United States
Environmental Protection
Agency

EPA-430/R-06/006
July 2006

Final Report

Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies

FOREWORD

Currently, over 50 percent of electricity in the U.S. is generated from coal. Given that coal reserves in the U.S. are estimated to meet our energy needs over the next 250 years, coal is expected to continue to play a major role in the generation of electricity in this country. With dwindling supplies and high prices of natural gas and oil, a large proportion of the new power generation facilities built in the U.S. can be expected to use coal as the main fuel. The environmental impact of these facilities can only be minimized by innovations in technology that allow for efficient burning of coal, along with an increased capture of the air pollutants that are an inherent part of coal combustion.

EPA considers integrated gasification combined cycle (IGCC) as one of the most promising technologies in reducing environmental consequences of generating electricity from coal. EPA has undertaken several initiatives to facilitate and incentivize development and deployment of this technology. This report is the result of one of these initiatives and it represents the combined efforts of a joint EPA/DOE team formed to advance the IGCC technology. The various offices within DOE that participated in the development/review of this report were the Office of Fossil Energy, including the Clean Coal Office and the National Energy Technology Laboratory.

IGCC is a dynamic and rapidly evolving technology. The economic and environmental information related to IGCC and other advanced combustion systems is changing quickly. The data and analysis presented in this report is an evaluation of information available as of February 2006. The report provides a snapshot of conditions in a changing industry and makes technical and cost information for the IGCC technology available to environmental professionals belonging to Federal and state organizations and other stakeholders. Detailed comparisons of the IGCC and pulverized-coal technologies are also provided, enabling the reader to observe and compare the capabilities of these technologies in relation to each other. The overall goal of this effort is to develop and compile technical and economic information to be used in connection with the development of EPA’s policies, as well as to provide technical support and information transfer to ensure effective implementation of environmental regulations and strategies. EPA believes it is useful to examine these technologies as part of an ongoing effort to evaluate IGCC and other advanced coal systems.

EPA REVIEW NOTICE

This report has been peer and administratively reviewed by the U.S. Environmental Protection Agency, and approved for publication. This publication provides technical and economic information to support the goals and purposes described in the report. The report does not establish, prescribe, or change any EPA policy or legal interpretation with respect to the regulation and permitting of IGCC or pulverized-coal facilities. Emissions limitations and permit conditions for such facilities should be determined by permitting authorities on the basis of applicable EPA and state regulations and the record in each permit proceeding. EPA retains the discretion to promulgate or amend regulations and policy concerning the control of emissions from such sources on the basis of this report and additional information or public comment in the record of an Agency action. Mention of trade names or commercial products in this publication does not constitute endorsement or recommendation for use.

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Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies

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ABSTRACT

The report presents the results of a study conducted to establish the environmental footprint and costs of the coal-based integrated gasification combined cycle (IGCC) technology relative to the conventional pulverized coal (PC) technologies. The technology options evaluated are restricted to those that are projected by the authors to be commercially applied by 2010. The IGCC plant configurations include coal slurry-based and dry coal-based, oxygen-blown gasifiers. The PC plant configurations include subcritical, supercritical, and ultra-supercritical boiler designs. Even though the ultra-supercritical design has not been applied in the U.S., it was included based on its commercial experience in Japan and Europe.

All study evaluations are based on the use of three different coals: bituminous, sub-bituminous, and lignite. In addition, the same electric generating capacity of 500 MW is used for each plant configuration. State-of-the-art environmental controls are also included as part of the design of each plant.

The environmental comparisons of IGCC and PC plants are based on thermal performance, emissions of criteria and non-criteria air pollutants, solid waste generation rates, and water consumption and wastewater discharge rates associated with each plant. The IGCC plants in these comparisons include NO_X and SO_2 controls considered viable for 2010 deployment. In addition, the potential for use of other advanced controls, specifically the selective catalytic reduction system for NO_X reduction and the ultra-efficient Selexol and Rectisol systems for SO_2 reduction, is also investigated.

The cost estimates presented in the report include capital and operating costs for each IGCC and PC plant configuration. Cost impacts of using the advanced NO_x and SO_2 controls are likewise included.

The report also provides an assessment of the CO_2 capture and sequestration potential for the IGCC and PC plants. A review of the technical and economic aspects of CO_2 capture technologies that are currently in various stages of development is included.

ACKNOWLEDGEMENTS

Nexant and Cadmus wish to acknowledge the U.S. Environmental Protection Agency work assignment manager, Sikander Khan, and Denny Smith from the U.S. Department of Energy for their comprehensive guidance and periodic reviews of emission estimates and power generation performance. Their inputs added significant value to the report results and are greatly appreciated.

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LIST OF ACRONYMS AND SYMBOLS

As	Arsenic
ASU	Air Separation Unit
bbl	Barrel
Be	Beryllium
BOP	Balance of Plant
Btu/kWh	British Thermal Units per Kilowatt Hour
C_2H_6	Ethane
$CaSO_3$	Calcium Sulfite
$CaSO_4$	Calcium Sulfate
CCPC	Canadian Clean Power Coalition
CCS	Carbon Capture and Storage
Cents/kWh	Cents per Kilowatt Hour
Cd	Cadmium
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COE	Cost of Electricity
COPHAC	Compact Hybrid Particle Collector
COS	Carbonyl Sulfide
Cr	Chromium
CSC	Convective Syngas Cooler
CS-ESP	Cold Side Electrostatic Precipitator
daf	Dry Ash Free
DOE	Department of Energy
E&M	Energy and Material
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FF	Fabric Filter
FGD	Flue Gas Desulfurization
GE	General Electric
GtCO2	Giga tons of CO_2
H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen Sulfide
H_2SO_4	Sulfuric Acid
HCl	Hydrochloric Acid
HF	Hydrofluoric Acid
Hg	Mercury
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
HS-ESP	Hot Side Electrostatic Precipitator
IC	Installed Cost
IDC	Interest during Construction
IGCC	Integrated Gasification Combined Cycle
kW	Kilowatt
lb/MMBtu	Pounds per Million British Thermal Units
lb/MWh	Pounds per Megawatt Hour

lb/TBtu	Pounds per Trillion British Thermal Units
LHV	Lower Heating Value
MDEA	Methyldiethanolamine
MMBtu/hr	Million British Thermal Units per Hour
MMBtu/lb	Million British Thermal Units per Pound
Mn	Manganese
MW	Megawatts (Electric)
N_2	Nitrogen
n/a	Not Applicable
NH_3	Ammonia
Ni	Nickel
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
O_2	Oxygen
O&M	Operating and Maintenance
PAC	Powdered Activated Carbon
Pb	Lead
PC	Pulverized Coal
PM	Particulate Matter
ppmvd	Parts Per Million By Volume Dry
PS	Particulate Scrubber
psia	Pounds Per Square Inch Absolute
psig	Pounds Per Square Inch Gauge
RSC	Radiant Syngas Cooler
SCOT	Shell Claus Off-Gas Treatment
SCR	Selective Catalytic Reduction
SCS	Separate, Capture, and Sequester
SDA	Spray Dryer Absorber
Se	Selenium
Si	Silica
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
TCC	Total Constructed Cost
t/MWh	Tons per Megawatt Hour
TPC	Total Plant Cost
TRS	Total Reduced Sulfur
V	Vanadium
VOC	Volatile Organic Compounds
WL-FGD	Wet Limestone Flue Gas Desulfurization
$/kW	Dollars per Kilowatt
$/kWh	Dollars per Kilowatt Hour
$-kW-yr	Dollars per Kilowatt Year
$/MMBtu	Dollars per Million British Thermal Units
$/MWh	Dollars per Megawatt Hour
$/ton	Dollars per Ton

Executive Summary

This report compares the environmental impacts and costs of integrated gasification combined cycle (IGCC) and pulverized coal (PC) fired power generation plants. The fuels and feedstocks for each type of plant studied include bituminous, subbituminous, and lignite coals. The PC plant configurations include subcritical, supercritical, and ultra-supercritical boiler designs. A coal-water slurry feed type of gasifier (typified by the Texaco, now GE Energy technology) is selected for the bituminous and subbituminous feedstocks. A solid feed gasifier (such as the Shell technology) is used with lignite. The technology options included in the IGCC and PC plant designs are restricted to those that are projected by the authors to be commercially applied by 2010.

The power generation technologies and emission control systems examined in this report continue to evolve in response to changes in market considerations and regulatory requirements. The report is a snapshot of conditions in the changing industry as of February 2006. Additional information on IGCC power plants proposed for development can be found at http://www.netl.doe.gov/coal/refshelf/ncp.pdf (accessed on June 21, 2006), which shows 24 proposed coal-fired power plants using gasification technology. The report contents are intended to serve as a broad screening tool consistent with the scope of work and project criteria established with EPA. Plant and site specific assessments will require more detailed engineering studies prior to technical or economic decision making. Individual facility permitting requirements will depend on the applicable regulations and the record before the permitting authority.

Introduction

IGCC and PC fired boilers are the primary competing technologies for coal-based power generation. Fluidized bed combustion is another technology that may have a significant role in the industry.

Development and implementation of the IGCC technology is relatively immature compared with the PC technology that has hundreds or thousands of units in operation globally. While there are a number of gasification units installed at petroleum and chemical plants, there are only a few installations using coal to make electric power as the primary product.[1] Most of these IGCC installations were installed with government subsidies and have experienced technical and commercial problems common to the startup of new technologies. While many of the problems with operability and maintainability have been mitigated, successful application of the IGCC technology at additional commercial installations is needed to address any remaining concerns.

Relatively little research or commercial work has been done to investigate gasification of low rank coals, including subbituminous and lignite, for electric generation purposes. The existing IGCC plants use bituminous coals as feedstocks. Almost four million tons of subbituminous coal was gasified at the Louisiana Gasification Technology Inc. facility located at Dow's Plaquemine, Louisiana chemical plant under a Synfuels Corporation

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[1] Gasification Technologies Council World Gasification Survey Database, GTC website http://www.gasification.org/, accessed on February 21, 2006.

Contract from 1987 to 1995. However, without additional research or commercial experience with the gasification of low rank coals, it is difficult to compare the gasification technology development with low rank coals to that of bituminous coal.

The ultra-supercritical PC technology used in this study has a few operating installations in Japan and Europe. Thermal performance of plants using this technology may match or exceed IGCC performance. However, this technology has no commercial experience in the U.S. Therefore, for application in this country, the technology is considered unproven with potential technical and economic risks.

Advanced technologies are also being developed to improve the IGCC performance: new technologies for air separation and oxygen production, higher temperature gas cleaning methods, advanced gas turbines, and fuel cells. These technologies are being developed with the goal of raising thermal efficiency (higher heating value) to 50 - 60 percent. However, these advances are not likely to be accomplished in the 2010 timeframe for this study.

Power Generation Performance Comparison

Exhibit ES-1 summarizes the results of the performance estimates for the IGCC and PC plants. The IGCC plant performance in particular can vary depending on design and site specific factors, and the estimates for IGCC plants using subbituminous and lignite coals are based on process models which were developed with limited test or other actual data. The ultra-supercritical plant performance is also estimated from modeling calculations and values found in the literature.

Based on the data presented in Exhibit ES-1, the IGCC has significantly better thermal performance than the subcritical and supercritical PC plants in commercial applications within the U.S. The estimates developed from limited data on ultra-supercritical technology show its thermal performance to exceed that of the IGCC for bituminous and sub-bituminous coal cases.

Environmental Impact Comparison

With the exception of controls for CO_2, the control systems included in this report for reducing emissions of air pollutants from IGCC plants have been demonstrated at the two existing coal- and petroleum coke-based U.S. plants, and very similar systems are broadly used within the petroleum and chemical industries. The one remaining uncertainty appears to be the long-term, continuous operational proof for the generation industry that the emission control processes/equipment will work in the IGCC power generation context. Such proof would involve the use of coal, which has physical and chemical properties that tend to be much more heterogenic than refinery feedstocks, and the individual plant’s capability to generate baseload power without significant planned or unplanned interruptions. Partly this uncertainty is related to the more general lack of information about IGCC system upsets, reliability, and a well-engineered definition of redundancy requirements.

Compared with the PC plants, the IGCC more closely resembles a chemical plant than one for power generation. However, the power industry has incorporated and learned to use chemical processes for flue gas desulfurization, ammonia-based selective catalytic NO_X reduction processes, and a variety of water treatment and cleanup operations, so operation of an IGCC plant by the power industry is possible.

Based on the investigations conducted for this study, the IGCC technology can offer environmental advantages over the PC technologies in most emission areas. In addition to the reduced air emissions from the IGCC technology, the plants typically consume significantly less water and generate less solid waste in comparison to the PC technology, depending on coal properties and whether or not the solid waste streams are sold as industrial byproducts.

Exhibit ES-2 presents environmental impact estimates for the specific control technologies and coals utilized for various study cases. The estimates are based on literature review, including recent air permits and related documents, contacts with certain potential suppliers of the control technologies, and power generation modeling software. In general, the estimates represent typical control technology capabilities, which, in many cases, reflect the levels determined through best available control technology reviews conducted during the processing of air permits for recent power plants. In some cases, such as the subbituminous coal- and lignite-based IGCC plants, relevant air permit or operating data were not available. For these plants, information from other study sources, including vendor contacts, were used to develop the emission estimates.

The emissions and (in parallel) the removal capabilities are similar across the technologies and coals with the clearest distinction being that IGCC emissions are less than for PC plants for all pollutants. The IGCC cases studied do not include SCR for the syngas turbines. MDEA amine type acid gas cleaning is used along with a system for sulfur recovery. The PC plants have wet limestone flue gas desulfurization (WL-FGD) for the bituminous and lignite coals; a lime spray dryer absorber (SDA) desulfurization for the low-sulfur subbituminous coal; and all the PC plants have selective catalytic reduction (SCR) post-combustion NO_X controls.

The coal characteristics and types of control technologies used for the study plants influence the estimates in Exhibit ES-2. Changes in design assumptions can result in different estimates. In addition, new developments continue to take place for both the PC and IGCC technologies. Therefore, the data presented in this report are subject to change in the future.

The Exhibit ES-2 data also show the IGCC plants generating less solid waste than the PC plants. This comparison assumes that no waste is sold for industrial use, except for the relatively small amount of sulfur produced from IGCC. IGCC plants can also produce sulfuric acid as an alternative to sulfur, should the market conditions require this change.

All solid waste products from both PC and IGCC plants have varying degrees of potential for industrial use. Therefore, if it is assumed that these plants can sell some or all of their solid wastes, the differences between the amounts of solid waste generated as shown in Exhibit ES-2 would either reduce or be eliminated. The study investigations show that while approximately 24 percent of the PC plants were able to sell the gypsum produced from the wet FGD systems in 2004, only five percent were able to do so for the SO_2 wastes from the SDA systems. So, even though the industrial use of PC solid wastes is projected to increase in the future, it appears that a large number of such plants may not be able to sell their wastes. If an IGCC plant cannot sell its sulfur byproduct, it would have to be disposed of as a waste.

The study investigations included a comparison of major non-criteria and hazardous air pollutant emissions for the PC and IGCC technologies. In most cases, these emissions are heavily influenced by the concentration of impurities in the coal being used. Therefore, emissions of certain pollutants can vary over a wide range, depending on the coal characteristics. The estimates of the emissions of non-criteria and hazardous air pollutants are presented within the report in Exhibits 3-10, 3-11, 3-13, 3-14, 3-15, and 3-26.

Industry and government organizations have recently begun considering the application of the SCR technology to reduce NO_X from syngas-fired turbines at IGCC plants. Section 4 includes a topical study of the issue. Industry is reluctant to install SCR units because of impacts on the overall operation, performance uncertainties and marginal cost. The study estimated a cost of $7,290 to $13,120 per ton of NO_X removed based on the difference between 15 parts per million by volume, dry basis (ppmvd) emissions with syngas dilution combustion controls, and three ppmvd after the SCR is added. The wide range of cost estimates results from uncertainty for the degree of sulfur control installation required to operate the catalytic NO_X control technology.

The use of a SCR with the coal-based IGCC synthesis gas-fired turbine combined cycle system has no commercial operating experience and is still evolving, which makes the evaluation difficult and necessarily limited to the present level of understanding and criteria defined for the study. SCR performance and the quality of the synthesis gas going to the turbine are issues that are being continually examined to determine the limits of contaminants in the synthesis gas, especially sulfur, which causes fouling in the downstream heat recovery steam generator. The technology to remove sulfur from the synthesis gas and the removal requirement strongly impacts costs and introduces the major uncertainty about cost estimates. A second major economic uncertainty is the SCR catalyst life and replacement costs over time.

Also, the SCR operation uses ammonia as the means to reduce NO_X emissions, and depending on how the SCR is operated some ammonia will be released (termed “ammonia slip”) to the atmosphere and is a pollutant. The methods to balance NO_X reduction and ammonia slip in the presence of sulfur in the flue gas and thus minimize total emission impacts are not yet well defined for the IGCC technologies. Despite the present uncertainties, and perhaps as an indicator of future installations, it is noted that the "reference" IGCC plant being engineered by GE Energy and Bechtel Corporation includes SCR[2]. In addition, certain recently filed or amended IGCC permit applications propose use of SCR technology. These applications are not covered in the report, since the information on the applications became available after the study investigations were completed.

Cost and Availability Comparisons

Cost and availability are issues of uncertainty for the IGCC technology. Even given higher thermal efficiency and lower emissions, the cost and availability differences between IGCC and PC plants continue to be a major hurdle to commercial applications. While the differences in cost estimates for new plants reported by several sources are not that great, less than $100 per kilowatt in some cases, the actual cost disparities for IGCC demonstration facilities have been much greater. The IGCC estimates presented here are for plants that assume commercial performance, and unfortunately the cost for the first generation of plants is bound to be more than for the "N^th^ plant". Similarly, the availability of the currently operating IGCC plants has been around 80 percent (higher availability levels were achieved only by operating the combined cycle portion of the plant on natural gas or oil). These plants were designed with single-gasifier trains and it is expected that the future commercial facilities, designed with a spare gasifier train, would achieve availability levels of 85 percent and higher. In comparison, the subcritical and supercritical PC can generally achieve greater than 90 percent availability levels.

Capital and annual operating costs estimated for the plants are shown in Exhibit ES-3. While the capital costs for IGCC plants are higher than the costs for all three PC plant configurations, there are only small differences between the operating costs for all plants. Further cost details and discussion of the estimating basis and methodology are in Appendix A. The risk and uncertainty issues noted for the technologies' performance estimates apply equally to the cost estimates. Only limited information is available from operating plants showing the impact of coal quality on the IGCC and PC generation technologies. Even conceptual engineering work is much less available for IGCC plants using low rank coals than for the plants using bituminous coal.

The costs reported here are derived from recent literature and experience with similar PC and IGCC studies conducted by Nexant. References for the cost data are noted in Appendix A of the report. New, study-specific cost estimates were not within the scope of the current EPA/DOE assessment, which is focused on environmental impacts of the modeled operations. As a general statement, the cost data is from U.S. DOE, the Electric Power Research Institute (EPRI), and international publications. These costs were examined and revised to reflect a 4th Quarter 2004 price and wage level and the nominal plant capacity of 500 MW.

Accounting for the variability in the overall scope of each plant using different technologies and three ranks of coal adds another element of cost (and performance) uncertainty. The results presented in the report again utilize the review and adjustment of

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[2] Gas Turbine World, Sept – Oct 2005 Volume 35 Number 4; "IGCC Closing the $/kW Cost Gap".

several data sources to estimate the costs associated with these variables. If the cost uncertainty is to be reduced, a more detailed engineering and design project would be required with site- and technology-specific criteria.

Carbon Dioxide Capture and Sequestration

The IGCC technology has received renewed attention from the perspective of greenhouse gas issues and carbon management. Section 5 contains a more detailed discussion of carbon management technologies. Applications of such technologies exist in industries other than power sector. A significant amount of research and development work is being done to address the technical and economic feasibility issues pertaining to the commercial application of these and other emerging technologies to IGCC and PC plants. Demonstration of the feasibility of permanently sequestering CO_2 in underground geological formations is part of these efforts.

The currently available carbon management technologies for IGCC are much more cost effective than similar technologies for removing CO_2 from PC plant flue gases. The major performance and economic impacts of applying these technologies to IGCC and supercritical PC plants for achieving approximately 90 percent CO_2 capture are reported as follows:

	IGCC	**Supercritical PC**
Net plant output (pre CO_2 capture), MW	425	462
Plant output derating, %	14	29
Heat rate increase, %	17	40
Total capital cost increase, %	47	73
Cost of electricity increase, %	38	66
CO_2 capture cost, \$/ton	24	35

The above comparison highlights the potential advantage for IGCC to capture and sequester CO_2 at significantly lower costs than PC technologies.

Future Actions

Improvement of the knowledge database for PC and IGCC technologies, especially for a complete range of North American coals, will require substantially more detailed process engineering and coordination with the technology developers. The limited contacts with technology developers for this study confirmed their willingness to work with industry and government, but they were not prepared to provide detailed information without a complete design basis from which to work, and in some cases this work would have to be compensated.

Executive Summary

Exhibit ES-1, Generation Performance Comparison

	Bituminous Coal				Subbituminous Coal			
Performance	IGCC Slurry Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC	IGCC Slurry Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC
Net Thermal Efficiency, % (HHV)	41.8	35.9	38.3	42.7	40.0	34.8	37.9	41.9
Net Heat Rate, Btu/kWh (HHV)	8,167	9,500	8,900	8,000	8,520	9,800	9,000	8,146
Gross Power, MW	564	540	540	543	575	541	541	543
Internal Power, MW	64	40	40	43	75	41	41	43
Fuel Required, lb/h	349,744	407,143	381,418	342,863	484,089	556,818	517045	460,227
Net Power, MW	500	500	500	500	500	500	500	500

	Lignite Coal			
Performance	IGCC Solid Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC
Net Thermal Efficiency, % (HHV)	39.2	33.1	35.9	37.6
Net Heat Rate, Btu/kWh (HHV)	8,707	10,300	9,500	9,065
Gross Power, MW	580	544	544	546
Internal Power, MW	80	44	44	46
Fuel Required, lb/h	689,720	815,906	752,535	720,849
Net Power, MW	500	500	500	500

Exhibit ES-2, Environmental Impact Comparison

	Bituminous Coal				Subbituminous Coal			
Environmental Impact lb/MWh	IGCC Slurry Feed Gasifier	Sub-Critical PC	Super-critical PC	Ultra Super-critical PC	IGCC Slurry Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC
NO_X (NO_2)	0.355	0.528	0.494	0.442	0.326	0.543	0.500	0.450
SO_2	0.311	0.757	0.709	0.634	0.089	0.589	0.541	0.488
CO	0.217	0.880	0.824	0.737	0.222	0.906	0.832	0.750
Particulate Matter[1]	0.051	0.106	0.099	0.088	0.052	0.109	0.100	0.090
Volatile Organic Compounds (VOC)	0.012	0.021	0.020	0.018	0.013	0.025	0.023	0.020
Solid Waste[3]	65	176	165	155	45	73	67	60
Raw Water Use	4,960	9,260	8,640	7,730	5,010	9,520	8,830	7,870
SO_2 Removal Basis, %	99	98	98	98	97.5	87[4]	87[4]	87[4]
NO_X Removal Basis[2]	15 ppmvd at 15% O_2	0.06 lb/MMBtu	0.06 lb/MMBtu	0.06 lb/MMBtu	15 ppmvd at 15% O_2	0.06 lb/MMBtu	0.06 lb/MMBtu	0.06 lb/MMBtu

NOTES:

1. Particulate removal is 99.9% or greater for the IGCC cases and 99.8% for bituminous coal, 99.7% for subbituminous, and 99.9% for lignite for the PC cases. Particulate matter emission rates shown include the overall filterable particulate matter only.
2. A percent removal for NO_X can not be calculated without a basis, i.e. an uncontrolled unit, for the comparison. Also, the PC and IGCC technologies use multiple technologies (e.g., combustion controls, SCR). The NO_X emission comparisons are based on emission levels expressed in ppmvd at15% oxygen for IGCC and lb/MMBtu for PC cases.
3. Solid Waste includes slag (not the sulfur product) from the gasifier and coal ash plus the gypsum or lime wastes from the PC system.
4. A relatively low SO_2 removal efficiency of 87% represents low subbituminous coal sulfur content of only 0.22%. Higher removal efficiencies are possible with increased coal sulfur content.

Exhibit ES-2, Environmental Impact Comparison, continued

	Lignite Coal			
Environmental Impact lb/MWh	IGCC Solid Feed Gasifier	Sub-Critical PC	Super-critical PC	Ultra Super-critical PC
NO_X (NO_2)	0.375	0.568	0.524	0.498
SO_2	0.150	0.814	0.751	0.714
CO	0.225	0.947	0.873	0.830
Particulate Matter[1]	0.053	0.114	0.105	0.100
Volatile Organic Compounds (VOC)	0.013	0.026	0.024	0.022
Solid Waste[3]	218	331	306	291
Raw Water Use	5,270	9,960	9,200	8,710
SO_2 Removal Basis, %	99	95.8[4]	95.8[4]	95.8[4]
NO_X Removal Basis[2]	15 ppmvd at 15% O_2	0.06 lb/MMBtu	0.06 lb/MMBtu	0.06 lb/MMBtu

NOTES:

1. Particulate removal is 99.9% or greater for the IGCC cases and 99.8% for bituminous coal, 99.7% for subbituminous, and 99.9% for lignite for the PC cases. The emission rates shown include the overall filterable particulate matter only.
2. A percent removal for NO_X can not be calculated without a basis, i.e. an uncontrolled unit, for the comparison. Also, the PC and IGCC technologies use multiple technologies (e.g., combustion controls, SCR). The NO_X emission comparisons are based on emission levels expressed in ppmvd at15% oxygen for IGCC and lb/MMBtu for PC cases.
3. Solid Waste includes slag (not the sulfur product) from the gasifier and coal ash plus the gypsum or lime wastes from the PC system.
4. A relatively low SO_2 removal efficiency of 95.8% represents low lignite sulfur content of only 0.64%. Higher removal efficiencies are possible with increased coal sulfur content.

Exhibit ES-3, Technology Cost Comparison

	Bituminous Coal				Subbituminous Coal			
Costs*	IGCC Slurry Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC	IGCC Slurry Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC
Total Plant Cost $/ kW	1,430	1,187	1,261	1,355	1,630	1,223	1,299	1,395
Total Plant Investment $/kW	1,610	1,303	1,384	1,482	1,840	1,343	1,426	1,526
Total Capital Requirement $/ kW	1,670	1,347	1,431	1,529	1,910	1,387	1,473	1,575
Annual Operating Cost $1,000s	27,310	27,700	29,000	30,400	29,700	28,300	29,600	31,100

	Lignite Coal			
Costs*	IGCC Solid Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC
Total Plant Cost $/ kW	2,000	1,255	1,333	1,432
Total Plant Investment $/kW	2,260	1,378	1,463	1,566
Total Capital Requirement $/ kW	2,350	1,424	1,511	1,617
Annual Operating Cost $1,000s	34,000	29,640	30,940	32,440

* All costs are based on 4th Quarter 2004 dollars.

Section 1 Process Design

Section 1 presents the design criteria and methodologies used in evaluating various processes and technologies discussed in this report.

1.1 Introduction

The U.S. Environmental Protection Agency (EPA) sponsored this study to evaluate and compare environmental impacts and costs of integrated gasification combined cycle (IGCC) and pulverized coal (PC) power plants. These estimated impacts and costs for the technologies will assist various government agencies to better understand the potential effects of rulemaking and regulatory actions on application of the technologies in practical, real-world conditions.

Results are based upon information collected in one of two ways. First, in-house Nexant software, experience with similar evaluations, and literature were used to estimate performance and costs of the two technologies. Second, equipment and process suppliers were contacted for updated information specific to the environmental control aspects of the plants. The suppliers' data were used to refine the first estimates and improve the performance and cost estimates of the environmental controls. Seeking new data from gasification technology developers was not within the scope of this report; it was judged that sufficient published and in-house data was available to assess gasification technology performance and cost.

1.2 Design Basis

The study examines five power generation technologies and three different coals. All the modeled power plants are sized for a net power generation of 500 MW. They are configured with equipment and processes that are judged available for deployment in power generation plants in the 2010 time period. The modeled plants include the following design features:

- IGCC plants with steam conditions of 1,800 psig and 1,000/1,000 ºF. The coal-water slurry feed type of gasifier represented by GE Energy (ex-ChevronTexaco) is used with two coals, and a solid feed gasifier such as Shell gasification is used with lignite.

- PC plants with subcritical steam conditions of 2,400 psig and 1,000/1,000ºF single reheat.

- PC plants with supercritical steam conditions of 3,500 psig and 1,050/1,050 ºF double reheat.

- PC plants with ultra-supercritical steam conditions of 4,500 psig and 1,100/1,100 ºF double reheat.

- Ambient conditions are 60 ºF dry bulb, 60% relative humidity, and sea level elevation. Heat rejection uses wet cooling tower technology.

Three coals were chosen by EPA for the study. The coal characteristics and ash mineral properties are shown in Exhibits 1-1a, 1-1b, and 1-2.

Exhibit 1-1a, Study Coal Proximate Analyses

Coal Property **Proximate Analysis**, Weight %	High-Sulfur Bituminous	Low-Sulfur Subbituminous	Lignite
Moisture	11.12	27.40	31.24
Ash	9.70	4.50	17.92
Volatile matter	34.99	31.40	28.08
Fixed carbon	44.19	36.70	22.76
Total	100.00	100.00	100.00

Exhibit 1-1b, Study Coal Ultimate Analyses

Coal Property, **Ultimate Analysis**, Weight%	High-Sulfur Bituminous		Low-Sulfur Subbituminous		Lignite	
	As Received	Dry Basis	As Received	Dry Basis	As Received	Dry Basis
Carbon	63.74	71.71	50.25	69.21	36.27	52.75
Hydrogen	4.50	5.06	3.41	4.70	2.42	3.52
Nitrogen	1.25	1.41	0.65	0.90	0.71	1.03
Oxygen	6.89	7.75	13.55	18.66	10.76	15.65
Sulfur	2.51	2.82	0.22	0.30	0.64	0.93
Ash	9.70	11.24	4.50	6.23	17.92	26.12
Moisture	11.12		27.40		31.24	
Undetermined	0.29		0.02		0.04	
Total	100.00	100.00	100.00	100.00	100.00	100.00
Higher heating value (HHV), Btu/lb	11,667		8,800		6,312	
HHV, KJ/kg	27,137		20,469		14,682	

Note: Dry Basis - calculated. Undetermined added to ash.

Exhibit 1-2, Mineral Analysis Data

Mineral Analysis, Weight %	High-Sulfur Bituminous	Low-Sulfur Subbituminous	Lignite
Silica	43.95	33.40	56.96
Ferric oxide	22.79	5.20	3.49
Alumina	20.89	16.30	19.01
Titania	1.00	1.20	1.25
Lime	4.05	21.50	8.39
Magnesia	0.79	6.40	1.88
Sulfur trioxide	2.87	11.70	5.49
Potassium oxide	1.97	0.35	0.74
Sodium oxide	1.15	1.90	0.36
Phosphorus pentoxide	0.12	1.20	0.05
Undetermined	0.42	0.85	2.38
Total	100.00	100.00	100.00

The PC power plants are evaluated with each of the coals. The IGCC plants are similarly evaluated except the type of gasifier is dependent on the type of coal used.

The EPA design basis also specifies the criteria and non-criteria pollutants considered in the environmental assessment. The items are shown in Exhibit 1-3.

Exhibit 1-3, EPA Criteria and Non-Criteria/Hazardous Pollutants

Criteria Air Pollutants	Non-Criteria/Hazardous Air Pollutants	
Nitrogen Oxides (NO_X)	Mercury (Hg)	Manganese (Mn)
Sulfur Dioxide (SO_2)	Volatile Organic Compounds (VOC)	Cadmium (Cd)
Carbon Monoxide (CO)	Chlorides (HCl)	Chromium (Cr)
Particulate Matter (PM_{10})	Fluorides (HF)	Formaldehyde
Fine Particulate Matter ($PM_{2.5}$)	Sulfur Trioxide (SO_3)	Nickel (Ni)
Lead (Pb)	Hydrogen Sulfide (H_2S)	Silica (Si)
	Sulfuric acid	Selenium (Se)
	Ammonia (NH_3)	Vanadium (V)
	Arsenic (As)	Total Reduced Sulfur (TRS)
	Beryllium (Be)	Reduced sulfur compounds

Section 2 describes the major processes and components of various IGCC and PC plant configurations included in this report.

2.1 Process Description

The PC and IGCC plants used for the study are relatively “conventional” plants. With the exception of the ultra-supercritical PC technology, the equipment is commercial or near-commercial. (Ultra supercritical technology with conditions similar to the study criteria is deployed in Japan and Europe to a limited extent. Major manufacturers are working to develop the technology for use in the U.S. Research is being pursued to increase the temperature beyond 1,100 ºF.) While the focus of the study is the environmental performance of the plants, a brief description of the plants is provided to illustrate the overall plant configuration. In general, Sections 2 and 3 of the study describe technologies that can be commercially deployed. Sections 4 and 5 describe technologies that can still potentially be deployed but have no direct commercial experience with the power generation technologies considered in this study. Exhibit 2-1 lists major features of each type of plant with emphasis on their differences.

Exhibit 2-1, Summary of Plant Design Features

Plant Features	Pulverized Coal Plants	Gasification Combined Cycle Plants
Generation Method	All coals, boiler and steam turbine cycle.	A. Bituminous and subbituminous coals, coal slurry feed gasifier combined cycle. B. Lignite coal, solid feed gasifier combined cycle.
Particulate Control	All coals, fabric filter baghouse.	All coals, high temperature metal filters. (The wet processing of the gas cleaning process adds to particulate removal downstream of the filters.)
NO_X Control	Combustion controls & SCR.	All coals, combustion controls with nitrogen dilution.

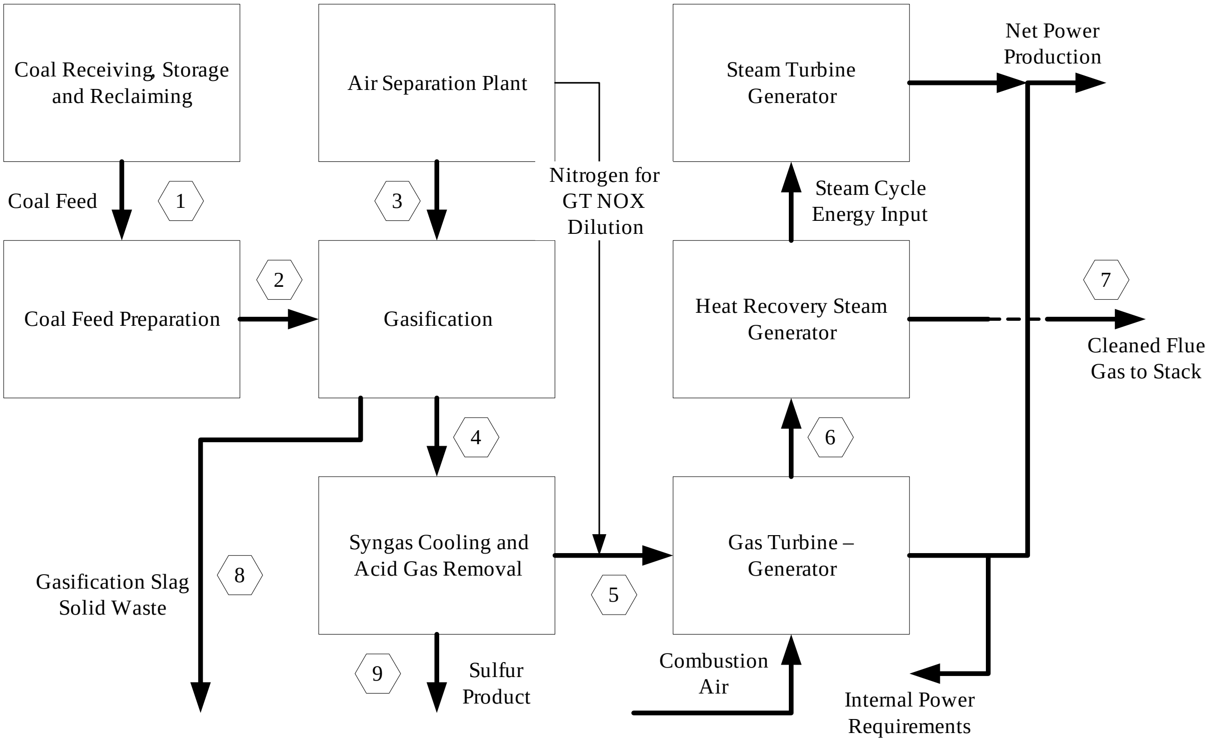
Plant Features	Pulverized Coal Plants	Gasification Combined Cycle Plants
SO_2 Control	A. Bituminous and lignite coals, wet limestone flue gas desulfurization and production of gypsum. B. Subbituminous coal, lime spray dryer desulfurization followed by fabric filter baghouse and production of solid waste containing SO_2 reaction products and ash	All coals, methyldiethanolamine (MDEA) gas cleaning and production of elemental sulfur.

In addition to the controls listed in Exhibit 2-1, the PC plants firing bituminous coal and lignite are equipped with a wet electrostatic precipitator (ESP) for controlling emissions of sulfuric acid mist. The cobenefits of a wet ESP may also include removal of other pollutants, such as particulate matter and mercury. The emissions and generation performance estimates presented for PC and IGCC plants are for "normal" operating conditions. All the plants will require a startup operation, often using oil or natural gas and generating emissions different from baseload design operations. Conditions may also change during shutdown operations and certainly during unplanned operating upsets where the plant or components may need to be shutdown or operated off-design without notice. Emissions from off-design operations are not addressed in this report. In addition, only the air emissions associated with the exhaust from the main stack are addressed for each plant. Other sources of air emissions, such as from an auxiliary boiler or IGCC flare, have not been reported, since they are considered to be minor in comparison to the main stack emissions.

2.1.1 IGCC Plants

The IGCC power plant processes are summarized in this section; more detailed descriptions of the environmental control systems are presented later. Exhibit 2-2 illustrates the nominal 500 MW IGCC plant. The material and energy balance tables related to the numbered major flow streams are presented in Appendix C. As noted with the balance tables, the calculations are derived from Nexant's spreadsheet power plant model, and are used primarily to estimate plant performance across the technologies and three coal ranks. The emission results may not be exactly the same as provided in other parts of the report due to rounding, calculation differences and the use of other sources, mainly air permit data, to define the emissions.

Exhibit 2-2, Integrated Gasification Combined Cycle Block Diagram



It is worth noting that there are significantly more technical and installation differences between the alternative gasification and IGCC systems than for the PC plants. Some of the differences arise from the technology's relatively young level of commercial maturity; others from the varying technology developers' designs. For the present study the bituminous and subbituminous coals utilize a GE Energy (Ex-ChervonTexaco, Texaco) type of gasifier with coal/water slurry feed system. The unit includes radiant and convective heat recovery for higher efficiency operations and uses two-50% gasification trains. For the high moisture lignite coal, a solid feed Shell type of gasifier was selected, also with two-50% gasification trains. All the plants use an F-type gas turbine in the combined cycle operation.

Performance data for bituminous coal- and petroleum coke-fueled IGCC plants is widely available in the literature and from previous Nexant work[3]. More limited up-to-date data is available for low-rank coal gasification. The best sources of data are, of course, the technology providers. However, creation of data at the level of detail that the major gasification developers feel necessary to support their technologies is costly and time consuming. For the present work, data from Nexant experience and the literature were

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[3] Gasification Plant Cost and Performance Optimization Project, U.S. DOE/NETL Contract No. DE-AC26-99FT40342, September 2003, prepared by Nexant, Inc., Bechtel Corporation and Global Energy.

the basis for performance estimates. As will be discussed later, the IGCC environmental control areas were evaluated by contacting potential suppliers for those components.

The performance levels reported in this study for various IGCC plant configurations are based on current technologies. Based on ongoing research and development activities, a potential exists for considerable improvements in the IGCC performance levels. The goals of these activities are to achieve overall plant thermal efficiency levels of 45 to 50 percent by 2010 and 50 to 60 percent by 2020[4].

In gasification's simplest form, coal is heated and partially oxidized with oxygen and steam and the resulting synthesis gas, or syngas (primarily hydrogen and carbon monoxide), is cooled, cleaned and fired in a gas turbine-generator. Oxygen for the gasifier is produced in an air separation plant. The gas turbine exhaust goes to a heat recovery steam generator (HRSG), producing steam that is sent to a steam turbine-generator. Power is produced from both the turbine-generators. It is generally accepted that the IGCC system, by removing most pollutants from the syngas prior to combustion, is capable of meeting more stringent emission standards than PC technologies. It is also generally accepted that IGCC costs are higher and more uncertain than for PC plants, because PC technology has been demonstrated at many more installations. At present, the IGCC system also has greater promise to incorporate CO_2 capture for sequestration without large cost and energy penalties.

There are many variations on the basic IGCC scheme, especially in the degree of process integration. Three major types of gasification systems are used today: moving bed; fluidized bed; and entrained flow. The figure from EPRI in Exhibit 2-3 shows major characteristics of the three gasifiers.[5]

In a moving-bed gasifier, a bed of crushed coal is supported by a grate and the reactions between coal, oxygen, and steam take place within this bed. The gasifier operates at temperatures below the ash slagging temperature.

Fluidized-bed gasifiers also have a discrete bed of crushed coal. However, the coal particles are kept in a constant motion by the upward gas flow. The fluidized bed is maintained below the ash fusion temperature.

In entrained-flow gasifiers, finely pulverized coal particles concurrently react with steam and oxygen with very short residence time. These gasifiers operate at high temperature where the coal ash becomes a liquid slag. These units form the majority of IGCC project applications and include the coal/water-slurry-fed processes of GE Energy and ConocoPhillips, and the dry-coal-fed Shell process. A major advantage of the high-

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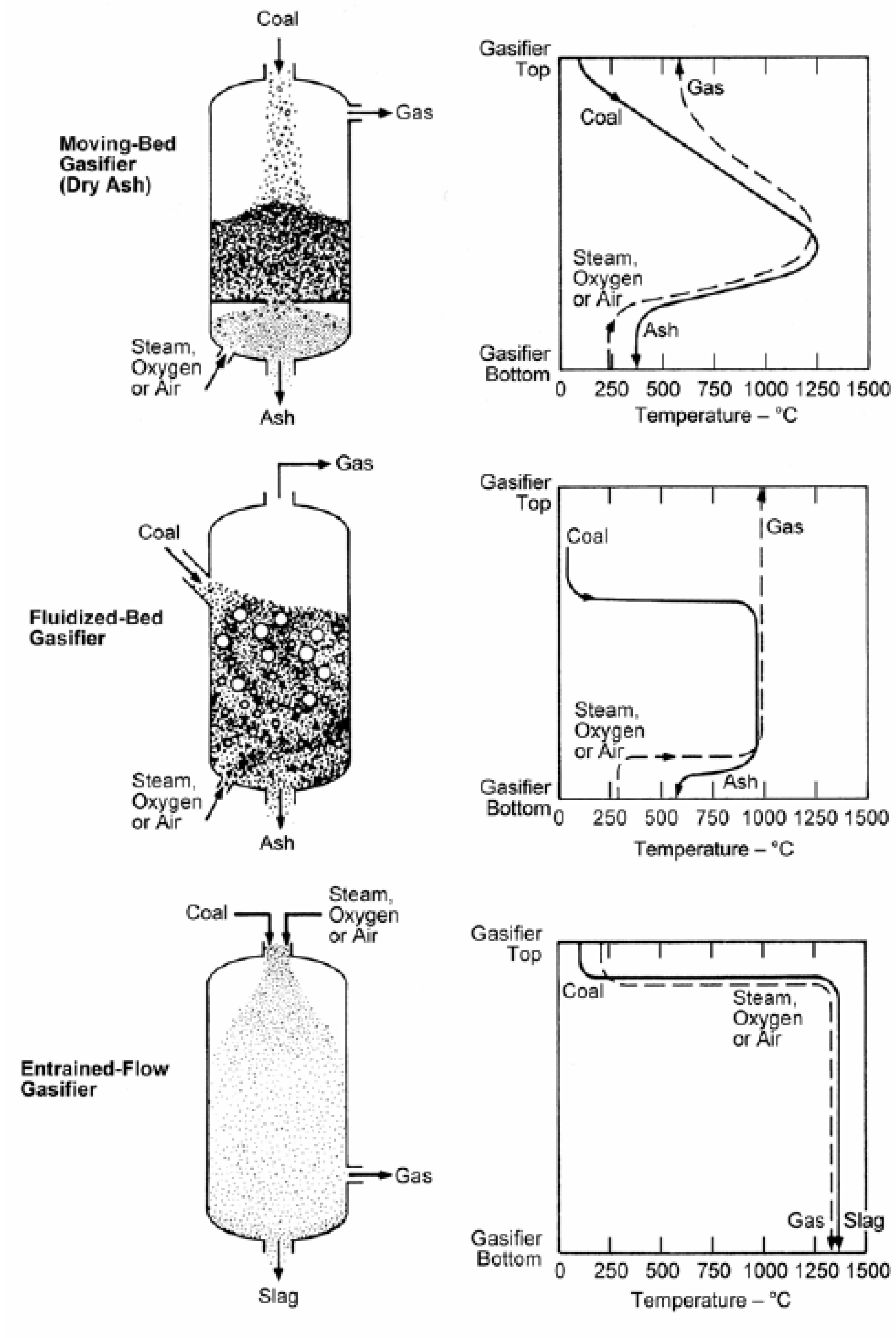
[4] H. Morehead, et al.,"Improving IGCC Flexibility through Gas Turbine Enhancement," Gasification Technologies Conference, October 4-5, 2004, Washington, DC.

[5] Neville Holt, "Gasification Process Selection – Trade-offs and Ironies", Gasification Technologies Conference, October 4-55, 2004, Washington, DC.

Exhibit 2-3, Major Gasification System Types



temperature entrained-flow gasifiers is that they avoid tar formation and its related problems.

Another variation in gasifier design involves use of air, instead of oxygen, to accomplish partial oxidation of fuel in a gasifier. This design eliminates the need for using an expensive air separator required for oxygen-blown gasifiers. The syngas produced from an air-blown gasifier has a lower calorific value, compared to the syngas produced from an oxygen-blown gasifier. Research and development work done both in the U.S. and Japan shows certain cost and performance advantages associated with the use of air-blown gasifiers, especially for low-rank coals. An IGCC demonstration plant, partially funded by DOE and using an air-blown Transport gasifier design, has recently been proposed to be built in Florida.[6]

All of the currently operating IGCC plants utilize oxygen-blown, entrained-flow gasifier designs. Therefore, this gasifier design is used for the IGCC plants in the present study.

IGCC operations have environmental benefits compared to PC units. Gasification occurs in a low-oxygen environment and the coal's sulfur converts to hydrogen sulfide (H_2S), instead of SO_2 as it does in the PC flue gas. The H_2S from gasification can be more easily captured and removed than the SO_2 in PC flue gas. Removal rates of 99% and higher for H_2S have been obtained with petrochemical industry cleanup technologies.[7]

NO_X emissions are an issue of special importance in the study of IGCC technology. Due to high flame temperature, the syngas can generate high NO_X emissions in the exhaust. However, IGCC units can be configured to operate with low NO_X emissions by saturating the syngas with steam or using nitrogen from the oxygen plant to dilute the fuel in the combustor. The base cases in this study use nitrogen dilution and saturation to control NO_X. A special analysis is presented later in this report, which examines the potential for including a SCR control device to further decrease the NO_X emission. An advantage of adding extra mass from the water and nitrogen is that additional power is generated in the gas turbine and steam cycle.

The IGCC concept was first demonstrated at the Cool Water Project in Southern California from 1984 to 1989. There are currently two commercial-scale, coal-based IGCC plants in the U.S. and two in Europe. The U.S. projects were supported by the DOE's Clean Coal Technology demonstration program.

The 262 MW Wabash River IGCC repowering project in Indiana started operations in

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[6] "Demonstration of a 285-MW Coal-Based Transport Gasifier," Project Facts, May 2005, NETL/DOE Internet Site, http://www.netl.doe.gov/publications/factsheets/fact_toc.html, accessed 5/2/2006.

[7] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report by: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann, & Massood Ramezan for National Energy Technology Laboratory, U.S. Department of Energy, December 2002.

1995 and uses the ConocoPhillips E-Gas gasification technology. The 250 MW Polk Power Station IGCC project in Florida started in 1996 and uses the GE Energy gasification technology. Both plants have operated on bituminous coals and petroleum cokes; no use of low-rank coal is known. These plants reported the following emission data on USDOE/NETL fact sheets[8, 9]

Wabash River

- SO_2 capture efficiency greater than 99%, or emissions below 0.1 lb per million Btu. An MDEA acid gas removal system is used at Wabash.
- NO_X emissions were 25 ppmvd at 15% O_2 (0.15 lb/MMBtu).
- Particulate emissions were below detectable limits. After experimenting with a ceramic filter, Wabash switched to metallic filters for particulate control. The wet downstream operations also remove any remaining solids from the syngas.
- CO emissions averaged 0.05 lb/MMBtu.

Tampa Electric Polk Power Station

- Sulfur removal was over 97%. An amine-based (MDEA + COS conversion) acid gas removal system is used. Sulfur recovery includes sulfuric acid production.
- NO_X emissions were 15 ppmvd at 15% O_2 (0.055 lb/MMBtu). Nitrogen injection is used to control NO_X.
- Particulates were 0.007 lb/MMBtu. Particulate removal is in a water-wash synthesis gas scrubber.
- CO emissions averaged 7.2 pounds per hour.

The Wabash River and Polk plants are low emission, coal-based power technologies. New IGCC technologies are forecast to achieve 99% or more sulfur removal[10], essentially total volatile mercury removal (greater than 90-95% removal[11]), and particulate emission levels of less than 0.015 lb per million Btu[12]. An IGCC plant will also produce less solid waste, and will use less total water than a PC plant. These emission levels of performance are likely to be available in the 2010 timeframe set for the study, but electric generation market conditions and financial/technical risk make their implementation by that time uncertain, especially with low-rank coals.

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[8] U.S. DOE Fact Sheet at Internet Site: http://www.netl.doe.gov/technologies/coalpower/cctc/summaries/tampa/tampaedemo.html, accessed 2/28/06.

[9] U.S. DOE Fact Sheet at internet Site: http://www.netl.doe.gov/technologies/coalpower/cctc/summaries/wabsh/wabashrdemo.html, accessed 2/28/06.

[10] Evaluation of Innovative Fossil fuel Power Plants with CO2 Removal, U.S. DOE/NETL and EPRI, Prepared by ParsonsEnergy and Chemicals Group, December 2000 – updated 2002.

[11] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report by: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann, & Massood Ramezan for National Energy Technology Laboratory, U.S. Department of Energy, December 2002.

[12] R. Brown, et. al., "An Environmental Assessment of IGCC Power Systems," 19th Annual Pittsburgh Coal Conference, September 2002.

For this study, the design basis includes use of two gasifiers for each plant configuration. This is intended to result in a design that can provide commercially acceptable plant availability. Based on experience from existing IGCC installations, the plant availability goals can also be achieved by using a standby fuel, natural gas or oil, for the gas turbines, in lieu of two gasifiers. The disadvantages to this approach include increased operating costs due to the use of expensive standby fuels as well as increased NO_X emissions from the gas turbines, which have been designed to handle syngas.

GE Energy Type Coal Slurry Feed Gasification

The coal is crushed and mixed with water to produce pumpable slurry that is 65 to 70 % coal by weight. Slurry is pumped into the gasifier with oxygen. The gasifier operates in a pressurized, down-flow, entrained design and gasification proceeds rapidly at temperatures in excess of 2,300 ºF. The raw gas is mainly composed of H_2, CO, CO_2, and H_2O. The hot syngas leaves the gasifier at the bottom and enters a radiant syngas cooler (RSC) where it is cooled to about 1,400 ºF, and in the process produces high pressure steam. The molten slag falls to the quench bath at the bottom of the cooler where it is solidified and removed with a lock hopper system. The syngas from the RSC is sent to a convective syngas cooler (CSC) for additional steam generation. The cooled gas is sent to the acid gas removal plant.

Air Separation Plant. A high-pressure cryogenic oxygen plant is used. The air for this plant is supplied in equal amounts from two sources: a bleed from the gas turbine compressor exhaust and an air stream supplied directly using a booster compressor. The gas turbine compressor bleed air preheats a nitrogen recycle stream sent to the gas turbine for NO_X control.

Particulates. Metal candle filters are used to remove ash particulates from the gasification process. Particulate emission from the IGCC process is usually termed negligible because the wet scrubbing devices employed with the acid gas cleaning and other operations remove all the measurable solids. Soot and other fine particulate may be emitted from auxiliary furnaces or other combustion devices if these are installed, and these emissions may need to be controlled.

Gas Cooling/Heat Recovery/Hydrolysis/Gas Saturation. The raw fuel gas is cooled in a series of heat exchangers and sent to acid gas removal. Any hydrogen chloride and ammonia is assumed to be in the condensate from these heat exchangers, which is then sent to an ammonia strip unit for further treatment. A catalytic hydrolyzer converts the carbonyl sulfide to hydrogen sulfide. Heat recovery is used for generating stripping steam and boiler feed water heating.

Acid Gas Removal (AGR). The MDEA/Claus/SCOT process is used for acid gas removal and sulfur recovery. In the MDEA process, the cooled gas enters an absorber where it comes into contact with the MDEA solvent. As it moves through the absorber, almost all of the H_2S and some of the CO_2 are removed. The solute-rich MDEA exits the absorber and is heated in a heat exchanger before entering the stripping unit. Acid gases from the top of the stripper are sent to the Claus/SCOT unit for sulfur recovery. The lean MDEA solvent exits the bottom of the stripper and is cooled through several heat exchangers. It is then filtered and sent to a storage tank for the next cycle.

The Claus process occurs in two stages. In the first stage, about one-quarter of the gases from the MDEA unit are mixed with the recycle acid gases from the SCOT unit and are burned in the first furnace. The remaining acid gases are added to the second stage furnace, where the H_2S and SO_2 react in the presence of a catalyst to form elemental sulfur. The gas is cooled in a waste heat boiler and then sent through a series of reactors where more sulfur is formed. The sulfur is condensed and removed between each reactor. A tail gas stream containing unreacted sulfur, SO_2, H_2S, and COS is sent for processing in the SCOT unit.

Gas Turbine and Steam Cycle. A General Electric F type of gas turbine is partly integrated with the Air Separation Unit (ASU). From the turbine compressor exhaust, a bleed stream supplies half of the air needed for the ASU. The remainder of the compressor discharge air is used to combust the clean fuel gas. The ASU returns a nitrogen stream to the gas turbine combustor for NO_X control.

The steam cycle's major components include a heat recovery steam generator (HRSG), steam turbine, condenser, steam bleed for gas turbine cooling, recycle water heater, deaerator, and cooling tower for condenser cooling.

Balance of Plant (BOP). The BOP includes the following major components:

- Piping and Valves
- Ducting and Stack
- Waste Water Treatment
- Accessory Electric Plant
- Instrumentation and Control
- Buildings and Structures

Shell Type Solid Feed Gasification

The gasifier is a dry-feed, pressurized, oxygen-blown, entrained-flow slagging reactor. The coal is pulverized and dried prior to being fed into the gasifier. Nitrogen is used as the coal transport gas. Coal, oxygen and steam enter the gasifier through the burners. Raw fuel gas is produced from high temperature gasification reactions and flows upwardly with some entrained particulates. The high reactor temperature converts the remaining ash into a molten slag, which flows down the walls of the gasifier and passes into a slag quench bath. The fuel gas is quenched at the reactor exit with cooled recycled fuel gas to avoid sticky solids entering the raw gas cooler. The raw gas cooler further cools the gas and generates high-pressure steam for the steam cycle. Solids are recovered in the particulate filter and recycled back to the reactor.

Air Separation Plant (ASU). The ASU is similar to the operation described for the slurry-feed gasifier.

Particulates. Metal candle filters are used to remove ash particulates from the gasification process. Particulate emission from the IGCC process is usually termed negligible because the wet scrubbing devices employed with the acid gas cleaning and other operations remove all the measurable solids. Soot and other fine particulate may be emitted from auxiliary furnaces or other combustion devices if these are installed, and these emissions may need to be controlled.

Gas Cooling Section. The raw fuel gas from the particulate filter enters a gas-cooling section with several heat exchangers, a catalytic hydrolyzer, and a water scrubber. The raw fuel gas is cooled and sent to the hydrolyzer, which converts the carbonyl sulfide (COS) to hydrogen sulfide. The gas stream is further cooled before entering a water scrubber. Hydrogen chloride and ammonia are assumed to be in the scrubber water discharge, which is sent to a water treatment unit. About 30% of the cooled fuel gas stream is recycled to quench the hot raw fuel gas stream exiting the gasifier. The remaining fuel gas is sent to the cold gas cleanup for sulfur removal. The heat recovered is used for reheating the cleaned fuel gas and for heating boiler feed water in the steam cycle.

Cold Gas Cleanup Unit**.** The MDEA/Claus/SCOT process is used for cold gas cleanup and sulfur recovery and is similar to the earlier description.

Gas Turbine and Steam Cycle. The gas turbine is an F type machine similar to the previous case. The steam cycle major components include a heat recovery steam generator (HRSG), steam turbine, condenser, steam bleed for gas turbine cooling, recycle water heater, cooling tower, and deaerator.

Balance of Plant. The BOP includes the following major components:

- Piping and Valves
- Ducting and Stack
- Waste Water Treatment
- Accessory Electric Plant
- Instrumentation and Control
- Buildings and Structures

2.1.2 PC Plants

The pulverized coal plants are briefly described in this section. The overall scope for the PC plants includes the following major systems:

- Solids Material Handling

- Steam Generation
- NO_X Controls
- Particulate Collection
- Flue Gas Desulfurization, either a wet limestone FGD (WL-FGD) for the bituminous and lignite coals or a lime spray dry absorber (SDA) for the low-sulfur subbituminous coal
- Steam Turbine Generator
- Condensate and Feedwater Systems
- Balance of Plant

Simple block diagrams of the PC plants are shown as Exhibit 2-4 for plants firing the three coals. The major difference between plants is the type of flue gas desulfurization. Material and energy balance tables related to the block diagram stream numbers are presented in Appendix C. The environmental controls and performance are examined in more detail later. While not shown in the block diagrams, the PC plants firing bituminous coal and lignite are to be equipped with wet ESP units to enhance removal of acid mist.

Subcritical PC Plant

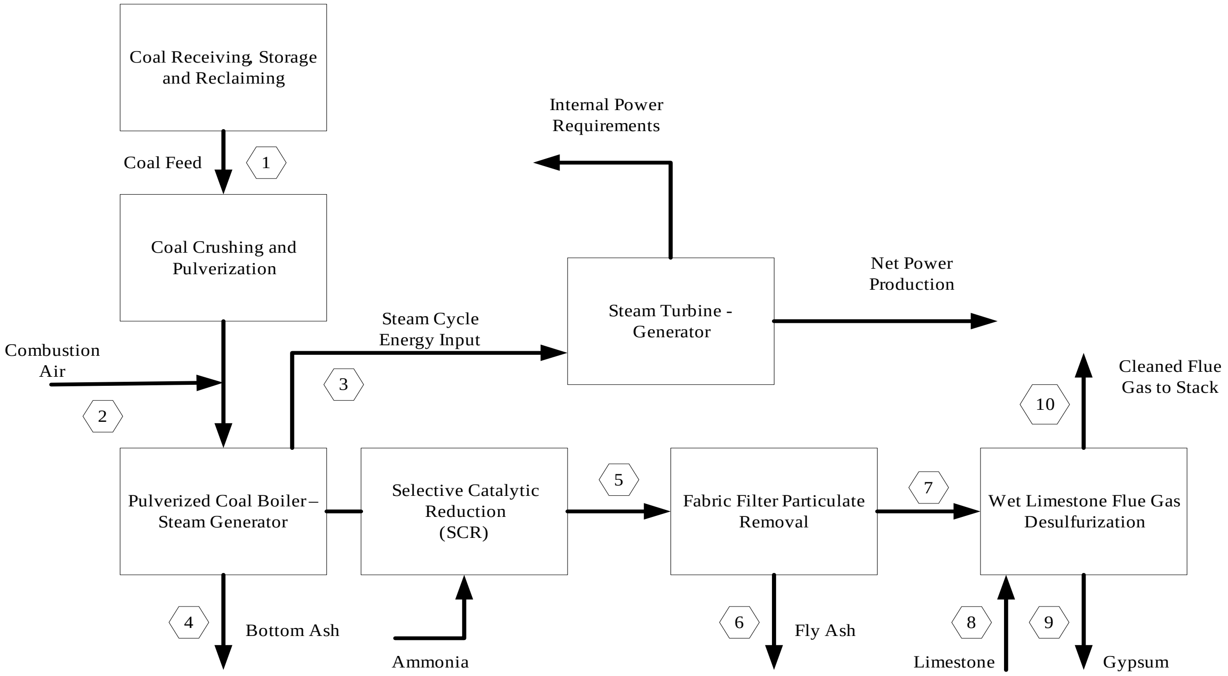
Solid Materials Handling. Solids handling includes receiving, conveying, storing and reclaiming coal, limestone or lime and the removal and disposal of coal ash and SO_2 reaction products. While there could be significant design differences between the three types of coals, the overall impact on generation and environmental performance would be small. For example, the lignite fuel is very likely to be used at a mine-mouth power plant and delivered by truck or conveyor. The bituminous and subbituminous coal options could be mine-mouth operations or not, with truck, conveyor, railroad, barge or some combination of delivery systems. Coal is reclaimed as needed from the storage; it is crushed and conveyed to short-term storage silos before being sent to the coal mills where it is pulverized for firing in the boiler.

Limestone for the WL-FGD unit is also delivered, stored and prepared on site. For the subbituminous coal plant with lime SDA SO_2 control, the lime is delivered, stored and slaked for use on site.

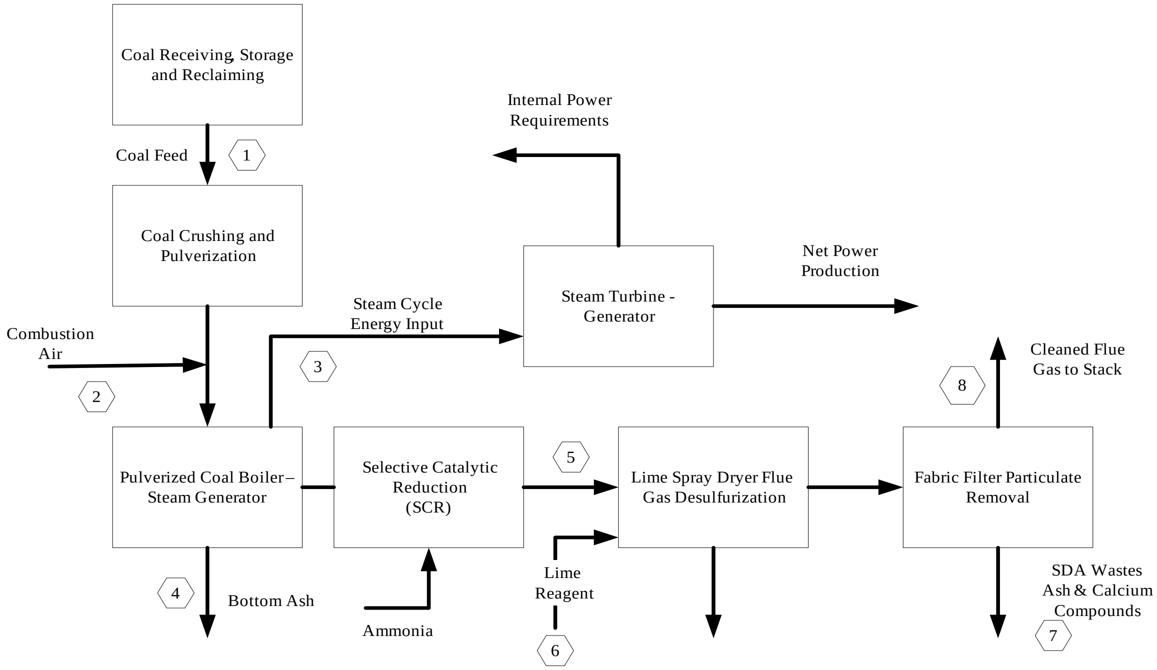
The ash handling system includes the equipment for conveying, preparing, storing, and disposing the fly ash and bottom ash produced on a daily basis by the boiler. Fly ash is conveyed to the fly ash storage silo from which it is loaded into trucks and sent to

Exhibit 2-4, Pulverized Coal Power Plant Block Diagrams

Bituminous and Lignite Coal-Fired Plant Diagram



Subbituminous Coal-Fired Plant Diagram



disposal. The bottom ash from the boiler is collected via a separate system and sent to disposal.

WL-FGD wastes (from processes using bituminous and lignite coals) are formed into gypsum and sent to dewatering and storage by placement in gypsum piles. Depending on market conditions and transportation costs, some plants may have the potential to produce salable gypsum and thus reduce their solid waste.

For the subbituminous coal and lime SDA sulfur control, the waste stream is a fine dry material that can be landfilled and disposed of with the coal fly ash. The potential for byproduct use of this desulfurization solid waste is limited, as discussed later in Section 3.6.

Steam Generation. This system includes the air handling and preheating systems, the coal burners, steam generation boiler and reheat, and soot and ash removal. The boiler is staged for low NO_X formation and is also equipped with a SCR as noted below. A drum-type steam generator is used to power a single-reheat subcritical steam turbine. The steam turbine conditions correspond to 2,400 psig and 1,000 °F at the throttle with 1,000 °F reheat.

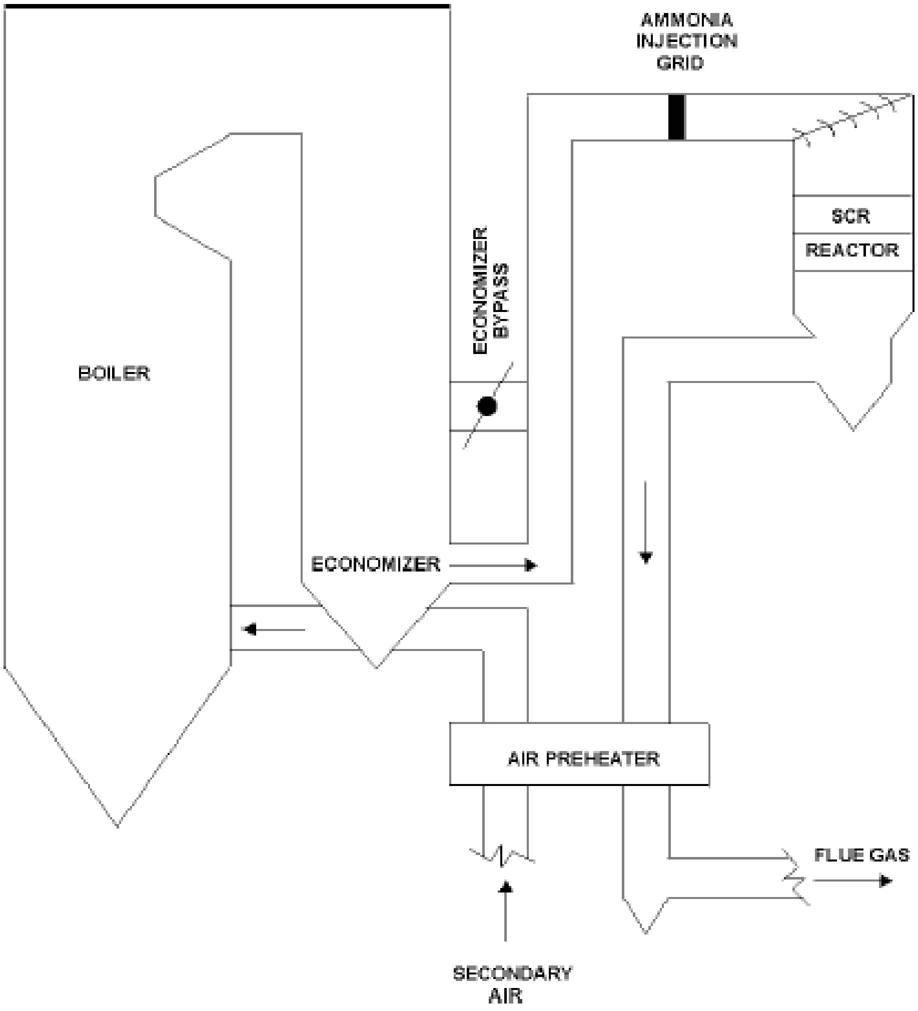
NO_X Controls. The NO_X controls for all three fuels consist of combustion controls and a selective catalytic reduction (SCR) system. The combustion controls include low-NO_X burners and overfire air. The SCR reactor is installed at the boiler economizer outlet, upstream of the air heater, as shown in Exhibit 2-5. These systems are described later in Section 3.

Particulate Collection. Particulate matter collection for all three coals is accomplished with the use of fabric filters. As an alternative, an electrostatic precipitator can also be used. However, a fabric filter was selected for this study, because it reduces reagent consumption when used in conjunction with a lime SDA system and it has better fine particulate and trace metal collection efficiencies.

Flue Gas Desulfurization. A WL-FGD is used with the high sulfur bituminous coal and the lignite. A lime SDA is used for the low-sulfur subbituminous coal. While the WL-FGD system is located after the fabric filter, the SDA unit is located downstream of the air preheater, followed by the fabric filter. The wet ESP used for the PC plants firing bituminous coal and lignite is located downstream of the WL FGD system (not shown in Exhibit 2-4).

Steam Turbine Generator. The turbine is tandem compound type, comprised of high pressure, intermediate pressure, two low pressure sections, and a final stage. The turbine drives a hydrogen-cooled generator. The throttle pressure at the design point is 2,400 psig. The exhaust pressure is 2.0/2.4 inch Hg in the dual pressure condenser. There are seven extraction points; the condenser is two shell, transverse, dual pressure type.

Exhibit 2-5, Example of SCR in a Pulverized Coal Boiler System



Condensate and Feedwater Systems. The condensate system moves condensate from the condenser to the deaerator, through the gland steam condenser and the low pressure feedwater heaters. The system consists of one main condenser; two 50 percent capacity condensate pumps; one gland steam condenser; four low pressure heaters; and one deaerator with a storage tank. The function of the feedwater system is to pump the feedwater from the deaerator storage tank through the high pressure feedwater heaters to the boiler economizer. Two 50 percent turbine-driven boiler feed pumps are installed to pump feedwater through the high pressure feedwater heaters.

Balance of Plant. The BOP includes the following major components.

- Steam Piping and Valves
- Circulating Water System with Evaporative Cooling Tower
- Ducting and Stack
- Waste Water Treatment

- Accessory Electric Plant
- Instrumentation and Control
- Buildings and Structures

Supercritical PC Plant

Solids Material Handling. The material handling systems are similar in scope to the subcritical plant discussion. Component sizes may be different because of higher efficiency of the supercritical plant (assuming equal generating capacity), but the impacts of this difference on performance and cost are small, especially compared to the impacts of specific site conditions, which can vary widely.

Steam Generation. The boiler is staged for low NO_X formation and is also equipped with a SCR. A once-through steam generator is used to power a double-reheat supercritical steam turbine. The steam turbine conditions correspond to 3,500 psig and 1,050°F at the throttle with 1,050°F at both reheats.

NO_X Controls. The controls used are the same as in the previous plant.

Particulate Collection. Fabric filters used are similar to the subcritical unit.

Flue Gas Desulfurization. The control technologies are the same as installed for the subcritical unit. Bituminous coal and lignite use WL-FGD systems preceded by the fabric filter, and the subbituminous coal uses a SDA followed by the fabric filter.

Steam Turbine Generator. The turbine consists of a very high pressure section, high pressure section, intermediate pressure section, and two low pressure sections, all connected to the generator by a common shaft. Main steam from the boiler passes through piping and valves and enters the turbine at 3,500 psig and 1,050 °F. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the boiler for reheating. The first reheat steam flows through the reheat and enters the HP section at 955 psig and 1,050 °F. The second reheat steam flows through the reheat and enters the IP section at 270 psig and 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 is split into four paths which flow through LP sections exhausting downward into the condenser.

Condensate and Feedwater Systems and Balance of Plant. These operations are the same as discussed for the subcritical unit.

Balance of Plant. The BOP includes the following major components.

- Piping and Valves
- Circulating Water System with Evaporative Cooling Tower
- Ducting and Stack

- Waste Water Treatment
- Accessory Electric Plant
- Instrumentation and Control
- Buildings and Structures

Ultra-Supercritical Plant

The ultra-supercritical plant level of technology maturity differs from that of the two technologies discussed previously, and it is relatively rarely used, especially in North America. There are more than 500 supercritical PC plants throughout the world (primarily in Europe with a majority of them in the former Soviet Union and Japan) operating at pressures 3,500 psig and above and at temperatures up to 1,050 ºF. There are ultra-supercritical commercial plants in Japan and Denmark and all belong to the 1,100 ºF class. Two ultra-supercritical plants currently operated by Danish power companies are in the 250-400 MW range. One of these plants, the Evader unit, has steam conditions of 4,350 psig and 1,112 ºF giving an efficiency of 47 percent. The Kawagoe plant in Japan, consisting of two 700 MW units and operated by Chubu Electric since 1989, has steam conditions of 4,500 psig and 1,050 ºF with double reheat. Its efficiency is 45 percent. Currently the leading companies offering the 1,100 ºF class ultra-supercritical plants are mostly in Japan, such as Hitachi, IHI, MHI, and Mitsui. They are actively promoting the commercial use of this class of plants in the world, often in the form of joint companies, such as Babcock-Hitachi, and Mitsui-Babcock.

The available data for the Japanese and Danish plants do not state the basis for efficiency calculations, but the efficiencies are likely based on lower heating values of the fuels. Also, Denmark has banned coal and the units have been switched to accommodate natural gas and biomass fuels.

The relative immaturity of the ultra-supercritical technology also means that there are fewer sources of data, and the performance estimates made for this study are likely to have a wider variability than for the better known subcritical and supercritical technologies.

Solids Material Handling. The material handling systems are similar in scope to the other two plant descriptions. Component sizes may be different because of higher efficiency of the ultra-supercritical plant (assuming equal generating capacity), but the impacts of this difference on performance and cost are small, especially compared to specific site conditions, which can vary widely.

Steam Generation. The boiler is staged for low NO_X formation and is also equipped with a SCR. A once-through steam generator is used to power a double-reheat ultra-supercritical steam turbine. The steam turbine conditions correspond to 4,500 psig and 1,100°F at the throttle with 1,110°F at both reheats.

NO_X Controls. The controls used are the same as in the previous plants.

Particulate Collection. Fabric filters used are similar to the subcritical unit.

Flue Gas Desulfurization. The control technologies are the same as installed for the other PC technologies.

Steam Turbine Generator. The turbine consists of a very high pressure section, high pressure section, intermediate pressure section, and two low pressure sections, all connected to the generator by a common shaft. The ultra-supercritical conditions are 4,500 psig and 1,100 ºF with double reheat.

Condensate and Feedwater Systems and Balance of Plant. These operations are the same as discussed for the previous plants.

Balance of Plant. The BOP includes the following major components.

- Steam Piping and Valves
- Circulating Water System with Evaporative Cooling Tower
- Ducting and Stack
- Waste Water Treatment
- Accessory Electric Plant
- Instrumentation and Control
- Buildings and Structures

2.1.3 Process Maturity and Data Availability

The comparisons made for this study are intended to be on an equal basis for all the technologies. However, decision makers using the report should recognize that the technical and cost data come from different sources that may not be using exactly the same basis or criteria. The quantity of available data varies among the technologies and coals. It is also noted the IGCC technology is still developing (and advancing) while the PC technology is much more mature.

Except for the ultra-supercritical technology, the PC systems are well-defined and understood. Costs for PC plants can be estimated with relative certainty provided there is sufficient preliminary engineering to determine site and owner specific costs. The power generation industry is familiar with the PC plant operations and understands their reliability, load following and other operating features.

There are a large number of gasification units in operation globally too, but as noted before, there are very few gasification plants using coal to generate electric power as envisioned for IGCC installations. Most of the gasification units are at petroleum or chemical plants where special conditions favor the gasification of solids or liquids as part of an integrated process. Coal-based IGCC plants have uncertain costs and concerns with operating reliability. The power generation industry views the IGCC operations as "chemical plants", and has historically been reluctant to own and operate them. One of the concerns is the attainment of commercially acceptable levels of plant availability. The plant availability levels with existing single gasifier-train IGCC plants have been below the design availability targets of 85 percent[13]. It is expected that such targets can be met with the use of a spare IGCC train, which is the design basis for the IGCC plants in this study. In comparison, plant availability levels exceeding 90 percent can be achieved with the mature subcritical and supercritical PC technologies.

The ultra-supercritical plant data are less available than data for the IGCC technologies. A great amount of engineering and process design work has been done for gasification in the last few years with increasing emphasis on the potential for the technology to more effectively incorporate carbon management processes. For the ultra-supercritical technology, most of the work appears to be with advanced materials to construct the units to make them more attractive from cost and performance aspects. Much of the advanced PC work also is in Europe and Japan, where fuel prices have for a long time been relatively expensive, and increases in efficiency have greater impacts on costs of electric power than in the U.S. Except for the carbon management issue, plant efficiency in the U.S. has historically not been regarded as a major benefit that justifies the expenditure of additional capital for equipment or process improvements.

Another area of uncertainty and difference among the technologies is the refinery or chemical plant type of operations required by the IGCC technologies. While not absent from PC plants, operational upsets and off-design operations seem potentially more likely at the more complicated IGCC plants. Such upsets and off-design conditions can presumably be minimized by careful engineering, possibly installation of spare or special equipment, and a well-trained plant staff. The emissions of a well-run IGCC plant should be lower than for other coal systems, but there is an element of uncertainty because the long-term commercial experience does not yet exist, especially for the applications on low-rank coals.

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[13] N. Holt,"Coal-Based IGCC Plant – Recent Operating Experience and Lessons Learned," Gasification Technologies Conference, October 5, 2004, Washington, DC.

Section 3 presents the results from the thermal and environmental performance assessments.

3.1 Power Generation Performance

The IGCC plant performance, based on the coal higher heating value (HHV), is summarized in Exhibit 3-1 for the bituminous and subbituminous coals. The slurry-feed type gasifier used for these coals is not well-suited to the high-moisture, high-ash lignite coal, and the subbituminous coal may be a difficult fuel to use for practical applications. High amounts of coal ash interfere with the radiant heat exchanger's ability to recover energy and generate steam. Also, high-ash slurry from the gasifier bottom is another source of heat losses. This has significant impact on the gasifier thermal efficiency. The Shell gasifier is more able to handle high-ash coals without heat loss penalties.

Gasification developers, such as GE Energy, have declined in the past to offer their technology for high moisture coals. On the other hand, ConnocoPhillips, who also offers a slurry-feed type system, has past subbituminous coal experience and would offer its gasifier for subbituminous coals in general. The Canadian Clean Power Coalition (CCPC) has examined low-rank coal gasification, but only reported summary level results.[14] In the CCPC summary, the efficiency for all the gasification cases was about 38%. It cannot be determined from this data whether, for example, the performance impacts of coal drying or increased oxygen demand were accounted for in the calculations. The CCPC study used GE Energy gasifiers for the bituminous and subbituminous coals, and Shell for the lignite. However, the Canadian subbituminous coal has less moisture, 20% compared to more than 27% for this study. Despite the uncertainty of low rank gasifier selection, the impacts on environmental issues would not be significantly different as all the IGCC technologies use very similar cleanup and control processes.

Exhibit 3-1, Integrated Gasification Combined Cycle Performance Estimates - Bituminous and Subbituminous Coals

GE-Energy Slurry Feed Gasifier and F-type Gas Turbine	Bituminous	Subbituminous
Net Thermal Efficiency (HHV), %	41.8	40.0
Net Heat Rate (HHV), Btu/kWh	8,167	8,520
Gross Power, MW	564	575
Internal Power, MW	64	75
Fuel required, lb/h	349,744	484,089
Net Power, MW	500	500

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[14] G. Morrison, "Summary of Canadian Clean Power Coalition work on CO2 capture and storage," IEA Clean Coal Centre, August 2004.

Exhibit 3-2 presents summary performance data for the Shell solid feed type of gasifier and the lignite coal.

Exhibit 3-2, Integrated Gasification Combined Cycle Performance Estimates - Lignite Coal

Shell Solid Feed Gasifier and F-type Gas Turbine	Lignite
Net Thermal Efficiency (HHV), %	39.2
Net Heat Rate (HHV), Btu/kWh	8,707
Gross Power, MW	580
Internal Power, MW	80
Fuel required, lb/h	689,720
Net Power, MW	500

Exhibit 3-3 lists the typical consumers of internal power at the IGCC plants. The impact of the air separation plant and oxygen compression is highlighted. The coal preparation (thermal drying) component of the Shell technology is an area of performance and emission uncertainty. Limited public data is available to support engineering estimates, and the cost of detailed engineering needed to create and validate new data would be significant.

Exhibit 3-3, Typical IGCC Auxiliary Power Consumption Breakdown

Plant Component	% of Total Aux. Power	Plant Component	% of Total Aux. Power
Coal Handling and Conveying	0.7%	Humidification Tower Pump	0.2%
Coal Milling	1.5%	Humidifier Makeup Pump	0.1%
Coal Slurry Pumps	0.4%	Condensate Pumps	0.6%
Slag Handling and Dewatering	0.3%	Boiler Feedwater Pump	5.9%
Scrubber Pumps	0.6%	Miscellaneous Balance of Plant	2.0%
Recycle Gas Blower	1.2%	Gas Turbine Auxiliaries	1.2%
Air Separation Plant	47.1%	Steam Turbine Auxiliaries	0.4%
Oxygen Boost Compressor	24.1%	Circulating Water Pumps	3.6%
Amine Units	2.6%	Cooling Tower Fans	2.2%
Claus/TGTU	0.2%	Flash Bottoms Pump	0.1%
Tail Gas Recycle	2.8%	Transformer Loss	2.2%

The high amount of ash (slag) in lignite makes it unsuitable for GE Energy's entrained flow gasifier, because heavy slagging of the radiant heat exchanger slows heat removal and exchange. Also, the need for high ash content slurry to be removed from the bottom of the gasifier which retains significant heat energy is another major source of heat loss. These two factors have significant impact on the thermal efficiency of the gasifier and overall IGCC plant. Although the GE Energy gasifier can handle high moisture coal, the efficiency loss from the ash content of lignite is significant enough to make it unattractive.

The Shell gasifier has a refractory-lined water wall for syngas heat removal which can handle high loading of ash and still be effective in heat transfer. There is no significant loss in efficiency in Shell gasifier.

Greater details of energy and material balances for the IGCC plants are included in Appendix C of this report.

Exhibits 3-4, 3-5, and 3-6 present summary performance data for the PC units and the three coals.

Exhibit 3-4 Subcritical Pulverized Coal Unit Performance Estimates

Subcritical PC	Bituminous	Subbituminous	Lignite
Net Thermal Efficiency, % HHV	35.9	34.8	33.1
Net Heat Rate, Btu/kWh (HHV)	9,500	9,800	10,300
Gross Power, MW	540	541	544
Internal Power, MW	40	41	44
Fuel required, lb/h	407,143	556,818	815,906
Net Power, MW	500	500	500

Exhibit 3-5 Supercritical Pulverized Coal Unit Performance Estimates

Supercritical PC	Bituminous	Subbituminous	Lignite
Net Thermal Efficiency, % HHV	38.3	37.9	35.9
Net Heat Rate, Btu/kWh (HHV)	8,900	9,000	9,500
Gross Power, MW	540	541	544
Internal Power, MW	40	41	44
Fuel required, lb/h	381,418	517,045	752,535
Net Power, MW	500	500	500

Exhibit 3-6 Ultra Supercritical Pulverized Coal Unit Performance Estimates

Ultra Supercritical PC	Bituminous	Subbituminous	Lignite
Net Thermal Efficiency, % HHV	42.7	41.9	37.6
Net Heat Rate, Btu/kWh (HHV)	8,000	8,146	9,065
Gross Power, MW	543	543	546
Internal Power, MW	43	43	46
Fuel required, lb/h	342,863	460,227	720,849
Net Power, MW	500	500	500

Greater details of energy and material balances for the PC plants are included in Appendix C of this report. Exhibit 3-7 shows the typical auxiliary power consumers at the PC plants.

Exhibit 3-7, Typical PC Plant Auxiliary Power Consumption Breakdown

Plant Component	% of Total Aux. Power	Plant Component	% of Total Aux. Power
Coal Handling and Conveying	1.3%	Precipitators	3.4%
Limestone Handling & Reagent Preparation	3.2%	FGD Pumps and Agitators	11.9%
Pulverizers	6.4%	Condensate Pumps	2.0%
Ash Handling	5.7%	Boiler Feed Water Pumps	9.2%
Primary Air Fans	4.2%	Miscellaneous Balance of Plant	6.9%
Forced Draft Fans	3.3%	Steam Turbine Auxiliaries	1.4%
Induced Draft Fans	17.4%	Circulating Water Pumps	12.2%
SCR	0.3%	Cooling Tower Fans	7.1%
Seal Air Blowers	0.2%	Transformer Loss	3.9%

3.2 Integrated Gasification Combined Cycle Emissions

Emission controls for IGCC systems are described extensively in several of the references included elsewhere in this report. For most of the conceptual design studies, emissions are assumed to be equal to a regulation or otherwise selected standard. Brief summaries of the emission controls are presented in this report, which, as noted, focuses on estimates for typical emission reduction capabilities available with state-of-the-art versions of these controls. The emission estimates reflected below are provided for informational purposes only. Publication of such estimates in this report does not establish the estimates as emissions limitations for any source or require that such estimates be used as emissions limitations in any permit. Emission limitations and permit conditions should be determined by permitting authorities on a case-by-case basis considering applicable EPA and State regulations and the record in each permit proceeding.

Particulates

Solid particulates from the gasifier must be removed prior to downstream cleanup processes and syngas combustion. Solids removal is accomplished with metal filters followed by wet scrubbing. The removal of the solids as dry materials with the upstream filter minimizes dewatering and waste disposal issues. The scrubbers remove ammonia, chlorides, and other trace organic and inorganic components from the synthesis gas. The scrubber reject (blowdown) stream is flashed to a vapor and disposed of in a high temperature furnace. The remaining slurry goes to a solid-liquids separation step before disposal.

Acid Gas Cleanup/Sulfur Recovery

After removal of the particulates, the synthesis gas is further cleaned in preparation for combustion in the gas turbine. Acid gas cleanup processes similar to those widely applied in the petroleum and chemical industries are used for the IGCC plants. Commercial alternatives for IGCC acid gas cleaning are the chemical solvent processes based on amines and physical solvent-based processes. The aqueous methyldiethanolamine (MDEA) is used in this study. The MDEA processes are preceded by carbonyl sulfide (COS) hydrolysis units to convert the COS to H_2S. This allows more total sulfur removal. Selexol™ (dimethylether or polyethylene glycol) and Rectisol™ (cold methanol) are examples of physical solvents. The physical solvent technologies are commonly used in the chemical or petroleum industries when deep sulfur removal is needed for products or downstream processes. In one coal-based application, Rectisol process has removed greater than 99.9% sulfur from syngas[15]. The physical solvents are examined later in the study for use with SCR and NO_X reduction.

For the study, the acid gas removal process uses an amine solvent, MDEA, which chemically reacts with the H_2S and CO_2. The reacted amine is sent to a stripper where heat (steam) is used to separate the gases and regenerate the MDEA for recycle to the cleaning process. Acid gas cleanup processes are commercial and widely used by the petroleum and chemical industries. Sulfur removal and recovery approaches 100%, with 99% removal efficiency assumed for this study. Discussions with the MDEA and acid gas removal suppliers confirm that the level of sulfur removal is very much an economic

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[15] M. Rutkowski, et al., ”The Cost of Mercury Removal in an IGCC Plant,” Gasification Technologies Public Policy Workshop, October 1, 2002, Washington, DC.

tradeoff between the surface area of absorber materials, amine recirculation and stripping rates and sulfur removal. There are many site- and coal- specific factors that will impact the MDEA process details and costs, and detailed engineering is required for the MDEA system to be fully specified. The 99% removal value selected for the study is consistent with inputs from the permit documents (see Appendix B) available from recent IGCC projects as well as with inputs from technology suppliers and serves as a reasonable near-term target for the study.

The acid gas removal system includes a sulfur recovery process where elemental sulfur or sulfuric acid can be made. A decision on the final design configuration for the acid gas removal system for an IGCC plant will be based on whether the byproduct produced is salable and a long-term market for it exists. A sulfur recovery process is selected for this study, which is a two-step process; a Claus process followed by a Shell Claus off-gas treatment (SCOT) tail-gas cleaning. The Claus sulfur recovery unit produces elemental sulfur from the H_2S. The Claus process removes about 98% of the sulfur. The Claus tail-gas is sent to a SCOT process for further sulfur recovery. SCOT is an amine-based process and can remove 99.8% of the sulfur.

Mercury

The details for what happens to the mercury in the coal at a gasification plant are not well understood. The relatively small amounts of the element present in the gas streams are difficult to measure and make tracking the material through the gasification process very difficult. From plant experience[16, 17], it does appear that plants without carbon beds for mercury capture will release 50 to 60 percent of the coal-derived mercury in the flue gas. However, addition of relatively inexpensive carbon bed filters will remove 90 to 95% of the emitted mercury.[18] The Eastman gasification plant in Tennessee uses such controls for their chemical production and reports excellent results.[19]

The Eastman gasification plant feedstock consists of medium- to high-sulfur bituminous coals. Based on this experience, it is assumed that use of the carbon-bed technology on all three study coals would result in 90% mercury removal efficiency. While the Eastman experience validates this assumption for the bituminous coal case, the lack of experience with carbon-bed application on low-rank coals raises the potential for less than 90% mercury removal for such applications.

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[16] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report by: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann, & Massood Ramezan for National Energy Technology Laboratory, U.S. Department of Energy, December 2002.

[17] The Cost of Mercury Removal in an IGCC Plant Final Report Prepared for Department of Energy National Energy Technology Laboratory by Parsons Infrastructure and Technology Group Inc. September 2002.

[18] Personal contact between Nexant and ConocoPhillips, August 15, 05.

[19] Gas Turbine World, Sept – Oct 2005 Volume 35 Number 4; "IGCC Closing the $/kW Cost Gap".

The Federal New Source Performance Standards currently require a mercury limit of 20×10^{-6} lb/MWh for new IGCC plants.[20] Any future changes to this requirement can be seen on the referenced EPA's website.

Turbine Combustion Impacts

While some initial discussions about the environmental impacts from the syngas combustion turbines indicated them to be the same, or similar to those of natural gas-fired turbines, the technical and regulatory communities have largely recognized that the combustion characteristics of syngas and natural gas are different, and require different consideration of control technologies.

Syngas has a different calorific value, gas composition, flammability characteristics, and presence of contaminants than natural gas. The GE Energy and Shell type gasifier plants produce syngas with a heating value from 250 to 400 Btu per standard cubic foot compared to about 1,000 Btu per standard cubic foot for natural gas. The composition of natural gas is primarily methane, and the syngas components are primarily carbon monoxide and hydrogen. The H_2 causes a high flame speed and temperature. The syngas will also contain some low level of sulfur contaminants, which may impact the reliability and effectiveness of post-combustion NO_X control technologies.

A diluent, steam or nitrogen, is used to lower flame temperature and minimize NO_X creation. Nitrogen can be taken from the air separation plant and integrated with the turbine. As a byproduct of the addition of mass to the gas flow, the turbine generating capacity will increase. Section 4 discusses the use of SCR with the syngas turbine to further reduce NO_X, but for the study base IGCC cases, at this time the state-of-the-art control for syngas-fired turbines is the addition of nitrogen that reduces NO_X emission to 15 ppmvd (at 15% oxygen and ISO conditions). GE hopes to develop combustors to achieve less than 10 ppmvd NO_X with syngas.

Non-Criteria and Hazardous Air Pollutants

Depending on the coal characteristics, the non-criteria and inorganic hazardous air pollutants (HAPs) with the most environmental concerns in IGCC systems are the trace metals: arsenic, cadmium, lead, mercury, and selenium. Exhibit 1-3 shows a more complete list of EPA non-criteria pollutants and HAPS. Measurement of HAPS has proven to be difficult with existing instrumentation used for the IGCC system. Computer-based thermodynamic equilibrium studies have been reported that show these metals are volatile and will be hard to control.[21] Less volatile trace metals will likely remain with the ash or be removed by downstream gas cleaning. Mercury, which primarily remains in the vapor-phase, is a special case discussed earlier. Indications are

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[20] Code of Federal Regulations, 40 CFR, Part 60, Subpart Da, http://www.epa.gov/epacfr40/chapt-I.info/chi-toc.htm, accessed 5/2/06.

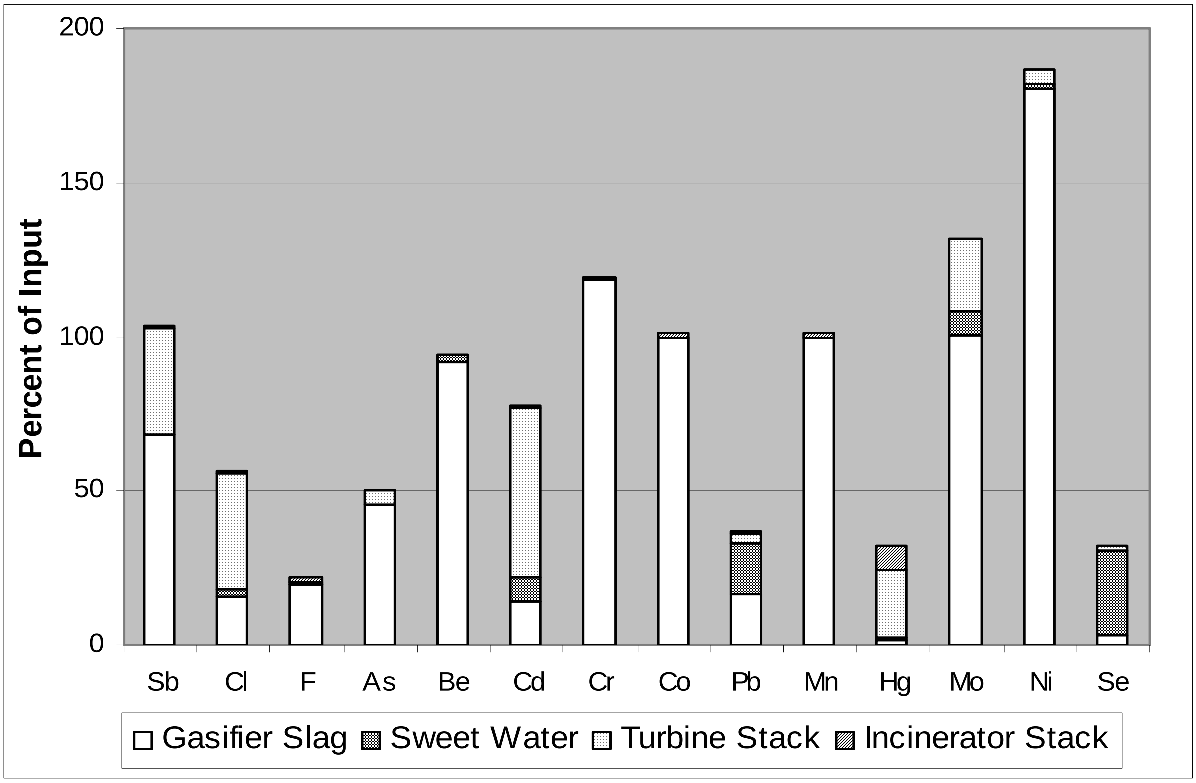
[21] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report by: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann, & Massood Ramezan for National Energy Technology Laboratory, U.S. Department of Energy, December 2002.

that most of the elemental, vapor phase mercury is emitted from the gasification process. However, effective control methods with carbon filters are in commercial use for other applications, and should be available to the IGCC cases at reasonable economic costs. It is estimated that installation of carbon bed filters will reduce mercury by 90 to 95%.

The energy and material balance for HAPS and the measurement of HAP emissions is complex and difficult to forecast accurately until more operating data becomes available. Trace elements can be divided into three classifications depending on volatility and the volatility of their simple compounds, such as oxides, sulfides and chlorides. Class I elements are the least volatile and remain in the ash. Class II elements are more volatile and report to both the ash and the gaseous phases, with condensation of vaporized species on the surface of ash particles as the gas cools. Class III elements are highly volatile. Elements that exit the gasifier as vapor will further separate downstream as condensation occurs. The thermodynamic models indicate that the metals are more volatile under the reducing gasification environment than in oxidizing combustion environments.

Detailed field measurements for trace metals were conducted at the 160 MW Louisiana Gasification Technology Inc. The reported results are shown in Exhibit 3-8.[22]

Exhibit 3-8, IGCC Trace Metal Reporting within the Process



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[22] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report by: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann, & Massood Ramezan for National Energy Technology Laboratory, U.S. Department of Energy, December 2002.

The graph in Exhibit 3-8 shows the partitioning of the trace elements among the major outlet streams – gasifier slag, processed "sweet" water, turbine stack gas, and incinerator stack gas. The report cautions that many of the elements are present at extremely low levels and may partially accumulate within an IGCC process, it is not unusual to obtain material balance closures of less than (or more than) 100%.

Trace element emission factors (lb/10^{12} Btu input basis), calculated for total stack emissions from the Louisiana gasification plant, are presented in Exhibit 3-9, and are from the same DOE/NETL final report.

Exhibit 3-9, Estimates of IGCC Trace Element Emissions

TRACE ELEMENT	**EMISSION FACTOR, lb/10^{12} Btu**	
	Average	**95% Confidence Level***
Antimony	4	4.7
Arsenic	2.1	1.9
Beryllium	0.09	0.03
Cadmium	2.9	3.8
Chloride	740	180
Chromium	2.7	0.63
Cobalt	0.57	0.58
Fluoride	38	22
Lead	2.9	1.5
Manganese	3.1	6.5
Mercury	1.7	0.43
Nickel	3.9	3.6
Selenium	2.9	1.3

* Mean value of the confidence interval in which there is a 95% probability that the value occurs

Trace element stack emissions are a function of their concentrations in the coal. Higher coal concentrations generally result in higher stack emissions, since the reduction levels within controls may stay the same. For the study cases, emission estimates are provided for only a few important trace elements, and these estimates either use a range of emission values or are based on coal concentrations. Exhibit 3-26 and Appendix B present a comparison of trace element limits from air permit documents for recent IGCC and PC plants.

Air Emission and Other Environmental Impact Estimates for IGCC Plants

Exhibits 3-10 and 3-11 present the environmental impact estimates for the two gasifier cases and three coals. The emission values for key air pollutants are provided in lb/MMBtu, lb/MWh, and ppmvd at 15%O_2. Lb/MWh values are based on MW gross.

Exhibit 3-10, IGCC Environmental Impacts, Slurry Feed Gasifier

GE Energy Slurry Feed Gasifier	500 MW Net Capacity Bituminous			500 MW Net Capacity Subbituminous		
Air Pollutants	Ppmvd (@ 15% O_2)	lb/MWh	lb/MMBtu	ppmvd (@ 15% O_2)	lb/MWh	lb/MMBtu
NO_X (NO_2)	15	0.355	0.049	15	0.326	0.044
SO_2	10	0.311	0.043	3	0.089	0.012
CO	15	0.217	0.030	17	0.222	0.030
Volatile Organic Compounds	--	0.012	0.0017		0.013	0.0017
Particulate Matter (overall)	--	0.051	0.007	--	0.052	0.007
Particulate Matter (PM_{10})	With the Overall Particulate Matter			With the Overall Particulate Matter		
Lead (Pb) lb/MMBtu	1.0×10^{-6} to 2.4×10^{-6} (see text below)			1.0×10^{-6} to 2.4×10^{-6} (see text below)		
Mercury		5.50×10^{-6}	0.76×10^{-6}		3.11×10^{-6}	0.42×10^{-6}
Acid Mist		0.030	0.0042		0.004	0.0005
Other Environmental Impacts	Ppmvd (@ 15% O_2)	Lb/MWh	lb/MMBtu	ppmvd (@ 15% O_2)	lb/MWh	lb/MMBtu
CO_2		1,441	199		1,541	208
Solid Waste (gasifier slag)		65	9		45	6
Raw Water Use		4,960	685		5,010	676
Sulfur Production, lb/h	8,679			1,044		
Sulfur Removal	99%			97.5%		
NO_X Removal	To 15 ppmvd			To 15 ppmvd		
Particulates	99.9% or greater. Typical value for IGCC is “negligible” emissions			99.9% or greater. Typical value for IGCC is “negligible” emissions		

Exhibit 3-11, IGCC Environmental Impacts, Solids Feed Gasifier

Shell Solid Feed Gasifier	500 MW Net Capacity Lignite		
Criteria Pollutants	ppmvd @15% O_2	lb/MWh	lb/MMBtu
NO_X (NO_2)	15	0.375	0.050
SO_2	4	0.150	0.020
CO	15	0.225	0.030
Volatile Organic Compounds		0.013	0.0017
Particulate Matter (overall)	--	0.053	0.007
Particulate Matter (PM_{10})	With the Overall Particulate Matter		
Lead (Pb), lb/MMBtu	1.0×10^{-6} to 2.4×10^{-6} (see text below)		
Mercury		5.48×10^{-6}	0.73×10^{-6}
Acid Mist		0.015	0.002
Other Environmental Impacts	ppmvd @15% O_2	lb/MWh	Lb/MMBtu
CO_2		1,584	211
Solid Waste (gasifier slag)		218	29
Raw Water Use		5,270	700
Sulfur Production, lb/h	4,370		
Sulfur Removal	99%		
NO_X Removal	To 15 ppmvd		
Particulates	99.9% or greater. Typical value for IGCC is “negligible” emissions		

The emissions for IGCC units listed above were estimated from energy and material balance calculations and other methods as noted below.

- The emission estimates have generally been based on air permit data (see Appendix B) and discussions with control technology suppliers. Only IGCC plants utilizing bituminous coal are included in the permit data available for this study. Also, only a small amount of operating data is available for IGCC application on low-rank coals.[23]

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[23] H. Frey and E. Rubin, ”Integration of Coal Utilization and Environmental Control in Integrated Gasification Combined Cycle Systems,” Environment Science Technology, Volume 26, No. 10, 1992.

The suppliers have indicated that the performance capabilities of control technologies would remain the same for all three types of study coals. This is based on experience with gasifier applications in the petroleum and chemical industries. Therefore, the emission estimates for subbituminous coal and lignite cases have been based on reduction levels similar to those used for the bituminous coal case. Because of the lack of relevant air permit or operating data for the subbituminous coal and lignite cases, some uncertainty still remains for these two estimates.

- NO_X is controlled by dilution of the gas turbine fuel-air mixture with steam and nitrogen. Utilizing existing technology and design considerations, the achievable concentration is 15 ppmvd at 15% oxygen. This was estimated from a discussion between Nexant and GE and reviews of recent air permit data and literature.

- SO_2 is controlled by the MDEA-based acid gas cleaning system and sulfur production. This system removes 99% of the total sulfur at the IGCC plants using bituminous coal and lignite, which is based on recent air permit data and discussions with MDEA process providers. The subbituminous coal selected for this study has a relatively low sulfur content of 0.22%. The total sulfur removal rate selected for the IGCC plant using this coal is 97.5%, which is based on a sulfur concentration in the syngas of 20 ppm and that in the stack flue gas of 3 ppm[24].

- CO is controlled by good combustion practices and the limit of 0.03 lb/MMBtu is estimated from the review of recent air permit data.

- The overall Particulate Matter, including PM_{10}, is controlled by the particulate removal filters and the acid gas removal wet scrubbing of the synthesis gas. It includes filterable particulate matter only. The removal rate is nearly 100%, which is based on the review of recent air permit data.

- Fine Particulate Matter ($PM_{2.5}$) – no data was found for the fine particulate emissions.

- VOCs are controlled by good combustion practices, i.e., efficient and stable gasification. The emission limit of 0.0017 lb/MMBtu is based on the review of recent air permit data.

- Lead emissions are estimated by review of recent air permit data. This limit is expected to vary significantly with the coal, depending on the coal lead content and as more is learned about its presence in the IGCC systems. From operating experience, it appears that about 5% of the lead in the coal is emitted. The remainder is left with gasifier slag and other parts of the gas cleaning systems.

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[24] Process Screening Analysis Of Alternative Gas Treating And Sulfur Removal For Gasification, Revised Final Report, December 2002, Prepared by SFA Pacific, Inc., U.S. DOE Task Order No. 739656-00100.

- Mercury limits are based on 90% removal within the controls provided specifically for mercury removal and controls for other pollutants. The uncontrolled mercury emission is based on an assumed average mercury content of each coal type, which was taken from a published source.[25] The reported emission will vary with the coal mercury content.

- Acid mist limits are based on air permit data for the bituminous coal case. For the subbituminous coal and lignite cases, the generation and removal rates used are the same as for the bituminous case.

- CO_2 is calculated with the assumption that all the carbon in the coal is converted to CO_2.

- Solid Waste is calculated using the ash content of the coals.

- Water losses are based on the USDOE/NETL report and Nexant performance spreadsheet calculations[26].

- Sulfur production is calculated based on the sulfur content of the coals.

3.3 Pulverized Coal Plant Emissions

The primary PC plant emission control devices are briefly described below. The technologies are commercially available, and are prevalent in many operating plants and in published data. The emission estimates reflected below are provided for informational purposes only. Publication of such estimates in this report does not establish the estimates as emissions limitations for any source or require that such estimates be used as emissions limitations in any permit. Emissions limitations and permit conditions should be determined by permitting authorities on a case-by-case basis considering applicable EPA and state regulations and the record in each permit proceeding.

The two most widely used flue gas desulfurization (FGD) technologies for PC plants are the wet FGD systems and dry FGD systems. In general, the wet FGD system is located downstream of the particulate control device, the flue gas is fully saturated with water, and the SO_2 reaction products are removed in a wet solid waste form. The dry FGD systems are located upstream of the particulate collection device, the flue gas is partially saturated, and the dry SO_2 reaction products are collected along with fly ash in the particulate collection device. Different types of wet and dry FGD systems are available, using different reagents. For this study, a wet limestone flue gas desulfurization (WL-FGD) system utilizing a scrubber with forced oxidation is used for the bituminous coal and lignite cases, and a lime spray dryer absorber (SDA) is used for the subbituminous

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[25] Coal Analysis Results, http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html#DA2, accessed on February 21, 2006.

[26] Power Plant Water Usage and Loss Study, U.S. DOE NETL, August 2005.

case. Most coal-fired power plants equipped with SO_2 controls use these two technologies, described below:

Flue Gas Desulfurization - Low-Sulfur Subbituminous Coal

Lime SDA is generally used to control SO_2 emissions from PC plants firing low-sulfur coal. The systems are located after the air preheaters, and the wastes are collected in a baghouse or fabric filter to achieve high rates of SO_2 removal (an electrostatic precipitator may also be used, in lieu of the fabric filter, but it requires a higher lime injection rate to achieve similar levels of SO_2 removal). The SDA treats the flue gas by injecting atomized lime slurry. The fine droplets absorb SO_2 from the flue gas and the SO_2 reacts with the lime to mostly form calcium sulfite. The cleaned flue gas, the reaction products, any unreacted lime, and the fly ash are all collected in the filters. The waste product contains $CaSO_3$, $CaSO_4$, calcium hydroxide, and ash.

SDA systems are commercial and range in size from less than 10 MW to 500 MW. Applications include commercial units with coal sulfur content as high as 2.0%. These systems are available from a number of vendors including: Alstom Environmental Systems, Babcock & Wilcox (B&W), Babcock Power, Hamon Research Cottrell, Marsulex Environmental Technologies, and Wheelabrator Air Pollution Control.

SDA systems have generally been applied to units which use low sulfur coals, including Powder River Basin and other western coals with inlet SO_2 less than 2.0 lb/MMBtu and low sulfur eastern bituminous coal with inlet SO_2 concentrations as high as 3.0 lb/MMBtu. Babcock & Wilcox installed SDA units at U.S. Operating Services’ 285 MW Chamber Works Unit, which utilizes bituminous coal, in 1993 and achieved 93% removal efficiency. B&W also achieved similar efficiency at Eastman Kodak’s 110 MW boiler #31, which uses bituminous coal. Alstom has achieved 95% removal efficiency at Pacific Gas and Electric Company’s 330 MW Indiantown plant and South Carolina Electric and Gas Company’s 385 MW Cope Unit #1, both installed in 1995.

Unlike WL-FGD absorbers, which must be constructed of expensive corrosion-resistant metals or other materials, SDA systems can be constructed of less expensive carbon steel due to the absence of water-saturated gas. Dry systems are able to efficiently capture SO_3, they efficiently remove oxidized forms of mercury from flue gas, and they consume less energy than wet systems. The SDA process has the other following advantages compared to WL-FGD technology:

- Waste products are in a dry form and can be handled with conventional pneumatic fly ash handling equipment. The waste is suitable for landfill and can be disposed of with fly ash.

- The dry system uses less equipment than does the WL-FGD system.

- Sulfur trioxide (SO_3) in the vapor form is removed efficiently with a SDA and fabric filter. Wet scrubbers capture up to 50% of SO_3 and require additional processing to avoid visible plume from the stack. New plants are likely to install wet ESP systems with the WL-FGD scrubbers to enhance SO_3 control.

- There are no liquid effluents from a dry system. Water used to slurry the lime is evaporated in the SDA process.

The dry process has the following disadvantages when compared to WL-FGD technology.

- For systems larger than about 300 MW, multiple trains of process equipment may be required.

- Lime is a more expensive reagent than the limestone used with the WL-FGD, and reagent utilization is lower for the dry system.

- The SDA waste has a few useful or commercial applications at this time. In some cases, the WL-FGD wastes can be converted to salable gypsum if there is a market.

- For the study, using coal with a sulfur content of only 0.22%, the SDA technology's SO_2 removal efficiency is 87%. If a higher sulfur coal was used, a higher removal rate would be possible.

Wet Limestone Flue Gas Desulfurization – Bituminous and Lignite Coals

WL-FGD technology is the most widely applied SO_2 removal technology for PC boilers. The forced-oxidation version of this technology produces oxidized solid waste (mostly calcium sulfate or gypsum), which is a stable compound that can be readily landfilled or sold for industrial applications, if a market exists. Another version of the WL-FGD technology produces un-oxidized solid waste (mostly calcium sulfite), which is less stable and must be mixed with other compounds, such as portland cement, to make it suitable for landfilling. The current industry trend is to use the forced oxidation system.

The main WL-FGD scrubber vessel is located after the plant's particulate removal system. The cleaned gas is then sent to the stack. The WL-FGD uses limestone or lime as a reagent. The lime is a magnesium enhanced reagent. Cost and economics will dictate the choice of reagents.

The system operation is similar for both reagents. The flue gas is treated in a limestone or lime slurry spray. Designs vary, but commonly the gas flows upward, countercurrent to the spray liquor. The slurry is atomized to fine droplets for uniform gas contact. The droplets absorb SO_2 which reacts with reagent in the slurry. Hydrogen chloride present in the flue gas is also absorbed and neutralized with reagent. Water in the spray droplets evaporates, cooling the gas to its saturated temperature (generally, 120 to 130°F). The desulfurized flue gas passes through mist eliminators to remove entrained droplets before the flue gas is sent to the stack. In some systems the clean flue gas is reheated to avoid acidic condensation in the stack. The choice of a “wet” or “dry” stack is another cost trade-off decision.

For the study, a limestone-based, forced-oxidation WL-FGD system is selected. The system SO_2 removal efficiency with bituminous coal is 98%. Due to lack of specific data, the same SO_2 mass emission rate achieved with bituminous coal is used for lignite.

NO_X Controls

The most widely applied NO_X controls for coal-fired boilers include combustion control and selective catalytic reduction (SCR) technologies. Both technologies can be applied simultaneously to maximize NO_X reduction.

Combustion controls consist of a low-NO_X burner (LNB) and the use of overfire air (OFA). These technologies utilize staged combustion techniques to reduce NO_X formation in the boiler primary combustion zone and a plant may opt to use one or both of these. An LNB limits NO_X formation by controlling the stoichiometric and temperature profiles of the combustion process. This control is achieved by design features that regulate the aerodynamic distribution and mixing of the fuel and air. OFA, also referred to as air staging, is a combustion control technology in which a fraction, 5 to 20%, of the total combustion air is diverted from the burners and injected through ports located downstream of the top burner level. OFA is used in conjunction with operating the burners at a lower-than-normal air-to-fuel ratio, which reduces NO_X formation. The OFA is then added to achieve complete combustion.

SCR is a post-combustion NO_X control technology capable of reductions in excess of 90 percent. Because NO_X reduction methods are commonly a combination of combustion controls (special burners, air and firing operations), it is difficult to specify a percent removal for SCR without a comparable case without SCR. In this report NO_X emission comparisons for the plant will be stated in units of ppmvd – parts per million by volume dry basis. Also, all the NO_X concentration estimates are adjusted to 15% oxygen so the PC and IGCC emissions can be better compared. NO_X reductions are achieved by injecting ammonia (NH_3) into the flue gas, which then goes through a catalyst. The NH_3 and NO_X react at the catalyst, forming nitrogen and water. The technology has been widely used for coal-fired applications for more than 30 years in Japan, Europe, and the United States. It has been applied to large utility and industrial boilers, process heaters, and combined cycle gas turbines. In the SCR process, NH_3 is injected into the flue gas within a temperature range of about 600 to 750 °F, upstream of the catalyst. Subsequently, as the flue gas contacts the SCR catalyst NO_X is chemically reduced when the flue gas contacts the SCR catalyst. The simple reaction is:

$$2NO + 2NH_3 + \tfrac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

Exhibit 2-5 illustrates the location of the SCR in a typical PC boiler system. The catalyst is located between the economizer and the air preheater; this is termed a hot-side SCR and is the most commonly used configuration. Theoretically one mole of NH_3 is required to reduce one mole of NO. It is important to keep the operation close to the theoretical limit because unreacted NH_3, or ammonia slip, will combine with SO_2 and SO_3 present in the flue gas to form ammonium sulfate and bisulfate compounds, which may cause fouling of downstream equipment.

Particulate Controls

Solid particulates are controlled by the installation of electrostatic precipitators (ESP) or fabric filters. Removal rates approach 100% with values of 99.7 to 99.9% used in the study, depending on the coal ash content and based on utilizing fabric filters. A practical system that will measure and monitor total particulates and the fine particulates, especially $PM_{2.5}$ materials, still needs to be developed by the industry.

Air Pollution Control Technology Advancements

There are ongoing activities in the industry that are concentrating on improving the performance of existing air pollution control technologies or developing new technologies. The data reported by the industry show several new technologies that are in various stages of development, with the potential to reduce costs and improve performance of controlling air pollution from coal-fired power plants.[27] Some of these technologies control more than one pollutant within the same system. These technologies were not considered for this study, as they were not considered to be commercial and available in the timeframe relevant to this study.

Non-Criteria and Hazardous Air Pollutants

HAPS from the PC plant operations are controlled by the flue gas desulfurization systems, particulate collection fabric filters and the SCR technology. The recent air permit data show the emission limits that can be achieved for certain HAPs (see Appendix B). The PC units have oxidizing combustion conditions, which help to reduce some of the HAP emissions by converting the metals to oxides that report to the ash materials. Currently, the coal ash wastes are not considered hazardous and can be disposed off in a landfill.

The potential for mercury removal with conventional controls used for criteria pollutants at PC plants was reported as shown in Exhibit 3-12.[28] The data presented in Exhibit 3-12 result in the following observations. The air pollution control technologies used on PC utility boilers exhibit average levels of mercury control that widely range in effectiveness, from 0 to 98 percent. The best levels of control are by emission control systems that use fabric filters. The amount of mercury captured by a control technology is higher for bituminous coal than for either subbituminous coal or lignite. The lower levels

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[27] Multipollutant Emission Control Technology Options for Coal-Fired Power Plants, EPA-600/R-05/034, March 2005.

[28] Control Of Mercury Emissions From Coal-Fired Electric Utility Boilers(Including Update): Original Report Dated 2-2002 and Update Dated 2-18-2005, U.S. EPA Office Of Research and Development, Prepared by National Risk Management Research Laboratory Research Triangle Park, NC 27711.

Exhibit 3-12, Estimates for PC Plant Mercury Removal with Conventional Controls

Post-combustion Control Strategy	Post-combustion Emission Control Device Configuration	Average Mercury Capture by Control Configuration		
		Coal Burned in Pulverized-coal-fired Boiler		
		Bituminous	Subbituminous	Lignite
PM Control Only	CS-ESP	36 %	3%	0 %
	HS-ESP	9 %	6 %	not tested
	FF	90 %	72 %	not tested
	PS	not tested	9 %	not tested
PM Control and Spray Dryer Absorber	SDA+CS-ESP	not tested	35 %	not tested
	SDA+FF	98 %	24 %	0 %
	SDA+FF+SCR	98 %	Not tested	not tested
PM Control and Wet FGD System[(a)]	PS+FGD	12 %	0 %	33%
	CS-ESP+FGD	75 %	29 %	44 %
	HS-ESP+FGD	49 %	29 %	not tested
	FF+FGD	98 %	Not tested	not tested

Notes: (a) Estimated capture across both control devices
CS-ESP = Cold side electrostatic precipitator
HS-ESP = Hot side ESP
FF = Fabric filter
PS = Particulate scrubber
SDA = Spray dryer absorber
SCR = Selective catalytic reduction
FGD= Wet limestone flue gas desulfurization (WL-FGD)

of capture at subbituminous and lignite plants are attributed to low coal chlorine content and low fly ash carbon content and higher relative amounts of elemental mercury, instead of oxidized mercury, in the flue gas.

Plants that only use particulate controls display average mercury emission reductions ranging from 0 to 90 percent, with the highest levels of control achieved by fabric filters. Mercury control at units equipped with SDA plus ESP or fabric filters ranges from 98 percent for bituminous coals to 24 percent for subbituminous coal. The relatively low removal rates for subbituminous and lignite coals are attributed again to the small amounts of oxidized mercury in the flue gas.

Mercury removal in units equipped with wet scrubbers is dependent on the relative amount of oxidized mercury in the inlet flue gas and on the particulate control technology used. Average removal in wet scrubbers ranged from 29 percent for one PC plant with a hot-side ESP and subbituminous coal to 98 percent in a plant with a fabric filter and wet scrubber burning bituminous coal. The high removal in this unit is attributed to increased oxidization of the mercury and its capture in the fabric filter.

In general, mercury removal in PC units with SDA and WL-FGD appears to provide similar levels of control on a percentage reduction basis. However, this observation is based on a small number of short-term tests at a limited number of plants. The subbituminous coals pose a special issue: The coal's mercury exists primarily as elemental mercury, which remains a vapor in the flue gas and mostly passes through FGD and SCR controls.

Unlike the technologies described above, where mercury removal is achieved as a cobenefit with removal of other pollutants, injection of dry sorbent, specifically powdered activated carbon (PAC), has been tested for mercury control at several coal-fired utility plants in the U.S. These tests included short-term, full-scale tests, with the PAC injected into the ductwork upstream of a particulate control device, such as an ESP or fabric filter. Other short- and long-term tests are planned for the future. Results from certain major tests using optimal PAC injection rates are summarized below:[29]

- Two PC boiler plants firing low-sulfur, bituminous coals: PAC injected upstream of CS-ESPs captured approximately 94 percent mercury.

- PC boiler plant equipped with a HS-ESP and firing low-sulfur, bituminous coals: PAC injected upstream of a small fabric filter (compact hybrid particle collector or COPHAC) captured greater than 90 percent mercury.

- PC boiler plant firing high-sulfur, bituminous coals: PAC injected upstream of a CS-ESP captured 73 percent mercury.

- PC boiler plant firing a subbituminous coals: PAC injected upstream of a CS-ESP captured 65 percent mercury.

The above data show that mercury removal was higher with PAC injection for low-sulfur bituminous coals than for subbituminous or high-sulfur bituminous coals. It is believed that higher amounts of chlorine present in bituminous coals promote oxidation of elemental mercury, thus facilitating its removal by PAC. Also, higher SO_3 content of high-sulfur coal flue gas may interfere with the capture of mercury by PAC.

In addition to the above tests with conventional PAC, other short-term tests have also been conducted using enhanced or halogenated PAC. The results from these tests show more encouraging results, especially for low-rank coals, as explained below.[29]

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[29] Control Of Mercury Emissions From Coal-Fired Electric Utility Boilers(Including Update): Original Report Dated 2-2002 and Update Dated 2-18-2005, U.S. EPA Office Of Research and Development, Prepared by National Risk Management Research Laboratory Research Triangle Park, NC 27711.

- PC boiler plants firing subbituminous or blended subbituminous coals: halogenated PAC injected upstream of CS-ESPs captured 80 to 94 percent mercury.

- PC boiler plant equipped with SDA and firing subbituminous coals: halogenated PAC injected upstream of a fabric filter captured 93 percent mercury.

- PC boiler plant firing high-sulfur bituminous coals: halogenated PAC injected upstream of a CS-ESP captured 70 percent mercury.

- PC boiler plant firing low-sulfur bituminous coals: halogenated PAC injected upstream of a HS-ESP captured greater than 80 percent mercury.

- PC boiler plant equipped with SDA and firing lignite: halogenated PAC injected upstream of a fabric filter captured 95 percent mercury.

Based on the above data, the following controls and mercury reduction levels were assumed for this study (since the data are based on short-term test results, uncertainties exist with the assumed reduction levels, and it is recognized that these levels may not be attainable for all new PC plants in the time frame selected for the study):

- With bituminous coal cases, where WL-FGD, SCR, fabric filter, and wet ESP are used, mercury removal is 90%.

- For subbituminous and lignite coals, the conventional controls reduce mercury by 70%. Activated carbon injection is added to achieve an overall 90% reduction.

The Federal NSPS require the following mercury emission limits for new PC plants (see EPA website for specific requirements or any future changes to these requirements):[30]

- For PC plants firing bituminous coals: 20×10^{-6} lb/MWh
- For PC plants firing sub-bituminous coals in county-level geographical areas with greater than 25 inches/year mean annual rain: 66×10^{-6} lb/MWh
- For PC plants firing sub-bituminous coals in county-level geographical areas with less than or equal to 25 inches/year mean annual rain: 97×10^{-6} lb/MWh
- For PC plants firing lignite: 175×10^{-6} lb/MWh

Air Emission and Other Effluent Estimates for PC Plants

Exhibits 3-13, 3-14, and 3-15 list the environmental impact estimates for PC plants and the three coals. The emission values for key air pollutants are provided in lb/MMBtu, lb/MWh, and ppmvd at 15%O_2. Lb/MWh values are based on MW gross. Following the exhibits, there is a brief discussion of how the emission values were obtained.

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[30] Code of Federal Regulations, 40 CFR, Part 60, Subpart Da, http://www.epa.gov/epacfr40/chapt-I.info/chi-toc.htm, accessed 7/6/06.

Exhibit 3-13, Subcritical Pulverized Coal Plant Environmental Impacts

Subcritical PC	Bituminous			Subbituminous			Lignite		
Air Pollutants	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu	Ppmvd @15% O_2	lb/MWh	lb/MMBtu
NO_X (NO_2) [1]	14	0.528	0.06	15	0.543	0.06	20	0.568	0.06
SO_2 [1]	15	0.757	0.086	11	0.589	0.065	10	0.814	0.086
CO [2]	39	0.880	0.10	40	0.906	0.10	55	0.947	0.10
Volatile Organic Compounds[2]		0.021	0.0024		0.025	0.0027		0.026	0.0027
Particulate Matter (overall) [1]		0.106	0.012		0.109	0.012		0.114	0.012
Particulate Matter (PM_{10}) [1]		0.106	0.012		0.109	0.012		0.114	0.012
Lead (Pb) [2]		$3.40x10^{-5}$ to $18x10^{-5}$	$3.86.x10^{-6}$ to $20x10^{-6}$		$18.1x10^{-5}$ to $23x0^{-5}$	$20x10^{-6}$ to $25.6x10^{-6}$		$18.9x10^{-5}$ to $24x10^{-5}$	$20x10^{-6}$ to $25.6x10^{-6}$
Mercury		$6.69x10^{-6}$	$0.76x10^{-6}$		$3.80x10^{-6}$	$0.42x10^{-6}$		$6.9x10^{-6}$	$0.73x10^{-6}$
Acid Mist		0.088	0.010		0.018	0.002		0.038	0.004
Other Environmental Impacts		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu
CO_2[1]		1,777	202		1,893	209		1,998	211
Solid Waste (ash/FGD waste)		176	20		73	8		331	35
Raw Water Use		9,260	1,050		9,520	1,050		9,960	1,050
Sulfur Removal, %	98			87			95.8		
Particulates, Removal, %	99.8			99.7			99.9		

1. Calculated based on air permit data, discussions with equipment suppliers, literature, and process model software.
2. Estimated from review of air permit data.

Exhibit 3-14, Supercritical Pulverized Coal Plant Environmental Impacts

Supercritical PC	Bituminous			Subbituminous			Lignite		
Criteria Pollutants	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu
NO_X (NO_2) [1]	14	0.494	0.06	15	0.500	0.06	14	0.524	0.06
SO_2 [1]	15	0.709	0.086	11	0.541	0.065	7	0.751	0.086
CO [2]	39	0.824	0.10	40	0.832	0.10	39	0.873	0.10
Volatile Organic Compounds[2]		0.020	0.0024		0.023	0.0027		0.024	0.0027
Particulate Matter (overall) [1]		0.099	0.012		0.100	0.012		0.105	0.012
Particulate Matter (PM_{10}) [1]		0.099	0.012		0.100	0.012		0.105	0.012
Lead (Pb) [2]		$3.18x10^{-5}$ to $17x10^{-5}$	$3.86.x10^{-6}$ to $20x10^{-6}$		$16.6x10^{-5}$ to $21x10^{-5}$	$20x10^{-6}$ to $25.6x10^{-6}$		$17.5x10^{-5}$ to $22x10^{-5}$	$20x10^{-6}$ to $25.6x10^{-6}$
Mercury		$6.26x10^{-6}$	$0.76x10^{-6}$		$3.49x10^{-6}$	$0.42x10^{-6}$		$6.37x10^{-6}$	$0.73x10^{-6}$
Acid Mist		0.082	0.010		0.017	0.002		0.035	0.004
Other Environmental Impacts		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu
CO_2[1]		1,665	202		1,739	209		1,842	211
Solid Waste (ash/FGD wastes)		165	20		67	8		306	35
Raw Water Use		8,640	1,050		8,830	1,060		9,200	1,055
Sulfur Removal, %	98			87			95.8		
Particulates Removal, %	99.8			99.7			99.9		

1. Calculated based on air permit data, discussions with equipment suppliers, literature, and process model software.
2. Estimated from review of air permit data.

Exhibit 3-15, Ultra Supercritical Pulverized Coal Plant Environmental Impacts

Ultra Supercritical PC	Bituminous			Subbituminous			Lignite		
Criteria Pollutants	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu
NO_X (NO_2) [1]	14	0.442	0.06	15	0.450	0.06	14	0.498	0.06
SO_2 [1]	15	0.634	0.086	11	0.488	0.065	7	0.714	0.086
CO [2]	39	0.737	0.10	40	0.750	0.10	39	0.830	0.10
Volatile Organic Compounds[2]		0.018	0.0024		0.020	0.0027		0.022	0.0027
Particulate Matter (overall) [1]		0.088	0.012		0.090	0.012		0.100	0.012
Particulate Matter (PM_{10}) [1]		0.088	0.012		0.090	0.012		0.100	0.012
Lead (Pb) [2]		$2.84x10^{-5}$ to $15x10^{-5}$	$3.86.x10^{-6}$ to $20x10^{-6}$		$15.0x10^{-5}$ to $19x10^{-5}$	$20x10^{-6}$ to $25.6x10^{-6}$		$16.6x10^{-5}$ to $21x10^{-5}$	$20x10^{-6}$ to $25.6x10^{-6}$
Mercury		$5.60x10^{-6}$	$0.76x10^{-6}$		$3.15x10^{-6}$	$0.42x10^{-6}$		$6.06x10^{-6}$	$0.73x10^{-6}$
Acid Mist		0.074	0.010		0.015	0.002		0.033	0.004
Other Environmental Impacts		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu
CO_2[1]		1,488	202		1,568	209		1752	211
Solid Waste (ash/FGD wastes)		155	21		60	8		291	35
Raw Water Use		7,730	1,050		7,870	1,050		8,710	1,050
Sulfur Removal, %	98			87			95.8		
Particulates removal, %	99.8			99.7			99.9		

1. Calculated based on air permits, discussions with equipment suppliers, literature, and process model software.
2. Estimated from review of air permit data.

The emissions from the PC units listed above were estimated from energy and material balance calculations and other methods as noted below.

- The emission limits for various pollutants have generally been based on air permit data (see Appendix B) and discussions with control technology suppliers.

- NO_X is reduced through use of combustion controls and SCR. The emission rate is estimated at 0.06 lb per MMBtu for all the plants. These estimates use air permit data, data from contacts with SCR suppliers, and data available from literature[31].

- SO_2 is controlled by a WL-FGD for the bituminous coal and lignite. The estimated removal rates are 98 and 95.8% for bituminous coal and lignite, respectively. The subbituminous coal plants use lime SDA technology and the removal efficiency is 87%. The SO_2 removal rates selected for both technologies are from air permit data, vendor contacts, and the literature[32, 33]. The SDA system treats flue gases originating from a coal with a sulfur content of only 0.22%. Based on the air permit data (see Appendix B), a controlled SO_2 emission rate of 0.065 lb/MMBtu was selected for this system, which results in the relatively low removal efficiency of 87%. With higher coal sulfur content, higher removal efficiencies can be expected from the SDA system of the type used in this study. Due to lack of recent data, the SO_2 mass emission rate with lignite firing is assumed to be the same as for bituminous coal.

- CO emissions are controlled by good combustion practices and estimated by reviews of the air permit data.

- The overall particulate matter and PM_{10} removal rates approach 100% and removal rates of 99.7 to 99.9% are used in this study, depending on the coal ash content and based on utilizing fabric filters. These removal rates are from air permit data and discussions with filter providers. The emissions rates include filterable particulate matter only.

- Fine Particulate Matter ($PM_{2.5}$) - no data was found for the fine particulate emissions.

- VOCs are controlled by good combustion practices, i.e. efficient and stable combustion. The limits listed in the exhibit are from recent air permit data.

- Lead is estimated by review of recent air permit data. It is expected to vary significantly based on site and fuel specifics, especially the coal lead content.

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[31] M. Oliva, et al., "Performance Analysis Of SCR Installations On Coal-Fired Boilers," Pittsburgh Coal Conference, September 2005, Pittsburgh, PA.

[32] Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000 Prepared for National Lime Association by Sargent & Lundy, January 2003.

[33] Dry Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000 Prepared for National Lime Association by Sargent & Lundy, September 2002.

- Mercury limits are based on 90% removal within the controls provided specifically for mercury removal and controls for other pollutants. The uncontrolled mercury emissions are based on an assumed average mercury content of each coal type, which was taken from a published source.[34] The reported emissions will vary with the coal mercury contents.

- Acid mist limits are based on 95% removal within the combined WL-FGD and wet ESP systems and 90% removal in the lime SDA system.

- CO_2 emissions are calculated, and it is assumed that all the carbon in the coal is converted to CO_2.

- Solid waste is calculated using the ash content of the coals and the FGD gypsum or lime wastes.

- Water losses are calculated based on the USDOE/NETL report and Nexant's performance software.[35]

3.4 Air Permit Data

Air permit data for the following facilities were examined. Information about a diversity of technologies and coals was sought.

1. Elm Road, Wisconsin: Two 615 MW Supercritical Pulverized Coal (PC) Units
2. Comanche Generating Station Unit 3, Colorado: One 7,421 MMBtu/hr Supercritical PC Unit
3. Longview Power, LLC, West Virginia: One 600 MW Subcritical PC Unit
4. Prairie State Generating Station, Illinois: Two 750 MW Subcritical PC Units
5. Intermountain Power Generating Station Unit 3, Utah: One 900 MW Subcritical PC Unit
6. Indeck-Elwood Energy Center, Illinois: Two 330 MW Circulating Fluidized Bed (CFB) Boiler Units
7. Plum Point Energy Station, Arkansas: One 550-800 MW PC Unit
8. Thoroughbred Generating Station, Kentucky: Two 750 MW PC Units
9. TS Power Plant, Nevada: One 200 MW PC Unit
10. Santee Cooper Cross Generating Station Units 3 and 4, South Carolina: Two 5,700 MMBtu/hr PC Units
11. Holocomb Unit 2, Kansas: One 660 MW PC Unit
12. Limestone Electric Generating Station Units 1 and 2, Texas: Two 7,863 MMBtu/hr PC Units

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[34] Coal Analysis Results, http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html#DA2, accessed on February 21, 2006.

[35] Power Plant Water Usage and Loss Study, U.S. DOE NETL, August 2005.

13. Elm Road, Wisconsin: One 600 MW IGCC Unit
14. Kentucky Pioneer Energy Facility, Kentucky: One 540 MW IGCC Unit
15. Polk Power Station, Florida: One 260 MW IGCC Unit
16. Southern Illinois Clean Energy Center, Illinois: One 544 MW IGCC Unit
17. Cash Creek, Kentucky: One 677 MW IGCC Unit

Appendix B provides a detailed list of data from the permit documents for the above-listed facilities on air emission limits for the criteria and non-criteria pollutants. It also lists these permit documents. The following sections summarize these data.

3.4.1 Criteria Pollutants

Exhibit 3-16 summarizes the data from the permit documents on criteria pollutants. The data point column shows the number of plants for that type of plant and fuel which were reviewed. Data points in the third and last rows document how many of the pollutants were regulated in the permits. For example, all five PC unit permits had data for NO_X, SO_2, CO and overall particulates; only four permits provided PM_{10} data, and none specified $PM_{2.5}$ limits.

Exhibit 3-16, Air Permit Data and Estimates for Criteria Pollutants
Pounds per Million Btu (except lead)

Data Points	Fuel (some plants may use more than one, or blend)	Nitrogen Oxides (NO_X)	Sulfur Dioxide (SO_2)	Carbon Monoxide (CO)	Particulate Matter (overall)	Particulate Matter (PM_{10})	Fine Particulate Matter ($PM_{2.5}$)	Lead (Pb) lb/10^{12} Btu
6	PC Units Bituminous Coal	0.07 to 0.08	0.1 to 0.182 (95 to 98% reduction)	0.1 to 0.16	0.012 to 0.018	0.018	No Data	3.86 to 20
5	PC Units Subbituminous Coal	0.067 to 0.09	0.065 to 0.12 (one unit with 94% reduction)	0.13 to 0.16	0.012 to 0.020	0.012 to 0.020	No Data	20 to 25.6
1	PC Units Lignite	0.5	0.82	0.11	0.03	No Data	No Data	33
12	Data Points All Pulverized Coal Units	12	12	12	10	9	0	9
1	High Sulfur Bituminous Coal CFB Unit	0.10	0.15	0.10	0.015	No Data	No Data	No Data

Exhibit 3-16, Air Permit Data and Estimates for Criteria Pollutants
Pounds per Million Btu (except lead), Cont'd

Data Points	Fuel (some plants may use more than one, or blend)	Nitrogen Oxides (NO_X)	Sulfur Dioxide (SO_2)	Carbon Monoxide (CO)	Particulate Matter (overall)	Particulate Matter (PM_{10})	Fine Particulate Matter ($PM_{2.5}$)	Lead (Pb) lb/10^{12} Btu
5	IGCC Units Bituminous Coal	0.055 to 0.10 (15 to 25 ppmvd@ 15% O_2)	0.03 to 0.17 (97 to 99.36% reduction)	0.03 to 0.046	0.007 to 0.011	0.007 to 0.011	No Data	1.0 to 25.7
5	Data Points IGCC Units	5	5	5	5	5	0	4

3.4.2 Non-Criteria Pollutants

Much less data was found in the literature to help estimate the environmental impacts of non-criteria pollutants. Data from recent power plant air permits were selected as a primary source of data. While permit limits can vary across States and may depend upon site- and fuel-specific considerations, relatively consistent values were found in the air permit data. The results are summarized in Exhibit 3-26 at the end of Section 3.

3.5 Emission and Air Pollution Control Data from the Literature

A reference list is included at the end of the report. Several of the most recent and useful documents are discussed here. Exhibit 3-17 is a helpful summary from a December 2002 U.S. DOE/NETL report. While the technologies are still developing and changing, the information is a good summation of IGCC and PC plant environmental impacts.

Exhibit 3-17 Summary of IGCC and PC Environmental Controls[36]

	Integrated Gasification Combined Cycle	Pulverized Coal Power Plant
Sulfur Control and Sulfur Byproducts	Greater than 98% sulfur control. H_2S and COS are removed from the syngas in an amine-based scrubber prior to combustion and recovered as elemental sulfur or sulfuric acid. Both are salable industrial commodities.	Up to 98% sulfur control. SO_2 is usually removed in a flue gas desulfurization process, such as a wet limestone scrubber. Advanced limestone FGD scrubbers typically produce a gypsum byproduct. Gypsum can be safely landfilled or sold for production of wallboard or utilized for other purposes.

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[36] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report by: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann, & Massood Ramezan for National Energy Technology Laboratory, U.S. Department of Energy, December 2002.

Exhibit 3-17 Summary of IGCC and PC Environmental Controls, Cont'd

Nitrogen Oxides Control	Fuel nitrogen mainly converted to N_2 and small amount of NH_3 and HCN, with the latter removed via syngas cleaning. Diluents, such as nitrogen and steam, are used in the gas turbine to lower the combustion flame temperature to minimize NO_X generation. Use of add-on control technologies, such as SCR, at this time has not been demonstrated for coal-based syngas-fired turbines.	Fuel nitrogen converted to NO_X. Low-NO_X burners are used to minimize conversion to NO_X. The NO_X formed may be removed with additional control technology, such as SCR. SCR unit can be installed between economizer and air heater. NH_3 preferentially adsorbs onto fly ash. Sulfates and bisulfates captured in particulate control equipment downstream of SCR.
Particulate Control	Virtually all particulate is removed. Fly ash entrained with syngas is removed downstream in wet scrubber. No acid mist problem.	Very high levels of particulate control. Fly ash is efficiently collected in a control device, such as an ESP or fabric filter. Acid mist may be a problem from FGD unit. A wet ESP can be installed downstream of the FGD to remove acid mist.
Trace Substance Control (metals and organics)	Most semi-volatile and volatile trace metals condensed and removed in syngas cleaning equipment. Elemental mercury emissions may exit with flue gas. Other metals exit with wastewater blowdown and wastewater treatment material. Trace organic emissions are extremely low. Activated carbon beds have been commercially demonstrated to remove more than 90% of syngas mercury.	Most semi-volatile and volatile trace metals condense on fly ash particles and are effectively removed with fly ash. Elemental mercury emissions may exit with flue gas. Other elements exit with ash and FGD byproduct. Trace organic emissions are extremely low. Hg emissions may depend on coal type and presence of FGD. system. Activated carbon injection upstream of a fabric filter can be added to remove 90% of mercury.
Solid Waste Disposal/ Utilization	Slag material is environmentally benign and can be safely landfilled. Slag can also be safely utilized for various applications, such as drainage material or roofing granules. Similar to material produced by wet-bottom PC plants.	Bottom ash and fly ash can be safely landfilled. Leaching of trace metals adsorbed by fly ash is more likely than with slag material. Ash can be utilized for a variety of applications, such as cement/concrete production and waste stabilization or solidification.
Carbon Dioxide Control Potential	Higher thermodynamic efficiency of IGCC cycle minimizes CO_2 emissions relative to other technologies. High pressure and high CO_2 concentration in synfuel provides optimum conditions for CO_2 removal prior to combustion, if required.	Generally higher CO_2 emissions than IGCC due to lower cycle efficiency. CO_2 removal from flue gas more technically challenging and more expensive than IGCC, based on existing technology.

Exhibit 3-18 compares IGCC and PC plant emission projections from various literature sources.

Exhibit 3-18, Emission Data from the Literature

Pollutant	IGCC Plant[37]	PC Plant[38]	EPRI Report PC and IGCC Plants[39]	Generic IGCC Plant[40]
SO_2	0.08 lb/MMBtu 0.7 lb/MWh	0.3 lb/MMBtu	99.5% removal	0.08 lb/MMBtu
NO_X (as NO_2))	0.09 lb/MMBtu 0.8 lb/MWh	0.09 lb/MMBtu	15 to 20 ppmvd	0.06 lb/MMBtu
PM_{10}, Particulate and Sulfuric Acid Mist	<0.015 lb/MMBtu <0.14 lb/MWh	0.03 lb/MMBtu	0.004 lb/MMBtu or less	0.006 lb/MMBtu
CO_2		2.0 lb/kWh		1.76 – 1.6 lb/kWh
Hg		80 – 90% removal		90 – 95% removal

3.6 PC Solid Wastes and Liquid Effluents

Estimates of solid wastes are summarized in Exhibit 3-19 for the PC plants and coals. Estimated values are shown in terms of pounds per hour and per million Btu of coal input. Estimates for the coal-ash wastes are relatively clear and leave little uncertainty; except for adjustments for unburned carbon and the small amounts of ash that are not captured, coal ash wastes are approximately "coal ash in = coal ash out".

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[37] R. Brown, et al., "An Environmental Assessment of IGCC Power Systems," 19th Annual Pittsburgh Coal Conference, September 2002.

[38] D. Radcliffe, "IGCC- An Important Part of Our Future Generation Mix," Workshop on Gasification Technologies, Knoxville, TN, April 12, 2005.

[39] Pulverized Coal And IGCC Plant Cost And Performance Estimates, George Booras & Neville Holt EPRI, Gasification Technologies 2004, Washington, DC, October 3-6, 2004.

[40] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report by: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann, & Massood Ramezan for National Energy Technology Laboratory, U.S. Department of Energy, December 2002.

Exhibit 3-19, PC Plant Solid Waste Estimate

PC Technology 500 MW Net	Subcritical Boiler			Supercritical Boiler			Ultra Supercritical Boiler		
Study Coal	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite
Sulfur Control	WL-FGD	SDA+ Filter	WL-FGD	WL-FGD	SDA+ Filter	WL-FGD	WL-FGD	SDA+ Filter	WL-FGD
UNITS	lbs/hr dry	lbs/hr dry	lbs/hr dry	lbs/hr dry	lbs/hr dry	lbs/hr dry	lbs/hr dry	lbs/hr dry	lbs/hr dry
Total Coal Ash	40,674	25,168	146,537	38,104	23,370	135,155	34,252	20,802	129,465
Bottom Ash	8,427	5,421	29,738	7,894	5,034	27,428	7,096	4,481	26,273
Fly Ash (with unburned carbon)	33,707	With SDA Filter Waste	118,461	31,132	With SDA Filter Waste	109,260	27,985	With SDA Filter Waste	104,660
Desulfurization Products -dry basis	54,086	34,656	30,741	51,802	32,181	29,432	49,395	28,644	28,066
Total Solid Waste	96,220	40,077	178,940	90,828	37,215	166,120	84,476	33,125	158,999
UNITS	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	Lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu
Total Coal Ash	8.6	5.1	28.5	8.6	5.1	28.5	8.6	5.1	28.5
Bottom Ash	1.8	1.1	5.8	1.8	1.1	5.8	1.8	1.1	5.8
Fly Ash (with unburned carbon)	7.1	With SDA Filter Waste	23.0	7.0	With SDA Filter Waste	23.0	7.0	With SDA Filter Waste	23.0
Desulfurization Products -dry basis	11.4	7.1	6.0	11.6	7.1	6.2	12.3	7.1	6.2
Total Solid Waste	20.3	8.2	34.7	20.4	8.2	35.0	21.1	8.2	34.9

Waste estimates from the two sulfur removal processes are more uncertain and dependent on the amounts of limestone or lime used to capture the sulfur, and other engineering factors. The estimates here are calculated by Nexant's PC plant process model.

The solid wastes generated from PC plants have several industrial uses, including gypsum wallboard, cement additive, concrete admixture, flowable fill material, autoclaved aerated concrete blocks, waste stabilization, roadway/runway construction, mine reclamation, and agriculture applications. The salability of each of the four different types of PC solid wastes, including fly ash, bottom ash, gypsum from the wet FGD system, and waste from the dry FGD system, generally depends on whether a market exists for its use near the plant. If any of these wastes cannot be sold, they would typically be disposed off in an on-site or off-site landfill.

Experience from existing coal-fired plant operations in the U.S. shows that some of these plants are able to sell their solid waste products for industrial use, especially fly ash and FGD gypsum[41]. The reported data show that while 20 percent of these plants sold fly ash, only 16 percent were able to sell bottom ash. Similarly, 26 percent of the 268 units equipped with wet FGD systems sold their gypsum, while only 5 percent of the 234 units equipped with dry FGD systems were able sell their FGD wastes. For the purpose of this study, no credit has been taken for the sale of any solid wastes, since the data show the majority of the plants disposing of their wastes in landfills.

There are several on-going programs in the industry to encourage use of coal combustion and FGD products. As an example, government organizations, such as EPA and DOE, have formed partnerships with other government and industry stakeholders to increase the amount of coal byproduct utilization.[42] A future increase in the use of solid wastes generated from the PC plants can be expected. Such an increase would result in a reduction of the solid waste volumes required to be landfilled.

A report from DOE examines in relative detail the water usage and losses at PC and IGCC plants.[43] The DOE report is used here as the basis for water balance assessments. It is noted however that water balances vary significantly because of raw water quality and design criteria, such as the number of cycles for the cooling tower water to be circulated. The number of cooling water cycles may vary from 2 to 6 cycles, which by itself can strongly impact the amounts of makeup water required. The DOE report assumes 3 cycles for PC and IGCC cooling water systems and thus provides a consistent source of data for comparison.

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[41] EIA website, EIA-767 Data Files for 2004, http://www.eia.doe.gov/cneaf/electricity/page/eia767.html, accessed January 27, 2006.

[42] U.S. EPA Coal Combustion Products Partnership, www.epa.gov/epaoswer/osw/conserve/c2p2/index.htm, accessed February 14, 2006.

[43] Power Plant Water Usage and Loss Study, U.S. DOE NETL, August 2005.

The DOE water study is for nominal 500 MW PC and IGCC plants. This study examines GE Energy, ConocoPhillips and Shell gasification, and subcritical and supercritical PC plants. A high sulfur bituminous coal (Pittsburgh #8 seam) is used for all the plants. The study does not examine an ultra-supercritical technology plant.

For reference, the subcritical and supercritical plant water balance estimates are presented (with rounding) from the DOE study in Exhibit 3-20.

Exhibit 3-20, Summary of PC Plant Water Balances
U.S. DOE/NETL Study Results

	Subcritical PC	Supercritical PC
Plant Gross Output, MW	554	550
Plant Net Heat Rate (HHV), Btu/kWh	9,638	8,564
Water Source	Flowrate, Gallon per Minute	
Coal Moisture	48	43
Conversion of Coal Hydrogen	326	288
Combustion Air Moisture	63	57
Air to WLFGD	0.4	0.3
Raw Water Use	10,146	8,990
TOTAL	10,584	9,378
Water Loss		
Flue Gas Exhaust	928	818
Water with FGD Gypsum	81	71
Cooling Tower Evaporation	6,415	5,688
Cooling Tower Blowdown	3,160	2,801
TOTAL	10,584	9,378

The water balance estimates for the present study PC plants and coals are shown in Exhibit 3-21. In these estimate, the cooling tower losses from evaporation and blowdown are by far the largest. Evaporative losses basically correspond to the size of the steam generation system, and blowdown is required periodically to limit the buildup of solids and other contaminants in the water system. Blowdowns from all the other parts of the plant, being relatively uncontaminated, are used as part of the cooling water makeup. Notes on the estimating procedures used with Exhibit 3-21 are listed below.

- Coal Moisture is calculated from the properties of each study coal.

- Conversions of Coal Hydrogen, Combustion Air Moisture, and Air to WL-FGD are calculated using the heat rate and gross output adjustment factors of the U.S. DOE study and the present study to estimate water flowrates.

Exhibit 3-21, Estimated Water Balances for PC Plants and Coals
Gallon per Minute

PC Technology 500 MW Net	Subcritical Boiler			Supercritical Boiler			Ultra Supercritical Boiler		
Study Coal	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite
Plant Gross Output, MW	540	541	544	540	541	544	543	543	546
Plant Net Heat Rate (HHV), Btu/kWh	9,500	9,800	10,300	8,900	9,000	9,500	8,000	8,146	9,065
Water Source									
Coal Moisture	94	318	531	88	295	490	79	263	469
Conversion of Coal Hydrogen	313	324	342	294	298	316	266	271	303
Combustion Air Moisture	61	63	66	58	59	63	53	54	60
Air to WLFGD	0.4	-	0.4	0.3	-	0.3	0.3	-	0.3
Raw Water Use	9,701	9,772	10,168	9,129	9,015	9,421	8,251	8,196	9,023
TOTAL	10,169	10,477	11,107	9,569	9,667	10,290	8,649	8,784	9,855
Water Loss									
Flue Gas Exhaust	892	922	974	835	846	898	754	768	860
Water with FGD Gypsum	78	-	85	72	-	78	66	-	75
Spray Dry Absorption Evaporation		48			46			44	
Cooling Tower Evaporation	6,163	6,369	6,732	5,804	5,880	6,241	5,246	5,342	5,977
Cooling Tower Blowdown	3,036	3,138	3,316	2,858	2,895	3,073	2,583	2,630	2,943
TOTAL	10,169	10,477	11,107	9,569	9,667	10,290	8,649	8,784	9,855

- Flue Gas Exhaust, Water with FGD Gypsum, Cooling Tower Evaporation, and Cooling Tower Blowdown are similarly calculated by the heat rate and gross output relationships.

- Spray Dry Absorption Evaporation is estimated from the process material balance sheets for the subbituminous coal cases.

- Raw Water is calculated as the difference between the total of water sources and the total of water losses in the items above.

The final PC plant blowdown/waste stream is typically sent to a pond or other evaporation system or is discharged to an outside source, after proper treatment. After evaporation, the remaining solid materials are secured in place or may be disposed off in other ways. Some of the water may be used for dust control or other plant operations, depending on the water quality.

3.7 IGCC Solid Wastes and Liquid Effluents

Exhibit 3-22 shows estimates of the IGCC plant solid wastes. The wastes are estimated by calculations in Nexant's gasification model. The gasifier slag consists of the coal ash, unburned carbon or char left with the ash. The sulfur product may or may not be a waste depending on the plant's ability to market and sell the sulfur. The gasifier slag can also be sold for industrial use, such as to cement industry. However, it is shown as a waste product in Exhibit 3-22.

Exhibit 3-22, IGCC and Supercritical PC Solid Wastes

Gasification Technology	Slurry Fed Gasifier	Slurry Fed Gasifier	Dry Fed Gasifier	Supercritical PC Total Solid Waste		
Study Coal	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite
Unit Rating MW Net	500	500	500			
Gross Generation MW	564	575	580			
Net Efficiency %	41.8	40	39.2			
UNITS	lbs/hr, dry	lbs/hr, dry	lbs/hr, dry	lbs/hr, dry	lbs/hr, dry	lbs/hr, dry
Gasifier Slag	36,054	25,185	124,099	96,220	40,077	178,940
Sulfur Product	8,679	1,044	4,370			
UNITS	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu
Gasifier Slag	8.8	5.9	28.5	20.3	8.2	34.7
Sulfur Product	2.1	0.2	1.0			

The three columns on the right show the supercritical PC plant total waste estimates. In comparison with the supercritical PC plants, the gasifier slag is approximately 40%, 60% and 80% by weight of the total solid PC wastes for bituminous, subbituminous and lignite coals respectively. However, it should be noted that this difference in the solid waste volumes would be reduced or eliminated, if the plants are able to sell some or most of their wastes for industrial use.

Consistent with the PC plants, the water balance is estimated for IGCC plants using the DOE report as the basis.[44] Exhibit 3-23 presents the results for two gasifiers from the DOE report. The results are rounded, and in the GE Energy case the DOE totals did not match. The GE Energy DOE case is for the radiant-convective gasifier option. The alternative GE quench technology is a less efficient, lower cost version of the technology, which was not used.

Exhibit 3-23, Summary of IGCC Plant Water Balances
U.S. DOE/NETL Study Results

	GE Energy	Shell
Plant Gross Output, MW	673.85	633.54
Plant Heat Rate (HHV) , Btu/kWh	8,668	8,503
Water Source	Gallon per Minute	
Coal Moisture	48	44
Combustion of Hydrogen in GT	483	332
Combustion of Hydrogen in Incinerator	NA	17
Combustion Air for GT	78	84
Combustion Air for Incinerator	21	0.7
Raw Water Use	7,143	6,668
TOTAL	7,772	7,145
Water Loss		
Coal Drying Moisture	NA	30
Gasification Shift	159	54
Ash Handling Blowdown	80	70
Water With Slag	32	33
COS Hydrolysis	0.3	2
GT Flue Gas	743	675
Incinerator Flue Gas	NA	14
Sour Water Blowdown	NA	41
Water Treatment Discharge	5	NA
Cooling Tower Blowdown	2,222	2,055
Cooling Tower Evaporation	4,511	4,172
Hot Water Blowdown	10	NA
Moisture in Air Separation Vent	21	NA
TOTAL	7,782	7,144

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[44] Power Plant Water Usage and Loss Study, U.S. DOE NETL, August 2005.

Exhibit 3-24 presents the water balances for the present study IGCC technologies and coals. Consistent with the PC plant estimates, the DOE data was adjusted using the heat rates and gross outputs of the several plants. Coal moisture and for Shell, coal drying moisture, is based on the study coal properties.

Exhibit 3-24, Estimated Water Balances for IGCC Plants and Coals
Gallon per Minute

Gasification Technology	Slurry Fed Gasifier	Slurry Fed Gasifier	Dry Fed Gasifier
Study Coal	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite
Plant Gross Output, MW	564	575	580
Plant Heat Rate Btu/kWh	8,167	8,520	8,707
Water Source	Gallon per Minute		
Coal Moisture	81	276	449
Combustion of Hydrogen in GT	381	405	311
Combustion of Hydrogen in Incinerator	NA	NA	16
Combustion Air for GT	62	65	79
Combustion Air for Incinerator	17	18	0.7
Raw Water Use	5,596	5,764	6,119
TOTAL	6,137	6,528	6,975
Water Loss			
Coal Drying Moisture	NA	NA	305
Gasification Shift	125	133	51
Ash Handling Blowdown	63	67	66
Water With Slag	25	27	31
COS Hydrolysis	0.2	0.3	2
GT Flue Gas	586	623	633
Incinerator Flue Gas	NA	NA	13
Sour Water Blowdown	NA	NA	38
Water Treatment Discharge	4	4	NA
Cooling Tower Blowdown	1,752	1,864	1,926
Cooling Tower Evaporation	3,557	3,784	3,910
Hot Water Blowdown	8	8	NA
Moisture in Air Separation Vent	17	18	NA
TOTAL	6,137	6,528	6,975

In comparison with the supercritical PC units, the IGCC water loss is only about 64 to 68% as great, or a saving of about 32 to 36%. Exhibit 3-25 summarizes the losses for the two technologies and the percent ratio of IGCC to the supercritical PC plant water loss.

Exhibit 3-25, Summary Comparison of IGCC and Supercritical PC Water Losses

	Bituminous	Subbituminous	Lignite
Supercritical PC, Water Loss GPM	9,569	9,667	10,290
IGCC Water Loss, GPM	6,137	6,528	6,975
Percent IGCC/SCPC	64%	68%	68%

Exhibit 3-26 presents the air permit data collected and used during the study.

Exhibit 3-26, Non-Criteria Pollutant Estimates, Air Permit Data (1 of 3 Tables)

Data Points	Fuel (some plants may use more than one coal, or blend)	Mercury (Hg)	Volatile Organic Compounds (VOC)	Chlorides (HCl)	Fluorides (HF)	Sulfur Trioxide (SO_3)	Hydrogen Sulfide (H_2S)	Reduced sulfur compounds	Ammonia (NH_3)
6	PC Units Bituminous Coal	0.14 to 3.2 lb/TBtu	0.0024 to 0.004 lb/MMBtu	0.0001 to 0.0042 lb/MMBtu	0.0001 to 0.00088 lb/MMBtu	No Data	No Data	0.00073 lb/MMBtu	5 ppm
5	PC Units Subbituminous Coal	0.45 to 13.1 lb/TBtu	0.0027 to 0.02 lb/MMBtu	0.00064 to 0.0131 lb/MMBtu	0.00049 to 1.17 lb/MMBtu	No Data	No Data	0.00073 lb/MMBtu	No Data
1	PC Units Lignite	51 lb/TBtu	0.0067 lb/MMBtu	0.0155 lb/MMBtu	0.01 lb/MMBtu	No Data	No Data	No Data	No Data
12	Data Points All Pulverized Coal Units	10	11	10	10	0	0	1	1
1	High Sulfur Bituminous Coal CFB Unit	0.000002 lb/MMBtu	0.004 lb/MMBtu	0.006 lb/MMBtu	No Data	No Data	No Data	No Data	No Data
5	IGCC Units Bituminous Coal	0.55 to 1.9 lb/trillion Btu	0.0017 to 0.006 lb/MMBtu	0.00112 lb/MMBtu	0.000092 lb/MMBtu	No Data	No Data	No Data	No Data
5	Data Points IGCC Units	5	5	1	1	0	0	0	0

Exhibit 3-26, Non-Criteria Pollutant Estimates, Air Permit Data (2 of 3 Tables)

Data Points	Fuel (some plants may use more than one coal, or blend)	Arsenic (As)	Beryllium (Be)	Manganese (Mn)	Cadmium (Cd)	Chromium (Cr)	Formaldehyde	Nickel (Ni)	Silica (Si)
6	PC Units Bituminous Coal	0.883 to 5.99 lb/TBtu	0.35 to 1.14 lb/TBtu	12.3 to 20.92 lb/TBtu	0.365 to 1.1 lb/TBtu	8.9 to 10.48 lb/TBtu	48.0 lb/TBtu	8.41 lb/TBtu	No Data
5	PC Units Subbituminous Coal	25.0 lb/TBtu	2.38 lb/TBtu	3.57 lb/TBtu	3.1 lb/TBtu	16.67 lb/TBtu	15.48 lb/TBtu	16.67 lb/TBtu	No Data
1	PC Units Lignite	22.0 lb/TBtu	9.0 lb/TBtu	156 lb/TBtu	7.6 lb/TBtu	6.2 lb/TBtu	Not Data	62.0 lb/TBtu	No Data
12	Data Points All Pulverized Coal Units	3	6	3	3	3	2	2	0
1	High Sulfur Bituminous Coal CFB Unit	No Data	No Data	No Data	No Data	No Data	No Data	No Data	No Data
5	IGCC Units Bituminous Coal	0.457 to 6.0 lb/TBtu	0.062 to 0.6 lb/TBtu	4.0 to 7.02 lb/TBtu	0.415 to 5.0 lb/TBtu	1.1 to 3.48 lb/TBtu	No Data	4.51 to 310 lb/TBtu	No Data
5	Data Points IGCC Units	3	3	2	2	2	0	2	0

Exhibit 3-26, Non-Criteria Pollutant Estimates, Air Permit Data (3 of 3 Tables)

Data Points	Fuel (some plants may use more than one coal, or blend)	Selenium (Se)	Vanadium (V)	Total Reduced Sulfur (TRS)	Opacity	Sulfuric acid mist emissions
6	PC Units Bituminous Coal Wet FGD	48.54 lb/TBtu	No Data	0.00073 lb/MMBtu	10 to 20%	0.0044 to 0.014 lb/MMBtu
5	PC Units Subbituminous Coal Spray Dryer	No Data	No Data	0.00073 lb/MMBtu	10%	0.0042 to 0.0061 lb/MMBtu
1	PC Units Lignite	1,370 lb/TBtu	267.0 lb/TBtu	No Data	15%	No Data
12	Data Points All Pulverized Coal Units	2	1	1	5	10
1	High Sulfur Bituminous Coal CFB Unit	No Data	No Data	No Data	20%	No Data
5	IGCC Units Bituminous Coal	1.4 to 12.5 lb/TBtu	No Data	No Data	0 to 20%	0.0005 to 0.0042 lb/MMBtu
5	Data Points IGCC Units	2	0	0	3	3

Section 4 presents two special studies which consider the IGCC technology. The first study examines the option for including a SCR with the syngas turbine to improve NO_X control; the second examines ultra-low sulfur removal with physical solvents such as Selexol and Rectisol. The present study is a “snapshot” of the technologies at one point of time. The limits on operating experience and data for the SCR technology with IGCC synthesis gas and the potential for cost variations are documented in this section and other parts of the report. It is emphasized that any decision about SCR use and the systems required to implement that use will require detailed site-specific engineering and process design to optimize economic tradeoffs and the overall emissions including a balance between gas turbine NO_X and ammonia from the SCR. The choice between MDEA, Selexol, and Rectisol in the context of SCR for the synthesis gas is uncertain until more experience and more detailed engineering is available. This report does not express a view as to whether or when such technologies should be required in permits to construct and operate IGCC facilities.

4.1 Technical and Economic Assessment of SCR for Gasification Combined Cycle NO_X Control

The NO_X emissions from syngas-burning gas turbines are in the range of 15 to 18 ppmvd, considering the use of steam and nitrogen for diluents in the combustion process.[45] Based on this and other investigations, this study assumed 15 ppmvd as the current maximum achievable limit, for modeling purposes, but takes no position on whether this level should be required in any particular permit. GE is currently in the process of modifying the combustor design, which could lower the level of NO_X emission to upper single digit ppmvd. If a lower emission level is required, e.g., in the two to three ppmvd range, then it would only be achievable through the use of a post-combustion control method, such as SCR.

Informal discussions with SCR providers confirm that the SCR system could reduce NO_X emissions from the IGCC system to about three ppmvd without a major impact on other IGCC performance. This study uses three ppmvd as the maximum achievable limit for syngas turbines with SCR, but takes no position on whether this level should be required in any particular permit. Sulfur content in the syngas is a concern for SCR installations and from the discussions with SCR suppliers, acceptable sulfur content at the inlet of the SCR would be in the 15 to 20 ppmvd range or lower. A high efficiency sulfur removal process, such as Selexol, can achieve this level provided there is a COS Hydrolysis Unit upstream. If a SCR is not used, the suppliers recommend sulfur content around 40 ppmvd is acceptable in the syngas for the combined cycle. Without a SCR, the sulfur content limit will depend on the HRSG design exit temperature and other factors that could cause corrosion or fouling in the cool, back end of the HRSG. The base case MDEA process should be able to limit the syngas sulfur content to 40 ppmvd. The MDEA process is also the least costly option and thus more likely to be acceptable from an economic standpoint.

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[45] Discussions between Nexant and GE Energy, July 2005.

There are no existing coal-fired IGCC plants with SCR installed. The Japanese have a ConnocoPhillips based IGCC fueled by refinery bottoms (asphalt) that does include a SCR with the combined cycle. Several recent studies have reported and the consolidated results indicate that the SCR would increase total NO_X removal and lower the emissions from about 15 to three ppmvd.[46, 47]

PC Plant Note on SCR

In telephone discussions for this study (9/2005) with Babcock and Wilcox (B&W), they indicated a demonstrated peak NO_X removal efficiency of 95% at an undisclosed PC plant, which is significantly different than the gasification combined cycle conditions. In the same discussion B&W also provided estimates of costs for the SCR ranging from \$80 to \$90/kW installed at a greenfield PC plant, and \$90 to \$175/kW for a retrofit installation.

4.1.1 Combustion NO_X Control Technologies

Although NO_X emissions from operating IGCC power plants are quite low, stricter regulations may require control to lower levels. Available combustion-based NO_X control options for syngas-fired turbines are more limited than those available for natural gas-fired turbines. Differences between syngas and natural gas composition and combustion characteristics cause the dry low-NO_X (DLN) technology, which permits the natural gas-fired turbines to achieve emissions as low as nine ppmvd (at 15% O_2), to be inapplicable to IGCC syngas turbines. Gasification syngas differs from natural gas in terms of calorific value, gas composition, flammability characteristics, and contaminants. An IGCC plant will typically produce syngas with a heating value ranging from 250 to 400 Btu/ft^3 (HHV basis), which is considerably lower than the approximately 1,000 Btu/ft^3 for natural gas. This yields a flow rate increase compared with natural gas (approximately 14%). Also, the combustible composition of natural gas is primarily methane (CH_4), and the syngas combustible components are carbon monoxide (CO) and hydrogen (H_2). Finally, coal-derived syngas will contain higher concentrations of sulfur in the form of H_2S, which will impact use of post-combustion NO_X control.

The current NO_X control with the IGCC technology adds diluents such as steam and/or nitrogen to lower flame temperature to prevent formation of thermal NO_X. Nitrogen is available from the air separation unit at partial oxidation IGGC plants. Syngas dilution can reduce NO_X emissions levels from syngas-fired turbines to approximately 15 to 18 ppmvd (at 15% O_2). As noted earlier, GE is working to lower emissions to single digit values by improved turbine designs.

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[46] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report by: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann, & Massood Ramezan for National Energy Technology Laboratory, U.S. Department of Energy, December 2002.

[47] Southern Illinois Clean Energy Center, Integrated Gasification Combined Cycle Plant and Substitute Natural Gas Methanation Plant, BACT Evaluation prepared for Steelhead Energy, LLC by Sargent & Lundy, October 2004.

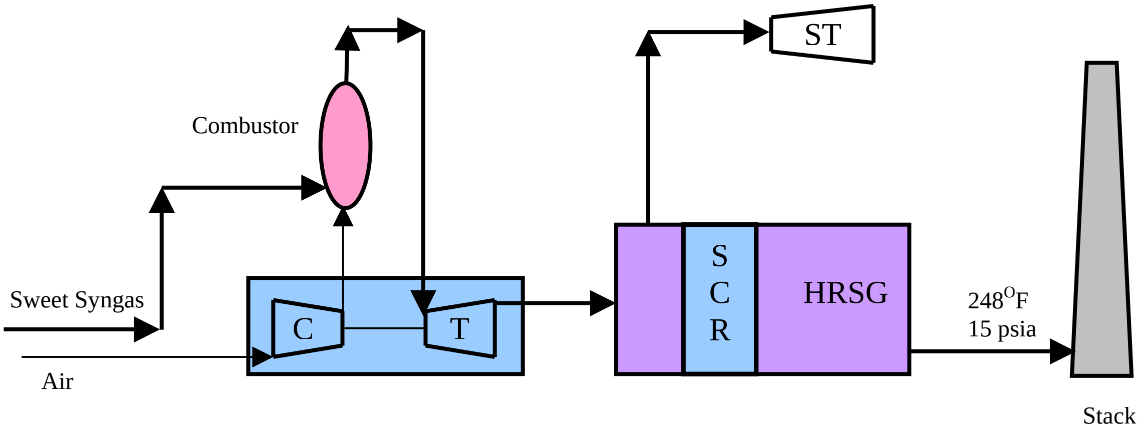
4.1.2 Post-Combustion NO_X Control

The currently available technology to achieve single-digit NO_X concentrations in the stack gas is post-combustion treatment of the flue gas which chemically reduces the NO_X to nitrogen. Selective catalytic reduction or SCR is a fully commercial technology used with natural gas-fired turbines. Variations of the natural gas SCR technology have also been installed with a number of coal-fired boilers. As noted above, there are fundamental differences between the natural gas and syngas-fired turbines that make the use of SCR with IGCC technologies more uncertain, and there are no installations at present at IGCC facilities firing coal.

Exhibit 4-1 shows how a SCR could be installed for post-combustion control at the IGCC facility. The SCR selectively reduces NO_X emissions by injecting ammonia (NH_3) into the flue gas upstream of a catalyst. The NO_X reacts with NH_3 and O_2 to form N_2 and H_2O. The SCR installation would be part of the HRSG, to allow for operation in the optimum range of temperature, about 600 to 750 ºF.

In a typical SCR ammonia injection system, anhydrous ammonia is drawn from a storage tank and evaporated using a steam- or electric-heated vaporizer. The vapor is mixed with a pressurized carrier gas to provide both sufficient momentum through the injection nozzles and effective mixing of the ammonia with the flue gases. The carrier gas is usually compressed air or steam, and the ammonia concentration in the carrier gas is about five percent. An alternative to using anhydrous ammonia is to use aqueous ammonia. The reduced ammonia concentration in an aqueous solution reduces safety concerns associated with anhydrous ammonia.

Exhibit 4-1, SCR Installation for IGCC Technology



In the informal telephone discussions with SCR suppliers, they remarked that the system could reduce NO_X below three ppmvd depending on economic considerations for the system, and also ammonia slip control. The ammonia-to-NO_X ratio can be varied to achieve the desired level of NO_X reduction. One mole of ammonia reduces one mole of NO, and two moles of ammonia reduces one mole of NO_2. Higher NH_3:NO_X ratios achieve higher NO_X emission reductions, but can result in increased un-reacted ammonia being emitted into the atmosphere. This un-reacted ammonia is known as ammonia slip. Also, SCR catalysts degrade over time, which changes the quantity of NH_3 slip. Catalyst life typically ranges from three to 10 years depending on the specific application. IGCC applications, with exhaust gas that is expected to be relatively free of contaminants, should yield a significantly longer catalyst lifetime than for a conventional coal-fired application. In the economic estimate below, four years catalyst life is set as criteria for the calculation. The four year criteria are based on engineering judgment, since no direct SCR experience with IGCC installations exist.

Installation of SCR in an IGCC's HRSG requires consideration of the environmental impacts of ammonia slip. Ammonia slip is typically limited to less than five ppmvd in most natural gas SCR applications, but may be higher if the NO_X level entering the catalyst bed is very low. Tradeoffs between NO_X and ammonia emissions show limited data, but subjectively represent problems as both emissions are pollutants and both are greenhouse gases.

There are operational impacts from the installation of a SCR system at the IGCC plant. First, the pressure loss across the SCR catalyst bed decreases gas turbine power output by approximately one-half percent and the ammonia storage and transfer equipment consumes some additional power. Second, chemical reactions may interfere with the operation of the plant. Any sulfur left in the syngas will oxidize to SO_2 and SO_3. If the sulfur in the syngas is not limited to 20 ppmvd or less and substantial levels of SO_3 are present in the flue gas, ammonia from the SCR can react with SO_3 to form ammonium salts. These salts are corrosive and sticky materials that can plug heat transfer equipment, reducing performance and increasing maintenance. Any fouling will also add to pressure drop power losses. The ammonium salts, if not deposited in the system remain in the flue gas as fine particulate matter ($PM_{2.5}$). Since a typical plant will not have particulate controls after the HRSG, the particulate emissions also need to be evaluated in the NO_X emission assessment.

In order to limit ammonium salt formation, either the ammonia slip or the SO_3 must be minimized. Some ammonia slip is inevitable, and discussions with SCR suppliers recommend a maximum of 20 ppmvd SO_2 in the syngas, or about two to three ppmvd in the flue gas going to the HRSG. While the IGCC case for the study can reduce sulfur in the syngas to about 40 ppmvd, additional cleaning such as with a physical solvent (Selexol, Rectisol) is needed to meet the 20 ppmvd sulfur limit for the syngas. Designs to balance the emissions of NO_X and ammonia slip require more detailed engineering, and the process providers were not willing to provide more data without specific design specifications.

A key factor in SCR operations is the frequency with which catalyst must be replaced to meet NO_X reduction and residual NH_3 performance targets. Until recently, catalyst replacement frequency was a source of debate between SCR control equipment suppliers and utility users. However, recent catalyst technology has made substantial advances, and catalyst suppliers are now willing to subject their product life cycles to rigorous, lengthy commercial guarantees for natural gas turbines and PC units. While there is no commercial experience with SCR and coal-fired IGCC systems, if IGCC sulfur removal is accomplished as discussed above, catalyst life cycle issues are likely to be very similar as experienced with PC units. The crucial question for IGCC will be the impact on HRSG performance of adding the SCR. This issue does not present itself for PC installations.

Although misleading, it is convenient to express the catalyst replacement frequency in terms of a single number reflecting useful catalyst life in years. In practice, a catalyst management strategy is employed to minimize the cumulative cost over the plant lifetime of providing for replacement and disposal of catalyst. Generally, a SCR unit when initially commissioned into service contains only a portion of the ultimate catalyst inventory, which after a number of years is gradually augmented with new catalyst to compensate for gradual deactivation. Ultimately, the original catalyst elements are considered "spent" and replaced with fresh catalyst, which in turn augments the older catalyst in the reactor. Specific strategies vary with site-specific design considerations.

While not completely equivalent to the issue of IGCC and SCR installations, European experience indicates that coal-fired boilers employing a proper catalyst management strategy will enjoy an average catalyst lifetime of six to10 years.[48] Vendors for Public Services New Hampshire (PSNH) Merrimack station commercial SCR installation guaranteed a catalyst life of six years; PSNH itself anticipates an eight-year life. New coal-fired boilers (e.g., U.S. Generating--Carneys Point and Stations in New Jersey) are securing vendor guarantees of a 10-year catalyst life. As noted above there is no experience with IGCC with SCR installations at this time; this is one reason for the relatively conservative life criteria selected for economic calculations. However, it appears that the operating environment for the IGCC's SCR catalyst should be less aggressive than that for the PC units and, therefore, the life may be significantly more than the four years allowed in the economic calculations.

4.1.3 Cost Estimates for SCR Addition

To consider the costs for increased NO_X control by adding the SCR to the system, the performance criteria is defined as follows based on Nexant's discussions with SCR suppliers and literature. The criteria are the basis for calculations; they are not guarantees of performance.

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[48] States' Report on Electric Utility Nitrogen Oxides Reduction - Nitrogen Oxides Reduction Technology Options for Application By the Ozone Transport Assessment Group, April 1996.

- The SCR evaluation is based on the IGCC case with bituminous coal. Anhydrous ammonia is used as the SCR reagent.
- The SCR reduces NO_X from 15 to three ppmvd.
- The base performance case (15 ppmvd) is the IGCC with steam and nitrogen dilution.
- With SCR, the gas turbine gross output is assumed to be reduced by one-half percent. The SCR system also consumes additional power in vaporizing anhydrous ammonia and in ammonia pumps and blowers, which is estimated at 60 kW.
- In addition to the SCR equipment, a physical solvent system such as Selexol is assumed to be provided to meet the 20 ppmvd sulfur limit to the SCR given by the SCR suppliers. The costs for SCR addition are reported both with and without a Selexol system.
- The installed cost of the SCR is $12/kW; the total capital requirement cost is $15/kW. Cost data is from the previously referenced Southern Illinois Clean Energy Center BACT evaluation. The generating capacity at this plant would be 544 MW net.
- The plant capacity factor is assumed at 85%.

NO_X emissions for the bituminous coal IGCC case with and without SCR are summarized in Exhibit 4-2.

Exhibit 4-2, NO_x Emissions for Bituminous Coal IGCC- with and without SCR

Emission Units	NO_X Emissions – Syngas Dilution	NO_X Emissions – SCR Installed
ppmvd at 15% O_2	15	3
lb/MMBtu	0.049	0.01
lb/MWh	0.36	0.07
Tons per year	729	146

Exhibit 4-3 shows the results from estimates of the cost per ton of NO_X for installing the SCR for lower NO_X emission. A cost per ton of NO_X reduced is shown for cases with and without considering a cost for lost power generation from the added SCR power consumption. With the MDEA acid gas removal system, the cost is $7,290 per ton of NO_X removed. When Selexol technology is used to replace the MDEA process for sulfur removal, the cost per ton approximately doubles.

Exhibit 4-3, Cost Effectiveness Estimate for SCR NO_X Reduction

Cost Items		Annualized Cost	Notes
SCR Capital Cost	$ 7,500,000	$ 900,000	Capital recovery at 12% and 30 year investment term
O&M Costs			
Ammonia		$ 107,400	Based on $363/ton of anhydrous ammonia[49]
Catalyst Replacement		$ 2,048,700	Based on 4 year catalyst life and a catalyst replacement cost of $396/cu.ft.[50]
Disposal Cost		$ 200,000	
Labor		$ 130,800	
Maintenance		$ 196,200	
Total O&M		$ 2,683,100	
Total O&M + Annualized Capital		$ 3,583,100	
Cost per Delta Ton Removed		$ 6,145	
Auxiliary Power Consumption		$ 668,000	Based on $0.04 per KWh
Cost per Delta Ton Removed When Aux. Power Included		$ 7,290	
Cost per Delta Ton Removed Aux. Power & Selexol Included		$ 13,120	

Due to the lack of experience with SCR application on coal-based IGCC units at this time, there are several unresolved issues that may have additional cost impacts, resulting in increases in the costs shown in Exhibit 4-3. Some of these issues are outlined below:

- Modifications to the HRSG design may become necessary to minimize adverse effects of ammonium salts formed from reaction between ammonia slip and SO_3. Such modifications have not been accounted for in the above estimates.

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[49] Potash Corp Website, http://www.potashcorp.com/investor_relations/markets_information/ammonia_margins/, accessed on February 21, 2006.

[50] Catalyst cost factor used in the EPA's IPM Model, Documentation for EPA Base Case 2004 (V.2.19), EPA 430-R-05-011, September 2005.

- Without proven experience, it may not be possible to obtain proper performance guarantees and warranties for the overall SCR/HRSG installation or such guarantees/warranties may be offered at higher costs.

- The catalyst suppliers may offer catalyst life guarantees below the levels assumed for this study.

- Uncertainty exists regarding optimal ammonia slip and syngas sulfur content levels required to mitigate HRSG effects. Selection of conservative levels can have an impact on the overall costs.

The impact of the above issues would vary with the operating conditions associated with each IGCC installation. Some of these issues can have a substantial impact on the SCR costs. As an example of cost sensitivity, if the catalyst life is reduced from 4 to 3 years, the cost per ton removed will increase from $7,290 to $8,460, about a 16% change.

The Selexol process suppliers were unwilling to provide cost data without more detailed design information and payment for their efforts. However cost data is available in the literature, and from Nexant experience with other gasification projects.[51] If Selexol is required to reduce the sulfur content below the limits of an MDEA acid gas cleaning process, the increased capital cost is estimated to be $20 million. The increased annualized capital cost would be $2.40 million; increased annual O&M costs are estimated to be $1million and the cost per delta ton increases to $13,120. Costs for the MDEA system from the Texaco study were used as a check against the published Selexol incremental costs.[52]

The need to replace the amine acid gas removal system with a more effective physical solvent technology is still uncertain. From the discussions with technology suppliers, technology selection requires more detailed examination for specific coals and plant designs. In some cases, the MDEA process may be able to reduce the syngas sulfur sufficiently for the SCR (about 20 ppmvd); also, the SCR technology for coal is still evolving and may become more sulfur tolerant.

4.2 Assessment of Sulfur Removal Technologies – Selexol and Rectisol

The uncertainties associated with SCR use with IGCC syngas or more stringent SO_2 removal requirements could lead to a need for deeper cleaning of the syngas. The removal capability of the amine-based MDEA chemical sorbent acid gas cleaning process is limited by economic trade-offs, so alternative sulfur removal processes, Selexol and Rectisol, are evaluated in this section for the deeper cleaning option.

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[51] Process Screening Analysis Of Alternative Gas Treating And Sulfur Removal For Gasification, Revised Final Report, December 2002, Prepared by SFA Pacific, Inc., U.S. DOE Task Order No. 739656-00100.

[52] Texaco Gasifier IGCC Base Cases, U.S. DOE/NETL, PED-IGCC-98-001 Latest Revision June 2000.

A major advantage of the Rectisol process is its removal of COS, so that no upstream COS hydrolysis step is necessary. The major cost issue for Rectisol is its requirement for refrigeration to cool the methanol in the process to low temperature. Rectisol can reduce the syngas sulfur content to as low as two ppmvd in the treated gas. Such low levels of sulfur concentration are not needed for SCR operation discussed earlier and unless there is another technical or regulatory reason, the added costs may not be justified.

The Selexol process cannot achieve the same low sulfur concentration as Rectisol, and requires COS hydrolysis. A typical coal syngas contains five percent of its total sulfur as COS, and the physical solvents are only about half as effective removing COS compared to H_2S. However, the Selexol process may be less complex and does not require cryogenic operating temperature as the Rectisol process does. To obtain sulfur removal for the SCR addition, Selexol may not need refrigeration equipment. The low temperature criterion adds to the energy penalty associated with the Rectisol process.

Exhibit 4-4 shows a comparison of the three technologies described above from the previously referenced Southern Illinois Clean Energy Center BACT evaluation based on an Illinois #6, high sulfur bituminous coal similar to this study's bituminous coal case.

Exhibit 4-4, Comparison of Sulfur Removal Technologies for IGCC

Sulfur Removal Technology	Syngas Sulfur Compounds Concentration ppmvd	SO_2 Emissions lb/MMBtu	Percent Reduction from Uncontrolled Emission %
MDEA Chemical Solvent	75	0.033	99.37
Selexol Physical Solvent	20	0.009	99.83
Rectisol Physical Solvent	10	0.0045	99.91

While the differences in Exhibit 4-4 appear small, for a point of reference if the uncontrolled SO_2 emissions were 100,000 tons per year, the emissions after applying each of the above technologies would be 630, 170 and 80 tons per year – the reductions achieved improve by a factor of eight, comparing the lowest controlled emission rates to the highest.

While the process developers would not provide cost data without a detailed design basis, according to the Rectisol (Linde) and Selexol (UOP) suppliers, sulfur content of the coal and thus the raw syngas is not a significant factor for removal efficiency and has a limited impact on costs.

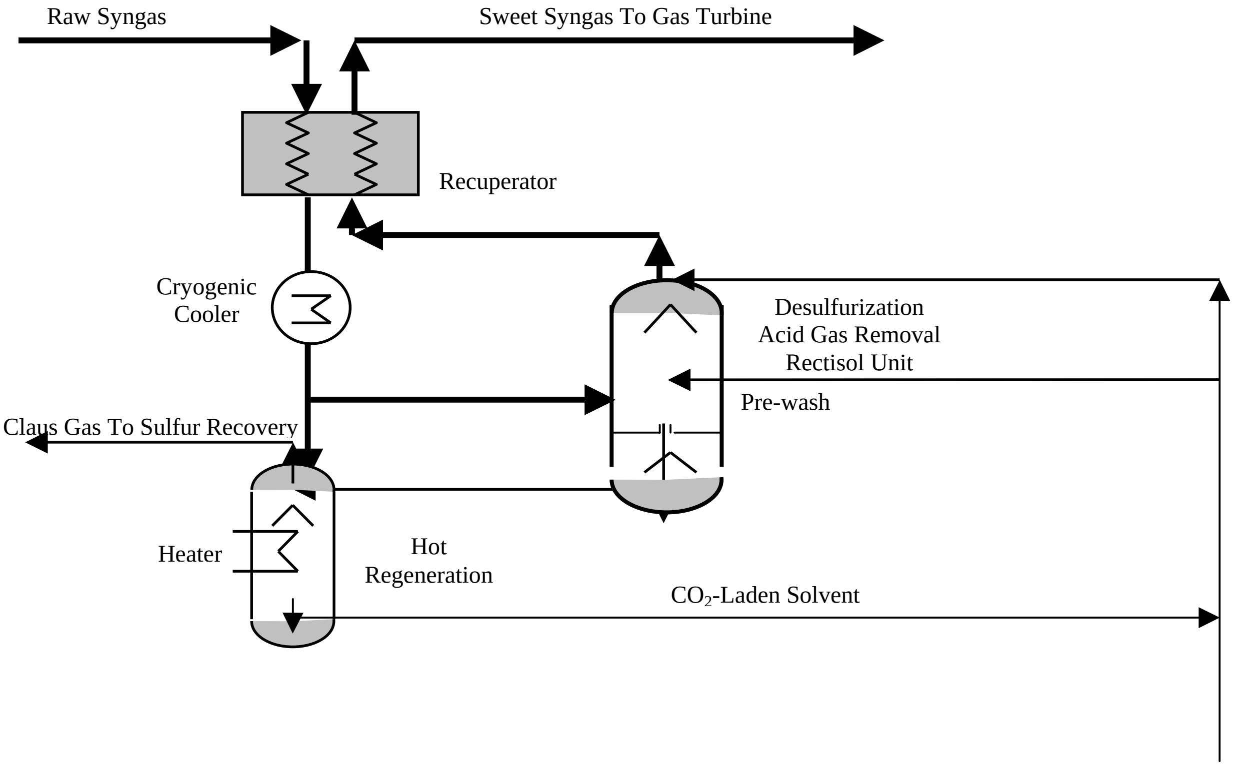
4.2.1 Sulfur Removal and Recovery Technologies

As mentioned earlier, in an acid gas removal process syngas is treated via contact with a solvent to remove H_2S and some CO_2. Physical solvents, such as Rectisol and Selexol are favored over chemical solvents when the sulfur content of the clean gas must be very low, such as for chemical plant operations. The removed H_2S is treated in a Claus process to recover sulfur similar to the other IGCC cases.

Rectisol Process

A simplified flow diagram of the Rectisol process is shown in Exhibit 4-5. The Rectisol process uses methanol as a physical solvent operating at cryogenic temperature for removal of acid gases. The feed gas is pre-cooled. The injected methanol plus water is separated from the gas, which is given into the wash column. H_2S and some CO_2 are physically absorbed from the raw gas by the cooled solvent. Sulfur is removed in this column down to < 10 ppmvd; the CO_2 slip is approximately 60-65%, meaning that approximately 35 - 40% of the incoming CO_2 is removed. H_2S is then desorbed by re-boiling the solvent. The CO_2-laden solvent is recycled back to the Rectisol unit. The released H_2S-loaded gas is sent to the sulfur recovery process (Claus process).

Exhibit 4-5, Rectisol Process Block Diagram



Selexol Process

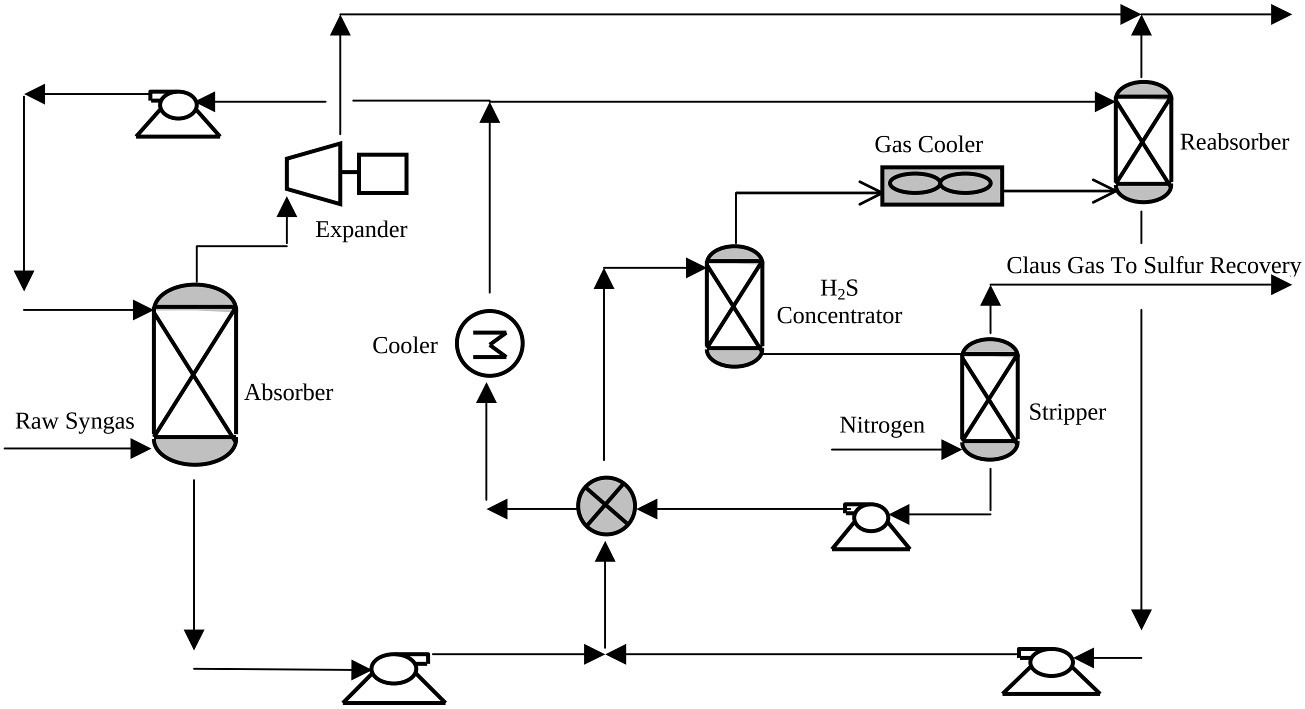
Selexol is a liquid physical solvent developed by Allied Signal in the 1950s, and is used for treating natural and synthesis gas streams. The solvent is used in more than 100 applications for the removal of H_2S, CO_2, mercaptans, and for both hydrocarbon and water-dew point control. The Selexol technology is currently owned by Union Carbide Corporation. Union Carbide has granted exclusive rights to UOP for licensing Selexol technology in the field of partial oxidation. In December 2005, Honeywell completed acquisition of UOP.

A simplified flow diagram of the Selexol process is shown in Exhibit 4-6. Untreated syngas is sent to the absorber, where it contacts cooled regenerated solvent, which enters at the top of the tower. In the absorber, H_2S, COS, CO_2 and other gases such as hydrogen, are transferred from the gas phase to the liquid phase. The treated gas exits the absorber and is sent out of the Selexol unit battery limits. The solvent streams from the absorber and re-absorber are treated rich solvent, and are combined and sent to the lean/rich exchanger. The solvent from the re-absorber is sent via the rich pump.

In the lean/rich exchanger the temperature of the rich solvent is increased by heat exchange with the lean solvent. The rich solvent is then sent to the H_2S concentrator, where a portion of the CO_2, CO, H_2 and other gases are stripped from the solvent. Nitrogen from the air separation unit is the stripping medium. The temperature of the overhead stream from the H_2S concentrator is reduced in the stripped gas cooler, and is sent to the re-absorber, where H_2S, COS and a portion of the other gases are transferred to the liquid phase. The stream from the re-absorber exits the unit battery limits.

The rich solvent from the re-absorber is combined with rich solvent from the absorber, as described above. The partially regenerated solvent exits the H_2S concentrator and is sent to the stripper, where the solvent is regenerated. The lean solvent is then sent to the other side of the lean/rich exchanger via the lean pump. The temperature of the lean solvent is further reduced in the lean solvent cooler. A portion of the lean solvent is then sent to the re-absorber, while the remainder is sent to the top of the absorber via the lean booster pump. Hydrogenated tail gas from the sulfur recovery unit is recycled back to the acid gas removal unit and enters with the feed to the re-absorber (not shown).

Exhibit 4-6, Selexol Process Block Diagram

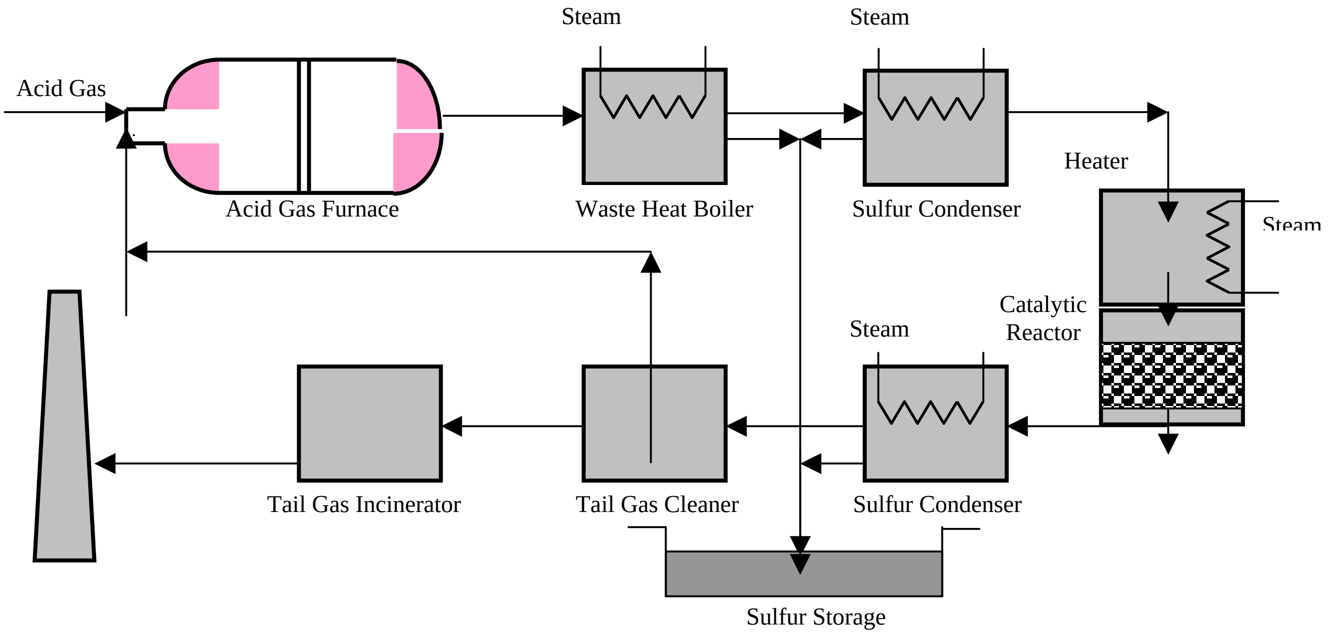


Sulfur Recovery

A simplified flow diagram of the Claus sulfur recovery process is shown in Exhibit 4-7. The Claus process produces elemental sulfur by burning in a furnace part of the H_2S to form SO_2, and by reacting un-combusted H_2S with SO_2. One-third of H_2S in the feed gas is oxidized to SO_2. Simultaneously, an un-catalyzed reaction occurs between the SO_2 and unburned H_2S, which are in stoichiometric ratio, converting about 60% of each to sulfur vapor. The gas, upon leaving the furnace, is then cooled to condense sulfur, reheated, and passed through a catalytic converter. A three-converter system recovers about 98% of the sulfur. The gas leaving the catalytic converter is sent to a tail gas cleaning unit (TGCU), which is generally a Shell Claus Off-gas Treatment (SCOT) process.

The SCOT process consists of two sections. In the first section, the tail gas is heated and reacted with H_2 over a catalyst. All sulfur compounds are converted to H_2S. The off-gas is then cooled in a waste heat boiler followed by a water quench. Finally, H_2S is selectively absorbed by an MDEA. The rich amine solution is stripped and the H_2S-rich stream is recycled to the front end of the Claus plant. The treated gas from the SCOT absorber is incinerated and the incinerated gas is discharged through a high stack.

Exhibit 4-7, Sulfur Recovery Block Diagram



4.2.2 Cost and Economic Estimates

The Selexol and Rectisol technology suppliers, UOP LLC and Linde Group respectively, were not able to provide cost information without a more detailed design basis and compensation for their efforts.

Other sources for costs were pursued and the results are reported below.

- Eastman Gasification Services Company in an October 2003 presentation to the Eastern Tennessee section of the AIChE, “Coal Gasification – Today’s Technology of Choice and Tomorrow’s Bright Promise” reported estimated costs of $20 million for Selexol and $40 million for Rectisol. Plant size is not given, so only the cost factor of 2 in estimating the difference between Selexol and Rectisol is useful. However, an article in Power magazine reports similar information and describes the cost for an IGCC of approximately 500 MW.[53] The absolute cost values are for costs above what is estimated for an MDEA alternative system.

- The previously referenced Southern Illinois Clean Energy Center BACT evaluation also provides estimates for a Selexol system to be installed on a 544 MW IGCC plant. All costs are provided as incremental costs (over an MDEA system). The total capital

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[53] Vol. 148, No. 2 March 2004 Power Magazine, “Coal Gasification: Ready for Prime Time” – Available at URL: http://www.businessweek.com/pdf/240648PWRePrint.pdf, accessed February 23, 2006.

cost for the Selexol system addition is estimated at approximately $40 million ($75/kW). The annual operating costs are estimated at approximately $6 million. The overall cost effectiveness is estimated at approximately $22,000 to $30,000 per ton of NOx removed, compared to the base case MDEA.

- The above BACT evaluation also includes addition of a Rectisol system to the same 544 MW IGCC plant. The incremental cost estimates provided show a capital cost of $81 million ($149/kW) and operating costs of $8.3 million.

Section 5 Carbon Management

As part of the study scope of work, a summary of technologies and current status for carbon dioxide (CO_2) separation, capture and sequestration was prepared and documented in this section.

5.1 CO_2 Separation, Capture and Sequestration Background

While CO_2 is not a regulated power plant emission, the strong scientific and political focus on how CO_2 impacts global climate has initiated a number of technical and economic assessments of technologies that could be installed to separate, capture and sequester (SCS) the gas for hundreds or thousands of years. SCS technologies and estimates of their performance and economics are discussed in this section of the report. The discussion focuses upon technologies that are likely to be commercially demonstrated in the 2010 time period.

While industry and government research is working diligently to reduce the cost and improve performance of SCS technologies, the timing of their wide-spread introduction into the commercial market is highly uncertain. Aside from economic considerations, the major implementation issue is the location, definition and justification of geological sequestration formations. The task of convincing the public, government and industry stakeholders that sequestration is safe and environmentally sound is difficult. Except for limited opportunities for enhanced oil or gas recovery operations in existing and geologically well defined-sites, the storage of very large amounts of CO_2 for hundreds of years will need to be carefully tested, demonstrated and monitored before the technology is accepted by enough stakeholders to allow the technology to move forward at the scale that is needed for serious power generation carbon management.

The CO_2 separation and capture technologies for power generation systems are traditionally split into "post-combustion and pre-combustion" categories. Capture of CO_2 from flue gases produced from combustion of fossil fuels, such as in a PC boiler, is referred to as post-combustion capture. A chemical sorbent process would normally be used for CO_2 capture for this purpose.

The concept of combusting coals (or other fuels) with oxygen instead of air can be classified as a SCS process that falls in the post-combustion category. This process is applicable to PC boilers and is in early stages of development. The process results in a flue gas stream that is mainly CO_2 and H_2O, making it possible to capture and sequester CO_2 at relatively low cost.

Pre-combustion usually means the application of gasification to produce a synthetic gas and then treatment of this gas to produce and capture CO_2, resulting in a stream of hydrogen-rich fuel that can be used for various applications, including power generation. Capturing of CO_2 is generally accomplished using a physical or chemical absorption process.

5.2 SCS Technologies for Pulverized Coal Power Plants

Post-combustion CO_2 separation and capture from PC plant flue gas (mainly by amine chemical absorption) is currently being examined by industry. While the amine process is technically proven in small-scale commercial operations, the economics and scale-up issues associated with a 500 MW or larger power plant are substantial.

5.2.1 Gas Absorption

Gas absorption processes are commonly used in commercial industrial operations to remove CO_2 from mixed-gas streams. Gas absorption can treat streams at widely ranging pressures and CO_2 concentrations. Typically gas absorption works by contacting the mixed-gas stream containing CO_2 with a liquid solvent in which CO_2 is soluble. Two types of solvents are used for CO_2 removal: physical solvents and chemically reactive solvents. Physical solvents follow Henry's law such that the mass of a gas that will dissolve into a solution is directly proportional to the partial pressure of that gas above the solution. Therefore, physical solvents are more suitable for gas streams that are under high pressure; resulting in an elevated CO_2 partial pressure. This increases CO_2 solubility, which, in turn, reduces the solvent circulation rate. Chemically reactive solvents first dissolve CO_2 and then react with it. Pressure has a secondary effect on the performance of chemically reactive solvents.

If the mixed-gas stream containing CO_2 is at elevated pressure, the physical solvent can be recovered and the CO_2 separated by simply flashing the gases to a lower pressure. Chemically reactive solvents require energy to reverse the chemical reaction to recover the dissolved gases. Commercial experience indicates that the physical solvent process is more economical if the CO_2 partial pressure is above 200 psia. At low-inlet CO_2 partial pressure such as a PC plant flue gas, chemically reactive solvent processes are required.

Some of the commonly used commercial gas absorption processes are listed in Exhibit 5-1. The first four processes use solvents that physically absorb the CO_2 and are applied to mixed gas streams under high pressure that contain a high concentration of CO_2. The solvent circulation rates for these processes are generally higher than for chemical absorption. For the three other processes, a chemically reactive solvent is used.

Alkanolamines are a group of amines that are used for CO_2 removal. They include monoethanolamine (MEA), diethanolamine (DEA), diglycolamine (DGA), diisopropanolamine (DIPA), and triethanolamine (TEA). Of these, MEA is the most alkaline; it has the highest dissociation constant and the highest pH in water solution. The others are progressively less alkaline in the order listed. Other properties that bear on the use of these amines follow in the same order as their alkalinities. The primary amines (MEA) form the most stable bond with the acid gas, followed by the secondary amines. The least stable bond is formed by the tertiary amines. Therefore, amine-based processes are the most common and are considered to be the best technology for the removal of CO_2 from PC flue gas with low CO_2 partial pressure.

Exhibit 5-1, Gas Absorption Processes Used for CO_2 Removal

Process	Owner	Application
Physical Solvents		
Sulfinol	Shell Oil Company	Natural gas, refinery gases and synthesis gases
Selexol	Universal Oil Products	Natural gas, refinery gases, and synthesis gases
Rectisol	Lurgi GmbH and Linde AG	Heavy oil partial oxidation process of Shell and Texaco; also Lurgi gasification
Purisol	Lurgi GmbH	Natural gas, hydrogen, and synthesis gases
Chemical Solvents		
Catacarb	Eickmeyer & Associates, Kansas	Any mixed-gas stream
Benfield	Universal Oil Products	Synthesis gas, hydrogen, natural gas, town gas, and others
Amines (alkanolamines and hindered amines)	Both generic solvents and proprietary formulations with additives	Any mixed-gas stream

In addition to the primary commercial process of absorption with MEA, there are other separation technologies under research and development including:

- Cryogenic Cooling
- Gas Separation Membranes
- Gas Absorption Membranes
- Gas Adsorption

None of the processes have been used at or near the scale of CO_2 removal required by large power generation plants, and most of the R&D is focused on natural gas-fired systems. The MEA process is judged the only process likely to be available in the study's timeframe for coal-fired plants and is discussed in more detail below.

5.2.2 MEA Absorption

For removal of CO_2 from low-pressure, low-CO_2 concentration pulverized coal flue gases, MEA scrubbing is considered state-of-the-art for fossil fuel-fired systems such as coal-fired boilers and gas turbines. A few commercial facilities use MEA-based solvents to capture CO_2 from coal, fuel oil, and natural gas flue gas streams for use in the food industry. However, these plant capacities are roughly 100 to 1,000 tons/day compared to more than 5,000 tons/day for a 500-MW coal-fired plant.

The low CO_2 partial pressure necessitates the use of MEA-based systems, and while MEA has the advantage of fast reaction rate with CO_2 at low partial pressures compared to other commercially available amines, there are significant disadvantages such as high heat of reaction, limited capacity and significant corrosion problems. Oxygen present in the flue gas causes rapid degradation of alkanolamines. The degradation byproducts lead to corrosion problems and cause significant deterioration in the overall separation performance. To counter the influence of oxygen, the approach currently practiced is the use of chemical inhibitors. For example, the processes licensed by Kerr-McGee/ABB Lummus Global Inc. and by Fluor Daniel use inhibited monoethanolamine solutions.[54, 55]

Commercial providers of MEA technology also include Praxair and Mitsubishi Heavy Industries (MHI). Recent advances in chemical solvents have included the commercial introduction of the KS-family of hindered amines by MHI. Their different molecular structures allow enhanced reactivity toward a specific gas component, in this instance CO_2. Benefits of these advanced amines in addition to extensive heat integration include the following: 1.) Higher absorption capacity (only one mole of hindered amine is required to react with 1 mol CO_2 compared with two moles MEA), 2.) 90% less solvent degradation, 3.) 20% lower regeneration energy, 4.) 15% less power, 5.) 40% lower solvent recirculation rates due to higher net absorption capacity, 6.) Lower regeneration temperature, 7.) less corrosion in the presence of dissolved oxygen, and 8.) Lower chemical additive cost. An example of a coal-fired power plant system employing an MEA process for CO_2 capture is presented in Exhibit 5-2 and briefly described below.

The flue gas is partially compressed to 17.5 psia by a centrifugal blower to overcome the gas-path pressure drop. The flue gas enters the absorber and flows upward and counter to the lean MEA solution. CO_2 is removed from the flue gas in the packed-bed absorber column through direct contact with MEA. The CO_2-depleted flue gas is exhausted to the atmosphere. The CO_2-rich solution is heated in a MEA rich/lean heat exchanger and sent to the stripper unit where low-pressure steam from the steam turbine (in a power plant) provides the thermal energy to liberate the CO_2. The CO_2 vapor is cooled to condense water and then sent to a multistage compressor where the CO_2 is compressed to a super-critical state of about 1,200 psia for pipeline transport. The CO_2 laden stream is further dehydrated using glycol or molecular sieve processes.

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[54] Barchas, R. and Davis, R. The Kerr-McGee/ABB Lummus Crest Technology for the Recovery of CO2 from Stack Gases. Energy Conversion Management, 33(5-8), p. 333, 1992.

[55] Sander, M.T. and Mariz, C.L. 1992. The Fluor Daniel Econamine FG Process: Past Experience and Present Day Focus. Energy Conversion Management, 33(5- 8), p. 341, 1992.

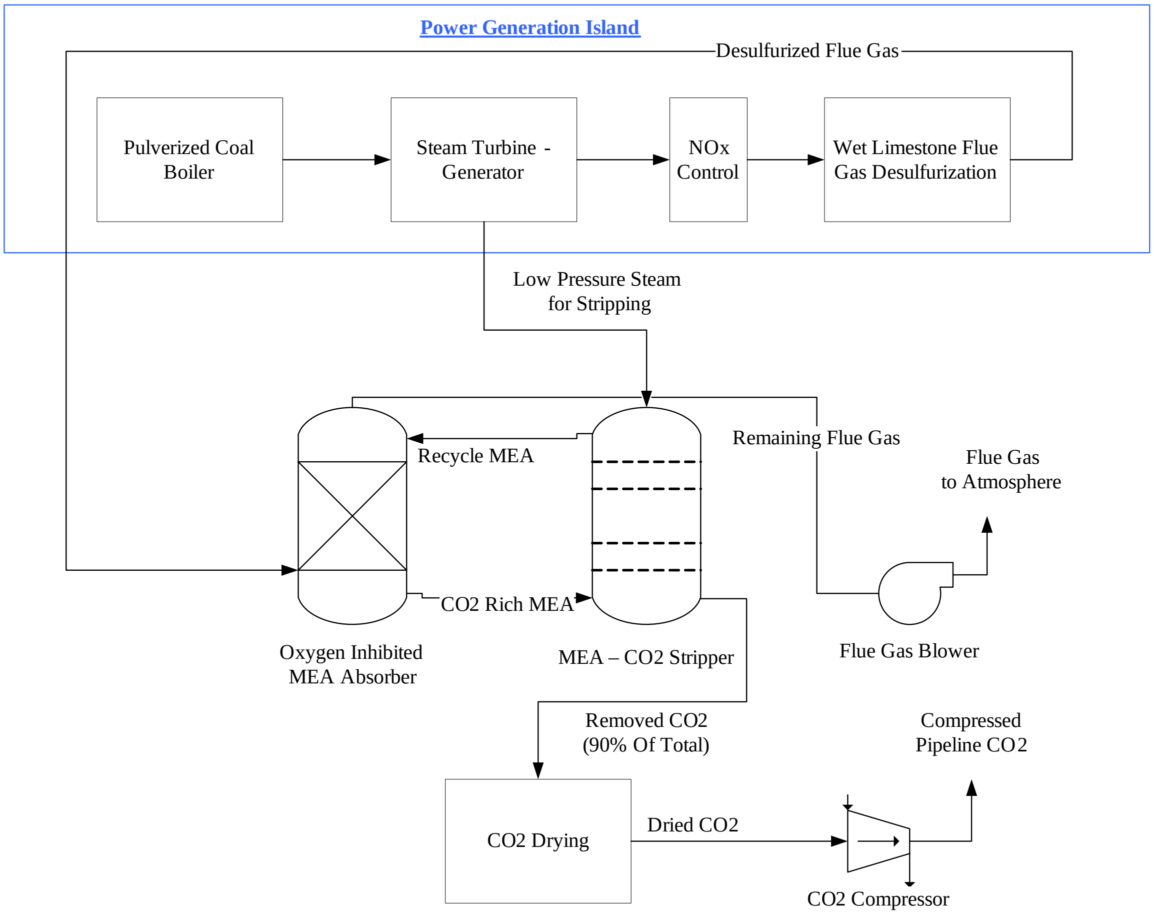

Exhibit 5-2, CO_2 Removal by MEA Absorber/Stripper

5.2.3 MEA CO_2 Absorption Performance

The MEA process can practically achieve recoveries of 85% to 95%, with CO_2 purities over 99% by volume. However, the MEA process requires large amounts of thermal energy (heat/steam) as well as auxiliary power to operate pumps and blowers for gas and solvent circulation. Depending on the exact concentration of the solution, the steam consumption can vary from 1,200 to 1,620 Btu per pound of CO_2 recovered. To prevent corrosion, the flue gas is treated so that SO_2 is below 10 ppmvd, NO_2 is below 20 ppmvd, and NO_X is below 400 ppmvd. Solvent degradation and losses also occur during the regeneration operation.

Recent U.S. DOE NETL and other studies indicate that the overall energy penalty associated with CO_2 separation and capture with an amine solution plus compression of the CO_2 gas ranges from 10 to 15% of the design capacity of a PC power plant without

CO_2 SCS.[56] For supercritical PC (SCPC) plants with and without CO_2 removal examined in the DOE study the major performance differences are illustrated in Exhibit 5-3.

Exhibit 5-3, U.S. DOE/NETL Study, CO_2 Removal Impacts – A Supercritical PC Plant

Performance	SCPC without CO_2 Removal	SCPC with CO_2 Removal
Gross Plant Power, MW	491.1	402.3
Total Auxiliary Power Requirement, MW	29.1	72.7
Net Plant Power, MW	462	329.3
Net Efficiency, % HHV	40.5	28.9
Net Heat Rate, Btu/kWh	8,421	11,816
Coal Feed, lb/hour	333,542	333,542

The main systems requiring increased auxiliary power are the larger induced draft flue gas blower (some 20 MW) required for the MEA removal process, and the CO_2 compression (about 30 MW). In addition, the large decrease in net efficiency is a result of amine solvent regeneration via steam stripping. This requires a significant amount of low pressure steam to be by-passed from the low pressure steam turbine, thereby preventing power generation. In the industry methodology for comparing technologies, this is accounted for in costs for equipment, and by calculating the "avoided cost" for CO_2 removal, which includes costs to replace the power lost by installing the removal system.

5.2.4 MEA Technology Status

Most of the new work and advances to the amine absorption technology have focused on natural gas-fired systems[57,58]. Other sources provide data for natural gas-fired systems and some of that information is summarized here in exhibits 5-4 and 5-5.[59] The performance data in Exhibit 5-4 is based on the fuel lower heating value (LHV). While this work has indicated significantly reduced costs and improved performance, the development of similar systems for PC plants does not appear to be progressing very rapidly.

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[56] Evaluation of Innovative Fossil fuel Power Plants with CO2 Removal, U.S. DOE/NETL and EPRI, Prepared by ParsonsEnergy and Chemicals Group, December 2000 – updated 2002.

[57] Daniel Chinn, Dag Eimer, and Paul Hurst, CO2 Capture Project: Post-Combustion "Best Integrated Technology" (BIT) Overview, presented at the Third National Conference on Carbon Capture and Sequestration, National Energy Technology Laboratory/Department of Energy, Alexandria, VA, May 3-7, 2004.

[58] M. Simmonds, et al., "Post Combustion Technologies for CO2 Capture: A Techno-Economic Overview Of Selected Options", uregina.ca/ghgt7/PDF/papers/nonpeer/471.pdf, Accessed June 28, 2006.

[59] Gasification Plant Cost and Performance Optimization Project, U.S. DOE/NETL Contract No. DE-AC26-99FT40342, September 2003, prepared by Nexant, Inc., Bechtel Corporation and Global Energy.

Exhibit 5-4, Natural Gas Combined Cycle CO_2 Capture Progress

Study Basis	Net Power, MW	Efficiency, LHV %	Capital Cost, $ millions	Operating Cost $ millions	CO_2 Avoided Cost $/ton
Natural Gas Combined Cycle Without CO_2 Capture	392	57.6	284	13	NA
Baseline Capture Study	322	47.3	418	26	60
Low-cost Capture Study	332	48.8	366	24	45
Low-cost Integrated Capture Study	335	50.6	345	24	35
Best Integration (BIT) Study	357	52.5	352	21	28

Exhibit 5-5, Solvents for CO_2 Removal

Supplier	Solvent	Solvent Loss, lb/ton of CO_2	Solvent Cost, $/lb	Solvent Cost, $ per ton of CO_2	Steam Use, ton per ton of CO_2
Non Proprietary	MEA	2 to 6	0.60	1.20 to 3.50	2
Econamine, Fluor	MEA plus Inhibitors	3.2	0.70	2.30	2.3
KS-1, MHI	Hindered Amines	0.7	2.30	1.55	1.5
PSR, Amit Chakma	Amine Mix	0.2 to 1.8	unknown	unknown	1.1 to 1.7

Research organizations, including U.S. DOE and industry, are concentrating efforts on non-amine processes such as ammonia scrubbing, membrane separation and oxygen combustion as possible methods to separate and capture CO_2 at PC plants. The following is from the DOE web site and indicates the difficulty of sequestration of CO_2 at coal-fire plants.[60] *"Pulverized coal (PC) plants, which are 99 percent of all coal-fired power plants in the United States, burn coal in air to raise steam. CO_2 is exhausted in the flue gas at atmospheric pressure and a concentration of 10-15 volume percent. This is a challenging application for CO_2 capture because:*

- *The low pressure and dilute concentration dictate a high actual volume of gas to be treated*
- *Trace impurities in the flue gas tend to reduce the effectiveness of the CO_2 adsorbing processes*

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[60] NETL Website, Carbon Sequestration, http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html, accessed February 13, 2006.

- *Compressing captured CO_2 from atmospheric pressure to pipeline pressure (1,200 - 2,000 pounds per square inch (psi)) represents a large parasitic load.*

Aqueous amines are the state-of-the-art technology for CO_2 capture for PC power plants. Analysis conducted at NETL shows that CO_2 capture and compression using amines raises the cost of electricity from a newly-built supercritical PC power plant by 84 percent, from 4.9 cents/kWh to 9.0 cents/kWh. The goal for advanced CO_2 capture systems is that CO_2 capture and compression added to a newly constructed power plant increases the cost of electricity by no more than 20 percent compared to a no-capture case."

Results from a 2000 DOE/Alstom Power study showed that capturing 90% of the flue gas CO_2 from an existing pulverized coal power plant (using conventional amines) has significant performance and economic impacts.[61] The results of the study show plant efficiency dropping from 35% to 21% with MEA and to 23% with combined MEA – MDEA, all based on the coal higher heating values.

5.3 Oxygen Combustion Technology

Substitution of oxygen for all or part of the combustion air for PC boiler (and other combustion devices including fluid bed furnaces and gas turbines) has been proposed in some concepts as a method to produce a CO_2-rich flue gas requiring no separation and that could be directly sequestered. Conventional air combustion processes in boilers or gas turbines produce flue gases that contain predominantly nitrogen (>80 vol%) and excess oxygen in addition to CO_2 and water. If oxygen rather than air is used as the combustion source and nitrogen is replaced with re-circulated CO_2, the nitrogen content of the flue gas approaches zero (assuming minimal air leakage into the system) and the flue gas contains predominantly CO_2 with a small amount of excess oxygen and water. Circulating a part of the recovered CO_2 controls the adiabatic flame temperature.

While schemes for oxygen combustion (or oxycombustion), usually with the recycle of flue gas for combustion control, have been conceptually examined, there are no units in operation. Commercial plant feasibility may be difficult to justify under most conditions because of the auxiliary power consumption of the air separation unit needed to produce the oxygen. The Canadian Clean Power Coalition (CCPC) and other Canadian organizations have performed significant study and tests with oxygen combustion.[62, 63] These investigations show higher costs and reduced performance compared to both gasification with CO_2 removal and amine CO_2 removal options.

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[61] Engineering Feasibility and Economics of CO2 Capture on an Existing Coal-Fired Power Plant, Alstom Power, ABB Lummus Global, and American Electric Power; prepared for the Ohio Coal Development Office and U.S. DOE contract DE-FC26-99FT40576, June 2001.

[62] CCPC Phase I Executive Summary, Summary Report on the Phase I Feasibility Studies conducted by the Canadian Clean Power Coalition, May 2004.

[63] Summary of Canadian Clean Power Coalition work on CO2 capture and storage by Geoffrey F Morrison, August 2004. IEA Clean Coal Centre.

One of the goals of research being conducted on oxycombustion technology is to lower the cost of air separation, which is expected to bring the overall cost of this technology closer to the carbon capture costs with gasification[64]. U.S. DOE just recently (November 2005) announced awards for two oxygen combustion related projects totaling nearly $10 million[65]. These projects are expected to help expedite the timeline for commercialization of oxycombustion technology through slip stream or pilot plant testing.

5.4 Coal Gasification with CO_2 Removal

Gasification technology developers and other proponents of coal gasification for production of electric power and co-production concepts are strongly focused on the potential advantages of gasification when combined with requirements for CO_2 separation, capture and treatment for transport to sequestration sites. Technology developers hope that the CO_2 issue will lead to greater introduction of gasification combine cycle (GCC) technology into the power generation market than has occurred in the past. A number of large scale gasification units have been installed globally, but the great preponderance of the installations are at petroleum refinery operations or chemical plants where often inexpensive fuels, a process need for synthesis gas (CO and hydrogen), and the in-plant need for power and thermal energy may all exist. Despite demonstrations of IGCC power plants in North America and internationally, industry has resisted commercial applications for some 30 years. The major issues preventing wider acceptance are high cost, uncertainty of technology performance – especially gasifier reliability, and the traditional power generation industry's reluctance to operate what they view as more of a chemical plant than a power plant.

Exhibit 5-6 is a simplified diagram to illustrate a process for IGCC with CO_2 removal. The process is similar to the IGCC cases without CO_2 removal except that the gas from the gasifier is sent to a CO shift converter prior to cooling, and the acid gas removal system (shown here as Selexol technology) removes CO_2 as well as the sulfur compounds.

The other significant difference between the IGCC processes with and without CO_2 removal is the compression and drying of the product CO_2, which is assumed to be made ready for pipeline transportation.

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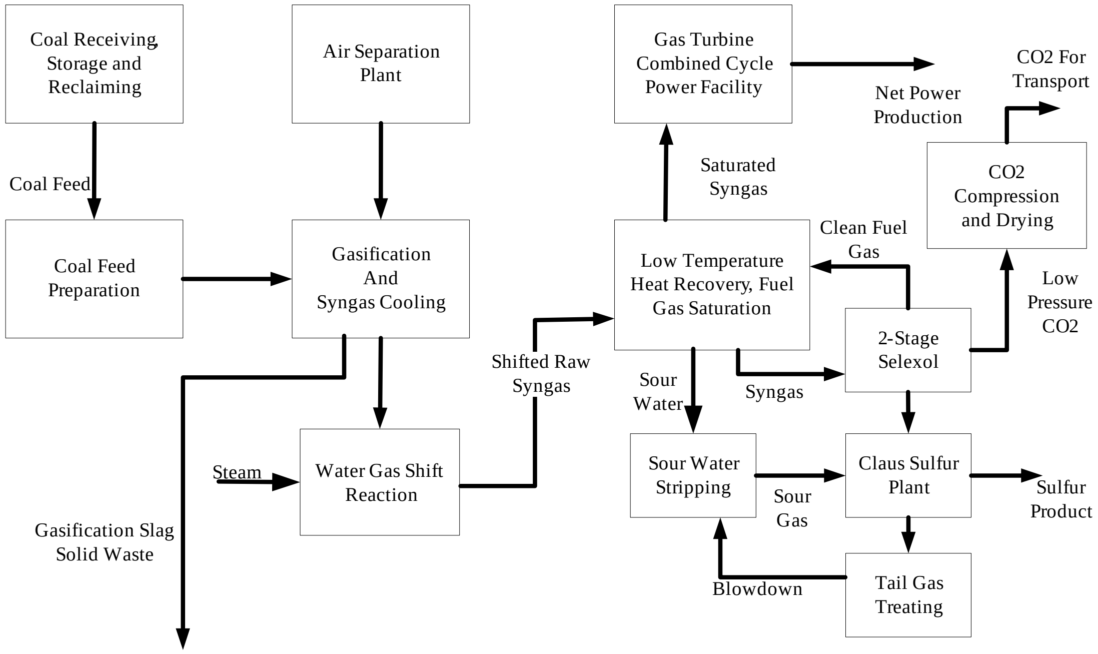
[64] F. Allix, "Today's Technologies, Tomorrow's Potential," Opening Plenary Session, 2005 Clean Coal & Power Conference, November 21-22, 2005, Washington, DC.

[65] NETL Website, Announcements, http://www.netl.doe.gov/publications/press/2005/tl_oxycombustion_award.html, Accessed on February 13, 2006.

Exhibit 5-6, IGCC with CO_2 Separation and Capture



None of the installed gasification plants are designed for the purpose of producing electric power and removing CO_2. The processes required to remove CO_2 from an IGCC plant are commercial in other gasification applications. Some work will be required to test the ability of gas turbines to use the more hydrogen rich fuel that will result from the CO_2 removal operation. Additionally, there are unique issues with the gasification of higher moisture subbituminous and lignite coals that need to be solved before these energy resources can become IGCC feedstocks.

Under the current and near-term state of power generation technologies, the IGCC concept is attractive because the gasification technology suffers significantly less of an energy penalty than alternatives, such as pulverized coal boilers or gas turbine combined cycle power plants, if carbon capture was added. Whatever the technology, the addition of carbon management will increase costs of electricity, and while there may be niche markets for CO_2 in enhanced oil/gas recovery operations, the vast majority of CO_2 generated will be a waste product and will incur disposal costs.

5.5 Power Generation Systems with and without CO_2 Removal

The original and updated Parsons reports sponsored by the U.S. DOE and EPRI are the most detailed engineering comparisons in the public literature.[66] Exhibit 5-7 presents information from the study for IGCC and two PC units. The gasifier used in this study is

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[66] Evaluation of Innovative Fossil fuel Power Plants with CO2 Removal, US DOE/NETL and EPRI, Prepared by ParsonsEnergy and Chemicals Group, December 2000 – updated 2002.

different from the GE-Energy (ex-Texaco) reactor used in the body of the report to calculate energy and material balances, but the relative comparison between systems with and without CO_2 removal would be consistent across types of gasifiers.

Exhibit 5-7, Carbon Management Comparison, U.S. DOE, EPRI, Parsons Study

Description	**IGCC - ConocoPhillips**		**Supercritical PC**		**Ultra Supercritical PC**	
Carbon Management	Capture	No Capture	Capture	No Capture	Capture	No Capture
Net Plant Size (MW)	404	425	329	462	367	506
CO_2 Capture Efficiency	91%	0%	90%	n/a	90%	n/a
Heat Rate (Btu/kWh) (HHV)	9,226	7,915	11,816	8,421	10,999	7,984
Efficiency (%,HHV)	37%	43%	29%	41%	31%	43%
Derating	14%		29%		27%	
Economic Criteria						
Cost-year basis	2000	2000	2000	2000	2000	2000
Capacity Factor	65%	65%	65%	65%	65%	65%
Fuel Cost ($/MMBtu) (HHV)	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24
Book life (years)	20	20	20	20	20	20
Fixed Carrying Charge	13.80%	13.80%	13.80%	13.80%	13.80%	13.80%
Capital Costs ($/kW)						
Total Plant Cost	$1,642	$1,111	$1,981	$1,143	$1,943	$1,161
Total Plant Investment	$1,787	$1,209	$2,142	$1,235	$2,101	$1,256
Total Capital Requirement	$1,844	$1,251	$2,219	$1,281	$2,175	$1,301
Operation and Maintenance Costs						
Total O&M ($/kW-yr)	52.1	41	49.2	28.7	46.3	27.7
Fixed O&M ($/kW-yr)	33	27.5	33.3	20.2	30.8	19.1
Variable O&M (cents/kWh)	0.4	0.3	1.1	0.6	1.1	0.6
Fuel (cents/kWh)	1.1	1	1.5	1	1.4	1
Levelized Costs (cents/kWh)						
Capital	4.47	3.03	5.38	3.11	5.27	3.15
Total O&M	0.96	0.76	1.71	1	1.61	0.95
Fixed O&M	0.58	0.48	0.58	0.35	0.54	0.33
Variable O&M	0.38	0.28	1.13	0.64	1.07	0.62
Fuel	1.14	0.98	1.47	1.04	1.36	0.99
Total Cost of Electricity	6.58	4.77	8.56	5.15	8.24	5.1
COE increase for capture	1.8		3.41		3.14	
CO_2 Costs ($/ton)						
CO_2 Emission rate (t/MWh)	0.07	0.72	0.11	0.77	0.11	0.77

Description	IGCC - ConocoPhillips		Supercritical PC		Ultra Supercritical PC	
Cost of CO_2 Captured ($/ton)*	23.63	n/a	35.09	n/a	32.35	n/a
Cost of CO_2 Avoided ($/ton)*	27.98	n/a	51.22	n/a	47.22	n/a

* See Section 5.7 for differences between CO_2 avoided and captured costs.

Exhibit 5-8 presents similar literature data from the International Energy Agency (IEA) Greenhouse Gas program (circa 2003). Here the two cases are for Shell and GE-Energy gasifiers.

Exhibit 5-8, Gasification Carbon Management Data, IEA GHG 2003

Description	IGCC - Shell		IGCC - GE Energy	
Carbon Management	Capture	No Capture	Capture	No Capture
Net Plant Size (MW)	676	776	730	827
CO_2 Capture Efficiency	85%	0%	85%	0%
Heat Rate (Btu/kWh) (HHV)	9,890	7,916	10,832	8,979
Efficiency (%,HHV)	35%	43%	32%	38%
Derating	20%		17%	
Economic Criteria				
Cost-year basis	2002	2002	2002	2002
Capacity Factor	85%	85%	85%	85%
Fuel Cost ($/MMBtu) (HHV)	$1.50	$1.50	$1.50	$1.50
Book life (years)	25	25	25	25
Fixed Carrying Charge	11.00%	11.00%	11.00%	11.00%
Capital Costs ($/kW)				
Total Plant Cost	$1,744	$1,287	$1,402	$1,114
Total Plant Investment	$1,859	$1,371	$1,494	$1,187
Operation and Maintenance Costs				
Total O&M ($/kW-yr)	60.3	57.6	59.7	52.5
Fuel (cents/kWh)	1.6	1.3	1.7	1.4
Levelized Costs (cents/kWh)				
Capital	3.69	2.76	3.04	2.4
Total O&M	0.96	0.84	1	0.84
Fuel	1.59	1.27	1.72	1.42
Total Cost of Electricity	6.23	4.87	5.76	4.67
COE increase for capture	1.37		1.09	

Description	IGCC - Shell		IGCC - GE Energy	
CO_2 Costs ($/ton)				
CO_2 Emission rate (t/MWh)	0.14	0.76	0.15	0.83
Cost of CO_2 Captured ($/ton)	16.89	n/a	12.81	n/a
Cost of CO_2 Avoided ($/ton)	22	n/a	16.01	n/a

In Exhibit 5-8, the IEA data is not clear about which version of the GE-Energy gasifier (quench or heat recovery) was studied, or if there is an installed spare unit for this GHG case. Even without describing the details of the studies further, several important conclusions can be made from the data.

- The added cost for CO_2 removal is significant regardless of the technology. Examining the Total Plant Cost (TPC), which should be the most consistent value of the capital cost items because fewer add-on factors are applied as percents to the basic estimate, the delta IGCC cost ranges from about $300 (GE-Energy) to more than $500 (ConocoPhillips) per kW. The two pulverized coal plants increase about $800 per kW when CO_2 removal is added.

- Gasification cost and performance, when CO_2 removal is installed, are much more favorably compared to the PC cases. The improved economic performance results largely from the lower energy penalty incurred by IGCC than for PC when CO_2 removal is required.

- The difference in costs for systems with CO_2 removal is strongest when avoided costs are calculated; this is attributed to higher efficiency for gasification over pulverized coal units.

- The costs per ton of CO_2 sequestration remain high for all cases, and the range of estimates indicates a level of uncertainty that can only be reduced by the real-world construction of several plants.

- As with all developing technology comparisons, the technologies are changing – for PC plants new and improved amines are being researched; the U.S. DOE and others are moving forward with oxygen combustion research; gasification developers are investigating optimization of the processes for CO_2 removal possibly eliminating some operations to save costs and increase performance. Thus, the situation will require review as the technologies advance.

- Nearly all of the engineering assessments of power generation carbon management have used bituminous coals as the feedstock for PC and gasifier units. Investigators are starting to explore power and CO_2 removal systems fueled by subbituminous and lignite coals. Australia is expanding the knowledge base with work on high moisture brown coals.[67] Canada has also performed significant work with low rank coals, some of which is available in the literature. The available information is summarized below.

5.6 Coal Quality and CO_2 Removal

The Canadian Clean Power Coalition (CCPC) reported the results from the first phase of its work.[68] Exhibit 5-9 summarized the data for three types of coal being gasified and for a pulverized coal plant with CO_2 separation using amine absorption and stripping.

Exhibit 5-9, CCPC Summary Data for Plants with CO_2 Removal

Coal	Bituminous	Subbituminous	Lignite	Lignite
Technology	Gasification Plants			Pulverized Coal Plant
	GE-Energy Gasification	GE-Energy Gasification	Shell Gasification	Amine Absorption
Net power (MW)	444.5	436.8	361.1	310.9
Efficiency, % (LHV)	32.97	27.71	30	31.8
Efficiency, % (HHV)[1]	30	25	26	27
CO_2 captured (%)	87	92	85.7	95
CO_2 emitted, g/kWh	130	102	182	60
Capital cost (U.S. $/kW)	1,917	2,190	2,828	2,824
COE (U.S. cents/kWh)	6.84	6.21	8.39	7.43

Note 1. HHV efficiencies estimated; LHV results stated in the report.

The U.S. and IEA efficiency and cost results compare fairly closely for bituminous coals. The new data from the Canadian work is the relative comparison of the three coals. Some of the conclusions which can be made from this data include:

- The efficiency difference between systems using bituminous and subbituminous/lignite coals is significant (about 5%). The lignite coal efficiency is greater than that of subbituminous coal because the Shell gasifier is a dry feed unit. It is not clear that all the impacts of the Shell versus GE-Energy units were considered. In the report, ChevronTexaco, who owned the gasifier technology at that time, did not believe that its gasifier could be practically used with lignite.

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[67] Victorian Government's Greenhouse Challenge for Energy, CRC for Clean Power from Lignite, August 2003.

[68] Summary of Canadian Clean Power Coalition Work on CO2 Capture and Storage, by Geoffrey F Morrison, August 2004.

- The capital cost difference is notably higher for the lignite gasification case than for both of the other coals.

- The costs for the lignite PC plant with amine CO_2 removal could be compared to the capital cost for the supercritical plant in the Parsons report as an indication of coal rank impacts on PC plants with CO_2 removal. The Parsons capital cost is $2,219 compared to $2,824 per kW for the Canadian lignite PC case. Aside from more specific differences that could exist between the studies, most of the cost difference is assumed to be caused by a larger boiler required to fire the low heating value lignite.

- The difference in efficiencies between the Parsons supercritical plant and the CCPC lignite plant is only about 2%. Much of the difference can likely be accounted for by the heat needed to evaporate the extra lignite moisture.

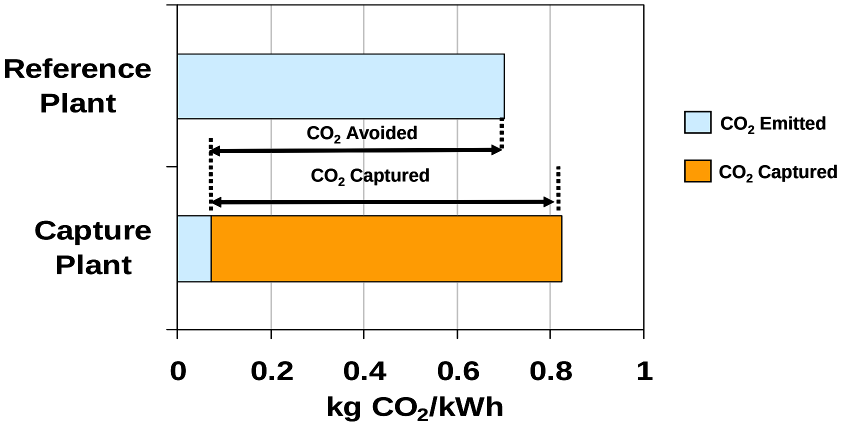
5.7 Note on Avoided Costs

The cost of an environmental control system can be discussed in terms of either the cost per ton of pollutant removed or the cost per ton "avoided." For a CO_2 removal system like amine scrubbers there is a big difference between the cost per ton CO_2 removed and the cost per ton CO_2 avoided. All avoided cost calculations require a "reference plant" without the removal system for a comparison to be made on unit cost avoided basis (see Exhibit 5-10 below). Avoided cost can be calculated as follows:

$$\$/tonneAvoided = \frac{COE_{Capture} - COE_{Reference}}{CO_2Emissions_{Reference} - CO_2Emissions_{Capture}}$$

Note: Cost of electricity (COE) in mills/kWh and CO_2 Emissions in kg/kWh

Exhibit 5-10, Illustration of Avoided Cost for CO_2 Capture



Some other references perform the calculation by adding lost capacity from a specified generation source such as a new gas turbine combined cycle plant with emissions of its own used in the calculation.

5.8 CO_2 Pipeline Transport

Pipeline transportation of CO_2 is a commercial operation in North America with more than 350 million standard cubic feet being moved significant distances, mainly for enhanced oil recovery operations.

CO_2 separation processes applied to a fossil fuel-fired power plant result in additional energy consumption and the direct reduction of power output. Starting with atmospheric pressure and a desired pipeline pressure of 1,600 psia, the energy requirement for CO_2 liquefaction by inter-cooled 5-stage compression is about 0.05 kWh/lb of CO_2. For 90% CO_2 removal, the CO_2 liquefaction reduces the efficiency of coal-fired power plants by about 3 to 5 percentage points. Estimates of pipeline diameter and CO_2 flow rates are shown in Exhibit 5-11.[69]

Exhibit 5-11 Pipeline Size and CO_2 Flows

Diameter, inches	Range of Flow Rate, millions of tons per year
12	1 to 3
16	3 to 7
20	7 to 12
24	12 to 19
28	19 to 28
32	28 to 40

An approximate straight-line cost for pipeline construction is $15,000 per inch-mile. Annual O&M costs are about $1,500 per mile independent of pipe diameter. The costs are strongly dependent on site and route specific features. However, transportation costs are typically viewed as relatively minor components of the overall cost for carbon management. Exhibit 5-12 shows CO_2 transportation cost estimates from a source, ranging from $0.50 to $2 per metric ton for a distance of 100 km, or about 220 miles.[70]

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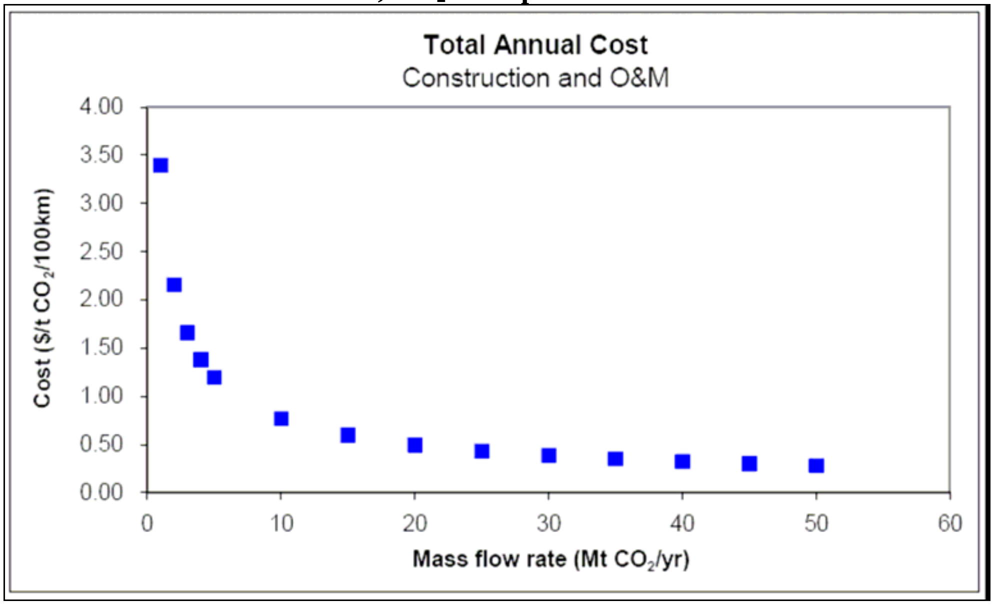
[69] Evaluation of Innovative Fossil fuel Power Plants with CO2 Removal, US DOE/NETL and EPRI, Prepared by ParsonsEnergy and Chemicals Group, December 2000 – updated 2002.

[70] The Economics of CO2 Storage, Gemma Heddle, Howard Herzog & Michael Klett, MIT. August 2003.

Exhibit 5-12, CO_2Transportation Cost Data



5.9 Geological Sequestration

Carbon sequestration is the removal and retention of carbon dioxide (CO_2) in terrestrial, oceanic, and geologic environments. Geologic sequestration – also known as carbon capture and storage (CCS) – is the underground emplacement of anthropogenic CO_2 captured from industrial facilities, such as power plants and cement manufacturing facilities. Instead of releasing the captured CO_2 to the atmosphere, CCS operations will compress the gas to a “supercritical” liquid and send it via a pipeline to an injection well, where it is pumped underground to depths generally greater than 800 meters to maintain critical pressures and temperatures. Once underground, the CO_2 occupies pore spaces in the surrounding rock. Candidate sites for geologic storage include deep saline formations, depleted oil and gas reserves, and unminable coal beds. Suitable sites have a caprock, or an overlying impermeable layer, that prevents CO_2 from escaping back towards the surface.

There appear to be no major technical hurdles to implementing geologic sequestration in the U.S. The various technologies required to implement a CCS project exist today and several are used in the field routinely by the oil and gas and waste disposal industries. Although there may be risks associated with large-scale injection and potential leaks of CO_2, it is anticipated that they can be avoided with proper siting, operation and maintenance, and long-term monitoring. Capture costs and concerns with long-term liability for storage sites are major considerations still being addressed by ongoing R&D. In addition to technical and economic hurdles to commercial deployment, public awareness and acceptance of projects to store very large volumes of CO_2 will need to be greatly increased. Also, while there is experience with regulations and permits for smaller amounts of materials, i.e. hazardous waste and waste injection wells, there is no set of regulations for CO_2 storage, and in addition to environmental issues, questions remain about ownership and liability for the CO_2 and for ownership of the storage pore space.

In the U.S., large point sources of CO_2 (each emitting more than 100,000 tons of CO_2 per year) originate from various industrial sectors including coal-fired power plants, ammonia production, and cement manufacture among others. There are approximately 1,700 of these sources in the U.S. that collectively emit more than 3 gigatons of CO_2 (GtCO2) per year.[71] Initial assessments show there is an abundance of geologic storage capacity, well distributed throughout the U.S. Although capacity estimates vary, recent studies from Battelle estimate storage capacity of more than 3,900 GtCO2

5.9.1 Potential Storage Formations

The geological formations of primary interest to sequestration include:

- Existing oil and gas fields and potential enhanced oil/gas recovery (EOR) conditions
- Depleted oil and gas fields
- Deep saline formations
- Deep unminable coal seams, possibly with coal bed methane recovery

Other possibilities include storage in mafic/basalt rock formations and above ground conversion of CO_2 to solid carbonate materials. These are much less mature options than the four bulleted items. The MIT reference noted previously contains details about the technologies and costs for various sequestration options.

Existing oil and gas fields and enhanced oil/gas recovery (EOR)

Enhanced recovery with CO_2 floods is used commercially in North America. There were some 70 CO_2 floods in the United States in 2000 that resulted in almost 200,000 bbl of oil per day, which is equivalent to 5 percent of total U.S. oil production during the same period. Most of these CO_2 floods are located in the southwestern United States within the Permian basin of western Texas and eastern New Mexico. The majority of the CO_2 for EOR operations comes from natural sources, because CO2 captured from most anthropogenic sources is currently too expensive to compete with the naturally occurring (produced) CO_2.

EOR and CO_2 sequestration are being studied extensively for the first time in an international project at the Weyburn field, Saskatchewan Canada. The CO_2 source is the Dakota Gasification plant near Great Plains North Dakota. The Weyburn EOR project will not conclude with the conventional “blowdown” which may release CO_2 back to the atmosphere. Instead the operators will maintain the site in order to test and monitor long-term sequestration. Sequestration as part of an EOR operation has the attraction of being a revenue producing process, and is very likely to be some of the first sequestration

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[71] “Carbon Dioxide Capture and Geological Storage,” Report by JJ Dooley, et al., April 2006, GTSP Website http://www.pnl.gov/gtsp/news/, accessed June 5, 2006

opportunities to be implemented at large scale. For example, the British Petroleum (BP) Carson Hydrogen Power project will convert the carbon in petroleum coke, a by-product of the refining process, and recycled waste water into hydrogen, a clean-burning gas, and CO_2. The hydrogen gas will be used to fuel a power station capable of providing the California power grid with 500 MW of electricity. At the same time, about 4 million tonnes of CO_2 per year will be captured, transported and stored in deep underground oil reservoirs where it will enhance existing oil production.

If EOR projects are to include a CO2 sequestration component, changes may be needed to the facility and/or operations. For example, different project goals may necessitate additional site characterization, the use of multiple geologic formations, or temporary CO2 storage. A critical component will be monitoring and verifying the volume of CO2 stored and additional site closure practices to ensure CO2 is sequestered for the long time frames required.

Depleted oil and gas fields

Injection of CO_2 into depleted oil and gas fields would be similar to commercial EOR experience. While one of the main attractions for using the fields is that large amounts of geological data will be available, the existing fields will also have numerous old wells that may no longer be sealed and could leak the CO_2 back to the atmosphere. Before sequestration, the existing field would have to be closely examined and issues such as concerns regarding old wells would have to be addressed.

Deep saline formations

Sequestration in deep saline deposits has the potential to geologically store the most CO_2. Along with the Weyburn field tests, the only other commercial-scale projects dedicated to geologic CO_2 storage are at the Sleipner West field in the North Sea and the In Salah gas field in Algeria. Sleipner West is a natural gas/condensate field operated by Statoil and is located about 500 miles off the coast of Norway. The natural gas has a CO_2 content of about 9 percent which, to meet commercial specifications, must be reduced to 2.5 percent. At Sleipner, the CO_2 is compressed and injected via a single well into the Utsira Formation, a 500 foot thick, brine saturated formation located at a depth of about 2,000 feet below the seabed. The operation is commercially driven by a carbon tax imposed by Norway.

In 2004, BP launched a CO2 capture and storage project at the In Salah gas field, in the Algeria desert. In Salah is a joint venture between Sonatrach, the Algeria national energy company, BP and Statoil. Approximately 10% of the gas in the reservoir is made up of CO_2. Rather than venting the CO_2, which is the established practice on other projects of this type, the project is compressing it and injecting it in wells 1,800 meters deep into a lower level of the gas reservoir where the reservoir is filled with water. Around one million tonnes of CO_2 will be injected into the reservoir every year.

The most important trapping mechanism to contain CO_2 in deep saline reservoirs is hydrodynamic trapping, where a caprock prevents upward movement of CO_2. Saline and other types of reservoirs also have two additional trapping mechanisms that help contain the CO_2 : solubility and mineral trapping. Solubility trapping is the dissolution of CO_2 into the reservoir fluids; mineral trapping is the reaction of CO_2 with minerals in the host formation to form carbonates. As the CO_2 moves through the deposit, it comes into contact with uncarbonated formation water and reactive minerals. A portion of the CO_2 dissolves in the formation water and becomes permanently fixed by reactions with minerals in the host rock. Over long periods of time, the CO_2 might all dissolve and be fixed by mineral reactions, essentially becoming permanently sequestered.

DOE and others are testing sequestration in deep saline deposits in the U.S. First round of tests are completed in the Frio formation, a deep saline deposit in Texas. A discussion of DOE's Regional Sequestration Partnership and summary of proposed projects follows in Section 5.10.

Deep unminable coal seams, possibly with coal bed methane recovery

Sequestration into deep coal seams has been proposed as a means to safely store CO_2 because the CO_2 will both react with the coal materials, and displace methane from the coal. Some tests have been performed for the purpose of enhancing coal-bed methane recovery, but little has been done to examine the sequestration issues. As with the other EOR technologies there is the potential benefit of increased energy production that could pay for some or all of the CO_2 sequestration costs.

5.10 CO_2 Sequestration Regional Partnerships

A very important effort to advance the technical knowledge and acceptance of sequestration is the U.S. DOE program of Regional Sequestration Partnerships. The seven partnerships include 40 States and 4 Canadian Provinces. More than 200 industry and government organizations are participating with the primary contractors. The major results and data from Phase I can be found at the NETL/DOE website.[72] These results will be used to deploy a geographic information system (GIS) database that will be available to partnership members and the public. DOE will use the regional data to develop a National/North American sequestration GIS.

As part of the regional effort to date, the partnerships examined CO_2 separation and capture technologies and have, to varying degrees, compared and matched technologies with the sources of CO_2 and the potential sequestration sites. The objective of this work was to estimate cost curves for carbon management within the region.

The same regional partnerships have been awarded contracts for a second phase of work. In Phase II, data collection, public awareness and regulatory assessment will continue, and fieldwork will inject small amounts of CO_2 into selected geological formations. Tests of terrestrial sequestration in the different regions will also be conducted.

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[72] NETL/DOE Website, www.netl.doe.gov/technologies/carbon_seq/partnerships/partnerships.html, accessed on May 30, 2006

As noted at the beginning of this report, challenges associated with geological sequestration could be the main obstacle to power generation carbon management. The DOE roadmap for sequestration includes one large scale sequestration project by 2009, but it is not clear how this demonstration would be coordinated with the regional partnerships' second phase, which also runs to about 2009 and DOE's FutureGen concept, which aims for completion by 2012. Such demonstrations will help reduce technical uncertainties, especially with regard to potential health, safety, and environmental impacts of commercial activities.

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Appendix A Cost Estimate Data

Appendix A covers the capital and operating cost estimates for IGCC and PC power plants. The costs are derived from recent published documents and Nexant experience with similar projects. The estimates specifically prepared for the plant configurations selected for this study are in the 4th Quarter 2004 dollars.

As noted previously, this study is a snapshot in time and costs as well as performance are evolving and changing as experience increases and because of more basic changes in the economy such as price changes (steel and energy are prime examples). The study costs are conceptually estimated for an Nth plant, i.e. one of many commercial facilities and not for demonstration or the first of a kind plants needed to obtain commercial viability. The Nth plant criteria are truer for PC plants than for IGCC plants because of the numbers built for each technology. There are also costs that can not be fully estimated such as site differences, warrantees/guarantees or fees for systems treating fuels or other conditions that are outside of the suppliers' experiences.

The uncertainty of cost estimates sometimes results in values presented as ranges, or with uncertainties assigned for all or parts of the estimates. The engineering level of this study did not employ this approach, but the study reader should be aware that the costs will vary for a number of reasons at the time of the "snapshot", and will also vary with time as the knowledge base expands.

Summary

Cost data presented in this appendix are drawn from a number of sources. Where appropriate, the data has been updated by escalation to the end of 2004 price and wage level, and adjusted to a consistent 500 MW net plant size. The costs are consistent with the plant performance estimates presented in the body of the report. However, it should be noted that site and design specific criteria can cause a significant range of costs that could only be refined with much more detailed engineering, including budgetary quotes and engineering packages from major technology suppliers.

Exhibits A-1 and A-2 summarize the cost estimates developed for the PC and IGCC plant configurations used in this study. The methodologies and sources for these estimates are discussed further in this appendix. While data is from several sources, the values have been adjusted as noted above and consistent factored cost elements such as engineering services, contingency and other owner's costs are used to calculate the cost categories in the exhibits.

Exhibit A-1, Total Capital Requirement and Operating Cost

Power Plants	Bituminous Coal	Subbituminous Coal	Lignite Coal
Subcritical PC			
Total Capital Requirement $/kW	1,347	1,387	1,424
Annual Operating Cost, 1,000s	27,700	28,300	29,640
Supercritical PC			
Total Capital Requirement $/kW	1,431	1,473	1,511
Annual Operating Cost, 1,000s	29,000	29,600	30,940
Ultra Supercritical PC			
Total Capital Requirement $/ kW	1,529	1,575	1,617
Annual Operating Cost, 1,000s	30,400	31,100	32,440
GE Energy IGCC			
Total Capital Requirement $/ kW	1,670	1,910	Not Applicable*
Annual Operating Cost, 1,000s	27,310	29,700	Not Applicable*
Shell IGCC			
Total Capital Requirement $/ kW	1,840	2,100	2,350
Annual Operating Cost, 1,000s	Not Reported	Not Reported	34,000

* The GE Energy gasification technology is not used with lignite.

Exhibit A-2 Summary of Costs

Power Plants	Total Plant Cost $/ kW	Total Plant Investment $/kW	Total Capital Requirement $/ kW	Operating Cost $1,000s
Subcritical PC				
Bituminous Coal	1,187	1,303	1,347	27,700
Subbituminous Coal	1,223	1,343	1,387	28,300
Lignite	1,255	1,378	1,424	29,640
Supercritical PC				
Bituminous Coal	1,261	1,384	1,431	29,000
Subbituminous Coal	1,299	1,426	1,473	29,600
Lignite	1,333	1,463	1,511	30,940
Ultra Supercritical PC				
Bituminous Coal	1,355	1,482	1,529	30,400

Power Plants	Total Plant Cost $/ kW	Total Plant Investment $/kW	Total Capital Requirement $/ kW	Operating Cost $1,000s
Subbituminous Coal	1,395	1,526	1,575	31,100
Lignite	1,432	1,566	1,617	32,440
GE Energy IGCC				
Bituminous Coal	1,430	1,610	1,670	27,310
Subbituminous Coal	1,630	1,840	1,910	29,700
Lignite*	Not Applicable	Not Applicable	Not Applicable	Not Applicable
Shell IGCC				
Bituminous Coal	1,570	1,770	1,840	Not Reported
Subbituminous Coal	1,790	2,020	2,100	Not Reported
Lignite	2,000	2,260	2,350	34,000

* The GE Energy gasification technology is not used with lignite.

Pulverized Coal Plant Cost Estimates

Capital Costs

Exhibits A-3, 4, and 5 present cost estimates for the pulverized coal plants with a capacity of 500 MW net. Exhibit A-3 show subcritical units with three study coal types – high-sulfur bituminous, low-sulfur subbituminous, and lignite. A breakdown of costs is shown for the first coal as an example of how costs are distributed among the major plant sections. Cost breakdowns would be similar for the other coals.

Exhibits A-4 and 5 show the estimates for supercritical and ultra-supercritical units and the three coals. An allowance for uncertainty (contingency) of 20% is used for the ultra-supercritical plant as an estimate of its less mature technology development. The allowance is 15% for other plants. Other cost factors used in the PC capital cost estimates are as follows:

- Engineering Services, 8% of Total Constructed Cost (TCC)
- Interest During Construction, 12% of TCC
- Startup, 2.5% of TCC
- Spare Parts, Working Capital, & Land, 2% of TCC
- Escalation to 2004 as required using 2% per year cost escalation

Exhibit A-6 presents a comparison of costs found in the literature for PC plants. While not exactly the same in all critical aspects, these plants are consistent and show the relatively small variance in costs from subcritical to ultra-supercritical. The differences in costs from the steam generator choice could easily be overshadowed by site conditions or owner preferences among the plants.

There is only a limited amount of cost information available in the industry for comparison of the PC plants fired by the three coals. The Canadian Clean Power Coalition (CCPC) published an executive summary of work with some information that is reported below.

Capital costs for supercritical plants in Canadian dollars (not reported, but the year is about 2002) and the associated heat rates are as follows:

300 MW lignite plant	$915 million	9,400 Btu/kWh
400 MW subbituminous plant	$1005 million	8,900 Btu/kWh
300 MW bituminous plant	$866 million	8,900 Btu/kWh

The above capital costs in $/kW, using 1.56 Canadian to U.S. dollars, are as follows:

300 MW lignite plant	$ 1,955
400 MW subbituminous plant	$ 1,610
300 MW bituminous plant	$ 1,850

There is a question of why the bituminous coal-fired plant is more expensive than the subbituminous plant. The CCPC has been contacted and asked if the reported values are correct, and the reason for the seemingly out-of-sequence cost comparison. The 500 MW bituminous supercritical plant cost developed for the EPA study is about $1,430 /kW. This is a significant difference with the DOE and EPRI costs, even considering Canadian conditions and economies of scale. The CCPC considers its work proprietary, and could not provide details that might explain the differences. The Canadian work, while noted, is not used in the current study.

An EPRI paper presented at the Gasification Technologies Conference, 2004, “Pulverized Coal and IGCC Plant Cost and Performance Estimates, George Booras and Neville Holt showed a graphic relationship between coal quality, cost and performance of PC plants and IGCC plants. The figure is repeated here as Exhibit A-7.

Exhibit A-3 Subcritical Pulverized Coal Estimates, 1,000s
2004 Price and Wage Level

500 MW Net	High-Sulfur Bituminous Coal				Subbitu-minous Coal	Lignite
Subcritical Pulverized Coal Plant	Equipment	Materials	Installation	Total Installed Cost	Total Installed Cost	Total Installed Cost
PC Boiler and Accessories	67,200	-	29,400	96,600	99,500	102,100
Flue Gas Cleanup	45,600	-	26,700	72,300	74,500	76,500
Ducting and Stack	13,100	400	10,400	23,900	24,600	25,300
Steam T-G Plant, including Cooling Water System	67,100	5,800	26,800	99,700	102,700	105,300
Accessory Electric Plant	12,200	3,800	11,100	27,100	27,900	28,700
Balance of Plant	61,200	25,200	76,700	163,100	168,000	172,400
Subtotal, Total Constructed Cost	266,400	35,200	181,100	482,700	497,200	510,300
Engineering Services, 8% of TCC				38,600	39,800	40,800
Allowance For Uncertainty, 15% of TCC				72,400	74,600	76,500
Total Plant Cost				593,700	611,600	627,600
Total Plant Cost - $ per Kilowatt				1,187	1,223	1,255
Interest During Construction (IDC), 12% of TCC				57,900	59,700	61,200
Total Plant Investment				651,600	671,300	688,800
Prepaid Royalties				0	0	0
Initial Catalyst and Chemicals				100	100	100
Startup, 2.5% of TCC				12,100	12,400	12,800
Spare Parts, Working Capital, & Land, 2% of TCC				9,700	9,900	10,200
Total Capital Investment				673,500	693,700	711,900
Total Capital Cost - $ per Kilowatt				1,347	1,387	1,424

Exhibit A-4 Supercritical Pulverized Coal Estimates, 1,000s
2004 Price and Wage Level

500 MW Net	High-Sulfur Bituminous Coal	Subbituminous Coal	Lignite
Supercritical Pulverized Coal Plant	Total Installed Cost	Total Installed Cost	Total Installed Cost
PC Boiler and Accessories	129,400	133,300	136,700
Flue Gas Cleanup	72,600	74,800	76,700
Ducting and Stack	24,300	25,000	25,700
Steam T-G Plant, including Cooling Water System	109,200	112,500	115,400
Accessory Electric Plant	28,600	29,400	30,200
Balance of Plant	148,600	153,000	157,000
Subtotal, Total Constructed Cost	512,700	528,000	541,700
Engineering Services, 8% of TCC	41,000	42,200	43,300
Allowance For Uncertainty, 15% of TCC	76,900	79,200	81,300
Total Plant Cost	630,600	649,400	666,300
Total Plant Cost - $ per Kilowatt	1,261	1,299	1,333
Interest During Construction (IDC), 12% of TCC	61,500	63,400	65,000
Total Plant Investment	692,100	712,800	731,300
Prepaid Royalties	0	0	0
Initial Catalyst and Chemicals	100	100	100
Startup, 2.5% of TCC	12,800	13,200	13,500
Spare Parts, Working Capital, & Land, 2% of TCC	10,300	10,600	10,800
Total Capital Investment	715,300	736,700	755,700
Total Capital Cost - $ per Kilowatt	1,431	1,473	1,511

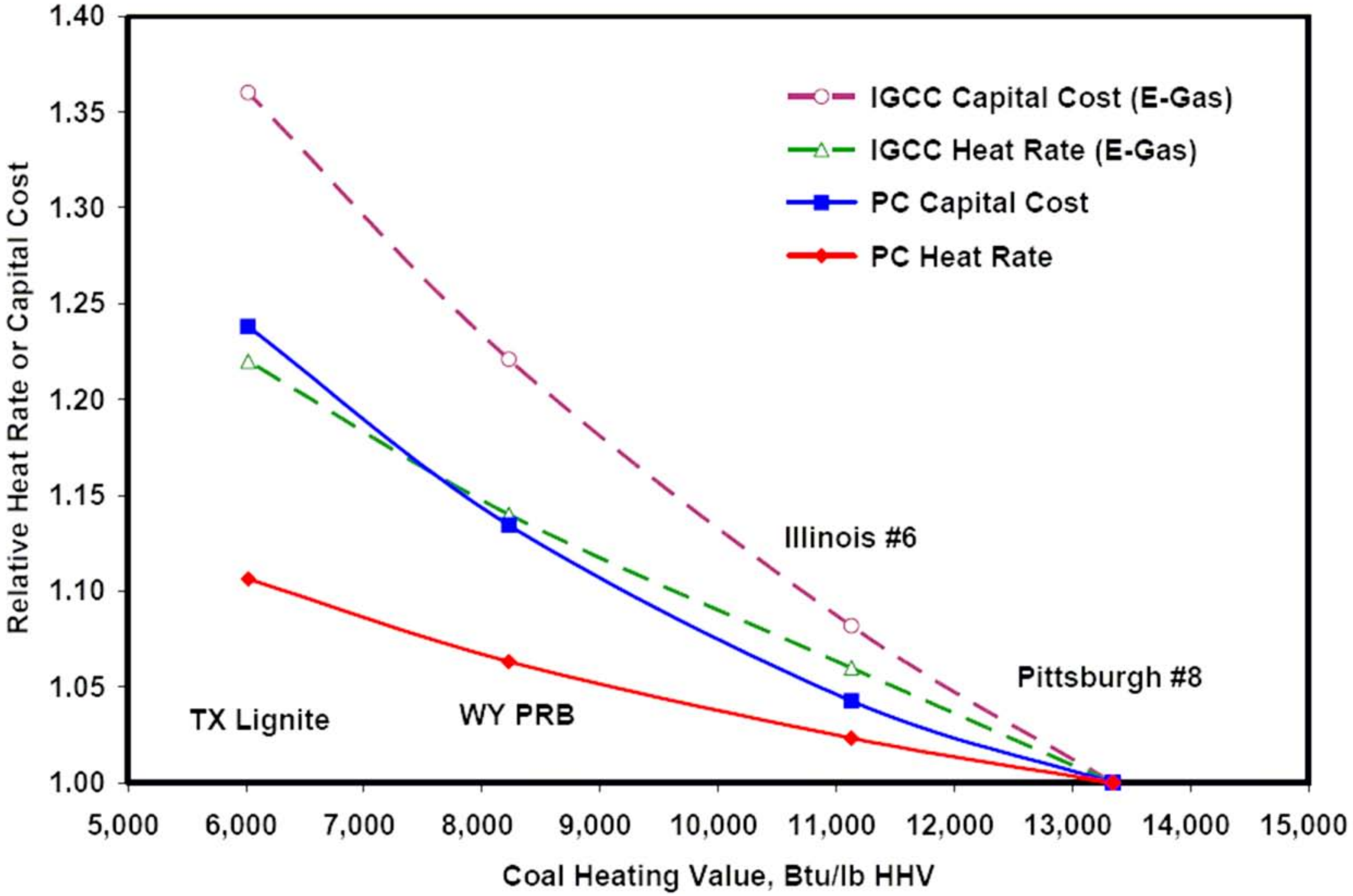
Exhibit A-5 Ultra Supercritical Pulverized Coal Estimates, 1,000s
2004 Price and Wage Level

500 MW Net	High-Sulfur Bituminous Coal	Subbituminous Coal	Lignite
Ultra Supercritical Pulverized Coal Plant	Total Installed Cost	Total Installed Cost	Total Installed Cost
PC Boiler and Accessories	138,200	142,300	146,000
Flue Gas Cleanup	67,500	69,500	71,400
Ducting and Stack	23,100	23,800	24,400
Steam T-G Plant, including Cooling Water System	130,800	134,700	138,200
Accessory Electric Plant	27,200	28,000	28,800
Balance of Plant	142,400	146,700	150,500
Subtotal, Total Constructed Cost	529,200	545,000	559,300
Engineering Services, 8% of TCC	42,300	43,600	44,700
Allowance For Uncertainty, 20% of TCC	105,800	109,000	111,900
Total Plant Cost	677,300	697,600	715,900
Total Plant Cost - $ per Kilowatt	1,355	1,395	1,432
Interest During Construction (IDC), 12% of TCC	63,500	65,400	67,100
Total Plant Investment	740,800	763,000	783,000
Prepaid Royalties	0	0	0
Initial Catalyst and Chemicals	100	100	100
Startup, 2.5% of TCC	13,200	13,600	14,000
Spare Parts, Working Capital, & Land, 2% of TCC	10,600	10,900	11,200
Total Capital Investment	764,700	787,600	808,300
Total Capital Cost - $ per Kilowatt	1,529	1,575	1,617

Exhibit A-6, Comparison of Cost Estimates from Published Sources

	Net Capacity, MW	Cost Year	Coal	SO$_2$ Control	NO$_X$ Control	Particulate	Heat Rate Btu/kWh % Efficiency, HHV	Total Plant Cost, $/kW
Market Based Advanced Coal Power Systems Final Report, May 1999 U.S. DOE/FE-0400								
Subcritical PC	400	1998	Illinois #6	WL-FGD	Low NO$_X$ Burners	ESP	9,077 37.6%	1,129
Supercritical PC	400	1998	Illinois #6	WL-FGD	Low NO$_X$ Burners, SCR	Fabric Filter	8,568 39.9%	1,173
Ultra Supercritical PC	400	1998	Illinois #6	WL-FGD	Low NO$_X$ Burners, SNCR	Fabric Filter	8,251 41.4	1,170
Evaluation of Innovative Fossil Fuel Power Plants with CO$_2$ Removal, EPRI, U.S. DOE/NETL 1000316 December 2000								
Supercritical PC	462	Dec-99	Illinois #6	WL-FGD	Low NO$_X$ Burners, SCR	Fabric Filter	8,421 40.5%	1,143
Ultra Supercritical PC	506	Dec-99	Illinois #6	WL-FGD	Low NO$_X$ Burners, SCR	Fabric Filter	7,984 42.7%	1,161
Pulverized Coal and IGCC Plant Cost and Performance Estimates, George Booras EPRI October 2004								
Subcritical PC	500	2003	Illinois #6	WL-FGD	Low NO$_X$ Burners, SCR	Fabric Filter	9,560	1,290
Subcritical PC	500	2003	Pittsburgh #8	WL-FGD	Low NO$_X$ Burners, SCR	Fabric Filter	9,310	1,230
Supercritical PC	500	2003	Illinois #6	WL-FGD	Low NO$_X$ Burners, SCR	Fabric Filter	8,920	1,340
Supercritical PC	500	2003	Pittsburgh #8	WL-FGD	Low NO$_X$ Burners, SCR	Fabric Filter	8,690	1,290

Exhibit A-7, Comparison of Coal Quality, Cost and Performance



Operating and Maintenance Costs

Operating costs from the DOE/NETL and EPRI report were reviewed and updated for the study. The costs are presented in Exhibit A-8.

Exhibit A-8, Annual Operating and Maintenance Costs, $1000s

Nominal 500 MW PC Plants	High Sulfur Bituminous Coal	Subbituminous Coal	Lignite
Subcritical Pulverized Coal			
Operating Labor	5,300	5,300	5,830
Maintenance	6,800	7,000	7,200
Administrative & Support Labor	2,100	2,100	2,310
Consumables	13,500	13,900	14,300
TOTAL	27,700	28,300	29,640
Supercritical Pulverized Coal			
Operating Labor	5,300	5,300	5,830
Maintenance	7,300	7,500	7,700
Administrative & Support Labor	2,100	2,100	2,310
Consumables	14,300	14,700	15,100
TOTAL	29,000	29,600	30,940
Ultra Supercritical Pulverized Coal			
Operating Labor	5,300	5,300	5,830
Maintenance	8,000	8,200	8,500
Administrative & Support Labor	2,100	2,100	2,310
Consumables	15,000	15,500	15,800
TOTAL	30,400	31,100	32,440

Fuel Costs and Credits for Byproducts are excluded.

As shown by the table, there is not a significant difference in O&M caused by coal type, or the PC technology. Operating and support labor is judged to be the same for the bituminous and subbituminous plants and somewhat more for lignite; Maintenance costs increase as the cost for the plants increase, as does consumables. The consumables include water, chemicals, miscellaneous consumables, and wastes disposal.

While not shown on the table because it is plant and location dependent, the fuel costs for the different coals would be a much larger delta of O&M costs. Typical costs and ranges for the three coals are shown on Exhibit A-9. Illinois and Ohio represent the high sulfur bituminous coal, North Dakota and Texas represent lignite and Wyoming is the subbituminous coal. (There is no explanation for the delivered Illinois price being lower than the mine cost.)

Exhibit A-8, 2004 Coal Price Data
EIA Coal Price Data 2004; cost per million Btus calculated

	$/ton	$/ton Delivered	$/MMBtu	$/MMBtu Delivered	Study Coals MMBtu/lb
Illinois	25.72	22.05	$ 1.10	$ 0.94	11,667
Ohio	23.82	31.99	$ 1.02	$ 1.37	11,667
North Dakota	9.67	10.20	$ 0.77	$ 0.81	6,312
Texas	15.39	21.82	$ 1.22	$ 1.73	6,312
Wyoming	7.12	15.28	$ 0.40	$ 0.87	8,800

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Integrated Gasification Combined Cycle Cost Estimates

Background

One of the first things to be noted is that costs vary among the alternative gasification and IGCC systems. The variations in cost are illustrated in later tables. For the present study, the summary results are limited to 500 MW net generation IGCC plants and three coals. For the bituminous and subbituminous coals a GE Energy (Ex-ChervonTexaco, Texaco) gasifier with coal-water slurry feed system is used. The unit includes radiant and convective heat recovery for higher efficient operations and uses two-50% gasification trains. For the high moisture lignite coal, a solid feed Shell gasifier is selected with two-50% gasification trains.

The estimated costs are summarized in Exhibit A-9. Costs are presented for Shell and the two other coals in addition to the lignite based plant. The costs are for the end of 2004 price and wage levels and 500 MW net IGCC plants. The costs are for plants with two 50% gasification trains, but do not have a spare gasifier.

Exhibit A-9, Summary of IGCC Cost Estimates

IGCC Plants	Bituminous Coal	Subbituminous Coal	Lignite Coal
GE Energy IGCC			
Total Plant Cost $/kW	1,430	1,630	Not Applicable
Total Plant Investment	1,610	1,840	Not Applicable
Total Capital Requirement $/kW	1,670	1,910	Not Applicable
Operating Cost	27,310	29,700	Not Applicable
Shell IGCC			
Total Plant Cost $/kW	1,570	1,790	2,000
Total Plant Investment	1,770	2,020	2,260
Total Capital Requirement $/kW	1,840	2,100	2,350
Operating Cost	Not Reported	Not Reported	34,000

While the ConocoPhillips technology has fewer operating installations than the GE Energy gasifier, estimates for the ConocoPhillips unit are consistently about $100 per kW less. This is relatively small in comparison to the total costs, and the cost values could change as site and coal specific designs are prepared for either or both technologies.

Cost Data

Two cost estimate tables are presented in Exhibits A-10 and 11. The exhibits show breakdowns of costs for the selected IGCC data. A later exhibit contains data from a number of recent publications, and is presented to compare costs across the data set for types of gasifiers with different types of coals.

Exhibit A-10, GE Energy (Ex-Texaco) IGCC Costs, $1,000s

Texaco Gasifier IGCC Base Case Escalated to 2004; Adjusted to 500 MW nominal size	Single Train Quench Gasifier	$/kW	Single Train Radiant + Convective Gasifier	$/kW
Coal Slurry Preparation	38,100	76	37,500	70
Oxygen Plant	73,800	148	74,000	137
Gasifier SINGLE UNIT	45,300	91	108,700	202
Soot Blower Recycle Compression	Na	na	4,800	9
Gas Cooling Saturation	24,100	48	14,500	27
MDEA	7,400	15	7,700	14
Claus	14,000	28	13,900	26
SCOT	5,900	12	5,900	11
Gas Turbine System	74,400	149	74,400	138
HRSG Steam Turbine	62,500	125	69,900	130
\Water Systems	24,400	49	29,200	54
Civil	31,800	64	37,900	70
Piping	24,400	49	29,200	54
Controls	8,900	18	10,700	20
Electrical	27,600	55	32,900	61
INSTALLED COST (IC)	462,600	925	551,200	1,023
Engineering, 8% of IC	37,000	74	44,100	82
Process Contingency, 5% of IC	23,100	46	27,600	51
Project Contingency, 15% of IC	69,400	139	82,700	153
TOTAL PLANT COST (TPC)	592,100	1,184	705,600	1,309
Total Plant Cost $/kW		1,184		1,309
Interest During Construction (IDC)	55,500	111	66,100	123
TOTAL PLANT INVESTMENT	647,600	1,295	771,700	1,432
Prepaid Royalties	2,310	5	2,760	5
Initial Catalyst and Chemicals	230	0	280	1
Startup	11,570	23	13,780	26
Spare Parts, Working Capital and Land	9,250	19	11,020	20
TOTAL CAPITAL REQUIREMENT	670,960	1,342	799,540	1,483
Total Capital Requirement $/kW	1,342		1,483	
Illinois #6 coal; Single train of gasification; W501 G turbine; cold gas cleaning (MDEA, CLAUS, SCOTT to elemental sulfur)				

Exhibit A-10 data is from the DOE/NETL report “Texaco Gasifier IGCC Base Cases”, PED-IGCC-98-001 latest revision June 2000. It is important to note that the costs are for a single train of gasification. Using two trains (50% each) or using two 50% trains plus a spare gasifier could increase costs by $150 to $200 per kW. The costs have been escalated to end of 2004 price levels and adjusted to 500 MW net plant size. Also, the cost items below the Installed Cost total have been adjusted to be consistent across the study plants. The plant with radiant and convective heat recovery generates more electricity and is more efficient, but is also more costly.

Exhibit A-11 shows similar (not as many breakdowns) data for the ConocoPhillips gasifier (Ex-EGas, Global Energy gasifier).

Exhibit A-11, ConocoPhillips (Ex-EGas) IGCC Costs, $1,000s

ConocoPhillips Gasifier Escalated to 2004; Adjusted to 500 MW nominal size	2 – 50% Gasifier Trains with H-Type Turbine	$/kW
Gasifier, ASU & Accessories	206,700	413
Gas Cleanup & Piping	42,400	85
Combustion Turbine and Accessories	77,200	154
HRSG, Ducting and Stack	25,800	52
Steam T-G Plant, including Cooling Water System	45,700	91
Accessory Electric Plant	28,800	58
Balance of Plant	106,500	213
INSTALLED COST	533,100	1,066
Engineering Services and Fee, 8%	533,100	1,066
Process Contingency, 5%	42,600	85
Project Contingency, 15%	26,700	53
TOTAL PLANT COST (TPC)	80,000	160
Total Plant Cost $/kW	682,400	1,365
Interest During Construction (IDC)	1,365	
TOTAL PLANT INVESTMENT	64,000	128
Prepaid Royalties	746,400	1,493
Initial Catalyst and Chemicals	2,700	5
Startup	300	1
Spare Parts	13,300	27
Working Capital	-	-
Land 200 Acres	10,700	21
TOTAL CAPITAL REQUIREMENT	-	-
Total Capital Requirement $/kW	773,400	1,547
Illinois #6 coal; 2 -50% trains of gasification; Advanced H turbine; cold gas cleaning (MDEA, CLAUS, SCOTT to elemental sulfur)		

Costs shown on Exhibit A-11 are from the DOE/NETL report “Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal”, 1000316, December 2000. Co-sponsors are U.S. DOE/NETL and EPRI. The costs have been escalated to the end of 2004 and adjusted to 500 MW net generation consistent with the process utilized for data in Exhibit A-10. From the two exhibits one may concluded that a reasonable Total Capital Cost would be $1,600 per kW, on a higher heating value basis. The higher cost value considers the GE Energy gasifier estimates only having a single gasifier train. The efficiency value may be optimistic in view of the relatively advanced turbines selected for the two cases.

Exhibit A-12 presents a compilation of data for the current study. Except for the first two items, which are summations of data in Exhibits A-10 and 11, the costs are raw data from the publications; they are not escalated or adjusted for plant size. However, the data is reasonably recent, and sizes are near the 500 MW nominal scale.

The data illustrates the cost variations for IGCC plants, even within the same category of gasifier. Design philosophies are important, especially the selection of gasification trains – a single train versus two 50% trains. Also, because of the relatively immature nature of the technology, some cases include spare gasification units as backup for planned and unplanned shutdowns.

Coal Quality and Cost

The great preponderance of engineering assessments for IGCC systems has been performed using bituminous coals as the feedstock. Because the gasifier vessel typically operates under pressure – from 400 to 1000 psia, and temperatures in the range of 2,500 F, two of the most widely used technologies have selected a coal/solids and water slurry feed to facilitate introduction of the solids into the gasifier. The third commercial unit developed by Shell and it licensee, Uhde, uses a lockhopper system to feed the solid fuel into the reactor. The feed for the Shell gasifier must be dried to about 5% total moisture to prevent material handling problems. The drying process for subbituminous and lignite coals can present technical problems, adds to the cost, and requires emission control.

In addition to the material handling issues and energy losses to evaporate excess water from the low rank coals, the water also increases the amount of oxygen that must be produced, again increasing costs and consuming more auxiliary power.

GE Energy has in the past declined to provide data for subbituminous and lignite coals as a feed for their gasifier. ConocoPhillips has claimed to be able to use subbituminous coals and are not clear about using lignite. For these various reasons, in this study, the GE Energy gasifier with radiant and convective heat recovery was chosen for the bituminous and subbituminous coals, and Shell is used with lignite.

To estimate costs for the three study coals, data shown on Exhibit A-12 from the studies by the Canadian Clean Power Coalition and EPRI was examined. The EPRI data appears to be the more consistent with experience at Nexant and Bechtel. The Canadian work is proprietary and details are not available. It is not clear that all of the impacts of the lignite, for example, have been accounted for in the cost or performance results. In an EIA report on the work, some of the results were either misprinted, or do not seem reasonable.

Exhibit A-12, Comparison of IGCC Cost Data $1,000s

Data Sources	Installed Cost	Total Plant Cost	Total Plant Cost $/kW	Total Plant Investment	Total Capital Requirement	Total Capital Requirement $/kW	% Efficiency HHV	MW Net	Feedstock
1. Texaco Gasifier IGCC Base Case; Escalated to 2004; Adjusted to 500 MW nominal size:[1,2]									
Quench Heat Recovery	462,635	592,173	1,184	665,207	692,507	1,385	39.7%	500	Illinois #6
Rad. + Conv. Heat Recovery	551,058	682,241	1,266	769,321	799,521	1,483	43.5%	539	Illinois #6
2. ConnocoPhillips with H Turbine Escalated to 2004; Adjusted to nominal 500 MW:[1,3]	533,100	682,400	1,365	764,288	795,654	1,591	43.1%	500	Illinois #6
3. IGCC Plant Cost and Performance Estimates:[4]									
ConocoPhillips with Spare			1,440			1,710	37.4%	500	Illinois #6
ConocoPhillips w/o Spare			1,330			1,580	37.4%	500	Illinois #6
ConocoPhillips with Spare			1,350			1,610	39.6%	500	Pittsburgh #8
ConocoPhillips w/o Spare			1,250			1,490	39.6%	500	Pittsburgh #8
4. 3/2005 GCEP Presentation, Neville Holt, EPRI, 2002 Data, all cases have spare gasifier.									
GE Quench (Texaco) 512 MW			1,300			Not Reported	36.7%	512	Pittsburgh #8
GE (Texaco) Radiant 550 MW			1,550			Not Reported	39.3%	550	Pittsburgh #8
ConocoPhillips 520 MW			1,350			Not Reported	39.6%	520	Pittsburgh #8
Shell 530 MW			1,650			Not Reported	40.7%	530	Pittsburgh #8
5. Canadian Clean Power Coalition[5]									
GE Energy Quench, 425 MW Net, Bituminous Coal			Not Reported			1,410	37.6%	425	Bituminous Coal

Data Sources	Installed Cost	Total Plant Cost	Total Plant Cost $/kW	Total Plant Investment	Total Capital Requirement	Total Capital Requirement $/kW	% Efficiency HHV	MW Net	Feedstock
GE Energy Quench, 425 MW Net, Subbituminous Coal			Not Reported			1,502	37.7%	425	Subbit. Coal
Shell Solid Feed Gasifier 425 MW Net, Lignite			Not Reported			1,644	37.8%	425	Lignite
6. IGCC Studies of CO_2 Capture for Sequestration:[6]									
Petroleum coke; 2 x Gasifier			1,276			Not Reported	40.8%	513	Petroleum coke
Pittsburgh #8; 2 x Gasifier			1,254			Not Reported	40.8%	524	Pittsburgh #8
Illinois #6; 2 x Gasifier			1,364			Not Reported	38.4%	522	Illinois #6
Powder River Basin Subbituminous; 3 x Gasifier			1,551			Not Reported	35.7%	520	PRB Subbit.
Lignite; 4 x Gasifier			1,738			Not Reported	33.4%	507	Lignite
ConocoPhillips Gasifier									

NOTES:

1. Items 1 and 2 are revised for this study. Other data is as published in the source materials.
2. “Texaco Gasifier IGCC Base Case,” PED-IGCC-98-001, U.S. DOE/NETL, June 2000
3. “”Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal,” 1000316, U.S. DOE/NETL and EPRI, December 2000 (Updated 2002)
4. G. Booras and N. Holt, “Pulverized Coal and IGCC Plant Cost and Performance,” Gasification Technologies, Washington, DC, October 3-6, 2004
5. “Phase I Executive Summary,” Canadian Clean Power Coalition, May 2004
6. N. Holt, et al., “Summary of Recent IGCC Studies of CO_2 Capture for Sequestration,” Gasification Technologies Conference, San Francisco, CA, October 14, 2003

Exhibit A-13 presents the cost results for the present study.

Exhibit A-13, IGCC Costs and Coal Quality

	GE Energy IGCC Bituminous 500 MW Net	GE Energy IGCC Subbituminous 500 MW Net	Shell IGCC Lignite 500 MW Net
Total Plant Cost $/kW	1,430	1,630	2,000
Total Plant Investment $/kW	1,610	1,840	2,260
Total Capital Requirement $/kW	1,670	1,910	2,350
Operating Costs $1,000s	27,310	29,700	34,000

Costs in Exhibit A-13 are for the GE Energy IGCC with radiant and convective heat recovery. Two 50% gasification trains are included for both the GE and Shell systems. While not done for the present study, it could be reasonable to add a higher level of risk, and thus contingency cost to the Shell and lignite plant. However, the costs are already so high that the option is unlikely to be commercially feasible. The Canadians appear to have switched from the assessment of gasification for lignites to the potential use of supercritical fluidized bed units. SaskPower is conducting a study for one of their plants that will evaluate the supercritical circulating fluidized bed option.

Cost Uncertainty

In addition to the typical project and process related uncertainties, the gasification technology costs may also vary because the estimates for permits, licenses, and other preliminary engineering items are not well defined. For example, gasification developers may charge significant amounts for coal tests and engineering "packages" that a power generator might use to evaluate technologies.

The questions about cost and performance guarantees still need to be answered. The three major gasification developers have teamed with engineering firms and plant component suppliers in an effort to structure the power plant so that performance and cost can be firmly established as is tradition for the power industry. Exactly how the guarantees will be negotiated and accepted by industry remains to be decided, but without some reasonable agreement on these points, arrangement of project financing will be difficult.

Gasification developers are presenting their technologies as the best option for carbon management by the power industry. Potential CO_2 regulations and carbon markets are other unknowns that make the costs uncertain and could at the minimum delay introduction into the power generation market.

Operating Cost

Operating costs from the Texaco Gasification report and other data were reviewed and updated for the study. The costs are presented in Exhibit A-14.

Exhibit A-14, Annual Operating and Maintenance Costs, $1,000s

IGCC O&M Items	High Sulfur Bituminous Coal	Subbituminous Coal	Lignite (Shell Technology)
Operating Labor	9,400	9,400	11,300
Maintenance	14,700	16,800	18,700
Administrative & Support Labor	1,200	1,200	1,400
Consumables	2,010	2,300	2,600
TOTAL	27,310	29,700	34,000

As shown by the table, there is not a significant difference in O&M caused by coal type except that lignite and the Shell technology will be more costly to operate and maintain. The consumables include water, chemicals for the MDEA, Scott, Claus and other processes, miscellaneous consumables, and wastes disposal.

While not shown on the table because it is plant and location dependent, the fuel costs for the different coals would cause a much larger delta between the O&M costs. Typical costs for the three coals at the mines are approximately $1.50, $0.75, and $0.50 per million Btu for bituminous, subbituminous and lignite coals respectively. Delivered costs to the power plant are more varied because of transportation and market competition impacts.

Appendix B Air Permit Raw Data

The exhibits in this appendix present the raw data for air emission limits summarized from recent air permits and other related documents.[73] Exhibit A presents criteria pollutants; Exhibit B has 3 tables and shows non-criteria pollutants. The following items provide further explanations of the data presented:

- For major pollutants, each emission value has been listed followed by the control device or method. For example in the first item the notation "0.15 pound per million Btu, Wet Flue Gas Desulfurization (Wet FGD)" is used in the SO_2 column.

- Blanks in the tables indicate that no data was found in the documents.

- Emission values listed, especially for criteria pollutants, mostly represent the actual emission limits provided in the permit documents. For certain emission values, data provided in the permit documents were used to convert these values to show them in consistent units for different plants.

- For some plants, more than one emission limit is provided in the permit documents for the same air pollutant. For example, two SO_2 emission limits may be provided for a plant based on different averaging periods (e.g., one based on a 24-hour rolling average and the other on a 30-day rolling average). In such cases, only the most stringent emission limit has been shown in the exhibits.

- The permit documents were examined to obtain emission values for all important air pollutants. However, for certain pollutants, either these documents did not contain any limits or the information was not provided in terms of actual limits that could be reported. These pollutants included fine particulate ($PM_{2.5}$), sulfur trioxide, silica, and hydrogen sulfide. In lieu of sulfur trioxide, the documents contained limits on sulfuric acid emissions, which are reported.

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[73] The permit documents reflect the information available as of February 2006. The reader should refer to the EPA RACT/BACT/LAER Clearing House Website, http://cfpub1.epa.gov/rblc/htm/bl02.cfm, and specific State websites to learn about permits for newly proposed facilities and any changes to the permit documents presently covered in this report.

Exhibit A, Criteria Pollutants From Air Permits and Other Documents

Projects	Fuel	Nitrogen Oxides (NO_X)	Sulfur Dioxide (SO_2)	Carbon Monoxide (CO)	Particulate Matter (overall)[7]	Particulate Matter (PM_{10})[7]	Lead (Pb)
Elm Road, Wisconsin: Two 615 MW Supercritical Pulverized Coal (PC) Boilers[1,2]	Bituminous Coal	0.07 lb/MMBtu Selective Catalytic Reduction (SCR)	0.15 lb/MMBtu Wet Limestone Flue Gas Desulfurization (WL-FGD)	0.12 lb/MMBtu	0.018 lb/MMBtu Baghouse and a Wet Electrostatic Precipitator (Wet ESP)	0.018 lb/MMBtu Baghouse and a Wet ESP	7.9 lb/TBtu
Comanche Generating Station, Unit 3, Pueblo, Pueblo County, Colorado: Super Critical PC Boiler Nominally Rated at 7,421 MMBtu/hr[4]	Subbituminous Coal	0.08 lb/MMBtu SCR	0.10 lb/MMBtu Lime Spray Dryer	0.13 lb/MMBtu	0.020 lb/MMBtu Baghouse	0.0120 lb/MMBtu Baghouse	
Longview Power, LLC Monongalia County West Virginia: 6,114 MMBtu/hr PC boiler, 600 MW[5]	Bituminous Coal	489 lb/hr (0.08 lb/MMBtu)[3] SCR	917 lb/hr (0.15lb/MMBtu) (97% reduction)[3] WL-FGD	673 lb/hr (0.11 lb/MMBtu)[3]	110 lb/hr (0.018 lb/MMBtu)[3] Baghouse	110 lb/hr (0.018 lb/MMBtu)[3] Baghouse	0.109 lb/hr (17.83 lb/TBtu[3])[3]

Projects	Fuel	Nitrogen Oxides (NO_X)	Sulfur Dioxide (SO_2)	Carbon Monoxide (CO)	Particulate Matter (overall)[7]	Particulate Matter (PM_{10})[7]	Lead (Pb)
Prairie State Generating Station, Illinois: Two 750 MW PC units[6]	Bituminous, Illinois coal (Herrin No. 6)	0.07 lb/MMBtu SCR	0.182 lb/MMBtu (98% reduction)[3] WL-FGD	0.12 lb/MMBtu	0.015 lb/MMBtu Dry Electrostatic Precipitator (ESP) and Wet ESP	0.035 lb/MMBtu (includes filterable and condensable; a limit of as low as 0.018 lb/MMBtu may be set, based on a field test) ESP and Wet ESP	0.0678 lb/h (0.0000091 lb/MMBtu)[3]
Intermountain Power Generating Station Unit 3, Millard County, Delta, Utah: PC Unit, 950-gross MW (900-net MW)[8,9]	Bituminous Coal, Sub-Bituminous Coal, and Blend	0.07 lb/MMBtu SCR	0.1 lb/MMBtu WL-FGD	0.15 lb/MMBtu	0.012 lb/MMBtu Baghouse		0.00002 lb/MMBtu,
Indeck-Elwood Energy Center, Elwood, Illinois: Nominal 660-MW Plant with two CFB boilers[10]	Bituminous, Illinois Coal	0.10 lb/MMBtu CFB boiler technology and Selective Non-Catalytic Reduction (SNCR)	0.15 lb/MMBtu CFB boiler technology, limestone addition to the bed, and Baghouse	0.10 lb/MMBtu	0.015 lb/MMBtu Baghouse		
Plum Point Energy Station, Arkansas: One PC Boiler 550-800 MW[11, 12]	Subbituminous Coal	0.09lb/MMBtu SCR	0.16 lb/MMBtu Lime Spray Dryer	0.16 lb/MMBtu	0.018 lb/MMBtu Baghouse	0.02 lb/MMBtu Baghouse	2.56x10^{-5} lb/MMBtu

Projects	Fuel	Nitrogen Oxides (NO_X)	Sulfur Dioxide (SO_2)	Carbon Monoxide (CO)	Particulate Matter (overall)[7]	Particulate Matter (PM_{10})[7]	Lead (Pb)
Thoroughbred Generating Station, Central City, Kentucky: Two PC Units, 750 MW[13, 14]	Bituminous Coal	0.08 lb/MMBtu SCR	0.167 lb/MMBtu WL-FGD	0.10 lb/MMBtu	0.018 lb/MMBtu ESP and Wet ESP	0.018 lb/MMBtu ESP and Wet ESP	0.00000386 lb/MMBtu
TS Power Plant, Eureka County, Nevada: One PC Unit, 200 MW[5]	Subbituminous Coal	0.067 lb/MMBtu SCR	0.09 lb/MMBtu for coal with ≥ 0.45% sulfur content (0.065 lb/MMBtu for coal with ≤ 0.45% sulfur content) Lime Spray Dryer	0.15 lb/MMBtu		0.012 lb/MMBtu Baghouse	
Santee Cooper Cross Generating Station Units 3 and 4, Berkeley County, South Carolina: Two PC Units, 5,700 MMBtu/hr[5]	Bituminous Coal (Petroleum Coke and Synfuel as secondary fuels)	0.08 lb/MMBtu SCR	0.13 lb/MMBtu (95% reduction)[3] WL-FGD	0.16 lb/MMBtu	0.015 lb/MMBtu ESP	0.018 lb/MMBtu ESP	0.0000169 lb/MMBtu
Holocomb Unit 2, Finney Kansas: One PC Unit, 660 MW[5]	Subbituminous Coal	0.12 lb/MMBtu (0.08 lb/MMBtu after initial 18 months) SCR	0.12 lb/MMBtu (94% reduction)[3] Lime Spray Dryer	0.15 lb/MMBtu		0.018 lb/MMBtu (99,71% reduction)[3] Baghouse	

Projects	Fuel	Nitrogen Oxides (NO_X)	Sulfur Dioxide (SO_2)	Carbon Monoxide (CO)	Particulate Matter (overall)[7]	Particulate Matter (PM_{10})[7]	Lead (Pb)
Limestone Electric Generating Station Units 1 and 2, Limestone County, Texas: PC Units, 7,863 MMBtu/hr[5]	Lignite (amendments to include sub-bituminous and petroleum coke)	0.5 lb/MMBtu[3] Water Injection	0.82 lb/MMBtu[3] WL-FGD	0.11 lb/MMBtu[3]	0.03 lb/MMBtu[3] ESP		0.000033 lb/MMBtu[3]
Elm Road, Wisconsin, IGCC Unit, 600 MW[2]	Bituminous Coal	15 ppmvd, 15% oxygen Diluent Injection System	0.03 lb/MMBtu Amine-based Scrubbing System	0.030 lb/MMBtu	0.011 lb/MMBtu Water Scrubbing	0.011 lb/MMBtu Water Scrubbing	0.0000257 lb/MMBtu
Kentucky Pioneer Energy Facility, Trapp Kentucky: IGCC Unit,540 MW net[15, 16]	High-sulfur Kentucky bituminous coal and pelletized refuse-derived fuel (RDF)	0.0735 lb/MMBtu based on 15 ppm by volume at 15 % oxygen Diluent Injection System	0.032 lb/MMBtu (99% reduction[3]) Syngas Scrubbing	0.032 lb/MMBtu Syngas Cleanup System	0.011 lb/MMBtu Syngas Cleanup System	0.011 lb/MMBtu Syngas Cleanup System	0.00001 lb/MMBtu[3]
Polk Power Station, Polk County Florida: IGCC Unit 260 MW unit[17, 19, 20]	Bituminous Coal, Coke, Blends	15 ppmvd Diluent Injection System (0.055 lb/MMBtu[3])	0.17 lb/MMBtu (97% reduction[3]) Amine-based Scrubbing System	Syngas 25 ppmvd (0.046 lb/MMBtu[3])	0.007 lb/MMBtu Water Scrubbing	0.007 lb/MMBtu Water Scrubbing	2.41×10^{-6} lb/MMBtu
Southern Illinois Clean Energy Center, Williamson County, Illinois: IGCC Unit, 544-MW (net)[18]	Bituminous Coal (Illinois Coal)	0.059 lb/MMBtu based on 15 ppmvd @ 15% O_2 Diluent Injection System	0.033 lb/MMBtu (99.36% reduction) Amine-Based Scrubbing System	0.04 lb/MMBtu	0.00924 lb/MMBtu (99.9% reduction) Dry Filter	0.00924 lb/MMBtu (99.9% reduction) Dry Filter	0.000001 lb/MMBtu

Projects	Fuel	Nitrogen Oxides (NO_X)	Sulfur Dioxide (SO_2)	Carbon Monoxide (CO)	Particulate Matter (overall)[7]	Particulate Matter (PM_{10})[7]	Lead (Pb)
Cash Creek, Kentucky: IGCC Unit, 677 MW[4]	Bituminous Coal	0.058 lb/MMBtu (0.087 lb/MMBtu on natural gas used as backup fuel) Diluent Injection System	0.043 lb/MMBtu Amine-based Scrubbing System	0.036 lb/MMBtu	0.007 lb/MMBtu Water Scrubbing	0.007 lb/MMBtu Water Scrubbing	

Exhibit B 1 of 3, Non-Criteria Pollutants from Air Permits and Other Documents

Projects	Mercury (Hg)	Volatile Organic Compounds (VOC)	Chlorides (HCl)	Fluorides (HF)	Hydrogen Sulfide (H_2S)	Reduced sulfur compounds	Ammonia (NH_3)
Elm Road, Wisconsin: Two 615 MW Supercritical Pulverized Coal (PC) Boilers[1,2]	1.12 lb/TBtu Heat Input Baghouse, WL-FGD and SCR system	0.0035 lb/MMBtu	16.2 pounds per hour	0.00088 lb/MMBtu			5 ppm and 20 pounds per hour.
Comanche Generating Station, Unit 3, Pueblo, Pueblo County, Colorado: Super Critical PC Boiler Nominally Rated at 7,421 MMBtu/hr[4]	20 x 10^{-6} lb/MWh	0.0035 lb/MMBtu	0.00064 lb/MMBtu,	0.00049 lb/MMBtu			
Longview Power, LLC Monongalia County West Virginia: 6,114 MMBtu/hr PC boiler, 600 MW[5]	1.46x10^{-2} lb/hr (0.0000024 lb/MMBtu)[3]	24.5 lb/hr (0.004 lb/MMBtu)[3]	0.61 lb/hr (1.00x10^{-4} lb/MMBtu)[3]	0.61 lb/hr (1.00x10^{-4} lb/MMBtu)[3]			

Projects	Mercury (Hg)	Volatile Organic Compounds (VOC)	Chlorides (HCl)	Fluorides (HF)	Hydrogen Sulfide (H_2S)	Reduced sulfur compounds	Ammonia (NH_3)
Prairie State Generating Station, Illinois: Two 750 MW PC units[6]	0.016 lb/h (0.0000021 lb/MMBtu)[3]	0.004 lb/MMBtu	24.4 lb/h (0.0033 lb/MMBtu)[3]	0.00026 lb/MMBtu			
Intermountain Power Generating Station Unit 3, Millard County, Delta, Utah: PC Unit, 950-gross MW (900-net MW)[8,9]	0.00000014 lb/MMBtu[3] (6 x 10^{-6} lb/ MWh) bituminous coal; and 0.00000046 lb/MMBtu (20 x 10^{-6} lb/ MWh)[3] subbituminous coal	0.0027lb/MMBtu	0.0042lb/MMBtu[3], (38.13 lb/hr)	0.0005 lb/MMBtu		0.00073 lb/MMBtu[3], (6.62 lb/hr)	
Indeck-Elwood Energy Center, Elwood, Illinois: Nominal 660-MW Plant with two CFB boilers[10]	0.000002 lb/MMBtu Injection of powdered activated carbon or other similar material	0.004 lb/MMBtu or 11.7 lbs/hour	0.01 lb/million or such lower limit, as low as 0.006 lb/MMBtu, as set by the Illinois EPA following the Permittee's evaluation of hydrogen chloride emissions and the acid gas control system	CFB boiler technology, limestone addition to the bed, and baghouse			

Projects	Mercury (Hg)	Volatile Organic Compounds (VOC)	Chlorides (HCl)	Fluorides (HF)	Hydrogen Sulfide (H_2S)	Reduced sulfur compounds	Ammonia (NH_3)
Plum Point Energy Station, Arkansas: One PC Boiler 550-800 MW[11, 12]	0.0000131 lb/MMBtu[3]	0.02 lb/MMBtu	0.0131 lb/MMBtu[3]	0.00044 lb/MMBtu or 90% reduction[3]			
Thoroughbred Generating Station, Central City, Kentucky: Two PC Units, 750 MW[13, 14]	0.00000321 lb/MMBtu	0.0072 lb/MMBtu	0.000825 lb/MMBtu	0.000159 lb/MMBtu			
TS Power Plant, Eureka County, Nevada: One PC Unit, 200 MW[5]				1.17 lb/MMBtu			
Santee Cooper Cross Generating Station Units 3 and 4, Berkeley County, South Carolina: Two PC Units, 5,700 MMBtu/hr[5]	0.0000036 lb/MMBtu SCR/WL-FGD/ESP	0.0024 lb/MMBtu	0.0024 lb/MMBtu	0.0003 lb/MMBtu			
Holocomb Unit 2, Finney Kansas: One PC Unit, 660 MW[5]		0.0035 lb/MMBtu					
Limestone Electric Generating Station Units 1 and 2, Limestone County, Texas: PC Units, 7,863 MMBtu/hr[5]	0.000051 lb/MMBtu[3]	0.0067 lb/MMBtu[3]	0.0155 lb/MMBtu[3]	0.01 lb/MMBtu[3]			

Projects	Mercury (Hg)	Volatile Organic Compounds (VOC)	Chlorides (HCl)	Fluorides (HF)	Hydrogen Sulfide (H_2S)	Reduced sulfur compounds	Ammonia (NH_3)
Elm Road, Wisconsin, IGCC Unit, 600 MW[2]	0.56lb/TBtu Carbon bed or filter containing similar material	0.004 lb/MMBtu					
Kentucky Pioneer Energy Facility, Trapp Kentucky: IGCC Unit,540 MW net[15, 16]	0.080 milligrams per dry standard cubic meter, corrected to 7% oxygen (0.0000007 lb/MMBtu[3])	0.0044 lb/MMBTU.	25 ppm by volume corrected to 7% oxygen (dry basis)				
Polk Power Station, Polk County Florida: IGCC Unit 260 MW unit[17]	0.0034 lb/h (1.9 lb/TBtu[3])	0.0017 lb/MMBtu					
Southern Illinois Clean Energy Center, Williamson County, Illinois: IGCC Unit, 544-MW (net)[18]	0.547 lb/TBtu Carbon Bed	0.0031 lb/MMBtu	1124.3 lb/TBtu	92.09 lb/TBtu			
Cash Creek, Kentucky: IGCC Unit, 677 MW[4]	0.00687 lb/hr	0.006 lb/MMBtu					

Exhibit B 2 of 3 Non-Criteria Pollutants from Air Permits and Other Documents

Projects	Arsenic (As)	Beryllium (Be)	Manganese (Mn)	Cadmium (Cd)	Chromium (Cr)	Formaldehyde	Nickel (Ni)	Silica (Si)
Elm Road, Wisconsin: Two 615 MW Supercritical Pulverized Coal (PC) Boilers[1,2]	5.99 lb/TBtu[3]	0.35 lb/TBtu	12.3 lb/TBtu[3]	1.1 lb/TBtu[3]	8.9 lb/TBtu[3]	48.0 lb/TBtu[3]	8.41 lb/TBtu[3]	
Comanche Generating Station, Unit 3, Pueblo, Pueblo County, Colorado: Super Critical PC Boiler Nominally Rated at 7,421 MMBtu/hr[4]								
Longview Power, LLC Monongalia County West Virginia: 6,114 MMBtu/hr PC boiler, 600 MW[5]		5.46×10^{-3} lb/hr						
Prairie State Generating Station, Illinois: Two 750 MW PC units[6]		0.0085 lb/h (1.14 lb/TBtu)						
Intermountain Power Generating Station Unit 3, Millard County, Delta, Utah: PC Unit, 950-gross MW (900-net MW)[8,9]								

Projects	Arsenic (As)	Beryllium (Be)	Manganese (Mn)	Cadmium (Cd)	Chromium (Cr)	Formaldehyde	Nickel (Ni)	Silica (Si)
Indeck-Elwood Energy Center, Elwood, Illinois: Nominal 660-MW Plant with two CFB boilers[10]		Addressed by limitation on PM Baghouse						
Plum Point Energy Station, Arkansas: One PC Boiler 550-800 MW[11, 12]	25 lb/TBtu[3]	2.38 lb/TBtu[3]	3.57 lb/TBtu[3]	3.1 lb/TBtu[3]	16.67 lb/TBtu[3]	15.48 lb/TBtu[3]	16.67 lb/TBtu[3]	
Thoroughbred Generating Station, Central City, Kentucky: Two PC Units, 750 MW[13, 14]	0.883 lb/TBtu	0.9 lb/TBtu	20.92 lb/TBtu	0.365 lb/TBtu	10.48 lb/TBtu			
TS Power Plant, Eureka County, Nevada: One PC Unit, 200 MW[5]								
Santee Cooper Cross Generating Station Units 3 and 4, Berkeley County, South Carolina: Two PC Units, 5,700 MMBtu/hr[5]		0.844 lb/TBtu						
Holocomb Unit 2, Finney Kansas: One PC Unit, 660 MW[5]								

Projects	Arsenic (As)	Beryllium (Be)	Manganese (Mn)	Cadmium (Cd)	Chromium (Cr)	Formaldehyde	Nickel (Ni)	Silica (Si)
Limestone Electric Generating Station Units 1 and 2, Limestone County, Texas: PC Units, 7,863 MMBtu/hr[5]	22.0 lb/TBtu[3]	9.0 lb/TBtu[3]	156 lb/TBtu[3]	7.6 lb/TBtu[3]	6.2 lb/TBtu[3]		62.0 lb/TBtu[3]	
Elm Road, Wisconsin, IGCC Unit, 600 MW[2]								
Kentucky Pioneer Energy Facility, Trapp Kentucky: IGCC Unit,540 MW net[15, 16]	6.0 lb/TBtu[3]	0.6 lb/TBtu	4.0 lb/TBtu[3]	0.020 milligrams per dry standard cubic meter, corrected to 7% oxygen (5.0 lb/TBtu[3])	1.1 lb/TBtu[3]		310 lb/TBtu[3]	
Polk Power Station, Polk County Florida: IGCC Unit 260 MW unit[17]	0.0006 lb/h	0.0001 lb/h						
Southern Illinois Clean Energy Center, Williamson County, Illinois: IGCC Unit, 544-MW (net)[18]	0.457 lb/TBtu	0.062 lb/TBtu	7.02 lb/TBtu	0.415 lb/TBtu	3.48 lb/TBtu		4.51 lb/TBtu	
Cash Creek, Kentucky: IGCC Unit, 677 MW[4]								

Exhibit B 3 of 3 Non-Criteria Pollutants from Air Permits and Other Documents

Projects	Selenium (Se)	Vanadium (V)	Total Reduced Sulfur (TRS)	Opacity	Sulfuric acid mist emissions
Elm Road,, Wisconsin: Two 615 MW Supercritical Pulverized Coal (PC) Boilers[1,2]	48.54 lb/TBtu[3]			20% or number 1 on the Ringlemann	0.010 lb/MMBtu heat input FGD system and wet electrostatic precipitator
Comanche Generating Station, Unit 3, Pueblo, Pueblo County, Colorado: Super Critical PC Boiler Nominally Rated at 7,421 MMBtu/hr[4]				10%	0.0042 lb/mmBtu lime spray dryer followed by a baghouse
Longview Power, LLC Monongalia County West Virginia: 6,114 MMBtu/hr PC boiler, 600 MW[5]				10%	45.8 lb/hr (0.0075 lb/MMBtu) dry sorbent injection in conjunction with fabric filter
Prairie State Generating Station, Illinois: Two 750 MW PC units[6]					0.005 lb/MMBtu WL-FGD (WFGD) and Wet Electrostatic Precipitator (WESP)

Projects	Selenium (Se)	Vanadium (V)	Total Reduced Sulfur (TRS)	Opacity	Sulfuric acid mist emissions
Intermountain Power Generating Station Unit 3, Millard County, Delta, Utah: PC Unit, 950-gross MW (900-net MW)[8,9]			0.00073 lb/MMBtu[3], (6.62 lb/hr)		0.0044 lb/MMBtu
Indeck-Elwood Energy Center, Elwood, Illinois: Nominal 660-MW Plant with two CFB boilers[10]				20%	Addressed by limitation on SO_2 CFB boiler technology, limestone addition to the bed, and baghouse
Plum Point Energy Station, Arkansas: One PC Boiler 550-800 MW[11, 12]					0.0061 lb/MMBtu
Thoroughbred Generating Station, Central City, Kentucky: Two PC Units, 750 MW[13, 14]				20%	0.00497 lb/MMBtu

Projects	Selenium (Se)	Vanadium (V)	Total Reduced Sulfur (TRS)	Opacity	Sulfuric acid mist emissions
TS Power Plant, Eureka County, Nevada: One PC Unit, 200 MW[5]					2.06 lb/hr
Santee Cooper Cross Generating Station Units 3 and 4, Berkeley County, South Carolina: Two PC Units, 5,700 MMBtu/hr[5]					0.0014 lb/MMBtu
Holocomb Unit 2, Finney Kansas: One PC Unit, 660 MW[5]					
Limestone Electric Generating Station Units 1 and 2, Limestone County, Texas: PC Units, 7,863 MMBtu/hr[5]	0.00137 lb/MMBtu	0.000267 lb/MMBtu		15 %	
Elm Road, Gasification Combined Cycle Unit, Wisconsin: 600 MW[2]				0%	0.0005 lb/MMBtu

Projects	Selenium (Se)	Vanadium (V)	Total Reduced Sulfur (TRS)	Opacity	Sulfuric acid mist emissions
Kentucky Pioneer Energy Facility, Trapp Kentucky: IGCC Plant,540 MW net[15, 16]	1.4 lb/TBtu[3]				
Polk Power Station, Polk County Florida: IGCC Plant 260 MW unit				10%	55 lb/h
Southern Illinois Clean Energy Center, Williamson County, Illinois: IGCC Plant, 544-MW (net)[18]	12.5 lb/TBtu			20%	0.0042 lb/MMBtu
Cash Creek, Kentucky: IGCC Plant, 677 MW[4]					

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20. Tampa Electric Integrated Gasification Combined-Cycle Project, DOE/FE-0469, June 2004.

Appendix C Energy and Material Balances

Appendix C presents the detailed energy and material (E&M) balance tables produced for the IGCC and PC plants. These tables were prepared with Nexant's spreadsheet model to estimate plant performances and validate the emissions values determined from air permits and other sources. Thus, the E&M balance tables may not equal other values used in the report either from rounding, differences in calculations, or the value may have been determined by other methods than the balance table models. The sources for emission values are documented in the text or footnotes as they are provided in the report.

The E&M balance for each IGCC and PC plant configuration includes a summary of major plant performance parameters as well as conditions of major flow streams. The flow stream numbers shown in each E&M correspond to the numbers shown in Exhibit 2-2, Integrated Gasification Combined Cycle Block Diagram, and Exhibit 2-4, Pulverized Coal Plant Block Diagram.

The major parameters covered in each E&M balance include the following:

- Plant thermal efficiencies, heat rates, power outputs, fuel consumption, and byproduct amount (if any)
- Amounts of solids, liquids, and gas constituents present in each flow stream
- Pressure, temperature, and energy content of each flow stream

IGCC Energy and Material Balances

GE Energy Slurry Feed Gasifier and Bituminous Coal – Summary

Cold Gas Efficiency	% HHV	77.8
Net Thermal Efficiency	% HHV	41.8
Net Heat Rate (HHV)	Btu/kWh	8,167
Gross Power	MW	564
Internal Power	MW	64
Steam Turbine	MW	127.5
Gas Turbine	MW	436.5
Fuel Required	lb/h	349,744
Sulfur By-product	lb/h	8,679

GE Energy Slurry Feed Gasifier and Bituminous Coal – E&M Balance

Stream	Stream No.	1 Raw Coal	2 Feed to Gasifier	3 Oxygen	4 Raw Gas	5 Clean Fuel Gas	6 GT Exhaust	7 Flue Gas to Stack	8 Slag to Disposal	9 Sulfur Product
Solids	Units									
Coal, daf	lb/h	275,913	275,913							
Bitumen		0	0							
Carbon/Char		0	0						1,115	
Ash/Slag		34,939	34,939						34,939	
Sorb/Flux		0	0						0	
$CaSO_4$		0	0						0	
Elem. Sulfur		0	0						0	8,679
Water		38,892	156,595						19,414	
Subtotal	lb/h	349,744	467,448						55,468	8,679
Gas	lb/h									
O_2				271,867	0	0	993,116	993,116		
N_2				12,527	16,910	16,840	4,649,773	4,649,773		
CO_2				0	150,553	112,291	770,555	811,951		
H_2O				0	95,498	197,995	432,672	432,672		
H_2				0	22,054	21,949	0	0		
CO				0	420,949	418,954	122	122		
CH_4				0	0	0	0	0		
C_2H_6				0	0	0	0	0		
H_2S				0	8,667	87	0	0		
COS				0	1,149	11	0	0		
SO_2				0	0		175	175		
NO_2				0	0	0	200	200		
Subtotal	lb/h	0	0	284,393	715,780	768,129	6,846,612	6,888,008	0	0
Total	lb/h	349,744	467,448	284,393	715,780	768,129	6,846,612	6,888,008	55,468	8,679

Stream	Stream No.	1 Raw Coal	2 Feed to Gasifier	3 Oxygen	4 Raw Gas	5 Clean Fuel Gas	6 GT Exhaust	7 Flue Gas to Stack	8 Slag to Disposal	9 Sulfur Product
Pressure	psia	15	609	537	464	450	15	15	15	15
Temperature	°F	77	158	307	2,606	572	1,107	248	77	77
Total Energy	mmBtu/h	4,083	4,113	17	4,050	4,097	2,433	838	18	35

Stream	Stream No.	10 Cooling Water	11 CT Make Up Water	12 Waste Water Discharge
Solids	Units			
Coal, daf	lb/hr			
Bitumen				
Carbon/Char				
Ash/Slag				
Sorb/Flux				
$CaSO_4$				
Elem. Sulfur				
Water	lb/hr	17,675,601	1,586,094	13,328
Subtotal	lb/hr	17,675,601	1,586,094	13,328
Gas				
O_2				
N_2				
CO_2				
H_2O				
H_2				
CO				

Stream	Stream No.	10 Cooling Water	11 CT Make Up Water	12 Waste Water Discharge
CH_4				
C_2H_6				
H_2S				
COS				
SO_2				
NO_2				
Subtotal	lb/hr	0	0	0
Total	lb/hr	17,675,601	1,586,094	13,328
Pressure	psia	65	50	30
Temperature	^oF	115	80	80
Total Energy	mmBtu/h	1,502	81	0.7

GE Energy Slurry Feed Gasifier and Subbituminous Coal - Summary

Cold Gas Efficiency	% HHV	69.1
Net Thermal Efficiency	% HHV	40.0
Net Heat Rate (HHV)	Btu/kWh	8,520
Gross Power	MW	575
Internal Power	MW	75
Steam Turbine	MW	160
Gas Turbine	MW	415
Fuel Required	lb/h	484,089
Sulfur By-product	lb/h	1,044

GE Energy Slurry Feed Gasifier and Subbituminous Coal – E&M Balance

	Stream No.	1	2	3	4	5	6	7	8	9
Stream		Raw Coal	Feed to Gasifier	Oxygen	Raw Gas	Clean Fuel Gas	GT Exhaust	Flue Gas to Stack	Slag to Disposal	Sulfur Product
Solids	Units									
Coal, daf	lb/h	329,568	329,568							
Bitumen		0	0							
Carbon/Char		0	0						1,216	
Ash/Slag		21,881	21,881						21,881	
Sorb/Flux		0	0						0	
$CaSO_4$		0	0						0	
Elem. Sulfur		0	0						0	1,044
Water		132,641	298,055						12,437	
Subtotal	lb/h	484,089	649,503	0	0	0	0	0	35,534	1,044

	Stream No.	1	2	3	4	5	6	7	8	9
Stream		Raw Coal	Feed to Gasifier	Oxygen	Raw Gas	Clean Fuel Gas	GT Exhaust	Flue Gas to Stack	Slag to Disposal	Sulfur Product
Gas	lb/h									
O_2				325,115	0	0	934,053	934,053		
N_2				14,980	18,143	18,069	4,355,256	4,355,256		
CO_2				0	321,041	239,462	802,488	886,729		
H_2O				0	243,526	67,804	304,477	304,477		
H_2				0	22,557	22,451	0	0		
CO				0	360,040	358,346	128	128		
CH_4				0	0	0	0	0		
C_2H_6				0	0	0	0	0		
H_2S				0	1,042	10	0	0	2,109	
COS				0	138	1	0	0		
SO_2				0	0		51	51		
NO_2				0	0	0	188	188		
Subtotal	lb/h	0	0	340,095	966,488	706,144	6,396,641	6,480,882	2,109	0
Total	lb/h	484,089	649,503	340,095	966,488	706,144	6,396,641	6,480,882	37,643	1,044
Pressure	psia	15	609	537	464	450	15	15	15	15
Temperature	°F	77	158	307	2,606	572	1,108	248	77	77
Total Energy	mmBtu/h	4,260	4,309	21	4,257	2,463	2,143	671	19	4

Stream	Stream No.	10 Cooling Water	11 CT Make Up Water	12 Waste Water Discharge
Solids	Units			
Coal, daf	lb/hr			
Bitumen				
Carbon/Char				
Ash/Slag				
Sorb/Flux				
$CaSO_4$				
Elem. Sulfur				
Water		22,195,009	1,982,121	10580
Subtotal	lb/hr	22,195,009	1,982,121	10,580
Gas	lb/hr			
O_2				
N_2				
CO_2				
H_2O				
H_2				
CO				
CH_4				
C_2H_6				
H_2S				
COS				
SO_2				
NO_2				
Subtotal	lb/hr	0	0	0
Total	lb/hr	22,195,009	1,982,121	10,580
Pressure	psia	65	50	30
Temperature	^oF	115	80	80
Total Energy	mmBtu/h	1,887	100	0.8

Shell Solid Feed Gasifier and Lignite Coal - Summary

Cold Gas Efficiency	% HHV	78.4
Net Thermal Efficiency	% HHV	39.2
Net Heat Rate (HHV)	Btu/kWh	8,707
Gross Power	MW	580
Internal Power	MW	80
Steam Turbine	MW	221
Gas Turbine	MW	359
Fuel Required	lb/h	689,721
Sulfur By-product	lb/h	4,370

Shell Solid Feed Gasifier and Lignite Coal – E&M Balance

Stream	Stream No.	1 Raw Coal	2 Feed to Gasifier	3 Oxygen	4 Raw Gas	5 Clean Fuel Gas	6 GT Exhaust	7 Flue Gas to Stack	8 Slag to Disposal	9 Sulfur Product
Solids	Units									
Coal, daf	lb/h	350,654	350,654							
Bitumen			0							
Carbon/Char									501	
Ash/Slag		123,598	123,598						123,598	
Sorb/Flux			0						0	
$CaSO_4$									0	
Elem. Sulfur										4,370
Water		215,469	24,961						66,822	
Subtotal	lb/h	689,721	499,213						190,921	4,370

	Stream No.	1	2	3	4	5	6	7	8	9
Stream		Raw Coal	Feed to Gasifier	Oxygen	Raw Gas	Clean Fuel Gas	GT Exhaust	Flue Gas to Stack	Slag to Disposal	Sulfur Product
Gas	lb/h									
O_2				273,807	0	0	1,083,611	1,083,611		
N_2				12,616	55,196	54,596	5,079,109	5,079,109		
CO_2				0	69,698	51,516	887,239	915,121		
H_2O				0	14,608	230,435	427,727	427,727		
H_2					17,603	17,401				
CO					538,044	531,871	131	131		
CH_4					15	15				
C_2H_6					0	0				
H_2S					4,363	44				
COS					578	6			8,747	
SO_2							87	87		
NO_2							218	218		
Subtotal	lb/h			286,423	700,107	885,884	7,476,794	7,506,322	8,747	
Total	lb/h	689,721	499,213	286,423	700,107	885,884	7,476,794	7,506,322	199,668	4,370
Pressure	psia	15	537	464	392	377	15	15	15	15
Temperature	°F	77	158	298	2,939	572	1,106	248	77	77
Total Energy	mmBtu/h	4,354	4,371	17	4,191	2,419	2,596	865	12	17

	Stream No.	10	11	12
Stream		Cooling Water	CT Make Up Water	Waste Water Discharge
Solids	Units			
Coal, daf	lb/hr			
Bitumen				

Stream	Stream No.	10 Cooling Water	11 CT Make Up Water	12 Waste Water Discharge
Carbon/Char				
Ash/Slag				
Sorb/Flux				
$CaSO_4$				
Elem. Sulfur				
Water	lb/hr	30,637,708	2,848,710	29,494
Subtotal	lb/hr	30,637,708	2,848,710	29,494
Gas				
O_2				
N_2				
CO_2				
H_2O				
H_2				
CO				
CH_4				
C_2H_6				
H_2S				
COS				
SO_2				
NO_2				
Subtotal	lb/hr	0	0	0
Total	lb/hr	30,637,708	2,848,710	29,494
Pressure	psia	65	50	30
Temperature	^oF	115	80	80
Total Energy	mmBtu/h	1,441	46	0.6

PC Plant Energy and Material Balances

Subcritical PC and Bituminous Coal - Summary

Summary		
Net Thermal Efficiency	35.9	% HHV
Net Heat Rate (HHV)	9,500	Btu/kWh
Gross Power	540	MW
Internal Power	40	MW
Fuel required	407,143	lb/h
Net Power	500	MW

Subcritical PC and Bituminous Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
Solids	Units									
Coal, daf	lb/h	321,195	0	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	0	0	36,194	0
Ash/Slag		40,674	0	0	8,427	33,707	33,232	475	0	0
$CaSO_4.2H_2O$		0	0	0	0	0	0	0	0	54,086

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
Water		45,274	0	3,571,590	0	0	0	0	0	6,010
Subtotal	lb/h	407,143	0	3,571,590	8,427	33,707	33,232	475	36,194	60,095
Gas										
O_2		0	1,002,292	0	0	183,426	0	183,426	0	0
N_2		0	3,302,954	0	0	3,308,035	0	3,308,035	0	0
CO_2		0	0	0	0	946,162	0	946,162	0	0
H_2O		0	27,419	0	0	245,089	0	227,859	0	0
SO_2		0	0	0	0	20,391	0	20,391	0	0
NO_2		0	0	0	0	285	0	285	0	0
Subtotal	lb/h	0	4,332,665	0	0	4,703,387	0	4,686,158	0	0
TOTAL	lb/h	407,143	4,332,665	3,571,590	8,427	4,737,094	33,232	4,686,633	36,194	60,095
Pressure	psia	14.7	14.7	2,415	14.7	14.0	14.7	15.0	14.7	14.7
Temperature	°F	59	59	1,000	2,498	288	287	302	32	86
Total Energy	mmBtu/h	4,753	58	5,216	12	583	18	561	0	1

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam to T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
Solids	Units							
Coal, daf	lb/h	0						
Sorbent		0						
Ash/Slag		57						
$CaSO_4.2H_2O$		0						
Water		0	3,250,147	2,762,625	74,518,170	3,058,656	1,512,294	38,461
Subtotal	lb/h	57	3,250,147	2,762,625	74,518,170	3,058,656	1,512,294	38,461
Gas								

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam to T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
O_2		183,426						
N_2		3,308,035						
CO_2		958,769						
H_2O		429,620						
SO_2		409						
NO_2		285						
Subtotal	lb/h	4,880,543	0	0	0	0	0	0
TOTAL	lb/h	4,880,600	3,250,147	2,762,625	74,518,170	3,058,656	1,512,294	38,461
Pressure	psia	14.7	560.0	115	55	25	15	15
Temperature	°F	128	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	580	4,934	2,832	2,832	3120	73	2

Subcritical PC and Subbituminous Coal - Summary

Summary		
Net Thermal Efficiency	34.8	% HHV
Net Heat Rate (HHV)	9,800	Btu/kWh
Gross Power	541	MW
Internal Power	41	MW
Fuel required	556,818	lb/h
Net Power	500	MW

Subcritical PC and Subbituminous Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas SDA	6 Lime to SDA	7 SDA Filter Waste	8 Flue Gas To Stack
Solids	Units								
Coal, daf	lb/h	379,082	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	4,242	0	0
Ash/Slag		25,168	0	0	5,421	21,686	0	21,627	59
$CaSO_4.2H_2O$		0	0	0	0	0	0	13,029	0
Water		152,568	0	3,577,159	0	0	21,210		0
Subtotal	lb/h	556,818	0	3,577,159	5,421	21,686	25,452	34,656	59
Gas									
O_2		0	987,528	0	0	180,724	0	0	180,724
N_2		0	3,254,301	0	0	3,257,947	0	0	3,257,947
CO_2		0	0	0	0	1,026,489	0	0	1,028,081
H_2O		0	27,015	0	0	318,550	0	0	504,140

Stream	Stream No.	1	2	3	4	5	6	7	8
		Coal Feed	Combustion Air	HP Steam to T/G	Bottom Ash	Flue Gas SDA	Lime to SDA	SDA Filter Waste	Flue Gas To Stack
SO_2		0	0	0	0	2,438	0	0	319
NO_2		0	0	0	0	2,94	0	0	294
Subtotal	lb/h	0	4,268,845	0	0	4,786,443	0	0	4,971,505
TOTAL	lb/h	556,818	4,268,845	3,577,159	5,421	4,808,129	25,452	34,656	4,971,564
Pressure	psia	14.7	14.7	2,415	14.7	15.0	14.7	14.7	14.7
Temperature	°F	59	59	1,000	2,498	270	59	86	132
Total Energy	mmBtu/h	4,649	57	5,224	11	630	0	0	699

Stream	Stream No.	9	10	11	12	13	14
		Reheat Steam to T/G	Turbine Exhaust to Condenser	Cooling Water to Condenser	Cooling Tower Evaporative Loses	Cooling Tower Blowdown	Waste Water (from Process)
Solids	Units						
Coal, daf	lb/h						
Sorbent							
Ash/Slag							
$CaSO_4.2H_2O$							
Water		3,255,214	2,766,932	74,634,356	3,160,892	1,563,107	7,818
Subtotal	lb/h	3,255,214	2,766,932	74,634,356	3,160,892	1,563,107	7,818
Gas							
O_2							
N_2							
CO_2							
H_2O							

Stream	Stream No.	9 Reheat Steam to T/G	10 Turbine Exhaust to Condenser	11 Cooling Water to Condenser	12 Cooling Tower Evaporative Loses	13 Cooling Tower Blowdown	14 Waste Water (from Process)
SO_2 NO_2							
Subtotal	lb/h	0	0	0	0	0	0
TOTAL	lb/h	3,255,214	2,766,932	74,634,356	3,160,892	1,563,107	7,818
Pressure	psia	560.0	115	55	25	15	15
Temperature	°F	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	4,941	2,836	2,836	3,225	75	0

Subcritical PC and Lignite Coal - Summary

Summary		
Net Thermal Efficiency	33.1	% HHV
Net Heat Rate (HHV)	10,300	Btu/kWh
Gross Power	544	MW
Internal Power	44	MW
Fuel required	815,906	lb/h
Net Power	500	MW

Subcritical PC and Lignite Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
Solids	Units									
Coal, daf	lb/h	414,480	0	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	0	0	18,135	0
Ash/Slag		146,537	0	0	29,738	118,951	118,461	490	0	0
$CaSO_4.2H_2O$		0	0	0	0	0	0	0	0	30,741
Water		254,889	0	3,596,072	0	0	0	0	0	3,416
Subtotal	lb/h	815,906	0	3,596,072	29,738	118,951	118,461	490	18,135	34,156
Gas		0	0	0	0	0	0	0	0	0
O_2		0	1,055,749	0	0	193,209	0	193,209	0	0
N_2		0	3,479,117	0	0	3,484,871	0	3,484,871	0	0
CO_2		0	0	0	0	1,078,921	0	1,078,921	0	0
H_2O		0	28,881	0	0	469,265	0	449,785	0	0

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
SO_2		0	0	0	0	10,424	0	10,424	0	0
NO_2		0	0	0	0	309	0	309	0	0
Subtotal	lb/h	0	4,563,748	0	0	5,237,000	0	5,217,520	0	0
TOTAL	lb/h	815,906	4,563,748	3,596,072	29,738	5,355,951	118,461	5,218,010	18,135	34,156
Pressure	psia	14.7	14.7	2,415	14.7	14.0	14.7	15.0	14.7	14.7
Temperature	°F	59	59	1,000	2,498	279	278	293	32	86
Total Energy	mmBtu/h	4,903	61	5,251	34	868	30	833	0	1

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam To T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
Solids	Units							
Coal, daf	lb/h	0						
Sorbent		0						
Ash/Slag		62						
$CaSO_4$.2H2O		0						
Water		0	3,272,426	2,781,562	75,028,976	3,341,047	1,651,773	21,860
Subtotal	lb/h	62	3,272,426	2,781,562	75,028,976	3,341,047	1,651,773	21,860
Gas								
O_2		193,209						
N_2		3,484,871						
CO_2		1,085,724						
H_2O		657,156						
SO_2		443						
NO_2		309						

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam To T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
Subtotal	lb/h	5,421,475	0	0	0	0	0	0
TOTAL	lb/h	5,421,537	3,272,426	2,781,562	75,028,976	3,341,047	1,651,773	21,860
Pressure	psia	14.7	560.0	115	55	25	15	15
Temperature	°F	139	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	857	4,968	2,851	2,851	3,408	79	1

Supercritical PC and Bituminous Coal - Summary

Summary		
Net Thermal Efficiency	38.3	% HHV
Net Heat Rate (HHV)	8,900	Btu/kWh
Gross Power	540	MW
Internal Power	40	MW
Fuel required	381,418	lb/h
Net Power	500	MW

Supercritical PC and Bituminous Coal – E&M Balance

	Stream No.	1	2	3	4	5	6	7	8	9
Stream		Coal Feed	Combustion Air	HP Steam to T/G	Bottom Ash	Flue Gas to Filter	Ash From Filter	Flue Gas to FGD	Limestone to FGD	Gypsum from FGD
Solids	Units									
Coal, daf	lb/h	300,901	0	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	0	0	34,666	0
Ash/Slag		38,104	0	0	7,894	31,577	31,132	445	0	0
$CaSO_4.2H_2O$		0	0	0	0	0	0	0	0	51,802
Water		42,414	0	3,576,288	0	0	0	0	0	5,756
Subtotal	lb/h	381,418	0	3,576,288	7,894	31,577	31,132	445	34,666	57,558
Gas										

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
O_2		0	938,963	0	0	171,836	0	171,836	0	0
N_2		0	3,094,261	0	0	3,099,021	0	3,099,021	0	0
CO_2		0	0	0	0	886,380	0	886,380	0	0
H_2O		0	25,687	0	0	230,135	0	213,993	0	0
SO_2		0	0	0	0	19,102	0	19,102	0	0
NO_2		0	0	0	0	267	0	267	0	0
Subtotal	lb/h	0	4,058,911	0	0	4,406,742	0	4,390,599	0	0
TOTAL	lb/h	381,418	4,058,911	3,576,288	7,894	4,438,319	31,132	4,391,045	34,666	57,558
Pressure	psia	14.7	14.7	3,515	14.7	14.0	14.7	15.0	14.7	14.7
Temperature	°F	59	59	1,050	2,498	288	287	302	32	86
Total Energy	mmBtu/h	4,453	54	5,083	11	546	17	526	0	1

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam to T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
Solids	Units							
Coal, daf	lb/h	0						
Sorbent		0						
Ash/Slag		54						
$CaSO_4.2H_2O$		0						
Water		0	3,254,422	2,766,259	74,616,184	2,880,487	1,423,633	36,837
Subtotal	lb/h	54	3,254,422	2,766,259	74,616,184	2,880,487	1,423,633	36,837
Gas								
O_2		171,836						
N_2		3,099,021						

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam to T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
CO_2		898,191						
H_2O		403,047						
SO_2		383						
NO_2		267						
Subtotal	lb/h	4,572,745	0	0	0	0	0	0
TOTAL	lb/h	4,572,799	3,254,422	2,766,259	74,616,184	2,880,487	1,423,633	36,837
Pressure	psia	14.7	560.0	115	55	25	15	15
Temperature	°F	128	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	544	4,940	2,835	2,835	2,938	68	2

Supercritical PC and Subbituminous Coal - Summary

Summary		
Net Thermal Efficiency	37.9	% HHV
Net Heat Rate (HHV)	9,000	Btu/kWh
Gross Power	541	MW
Internal Power	41	MW
Fuel required	517,045	lb/h
Net Power	500	MW

Supercritical PC and Subbituminous Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas SDA	6 Lime to SDA	7 SDA Filter Waste	8 Flue Gas To Stack
Solids	Units								
Coal, daf	lb/h	352,005	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	3,939	0	0
Ash/Slag		23,370	0	0	5,034	20,137	0	20,082	54
$CaSO_4.2H_2O$		0	0	0	0	0	0	12,099	0
Water		141,670	0	3,581,627	0	0	19,695	0	0
Subtotal	lb/h	517,045	0	3,581,627	5,034	20,137	23,634	32,181	54
Gas									
O_2		0	916,991	0	0	167,815	0	0	167,815
N_2		0	3,021,853	0	0	3,025,239	0	0	3,025,239
CO_2		0	0	0	0	953,169	0	0	954,647
H_2O		0	25,086	0	0	312,611	0	0	471,206

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas SDA	6 Lime to SDA	7 SDA Filter Waste	8 Flue Gas To Stack
SO_2		0	0	0	0	2,264	0	0	293
NO_2		0	0	0	0	271	0	0	271
Subtotal	lb/h	0	3,963,930	0	0	4,461,369	0	0	4,619,472
TOTAL	lb/h	517,045	3,963,930	3,581,627	5,034	4,481,506	23,634	32,181	4,619,526
Pressure	psia	14.7	14.7	3,515	14.7	14.0	14.7	14.7	14.7
Temperature	°F	59	59	1,050	2,498	256	32	86	132
Total Energy	mmBtu/h	4,550	55	5,091	10	643	0	0	635

Stream	Stream No.	9 Reheat Steam to T/G	10 Turbine Exhaust To Condenser	11 Cooling Water to Condenser	12 Cooling Tower Evaporative Loses	13 Cooling Tower Blowdown	14 Waste Water (from Process)
Solids	Units						
Coal, daf	lb/h						
Sorbent							
Ash/Slag							
$CaSO_4.2H_2O$							
Water		3,259,280	2,770,388	74,727,581	2,918,205	1,442,063	7,259
Subtotal	lb/h	3,259,280	2,770,388	74,727,581	2,918,205	1,442,063	7,259
Gas							
O_2							
N_2							
CO_2							
H_2O							
SO_2							
NO_2							

Stream	Stream No.	9 Reheat Steam to T/G	10 Turbine Exhaust To Condenser	11 Cooling Water to Condenser	12 Cooling Tower Evaporative Loses	13 Cooling Tower Blowdown	14 Waste Water (from Process)
Subtotal	lb/h	0	0	0	0	0	0
TOTAL	lb/h	3,259,280	2,770,388	74,727,581	2,918,205	1,442,063	7,259
Pressure	psia	560.0	115	55	25	15	15
Temperature	°F	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	4,948	2,840	2,840	2,977	69	0

Supercritical PC and Lignite Coal - Summary

Summary		
Net Thermal Efficiency	35.9	% HHV
Net Heat Rate (HHV)	9,500	Btu/kWh
Gross Power	544	MW
Internal Power	44	MW
Fuel required	752,535	lb/h
Net Power	500	MW

Supercritical PC and Lignite Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
Solids	Units									
Coal, daf	lb/h	382,288	0	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	0	0	16,727	0
Ash/Slag		135,155	0	0	27,428	109,712	109,260	452	0	0
$CaSO_4.2H_2O$		0	0	0	0	0	0	0	0	29,432
Water		235,092	0	3,599,756	0	0	0	0	0	3,270
Subtotal	lb/h	752,535	0	3,599,756	27,428	109,712	109,260	452	16,727	32,702
Gas										

	Stream No.	1	2	3	4	5	6	7	8	9
Stream		Coal Feed	Combustion Air	HP Steam to T/G	Bottom Ash	Flue Gas to Filter	Ash From Filter	Flue Gas to FGD	Limestone to FGD	Gypsum from FGD
O_2		0	973,749	0	0	178,202	0	178,202	0	0
N_2		0	3,208,895	0	0	3,214,201	0	3,214,201	0	0
CO_2		0	0	0	0	995,122	0	995,122	0	0
H_2O		0	26,638	0	0	433,358	0	415,389	0	0
SO_2		0	0	0	0	9,615	0	9,615	0	0
NO_2		0	0	0	0	285	0	285	0	0
Subtotal	lb/h	0	4,209,282	0	0	4,830,786	0	4,812,814	0	0
TOTAL	lb/h	752,535	4,209,282	3,599,756	27,428	4,940,495	109,260	4,813,266	16,727	32,702
Pressure	psia	14.7	14.7	3,515	14.7	14.0	14.7	15.0	14.7	14.7
Temperature	°F	59	59	1,050	2,498	279	278	293	32	86
Total Energy	mmBtu/h	4,774	59	5,117	33	846	30	812	0	1

	Stream No.	10	11	12	13	14	15	16
Stream		Flue Gas to Stack	Reheat Steam To T/G	Turbine Exhaust to Condenser	Cooling Water to Condenser	Cooling Tower Evaporative Loses	Cooling Tower Blowdown	Waste Water (from Process)
Solids	Units							
Coal, daf	lb/h	0						
Sorbent		0						
Ash/Slag		57						
$CaSO_4.2H_2O$		0						
Water		0	3,275,778	2,784,411	75,105,834	3,097,367	1,530,729	20,929
Subtotal	lb/h	57	3,275,778	2,784,411	75,105,834	3,097,367	1,530,729	20,929
Gas								

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam To T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
O_2		178,202						
N_2		3,214,201						
CO_2		1,001,396						
H_2O		606,687						
SO_2		409						
NO_2		285						
Subtotal	lb/h	5,000,963	0	0	0	0	0	0
TOTAL	lb/h	5,001,020	3,275,778	2,784,411	75,105,834	3,097,367	1,530,729	20,929
Pressure	psia	14.7	560.0	115	55	25	15	15
Temperature	°F	139	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	835	4,973	2,854	2,854	3,159	73	1

Ultra Supercritical PC and Bituminous Coal - Summary

Summary		
Net Thermal Efficiency	42.7	% HHV
Net Heat Rate (HHV)	8,000	Btu/kWh
Gross Power	543	MW
Internal Power	43	MW
Fuel required	342,863	lb/h
Net Power	500	MW

Ultra Supercritical PC and Bituminous Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
Solids	Units									
Coal, daf	lb/h	270,485	0	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	0	0	33,055	0
Ash/Slag		34,252	0	0	7,096	28,385	27,985	400	0	0
$CaSO_4.2H_2O$		0	0	0	0	0	0	0	0	49,395
Water		38,126	0	3,691,197	0	0	0	0	0	5,488
Subtotal	lb/h	342,863	0	3,691,197	7,096	28,385	27,985	400	33,055	54,883
Gas										
O_2		0	844,050	0	0	154,467	0	154,467	0	0
N_2		0	2,781,483	0	0	2,785,762	0	2,785,762	0	0
CO_2		0	0	0	0	796,782	0	796,782	0	0
H_2O		0	23,090	0	0	207,287	0	191,191	0	0

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
SO_2		0	0	0	0	17,171	0	17,171	0	0
NO_2		0	0	0	0	240	0	240	0	0
Subtotal	lb/h	0	3,648,623	0	0	3,961,709	0	3,945,613	0	0
TOTAL	lb/h	342,863	3,648,623	3,691,197	7,096	3,990,094	27,985	3,946,013	33,055	54,883
Pressure	psia	14.7	14.7	4,515	14.7	13.9	14.7	15.0	14.7	14.7
Temperature	°F	59	59	1,100	2,498	288	287	304	32	86
Total Energy	mmBtu/h	4,002	48	5,413	10	492	15	473	0	1

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam to T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
Solids	Units							
Coal, daf	lb/h	0						
Sorbent		0						
Ash/Slag		48						
$CaSO_4.2H_2O$		0						
Water		0	3,358,989	2,855,141	77,013,663	2,603,555	1,286,649	35,125
Subtotal	lb/h	48	3,358,989	2,855,141	77,013,663	2,603,555	1,286,649	35,125
Gas								
O_2		154,467						
N_2		2,785,762						
CO_2		807,399						
H_2O		362,587						
SO_2		344						
NO_2		240						

	Stream No.	10	11	12	13	14	15	16
Stream		Flue Gas to Stack	Reheat Steam to T/G	Turbine Exhaust to Condenser	Cooling Water to Condenser	Cooling Tower Evaporative Loses	Cooling Tower Blowdown	Waste Water (from Process)
Subtotal	lb/h	4,110,799	0	0	0	0	0	0
TOTAL	lb/h	4,110,847	3,358,989	2,855,141	77,013,663	2,603,555	1,286,649	35,125
Pressure	psia	14.7	560.0	115	55	25	15	15
Temperature	°F	128	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	490	5,099	2,927	2,927	2,656	62	2

Ultra Supercritical PC and Subbituminous Coal - Summary

Summary		
Net Thermal Efficiency	41.9	% HHV
Net Heat Rate (HHV)	8,146	Btu/kWh
Gross Power	543	MW
Internal Power	43	MW
Fuel required	460,227	lb/h
Net Power	500	MW

Ultra Supercritical PC and Subbituminous Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam To T/G	4 Bottom Ash	5 Flue Gas SDA	6 Lime to SDA	7 SDA Filter Waste	8 Flue Gas To Stack
Solids	Units								
Coal, daf	lb/h	313,323	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	3,506	0	0
Ash/Slag		20,802	0	0	4,481	17,924	0	17,875	49
$CaSO_4.2H_2O$		0	0	0	0	0	0	10,769	0
Water		126,102	0	3,696,681	0	0	17,531	0	0

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam To T/G	4 Bottom Ash	5 Flue Gas SDA	6 Lime to SDA	7 SDA Filter Waste	8 Flue Gas To Stack
Subtotal	lb/h	460,227	0	3,696,681	4,481	17,924	21,037	28,644	49
Gas									
O_2		0	816,223	0	0	149,374	0	0	149,374
N_2		0	2,689,782	0	0	2,692,795	0	0	2,692,795
CO_2		0	0	0	0	848,425	0	0	849,741
H_2O		0	22,329	0	0	278,655	0	0	417,481
SO_2		0	0	0	0	2,015	0	0	265
NO_2		0	0	0	0	244	0	0	244
Subtotal	lb/h	0	3,528,333	0	0	3,971,509	0	0	4,109,899
TOTAL	lb/h	460,227	3,528,333	3,696,681	4,481	3,989,433	21,037	28,644	4,109,948
Pressure	psia	14.7	14.7	4,515	14.7	13.9	14.7	14.7	14.7
Temperature	°F	59	59	1,100	2,498	256	32	86	132
Total Energy	mmBtu/h	4,076	50	5,421	9	576	0	0	569

Stream	Stream No.	9 Reheat Steam To T/G	10 Turbine Exhaust to Condenser	11 Cooling Water To Condenser	12 Cooling Tower Evaporative Loses	13 Cooling Tower Blowdown	14 Waste Water (from Process)
Solids	Units						
Coal, daf	lb/h						
Sorbent							
Ash/Slag							
$CaSO_4.2H_2O$							

Stream	Stream No.	9 Reheat Steam To T/G	10 Turbine Exhaust to Condenser	11 Cooling Water To Condenser	12 Cooling Tower Evaporative Loses	13 Cooling Tower Blowdown	14 Waste Water (from Process)
Water		3,363,980	2,859,383	77,128,092	2,651,199	1,310,061	6,461
Subtotal	lb/h	3,363,980	2,859,383	77,128,092	2,651,199	1,310,061	6,461
Gas							
O_2							
N_2							
CO_2							
H_2O							
SO_2							
NO_2							
Subtotal	lb/h	0	0	0	0	0	0
TOTAL	lb/h	3,363,980	2,859,383	77,128,092	2,651,199	1,310,061	6,461
Pressure	psia	560.0	115	55	25	15	15
Temperature	°F	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	5,107	2,931	2,931	2,704	63	0

Ultra Supercritical PC and Lignite Coal - Summary

Summary		
Net Thermal Efficiency	37.6	% HHV
Net Heat Rate (HHV)	9,065	Btu/kWh
Gross Power	546	MW
Internal Power	46	MW
Fuel required	720,849	lb/h
Net Power	500	MW

Ultra Supercritical PC and Lignite Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
Solids	Units									
Coal, daf	lb/h	366,191	0	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	0	0	16,022	0
Ash/Slag		129,465	0	0	26,273	105,093	104,660	453	0	0
$CaSO_4.2H_2O$		0	0	0	0	0	0	0	0	28,066
Water		225,193	0	3,715,590	0	0	0	0	0	3,118
Subtotal	lb/h	720,849	0	3,715,590	26,273	105,093	104,660	453	16,022	31,184
Gas										

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
O_2		0	932,749	0	0	170,699	0	170,699	0	0
N_2		0	3,073,783	0	0	3,078,867	0	3,078,867	0	0
CO_2		0	0	0	0	953,222	0	953,222	0	0
H_2O		0	25,517	0	0	415,559	0	396,467	0	0
SO_2		0	0	0	0	9,210	0	9,210	0	0
NO_2		0	0	0	0	272	0	272	0	0
Subtotal	lb/h	0	4,032,049	0	0	4,627,829	0	4,608,736	0	0
TOTAL	lb/h	720,849	4,032,049	3,715,590	26,273	4,732,921	104,660	4,609,190	16,022	31,184
Pressure	psia	14.7	14.7	4,515	14.7	13.9	14.7	15.0	14.7	14.7
Temperature	°F	59	59	1,100	2,498	279	278	295	32	86
Total Energy	mmBtu/h	4,538	56	5,448	31	805	28	772	0	1

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam to T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
Solids	Units							
Coal, daf	lb/h	0						
Sorbent		0						
Ash/Slag		55						
$CaSO_4.2H_2O$		0						
Water		0	3,381,187	2,874,009	77,522,608	2,966,345	1,465,973	19,958
Subtotal	lb/h	55	3,381,187	2,874,009	77,522,608	2,966,345	1,465,973	19,958
Gas								
O_2		170,699						
N_2		3,078,867						
CO_2		959,232						

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam to T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
H_2O		581,479						
SO_2		390						
NO_2		272						
Subtotal	lb/h	4,790,730	0	0	0	0	0	0
TOTAL	lb/h	4,790,785	3,381,187	2,874,009	77,522,608	2,966,345	1,465,973	19,958
Pressure	Psia	14.7	560.0	115	55	25	15	15
Temperature	°F	139	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	794	5,133	2,946	2,946	3,026	71	1

Notes on waste Streams:

Solid Waste:
The solid waste streams from a PC boiler are: furnace bottom ash, fly ash and gypsum or other waste products resulting from the sulfur capture. The fly ash is captured by fabric filters. The wet FGD process generates gypsum. In the dry FGD process, the calcium waste is captured in the fabric filter with fly ash.

Liquid Waste:
Liquid waste is primarily from boiler blowdown in drum type subcritical boilers, and from cooling tower blowdown. In addition, the wet FGD process may generate a bleed waste stream. This waste stream is reported as part of the total waste water discharge. The dry process does not generate a wastewater stream during the sulfur capture process.

Make-Up Water:
Make-up water includes waste water discharge, as well as losses in the cooling tower.