptual	
Plant Size (MW,net):		1,148					Cost Base:			Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost (excluding RCF)	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1 Coal & Sorbent Handling											
1.1	Coal Receive & Unload	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.2	Coal Stackout & Reclaim	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.3	Coal Conveyors	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.4	Other Coal Handling	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.5	Sorbent Receive & Unload	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.6	Sorbent Stackout & Reclaim	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.7	Sorbent Conveyors	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.8	Other Sorbent Handling	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.9	Coal & Sorbent Hnd. Foundations	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2 Coal & Sorbent Prep & Feed											
2.1	Coal Crushing & Drying	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2.2	Coal Conveyor to Storage	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2.5	Sorbent Prep Equipment	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2.6	Sorbent Storage & Feed	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2.9	Coal & Sorbent Feed Foundation	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3 Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$3,216	\$4,077	\$3,329	\$0	\$10,622	\$956	\$0	\$1,737	\$13,314	\$13
3.2	Water Makeup & Pretreating	\$1,113	\$115	\$571	\$0	\$1,799	\$162	\$0	\$392	\$2,353	\$2
3.3	Other Feedwater Subsystems	\$1,507	\$498	\$416	\$0	\$2,420	\$218	\$0	\$396	\$3,034	\$3
3.4	Service Water Systems	\$134	\$268	\$863	\$0	\$1,265	\$114	\$0	\$276	\$1,655	\$2
3.5	Other Boiler Plant Systems	\$905	\$338	\$778	\$0	\$2,021	\$182	\$0	\$331	\$2,534	\$2
3.6	Natural Gas, incl. pipeline	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3.7	Waste Treatment Equipment	\$389	\$0	\$225	\$0	\$614	\$55	\$0	\$134	\$802	\$1
3.8	Misc. Equip. (Cranes, Air Comp., Comm.)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$7,263	\$5,296	\$6,182	\$0	\$18,741	\$1,687	\$0	\$3,265	\$23,692	\$22

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Case:		2	– Subcritical PC w/ NGCC CHP				Estimate Type:			Conceptual	
Plant Size (MW,net):		1,148					Cost Base:			Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost (excluding RCF)	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
4 Boiler & Accessories											
4.1	PC Boiler & Accessories	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.2	SCR	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.5	Primary Air System	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.6	Secondary Air System	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.8	Major Component Rigging	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.9	Boiler Foundations	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A Gas Cleanup & Piping											
5A.1	Absorber Vessels & Accessories	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A.2	Other FGD	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A.3	Bag House & Accessories	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A.4	Other Particulate Removal Materials	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A.5	Gypsum Dewatering System	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5A.6	Mercury Removal System	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5B CO ₂ Removal & Compression											
5B.1	CO ₂ Removal System	\$150,894	\$55,170	\$117,865	\$0	\$323,929	\$27,914	\$55,829	\$72,578	\$480,249	\$453
5B.2	CO ₂ Compression & Drying	\$44,551	\$6,683	\$14,668	\$0	\$65,902	\$6,590	\$0	\$14,498	\$86,991	\$82
5B.3	CO ₂ Removal System Let Down Turbine	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$195,445	\$61,852	\$132,533	\$0	\$389,831	\$34,505	\$55,829	\$87,076	\$567,240	\$535
6 Combustion Turbine & Accessories											
6.1	Combustion Turbine Generator	\$104,200	\$0	\$6,341	\$0	\$110,541	\$9,949	\$0	\$12,049	\$132,539	\$125
6.9	Combustion Turbine Foundations	\$0	\$879	\$950	\$0	\$1,829	\$165	\$0	\$399	\$2,392	\$2
	Subtotal	\$104,200	\$879	\$7,291	\$0	\$112,370	\$10,113	\$0	\$12,448	\$134,931	\$127
7 HRSG, Ducting, & Stack											
7.1	Heat Recovery Steam Generator	\$33,030	\$0	\$6,112	\$0	\$39,143	\$3,523	\$0	\$4,267	\$46,932	\$44
7.2	SCR System	\$1,970	\$828	\$1,154	\$0	\$3,952	\$356	\$0	\$646	\$4,954	\$5
7.3	HRSG, Duct & Stack Foundations	\$0	\$550	\$516	\$0	\$1,066	\$96	\$0	\$232	\$1,395	\$1
7.4	PC Plant Ductwork	\$8,539	\$0	\$5,390	\$0	\$13,929	\$1,393	\$0	\$2,298	\$17,620	\$17
7.5	PC Plant Stack	\$10,172	\$0	\$5,912	\$0	\$16,084	\$1,608	\$0	\$1,769	\$19,462	\$18

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Case:		2	– Subcritical PC w/ NGCC CHP				Estimate Type:		Conceptual		
Plant Size (MW,net):		1,148					Cost Base:		Jun 2011		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost (excluding RCF)	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
7.9	PC Plant Duct & Stack Foundations	\$0	\$1,055	\$1,253	\$0	\$2,309	\$231	\$0	\$508	\$3,047	\$3
	Subtotal	\$53,712	\$2,433	\$20,337	\$0	\$76,482	\$7,207	\$0	\$9,720	\$93,409	\$88
8 Steam Turbine Generator											
8.1	Steam TG & Accessories	\$26,643	\$0	\$5,111	\$0	\$31,754	\$2,858	\$0	\$3,461	\$38,073	\$36
8.2	Turbine Plant Auxiliaries	\$152	\$0	\$485	\$0	\$637	\$57	\$0	\$69	\$764	\$1
8.3	Condenser & Auxiliaries	\$219	\$0	\$244	\$0	\$462	\$42	\$0	\$50	\$554	\$1
8.4	Steam Piping	\$12,240	\$0	\$5,194	\$0	\$17,434	\$1,743.42	\$0	\$2,877	\$22,054	\$21
8.9	TG Foundations	\$0	\$0	\$1,657	\$0	\$1,657	\$149	\$0	\$361	\$2,167	\$2
	Subtotal	\$39,253	\$0	\$12,691	\$0	\$51,944	\$4,849	\$0	\$6,819	\$63,612	\$60
9 Cooling Water System											
9.1	Cooling Towers	\$10,295	\$0	\$3,184	\$0	\$13,479	\$1,348	\$0	\$1,483	\$16,310	\$15
9.2	Circulating Water Pumps	\$2,069	\$0	\$132	\$0	\$2,202	\$220	\$0	\$242	\$2,664	\$3
9.3	Circ. Water System Auxiliaries	\$573	\$0	\$76	\$0	\$648	\$65	\$0	\$71	\$785	\$1
9.4	Circ. Water Piping	\$0	\$4,825	\$4,370	\$0	\$9,195	\$920	\$0	\$1,517	\$11,632	\$11
9.5	Make-up Water System	\$348	\$0	\$447	\$0	\$795	\$79	\$0	\$131	\$1,005	\$1
9.6	Component Cooling Water Sys.	\$467	\$0	\$358	\$0	\$825	\$83	\$0	\$136	\$1,044	\$1
9.9	Circ. Water Foundations & Structures	\$0	\$2,563	\$4,257	\$0	\$6,820	\$682	\$0	\$1,500	\$9,003	\$8
	Subtotal	\$13,752	\$7,389	\$12,824	\$0	\$33,965	\$3,396	\$0	\$5,081	\$42,442	\$40
10 Ash & Spent Sorbent Handling Systems											
10.6	Ash Storage Silos	\$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
10.9	Ash/Spent Sorbent Foundation	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
11 Accessory Electric Plant											
11.1	Generator Equipment	\$4,956	\$0	\$2,932	\$0	\$7,888	\$710	\$0	\$645	\$9,243	\$9
11.2	Station Service Equipment	\$4,333	\$0	\$372	\$0	\$4,706	\$424	\$0	\$385	\$5,514	\$5
11.3	Switchgear & Motor Control	\$5,332	\$0	\$926	\$0	\$6,258	\$563	\$0	\$682	\$7,504	\$7
11.4	Conduit & Cable Tray	\$0	\$2,787	\$8,028	\$0	\$10,815	\$973	\$0	\$1,768	\$13,556	\$13
11.5	Wire & Cable	\$0	\$8,955	\$5,092	\$0	\$14,046	\$1,264	\$0	\$2,297	\$17,607	\$17
11.6	Protective Equipment	\$0	\$722	\$2,506	\$0	\$3,228	\$291	\$0	\$352	\$3,871	\$4
11.7	Standby Equipment	\$121	\$0	\$113	\$0	\$234	\$21	\$0	\$25	\$280	\$0

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Case:		2	– Subcritical PC w/ NGCC CHP				Estimate Type:		Conceptual		
Plant Size (MW,net):		1,148					Cost Base:		Jun 2011		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost (excluding RCF)	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
11.8	Main Power Transformers	\$11,449	\$0	\$175	\$0	\$11,624	\$1,046	\$0	\$1,267	\$13,937	\$13
11.9	Electrical Foundations	\$0	\$151	\$383	\$0	\$534	\$48	\$0	\$116	\$698	\$1
	Subtotal	\$26,192	\$12,614	\$20,527	\$0	\$59,333	\$5,340	\$0	\$7,537	\$72,211	\$68
12 Instrumentation & Control											
12.1	PC Control Equipment	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12.3	Steam Turbine Control	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12.4	Other Major Component Control	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12.5	Signal Processing Equipment	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12.6	Control Boards, Panels & Racks	\$230	\$0	\$141	\$0	\$371	\$33	\$0	\$61	\$465	\$0
12.7	Computer & Accessories	\$3,689	\$0	\$113	\$0	\$3,801	\$342	\$0	\$414	\$4,558	\$4
12.8	Instrument Wiring & Tubing	\$0	\$686	\$1,214	\$0	\$1,900	\$171	\$0	\$311	\$2,382	\$2
12.9	Other I&C Equipment	\$4,265	\$0	\$9,874	\$0	\$14,138	\$1,272	\$0	\$1,541	\$16,952	\$16
	Subtotal	\$8,184	\$686	\$11,341	\$0	\$20,211	\$1,819	\$0	\$2,327	\$24,357	\$23
13 Improvements to Site											
13.1	Site Preparation	\$0	\$104	\$2,205	\$0	\$2,308	\$208	\$0	\$503	\$3,019	\$3
13.2	Site Improvements	\$0	\$951	\$1,257	\$0	\$2,208	\$199	\$0	\$481	\$2,889	\$3
13.3	Site Facilities	\$1,943	\$0	\$2,038	\$0	\$3,980	\$358	\$0	\$868	\$5,206	\$5
	Subtotal	\$1,943	\$1,055	\$5,499	\$0	\$8,497	\$765	\$0	\$1,852	\$11,114	\$10
14 Buildings & Structures											
14.1	Combustion Turbine Building	\$0	\$303	\$160	\$0	\$463	\$42	\$0	\$76	\$581	\$1
14.2	Steam Turbine Building	\$0	\$1,859	\$2,474	\$0	\$4,333	\$390	\$0	\$708	\$5,431	\$5
14.3	Administration Building	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
14.4	Circulation Water Pumphouse	\$0	\$293	\$145	\$0	\$437	\$39	\$0	\$72	\$548	\$1
14.5	Water Treatment Buildings	\$0	\$594	\$541	\$0	\$1,135	\$102	\$0	\$186	\$1,423	\$1
14.6	Machine Shop	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
14.7	Warehouse	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
14.8	Other Buildings & Structures	\$0	\$105	\$77	\$0	\$182	\$16	\$0	\$30	\$228	\$0
14.9	Waste Treating Building & Str.	\$0	\$412	\$736	\$0	\$1,148	\$103	\$0	\$188	\$1,439	\$1
	Subtotal	\$0	\$3,566	\$4,132	\$0	\$7,699	\$693	\$0	\$1,259	\$9,650	\$9
	Total	\$449,944	\$95,771	\$233,359	\$0	\$779,073	\$70,374	\$55,829	\$137,384	\$1,042,660	\$983

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Exhibit 5-52. Case 2 owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$6,436	\$6
1 Month Maintenance Materials	\$1,027	\$1
1 Month Non-fuel Consumables	\$993	\$1
1 Month Waste Disposal	\$0	\$0
25% of 1 Months Fuel Cost at 100% CF	\$4,679	\$4
2% of TPC	\$20,853	\$20
Total	\$33,988	\$32
Inventory Capital		
60 Day Supply of Fuel and Consumables at 100% CF	\$1,703	\$2
0.5% of TPC (spare parts)	\$5,213	\$5
Total	\$6,916	\$7
Other Costs		
Initial Cost for Catalyst and Chemicals	\$0	\$0
Land	\$0	\$0
Other Owner's Costs	\$156,399	\$147
Financing Costs	\$28,152	\$27
Total Overnight Costs (TOC)	\$1,268,115	\$1,196
TOC Including Retrofit Contingency	\$1,394,927	\$1,315
TASC Multiplier (IOU, high-risk, 33 year)	1.078	
Total As-Spent Cost (TASC) including Retrofit Contingency	\$1,503,731	\$1,418

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Exhibit 5-53. Case 2 initial and annual operating and maintenance costs

Case:	2	– Subcritical PC w/ NGCC CHP			Cost Base:	Jun 2011
Plant Size (MW _{net}):	1,060	Heat Rate-net (Btu/kWh):	8,468	Capacity Factor (%):	85	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		39.70	\$/hour	Skilled Operator:		3.0
Operating Labor Burden:		30.00	% of base	Operator:		13.3
Labor O-H Charge Rate:		25.00	% of labor	Foreman:		2.0
				Lab Techs, etc.:		3.0
				Total:		21.3
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$9,644,726	\$9.09
Maintenance Labor:					\$13,871,750	\$13.081
Administrative & Support Labor:					\$5,879,119	\$5.544
Property Taxes and Insurance:					\$42,407,491	\$39.989
Total:					\$71,811,059	\$67.72
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$20,807,625	\$2.64
Consumables						
	Consumption				Cost (\$)	
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	6,762	\$1.67	\$0	\$3,511,929	\$0.44
Makeup and Wastewater Treatment Chemicals (lbs):	0	32,733	\$0.27	\$0	\$2,719,998	\$0.34
Limestone (ton)	0	489	\$33.48	\$0	\$5,074,583	\$0.64
Hydrated Lime (ton)	0	100	\$155.00	\$0	\$4,791,516	\$0.61
Activated Carbon (ton)	0	3	\$1,255.00	\$0	\$1,120,454	\$0.14
CO ₂ Capture System Chemicals ^A	Proprietary				\$6,227,603	\$0.79
Triethylene Glycol (gal)	0	325	\$6.57	\$0	\$662,001	\$0.08
Ammonia (19% NH ₃ , ton)	0	74	\$330.00	\$0	\$7,624,375	\$0.97
SCR Catalyst (m ³)	0	0.47	\$8,938.80	\$0	\$1,290,704	\$0.16
Subtotal:				\$0	\$33,023,163	\$4.18
Waste Disposal						
Fly Ash (ton)	0	490	\$25.11	\$0	\$3,816,581	\$0.48
Bottom Ash (ton)	0	96	\$25.11	\$0	\$750,759	\$0.10
Amine Purification Unit Waste (ton)	0	21	\$0.00	\$0	\$0	\$0.00
Thermal Reclaimer Unit Waste (ton)	0	2	\$0.00	\$0	\$0	\$0.00
Prescrubber Blowdown Waste (ton)	0	46	\$0.00	\$0	\$0	\$0.00
Subtotal:				\$0	\$4,567,340	\$0.58
By-Products						
Gypsum (ton)	0	758	\$0.00	\$0	\$0	\$0.00
Subtotal:				\$0	\$0	\$0.00
Variable Operating Costs Total:				\$0	\$58,398,127	\$7.40
Fuel Cost						
Illinois Number 6 (ton):	0	4,944	\$68.54	\$0	\$105,133,176	\$13.31
Natural Gas (MMBtu):	0	100,384	\$6.13	\$0	\$190,912,983	\$24.18
Total:				\$0	\$296,046,159	\$37.49

^ACO₂ Capture System Chemicals includes Ion Exchange Resin, NaOH, and Cansolv Solvent.

ELIMINATING THE DERATE OF CARBON CAPTURE RETROFITS

Exhibit 5-54. Case 2 COE breakdown

Component	Value, \$/MWh	Percentage
Capital	19.6	25%
Fixed	9.1	12%
Variable	7.4	10%
Fuel	37.5	48%
Total (Excluding T&S)	73.6	N/A
CO ₂ T&S	4.1	5%
Total (Including T&S)	77.7	N/A

6 RESULTS ANALYSIS

The following sections present the performance and economic results of the study and compare the contributing effects of different approaches to supplying the energy needs of the carbon capture retrofit system.

6.1 PERFORMANCE

A summary of the performance and environmental profiles for all cases is presented in Exhibit 6-1.

Exhibit 6-1. Performance summary and environmental profile

Parameter	Retrofit Baseline	Auxiliary Repowering	
	Case 0 No CHP	Case 1 NGSC CHP	Case 2 NGCC CHP
	Combined Plant Performance		
Gross Power Output (MWe)	501	811	1,148
Auxiliary Power Requirement (MWe)	76	81	88
Net Power Output (MWe)	425	730	1,060
Coal Flow rate (lb/hr)	411,949	412,005	412,005
Natural Gas Flow rate (lb/hr)	N/A	100,984	185,484
HHV Thermal Input (kWt)	1,408,440	2,074,494	2,631,664
Net Plant HHV Efficiency (%)	30.2%	35.2%	40.3%
Net Plant HHV Heat Rate (Btu/kWh)	11,301	9,700	8,468
Raw Water Withdrawal (gpm)	6,711	8,212	9,392
Process Water Discharge (gpm)	1,545	1,882	2,148
Raw Water Consumption (gpm)	5,166	6,330	7,244
Overall CO ₂ Capture	90%	71%	60%
CO ₂ Emissions (lb/MMBtu)	20	52	66
CO ₂ Emissions (lb/MWh-gross)	195	453	516
CO ₂ Emissions (lb/MWh-net)	230	503	559
SO ₂ Emissions (lb/MMBtu)	0.000	0.000	0.000
SO ₂ Emissions (lb/MWh-gross)	0.000	0.003	0.003
NO _x Emissions (lb/MMBtu)	0.073	0.058	0.047
NO _x Emissions (lb/MWh-gross)	0.700	0.511	0.366
PM Emissions (lb/MMBtu)	0.009	0.007	0.006
PM Emissions (lb/MWh-gross)	0.090	0.065	0.046
Hg Emissions (lb/TBtu)	0.313	0.246	0.194
Hg Emissions (lb/MWh-gross)	3.00E-06	2.15E-06	1.52E-06

6.1.1 Steam Extraction Turbine Derate

Steam required for the carbon capture retrofit system, mainly for solvent regeneration, represents heat that could have otherwise been used to generate power. If an existing steam cycle is modified to accommodate this steam demand through extraction (i.e., Case 0), the output would decrease proportionally to the reduced enthalpy of the steam and would be further reduced due to operation of the existing steam turbine outside of the original design conditions (see Section 6.1.2 below). The retrofit baseline Case 0 uses steam extraction from the existing turbine, taking 32 percent of the IP-LP crossover steam and results in a decreased steam turbine gross output by approximately 17 percent. The addition of the letdown turbine to recover energy from the extracted steam as its pressure is reduced to that required for the solvent regeneration system partially mitigates the derate, and the overall reduction to the gross plant output is closer to 14 percent compared to the pre-retrofit plant gross output. The steam requirements and sources for all the cases are compared in Exhibit 6-2.

Exhibit 6-2. CO₂ capture system steam requirements

Parameter	Case 0	Case 1	Case 2
CO ₂ Captured, lb/hr	880,451	880,571	880,571
CO ₂ Capture Plant Steam Demand, MMBtu/hr	942	942	942
Aux Plant Steam Production, MMBtu/hr	0	942	942
Aux Plant Thermal Input, MMBtu/hr	N/A	2,272	4,173
Aux Plant Steam/Thermal Input Ratio	N/A	.41	.23
Steam Extraction, MMBtu/hr	942	0	0
Steam Extraction, % of IP-LP Crossover Flow	32	0	0
ST Gross Output, MW	484	581	581
Letdown Turbine Output, MW	17	N/A	N/A
NGCC extraction steam requirement if capture is added (based on steam turbine gross power in case B31B – steam turbine gross power in case B31A of NETL Bituminous Baseline Report [3])	N/A	N/A	40
Total ST Extraction Derate for case, %	14	0	0

6.1.2 CCS Retrofit Off-Design Derate

Using the subcritical PC plant, modeled as Case B11A in the NETL Bituminous Baseline Report [3] as a basis, the Case 0 retrofit plant holds the coal feed constant, while adding a solvent based CO₂ capture system to treat the flue gas. This reduces the net plant output by 125 MW split between steam extraction (80 MW electrical equivalent) and increased auxiliary loads (45 MW) as seen in Exhibit 6-3.

When retrofitting a PC plant with a CCS process and extracting the required steam from an existing steam cycle, such as in Case 0, alterations to the steam turbine must be made to accommodate these demands. Case 0 assumes a throttled IP-LP crossover extraction scheme, where a throttling valve, along with the associated flanges, spool pieces, and piping, is 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, but steam turbine modifications were not included in the cost estimates for this study. The derate for adding CCS and extracting 32 percent of the LP steam flow is compared to an idealized case with no steam turbine derate in Exhibit 6-3 to show the effects of running the LP section at off-design conditions.

Exhibit 6-3. CCS retrofit derate

Parameter	"Business as Usual" Case B11A	No Off-Design Derate Case 0	Case 0
ST Power, MW	581	512	501
Auxiliary Load, MW	31	76	76
Net Power, MW	550	436	425
Efficiency %	39.0	30.9	30.2
Steam Extraction, % of IP-LP Crossover	0	32	32
ST Off-design Derate, %	N/A	0	2.1

The additional off-design efficiency penalty is a function of the quantity and properties of the steam diverted from the existing turbine (for Case 0, the steam extracted from the IP-LP crossover). In addition to the reduction in output due to the redirected steam flow, the additional base case off-design steam turbine derate was estimated using the ratio of the steam turbine gross output for the reference throttled LP turbine CCS retrofit and the greenfield plant with CCS from the Lucquiaud et al. study, which was tested against published data from the International Energy Agency greenhouse gas (IEA GHG) study done by a collaboration between Alstom Power, Mitsui Babcock, Fluor, and Imperial College. [45, 47] The linear decrease in steam turbine efficiency for the throttled LP extraction configuration serves 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 CCS 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 among extraction configurations. 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. Turning off one of the two LP sections in a clutched LP turbine configuration, while more efficient, offers the least flexibility as less steam is extracted because the one running LP section is already at full capacity. While there is no off-design performance derate running at this reduced steam load, there is no available turbine capacity to direct any additional steam once the non-operational clutched LP turbine section is turned off.

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 specified 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 minimum achievable condenser temperature approach would decrease using the existing condenser. Additional study on the heat transfer coefficient and limits of condenser operation for retrofit applications is recommended to more accurately determine the range of condenser pressures that can be considered for sensitivities to these cases.

6.1.3 CO₂ Capture System Retrofit Energy Penalty

A useful metric for quantifying the impact to electrical output to capture each pound of CO₂ under each CCS retrofit scenario is the energy penalty, as defined below:

$$\text{Energy Penalty} \left(\frac{\text{kWh}}{\text{lb CO}_2} \right) = \frac{\left(\frac{1}{\text{HRNC}} - \frac{1}{\text{HRCC}} \right)}{\text{Capture Rate} * \text{CO}_2 \text{ Emissions Factor}}$$

Where:

HRNC $\left(\frac{\text{Btu}}{\text{kWh}} \right)$ = Heat rate of the existing plant

HRCC $\left(\frac{\text{Btu}}{\text{kWh}} \right)$ = Overall heat rate of the retrofitted + auxiliary plants

Capture Rate (%) = Overall capture rate of the retrofitted + auxiliary plants

CO₂ Emissions Factor $\left(\frac{\text{lb CO}_2}{\text{MMBtu}} \right)$ = Weighted average for fuels

Using Case B11A from the NETL Bituminous Baseline Report [3] as the existing plant reference, the energy penalty calculated for each case is shown in Exhibit 6-4. The addition of CHP auxiliary repowering in the retrofit system acts to offset the efficiency penalty that adding capture creates. Due to the comparatively high overall efficiency of the NGCC-based auxiliary CHP plant in Case 2, the overall heat rate of the combined plant (HRCC in equation above) is lower than the existing plant, and the computed energy penalty is negative.

Exhibit 6-4. Retrofit energy penalty

Parameter	Case B11A	Case 0	Case 1	Case 2
Overall HHV Heat Rate, Btu/kWh	8,740	11,301	9,700	8,468
Overall CO ₂ Emissions Factor, lb CO ₂ /MMBtu of Fuel	204	204	176	164
Overall CO ₂ Capture Rate, %	0	90	70.6	59.8
Energy Penalty, kWh/lb CO ₂	-	0.14	0.09	-0.04

6.1.4 Auxiliary Power and Steam Generation

Auxiliary CHP plants were designed to repower an existing 550 MW PC plant when CCS retrofit is added. Two main benefits to be investigated in such a configuration would be the continued use 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 CCS 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 as its own stand-alone plant. Having a dedicated plant for generating the required power and steam should reduce the complexity of the CCS retrofit. For all cases with an auxiliary plant, the CCS 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 CCS 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 CL system, returning the condensate to the auxiliary plant.

Additionally, if a stand-alone auxiliary plant is used to power the CO₂ removal process, the auxiliary plant will have to be running whenever CO₂ is being captured. For retrofit on a baseload generating plant, the auxiliary plant is assumed to be required to run similar to a baseload plant.

6.2 ECONOMICS

A summary of the cost results for all cases is presented in Exhibit 6-5. The results from the corresponding greenfield cases in the NETL baseline report are included for comparison.

Exhibit 6-5. Cost summary for all cases

Parameter	Greenfield Baseline [3]		Retrofit Baseline	Auxiliary Repowering		Greenfield Baseline
	B11A No CCS	B11B W CCS	Case 0 No CHP	Case 1 NGSC CHP	Case 2 NGCC CHP	Case B31A No CCS
	Cost					
Total Plant Cost (2011\$/kW)	1,960	3,467	1,743	1,192	983	685
<i>Bare Erected Cost</i>	1,582	2,665	1,241	872	735	561
<i>Home Office Expenses</i>	158	257	114	79	66	51
<i>Project Contingency</i>	220	427	254	77	53	73
<i>Process Contingency</i>	0	118	135	164	130	0
Total Overnight Cost (2011\$MM)	1,336	2,346	898	1,057	1,268	528
Total Overnight Cost (2011\$/kW)	2,429	4,267	2,111	1,448	1,196	838
<i>Owner's Costs</i>	469	800	367	256	213	154
TOC including RCF (2011\$MM)	N/A	N/A	987	1,162	1,394	N/A
TOC including RCF (2011\$/kW)	N/A	N/A	2,322	1,593	1,315	N/A
Total As-Spent Cost (2011\$/kW)	2,755	4,865	2,276	1,561	1,289	901
TASC with RCF (2011\$/kW)	N/A	N/A	2,503	1,717	1,418	N/A
COE (\$/MWh) (excluding T&S)	82.0	133.5	103.3	84.6	73.6	57.6
<i>Capital Costs</i>	37.8	71.0	34.6	23.7	19.6	11.8
<i>Fixed Costs</i>	9.3	15.1	19.0	12.2	9.1	3.4
<i>Variable Costs</i>	9.2	15.1	16.4	10.1	7.4	1.7
<i>Fuel Costs</i>	25.7	32.2	33.2	38.5	37.5	40.7
COE (\$/MWh) (including T&S)	82.0	143.5	113.6	90.6	77.7	57.6
CO ₂ T&S Costs	0.0	10.0	10.3	6.0	4.1	0.0

6.2.1 Capital Cost and Cost of Electricity

A summary of capital costs is shown in Exhibit 6-6 and a COE breakdown for each case is presented in Exhibit 6-7. The COE and net capacity for the existing, fully depreciated, subcritical PC plant are included in the COE chart for reference, and the results from the corresponding greenfield cases in the NETL baseline report are included for comparison. [3] The COE includes only the ongoing O&M costs associated with depreciated plant. A capital cost RCF of 1.1 is applied to the TOC to along with the CCF to calculate the capital portion of the COE for cases 0, 1, and 2. Sensitivities are presented above each COE breakdown bar. The RCF represents a simplified multiplier approach to account for cost uncertainties associated

with retrofit construction projects, which cannot be specifically identified for a generic site. NETL has established this methodology and its application to retrofit cost estimation. [4] Section 6.2.2 and Section 6.2.4 discuss the approach taken to retrofit costing and uncertainties due to site specific concerns.

Assuming the existing capital is paid down on the existing plant, the base case in this study (Case 0 – CCS-only retrofit) shows a post-retrofit COE of \$113.6/MWh and a retrofitted capital cost incurred (using TOC per post-retrofit net kW of generation as a metric) of \$2,322/kW. Because the Case 0 retrofit scenario takes advantage of existing equipment and infrastructure, it is more cost effective than a 550 MW-net greenfield subcritical PC plant with identical environmental controls on a COE (\$143.5/MWh) and TOC (\$4,267/kW) basis [3] despite the reduction in net plant output from 550 MW to 425 MW-net. In Case 1 and Case 2, the net electrical generation is greater than the original 550 MW. Providing additional capital to replace the lost generation through CHP auxiliary repowering improves the retrofit economics relative to Case 0 due to the extra revenue gained through the excess power generated by the auxiliary plant. The additional electrical generation acts to dilute the increased capital costs in the COE for these cases. Inherent to the results for Case 1 and Case 2 is the avoidance of the negative economic impacts incurred by duct firing, significant T&D grid modifications, and off-design operation of the existing steam turbine. Costs associated with any of the above diminish the attractiveness of CHP repowering.

Exhibit 6-6. Capital costs

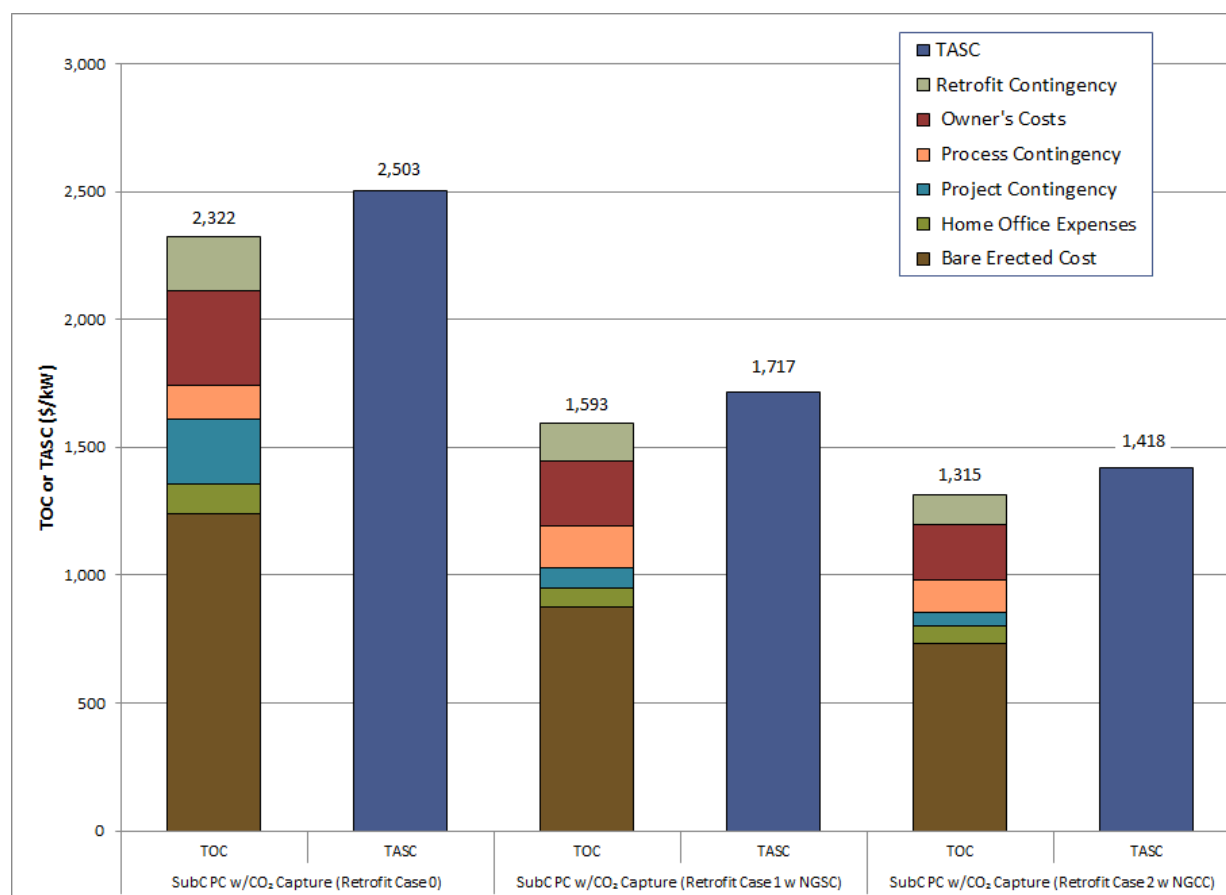
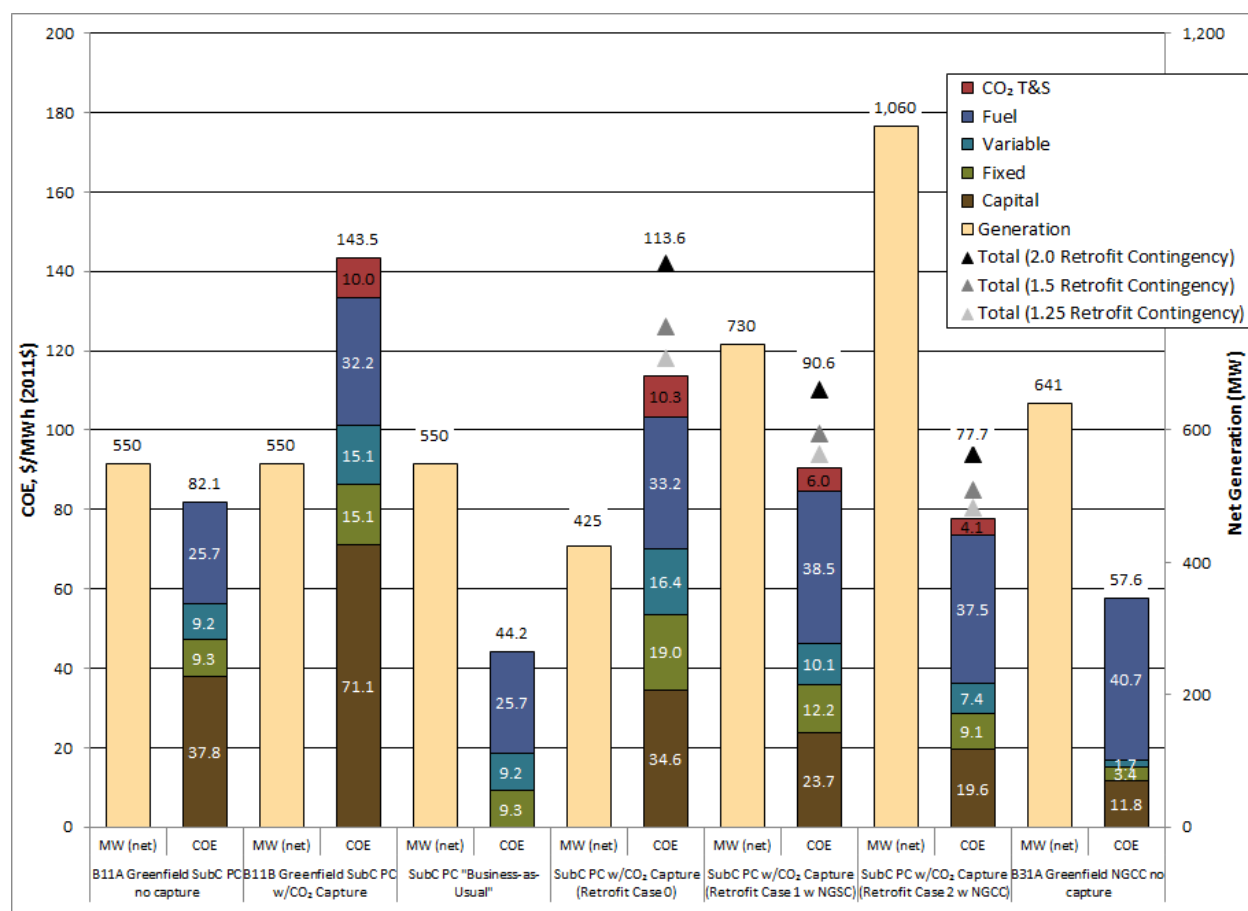


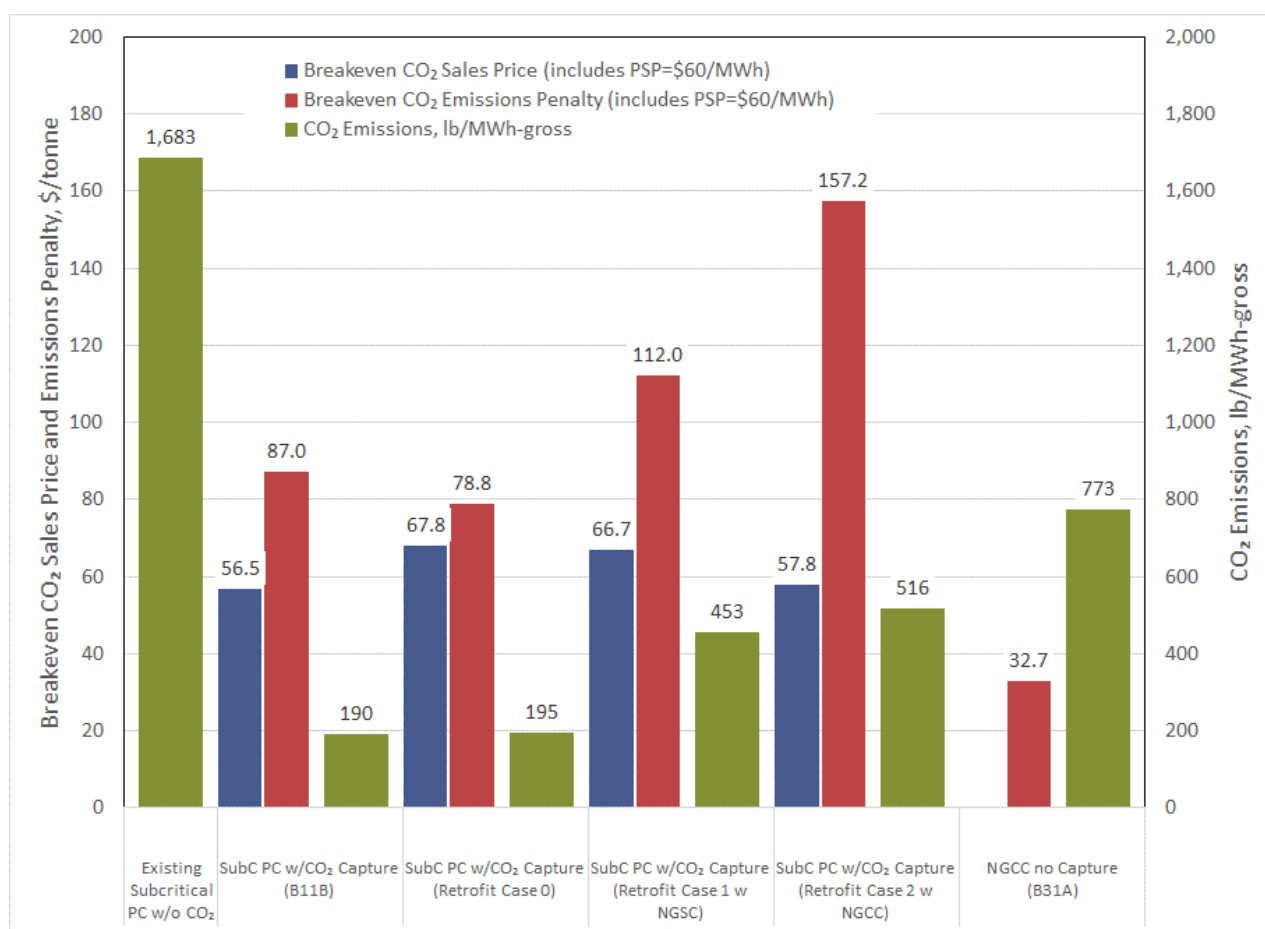
Exhibit 6-7. COE breakdown

6.2.2 Economic Metrics of CO₂ Capture

The breakeven CO₂ sales price and breakeven CO₂ emissions penalty metrics defined in Section 2.7.4 provide additional insight into the costs incurred for the CCS retrofit options presented in this study relative to the cost of generation of an existing PC plant. The annual cost for the existing, fully depreciated, subcritical PC plant was assumed to be the sum of the annual fixed and variable O&M and fuel costs at the 85 percent capacity factor for Case B11A in the NETL Bituminous Baseline Report at a value of approximately \$255 million. [3] These annual charges are included in the retrofit COEs for each case. The incremental annual costs of adding capture are the capital charges for the retrofitted systems plus the difference between annual fixed and variable O&M plus fuel costs and the annual cost for the existing plant. The cost or credit for any difference between the existing power plant annual net generation and the after retrofit annual net generation is also included at a projected sales price (PSP) for electricity of \$60/MWh. The incremental annual costs are divided by the tonnes of CO₂ captured in the retrofitted plant to calculate the breakeven CO₂ sales price for each case. The incremental annual costs are divided by the difference in annual tonnes of CO₂ emitted from the existing plant and the retrofitted plant to calculate the breakeven CO₂ emissions penalty for each case. Exhibit 6-8 shows the breakeven CO₂ sales price and emissions penalty for each of the retrofit scenarios as well as the emissions per MWnet

capacity. Case B31A, a greenfield NGCC without CO₂ capture from the NETL Bituminous Baseline Report [3], is included for comparison to the PC retrofit cases. The emissions penalty on Case B31B is calculated the same way as the retrofit cases using the annual costs of a new NGCC plant minus the annual costs of the existing PC plant. This case shows that an NGCC build can provide a lower emissions penalty, but at 773 lb CO₂/MWh-gross, has a greater CO₂ intensity than each of the PC retrofit scenarios examined, which range from 195 to 516 lb CO₂/MWh-gross. Case B11B, a greenfield subcritical PC with CO₂ capture, from the NETL Bituminous Baseline Report [3], is included for comparison also. The metrics for the greenfield capture cases are calculated including the capital component of the COE for the non-capture reference Case B11A, a greenfield subcritical PC without CO₂ capture, as presented in the NETL Bituminous Baseline Report. [3]

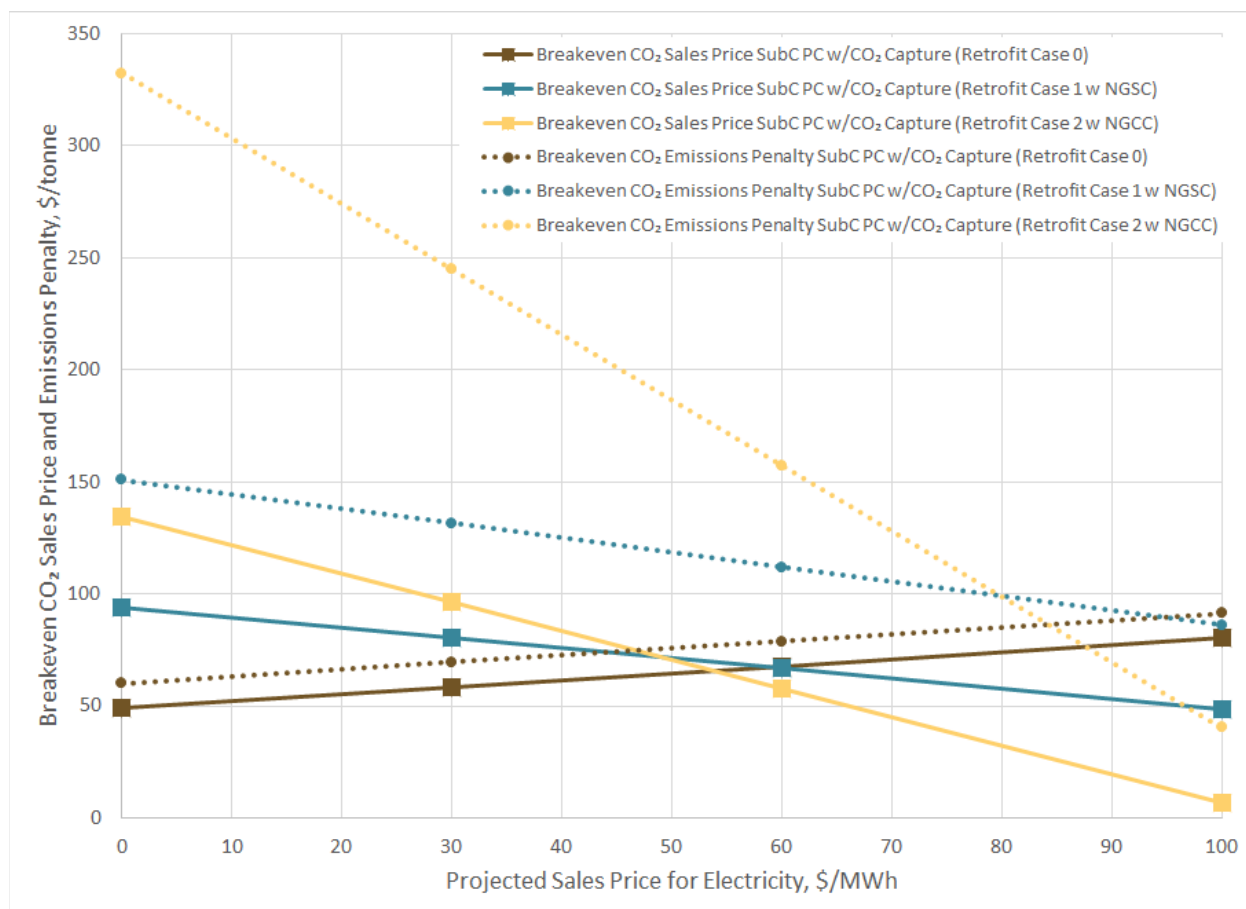
Exhibit 6-8. Breakeven CO₂ sales prices and emissions penalties



If the price a plant would receive by selling CO₂ is greater than the breakeven sales price, then the plant has an economic incentive to install the capture system and sell the CO₂ for revenue. If the penalties for emitting CO₂ or the price of allowances to emit CO₂ are greater than the breakeven emissions penalty, then the plant has an economic incentive to capture the CO₂ and avoid the penalties or purchase of allowances. But the economic incentive to choose between the cases is dependent on the PSP included in the calculations as shown in

Exhibit 6-9. At the assumed PSP of \$60/MWh in this study, Case 2 has the lowest breakeven sales price; but at PSP values below \$55/MWh, Case 0 has the lowest sales prices. At the assumed PSP of \$60/MWh in this study, Case 0 has the lowest emissions penalty; but at PSP values above \$85/MWh, Case 2 has the lowest emissions penalty.

Exhibit 6-9. Breakeven CO₂ sales prices and emissions penalties sensitivity to PSP



6.2.3 Retrofit Auxiliary Plant Costing

The costs for the additional equipment required for the CCS retrofit and the auxiliary plants were scaled from the NETL Bituminous Baseline Report cases as well as other costs developed as part of baseline series. [3, 46] The additional number of plant workers required for each CCS and auxiliary plant installation was added to the existing plant personnel based on the headcount attributable to retrofit capital. The costs of electricity after retrofit were calculated based on the capital costs of the additional retrofitted CCS 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 an existing plant that is paid off (or a sunk cost) is considering adding such a retrofit and could translate this price of retrofitted generation to the required CO₂ credit, which would make such an investment economically attractive.

A retrofit contingency was applied to the scaled plant capital costs to account for the complexity and limitations of retrofitting to an existing plant. The factors were applied to the

baseline costs 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 contingency factor to account for site specific factors and could affect the desirability of these retrofit options. The simplified retrofit contingency factor was estimated as the weighted average of the incremental retrofit difficulty factors, using the high value applied to a retrofit of an existing subcritical PC plant. [4]

6.2.4 Space Requirements

The CCS retrofit and different auxiliary plant options each have their own 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 large proportion of existing sites. The combined cycle auxiliary plant in Case 2 will require the most amount of space with Case 0 requiring the least. Construction of transmission piping for utility steam places a secondary degree of constraint on the retrofitted equipment layout in all cases. However, the final layout will be ultimately determined based on the available space for the large processes.

Typically, coal plants have a buffer zone surrounding the plant to prevent noise and pollution from reaching residents that would conceivably contribute to the available land for a CCS retrofit and combustion turbine. In comparison, 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 contingency sensitivities.

7 CONCLUSIONS

The objective of this study is to examine the performance, environmental impact, and economics of retrofitting CCS to an existing 550 MW-net PC plant and the effects of retrofitting an additional auxiliary plant to satisfy the CCS plant steam and electrical demand, which would otherwise reduce the output of the retrofit plant. Several study assumptions were established that provide context for the results and conclusions provided in this report. These assumptions include:

- The retrofitted CCS facility only treats the flue gas emitted from the PC boiler. CO₂ is not removed from the exhaust gas emitted by the auxiliary CHP plants.
- The existing T&D grid infrastructure is capable of and amenable to accepting all electrical generation produced by the CHP facilities in excess of the generation previously produced by the existing plant.
- The CHP auxiliary plants are sized such that the entire thermal demand of the retrofitted CCS facility is met by steam raised by the auxiliary CHP plant without duct firing or steam extraction from the existing steam turbine.
- The hypothetically sized CT required for the NGSC CHP auxiliary plant configuration is assumed to be available and is capable of satisfying the thermal demand of the CCS facility without duct firing or steam extraction from the existing steam turbine.
- All capital on the existing plant is fully paid down; financing for the additional retrofit equipment costs is amortized over a three-year construction period and a 30-year plant lifetime.
- No retrofit or life-extension upgrades are required by the existing unit, and all non-retrofit equipment has a remaining useful life consistent with the financing period of the retrofit equipment.

Given these study assumptions, the following major conclusions can be drawn from the results presented in Section 6:

- Providing the auxiliary steam and power requirements of a retrofitted CCS facility from the existing steam turbine generator is the lowest up-front capital investment option on an absolute dollar TOC basis including retrofit contingency (\$987MM). However, the performance derate of the steam turbine makes this the least attractive long-term option on a COE basis (\$113.6/MWh).
- Supplying auxiliary electrical power and steam with combustion turbine-based CHP technologies can more than offset the losses in net plant output, which would otherwise be incurred. In doing so, the long-term project economics are improved on a COE basis at the expense of higher up-front capital investment.
- Of the retrofit options examined, repowering a retrofitted PC plant with an NGCC CHP plant provides the most favorable long-term economics (\$77.7/MWh), driven primarily by the addition of high efficiency generation.

8 FUTURE WORKS

8.1 REFINING RETROFIT COSTS

The true cost of CCS retrofit can be refined by quantifying more of the ancillary retrofit costs, which would allow for more precise comparison of the cases using more precise retrofit contingencies. Site-specific considerations could also be used to make even finer adjustments. Potential upgrades to the electrical transmission and distribution equipment, outside the scope of these results, could be incorporated as could other infrastructure pieces that were assumed to be available, such as the pipeline access to natural gas for the auxiliary plants. Since the comparisons of the COE for the different retrofit options are within the range of the retrofit contingency sensitivity, ranging from a factor of one to two, the relative differences and site-specific adjustments could influence one choice under a given set of constraints.

8.2 IDENTIFICATION OF POTENTIAL FIRST ADOPTERS

Further study into the existing U.S. coal generation fleet is needed in order to gain deeper insight into potential first adopters of CCS retrofit repowering projects. A greater understanding is needed of how much of the existing fleet capacity meets defined criteria that favor retrofits. Criteria such as available on-site combustion turbine capacity, nearby enhanced oil recovery potential, and known T&D infrastructure limitations can impact the economic outlook of retrofit repower projects by leveraging sunk costs and favorable economic factors. The age, expected remaining lifetime, and remaining unpaid debt on a given PC plant also has significant implications on retrofit repowering project risk evaluations. The information gathered can be used to rank plants accordingly and quantify the potential CO₂ emissions savings.

8.3 POWER GENERATION AND CO₂ ECONOMICS

The breakeven CO₂ emissions penalty (formerly known as the cost of CO₂ avoided in the referenced reports) presented in this study uses a fully depreciated existing PC plant as the basis and allows for technology comparisons that represent the choices facing stakeholders. This metric can be developed in more depth to better represent the economic decisions faced by existing plant owners or states considering how to value and manage their assets for a CO₂ state implementation plan.

Understanding the costs and penalties for CO₂ emissions and a more realistic and refined economic profile for existing plants can help reflect the current choices facing plant owners, operators, and the fleet. Different permutations on this metric should be explored such as the percentage of the capital cost that is fully depreciated, and whether fixed costs should be included for a more representative dispatch COE, can all shed light on different scenarios as outlined above. The validity and usefulness of these metrics should also be explored. The cost profiles for some of the low cost retrofit options to existing plants (such as co-firing or CHP) could have low fully depreciated CO₂ emission penalties. The individual cost and performance inputs can be used in macroeconomic electricity generation models to validate

the metric by showing that the abatement options are deployed to meet a range of overall emissions targets while reducing compliance costs.

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