MAJOR ENVIRONMENTAL ASPECTS OF GASIFICATION-BASED POWER GENERATION TECHNOLOGIES

Final Report

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DISCLAIMER

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ACRONYMS and ABBREVIATIONS

ACAA – American Coal Ash Association
ADEM – Alabama Department of Environmental Management
AFBC – Atmospheric fluidized-bed combustor
AOS – Alternate operating scenarios
APCDJC – Air Pollution Control District for Jefferson County (Kentucky)
As – Arsenic
ASU – Air separation unit
ASTM – American Society for Testing and Materials
atm – Atmosphere
ATS – Advanced Turbine System
Avg – Average
B – Boron
Ba – Barium
BACT – Best Available Control Technology
BAT – Best Available Technology
BCT – Best Control Technology
Be – Beryllium
BFW – Boiler feedwater
BGL – British Gas Lurgi
BOD – Biochemical oxygen demand
BTA – Best Technology Available
Btu – British thermal unit
CAA – Clean Air Act
CAAA – Clean Air Act Amendments
CCB – Coal combustion by-product
CCP – Coal Combustion Products
CCT – Clean Coal Technology
CCW – Coal combustion waste
Cd – Cadmium
CEM – Continuous emission monitor
CERCLA – Comprehensive Environmental Response, Compensation, and Liability Act
CESQG – Conditionally Exempt Small Quantity Generator
CFR – Code of Federal Regulations
CGCU – Cold gas cleanup unit

CH_4 – Methane

Cl^- – Chloride ion

Cl – Chloride

CO – Carbon monoxide

CO_2 – Carbon dioxide

Co – Cobalt

COD – Chemical oxygen demand

COE – Cost of electricity

COS – Carbonyl sulfide

Cr – Chromium

CRF – Codified Regulations Federal (interchangeable with CFR)

CSC – Connective syngas cooler

CSI – Clear Shies Initiative

CT – Combustion turbine

Cu – Copper

CUB – Coal utilization by-product

CW – Cooling water

CWA – Clean Water Act

CWIS – Cooling water intake structure

DAQ – Division of Air Quality

DEP – Department of Environmental Protection

DIZ – Discharge information zone

DLE – Dry-low emissions

DR– Designated representative

DLN – Dry low NOx

DOE – U.S. Department of Energy

EA – Environmental Assessment

EERC – Energy and Environmental Research Center

EIA – Environmental Impact Assessment

EIS – Environmental Impact Statement

EKPC – East Kentucky Power Cooperative

EOR – Enhanced oil recovery

EP – Extraction procedure

EPA – U.S. Environmental Protection Agency

EPCRA – Emergency Planning and Community Right to Know Act
EPD – Environmental Protection Division
EPRI – Electric Power Research Institute
ESP – Electrostatic precipitator
F – Fluoride
F.A.C. – Florida Administrative Code
FBC – Fluidized bed combustion
FDEP – Florida Department of Environmental Protection
Fe^{3+} – Ferric ion
FFC – Fossil fuel combustion
FGD – Flue gas desulfurization
FONSI – Finding of no significant impact
FR – Federal Register
FWPCA – Federal Water Pollution Control Act
GE – General Electric
Ge – Germanium
H^- – Hydrogen ion
H_2 – Hydrogen
H_2S – Hydrogen sulfide
H_2SO_4 – Sulfuric acid
HAP – Hazardous air pollutant
HCN – Hydrogen cyanide
HF – Hydrogen fluoride
HHV – Higher Heating Value
Hg – Mercury
$HgCL_2$ – Mercuric Chloride
HGCU – Hot gas cleanup system
HgO – Oxidized mercury
HgS – Mercuric sulfide
HPC – Heterotrophic plate count
HRSG – Heat recovery steam generator
HTHRU – High temperature heat recovery unit
HTW – High Temperature Winkler
IAC – Indiana Administrative Code
IC – Indiana Code

ICCI – Illinois Clean Coal Institute
ICR – Information Collection Request (U.S. EPA)
IDEM – Indiana Department of Environmental Management
IDOT – Illinois Department of Transportation
IEPA – Illinois Environmental Protection Agency
IGCC – Integrated Gasification Combined Cycle
IPP – Independent Power Producer
IWP – Industrial wastewater pretreatment
KDEP – Kentucky Department for Environmental Protection
KPDES – Kentucky Pollutant Discharge Elimination System
KRS – Kentucky Regulatory Standard
KWh – Kilowatt-hour
LAC – Louisiana Administrative Code
LAER – Lowest Achievable Emission Rate
lb – Pound
LDR – Land disposal restrictions
LGTI – Louisiana Gasification Technology Incorporated
LHV – Lower heating value
Li – Lithium
LNG – Liquified Natural Gas
MACT – Maximum Achievable Control Technology
MCL – Maximum Contaminant Level
MCLG – Maximum Contaminant Level Goal
MDEA – Methyl diethanolamine
MGD – Million gallons per day
Mg/l – milligrams per liter
Mn – Manganese
Mo – Molybdenum
Mpa – Mega Pascals
MS – Molecular Sieve
MSDS – Material Safety Data Sheet
MSGP – Multi Sector General Permit
MSW – Municipal Solid Waste
MVR – Mechanical Vapor Recompression
MWC – Municipal Waste Combustor

MWe – Megawatts of electricity

MWh – Megawatt-hour

N_2 – Nitrogen

Na^+ – Sodium ion

NAAQS – National Ambient Air Quality Standards

NATEMIS – National Emission Inventory of Electric Utility Mercury

NAS – National Academy of Sciences

NEPA – National Environmental Policy Act

NESHAP – National Emission Standard for Hazardous Air Pollutants

NETL – National Energy Technology Laboratory

ng/J – Nanograms per joule

NGCC – Natural gas combined cycle

NH_3 – Ammonia

NH_4^+ – Ammonium ion

NH_4NO_3 – Ammonium Nitrate

$(NH_4)_2SO_4$ – Ammonium sulfate

Ni – Nickel

NO – Nitric oxide

NO_2 – Nitrogen dioxide

NO_2^- – Nitrite ion

NO_3^- – Nitrate ion

NOx – Nitrogen oxides

NOI – Notice of intent

NPDES – National Pollutant Discharge Elimination System

NSDWR – National Secondary Drinking Water Regulations

NSPS – New Source Performance Standards

NSR – New Source Review

NYCRR – New York Code of Rules and Regulations

NYSDEC – New York State Department of Environmental Conservation

O_3 – Ozone

OAQP – Office of Air Quality and Planning (U.S. EPA)

OEPA – Ohio Environmental Protection Agency

OSHA – Occupational Safety and Health Administration

OTAG – Ozone Transport Assessment Group

OWM – Office of Water Management

PAH – Polycyclic Aromatic Hydrocarbons
PAN – Peroxyacetylnitrate
Pb – Lead
PBT – Persistent bioaccumulative toxic
PC – Pulverized coal
PCDD – Polychlorinated dibenzo-*p*-dioxins
PCDF – Polychlorinated dibenzo-furans
PFBC – Pressurized fluidized bed combustion
PM – Particulate matter
PM10 – Particulate matter $\leq$ 10 μm in diameter
PM2.5 – Particulate matter $<$ 2.5 μm in diameter
POTW – Publicly Owned Treatment Works
PPA – Pollution Prevention Act
ppm – parts per million
ppmvd – parts per million by volume dry
PPSA – Power Plant Siting Act
PSD – Prevention of Significant Deterioration
PSES – Pretreatment Standards for Existing Sources
PSIA – Pounds per square inch - absolute
PSNS – Pretreatment Standards for New Sources
RACI – Reasonably Available Control Technology
RCRA – Resource Conservation and Recovery Act
RDF – Refuse-derived fuel
RMP – Risk Management Plan
Rn – Radon
RSC – Radiant syngas cooler
SASOL – South Africa Coal, Oil, and Gas Corporation
Sb – Antimony
SCE – Southern California Edison
SCR – Selective catalytic reduction
SDWA – Safe Drinking Water Act
Se – Selenium
SFC – Synthetic Fuels Corporation
SGP – Shell Gasification Plant

SHPO – State Historic Preservation Office

SIC – Standard Industrial Classification

SIP – State Implementation Plan

SLA – Slag lightweight aggregate

SMCL – Secondary Maximum Contaminate Levels

SMCRA – Surface Mining Control and Reclamation Act

SNCR – Selective non-catalytic reduction

SNG – Synthetic natural gas

SO_2 – Sulfur dioxide

SO_3^{2-} – Sulfite ion

SO_4^{2-} – Sulfate ion

SPDES – State Pollutant Discharge Elimination System

Sr – Strontium

SVOC – Semi-volatile organic compounds

SWPPP – Strom Water Pollution Prevention Plan

TAP – Toxic air pollutant

TC – Toxicity Characteristic

TCLP – Toxicity Characteristic Leaching Procedure

TDEC – Tennessee Department of Environment and Conservation

TECO – Tampa Electric Company

Th – Thorium

TMDL – Total Maximum Daily Load

TNRCC – Texas Natural Resource Conservation Commission

TRI – Toxic Release Inventory

TSDF – Treatment, storage, and disposal facility

TSS – Total suspended solids

TSP – Total suspended particulates

U – Uranium

ULWA – Ultra lightweight aggregate

U.S.C.A. – United States Code Annotated

UAT – Urban Air Toxics

UIC – Underground Injection Control

USDW - Underground Sources of Drinking Water

UTS – Universal treatment standards

V – Vanadium

VCAPC – Vigo County Air Pollution Control
VOC – Volatile organic compound
VOM – Volatile Organic Material
WET – Whole effluent toxicity
WQC – Water quality criteria
WQBEL – Water Quality Based Emission Limitation
Zn – Zinc
$\mu g/m^3$ – microgram per cubic meter

EXECUTIVE SUMMARY

The objective of this report is to provide a comprehensive reference resource for gasification-based power generation technologies that examines both environmental performance and regulatory topics affecting the siting and operation of commercial plants. The sources used in preparing this report include data and information gathered from utility and government-sponsored testing programs at commercial and pilot Integrated Gasification Combined Cycle (IGCC) and gasification facilities, independent environmental performance monitoring and tests at operating IGCC plants, environmental impact assessments (EIAs) for commercial plants, bench-scale gasification projects, gasifier performance modeling studies, technology developers, and related government and industry reports, technical papers, and databases.

The report focuses on the most important environmental performance aspects of IGCC power generation, which are similar to those associated with all power plants that consume solid fuels, such as coal and petroleum coke:

- Discharge of criteria and hazardous air pollutants into the atmosphere;
- Discharge of aqueous effluents that contain hazardous species into water bodies;
- Handling and long-term storage of large quantities of solid ash residues and their potential for leaching toxic substances into the soil and groundwater;
- Safe utilization of by-products generated by environmental control processes; and
- Discharge of carbon dioxide into the atmosphere, which may impact global climate change.

Because gasification-based power generation is a relatively new technology with few operating plants, its unique operating features and its environmental performance capability, relative to the above topics, are not well known. However, based on the available data presented in this report, gasification-based energy conversion systems are capable of providing stable, high-efficiency energy supply with reduced environmental impact compared with competitive technologies. They can provide flexibility in the production of a wide range of products including electricity, fuels, chemicals, hydrogen, and steam, while utilizing low-cost, widely available feedstocks, such as coal and petroleum coke. In particular, gasification of abundant U.S. coal provides an alternative to coal-fired combustion systems that is more efficient and environmentally friendly. Coal gasification is a well-proven technology that started with the production of coal gas for urban areas, progressed to the production of fuels, such as oil and synthetic natural gas (SNG), chemicals, and most recently, to large-scale Integrated Gasification Combined Cycle (IGCC) power generation.

Although the number of operating IGCC power plants is small, there are at least 163 commercial gasification plants in operation, under construction, or in planning and design stages in twenty-eight countries in North and South America, Europe, Asia, Africa and Australia.[a] This is equivalent to 67,800 MW_{th} syngas capacity installed or planned (about 37,000 MWe IGCC equivalent), with most new plants based on electricity production and co-production of steam and syngas for hydrogen or chemicals. There have been six large-scale IGCC power generation plants built that have used coal and/or petroleum coke as the primary feedstock. The first two

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[a] Based on a 1999 survey sponsored by U.S. DOE and the Gasification Technologies Council.

U.S. plants, Texaco's Cool Water and Dow's LGTI plant, were important first-generation IGCC projects that demonstrated the major IGCC characteristics of low emissions and stable integrated control of the gasification process with a combined cycle in a power utility application. The four second-generation IGCC systems that are currently operating commercially, and which were designed solely to generate electricity, are Tampa Electric's Polk Power Station in Florida (ChevronTexaco Gasification Process),[b] PSI Energy's Wabash River Generating Station in Indiana (Global Energy's E-Gas Process),[b] NUON/Demkolec/Willem Alexander IGCC Plant in Buggenum, The Netherlands (Shell Gasification Process), and the Elcogas/Puertollano IGCC Plant in Puertollano, Spain (Uhde's Prenflo Process). Detailed descriptions of these plants are provided in Appendix 1B.

These commercial IGCC power plants have proven capable of exceeding the most stringent emissions regulations currently applicable to comparable combustion-based[c] power plants. They have achieved the lowest levels of criteria pollutant air emissions (NOx, SOx, CO, PM10) of any coal-fueled power plants in the world. Emissions of trace inorganic and organic hazardous air pollutants (HAPs) are extremely low, comparable with those from coal combustion-based plants that use advanced emission control technologies. If mercury is regulated, commercial mercury control equipment is already available for IGCC. The ash (slag or bottom ash) and sulfur (or sulfuric acid) generated by operating IGCC plants have been tested to be environmentally benign and can be sold as valuable by-products. Discharge of solid by-products and wastewater is reduced by roughly 50% compared with combustion-based plants. Another significant environmental benefit is a reduction of carbon dioxide (CO_2) emissions, by at least 10% for an equivalent net production of electricity, due to higher operating efficiency compared to existing coal-fueled, combustion-based power generation technology. If more significant CO_2 reduction is required in the future, gasification technology has major operating advantages that can be exploited to capture CO_2 more efficiently than is currently possible with combustion technology.

While IGCC's demonstrated environmental performance capabilities allow it to meet or exceed current environmental standards established for coal-based combustion systems, there are regulatory ambiguities associated with the specific environmental standards that IGCC must meet. Whereas a pulverized coal-fired (PC) plant is regulated and permitted strictly as a coal-fired boiler due to its single-stage combustion process design, an IGCC plant is unlikely to be treated similarly. The multi-stage process configuration of IGCC, which physically separates solid fuel conversion into syngas (in a gasifier) from final combustion of the syngas in a combustion turbine (CT), can lead to environmental permitting based on CT technology, as well as other emission sources within the plant (e.g., sulfur recovery subsystem). Thus, even if both types of plants consume the same coal, they may have to comply with different regulatory standards. If CT technology is used as the basis for regulating the air emissions of an IGCC plant, it is very important for regulators to evaluate the unique performance capabilities of a CT that fires syngas.

In light of such important performance and regulatory issues, this report presents a comprehensive evaluation of the environmental performance of IGCC power generation

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[b] The Polk and Wabash River IGCC plants were selected and put into service in the U.S. under DOE's cooperative Clean Coal Technology (CCT) demonstration program.

[c] Combustion-based power plants refers to technologies that directly combust their solid fuel, such as pulverized coal-fired (PC-fired or PC), fluidized-bed combustion (FBC), stoker-fired, and cyclone-fired plants.

technology for all media types (air, water, and land), compares the performance with competing fossil-based combustion technologies, and relates the expected performance to specific regulatory requirements. Chapter 1 supports this assessment by providing an overview of gasification and IGCC technology that identifies alternative gasifier designs, describes other key IGCC process equipment, and defines primary resource inputs and emissions/effluent discharges, the latter being of critical importance in characterizing environment performance. The chapter also describes six demonstration/commercial plants and compares IGCC's operational and environmental control features with those of state-of-the-art PC and fluidized bed combustion (FBC) power plants, both of which are important competing technologies.

Relying upon this descriptive information, Chapter 2 comprehensively evaluates IGCC technology's environmental performance within different chapter sections that exclusively cover air emissions, water effluents, and solid wastes/by-product discharges, respectively. Each section provides the following basic information:

- Identification and characterization of emissions, effluents, or discharges;
- Review of IGCC plant operating data and experience;
- Assessment of control/treatment/handling technologies and methods; and
- Comparison of the environmental performance of IGCC with PC and FBC Power Plants.

Finally, Chapter 3 examines existing and future environmental regulations that may impact the siting, environmental permitting, and operation of gasification-based power plants. In order to correspond with the performance information presented in Chapter 2, material is also presented in chapter sections that exclusively cover each media type – air, water and land. Potentially applicable federal, state, and local regulations that deal with criteria air pollutants, organic and inorganic hazardous air and water pollutants, and solid wastes/by-products are appropriately divided among the media-specific sections. The information presented indicates that increasingly restrictive regulatory requirements for coal-based power generation are a critical factor impacting selection, acceptability, and operability of IGCC versus competing technologies. Critical issues regarding applicable regulations and permitting requirements are factored into the discussions.

IGCC Environmental Performance Summary

A summary of IGCC environmental performance results is presented below for each of the key environmental topics previously identified. These results are primarily based on operating experience with a limited number of IGCC plants that use entrained flow, slagging gasifier technology (e.g., ChevronTexaco, E-Gas, Shell, and Prenflo). Therefore, the information presented does not necessarily account for different operating outcomes that may result from the use of the other gasification reactor types (e.g., moving-bed and fluidized bed) in IGCC systems. For example, moving-bed gasifiers (e.g., BGL and Lurgi Dry-Ash) are much more likely to generate higher levels of organic emissions, such as tars and oils, than entrained-flow and fluidized bed gasifiers, which consequently will impact environmental control requirements and, possibly, emissions. Additionally, not only are there fundamental performance differences among these three generic gasifier types, unique gasifier designs may exhibit different operating characteristics, even within a particular category. Some of the entrained-flow designs, for example, have demonstrated tendencies to yield excessive carbon in the slag. Therefore, the reader should not over-generalize these results to cover all IGCC designs, configurations, and feedstocks. While there are similarities between alternative gasification technologies and the manner in which they integrate into IGCC systems, there are also important differences that must be considered when evaluating their operating and environmental performance.

Nevertheless, the four operating IGCC power plants discussed in this report, all using different gasifier designs from four different vendors, have clearly demonstrated that they can be designed to achieve very low environmental impact. There is no reason to believe that the same will not be true for IGCC plants that make use of other gasifier types and alternative integration methods.

Discharge of Criteria and Hazardous Air Pollutants into the Atmosphere

Criteria pollutant emissions from state-of-the-art, coal-fed IGCC plants have been demonstrated to be well below existing Federal New Source Performance Standards (NSPS) established for large-scale, combustion-based power plants that consume coal. While these standards may not necessarily apply to IGCC technology installations, they provide an important benchmark for IGCC technology emission control effectiveness. Keeping this in mind, projected IGCC criteria pollutant emission levels, based on operating plant results, are listed below in Table ES-1 and are compared with their associated combustion-based NSPS limits, as well as well the operating permit levels required at the Polk and Wabash River IGCC plants.

TABLE ES-1. IGCC CRITERIA POLLUTANT EMISSION LEVELS

CRITERIA POLLUTANT	PROJECTED IGCC EMISSION LEVELS[a]	COAL COMBUSTION-BASED NSPS LIMIT	POLK IGCC OPERATING PERMIT LIMIT[b]	WABASH RIVER IGCC OPERATING PERMIT LIMIT[c]
SO_2	0.08 lb/10^6 Btu 0.7 lb/MWh	1.2 lb/10^6 Btu (No lb/MWh basis)	1.43 lb/MWh (357 lb/hr)	1.25 lb/MWh[e] (315 lb/hr)
NOx (as NO_2))	0.09 lb/10^6 Btu 0.77 lb/MWh	0.15 lb/10^6 Btu 1.6 lb/MWh	0.53 lb/MWh (15 ppm or 132 lb/hr)	1.35 lb/MWh (25 ppmvd or 0.15 lb/10^6Btu)
PM10, Particulate and H_2SO_4 Mist	0.011 lb/10^6 Btu 0.10 lb/MWh	0.03 lb/10^6 Btu (No lb/MWh basis)	0.288 lb/MWh[d] (72 lb/hr)	0.25 lb/MWh[f] (64 lb/hr)
CO	0.033 lb/10^6 Btu 0.29 lb/MWh	None	0.392 lb/MWh (98 lb/hr)	2.2 lb/MWh (555 lb/hr)[g]

[a] Basis: Heat rate equals 8,600 Btu/kWh. SO_2 emissions are based on 2.5% sulfur, 12,000 Btu/lb coal, and 98% reduction. NOx emissions are based on a turbine combustor that emits 15 ppm NOx (15% O_2, dry). CO, PM10, and H_2SO_4 emissions are based on 1998 Wabash River plant experience.

[b] Values provided by TECO Energy

[c] Basis: permit limits specified in final technical report for Wabash River Coal Gasification Repowering Project.

[d] Basis: 0.068 lb/MWh for particulate-only (17 lb/hr, excluding H_2SO_4 mist) and 0.22 lb/MWh (55 lb/hr H_2SO_4)

[e] Basis: 252 MWe @ 6000 hrs/year, 1,512,000 MWh/year

[f] Basis: limits specified for combustion turbine (20% max opacity, 0.01 lb/10^6Btu H_2SO_4) and tail gas incinerator (6.8 tons/yr)

[g] Based on limits specified for flare, combustion turbine, and tail gas incinerator.

The inorganic hazardous air pollutants (HAPs) of greatest environmental concern are generally thought to be the trace metals arsenic, boron, cadmium, lead, mercury, molybdenum, and selenium, but others may also be included in this list depending on feedstock type and concentration. While in-situ measurement of these species has proven to be quite difficult in the reducing atmosphere of an IGCC system, computer-based thermodynamic equilibrium studies have indicated that these metals are highly volatile and hard to control. Other trace metals will most likely either remain with the slag/bottom ash or be removed from the syngas in downstream process equipment. Most troublesome, as verified by bench-, pilot-, and full-scale testing, is mercury, which primarily remains in the vapor-phase. Elemental mercury is, by far, the predominant chemical form in gasification systems.

While there is every indication that elemental mercury exits IGCC plants in the stack gas, a significant portion also appears to be removed within the IGCC process. There is evidence that mercury is removed by the amine solvent, accumulates in the acid gas scrubbing loop, and/or is stripped from the amine solvent upon regeneration and partitions to the sulfur recovery unit. Some mercury, especially particulate-phase and oxidized forms, may also be removed in the wet particulate scrubber and discharged with wastewater sludge. Overall, mercury testing indicates that stack gas emission factors range from 3 to 6 x 10^{-5} lb/MWh (1.5 to 5 lb/10^{12} Btu). Comparison with similar tests performed at PC power plants indicates that IGCC mercury emissions are of a similar magnitude. If PC plants are required to control mercury as a result of expected EPA regulations, then IGCC plants will also likely need to control mercury emissions.

Compared with combustion-based power plants, IGCC plants have a major advantage when it comes to mercury control. Commercial methods have been employed for many years that remove trace amounts of mercury from natural gas and gasifier syngas. Both molecular sieve technology and activated carbon beds have been used for this purpose, with 90 to 95% removal efficiency reported. While such mercury control technology has not yet been incorporated into an operating IGCC system, the successful, long-term experience with these processes indicates that mercury emissions control may be more of an economic issue than a technical one. A recent DOE cost study was conducted for applying a packed-bed carbon adsorption system to an IGCC plant. Based on an eighteen-month carbon replacement cycle and 90% reduction of mercury emissions, the total cost of mercury reduction is estimated to be $3,412 per pound of mercury removed, which is projected to be about one-tenth the cost of flue gas-based mercury control.

Release of trace organic compounds is also an environmental concern, since some of these compounds, such as formaldehyde, can have deleterious effects on the environment or human health. While limited data are available to characterize trace organic releases to the air from IGCC systems, detailed test results from the LGTI IGCC plant indicates extremely low levels of all trace organic emissions, in-line with emissions expected from combustion-based plants. In particular, formaldehyde emissions from a syngas-fired combustion turbine appear to be more than an order-of-magnitude lower than from natural gas-fired combustion turbines. While this conclusion applies to this particular unit, less detailed data from other IGCC plants seems to corroborate the overall low levels of organic emissions.

Discharge of Aqueous Effluents that Contain Hazardous Species into Water Bodies

Coal gasification-based power plants have two principal water effluents that are similar to those in combustion-based power plants. The first is wastewater from the steam cycle, including blowdowns from the boiler feedwater (BFW) purification system and the cooling tower.

Gasification processes typically purify and recycle raw process streams, and net water discharge is normally only a blowdown stream. These effluents contain salts and minerals that have been concentrated from the raw feedwater. The second aqueous effluent is process water blowdown, which is typically high in dissolved solids and gases along with the various ionic species washed from the syngas, such as sulfide, chloride, ammonium, and cyanide. Detailed test results from the Wabash River IGCC plant have recently shown wastewater constituents to be in compliance with environmental permit limits. An add-on mechanical vapor recompression (MVR) system was installed in 2001 to better control arsenic, cyanide, and selenium in the wastewater stream. The Polk IGCC plant treats process water blowdown via a series of cleanup steps (ammonia stripping, vapor compression concentration, and crystallization) to completely eliminate process water discharge. However, the plant has had a problem with process water run-off from the slag storage and process areas of the facility, which subsequently contaminated their cooling reservoir. Remediation actions are addressing this plant-specific problem.

In general, water effluents may create fewer problems for IGCC than for combustion-based power generation, because the steam cycle in an IGCC plant typically produces less than 40% of the plant's power. While effluents from cooling-water blowdown are significantly less, BFW blowdown may be the same as, or even larger, than a PC-based plant of comparable output, even if it is well designed, operated and maintained. A gasification process can easily consume considerable quantities of BFW via tap purges, pump seals, intermittent equipment flushes, as well as syngas saturation for NOx control and direct steam injection into the gasifier as a reactant and/or temperature moderator. The amount of process water blowdown is about the same for both gasification and a PC-based steam plant.

Handling and Long-Term Storage of Large Quantities of Solid Ash Residues and the Potential for Leaching Toxic Substances into the Soil and Groundwater

In terms of quantities of waste material produced, as well as the potential for leaching of toxic substances into the soil and groundwater, IGCC power generation has demonstrated reduced environmental impact compared with similarly sized coal combustion-based power plants. The largest solid waste stream produced by IGCC is slag or bottom ash, depending on the type of gasifier utilized. Slagging gasifiers are focused on in this report. Slag is a black, glassy, sand-like material that is potentially a marketable by-product. Slag production is a function of ash content, so coal produces much more slag than an alternative fuel like petroleum coke. Regardless of the feed, as long as the operating temperature is above the fusion temperature of the ash, slag will be produced. Leachability data obtained from different gasifiers unequivocally shows that gasifier slag is highly non-leachable. Therefore, gasifier slag need not be treated any differently than coal combustion waste material that is classified as non-hazardous. However, local regulations may dictate otherwise. Although the slag is classified as non-hazardous at the Polk IGCC plant, local regulations require disposal in a different class of landfill. Polk must use a Class I landfill that is double-lined with leachate extraction/control versus a much less expensive and more available Class III landfill. Conversely, possible utilization of slag in a variety of applications may negate the need for long-term disposal. Polk has recently demonstrated that they can produce slag that is consistently suitable for the cement industry. The Wabash River IGCC plant markets a portion of their slag for asphalt, construction backfill, and landfill cover operations.

Most gasification systems also produce a smaller quantity of char (unreacted fuel) and/or flyash that is entrained with the syngas. These are typically captured and recycled to the gasifier to maintain high carbon conversion efficiency and to convert the flyash into slag to eliminate flyash disposal. Some gasifiers (e.g., ChevronTexaco) produce a char that is mixed with a "glassy frit" that needs to be separated from the char before recycle. This frit is not an environmental problem, and can be disposed of economically or utilized commercially, if it is decontaminated via washing with clean water. However, the water is a potential environmental problem if not treated before recycle, which increases overall water treatment requirements and cost. Frit cleaning also increases the plant's water consumption. This is not an issue with all gasification processes, but it is discussed as another example of the need to address specific operating characteristics of different gasifier/IGCC designs that may yield different environmental impacts.

Utilization of By-Products Produced by Environmental Control Processes

The other large-volume by-product produced by IGCC plants is solid (or liquid) sulfur or sulfuric acid, both of which can be sold to help offset plant operating costs. In comparison, most coal combustion plants recover sulfur as wet scrubber sludge, dry or semi-dry spent sorbent, or gypsum. These sulfur forms have significantly larger mass and volume than pure sulfur, are often more difficult to handle and market, and must usually be disposed of in an appropriate landfill or surface impoundment.

IGCC slag has the potential to be a valuable by-product for applications such as lightweight aggregates and asphalt shingle roofing granules. IGCC slag is similar to the material produced in wet-bottom PC plants, and has as good or better leachability characteristics. Such slag is often characterized by low bulk density, high shear strength, good drainage and filtering characteristics. Unfortunately, due to the relatively small quantities of boiler slag produced in the U.S., relative to fly ash and FGD material, the markets for this type of material are not yet fully developed. There is also relatively little experience in the U.S. with using coal gasification slag. However, utilization of slag from PC boilers has been estimated to be about 94%, which indicates high acceptability, if material specifications are met.

The primary technical barrier to commercial utilization of IGCC slag is meeting particular industry specifications for the slag by-product. Cement production is a good example in that it is a large-volume market that requires stringent criteria for slag quality and consistency, particularly carbon content. Slag (or bottom ash) with excessive carbon content can be an issue for some gasifier designs and operating regimes. Recently excessive carbon had been a problem with the ChevronTexaco gasifier at the Polk IGCC plant, which solved it by installing additional slag handling equipment to separate unconverted carbon. Not only does the slag now meet specifications, but also the carbon can be recycled back to the plant or used elsewhere. While this is not a generic gasifier issue, it appropriately points out that potential by-product applications need to be considered in the design and operation of an IGCC system.

Discharge of Carbon Dioxide into the Atmosphere

Carbon contained in the fuel fed to an IGCC power plant will ultimately be converted into CO_2. Although CO_2 emissions are higher than for gas-fired power plants, IGCC's improved efficiency reduces CO_2 emissions relative to existing PC plants. Repowering the Wabash River plant reduced CO_2 emissions by approximately 20% on a per kWh basis. On average, IGCC plants produce CO_2 at a rate of about 1.8 lb/kWh (assuming 40% efficiency), while PC plants yield about 2 lb/kWh. An advanced gasification-based fuel cell plant may be able to achieve a discharge rate of 1.2 lb/kWh.

If an even lower CO_2 release rate is required in the future, IGCC technology has two major advantages that can be exploited to capture CO_2 more efficiently than is possible with combustion-based technology. First, syngas has a high CO_2 concentration, which can be further increased by converting CO to CO_2 prior to combustion (while simultaneously producing more hydrogen), and second, IGCC gasifiers typically operate under relatively high pressure (~400 psig in the Wabash plant), making recovery of the CO_2 from the syngas much easier than capture from flue gas. Several recent design studies, one performed for DOE and another for ChevronTexaco in cooperation with General Electric (GE), bracket plant output loss at between 3 to 6% of original net plant electricity generation if CO_2 is captured. The DOE study indicates that comparable CO_2 capture (on a percentage basis) for a natural gas combined cycle (NGCC) plant and a PC plant would yield an output loss of 21% and 28%, respectively. Lower energy consumption for CO_2 capture means that less additional generation capacity is needed to make up for this parasitic loss. Since additional CO_2 will likely be generated by any added fossil-based capacity, IGCC minimizes this effect. Including CO_2 capture, the overall cost of electricity (COE) of the IGCC plant is shown to be about 6.3 ¢/kWh versus 7.9 ¢/kWh for the PC plant, while the NGCC plant's COE is also 6.3 ¢/kWh at a natural gas price of approximately \$4 /10^6Btu.

The ChevronTexaco/GE-sponsored study investigated a design concept based on incorporating CO_2 capture capability into a new IGCC facility without requiring that it initially be used, and that would require incremental equipment upgrades to make CO_2 capture operational. The design study concluded that 75% of the CO_2 could be captured from a 900 MWe IGCC plant with only a 2 percent loss in efficiency (3% reduction in electricity output) at an incremental cost of \$5 to \$11/kW, based on an original plant cost of \$974/kW (mid-2001 dollars). This result suggests that the economic impact of CO_2 capture may be quite a bit less than previously thought, with appropriate design forethought. However, the evaluation did not account for transport of the CO_2 to utilization or sequestration sites and any further processing.

Existing and Future Environmental Regulations that Affect the Siting and Operation of Gasification-Based Power Systems

Many existing and future environmental regulations may impact the siting, environmental permitting, and operation of gasification-based power plants. These federal, state, and local regulations deal with criteria air pollutants, organic and inorganic hazardous air and water pollutants, and solid wastes/by-products in all media – air, water and land. Increasingly restrictive regulatory requirements for coal-fueled power plants are a critical factor impacting selection, acceptability, and operability of competing technologies. While regulations are generally intended to treat all technologies equally and consistently, current permitting procedures originally established for solid-fuel combustion-based technology, may in fact discriminate against advanced technologies, such as gasification-based IGCC.

The legal instrument used in the U.S. to ensure compliance with environmental regulations is the environmental permit. A permit may specify in considerable detail how a facility may be constructed or operated and, therefore, must be obtained prior to commencement of any activity, including construction. Industrial and municipal facilities are required to obtain these permits to control their pollutant emissions to the air, land, and water. In general, permit programs are defined in the regulations to ensure that the requirements of the original statute are properly implemented. Rather than issuing most permits itself, EPA generally has established programs to authorize state, tribal, and local permitting authorities to perform most permitting activities.

State and local governments have the right to be more restrictive than the federal requirements. A review of states with a large base of existing coal-based electric power generation indicates, in general, that the states follow federal regulations with respect to criteria and hazardous air pollutants, but may be more restrictive with water quality standards. Also, states generally exempt coal utilization by-products from regulation as hazardous waste and allow their commercial utilization. This report provides detailed information about the current regulatory practices in those states that have a large base of existing coal-based electric power generation.

Air Pollution Regulations

The federal government has established environmental regulations that specify maximum emission limits. Air emissions from a fossil-fueled plant are effectively required to comply with two major regulatory programs required by the Clean Air Act (CAA), New Source Performance Standards (NSPS) and New Source Review (NSR), to achieve national ambient air quality standards (NAAQS). NSPS specifies maximum emission limits on criteria air pollutants, but can be superseded by provisions of NSR that impose emission limits on individual sources, such as a coal-fueled power plant. Other regulatory limits are based on Titles I, III and IV of the 1990 Clean Air Act Amendments (CAAA) covering ozone and PM10 nonattainment, hazardous air pollutant emissions and aggregate emissions of acid rain precursors, respectively. These regulations control emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon monoxide (CO), particulate matter (PM10), ozone (O_3), lead (Pb), and particular inorganic and organic hazardous air pollutants.

The manner in which these regulations are currently being applied to IGCC power plants, via the permitting process, differs from their application to combustion-based power plants. The unique process design of an IGCC plant has resulted in discreet unit operations (separate pollution sources) being independently permitted. Therefore, units such as the gasifier, combustion turbine/HRSG, Claus plant or acid plant, process flare, etc., have to individually meet their own regulated limits, as opposed to permit limits covering the overall facility. This results in markedly different emission limits compared to a PC plant that uses the identical fuel to generate an equivalent power output.

Air permitting is by far the most time-consuming and complex aspect of developing an IGCC project. New plants have to go through NSR, using either a BACT (best available control technology) determination in an attainment area or LAER (lowest achievable emission rate) determination in a nonattainment area. For areas that are designated as attainment, the major source threshold for most emission sources is 250 tons per year of the applicable pollutant. (For fossil-fueled steam electric plants, the trigger is 100 tons per year of the applicable pollutant.) For areas designated as nonattainment, the compliance threshold ranges from 100 tons per year of the designated pollutant down to 10 tons per year, depending on the severity of the air quality compromise where the plant is located. If a proposed plant site is in a designated nonattainment area, requiring LAER treatment, the project developer loses the ability to argue that specific controls are not reasonably cost-effective. For attainment areas, most of the emissions sources and BACT determinations for a new IGCC plant are not expected to be a problem, since most of the balance-of-plant equipment (cooling towers, flares, materials handling) and their emissions are well-defined and understood. However, since the IGCC process differs fundamentally from coal combustion-based power generation technology, its unique technology may raise questions with respect to appropriate CT emission levels, applicable regulations, and appropriate BACT equipment. Determining proper emissions levels for NOx, SO_2, and CO for the combustion turbine in IGCC requires detailed analysis to avoid permitting problems.

In particular, setting NOx emission limits has had the biggest impact on IGCC technology. The initial response by regulators has been to suggest that NOx emissions be controlled to the same low levels as those from a natural gas-fired CT. EPA's "top-down-approach" for determining BACT has resulted in lowering allowable natural gas turbine NOx emission levels to values significantly less than federal new source performance standards (NSPS). Currently, this top-down BACT typically requires a new natural gas-fired turbine to achieve a NOx output level in the range of 2 - 4 ppm NOx, and often requires the use of both combustion controls and flue gas treatment equipment, such as selective catalytic reduction (SCR). However, new units in ozone nonattainment areas are required to install LAER technology, without cost consideration, to reach emission levels as low as 2.5 ppm NOx.

However, it is very important for regulators to understand that the combustion characteristics of syngas and natural gas are fundamentally different, which results in different NOx emission levels and different control capabilities for each. Use of Lean-Premix Technology is not applicable to IGCC gas turbines that fire gasification-derived syngas, and the SCR technology has also reported to be problematic due to excessive SO_2 concentration (> 2 ppm) in the turbine exhaust gas. The current state-of-the-art control for syngas-fired turbines makes use of diluents, such as nitrogen or steam, to reduce NOx emission levels to approximately 15 ppm (@ 15% oxygen and ISO conditions). This approach has been supported by a final NOx BACT determination for the Polk IGCC power plant in February 2002, which bases control on the application of an N_2 diluent to lower the syngas-fired turbine NOx emission limit from 25 ppm to 15 ppm (15% O_2 basis and ISO conditions) on a 30-day rolling average. Alternatively, setting BACT based on the types of NOx controls applied to a natural gas-fired CT will impose add-on technology solutions that may negatively impact the operating efficiency and performance of IGCC.

Water Pollution Regulations

The Clean Water Act outlines the regulation of discharges into U.S. waters. The National Pollutant Discharge Elimination System (NPDES) program limits the concentration of various pollutants in water discharges. States may submit State Pollutant Discharge Elimination System (SPDES) plans to the Administrator of the EPA for approval. SPDES may outline more stringent regulations but must be at least as stringent as the NPDES. NPDES plans differentiate between process wastewater and storm water runoff and regulate the two independently. The design of cooling systems and wastewater treatment facilities must ensure that their discharges are permittable under the applicable program. None of the applicable water discharge regulations appear to limit the introduction of IGCC technology any more than they limit coal combustion-based technology. The existing IGCC plants discussed in the report are complying with their water permit limits, although some modifications to their original water treatment system designs have been necessary.

Solid Waste/By-product Regulations

Solid waste regulations are outlined in the Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act (RCRA). Regulated wastes are characterized as either hazardous (covered by RCRA Subtitle C) or non-hazardous (covered by RCRA Subtitle D) wastes with regulations specific to the pertinent waste type. Subtitle C of RCRA imposes requirements on the generation, transportation, storage, treatment and disposal of “hazardous” wastes, while those that fall under Subtitle D are subject to regulation by the states as solid waste. A significant policy issue affecting electric utilities that use coal has been the question of whether or not coal combustion by-products (CCBs) should be regulated at the Federal level as hazardous wastes under Subtitle C. A 1993 EPA final regulatory determination *exempted* coal utilization by-products (CUBs) generated by electric utilities and independent power producers from regulation as a hazardous waste under RCRA. EPA currently applies this exemption to fly ash, bottom ash, slag and flue gas desulfurization (FGD) by-products that are managed independently of any other wastes. In April 2000, an EPA regulatory determination concluded that CUBs that are co-managed with other wastes do not warrant regulation as hazardous wastes under Subtitle C of RCRA, and EPA also concluded that, except for mine filling, no additional regulations are warranted for coal combustion wastes that are used beneficially. However, EPA also stated its intent to develop *nationwide regulations* for disposal of CUBs; prior to this, all regulations governing CUB disposal and use had come from individual states.

None of the applicable solid waste discharge regulations appear to limit the introduction of IGCC technology any more than they limit coal combustion-based technology. Forty-five (45) states, encompassing 96% of coal-fired utility generating capacity, duplicate the federal exemption of coal combustion by-products from being categorized as a hazardous waste. Since IGCC by-products have demonstrated better toxicity characteristics than wastes from coal combustion-based plants, IGCC should be no more impacted than such plants. Leachability test data from demonstration and operating plants indicate that IGCC slag is comparable to that produced in wet-bottom PC power plants and should clearly fall under the classification of non-hazardous waste. Unfortunately, even if IGCC slag/bottom ash is classified as non-hazardous, local regulations still may require disposal in a different class of landfill. As mentioned previously, the Polk IGCC plant is currently required to use a Class I landfill (double-lined with leachate extraction and control) versus much less costly and more available Class III landfills that don’t require such strict standards.

Ultimately, it is highly desirable to avoid IGCC by-product disposal by selling the by-product material for commercial applications. Unfortunately, most states currently do not have specific regulations addressing the use of CUBs as commercial by-products, and requests for specific uses are handled on a case-by-case basis or under generic state recycling laws or regulations. Many states have “generic” laws and regulations that authorize limited reuse and recycling of hazardous and/or solid wastes. If by-product utilization is planned as part of a project, this issue needs to be fully addressed in waste handling permit applications.

Future Regulations

Uncertainty over how environmental regulations and rules will be implemented, and existing regulations and rules tightened, is of major importance to the future development of IGCC technology. Recent congressional attempts to introduce national multi-pollutant control legislation would not only significantly reduce total emissions of SO_2 and NOx, but would also dramatically reduce total CO_2 and mercury emissions. However, since it has currently been decided that the United States will neither participate in the Kyoto agreement nor pursue mandatory efforts to limit CO_2 emissions from power plants, the status of multi-pollutant control legislation that includes CO_2 is clearly uncertain. This is supported by the proposed Bush Administration’s

Clear Skies Act (CSA), which only supports further control of SOx, NOx, and mercury. The CSA proposes the following annual emission targets:

- SO_2: 4.5 million tons by 2010 and 3 million tons by 2018 (currently 11 million tons)
- NOx: 2.1 million tons by 2010 and 1.7 million tons by 2018 (currently 5.4 million tons)
- Mercury: 26 tons by 2010 and 15 tons by 2018 (currently 48 tons)

However, the most recent multi-pollutant control legislation to be introduced to the 107th Congress, the Clean Air Planning Act of 2002 (CAPA), sets national caps on SO_2, NOx, CO_2, and mercury emissions from electric power plants. The more aggressive CAPA proposes the following annual emission targets:

- SO_2: 4.5 million tons by 2008, 3.5 million tons by 2012, and 2.25 million tons by 2015 (currently 11 million tons)
- NOx: 1.87 million tons by 2008 and 1.7 million tons by 2012 (currently 5.4 million tons)
- Mercury: 24 tons by 2008 and 5-16 tons by 2012, with EPA to set the cap (currently 48 tons)
- CO_2: ~ 2.6 billion tons by 2008 and ~2.3 billion tons by 2012 (currently 2.4 billion tons)

These proposed limits are independent of the impending plant-specific mercury regulations that EPA must issue by December 15, 2004. Installation of mercury controls, based on MACT standards, will be required no earlier than three years after the regulation goes into effect. As discussed previously, commercial methods have been employed for many years that remove trace amounts of mercury from natural gas and gasifier syngas, although such mercury control technology has not yet been incorporated into an operating IGCC system.

At the state and local level, tightening of existing regulations, such as lower BACT/LAER requirements for NOx and HAPs, is equally important. Further complicating the uncertainty for IGCC technology is how future regulations will deal with the inherent fuel flexibility of gasifiers, which allows them to feed coal in combination with alternative feedstocks like municipal solid waste (MSW).

1. INTRODUCTION TO GASIFICATION-BASED POWER SYSTEMS

Gasification-based energy conversion systems are capable of providing a stable, affordable, high-efficiency energy supply with a minimal environmental impact. They can provide flexibility in the production of a wide range of products including electricity, fuels, chemicals, hydrogen, and steam, while utilizing low-cost, widely available feedstocks. In particular, gasification of abundant U.S. coal provides an alternative to commercial coal-based combustion systems that is generally more efficient and environmentally benign. Coal gasification is a well-proven technology that has had many applications, starting with the production of coal gas for urban areas, progressing to the production of fuels, such as oil and synthetic natural gas (SNG), chemicals, and most recently, to large-scale Integrated Gasification Combined Cycle (IGCC) power generation.

The first commercial IGCC plants[a] were put into service in the U.S. through DOE's cooperative Clean Coal Technology (CCT) program, and have proven capable of exceeding the most stringent emissions regulations currently applicable to coal-fueled power plants. They have achieved the lowest levels of criteria pollutant air emissions (NOx, SOx, CO, PM_{10}) of any coal-fueled power plants in the world. However, because of ever-tightening environmental regulations governing fossil fuel-based power generation, it is important to assess the environmental performance of IGCC technology in order to address key regulatory issues that may affect both the siting and operation of future commercial plants.

This section of the report, and its accompanying appendices, presents a brief primer on gasification and IGCC technology, starting with a generalized overview of key gasification-based energy conversion concepts, with IGCC currently representing one of the most promising configurations. This is followed in Section 1.1 (in conjunction with Appendix 1A) with detailed descriptions of major IGCC components, including alternative gasifier designs and basic environmental control options for criteria pollutants. Section 1.2 characterizes the primary resource inputs and effluent discharges, the latter being of critical importance in defining the impact of IGCC technology on the environment. Section 1.3 (in conjunction with Appendix 1B) provides an overview of six large, commercial-scale IGCC plants that have successfully demonstrated coal-based IGCC technology. Finally, Section 1.4 provides a general comparison of IGCC operational/environmental performance with that of state-of-the-art pulverized coal-fired (PC) and fluidized bed combustion (FBC) power plants.

FIGURE 1-1 depicts a simplified flow chart illustrating alternative gasification-based energy conversion options. Various gasification and environmental cleanup technologies convert coal (or other carbon-based feedstocks) and an oxidant to synthesis gas (syngas) for further conversion into marketable products, such as electricity, fuels, chemicals, steam, and hydrogen. FIGURE 1-2 identifies many of the basic components that make up the systems illustrated in FIGURE 1-1. The heart of any gasification-based system is the gasifier, which can process a wide variety of feedstocks, including coal, biomass, petroleum coke, refinery residues, and other wastes. The gasifier converts carbonaceous feedstock into gaseous products at high temperature and (usually) elevated pressure in the presence of oxygen and steam. Partial oxidation of the feedstock in a reducing (oxygen starved) atmosphere provides the heat. At operating conditions, chemical reactions occur that produce the syngas, a mixture of predominantly CO and H_2.

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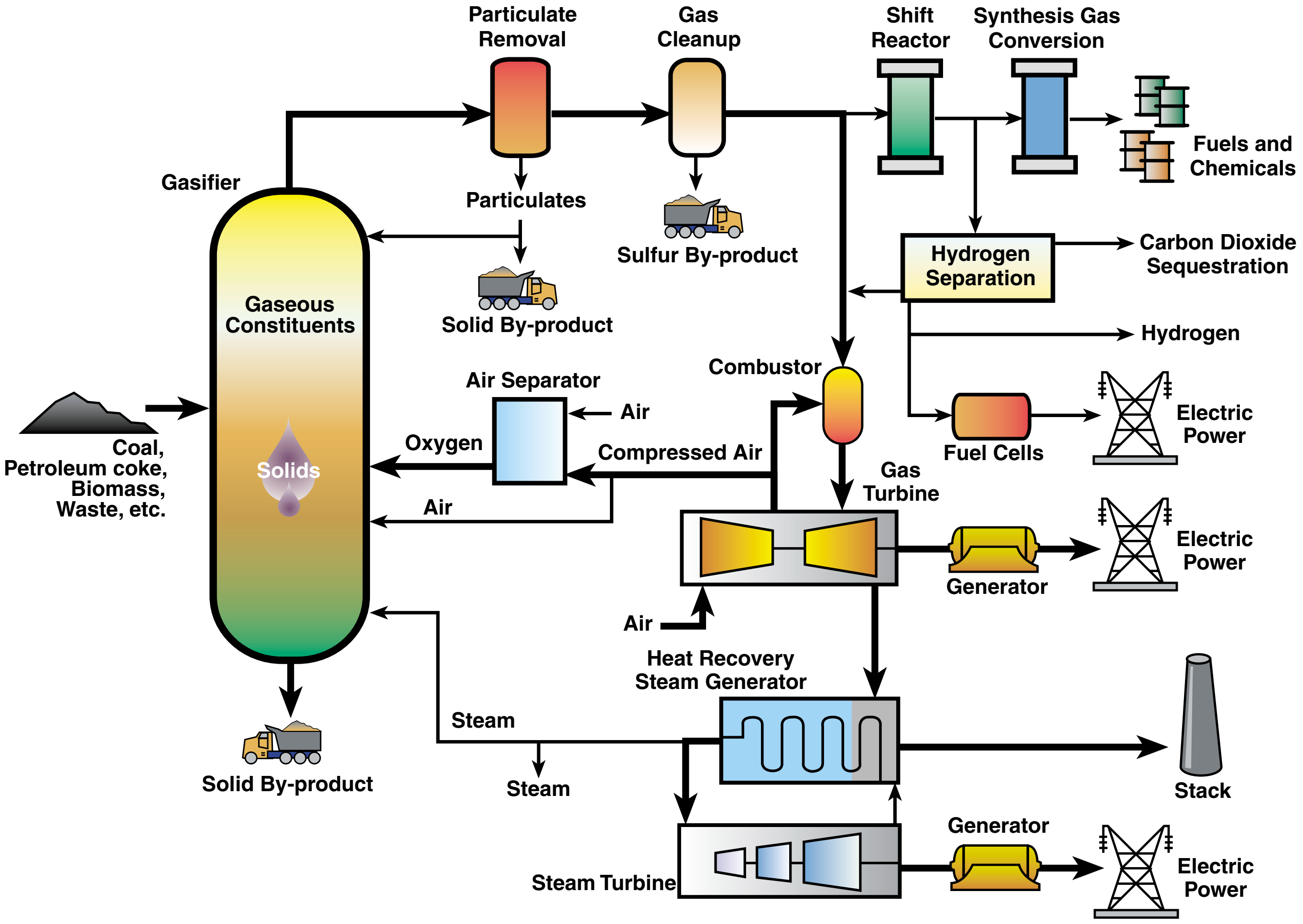
[a] Tampa Electric Company's new 250 MWe Polk Power plant was placed into service in October 1996 and PSI Energy's 262 MWe retrofit of the Wabash River Generating Station was placed into service in November 1995.

FIGURE 1-1. GASIFICATION-BASED ENERGY CONVERSION SYSTEM CONCEPTS



Minerals in the feedstock (ash) separate and leave the bottom of the gasifier as an inert slag (or bottom ash), a potentially marketable solid product.[b] The fraction of the ash entrained with the syngas, which is dependent upon the type of gasifier employed, requires removal downstream in particulate control equipment, such as filtration and water scrubbers. This particulate is typically recycled to the gasifier to ensure high carbon conversion. Some gasifiers also yield devolatilization or pyrolysis products (coal tars, oils, phenols, etc.) that can and must be controlled. While this is a major issue with moving-bed gasifiers, it is less of a concern for fluid-bed and multi-stage/single-stage entrained-flow gasifiers.

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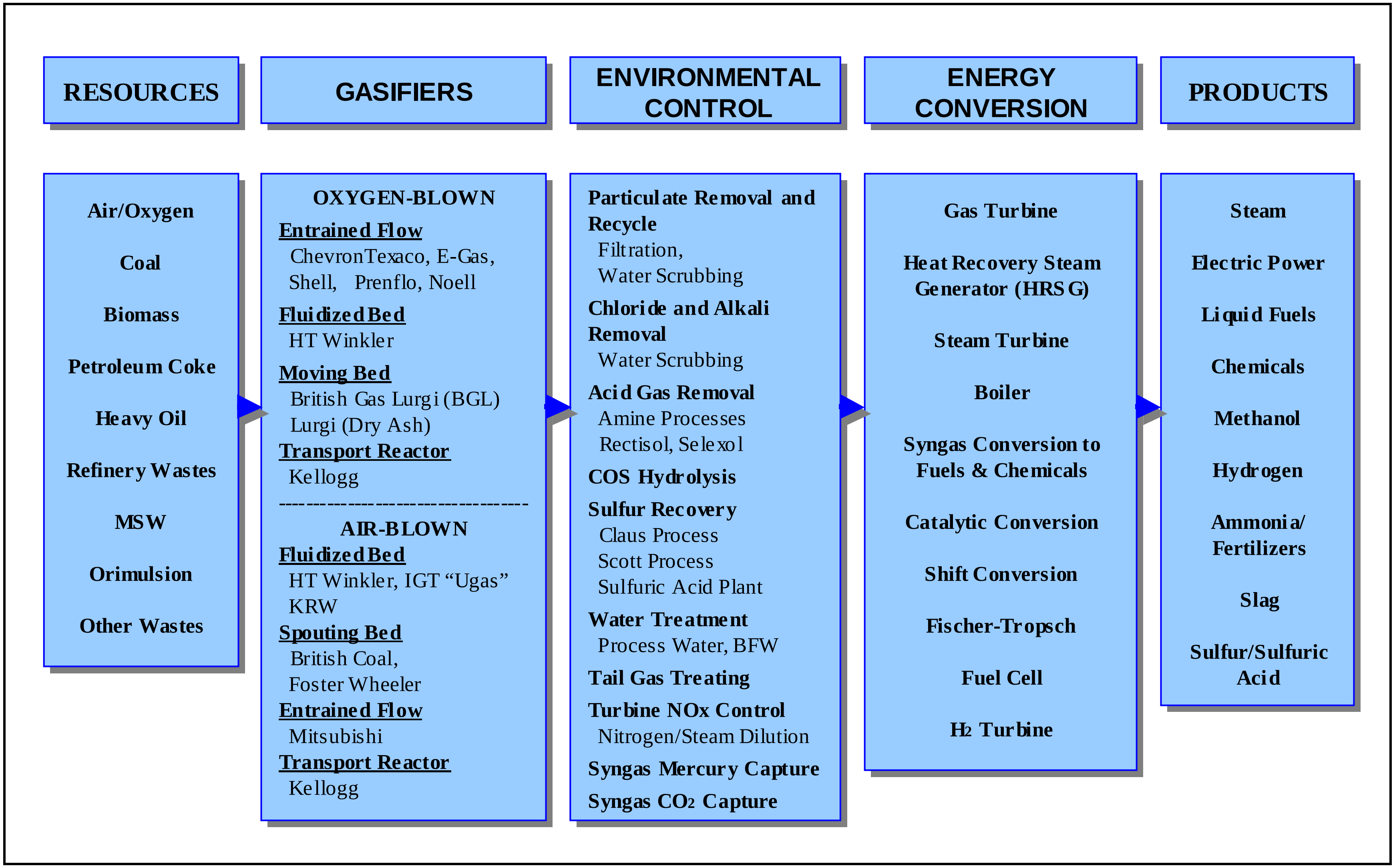
[b] When applicable, char must be separated from slag or bottom ash before it can be marketed.

FIGURE 1-2. GASIFICATION-BASED ENERGY CONVERSION SYTEM OPTIONS



RESOURCES

- Air/Oxygen
- Coal
- Biomass
- Petroleum Coke
- Heavy Oil
- Refinery Wastes
- MSW
- Orimulsion
- Other Wastes

GASIFIERS

OXYGEN-BLOWN

Entrained Flow
ChevronTexaco, E-Gas, Shell, Prenflo, Noell

Fluidized Bed
HT Winkler

Moving Bed
British Gas Lurgi (BGL)
Lurgi (Dry Ash)

Transport Reactor
Kellogg

AIR-BLOWN

Fluidized Bed
HT Winkler, IGT "Ugas"
KRW

Spouting Bed
British Coal, Foster Wheeler

Entrained Flow
Mitsubishi

Transport Reactor
Kellogg

ENVIRONMENTAL CONTROL

Particulate Removal and Recycle
Filtration,
Water Scrubbing

Chloride and Alkali Removal
Water Scrubbing

Acid Gas Removal
Amine Processes
Rectisol, Selexol

COS Hydrolysis

Sulfur Recovery
Claus Process
Scott Process
Sulfuric Acid Plant

Water Treatment
Process Water, BFW

Tail Gas Treating

Turbine NOx Control
Nitrogen/Steam Dilution

Syngas Mercury Capture

Syngas CO_2 Capture

ENERGY CONVERSION

- Gas Turbine
- Heat Recovery Steam Generator (HRSG)
- Steam Turbine
- Boiler
- Syngas Conversion to Fuels & Chemicals
- Catalytic Conversion
- Shift Conversion
- Fischer-Tropsch
- Fuel Cell
- H_2 Turbine

PRODUCTS

- Steam
- Electric Power
- Liquid Fuels
- Chemicals
- Methanol
- Hydrogen
- Ammonia/ Fertilizers
- Slag
- Sulfur/Sulfuric Acid

Other potential pollutants, such as sulfur and nitrogen compounds, form species that can be readily extracted. Hydrogen sulfide (H_2S) and carbonyl sulfide (COS), once hydrolyzed, are removed by dissolution in, or reaction with, an organic solvent and converted to valuable by-products, such as elemental sulfur or sulfuric acid. Fuel nitrogen is mainly converted to diatomic nitrogen, but a small fraction is converted to ammonia (NH_3) and some cyanide and thiocyanate in the gasifier's reducing environment, which is readily removed via water scrubbing. Most trace pollutants are removed in the slag/bottom ash or in the particulate control equipment. Since some pollutants end up in the wastewater, proper water treatment facilities are quite important for overall environmental performance.

After cleanup, the syngas can:

- Be combusted in a gas turbine, the waste heat from which can be used to generate steam in a combined cycle mode (so-called IGCC configuration);
- Provide hydrogen, through separation, for refinery applications or as a fuel for highly efficient fuel cells, the waste heat from which can be used to generate steam in a combined cycle mode; and
- Produce a broad range of chemicals and clean fuels using established processes.

The IGCC configuration, which is the primary subject of this report, is an innovative electric power generation concept that combines modern coal gasification technology with both gas turbine (Brayton cycle) and steam turbine (Rankine cycle) power generation. IGCC is highly flexible and can be used for new power generation applications, as well as for repowering older coal-fired plants, significantly improving their environmental performance. IGCC provides feedstock and product flexibility, greater than 40 percent net efficiency (based on HHV), and very low pollutant emissions. The high process efficiency also has the added benefit of reducing CO_2 production per unit of electricity output. Because CO_2 can readily be recovered in concentrated form with oxygen-blown gasification, CO_2 capture technology can be integrated into IGCC as part of a future strategy to reduce greenhouse gas emissions.

1.1 Description of Major IGCC System Components

IGCC power systems use a gasifier to convert a carbon-based feedstock into syngas consisting of a mixture of carbon monoxide (CO) and hydrogen (H_2) with some carbon dioxide (CO_2) and traces of other gases. The syngas is cleaned of particulates, sulfur, and other contaminants and is then combusted in a high-efficiency combustion turbine/generator. Heat from the turbine exhaust gas is extracted in a heat recovery steam generator (HRSG) to produce steam to drive a steam turbine/generator. FIGURE 1-3 shows a simplified flow chart of a generic IGCC plant.

Major system components for coal-fed IGCC plants include:

- Air Separation Plant (separates oxygen from air to supply 95%+ pure oxygen to the gasifier) – used for oxygen-blown gasification processes[c]
- Gasifier (oxygen-blown or air-blown)
- Syngas cooler

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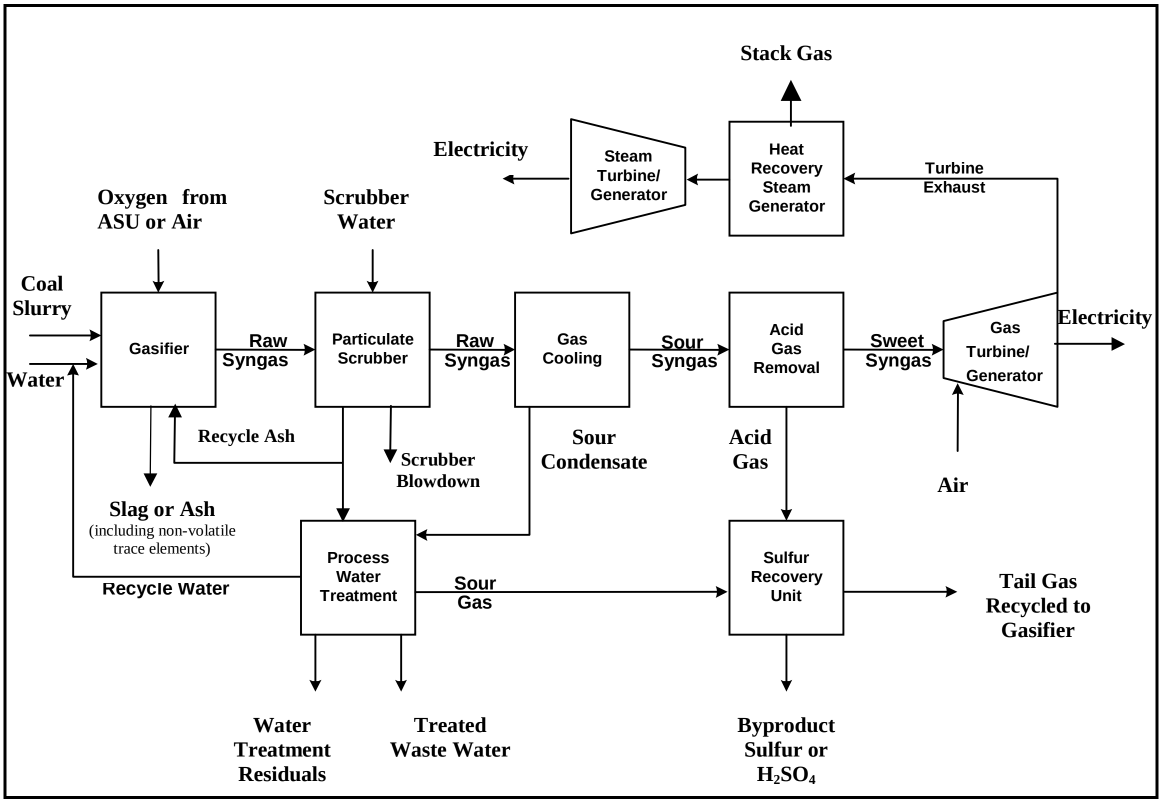
[c] Chemicals co-production often requires high-purity oxygen

- Particulate removal and recycle–water scrubbing or hot filtration
- Acid Gas Cleanup (H_2S and COS removal and sulfur recovery)
- Combustion turbine/Generator
- Heat Recovery Steam Generator
- Steam turbine/Generator
- Water treatment and recycle

FIGURE 1-3. SCHEMATIC OF GENERIC IGCC POWER PLANT



1.1.1 Air Separation Plant

All coal gasification processes require an oxidant to maintain the temperature required for gasification. The oxidant, usually in combination with steam, reacts with the coal to produce carbon monoxide and as little carbon dioxide as possible. The oxidant can be air, oxygen, or oxygen-enriched air. The choice of oxidant affects the amount of nitrogen the gasification system has to handle and depends on the application, type of gasifier, and degree of system integration.

Oxygen-blown systems have several advantages over air-blown systems. Syngas from an oxygen-blown gasifier has a heating value ranging from 250 to 400 Btu/scf, compared to an air-blown gasifier with 90 to 170 Btu/scf fuel gas and high nitrogen content. The medium Btu syngas can potentially be used as a replacement for natural gas[d] or as synthesis gas for higher-value chemicals production. In addition, the moderate heating value of the gas helps minimize the size of the gasifier and auxiliary systems. The "cold-gas" efficiency[e] is 7-10% higher for oxygen-blown gasification due to the avoidance of nitrogen dilution. Gasifier operability and carbon conversion also improves with the use of oxygen.[1]

An air separation unit (ASU), usually high-pressure cryogenic-type, supplies pure oxygen for oxygen-blown gasification processes. A conventional ASU is capable of producing 99+% pure oxygen for use in the gasifier and sulfuric acid plant, but lower purity oxygen (e.g., 95%) is believed to be the economic optimum for IGCC plants. If co-production of chemicals is also incorporated into the plant, then higher purity oxygen is usually required.[2] The other product of the ASU, high purity nitrogen (e.g., over 98% pure) can also be utilized in appropriately designed combustion turbines. The addition of nitrogen to the syngas has dual benefits. First, this additional mass flow has the advantage of higher power output from the combustion turbine, and second, the nitrogen acts to control NOx emissions by reducing the combustor flame temperature, which reduces the formation of thermal NOx (see Section 2.2.1.3).

1.1.2 Gasification Process and Reactor Types

In comparison with combustion technology, which uses air (or oxygen) in excess of the stoichiometric amount theoretically required to completely convert all carbon to CO_2, gasification generally uses one-fifth to one-third of the theoretical oxygen (substoichiometric) to only partially oxidize the combustible constituents of the feedstock material (e.g., coal). The major combustible products of gasification are carbon monoxide (CO) and hydrogen (H_2), with a small fraction of the carbon completely oxidized to yield some CO_2. A small amount of methane may also be present. The heat produced by the partial oxidation provides most of the energy required to break chemical bonds in the coal, increase the gasifier products to reaction temperature, and drive endothermic (heat-producing) gasification reactions.[1]

While the chemistry of coal gasification is quite complex, FIGURE 1-4 presents the major gasification reactions. Rising temperature in the gasifier initiates devolatilization and breaking of weaker chemical bonds to yield tars, oils, phenols and hydrocarbon gases. These products generally further react to form H_2, CO, and CO_2. The fixed carbon that remains after devolatilization is gasified through reactions with O_2, steam, CO_2, and H_2, and these gases react further to produce the final gas mixture. The water-gas shift reaction alters the H_2/CO ratio in the final mixture, but does not greatly impact the heating value of the synthesis gas. Methane formation, via the two methanation reactions shown in FIGURE 1-4, are favored by high pressures and low temperatures, thus are important in lower-temperature systems. Methane formation is a highly exothermic reaction that does not consume oxygen and therefore increases the efficiency of gasification and the final heating value of the synthesis gas. Overall, about 70% of the feed fuel's heating value is associated with the CO and H_2 components of the gas, but can be higher depending upon the gasifier type.

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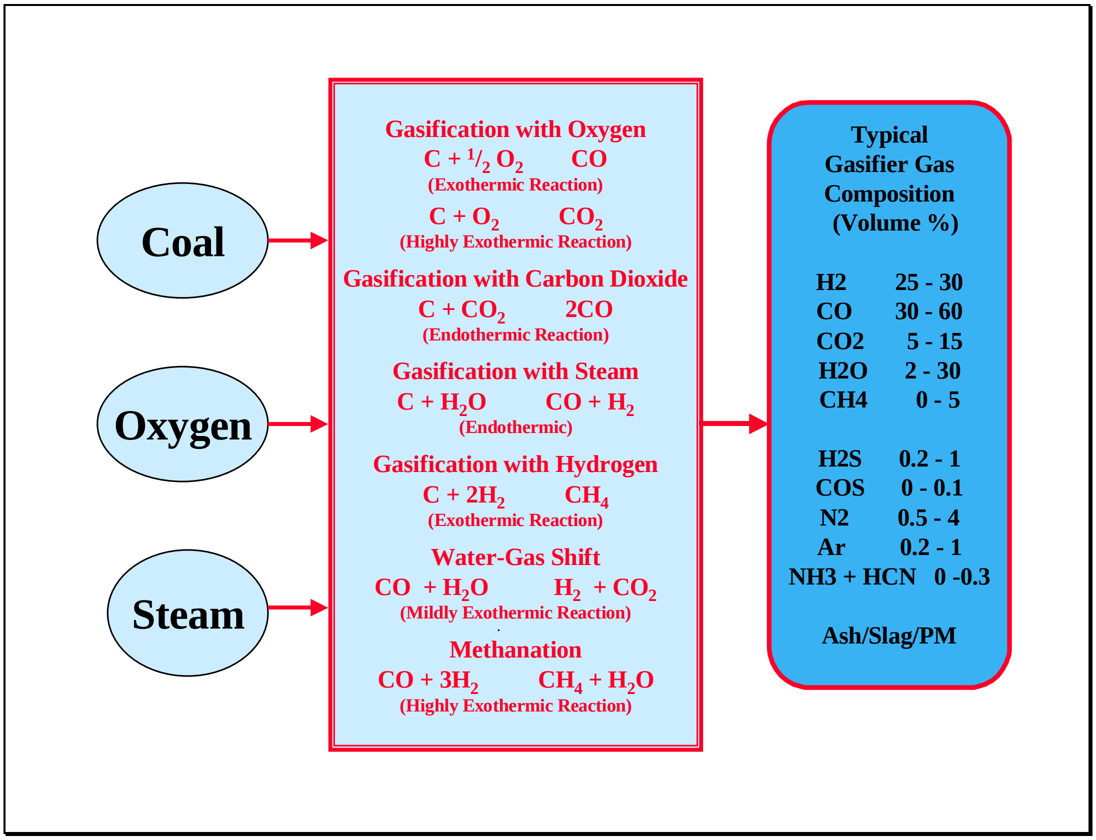
[d] Equipment modifications may be required to utilize medium Btu syngas as a replacement for natural gas.

[e] Cold gas efficiency is a measure of the percentage of a feedstock's chemical combustion energy that is contained in the gasifier syngas.

FIGURE 1-4. MAJOR GASIFICATION REACTIONS



The minor and trace components of coal (or other solid fuel feedstocks) are also transformed in the gasification reactor, and their ultimate fate is of significant importance to the environmental impacts of gasification. Under the substoichiometric, reducing conditions of gasification, most of the fuel's sulfur converts to hydrogen sulfide (H_2S), but some (3-10%) also converts to carbonyl sulfide (COS). Nitrogen bound with the fuel generally converts to gaseous nitrogen (N_2), with some ammonia (NH_3) and a small amount of hydrogen cyanide (HCN) also being formed. Most of the chlorine content of the fuel is converted to hydrogen chloride (HCl) gas and some particulate-phase chlorides. Trace elements associated with both organic and inorganic components of the coal, such as mercury and arsenic, are released during gasification and partition between the different ash fractions (e.g., fly ash, bottom ash, slag) and gaseous emissions. The particular chemical species and physical forms of condensed-phase and vapor-phase trace elements are functions of gasifier design and operating conditions. These contaminants need to be removed from the syngas prior to delivery to the energy conversion device (e.g., gas turbine or fuel cell).

Although there are various coal gasification reactors, with different design and operating characteristics, all are based on one of three generic types:[1]

- Moving-bed reactors (also call fixed-bed)
- Fluidized-bed reactors
- Entrained-flow reactors

TABLE 1-1 summarizes the characteristics of the generic reactors types.

1.1.2.1 Moving-bed reactors

In moving-bed (also called fixed-bed) reactors, large particles of coal move slowly down through the bed while reacting with gases moving up through the bed. Reaction "zones" are often referred to in describing the types of reactions occurring. In the drying zone at the top of the gasifier, the entering coal is heated and dried, while cooling the product gas before it leaves the reactor. The coal is further heated and devolatized by higher temperature gas as it descends through the carbonization zone. In the next zone, the gasification zone, the devolatized coal gasifies by reaction with steam and carbon dioxide. Near the bottom of the gasifier, in the combustion zone, which operates at the highest temperature, oxygen reacts with the remaining char. In a dry-ash version (e.g., Lurgi dry ash gasifier), the temperature is moderated to below the ash-slagging temperature by reaction of the char with steam, in the presence of excess steam. The ash below the combustion zone is cooled by the entering steam and oxidant (oxygen or air).[1] In a slagging version (e.g., British Gas/Lurgi or BGL gasifier), much less steam is used, which maintains the temperature above the ash-slagging temperature.

Feed coal moisture content principally controls the discharge gas temperature. High-moisture lignite coal produces a raw gas temperature of about 600°F, while low-moisture bituminous coal produces a raw gas temperature of over 1000°F. The raw gas leaving the reactor is quenched directly with recycle water to condense and remove tars and oils. After the quench, low-level heat can be recovered from the gas.

All moving-bed reactors have the following characteristics:

- Low oxidant requirements
- Design modifications required for handling caking coals
- Production of hydrocarbon liquids, such as tars and oils
- High "cold-gas" thermal efficiency, when the heating value of the hydrocarbon liquids are included
- Limited ability to handle fines.

Moving-bed gasifiers differ in exit ash condition and in special design configurations. There are two main commercial moving bed gasifier technologies. The Lurgi dry-ash gasifier was originally developed in the 1930s and has been used extensively for Town Gas production and in South Africa for chemicals from coal. In this gasifier, the temperature at the bottom of the bed is kept below the ash fusion point so the coal ash is removed as a solid. In the 1970s, Lurgi and the then British Gas Corporation (now BG plc) developed a slagging version in which the temperature at the bottom is sufficient for the ash to melt. This gasifier is referred to as the BG Lurgi (BGL) gasifier. Several BGL gasifiers are currently operating for gasifying solid wastes and co-gasifying coal and waste.

TABLE 1-1. IMPORTANT CHARACTERISTICS OF GENERIC TYPES OF GASIFIERS[1]

GASIFIER TYPE	**MOVING-BED**		**FLUIDIZED-BED**		**ENTRAINED-FLOW**
Ash Conditions	**Dry Ash**	**Slagging**	**Dry Ash**	**Agglomerating**	**Slagging**
FEED FUEL CHARACTERISTICS:					
Fuel size limits	6-50 mm	6-50 mm	<6 mm	<6 mm	<0.1 mm
Acceptability of caking coal	Yes (with modifications)	Yes	Possibly	No, Non-caking	Yes
Preferred feedstock	Lignite, reactive bituminous coal, anthracite, wastes	Bituminous coal, anthracite, petcoke, wastes	Lignite, reactive bituminous coal, anthracite, wastes	Lignite, bituminous coal, anthracite, cokes, biomass, wastes	Lignite, reactive bituminous coal, anthracite, petcokes
Ash content limits	No limitation	<25% preferred	No limitation	No limitation	<25% preferred
Preferred ash melting temperature, °F	>2200	<2370	>2000	>2000	<2372
OPERATING CHARACTERISTICS:					
Exit gas temperature, °F	Low[a] (800 –1200)	Low (800 –1200)	Moderate (1700 – 1900)	Moderate (1700 – 1900)	High (>2300)
Gasification Pressure, psi	435+	435+	15	15 – 435	< 725
Oxidant requirement	Low	Low	Moderate	Moderate	High
Steam requirement	High	Low	Moderate	Moderate	Low
Unit Capacities, MWth	10 – 350	10 – 350	100 – 700	20 – 150	Up to 700
KEY DISTINGUISHING CHARACTERISTICS	Hydrocarbon liquids in raw gas		Large char recycle		Large amount of sensible heat energy in the hot raw gas
KEY TECHNICAL ISSUE	Utilization of fines & hydrocarbon liquids		Carbon conversion		Raw gas cooling

a. Moving-bed gasifiers operating on low rank fuels have exit temperatures lower than 800° F.

Since the moving-bed gasifier has very high cold gas efficiency, compared with other gasifiers, a larger portion of the original heating value of the coal appears as chemical energy in the gas as opposed to thermal energy. Thus, the moving bed gasifier typically does not feature high-temperature heat exchangers as required by entrained-flow and fluidized-bed systems. When incorporated into an IGCC configuration, the gasification island and power generation unit are, therefore, less closely coupled, as the gas-cooling train is not intimately integrated into the steam turbine cycle. Thus, in a moving-bed IGCC system, more of the power is generated by the gas turbine and less by the steam turbine than in an entrained-flow system.

Appendix 1A provides a detailed description of the Lurgi Dry Ash and BGL gasifiers.

1.1.2.2 Fluidized-Bed Reactors

Fluidized-bed reactors are highly back-mixed and efficiently mix feed coal particles with coal particles already undergoing gasification. Coal enters at the side of the reactor, while steam and oxidant enter near the bottom, suspending or fluidizing the reacting bed. A constant temperature is sustained that is below the ash fusion temperature, which avoids clinker formation and possible de-fluidization of the bed. This in turn means that fluidized bed gasifiers are best suited to relatively reactive fuels, such as biomass. Some char particles are entrained in the raw gas as it leaves the top of the gasifier, but are recovered and recycled back to the reactor via a cyclone. Ash particles, removed below the bed, give up heat to the incoming steam and recycle gas.

Fluidized-bed gasifiers have the following characteristics:

- Accepts a wide range of solid feedstock (including solid waste, wood, and high ash coals)
- Uniform, moderate temperature
- Moderate oxygen and steam requirements
- Extensive char recycling.

Fluidized bed gasifiers may differ in ash conditions (dry or agglomerated) and in design configurations for improving char use. Commercial versions of this type of gasifier include the High Temperature Winkler (HTW) and KRW designs. The latter gasifier was incorporated into the Pinon Pine Coal Gasification Plant. There are relatively few large fluidized bed gasifiers in operation.

Appendix 1A provides a detailed description of the High Temperature Winkler (HTW) and KRW gasifiers.

1.1.2.3 Entrained-flow Reactors

Entrained-flow gasifiers react fine coal particles with steam and oxidant. Residence time in this type of reactor is very short. Entrained-flow gasifiers generally use oxygen as the oxidant and operate at high temperatures, well above ash-slagging conditions, to assure high carbon conversion.

Entrained-flow gasifiers have the following characteristics:

- Ability to gasify all coals regardless of coal rank, caking characteristics, or amount of coal fines (although feedstocks with lower ash content are favored)
- Uniform temperatures

- Very short fuel residence time in gasifier
- Solid fuel must be very finely divided and homogeneous
- Relatively large oxidant requirements
- Large amount of sensible heat in the raw gas
- High-temperature slagging operation
- Entrainment of some molten slag in the raw gas.

Differences among entrained-flow gasifiers include the coal feed systems (water slurry or dry coal feed systems can be used), internal design to handle the very hot reaction mixture, and heat recovery configuration. Entrained flow gasifiers have been selected for nearly all the coal- and oil-based IGCCs currently in operation or under construction. Commercial entrained flow gasifiers include the ChevronTexaco gasifier, the two variants of the Shell gasifier (one for coal, the other for oil), the Prenflo gasifier, the E-Gas (formerly Destec) gasifier, and the Noell gasifier. Of these, both the ChevronTexaco gasifier and the Shell oil gasifier have over 100 units in operation worldwide.

Appendix 1A provides a detailed description of the ChevronTexaco, Shell, E-Gas, Prenflo, and Noell gasifiers.

1.1.3 Syngas Cooler/Heat Recovery

Coal gasification processes operate at high temperatures, and, therefore, some method of heat recovery is typically utilized to increase overall system efficiency. Heat recovery can represent about 15% of the energy in the feed fuel, but this varies with the gasification technology employed (5% for moving bed to 25% for entrained flow processes).

The raw syngas leaving the gasification reactor can be cooled by radiant and/or convective heat exchange and/or by a direct quench system, which injects either water or cool recycle gas into the hot raw syngas. The syngas next passes through a gas cooling process, which usually is a series of heat exchangers. The heat recovered can be utilized for steam generation or process heating.

In most IGCC plant design configurations, saturated steam raised from cooling the raw gasifier syngas is sent to the HRSG for superheat and reheat. The steam and water systems are integrated between the gasification island and the power conversion block and superheated steam is generally better generated in the HRSG than in the raw syngas coolers.[f]

1.1.4 Particulate Removal

The syngas exiting a gasifier contains fine char and ash particulate and therefore particulate removal (and recycle) is necessary for all processes. Coal gasification, however, has an advantage over combustion technologies, as it operates at high pressure and generates a significantly smaller gas volume. Fly ash and remaining char particles need to be removed from the gas in both slagging and non-slagging gasifiers. The particulate is removed by either hot, dry barrier filters, of the candle (either ceramic or metallic) type, located upstream of the high

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[f] The higher metal temperatures required for superheated steam raising from the hot raw syngas make this form of heat recovery much more difficult and expensive than saturated steam raising.

temperature heat recovery devices or by “warm gas” water scrubbers located downstream of the cooling devices. Hot candle filters are advantageous since the particulate is removed as a dry solid; however, these filters are subject to blinding and breakage. In water scrubbers, the particulate is removed as a slurry which must be dewatered; however, the water scrubber also removes the trace quantities of chlorides which may be present in the syngas and which, if not removed, will poison the hydrolysis catalyst and cause metallurgy problems in downstream equipment. In both cases, the recovered particulate is recycled back to the gasifier.

Conventional wet scrubbers are used for fine particulate removal in many coal gasification systems currently operating commercially. The coal gasifier’s high operating pressure allows the scrubbers to operate at reasonably large pressure drops, which makes them small, efficient, and inexpensive. Scrubbers also remove ammonia, chlorides, and other trace organic and inorganic components from the synthesis gas. The blowdown water from the scrubber is flashed, sometimes under vacuum, and the flash gas is sent to a Claus plant or sulfuric acid decomposition furnace. Particulate-laden water is sent to a water handling system, which separates the solids for recycle to the gasifier or disposal.

Advanced hot gas cleanup systems must achieve fine particulate removal without cooling the gas. Development of this technology focuses primarily on barrier-type filters, including fiber filters, ceramic candle filters, cross-flow filters, and screenless granular bed filters. Chlorides and other trace components can also be removed with the dry fly ash, but no commercially available methods are currently available. Recovering the dry fly ash significantly reduces salt build up in the recycle process water and wastewater cleanup costs. Recovered particulates can then be recycled back to the gasifier for gasification of residual carbon.[3] Hot gas cleanup technology is not commercially available. Warm gas particulate removal via wet scrubbing is typically employed.

1.1.5 Acid Gas Cleanup/Sulfur Recovery

Acid gas cleanup processes are very effective and have been proven by the oil and gas industries for many years with over 99.8% sulfur recovery. The gasifier’s raw syngas (called sour gas) contains carbonyl sulfide (COS) and hydrogen sulfide (H_2S), both of which require a high degree of removal for the power plant to achieve a low SO_2 level in the stack gas. H_2S can be removed in an acid gas removal system; however COS is not readily removed unless it is first converted to H_2S by hydrolysis. A hydrolysis unit reacts COS with water in the presence of a catalyst to form CO_2 and H_2S. The cooled syngas is then sent through an acid gas removal process to remove most of the H_2S and some of the CO_2.

Conventional acid gas removal processes treat the syngas via contact with chemical or physical solvents to capture the H_2S and some of the CO_2. Amine solvents, such as MDEA (Methyldiethanolamine), react to form a chemical bond between the acid gas and the solvent. Physical solvents, such as Selexol (dimethylether or polyethylene glycol) or Rectisol (cold methanol) remain chemically non-reactive with the gas, which avoids the formation of heat-stable salts that sometimes impacts amine systems. The cleaned gas is sent to the downstream conversion device, such as a combustion turbine. The rich amine (or other solvent) from the absorber is sent to the stripper where it is stripped of acid gases. The amine (or other solvent) is recycled and the recovered acid gases are sent to a sulfur recovery process for conversion into by-products.

Sulfur recovery processes recover sulfur either as sulfuric acid or as elemental sulfur. Sulfuric acid plants convert the H_2S to SO_2 by combustion with air. The SO_2 is oxidized to form SO_3, which is then scrubbed with weak sulfuric acid to make 98% H_2SO_4, which can be sold commercially. The remaining SO_2 and SO_3 are at low enough concentrations to permit discharge to the atmosphere. A sulfuric acid plant typically recovers 99.8% of the H_2S feed.

For high recovery efficiency, sulfur recovery processes often are comprised of two processes, one for bulk removal, and a second for fine recovery from the bulk tail-gas. The most common removal system is the Claus process followed by a tail-gas treating process such as the SCOT (Shell Claus Off gas Treatment) process. A Claus sulfur recovery unit produces elemental sulfur from the H_2S in the syngas in a series of catalytic stages. Part of the H_2S is burned to produce SO_2, which is then reacted with the remaining H_2S to produce elemental sulfur and water. The Claus process removes about 98% of the sulfur in the syngas, and the tail-gas is then sent to a SCOT process for further sulfur recovery.[g] The SCOT system is amine-based and can achieve an overall sulfur recovery of 99.8%. High quality elemental sulfur is recovered which can be sold commercially.[4] Other commercially available processes include wet oxidation systems such as Stretford, LO-CAT, and Sulferox.

1.1.6 Combustion Turbines

In IGCC systems, the cleaned syngas is used, in whole or in part, to fuel a combustion turbine. The combustion turbine drives an electric generator, may provide compressed air to the air separation unit or gasifier, and produces heat (exhaust) to generate steam for a steam turbine. This combined use of combustion and steam turbines significantly boosts generation efficiency.

Air-blown coal gasification processes supply a portion of the air to the gasifier from the combustion turbine air compressor. A necessary adjustment for existing combustion turbines is to balance and match the air and turbo-expander mass flows. Extracted air, however, must be cooled and compressed further to achieve gasifier operating pressure. In addition, the low-Btu syngas produced by air-blown gasifiers often requires modifications to the combustion turbine's burners.

The medium-Btu fuel gas produced by oxygen-blown coal gasification processes requires less modification to existing combustion turbines and less integration than the low-Btu gas produced by air-blown gasifiers. However, with oxygen-blown IGCC systems, air may be extracted from the combustion turbine to supply some or all of the ASU (air separation unit) feed air, which better balances the air and turbo-expander mass flows for which existing combustion turbines are designed. Additionally, this integration increases the overall performance of IGCC.[h]

Gas turbine exhaust emission regulations for nitrogen oxides (NOx) add additional criteria for the design of IGCC turbine combustors. General Electric (GE) currently uses diffusion combustion systems with diluent (inert) injection for IGCC NOx control.[5] This contrasts with

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[g] An approach that is gaining more attention in design studies is to compress and return the tail gas from the sulfuric acid plant or Claus plant to the process, thereby eliminating at least part of the tail gas treating unit cost. This is currently not practiced in operating IGCC units.[2]

[h] Full integration (all ASU air supplied by the combustion turbine) increased the startup time and operating complexity for the two European solid fuel-fed IGCCs, so this performance improvement has offsetting impacts. Therefore, the industry appears to have moved away from full integration as a result. Also, some turbines cannot accommodate full integration.

the use of their dry low-NOx (DLN) combustor technology with natural gas. GE claims that the flame speed of the hydrogen component of the gasifier syngas is too fast to be compatible with the combustor design.[6] Most IGCC plants also saturate the syngas with water to minimize NOx formation.

1.1.7 Heat Recovery Steam Generator (HRSG)/Steam Turbine

The exhaust temperature from the combustion turbine is generally about 1100°F, which makes additional power generation through a steam cycle very effective. A HRSG can produce steam by cooling the combustion turbine flue gas; 1500 psig, 1000°F superheat/1000°F reheat steam can be generated without supplemental firing of the HRSG. This steam is supplied to a steam turbine to generate additional electric power. In addition, the HRSG is always used to superheat the high-pressure steam generated in the syngas cooler,[1] since satisfactory superheater materials have not been demonstrated in the reducing atmosphere of a syngas cooler.

1.1.8 Water Treatment and Recycle

Gasification cycles minimize water consumption and water discharge by reusing process water. Process water produced within the gasification process is treated to remove dissolved gases before being recycled to the slurry preparation area or being discharged to the water outfall. The gases are removed from the process water (sour water), in a two-step process. CO_2 and the bulk of the H_2S are removed in a steam stripper column. The removed H_2S is sent to the sulfur recovery process. The water is further cooled and the majority is recycled to the slurry preparation area. Any excess water is treated in an ammonia stripper column to remove ammonia and trace components. The stripped ammonia is combined with the recycled slurry water. The water out of the ammonia stripper is purified sufficiently to meet environmental requirements for discharge. If the discharge water is out of specifications, for any reason, it can be stored in holding tanks for further testing and possible recycle before final disposition.[7,i] Gasification processes that produce organics (tars and oils) typically require additional processing steps to separate them.

1.2 Primary Resource Input Flows, Effluent Discharge Flows, and Product Flows

FIGURE 1-5 presents a generic IGCC block flow chart that identifies all major resource input streams and effluent flows. Coal, water, and oxygen are the primary inputs for IGCC, with secondary inputs typically being the makeup solvents and catalysts used by the environmental control processes, including MDEA, catalyst for the Claus process, and catalyst for the SCOT process. The primary material effluents from IGCC systems include stack gas from the HRSG, bottom ash or slag, flyash, and wastewater blowdown. The primary IGCC product flows are electricity and sulfur or sulfuric acid by-product. These major input and effluent flows for a generic IGCC plant are characterized in TABLE 1-2 in terms of their potential environmentally sensitive constituents.

Typical plant flow rates and conditions are presented in TABLE 1-3 for a 400 MWe IGCC plant using an oxygen-blown, entrained-flow gasifier.

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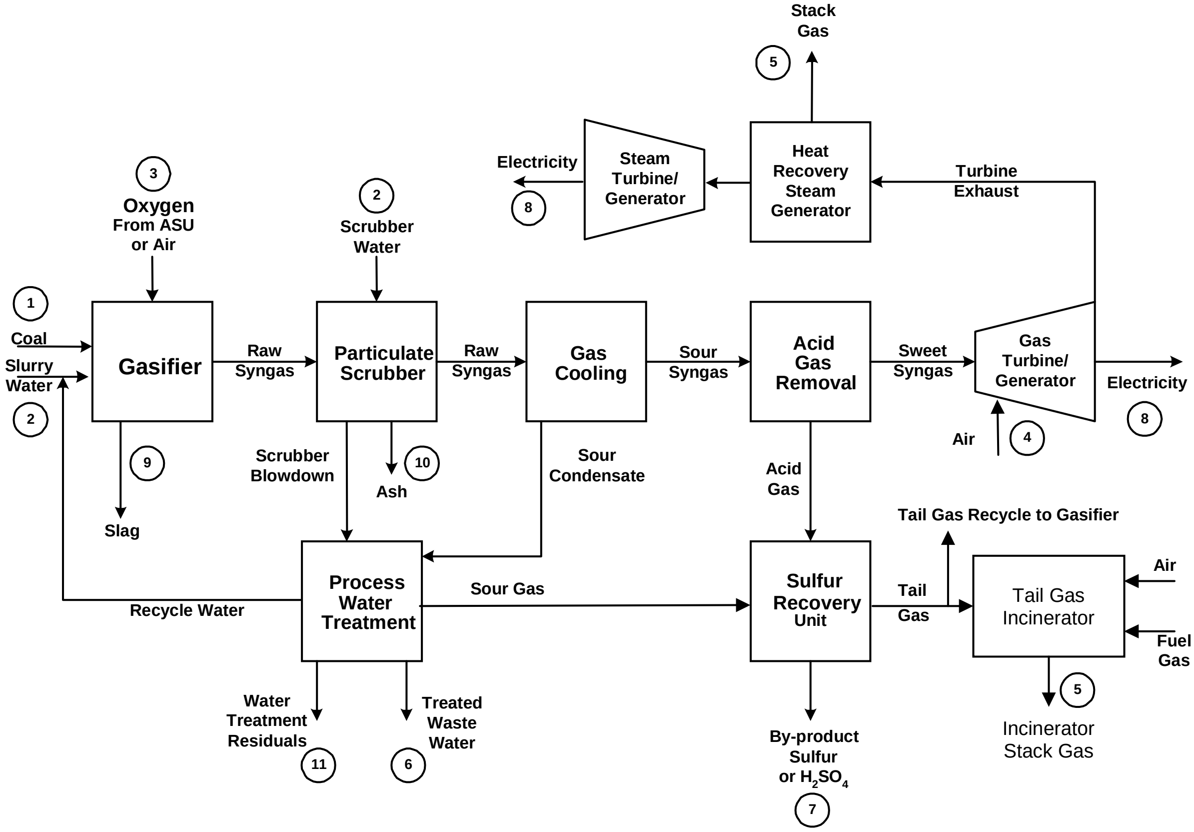
[i] The Polk IGCC system uses a viable alternative to the system described above for zero process water discharge. A brine concentration unit processes “grey” water discharged from the gas cleanup systems, recovering a usable water stream for slurry preparation and a land-fillable solid waste stream. There is no liquid effluent.[12]

FIGURE 1-5. GENERIC IGCC INPUT RESOURCES AND OUTPUT EFFLUENT STREAMS



1.2.1 Material Input Flows

Coal is processed through coal handling and preparation before it enters the gasifier. After being delivered to the plant, coal is crushed or ground, depending on the gasifier system, and then fed to the gasifier either dry or slurried with water. Recycled process water and makeup water is used to make the coal slurry. Other carbonaceous feeds, such as petcoke, may also be used, and will be handled and prepared via suitable methods.

High-pressure oxidant is injected into the gasifier, either as air, oxygen, or oxygen-enriched air. Air supplied for air-blown gasifiers is bled from the gas turbine compressor exhaust; some applications may require an additional booster compressor to reach the desired pressure. Oxygen for oxygen-blown gasifiers is produced within an air separation unit (ASU), the compressed air being mostly provided by a dedicated air compressor, but can be partially supplied by the gas turbine compressor in a more integrated IGCC design configuration (see Section 1.3). A conventional ASU is a high-pressure cryogenic system that typically separates ambient air into 95% pure oxygen and 98% pure nitrogen. For chemicals co-production, a higher purity O_2 may be produced.

TABLE 1-2. GENERIC IGCC PRIMARY RESOURCE INPUTS AND EFFLUENTS[3]

INPUT AND EFFLUENT STREAMS	FIGURE 1-5 STREAM NO.	IGCC PLANT STREAM DESCRIPTION	POTENTIAL ENVIRONMENTALLY SENSITIVE CONSTITUENTS
ENERGY AND MATERIAL INPUTS			
Gasifier Feed	**1**	Coal or other carbon-based fuels	Ash, Sulfur, Nitrogen, Chlorine, Trace Metals
Process Makeup Water	**2**	Condenser cooling, coal slurry water, scrubber water	None
Gasifier Oxidant	**3**	Air from gas turbine compressor or 95% Pure Oxygen from ASU	None
Process Air	4	Air to gas turbine	None
Makeup Solvents and Catalysts	**-**	Amine solvent for H_2S removal, Catalysts for sulfur or sulfuric acid plants, COS hydrolysis	None
Electricity	-	Auxiliary electricity	None
ENERGY AND MATERIAL OUTPUTS			
Gaseous Effluents	**5**	Stack Gas from HRSG, Tail Gas Incinerator	Fine particulates, SO_2, NOx, CO_2, CO, H_2SO_4 mist, HCl, HF, NH_3, HCN, Trace metals, trace organics
Liquid Effluents	**6**	Water treatment blowdown	Trace metals, cyanide, organics, ammonia, anions, sulfide
Material By-products	**7**	94 - 98% Sulfuric Acid, sulfur	Metals
Energy By-products	**8**	Electricity	None
Solid Effluents	**9, 10, 11**	Slag, fly ash, fines and water treatment solids	Metals, anions
Gaseous Fugitive Emissions	**-**	Equipment leakage	CO, H_2S, organics, NH_3
Solid Fugitive Emissions	**-**	Coal, Slag, Slurry	Fine particulate

TABLE 1-3. TYPICAL IGCC PLANT FLOW CONDITIONS FOR A 400 MWe IGCC PLANT USING AN OXYGEN-BLOWN ENTRAINED BED GASIFIER[8]

LOCATION	FLOW (lb/h)	TEMPERATURE (°F)	PRESSURE (psia)
INPUT FLOWS:			
Coal	224,910	-	-
Plant Total Water Consumption	2,807,308[a]	-	-
Oxygen	169,187	249	620
Air for combustion turbine	3,858,840	63	14.4
INTERNAL FLOWS:			
Fuel gas from gasifier		1900	
Fuel gas to THGD[b]		1100	425
Cooled fuel gas to combustion turbine	461,251	1105	372
DISCHARGE FLOWS:			
Quenched Slag	22,414	-	-
Stack gas	4,737,159	252	14
H_2SO_4 by-product	17,190	-	-

a ChevronTexaco quench gasification system[9]
b THGD - transport hot gas desulfurizer system

1.2.2 Effluent Flows

1.2.2.1 Slag

Solids discharged from the bottom of the gasifier consist of slag, char, and sometimes limestone. Slag is formed when the ash mineral content of coal is liquified. Molten slag flows out of the bottom of the gasifier into a quench bath for cooling. The non-leachable slag is typically saleable for blasting grit, roofing tiles, other construction building products, and as aggregate for asphalt roads.

1.2.2.2 Flyash

Flyash entrained in the syngas is recovered in the particulate removal system and is either recycled to the gasifier or combined with other solids in the water handling system and shipped off site for reuse or to be landfilled.

1.2.2.3 Sulfur By-Products

Depending on the gas cleanup system used, sulfur or sulfuric acid is produced from the sulfur containing gases removed from the syngas. The sulfuric acid produced is generally about 98% pure and the sulfur by-product is typically greater than 99.99% pure. Both are valuable by-products that are readily sold to existing markets, including fertilizer production.

1.2.2.4 Stack and Incinerator Gas

Emissions in the turbine/HRSG stack flue gas typically include sulfur dioxide (SO_2) from residual H_2S sent to the gas turbine, nitrogen oxides (NOx), carbon dioxide (CO_2), residual particulates, residual halogens, such as hydrogen chloride (HCl), and trace organic and inorganic species.

An incineration system is typically used to convert trace acid gas components in tank vents to oxide form (SO_2, NOx, H_2O, CO_2). The tank vent stream is primarily composed of air purged through various process storage tanks and may contain very small amounts of acid gas. The high temperature in the incinerator results in complete conversion of any hydrogen sulfide present in the tank vents to SO_2 before the gas is vented to the atmosphere. Heat recovery is provided in the incinerator hot exhaust gas to produce medium pressure steam before the vent gas is directed to a tall stack for dispersion in the atmosphere

1.2.2.5 Discharged Water

Process wastewater includes all wastewater streams generated or captured during normal operations and equipment purges/wash-downs during maintenance activities. The combined streams include, but are not limited to: cooling tower blowdown; gasification plant process waste water; regeneration waste water from the demineralizer system in the power block; rainwater collected in both the gasification and the power blocks; equipment purges (blowdowns) and water wash-downs during maintenance procedures; and un-recycled condensed water from the process.[7]

Process wastewater potentially contains small amounts of dissolved solids and gases and is treated to remove the contaminants before being recycled to the slurry preparation or being discharged to the water outfall. Dissolved gases are driven from the water via flashing (sometimes under vacuum) or steam stripping with low-pressure steam (which provides heat and a sweeping medium to expel the gases from the water). The flash gas is sent to the Claus plant or sulfuric acid decomposition furnace. Removal of solid contaminants, such as trace metals, may require additional wastewater treatment using other equipment, such as a mechanical vapor recompression (MVR) system. Most of the treated process water is recycled to the plant, and only a relatively small amount is discharged as a blowdown to a pond. Reuse of the water within the gasification plant minimizes water consumption and water discharge. Chapter 2, Sections 2.3.3 and 2.3.4 more fully discuss wastewater treatment.

1.2.3 Solid and Gaseous Fugitive Emissions

Fugitive dust emissions may occur from coal piles and coal slurry and slag transport. Gaseous fugitive emissions, such as H_2S, CO, HCN, and ammonia (NH_3), may occur from leaking valves and process equipment.

1.3 Overview of Large Commercial-Scale IGCC Plants

IGCC, as represented by existing commercial plants, is one of the most efficient and cleanest of available technologies for fossil-based power generation. The core process, gasification, is commercially proven technology that has been deployed on a worldwide basis for the refining, chemical, and power industries. In 1999, the first World Gasification Survey was conducted with support from the U.S. Department of Energy, and in cooperation with the member companies of the Gasification Technologies Council.[10] The survey identified and gathered information on at least 163 commercial gasification plants in operation, under construction, or in planning and design stages in twenty-eight countries in North and South America, Europe, Asia, Africa and Australia. At the time the survey was completed, there was an equivalent 67,800 MW_{th} syngas capacity installed or planned (about 37,000 MWe IGCC equivalent), with most new plants based on electricity production with co-production of steam and syngas for hydrogen or chemicals. The post-2000 power-to-chemicals syngas volume ratio is projected to be almost 3:1 in favor of power generation, reflecting increasing electricity demand and deregulation of electricity markets around the world.[j]

Although there are numerous gasifiers operating commercially worldwide, with at least fifteen technology suppliers, there is far less (but growing) experience with commercial operation of IGCC plants. There are currently eleven major IGCC plants operating internationally that use coal, petroleum coke, and refinery residue as feedstock. The largest market for IGCC systems has been in the petroleum refining and petrochemical industries using petroleum residual feedstocks such as vacuum residual oil, deasphalter bottoms and petroleum coke. These plants typically feature multi-train designs for high reliability and the co-production of power, steam and hydrogen for the refinery. A portion of the syngas is shifted for hydrogen production and CO_2 is removed (and currently is vented). Partly because of the need for hydrogen most of these IGCC plants that are adjacent to or within refineries use quench type gasifiers. Power is generated from the gas turbine for refinery use or sale. Some steam is also often used for additional power generation, however refineries are large steam consumers and this is often supplied directly to the refinery from the HRSG.[11]

This section focuses on successfully demonstrated commercial-scale IGCC plants, both domestic and foreign, designed solely for power generation and that use coal and/or petroleum coke feedstock. These plants are listed below in TABLE 1-4, and are described in detail in Appendix 1B. Lessons learned from these demonstration projects in the U.S. and Europe identified proper component integration as most significant to the success of IGCC.

The first two U.S. plants listed in the table, Cool Water and LGTI (Louisiana Gasification Technology Inc Project), were important first-generation, large-scale IGCC projects that demonstrated the major IGCC characteristics of low emissions and stable integrated control of the gasification process with a combined cycle in a power utility setting.[11] Cool Water was originally funded by a consortium of industrial partners, with guaranteed product price support from the U.S. Synthetic Fuels Corporation (SFC, which no longer exists). The LGTI facility (sometimes called the Dow Syngas Project) was supported by a price guarantee contract offered to Dow Chemical by the SFC. Both of these first-generation IGCC plants were shut down once the duration of the price guarantee period expired.

The second two plants listed, Wabash River and Polk, are second-generation IGCC systems that are the direct beneficiaries of the knowledge and experience gained from the initial plants. DOE’s Clean Coal Technology (CCT) Demonstration Program co-funded the construction and initial operation of Tampa Electric’s Polk Power Station[12] (Tampa Electric Integrated Gasification Combined-Cycle CCT Project) and PSI Energy’s Wabash River Generating Station[4] (Wabash River Coal Gasification Repowering CCT Project).

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[j] A summary of the survey can be found at the Gasification Technologies Council’s web site: http://www.gasification.org/story/worldwid/worldwid.html.

The Buggenum and Puertollano demonstration plants also represent the current generation of IGCC plants, but make use of different gasifiers designs and turbine vendor. The Buggenum plant is fully owned by the Netherlands utilities. The Puertollano project, owned by utilities from Spain and France, was the first targeted project funded under the EU's Thermie-Programme.

TABLE 1-4. COMMERCIAL-SCALE COAL/PETROLEUM COKE BASED IGCC POWER PLANTS

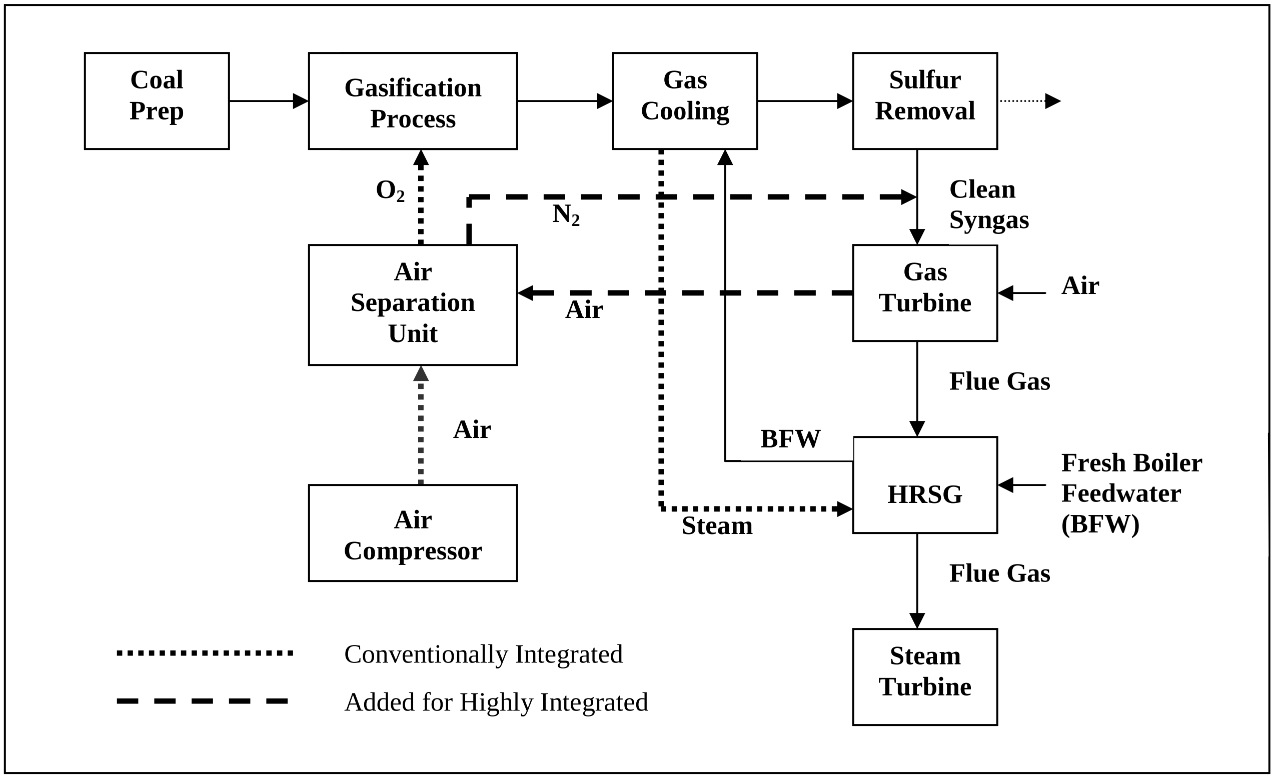
PLANT NAME	PLANT LOCATION	OUTPUT (MWe)	FEEDSTOCK	GASIFIER TYPE	POWER ISLAND	OPERATION STATUS
U.S. IGCC PLANTS						
Texaco Cool Water	Daggett, CA, USA	125	Bituminous Coal (1,000 tpd)	Texaco	CCGT – GE 7FE	1984 - 1988
Dow Chemical/Destec LGTI Project	Plaquemine, LA, USA	160	Subbituminous Coal (2200 tpd)	E-Gas (formerly Destec)	CCGT – Westinghouse 501	1987 – 1995
Tampa Electric Polk Plant	Polk County, FL, USA	250	Bituminous Coal (2200 tpd)	ChevronTexaco	CCGT – GE 7FA	1996 - Present
PSI Energy/Global Energy Wabash River Plant	West Terre Haute, IN, USA	262	Bituminous Coal and Petroleum Coke (2544 tpd)	E-Gas (formerly Destec)	CCGT – GE 7FA	1995 - Present
FOREIGN IGCC PLANTS						
NUON/Demkolec/ Willem-Alexander	Buggenum, The Netherlands	253	Bituminous Coal	Shell	CCGT – Siemens V94.2	1994 - Present
ELCOGAS/ Puertollano	Puertollano, Spain	298	Coal and Petroleum Coke (2500 tpd)	Prenflo®	CCGT – Siemens V94.3	1998 - Present

CCGT – Combined Cycle Gas Turbine, tpd – short tons per day

Each of the four major commercial-sized, coal/coke-based IGCC demonstration plants currently in operation use a different gasification technology, gas cooling and gas cleanup arrangement, and integration scheme between the plant units. All of the current coal based plants integrate the steam systems of the gasification and power block sections. Typically boiler feed water (BFW) is preheated in the HRSG and passed to the gasification section where saturated steam is raised from cooling of the raw syngas. The saturated steam passes to the HRSG for superheating and reheating prior to introduction, with additional HRSG superheated steam, to the steam turbine for power production.[11] The operating U.S. plants are based on GE 'F' gas turbines with turbine inlet temperatures of about 1260°C (2300°F) and equipped with multiple-can combustors in an annular arrangement. The European IGCC projects are both based on Siemens gas turbines equipped with dual-silo combustion chambers, with turbine inlet temperatures of 1100°C (2000°F, Buggenum) and 1260°C (2300°F, Puertollano).

The characteristic of integration design that is most varied among the coal/coke-based IGCC plants identified above has been the degree of integration between the gas turbine and the ASU. There is a major design divergence between the two European IGCC plants and the U.S. plants, which derives from the gas turbine selection and design philosophy differences regarding the relative importance of efficiency compared to availability. The Buggenum and Puertollano demonstration plants are both highly integrated designs with all the air for the ASU being taken as a bleed of extraction air from the combustion turbine compressor. In contrast, the operating U.S. plants, Polk and Wabash, are less integrated, and the ASUs have their own separate air compressors. The more tightly integrated design results in higher plant efficiency, since the auxiliary power load is lowered by the elimination of the separate air compressor. However, there is a potential loss of plant availability and operating controllability for the highly integrated system. Start-up time is also longer with this design because the combustion turbine must be run on a more expensive secondary fuel (natural gas or oil) before extraction air can be sent to the ASU for its cool-down and start-up.[11] FIGURE 1-6 presents a block flow diagram that identifies the difference between the integration schemes.

FIGURE 1-6. BLOCK FLOW DIAGRAM OF INTEGRATED IGCC POWER PLANT[11]



In Europe where fuel prices are higher, efficiency is a major driver that has favored capital investment for the tightly integrated plant. In the U.S., fuel prices are lower and availability is a more important factor than efficiency. It is now the general consensus among IGCC plant designers that the preferred design is an intermediate approach; one in which the ASU derives part of its air supply from the gas turbine compressor and part from a separate dedicated compressor. This provides the necessary flexibility for quicker start up, less usage of expensive secondary fuels, and an auxiliary power load intermediate between the two options.[11]

1.3.1 Design Features and Steady-State Operating/Environmental Performance

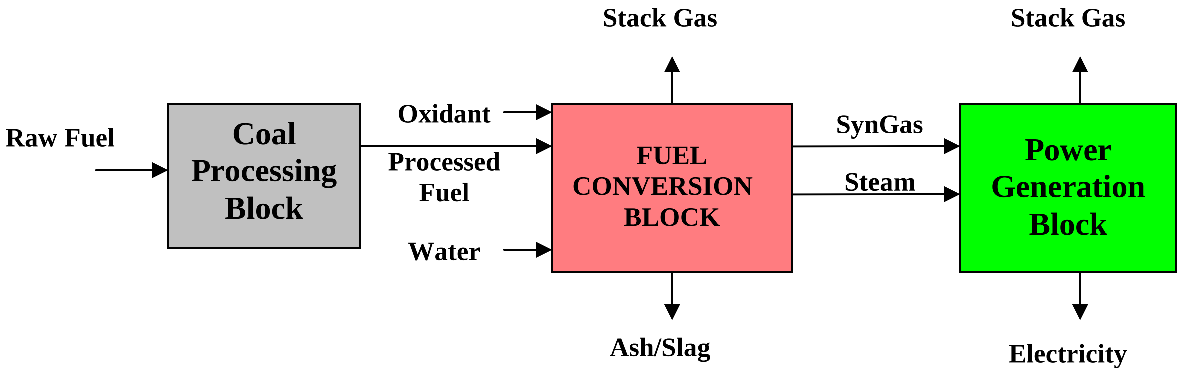
Design features of the Cool Water and LGTI plants are presented in TABLE 1-5. The same information is provided for the currently operating plants in TABLE 1-6. IGCC offers high system efficiencies and very low pollution levels, as can be seen in the performance data for the Tampa, Wabash, Buggenum, and Puertollano plants given in TABLE 1-7.

Information about the Cool Water project comes from a detailed description provided in EPRI's Coal Gasification Guidebook.[1] The source of data for the LGTI facility is based on a joint DOE/EPRI/LGTI project[3] (in 1995) to characterize the trace substance emissions from advanced gasification technology. Information and data about the Polk and Wabash plants comes from DOE project reports,[4,12] additional operational data made available by the operators since completion of the DOE demonstration projects, as well as EPA's very recent information collection request (ICR) to evaluate power plant mercury emissions. Basic information about the Buggenum and Puertollano demonstration plants was obtained from published technical papers. Appendix 1B contains detailed descriptions of the six IGCC plants discussed in this section, as well as their current status.

1.4 Comparison of IGCC with PC and FBC Power Plants

This section compares IGCC with commercial pulverized coal-fired (PC) and fluidized bed combustion (FBC) power plants FIGURE 1-7 illustrates the generic design aspects of any solid fuel-based power generation technology, whether IGCC or combustion-based. Raw solid fuel (e.g., coal) initially undergoes handling and processing into an optimum form for the energy conversion equipment (e.g., dry pulverized coal or coal-water slurry). The processed fuel is then input into the conversion equipment (e.g., boiler or gasifier) to release and transfer its latent chemical energy to a secondary medium (e.g., water/steam) and/or convert the solid fuel into flue gas or syngas. The secondary medium is then introduced to the power generation equipment (e.g., steam turbine) to produce electricity. If syngas is produced, it is transferred to a power conversion device (e.g., gas turbine) in the Power Block. Other primary inputs, in addition to fuel, are air or oxygen, water and perhaps some other chemicals used for pollution control (e.g., MDEA, limestone). Primary outputs include electricity, stack gas that contains residual pollutants (e.g., SO_2, NOx, CO, particulates, trace metals) and carbon as CO_2, mineral matter in the form of ash or slag, and useful by-products (e.g., sulfur, sulfuric acid, gypsum) produced from fuel constituents released during the fuel conversion process.

FIGURE 1-7. SCHEMATIC DIAGRAM OF GENERIC COAL-FIRED POWER PLANT



The configuration of the Fuel Conversion and Power Generation blocks for IGCC is fundamentally different from either a PC or FBC plant. In PC and FBC plants, the processed carbonaceous fuel is converted (combusted) in a single step in a boiler, where the released energy is transferred directly to water/steam. The steam is transferred to the power block (a steam turbine) to produce electricity. Included in the fuel conversion block is pollution control equipment, such as an ESP or fabric filter, to remove fly ash, and flue gas desulfurization (FGD) equipment to remove SO_2 to remove pollutants from the combustion gas. While NOx production is primarily controlled in the fuel combustion process, post combustion equipment, such as selective catalytic reduction (SCR), may also used to meet regulatory limits.

In an IGCC plant, the processed feedstock (e.g., coal or petroleum coke) is input to the Fuel Conversion (gasification) system in order to produce a clean, synthesis gas (syngas) via reaction with steam and oxygen at high temperature and pressure in a reducing (oxygen-starved) atmosphere. The primary syngas constituents, typically greater than 85% by volume, are carbon monoxide (CO) and hydrogen (H_2) and smaller quantities of carbon dioxide (CO_2) and methane (CH_4). The syngas is subsequently transported to the Power Generation Block and combusted in a stationary gas turbine to produce power. The hot exhaust gas from the gas turbine is then fed to a heat recovery steam generator (HRSG) to produce steam for input to a steam turbine. Flue gas leaving the HRSG is then emitted to the atmosphere via a stack. Thus, the Power Generation Block includes both a gas turbine and a steam turbine, hence combined cycle power generation. Included in the Fuel Conversion Block is pollution control equipment to remove pollutants from the syngas, such as a wet scrubber to remove fly ash and chlorides and acid gas equipment to remove H_2S and COS (the sulfur compounds primarily formed during gasification). Since NOx is only produced during combustion of the syngas in the gas turbine, control efforts typically focus on minimizing production in the combustion turbine.

The aforementioned description emphasizes that the IGCC design basically separates the coal conversion process into two distinct stages and two physically separate operational units, namely the gasifier and the combustion turbine. This process design translates into significant operational advantages compared to the direct combustion-type plants. TABLE 1-8 compares the general operational features of IGCC with commercial PC and FBC-type power plants.

TABLE 1-5. OVERVIEW OF NON-OPERATING COMMERCIAL-SCALE IGCC DEMONSTRATIONS PLANTS

	Texaco Cool Water Project	**Dow Chemical/Destec LGTI Project**
Net Power Generation Capacity (MWe)	125	160
Fuel Feed	Bituminous Coal (Illinois #6 and Pittsburgh #8)	Low Sulfur Subbituminous
Gasification Technology	Texaco	E-Gas
Gasification Process Type/Fuel Feed Type	Single-Stage Entrained-Bed/Slurry Fed	Two-Stage Entrained Bed/ Slurry Fed
Oxidant	99.5% Pure Oxygen	95% Pure Oxygen
Slag Removal	Lock Hoppers	Continuous
Syngas Cooler Type	Downflow Radiant Water Tube And Convective Firetube	Downflow Firetube
Gas Cleanup System	Low-Temperature	Low-Temperature
Particulate Control	Water Scrubber	Water Scrubber
Chloride, Fluoride, and Ammonia Control	Water Scrubber	Water Scrubber
COS Hydrolysis	Catalytically Converted to H_2S	Catalytically Converted to H_2S
Acid Gas Cleanup and Sulfur Recovery/ Sulfur By-product	Selexol Scrubber/Claus Unit with SCOT Tailgas Unit/Sulfur	Selectamine^{TM} Scrubber and Selectox^{TM} Plant/ Sulfur
Sulfur Recovery Capability	97% for low sulfur coal 99% for high sulfur coal	85% Design
Air Separation Unit	Cryogenic Distillation	Cryogenic Distillation
Air Supply Compressor	100% Separate	100% Separate
Nitrogen Use	Mostly Vented	Mostly Vented
Gas Turbine	GE Frame 7E	CCGT – Westinghouse 501-D5
Combustors	Multiple Cans	Multiple Cans
Syngas Heating Value (HHV), Btu/lb	265	260
Firing Temperature, ^oF (°C)	1985 (1085)	1900 (1037)
NOx Control	Syngas Saturation with Hot Water (25% by volume H_2O)	Steam Dilution To Combustion Turbine
Heat Recovery Steam Generator	Single-Pressure, Natural Circulation, No Reheat	Single-Pressure, Natural Circulation, No Reheat
Steam Turbine	55 MW, no intermediate pressure reheat cycle	75 MW, 1,250 psig/950^oF superheated steam, no reheat

TABLE 1-6. OVERVIEW OF OPERATING COMMERCIAL-SCALE IGCC PLANTS FED WITH COAL/PETROLEUM COKE [3]

	Polk Power Station (Florida, USA)	**Wabash River Generating Station (Indiana, USA)**	**NUON/Demkolec (Buggenum, The Netherlands**	**ELCOGAS (Puertollano, Spain)**
Net Power Generation Capacity (MWe)	250	262	253	298
Fuel Feed	High Sulfur Bituminous	High Sulfur Bituminous	Bituminous Coal	Bituminous Coal and Petroleum Coke
Gasification Technology	ChevronTexaco	E-Gas	Shell	Prenflo
Gasification Process Type/Fuel Feed Type	Single-Stage Entrained-Bed/Slurry Fed	Two-Stage Entrained Bed/ Slurry Fed	Single-Stage Upflow Entrained/dry fed	Single-Stage Upflow Entrained/dry fed
Oxidant	95% Pure Oxygen	95% Pure Oxygen	95% Pure Oxygen	95% Pure Oxygen
Slag Removal	Lock Hoppers	Continuous	Lock Hoppers	Lock Hoppers
Syngas Cooler Type	Downflow Radiant Water Tube And Convective Firetube	Downflow Firetube	Downflow Concentric Coil Water Tube	Upflow/Downflow (Two-Pass) Radiant Water Tube And Convective Water Tube
Gas Cleanup System	Low-Temperature	Low-Temperature	Low-Temperature	Low-Temperature
Particulate Control	Water Scrubber	Metallic Candle Filter System and Water Scrubber	Candle Filter (Operating at 230°C)	Candle Filter (Operating at 240°C)
Chloride, Fluoride, and Ammonia Control	Water Scrubber	Water Scrubber	Water Scrubber	Water Scrubber
COS Hydrolysis	Catalytically Converted to H_2S	Catalytically Converted to H_2S	Catalytically Converted to H_2S	Catalytically Converted to H_2S
Acid Gas Cleanup and Sulfur Recovery/ Sulfur By-product	MDEA Scrubber and H_2SO_4 Plant/Sulfuric Acid	MDEA Scrubber and Claus Plant/Sulfur	Sulfinol M Scrubber and Claus Plant/Sulfur	MDEA Scrubber and Claus Plant/Sulfur
Sulfur Recovery Capability	98% Design	99% Design	99% Design	99% Design
Air Separation Unit	Cryogenic Distillation	Cryogenic Distillation	Cryogenic Distillation	Cryogenic Distillation
Air Supply Compressor	100% Separate	100% Separate	100% from Gas Turbine	100% from Gas Turbine
Nitrogen Use	GT NOx Control	Mostly Vented	Syngas Saturator for GT NOx Control	Syngas Saturator for GT NOx Control
Gas Turbine	GE MS 7001FA	GE MS 7001FA	Siemens V 94.2	Siemens V 94.3
Combustors	Multiple Cans	Multiple Cans	Twin Vertical Silos	Twin Horizontal Silos
Syngas Heating Value (HHV), Btu/lb	267	280	-	-
Firing Temperature, °F (°C)	2350 (1287)	2350 (1287)	2012 (1100)	2300 (1260)
NOx Control	Nitrogen and Steam Dilution To Combustion Turbine	Steam Dilution To Combustion Turbine	Syngas Saturation and Nitrogen Dilution	Syngas Saturation and Nitrogen Dilution
Heat Recovery Steam Generator	Three-Pressure, Natural Circulation, Reheat	Three-Pressure, Natural Circulation, Reheat	Three-Pressure, Natural Circulation, Reheat	Three-Pressure, Natural Circulation, Reheat
Steam Turbine	1,465 psia, 1000°F with 1000°F Reheat	1,600 psia, 1010°F with 1010°F Reheat	-	-

TABLE 1-7. OPERATING COMMERCIAL-SCALE IGCC PLANTS FED WITH COAL/PETROLEUM COKE -- STEADY-STATE OPERATIONAL/ENVIRONMENTAL PERFORMANCE

	Polk Power Station (Florida, USA)	**Wabash River Generating Station (Indiana, USA)**	**NUON/Demkolec (Buggenum, The Netherlands**	**ELCOGAS (Puertollano, Spain)**
Gas turbine, MWe	192	192	155	182
Steam turbine, MWe	121	104	128	135
Auxiliary power, MWe	63	34	31	35
Net Power Output MWe	250	262	253	298
Efficiency, % (HHV basis)	37.5	39.7	41.4	41.5
Efficiency, Btu/kWh (HHV basis)	9,100	8,600	8,240	8,230
Total Operating Hours	>25,700 through 9/2001	21,991 through 2001	>23,000 through 2000	> 6700 through 3/2001
Coal Usage (tons/day)	2,200	2,544	2,200	2,400
Gasifier Availability, % Power Block Availability, %	84.2[a] 94.4[a]	85[b] 89.9[b]	50 (combined)[h]	68[g] 84.6[g]
Emissions:				
SO_2 (lb/MWh)	<1.35[c]	1.08[e]	0.44[i]	0.15[j]
NOx (lb/MWh)	0.86[d]	1.09[e]	0.7[i]	0.88[j]
Particulates (lb/MWh)	<0.14[c]	<0.10[e]	0.01[i]	0.044[j]
Hg (lb/MWh)[f]	4.8×10^{-5}	6.1×10^{-5}	Unavailable	Unavailable
Sulfur Removal, %	> 98	> 97	>99	99.9

[a] Year 5 operation, ending September 2001

[b] Year 5 operation in 2000

[c] Reported emissions in 2000

[d] Average of 14 months of CEMS data

[e] Average Emissions in 2001[13]

[f] EPA ICR Results in 2000

[g] 2001 operating statistics through 9/2001[14]

[h] Average plant availability in 2000 through September[15]

[i] Average emissions reported for 2001[16]

[j] Average emissions reported for 2001[17]

TABLE 1-8. GENERAL COMPARISON OF IGCC, PC, AND FBC POWER PLANTS

	IGCC PLANT	PC PLANT	FBC PLANT
Operating Principal	Feedstock is only partially oxidized. The high-pressure synthesis gas produced is combusted and expanded in a combustion turbine to produce power. Heat is recovered from the turbine exhaust gas to produce steam for expansion in a steam turbine to produce added power.	Pulverized coal is combusted in a boiler where the heat is directly transferred to produce high-pressure steam that is expanded in a steam turbine to produce power.	Air-suspended coal is combusted together with sorbents for sulfur control. Heat is directly transferred to produce high-pressure steam. Boiler operates at either atmospheric pressure or may be pressurized. Key designs are bubbling bed and circulating bed boilers.
Oxidant	Air or oxygen in the gasifier. Air in the combustion turbine.	Air in the boiler	Air in the boiler
Operating Pressure	25 to 40 atmospheres	1 atmosphere	1 to 100+ atmospheres
Coal Sulfur Conversion	Sulfur is primarily converted to H_2S and some COS in the synfuel.	Sulfur is converted to SO_2 in the combustion process and exits boiler with flue gas.	Sulfur is converted to SO_2 in the combustion process and is mostly captured by an in-bed sorbent such as limestone. Residual SO_2 exits the boiler with the flue gas.
Coal Nitrogen Conversion	Converted to ammonia and nitrogen in the gasifier. Ammonia is removed from the syngas prior to combustion in the combustion turbine. NOx is formed in the combustion turbine. Exits turbine as constituent of flue gas.	Converted to NOx. Low-NOx burners are used to minimize conversion to NOx. NOx exits boiler as constituent of flue gas.	Converted to NOx. FBC is an inherently low NOx producer due to its low combustion temperature. NOx exits boiler as constituent of flue gas.
Process Solids	Most of the coal ash is recovered as inert slag or bottom ash from the gasifier. Only a small portion of the ash is entrained with the synfuel.	Approximately 80% of the coal ash is entrained in the flue gas as fly ash. The remaining ash is recovered as bottom ash or inert slag.	Ash and spent sorbent (limestone) is entrained in the flue gas collected in a control device such as a cyclone and returned to the boiler. Most solids collected as bottom ash.
Thermal Efficiency, % (HHV Basis)	38 - 50	34 - 42	36 - 45

1.4.1 Environmental Control Comparison of IGCC with PC and FBC Power Plants

IGCC, PC, and FBC power plants use different methods of environmental control due to their different design configurations. Generally, stringent emission requirements favor IGCC over PC and FBC power plants. Coal gasification can meet strict air pollutant emission standards, produce only a small amount of inert solid waste, and recover sulfur as valuable elemental sulfur or sulfuric acid. PC and FBC plants can also achieve relatively low levels of emissions by utilizing advanced low-NOx burners and SCR for high-efficiency NOx control, high-efficiency flue gas desulfurization for SO_2 control (95%+ removal), and state-of-the-art particulate control (e.g., fabric filter). The major environmental benefit of selecting FBC technology is the removal of SO_2 (90-95%) and NOx (emission is less than 100 ppm) in the combustion process without adding post-combustion cleaning equipment, such as wet or dry flue gas desulfurization (FGD) systems and selective catalytic reduction (SCR) systems. TABLE 1-9 compares the emission control methods used by the different these power generation technologies.

Coal gasification has advantages over coal combustion. Because gasification-based power generation operates at higher efficiency levels than combustion-based power plants, they emit less CO_2 per unit of energy. Furthermore, gas cleanup is relatively inexpensive in an IGCC power plant compared with flue gas cleanup in coal combustion-based power plants. Smaller equipment is required because a much smaller volume of gas is cleaned, as contaminants are removed from the pressurized syngas before combustion. In contrast, the volume of flue gas from a combustion-based power plant is 40-60 times greater.[9] The emissions of sulfur dioxide and nitrogen oxides, gases linked to acid rain, are a small fraction of allowable limits. The water required to run an IGCC plant is considerably less than that required to run a PC plant with a flue gas scrubbing system. Furthermore, discharge of solid waste/by-products and wastewater is typically 30 to 50% lower than PC and FBC plants. Recovery of high-value-added by-products or co-products is a valuable advantage of coal gasification, in that their sales can actually bring higher revenues and return on investment than the sale of electricity.

TABLE 1-9. COMPARISON OF ENVIRONMENTAL CONTROL METHODS FOR IGCC, PC and FBC POWER GENERATION TECHNOLOGIES

	IGCC PLANT	PC PLANT	FBC 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 valuable 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.	90 to 95% sulfur control. SO_2 is removed within the fluid or circulating bed via use of a sorbent such as limestone. Calcium-sulfate-based ashes are chemically stable and are easily disposed. This ash can be used as raw material for cement manufacturing, soil stabilization, concrete blocks, road base, structural fills, etc.
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 NOx generation. Use of add-on control technologies, such as SCR, have not been demonstrated for syngas-fired turbines.	Fuel nitrogen converted to NOx. Low-NOx burners are used to minimize conversion to NOx. The NOx 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 flyash. Sulfates and bisulfates captured in particulate control equipment downstream of SCR.	Fuel nitrogen converted to NOx. FBC is an inherently low NOx producer, but N_2O may be produced. The NOx formed may be removed with additional control technology, such as SCR, although it is not typically applied. SCR unit can be installed between economizer and air heater. NH_3 preferentially adsorbs onto flyash. 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 problem from FGD unit.	Very high levels of particulate control. Ash and spent sorbent (limestone) is collected in a control device such as a cyclone. Usually primary and secondary particulate control devices. No acid mist problem.
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.	Most semi-volatile and volatile trace metals condense on fly ash particles and are effectively removed with ash. Elemental mercury emissions may exit with flue gas. Other elements exit with calcium-sulfate-based ash. Trace organic emissions are extremely low. Hg emissions may depend on coal type.
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/solidification.	Calcium-sulfate-based ashes are chemically stable and are easily disposed. Leaching of trace metals adsorbed by fly ash is more likely than with slag material. This ash can be used as raw material for cement manufacturing, soil stabilization, concrete blocks, road base, structural fills, etc.
Carbon Dioxide Control	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.	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.

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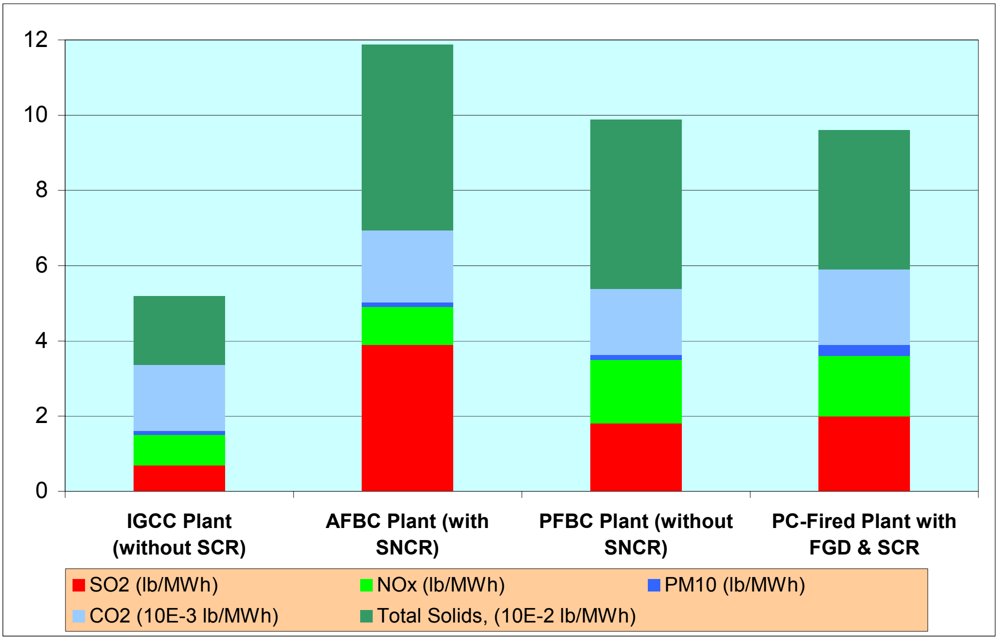
[17] Carnot Online, Case study: “Conversion of Solid-Fuels, Puertollano IGCC Power Plant,” http://enpov.aeat.com/carnot/case_studies/pdf/Puertollano.pdf, 2001.

2. DETAILED EVALUATION OF THE ENVIRONMENTAL PERFORMANCE OF GASIFICATION-BASED POWER SYTEMS

2.1 Introduction and Summary of Information Presented

The single most compelling reason for utilities to consider coal gasification for electric power generation is superior environmental performance.[1] As shown in Figure 2-1, gasification has fundamental environmental advantages over direct coal combustion. Commercial-scale plants for both integrated gasification combined cycle (IGCC) electric power generation and chemicals applications have already successfully demonstrated these advantages. The superior environmental capabilities of coal gasification apply to all three areas of concern: air emissions, water discharges, and solid wastes. This chapter of the report presents a comprehensive evaluation of the environmental performance of IGCC power generation technology and compares performance with other coal-fired technologies.

FIGURE 2-1. EMISSIONS AND WASTES FROM DIFFERENT POWER CYCLES*



* Plant assumptions are defined in Section 2.2.7

2.1.1 Chapter Organization

The chapter is divided into three major sections (in addition to this introductory section) that exclusively cover air emissions in Section 2.2, water effluents in Section 2.3, and solid wastes/byproduct discharges in Section 2.4, respectively. Each provides the following basic information:

- Identification and Characterization of Emissions, Effluents, or Discharges
- Review of IGCC Plant Operating Data and Experience

- Assessment of Control/Treatment/Handling Technologies and Methods
- Comparison of the Environmental Performance of IGCC with Pulverized Coal-Fired and Fluidized Bed Power Plants.

A brief summary of the information presented in Sections 2.2, 2.3, and 2.4 is presented below. The chapter concludes by listing cited references in Section 2.5.

2.1.2 Air Emissions Summary

The most important environmental issue associated with coal-based power generation has been the level of pollutant (and other) emissions discharged to the air. These emissions include:

- Major criteria air pollutants: SO_2, NOx, CO, lead, and particulates (PM10) – Section 2.2.1
- Trace ionic species emissions: sulfate, nitrogen-containing ions, chloride, fluoride, phosphate, and cyanide – Section 2.2.2
- Trace metal emissions: Trace metal constituents of coal (or other solid gasifier feed material), such as mercury and arsenic – Section 2.2.3
- Trace organic emissions: Trace organic species produced during gasification and combustion of synfuel, such as formaldehyde – Section 2.2.4
- Greenhouse Gases: Carbon Dioxide (CO_2) – Section 2.2.5

Section 2.2.1 examines the release of criteria air pollutants from IGCC power plants. Sulfur (as H_2S and COS) and particulates are very effectively removed from raw gasifier syngas by gas cleanup equipment located upstream of the combustion turbine. A major advantage of a high temperature, slagging gasifier is that most of the coal ash is discharged as molten slag from the bottom of the gasifier, with only a small portion entrained with the syngas. Reducing conditions in the gasifier converts most of the chemically bound nitrogen in the coal into harmless nitrogen gas, rather than into NOx as occurs in direct combustion. While NOx is still formed when the clean syngas is fired in the combustion turbine, turbine manufacturers have developed highly effective means of minimizing thermal NOx formation without resorting to post-combustion control technologies, such as SCR. These combustion-based methods also limit CO emissions to relatively low levels, but fugitive CO emissions from upstream components and the plant's flare system, represent sources of CO that must be efficiently controlled. In the aggregate, the criteria pollutant emissions from a state-of-the-art IGCC plant are well-below current emissions standards for coal-fired[a] power plants. TABLE 2-22 (on page 2-51) compares IGCC emissions with those from other types of coal-fired power plants. Demonstrated IGCC criteria pollutant emission levels are:

- SO_2: < 0.15 lb/10^6 Btu or 1.35 lb/MWh (NSPS limit[b] = 1.2 lb/10^6 Btu)
- NOx: < 0.1 lb/10^6 Btu or 0.9 lb/MWh or 15 ppm (NSPS limit[b] = 1.6 lb/MWh)

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[a] Coal-fired refers to combustion-based technologies, such as pulverized coal-fired (PC-fired or PC), fluidized-bed combustion (FBC), stoker-fired, and cyclone-fired plants.

[b] EPA's New Source Performance Standards (NSPS) for solid-fueled power plants

- PM10: < 0.015 lb/10^6 Btu or 0.14 lb/MWh (NSPS limit[b] = 0.03 lb/10^6 Btu)
- CO: < 0.033 lb/10^6 Btu or 0.3 lb/MWh (no NSPS limit)

Release of both inorganic and organic trace substances is assessed in Sections 2.2.2, through 2.2.4. If these substances are emitted from an IGCC system, of primary concern is the degree of release, the chemical form of the release, as well as the specific source of the release from the plant. Section 2.2.2 characterizes ionic species (sulfate, ammonia, cyanide, chloride and fluoride). Cyanide is the only ionic species to be identified as a potential problem; both the Wabash River and LGTI plants have experienced levels in aqueous discharges that exceeded permit levels. However, Wabash River has recently installed new wastewater treatment equipment that has apparently solved this problem.

Section 2.2.3 identifies and characterizes potential trace metal emissions (e.g., mercury, arsenic, selenium). The section initially discusses how chemical forms and partitioning of trace species among various gas, liquid and solid streams in IGCC ultimately depend upon coal characteristics, gasifier type (e.g., fluidized bed, slagging entrained-flow), operating conditions, operating conditions downstream of the gasifier, and the downstream processing of the syngas. The trace metals of greatest environmental concern are considered to be arsenic, boron, cadmium, mercury, and selenium. All are volatile or semi-volatile elements that are likely to exit the gasifier in the syngas. While in-situ measurement of these species has proven to be quite difficult in the reducing atmosphere of an IGCC system, computer-based thermodynamic equilibrium studies have identified arsenic, boron, cadmium, mercury, and selenium as the most highly volatile, and hard to control species. Other trace metals will generally either remain with the slag or be removed from the syngas in downstream processing equipment. Most troublesome, as verified by bench-, pilot-, and full-scale testing, is mercury, which primarily remains in the vapor-phase. Elemental mercury is, by far, the predominant chemical form in gasification systems.

As discussed in Section 2.2.3.3, mercury testing at the Wabash River, Polk, and LGTI IGCC plants has yielded relatively poor mass balance closures (33 to 67%). Therefore, while there is no question that elemental mercury exits these plants in the stack gas, it appears that a significant portion is removed within IGCC process components. There is evidence that mercury is removed by the amine solvent, accumulates in the acid gas scrubbing loop, and/or is stripped from the amine solvent upon regeneration and partitions to the sulfur recovery unit. Some mercury, especially particulate-phase and oxidized forms, may be removed in the wet particulate scrubber and discharged with wastewater sludge. Overall, mercury testing indicates that stack gas emission factors range from 3×10^{-5} to 6×10^{-5} lb/MWh (1.5 to 5 lb/10^{12} Btu). Comparison with tests performed at PC power plants indicates that IGCC mercury emissions are of a similar magnitude. If PC plants are obligated to control mercury as a result of expected EPA regulations, then IGCC plants will also likely be required to control mercury emissions.

IGCC has a major advantage when it comes to mercury control. Commercial methods have been employed for many years that remove trace amounts of mercury from natural gas and gasifier syngas. As described in Section 2.2.6.2, UOP and the Eastman Chemical Company have used molecular sieve technology and activated carbon beds, respectively, for this purpose. Eastman Chemical reports 90 to 95% mercury capture using Calgon Corporation's sulfur-impregnated activated carbon, with carbon lifetime ranging from 12 to 18 months. Thus, mercury emissions control for IGCC technology is likely to be more of an economic issue than a technical one.

Section 2.2.4 identifies and characterizes potential trace organic compounds (aldehydes and ketones, VOCs, SVOCs, PAHs, and chlorinated dioxins and furans) that may be discharged with the flue gas, wastewater, or byproduct solids. Release of organic compounds is also an environmental concern, since some of these compounds, such as formaldehyde, can have deleterious effects on the environment or human health. Trace organics can be released from coal reactors via complex, non-oxidizing, pyrolytic processes. While limited data is available to characterize trace organic releases to the air from gasification systems, detailed test results from the LGTI IGCC plant indicate extremely low levels of all trace organic emissions, in-line with emissions expected from plants that directly combust solid and gaseous fuels. In particular, formaldehyde emissions from a syngas-fired combustion turbine appear to be more than an order-of-magnitude lower than emissions from a natural gas-fired combustion turbine (see Section 2.2.4.2).

A more global environmental concern related to power generation from fossil fuels is the production of carbon dioxide (CO_2), discussed in Section 2.2.5. The carbon in the fuel fed to an IGCC plant will ultimately be converted into CO_2. Although still significantly higher than that from a gas-fired plant, IGCC's improved efficiency reduces CO_2 emissions relative to other coal-based plants. For example, repowering the Wabash River plant reduced CO_2 emissions by approximately 20% on a per kWh basis. TABLE 2-21 (on page 2-38) compares uncontrolled CO_2 emissions from different types of fossil-fired power plants. If the amount of CO_2 released is regulated in the future, IGCC has two major operating advantages that permit more efficient CO_2 capture than is possible with conventional combustion technology. Syngas has a high CO_2 concentration, which can be increased by the water gas shift reaction to convert CO to CO_2 prior to combustion (while simultaneously producing more hydrogen). Also, IGCC gasifiers typically operate under relatively high pressure (~400 psig at the Wabash River plant). Both of these conditions make recovery of the CO_2 from the syngas much easier than capture from flue gas. A recent study of one design concept concluded that 75% of the CO_2 could be captured from an IGCC plant with only a 4% loss in efficiency at a cost of \$5 to \$11/kW. This result shows that the economic impact of CO_2 capture may be quite a bit less than previously thought. It should be noted that this particular performance and cost estimate is based on a plant design that originally incorporates required equipment and does not include transport of the CO_2 to a site for use or sequestration (see Section 2.2.6.3).

In order to put the IGCC air emissions into proper perspective, Section 2.2.7 provides a comparison of IGCC's performance with PC-fired and fluidized-bed power plants. TABLE 2-22 (on page 2-51) provides a realistic indicator of how well IGCC performs with respect to criteria air pollutants, ionic species, and CO_2. In all respects, potential air pollution impacts from IGCC are likely to be significantly less, or less costly, than from competing coal-based technologies. While uncontrolled mercury emissions from IGCC plants appear to be comparable to those from the other power plant types (based on consumption of similar coals), effective mercury control has already been demonstrated for IGCC plants, if required. Uncontrolled CO_2 emissions from current IGCC technology, measured on an output basis (lb/kWh), are about 10% lower than a modern PC plant and probably equivalent to those from an advanced PFBC plant.

2.1.3 Aqueous Effluents Summary

While air emissions can affect large geographical areas and are often of greatest concern to regulators, both water consumption and aqueous discharges from coal-fired plants are quite important at the local level. Water is required for the plant's steam cycle as boiler feedwater and cooling water, as well as for process operations, such as syngas emissions control. While the steam cycle in an IGCC plant typically produces less than 50% of the power plant's total power output, its water consumption is not proportionately lower (compared with a similarly sized conventional steam plant), since the gasification process itself consumes considerable quantities of boiler feed water. On an output basis, IGCC will consume roughly 30% to 60% less water than the competing technologies, which gives it more siting and permitting flexibility.

As discussed in Section 2.3, gasification plants have two principal water effluents that are similar to those from coal-fired plants. The first is wastewater from the steam cycle, including blowdowns from the boiler feedwater purification system and the cooling tower. Gasification processes typically purify and recycle raw process streams, and net water discharge is normally only a blowdown stream. These effluents contain salts and minerals that have been concentrated from the raw feedwater. The second aqueous effluent is process water blowdown, which is typically high in dissolved solids and gases with the various ionic species removed from the syngas, such as sulfide, chloride, ammonium, and cyanide. Detailed test results from the Wabash River plant have generally shown wastewater constituents to be well within environmental permit limits, with the exception of arsenic, cyanide, and selenium. However, recent installation of an add-on mechanical vapor recompression (MVR) system appears to have brought the wastewater stream into full compliance, although some operational problems have occurred. While the Polk IGCC plant has zero process water discharge, it comes at the price of operating several wastewater treatment systems.

2.1.4 Solid Waste and Byproducts Discharge Summary

Solid waste from coal-fired power plants is a significant local environmental issue due to the large quantities produced and the potential for leaching of toxic substances into the soil and groundwater at disposal sites. In both these areas, IGCC power generation poses minimal environmental impact. The largest solid waste stream produced by an IGCC that incorporates a slagging gasifier (currently the preferred choice) is slag, a black, glassy, sand-like material that can potentially be a marketable by-product. The amount of slag produced is a function of fuel ash content, so coal produces much more slag than alternative fuels like petroleum coke. Regardless of the fuel, as long as the operating temperature is above the ash fusion temperature, slag will be produced. Leachability data obtained from different gasifiers (see Section 2.4.2) unequivocally shows that gasifier slag is highly non-leachable and indicates gasifier slag need not be treated any differently than coal combustion wastes classified as non-hazardous. Even more important, the possible use of this material in a variety of applications may negate the need for long-term disposal (see Section 2.4.6).

The other large-volume by-product produced by IGCC plants is solid (or liquid) sulfur or sulfuric acid. Both can be sold as by-products that help offset plant costs. In comparison, most coal combustion processes recover sulfur in the form of wet scrubber sludge, dry or semi-dry spent sorbent, or gypsum. These sulfur forms have significantly larger mass and volume than pure sulfur, are often more difficult to handle and market, and must usually be disposed of in an appropriate landfill or surface impoundment. Should IGCC solid by-products require disposal, Sections 2.4.3, 2.4.4, and 2.4.5 discuss current storage stability, management practices and handling experience to minimize site contamination. However, due to the potential economic value of IGCC by-products, temporary surface impoundments for slag and containment vessels for sulfur or sulfuric acid may be the likely storage practice.

IGCC's solids generation amounts to about 50% less than that produced by a PC plant and 63% less than that of the atmospheric fluidized bed combustion (AFBC) technology when comparing plants of equivalent size that consume a bituminous coal with 4% sulfur content. While all of these plants produce byproduct material that may have commercial value, the slag and sulfur produced by the IGCC plant should be highly valued commodities in numerous areas of the country.

2.2 Air Emissions –Identification, Characterization and Control

The level of pollutant emissions emitted to the air is probably the most important environmental issue associated with gasification-based power generation. This section identifies and characterizes the potential air emissions within the following categories:

- Major criteria air pollutants: SO_2, NOx, CO, lead, and particulates (PM10) – Section 2.2.1
- Trace ionic species emissions: sulfate, nitrogen-containing ions, chloride, fluoride, phosphate, and cyanide – Section 2.2.2
- Trace metal emissions: Trace metal constituents of coal (or other solid gasifier feed material), such as mercury and arsenic – Section 2.2.3
- Trace organic emissions: Trace organic species produced during gasification and combustion of synfuel, such as formaldehyde – Section 2.2.4
- Greenhouse Gases: Carbon Dioxide (CO_2) – Section 2.2.5

While ample data are available to characterize the criteria pollutants with a relatively high degree of certainty, considerably less data is available to dependably identify and characterize the trace emissions. Therefore, more space is devoted here to examine various types of data and information, including model predictions, which help define and describe the trace emissions. This includes identifying their likely chemical forms, their partitioning behavior within an IGCC power generation system, and estimates of their magnitude (to assess control requirements if needed). Since trace mercury emissions from fossil-fueled power plants has been identified by the EPA as possibly requiring future control (see Section 3.2.2), mercury emissions are accorded a more detailed examination than other trace substances.

Information and data are also provided regarding the control of NOx, mercury and CO_2 emissions in Section 2.2.6, and Section 2.2.7 provides a detailed comparison of IGCC air emissions with those generated by PC and FBC power plants.

2.2.1 Identification and Characterization of Criteria Air Pollutants

SO_2, NOx (as NO and NO_2), particulates, CO, and lead are the EPA-designated criteria air pollutants produced by the conversion of coal and other solid carbonaceous fuels (e.g., petroleum coke) in gasification-based power cycles. As discussed in Chapter 1 of this report, clean gasifier syngas is burned in the combustion turbine, where these pollutants are formed from constituents of the syngas and air. Upon leaving the combustor, the hot turbine exhaust gas is typically cooled in a heat recovery steam generator (HRSG) before being exhausted to the stack. Therefore, the criteria air pollutants are discharged to the atmosphere as constituents of the stack gas. Criteria pollutants may also be emitted in much smaller amounts from equipment installed to treat the tail gas from the sulfur recovery process (see Section 1.1.5). This section describes the formation of the criteria air pollutants and the extent of their release from an IGCC plant.

2.2.1.1 Sulfur Dioxide (SO_2)

During high-temperature gasification of coal (or other solid fuels), most of the sulfur constituent is released and converted to hydrogen sulfide (H_2S), as well as a small amount of carbonyl sulfide (COS), due to the reduced oxygen environment. The concentration levels of these so-called acid gases, in the raw syngas exiting the gasifier, are almost entirely dependent on the levels of sulfur in the solid fuel (e.g., coal).[2,3] These H_2S and COS contaminants are mostly removed from the syngas in the acid gas removal equipment prior to combustion or other forms of fuel conversion (e.g., fuel cell).

There are inherent advantages in removing syngas contaminants prior to utilization of the syngas.[4] These advantages are:

- Removal prevents potential damage to the conversion devices, such as gas turbines, that result from contamination, corrosion, or erosion of materials;
- Relatively high concentration of H_2S in syngas, versus much lower concentration that would be found in the combustion flue gas, improves removal;
- High-pressure gasifier operation significantly reduces the gas volume requiring treatment;
- Conversion of H_2S into elemental sulfur (or sulfuric acid) is technically much easier and more economical than capture and conversion of SO_2 into salable by-products; and
- The oil and gas industries already have significant commercial experience with efficient removal of acid gases and particulates from natural gas.

As described in Section 1.1.5, the acid gas removal equipment extracts from 95% to greater than 99% of the H_2S and COS, once hydrolyzed, from the fuel gas and converts it to a salable sulfur or sulfuric acid (H_2SO_4) byproduct.[2] The small amount of residual sulfur that remains in the syngas is converted to SO_2 in the combustion turbine and released to the atmosphere in the HRSG stack gas. Other secondary sources of SO_2 emissions in an IGCC plant will typically include the sulfur recovery system's tail gas incinerator stack, auxiliary boilers (if applicable), and the syngas flare during gasifier startup and system upset conditions. These secondary SO_2 sources are typically be significantly smaller than the HRSG stack emissions.

Both of the U.S. commercial IGCC plants discussed in Chapter 1, Polk and Wabash River, achieve total SO_2 emissions below 0.15 lb $SO_2/10^6$ Btu heat input (< 1.3 lb/MWh for 8,600 Btu/kWh heat rate) or greater than 97% sulfur reduction. EPA's New Source Performance Standards (NSPS) for solid-fueled power plants requires 70 to 90% sulfur removal with a maximum SO_2 emission rate of 1.2 lb $SO_2/10^6$ Btu heat input (see Section 3.2.1.1.1).

2.2.1.2 Particulate Matter (PM)

While ash is released from the solid fuel during the gasification process, most gasifiers release only a small portion as fly ash that becomes entrained with syngas. Particulate control in gasification processes is highly efficient for reasons provided in Section 1.1.4. Not only does the gasification process provide an inherent capability to remove most ash as slag or bottom ash, but the fly ash that is produced is concentrated is a relatively small gas volume relative to solid fuel combustion processes, which further assists its cost-effective collection. Both the Polk and Wabash River plants use a wet scrubber to efficiently capture fine particulates that are entrained in the syngas. Additional particulate removal occurs in the gas cooling operations and in the acid gas removal systems. As a result, very low particulate emission levels are achieved.

Other particulate matter emission sources include:[5]

- The sulfur recovery system tail gas incinerator;
- The flare system used during cold start-up, shutdown, and during upset conditions, when the combustion turbine may be unavailable;
- Mineral matter in the spray from the cooling towers (if applicable); and
- Coal and ash/slag handling and storage operations.

The Wabash plant reported emissions of less than 0.012 lb/10^6 Btu heat input (0.088 lb/MWh output), while the Polk plant typically emits less than 0.015 lb/10^6 Btu. These emissions are significantly less than the current Federal NSPS requirement of 0.03 lb/10^6 Btu heat input (see Section 3.2.1.1.3).

2.2.1.3 NOx

The term "NOx" refers to the sum of the nitric oxide (NO) and nitrogen dioxide (NO_2) emissions from a combustion source. While most of the NOx produced during the combustion of syngas is in the form of NO, it is subsequently oxidized to NO_2 in the atmosphere. (Federal NOx emission standards are based on NOx expressed as converted to NO_2.) NOx is formed in fossil combustion systems by two primary mechanisms. "Fuel NO" is formed via the oxidation of chemically-bound nitrogen in the fuel, and "thermal NO" is formed via the dissociation of molecular nitrogen and oxygen to their atomic forms (at high temperatures) and subsequent recombination into oxides of nitrogen. Unlike natural gas, coal contains chemically-bound nitrogen that forms most of the NOx emissions when it is fired in a typical excess-oxygen environment, such as a utility boiler. Fuel NO typically contributes over 80% of the total NOx emissions in a coal-fired combustion unit, and its formation is highly insensitive to the flame temperature.[6] Generally, thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time.

The gasification process differs significantly from combustion with respect to the impact of chemically bound nitrogen in solid fuels, like coal. Gasification, because it operates with a deficiency of oxygen, converts most of the fuel nitrogen into harmless nitrogen gas (N_2). While a small portion is converted to ammonia (NH_3) and hydrogen cyanide (HCN), these water-soluble species are removed during fuel gas cooling and cleaning and are usually converted to nitrogen in the sulfur recovery process.[3] Therefore, the syngas produced is virtually free of fuel-bound nitrogen, and NOx formation is primarily the result of thermal NO produced at the high temperatures in the turbine combustor. The following relationships exist between turbine combustor operating conditions and thermal NO_x production:[7]

- NO_x increases strongly with fuel-to-air ratio or with firing temperature
- NO_x increases exponentially with combustor inlet air temperature
- NO_x increases with the square root of the combustor inlet pressure

- NO_x increases with increasing residence time in the flame zone
- NO_x decreases exponentially with increasing water or steam injection or increasing specific humidity.

Therefore, by maintaining a low fuel-air ratio (lean combustion) and adding a diluent (e.g., nitrogen from the air separation unit or steam from the steam turbine), the flame temperature can be lowered to significantly reduce thermal NO_X formation (see Section 2.2.6.1.1). The gas turbines installed in commercially operated IGCC plants have made use of this combustion-based control method to minimize NOx emissions. TABLE 2-1 lists the typical NOx emissions that have been recorded for commercially operated IGCC power plants in the U.S., and confirms that current IGCC plants can meet the Federal NOx NSPS for utility power plants of 1.6 lb NO_2/MWh or 0.15 lb $NO_2/10^6$ Btu (about 25 ppm for a gas turbine). As discussed below, the current state-of-the-art combustion control for a syngas-fired turbine has been demonstrated to be 15 ppm (15% O_2 basis and ISO conditions), and a recent BACT determination for the Polk IGCC plant specifies this value.

2.2.1.3.1 Comparison of NOx Emissions from Syngas-Fired Turbines versus Natural Gas-Fired Turbines

Since IGCC technology incorporates a combustion turbine (CT) in its power cycle, which accounts for most of the air emissions, its environmental performance is inevitably compared with that of a natural gas-fired combustion turbine, either a simple cycle or a natural gas combined cycle (NGCC) plant. Based on so-called Lean-Premix combustion technology (see Section 2.2.6.1.1), the PSD BACT standard for natural gas-fired stationary gas turbines, discussed in Section 3.2.1.1.2, specifies a NOx emission level of 9 ppm or 0.04 lb/10^6 Btu. Additionally, new units sited in ozone nonattainment areas have been required to install Lowest Achievable Emissions Reduction (LAER) technology, such as selective catalytic reduction (SCR), to reach emission levels as low as 2 or 3 ppm (equivalent to 0.01 lb/10^6 Btu) in some states.

With regard to recently installed IGCC plants, the initial response by regulators has been to suggest that NO_X emissions be controlled to the same low levels as those from NGCC plants. However, it is very important to understand that the combustion characteristics of syngas and natural gas are fundamentally different, which results in different NOx emission levels and different control capabilities for each. As discussed in detail in Section 2.2.6.1.1, use of the Lean-Premix Technology is not applicable to IGCC gas turbines that fire gasification-derived syngas, and the SCR technology has also reported to be problematic due to excessive SO_2 concentration in the turbine flue gas. The current state-of-the-art control for syngas-fired turbines makes use of diluents, such as nitrogen or steam, to reduce NOx emission levels to approximately 15 ppm (at 15% oxygen and ISO conditions).[8]

In summary, even though IGCC NOx emissions are quite low relative to emissions allowed from other coal-based power systems, enhanced control technology will likely be needed if the current requirements for stationary, natural gas-fired combustion turbines are used by regulators as a future standard for syngas-fired turbines. To date, regulators in Florida have concluded that a unique NOx standard for syngas-fired turbines is more appropriate, based on cited limitations.

TABLE 2-1. TYPICAL NOX EMISSIONS FROM IGCC PLANTS

IGCC PLANT NAME	PLANT SIZE, MWe	APPLICATION, FUEL TYPE	GASIFICATION TECHNOLOGY	GAS TURBINE TYPE	NOX EMISSIONS	
					ppmvd @ 15% O_2, Dry	$lb/10^6$ Btu (lb/MWh as NO_2)
Cool Water[9]	125	Demonstration Power Plant, Coal	ChevronTexaco pressurized oxygen-blown entrained-flow	GE 7FE	25	Unknown
Polk[10]	250	New Power Plant, Coal	ChevronTexaco pressurized oxygen-blown entrained-flow	GE 7FA	<20[a]	0.08 - 0.11[a] (0.8 – 1.03)
Wabash River[11]	262	Repowered PC Plant w IGCC, Coal	E-Gas two-stage pressurized oxygen-blown entrained-flow	GE 7FA	25	0.15 (1.09)
Chevron Texaco Eldorado[5]	40	Cogeneration Plant, Petroleum Coke	ChevronTexaco pressurized oxygen-blown entrained-flow	GE 6B	<25	Unknown
LGTI[9]	160	Demonstration Power Plant, Coal	E-Gas two-stage pressurized oxygen-blown entrained flow	Westinghouse WD501-D5	70	0.26
Motiva; Delaware City, DE[9]	240	Refinery, Petroleum Coke	ChevronTexaco pressurized oxygen-blown entrained-flow	GE 2-6FA	16	0.1

[a] Based on 14 months of CEMS data at the Polk plant. The average of the monthly highs is just under 0.10 $lb/10^6$Btu and the average of the monthly lows is just under 0.085 $lb/10^6$Btu. Polk's emissions will be reduced to 15 ppm (0.076 $lb/10^6$Btu) in July 2003 based on a recent BACT determination.

2.2.1.4 Carbon Monoxide (CO)

CO emissions are typically the result of incomplete combustion but can also result from fugitive emissions from the gasification equipment. In an IGCC system, sources are typically the gas turbine, sulfur recovery unit tail gas incinerator, and the flare system and equipment leaks.

Detailed CO emissions from the Wabash IGCC plant are characterized below in TABLE 2-2. The original Wabash coal-fired plant, which was repowered by the IGCC plant, emitted CO at an annual average rate of 0.64 lb/MWh.

While CO emissions from the primary combustion equipment appear be able to comply with emission standards, total CO emissions also depend upon fugitive sources and emissions from the flare system. These latter sources may cause CO emissions to exceed site permit specifications if not carefully controlled.

TABLE 2-2. 1998 CO EMISSIONS FROM THE WABASH RIVER IGCC PLANT[11]

PROCESS COMPONENT	EMISSION RATE		PERMITTED EMISSION RATE[a]
	lb/hr	lb/MWh	lB/MWh
Tail Gas Incinerator	0.46[b]	0.0018[b], 0.0009[c]	0.21
Flare	63.8[h]	0.25	42[e]
Power Block – Gas Turbine	11.2[d]	0.045[d]	15 ppm, (corrected to 15% oxygen and 75% or greater load)
Fugitive Emissions	0.0011[f]	4.5 x 10^{-6}	None Required
TOTAL	75.5	0.30[g]	

[a] Based on 56 lb/hr and 221 tons/yr permit limits and 251 MWe net actual output
[b] Based on initial compliance stack testing
[c] Average based on 1998 emission inventory of 0.588 tons/yr, 5,279 hours of operation, and 1,322,985 MW-hr net output
[d] Average based on 1998 emission inventory of 29.68 tons/yr, 5,279 hours of operation, and 1,322,985 MW-hr net output
[e] Based on CO flare permit limit of 11,099 lb/hr, 95% efficiency of CO combustion in the flair at maximum syngas flow
[f] Based on reported emissions of 0.003 tons/yr in 1998
[g] Equivalent to 0.033 lb CO/10^6 Btu coal heat input, as reported by Wabash in 1998
[h] Data not directly provided, calculated by difference based on reported total CO emissions of 0.033 lb/10^6 Btu

2.2.1.5 Lead

Lead (Pb) is found in coal in trace amounts in various forms (e.g., PbO_2, PbS, etc.). The mean concentration (ppm by weight) of lead found in U.S. coals is tabulated in TABLE 2-3.

TABLE 2-3. MEAN LEAD CONCENTRATION (PPM BY WEIGHT) IN U.S. COALS[12]

Appalachian	Interior	Gulf	Great Plains	Rocky Mountain	All U.S. Coals
15.3	55	20	5.3	5.5	16

Lead, a semi-volatile metal, is released from coal during combustion or gasification. It is classified as a Group II metal (see Section 2.2.3.2.1) that partially volatizes and becomes enriched on fly ash particles of decreasing particle size, as exhibited in results of analytical investigations completed on a slagging gasifier demonstration for IGCC power generation.[12] Such enrichment has been explained by a volatization-condensation mechanism, similar to that which takes place in coal combustion. In 1996 bench-scale study,[13] in which Illinois No. 6 coal was gasified in an entrained flow device at a gas temperature of 1450^o C (2642^o F), over 40% of the lead contained in the coal vaporized. Under the reducing conditions in a gasifier, chemical equilibrium analysis indicates that Pb will remain in the vapor phase at temperatures over 500^o C (932^o F) and condense on cooling to 400^o C (752^o F).[14] Both bench-sale testing and thermodynamic equilibrium models[15] indicate that the most likely chemical forms of lead in gasifier product gas will be Pb, PbS, $PbCl_2$ and PbCl. Key variables that influence the formation of these lead species are the lead species present in the coal, coal pretreatment, gasifier temperature profile, oxygen partial pressure and reaction time. Most, but not all, of the lead species should be removed in the plant's particulate and acid gas cleanup systems. Any residual lead in the fuel gas will be discharged from the combustion turbine as Pb, $PbCl_2$, or PbO.

Trace metal mass balance results for LGTI's IGCC plant showed that about one-third of the lead in the coal ended up in the gasifier slag and less than 5% as air emissions. The remaining lead was assumed to be removed in the particulate and acid gas cleanup systems and discharged with solid and liquid waste streams. Turbine stack emissions showed an average lead content of 1.6 $\mu g/Nm^3$, with 62% in the particulate phase and 38% in the vapor phase. A total average air emission factor for lead at the LGTI plant was calculated to be 2.9 $lb/10^{12}$ Btu of heat input.

In summary, trace amounts of lead contained in coal can be efficiently removed in an IGCC plant with minimal discharge to the atmosphere. While lead discharged with the slag can be effectively sequestered, the form of the lead species discharged in solid or liquid streams from the plant's water treatment facility is not known.

2.2.2 Identification and Characterization of Emissions of Trace Ionic Species

Ionic species[c] of environmental concern in the effluent streams of gasification-based power plants include sulfate, nitrogen-containing ions (e.g., nitrate, ammonium), chloride, fluoride, phosphate and cyanide. The ionic forms of these species in stack gases are present only in the aerosol phase.[16] Chloride and fluoride, however, can exist as acids and, thus, may appear in the gas phase as well. In IGCC plants, cyanide in process wastewater discharge appears to be the ionic species that is most problematic due to its toxic nature.

2.2.2.1 Sulfate

Sulfur species are typically the major anionic component of fossil fuel waste streams, typically present as sulfate (SO_4^{2-}) and sulfite (SO_3^{2-}) species. Sulfate is usually the dominant species in aqueous solution due to its stability over a wide range of Eh[d] and pH.[17] In stack gas, residual sulfur will primarily be in the gas phase, with a much smaller portion in the particulate phase. As discussed in Chapter 1, high-efficiency removal of H_2S and particulate from the synthesis gas limits emissions of aerosol sulfates and sulfuric acid to very low levels.

Sulfuric acid mist (H_2SO_4) has been identified as a constituent of incinerator tail gas emissions at the Wabash IGCC plant. In general, emissions are controlled by limiting fuel gas to less than or equal to 360 ppmdv of sulfur and ensuring that exhaust stack temperature is maintained at or above 264 ºF.[11] Initial compliance testing at the plant measured acid emissions of 2.69 lb/hr versus a permit limit of 3.79 lb/hr (6.8 tons/yr). 1997 annual emissions of sulfuric acid were estimated to be 3.84 tons/yr, and 1998 emissions were estimated to be 0.63 tons/yr.

Another potential source of sulfate emissions, as mentioned in Section 2.2.1.1, is the flare system that is used during cold start-up, shutdown, and during upset conditions, when the combustion turbine is unavailable. Since the flare is designed to efficiently combust the clean syngas at high temperatures (> 1830^{o} F), emissions of H_2SO_4 are small compared to the rest of the plant.

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[c] An ion is an atom or a group of chemically combined atoms that is electrically charged through addition or removal of one or more electrons. Examples are sodium ion (Na^+), chloride ion (Cl^-), ferric ion (Fe^{3+}), sulfate ion (SO_4^{2-}), and hydride ion (H^-).

[d] Redox potential – measures ability of an environment to supply or use electrons.

2.2.2.2 Nitrogen-Based Species

Excluding NOx in stack gas, the trace nitrogen species most frequently found in fossil power plant effluent streams (including IGCC fugitive emissions) are NH_3^0, NH_4^+, NO_3^-, and NO_2^-. Ammonia is generated in the gasification process, but most is removed from the syngas during acid gas and particulate removal. Fugitive emissions of ammonia vapor at the Wabash IGCC plant have been estimated to be 0.0374 tons/yr in 1997 and 0.00011 tons/yr in 1998.[11] Stack gas testing at Wabash measured less than 0.0031 lb/hr of total ammonia in 1998. Testing at the LGTI plant measured combined ammonia emissions in the stack gas and incinerator tail gas as 1.5 lb/hr (534 lb/10^{12} Btu).[18]

2.2.2.3 Chloride

Chloride is a common constituent in the effluent streams from coal-fired power plants due to the chlorine in U.S. coals (primarily as sodium and potassium chlorides), ranging from 0.01 to 0.5% by weight. While most U.S. coals have relatively low chlorine content, about 2.5% of the total estimated reserves have chlorine content above 0.2 percent, and these are mostly concentrated in the states of Illinois and Indiana.[19] Therefore, the relatively low chloride content of most coals limits chloride levels in effluent streams to low levels.

Most of the chlorine in coal is organically bound. During gasification, most of the chlorine is converted to hydrogen chloride (HCl) gas that appears in the untreated syngas.[14] The concentration in solid waste effluent streams (e.g., slag and ash) is affected primarily by a volatilization/condensation mechanism. The vapor-phase HCl and particulate-phase chlorides can be efficiently removed from the raw syngas in a water scrubber. As explained in Chapter 1, the scrubber effluent (bottoms) are treated in the water treatment system where particulates are separated for return to the gasifier, and the effluent is concentrated and solids crystallized for use or disposal in a landfill.[10] The results of a chloride mass balance, performed at the LGTI power plant, are shown in TABLE 2-4.

TABLE 2-4. CHLORIDE MASS BALANCE AT LGTI PLANT

INPUT	OUTPUT, lb/HR (% OF INPUT)			
COAL FEED, lb/hr	SLAG	INCINERATOR STACK GAS	GAS TURBINE STACK GAS	SOLIDS AND WASTEWATER EFFLUENTS
5.3 (100%)	0.83 lb/hr (15%)	0.09 lb/hr (2%)	2.0 lb/hr (38%)	2.38 lb/hr (45%)

In summary, regardless of gasifier type, low-temperature water scrubbing of the syngas can remove a significant portion of the chlorides, input with the coal feed, that exit the gasifier as a constituent of the syngas. However, more than one-third of the chlorides may exit the plant with the stack gas.

2.2.2.4 Fluoride

Fluoride is a common constituent in the effluent streams from coal-fired power plants due to the fluorine content of U.S. coals, ranging from 10 to 295 ppm.[14] The relatively low fluorine content of coal limits fluoride levels in effluent streams to low levels. Most of the fluorine in coal is organically bound and during gasification, is converted to hydrogen fluoride (HF) gas in the raw syngas. The concentration in the solid streams (slag and ash) is affected primarily by a volatilization/condensation mechanism. The highly soluble vapor-phase HF, and particulate-phase fluorides can be efficiently removed from the raw syngas in a water scrubber.

Results of a fluoride mass balance, performed at the LGTI power plant, are shown in TABLE 2-5:

TABLE 2-5. CHLORIDE MASS BALANCE AT LGTI PLANT

INPUT, lb/hr	OUTPUT, lb/hr (% OF INPUT)			
COAL FEED	SLAG	INCINERATOR STACK GAS	GAS TURBINE STACK GAS	SOLIDS AND WASTEWATER EFFLUENTS
10	2.0 (20%)	0.0012 (0%)	0.1 (1%)	7.9 (79%)

In summary, regardless of gasifier type, low-temperature water scrubbing of the syngas can remove most of the fluorides.

2.2.2.5 Cyanide

Hydrogen cyanide (HCN) is a toxic species that can be produced in the reducing environment of a gasifier process.[18] Likely formation reactions are:

$$CH + N_2 \rightarrow HCN + N$$

$$CH_3 + N \rightarrow HCN + 2H$$

IGCC process effluent gas streams that may contain HCN are the gas turbine/HRSG stack gas and the incinerator stack gas. Cyanide compounds may also occur on surfaces of particle entrained in gas streams. Aqueous streams may also contain dissolved cyanide as a result of syngas scrubbing to remove particulates and acid gases.

Emissions testing at both the LGTI and Wabash plants indicates extremely low levels of cyanide in both the turbine and incinerator stack gases, as indicated in TABLE 2-6.

TABLE 2-6. TURBINE AND INCINERATOR STACK GAS EMISSIONS OF CYANIDE

EFFLUENT STREAM	PARTICULATE PHASE CYANIDE, AVERAGE	VAPOR PHASE CYANIDE, AVERAGE	TOTAL CYANIDE, AVERAGE
LGTI PLANT[18]			
Turbine Stack Emissions, μg/Nm^3	Not Analyzed	<3.2	Not Calculated
Incinerator Stack Emissions, μg/Nm^3	Not Analyzed	5	Not Calculated
WABASH PLANT[11]			
Turbine Stack Emissions, lb/hr (1998)	None Reported	None Reported	<0.00006 (below detection limit)
Incinerator Stack Emissions, lb/hr	None Reported	None Reported	None Reported

2.2.3 Identification and Characterization of Trace Element Emissions

Coal contains most of the naturally occurring chemical elements in (at least) trace amounts,[e] with specific elements and their concentrations dependent upon the rank of the coal and its geological origins.[20] Some are potentially toxic trace metals and metal compounds bound with the coal's mineral and organic matter components. While associated with both the organic and inorganic constituents of the coal, they are more often associated with the three groups that make up the mineral content– silicate-rich minerals, carbonates, and sulfides. These trace species may be released during gasification or combustion and can pose an environmental and human health risk, depending upon their abundances, physicochemical forms, toxicity, partitioning behavior relative to process streams, and their ultimate disposal/deposition in the local and regional ecosystems associated with the coal conversion system.

TABLE 2-7 lists the trace metals and groups them according to their perceived level of environmental impact. The table also identifies the eleven trace elements (shown in bold), among a total of 189 substances, considered as hazardous air pollutants (HAPs) by the 1990 Clean Air Act Amendments (CAAA), see Section 3.2.7.3. These elements (and their compounds) are found in coals at concentrations ranging from a few ppb for elements such as Sb and Hg, to several hundred ppm for Mn. Some of these eleven trace elements, as well as the radionuclides uranium (U) and thorium (Th), may be the focus of future regulations.

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[e] By definition, trace elements are those that are present at levels no greater than 1000 ppm (0.1% or 1000 μg/g).

TABLE 2-7. TRACE ELEMENTS OF ENVIRONMENTAL CONCERN ASSOCIATED WITH COAL COMBUSTION/GASIFICATION[12]

Trace Elements of Greatest Environmental Concern	**Arsenic** (As), Boron (B), **Cadmium** (Cd), **Lead** (Pb), **Mercury** (Hg), Molybdenum (Mo), and **Selenium** (Se)
Trace Elements of Moderate Concern	Chlorine (Cl)**, Chromium** (Cr), Copper (Cu), **Nickel** (Ni), Vanadium (V), and Zinc (Zn)
Trace Elements of Minor Environmental Concern	**Antimony** (Sb), Barium (Ba), **Beryllium** (Be), **Cobalt** (Co), Fluorine (F), Germanium (Ge), Lithium (Li), **Manganese** (Mn), Strontium (Sr)
Radioactive Elements of Concern	Radon (Rn), Thorium (Th), Uranium (U)

Determining the amount and chemical form of trace constituents that partition to the gaseous effluents (and liquid discharges and solid residues) of a gasification-based power generation system can be quite difficult and uncertain. It requires proper sampling, sample recovery, awareness of potential contamination errors, choice of appropriate reference materials, and appropriate analytical techniques. This is complicated by a number of problems that lead to data uncertainty and inadequate mass balances for trace inorganic (and organic) species, such as mercury, exiting an IGCC plant. These problems can be been categorized as follows:

- Low concentrations of species being measured
- Inaccurate identification of all input and output streams and deposition locations, solid and liquid
- Inaccurate plant operating assumptions
- Inaccuracies in the measurement methods.

A detailed review of previously tested trace (inorganic and organic) pollutant measurement and monitoring techniques is provided in Appendix 2A, along with an assessment of the critical factors that may yield significant data inaccuracy. This is presented so that the reader fully understands the potential imprecision associated with the information presented in this section, as well as the other sections that deal with trace species.

2.2.3.1 Predicted Physical and Chemical Forms of Trace Elements within an IGCC System

Data on the chemical and physical forms of trace elements during coal gasification is quite limited compared to that from conventional boilers. However, information is available from thermodynamic equilibrium modeling studies, bench- and pilot-scale units, and several commercial-scale IGCC plants.

A variety of computer-based thermodynamic equilibrium studies have been performed to identify the chemical and physical forms of vapor-phase trace elements likely to be produced in a gasification process. This work makes use of global free energy minimization calculations and trace metal thermodynamic data to establish thermo-chemical equilibrium for specified fuel gas composition, temperature and pressure conditions. When total Gibbs free energy is at a minimum, all possible chemical reactions – homogeneous and heterogeneous – have reached equilibrium, and only stable chemical species and phases remain. While many of the reactions in coal combustion and gasification are kinetically (reaction rate) controlled and may not actually reach equilibrium, the equilibrium analysis provides a computational approach that has proven to yield insight into the chemical and physical behavior of trace elements in both combustion and gasification systems.

One such study evaluated the partitioning between vapor and condensed phases for the elements As, Cr, Hg, Pb, Se and Zn as a function of temperature at pressures of 0.1 MPa (1 atmosphere) and 2 MPa (20 atmospheres) for the entrained-flow gasification of Illinois No. 6 coal.[21] TABLE 2-8 identifies the most likely chemical forms of the vapor and condensed phases and the temperature at which 10 percent of a species condenses. Both Hg and Se are predicted to remain primarily in the vapor phase throughout an IGCC power cycle (regardless of operating pressure); whereas, other elements should condense and partition among particulate solids, heat transfer surfaces, and/or aqueous streams. Based on its condensation temperature, arsenic would most likely condense on the heat transfer surfaces that cool the synthesis gas prior to water washing and acid gas removal.

TABLE 2-8. EQUILIBRIUM MODEL PREDICTIONS OF VOLATILE TRACE ELEMENT CHEMICAL FORMS IN ENTRAINED FLOW GASIFIER[21]

Element	Prominent Vapor-Phase Species	Prominent Condensed-Phase Species	Condensation Temperature (^oF) @ 14.7 psi	Condensation Temperature (^oF) @ 290 psi
As	AsO	As_2S_2	675	819
Cr	Not identified	Cr_2O_3	2672	2942
Hg	Hg^o	HgS	152	207
Pb	PbS, Pb^o	PbS	927	1070
Se	H_2Se	Se	152	189
Zn	Not identified	ZnS	1412	1592

Equilibrium calculations assume that all Cl and S in coal are present in vapor phase as HCl and H_2S.

A second, but more comprehensive analysis, evaluated all of the above trace elements, as well as antimony, boron, beryllium, cadmium, cobalt, gallium, nickel, phosphorous, tin, titanium, vanadium, and zinc.[22] In this analysis, the syngas composition was based on a subbituminous coal, and the key design parameters included a stoichiometric ratio set at 0.6 (versus 1.2 for combustion) and a total pressure of one atmosphere. TABLE 2-9 presents the results of this analysis.

Another study evaluated gasification of a British coal at conditions representative of an air-blown, pressurized fluidized bed gasification plant.[23] Calculations considered each element in isolation, only simple salts (chlorides, oxides, and sulfides), and only the formation of pure condensed phases. Gasifier pressure was set at 290 psi. Calculations predicted the generalized trace metal behavior shown in TABLE 2-10 for As, Cd, Co, Cu, Cr, Hg, Mo, Mn, Ni, Pb, Se, Sn, V, and Zn. As indicated earlier, while most trace elements will be removed from the gas, potential problems exist with Hg, Se, As, and Cd.

TABLE 2-9. EQUILIBRIUM MODEL PREDICTIONS OF TRACE ELEMENT CHEMICAL FORMS IN AN AIR-BLOWN, ATMOSPHERIC GASIFIER[22]

Element	Prominent Vapor-Phase Species	Prominent Condensed-Phase Species	Condensation Temperature (^{o}F) @ 14.7 psi
Arsenic, As	AsO (>800^{o}F), AS_4 (530-800^{o} F)	As_2S_2	530
Boron, B	HBO_2 (>1880^{o} F), H_3BO_3 (250-1350^{o} F)	HBO_2	250
Beryllium, Be	$Be(OH)_2$	BeO	1250
Cadmium, Cd	Cd	CdS	710
Cobalt, Co	Co	CoS_2 (<370 F), $CoS_{0.89}$ (370-1250^{o} F), Co (1250-2000^{o} F)	2500
Chromium, Cr	CrO_2, CrO, Cr	Cr_2O_3	2800
Gallium, Ga	Ga_2S, Ga_2O, Ga, GaCl (complex equilibrium chemistry)	Ga_2S_3 (< 675 F), Ga_2O_3 (675-1350^{o} F)	1350
Germanium, Ge	GeS (1000^{o} F), GeO (3000^{o} F)	GeO_2	800
Mercury, Hg	Hg (100-3000^{o} F)	Not identified	Not identified
Nickel, Ni	Ni	NiS_2	2600
Phosphorous, P	$(P_2O_3)_2$ (314-2500^{o} F), PO_2 (>2500^{o} F)	H_3PO_4	314
Lead, Pb	Pb (> 1200^{o} F), PbS (<1200^{o} F)	PbS and/or $PbCl_2$	1000
Selenium, Se	H_2Se	None identified	Not identified
Antimony, Sb	SbS	None identified	Not identified
Tin, Sn	SnS	SnO_2	980
Titanium, Ti	None	TiO_2 (100-3100^{o} F)	Not applicable
Vanadium, V	VO_2	V_2O_3, V_2O	2800
Zinc, Zn	Zn	ZnS	1340

TABLE 2-10. EQUILIBRIUM MODEL PREDICTIONS OF VOLATILE TRACE ELEMENT BEHAVIOR IN PRESSURIZED FLUIDIZED BED GASIFIER[23]

Synthesis Gas Conditions: Temperature, Pressure	Trace Metals	Phase of Trace Metal at Specified Conditions: Condensed or Vapor
> 1832° F, 290 psi (Gasifier conditions)	Co, Ni, Cr, V	Condensed
1100° F, 290 psi	Zn, Cu, Mo	Condensed
750° F, 290 psi	Sn, Pb, Mn	Condensed
< 750° F, 290 psi	Hg, Se, As, Cd	Vapor

As discussed above, gasification-oriented equilibrium modeling studies identify the most highly volatile species as mercury, selenium, arsenic, cadmium, and boron. Such species are potentially the most difficult to control in gasification-based power generation systems. All other trace metals will most likely be removed from the synthesis gas, as described in Section 2.2.3.2.1, and discharged in the solid and aqueous effluents.

2.2.3.2 Partitioning of Trace Pollutant Species Among Air, Water and Solid Discharge Streams

The partitioning behavior of trace elements significantly influences their potential environmental impact. If a trace element is primarily captured within the slag, then it is essentially permanently sequestered and poses very little environmental threat. On the other hand, trace pollutants in the gaseous state that are emitted to the atmosphere in the flue gas may be more damaging to the environment and human health. The purpose of this section is to characterize partitioning behavior based on theoretical expectations and actual data. In order to present a cohesive discussion, this section covers multi-media partitioning behavior.

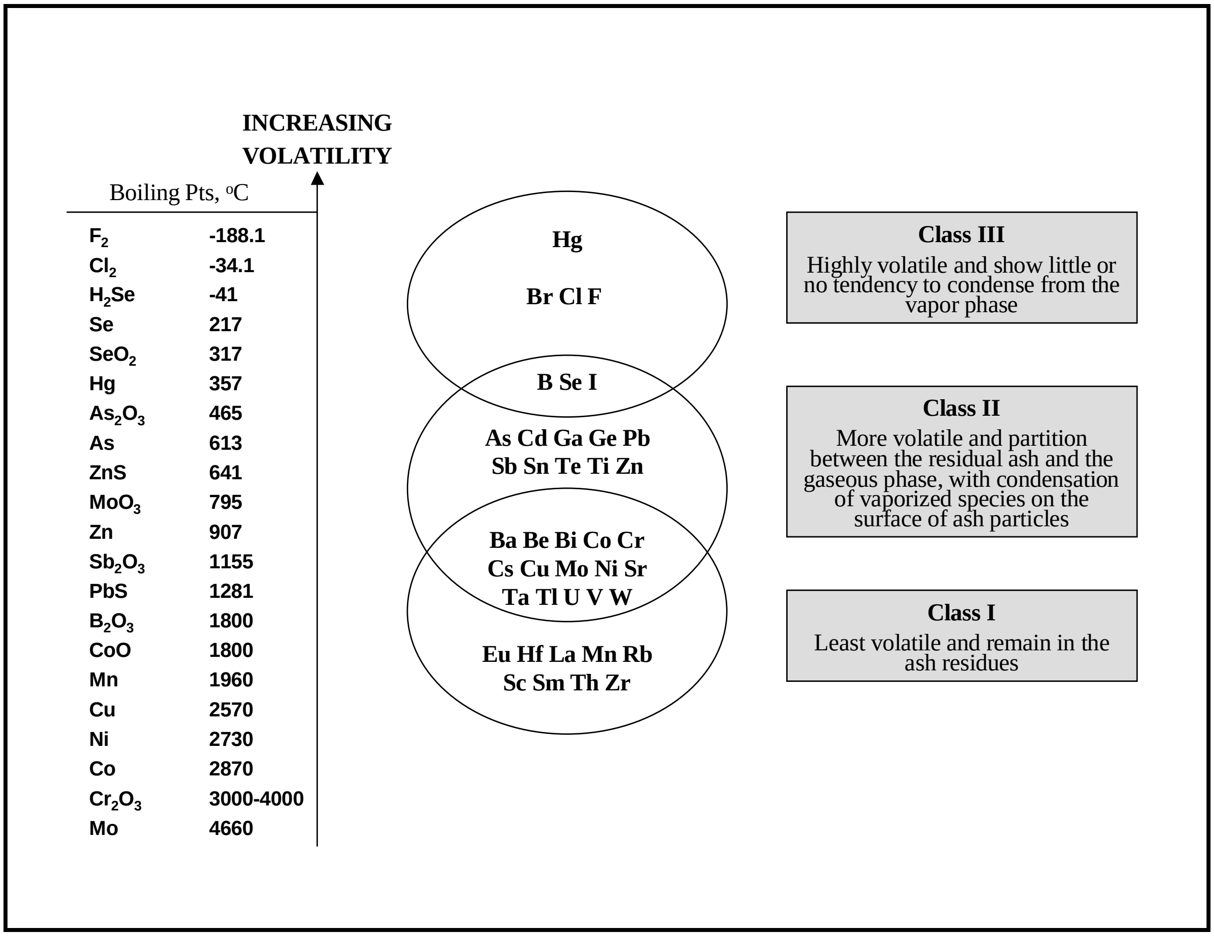
Elements that partition to IGCC solid residue streams will primarily impact the environment and health via leachability. Section 2.4 presents data that indicates that any such trace elements that are trapped in gasifier slag are highly non-leachable. Trace species that partition to the flue gas effluent are more likely to be a problem. As discussed in Section 3.2.1, EPA’s 1998 Report to Congress on hazardous air pollutants from fossil-fired plants concluded that mercury from coal-fired utilities was the HAP of greatest potential concern[24] and merited additional research and monitoring to determine if flue gas control was warranted. Therefore, in addition to an overall review of trace metals partitioning to the flue gas stream, this section focuses particularly on the fate of mercury in an IGCC plant. Partitioning to aqueous and by-product streams is also discussed.

2.2.3.2.1 Predicted Partitioning Behavior of Trace Elements

In order to better understand their partitioning behavior, trace elements are typically divided into three classifications depending on their 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 partition between the ash and the gaseous phase, with condensation of vaporized species on the surface of ash particles as the gas cools. *Class III* elements are highly volatile (e.g., low boiling point) and show little or no tendency to condense from the vapor-phase. Investigators have often disagreed on the classification of particular trace elements. Many elements have shown "intermediate" behavior that could place them in more than one category. FIGURE 2-2, a compilation of various study results,[20] identifies trace elements by class, indicates the potential for intermediate behavior, and qualitatively correlates the class behavior with some measure of volatility, such as boiling point. Many of the environmentally sensitive elements fall into classes II and III.

During combustion or gasification of coal, the trace elements partition between ash (fly ash, bottom ash, slag) and the gaseous stream. The initial distribution depends upon the degree of volatilization of their particular forms in the coal and the extent to which they may be physically or chemically bound to the carbon matrix or the primary aluminosilicate minerals. Those elements (major, minor, and trace) that are not volatized during combustion/gasification will comprise the fly ash and the bottom ash/slag in the form of a homogeneous "melt," as well as crystalline phases; the split between bottom ash/slag and fly ash is determined primarily by the furnace/gasifier design and, to a lesser extent, by operating conditions and coal rank.[25] Trace elements that exit the furnace/gasifier in a vaporized state will further partition downstream as the gas cools and condensation occurs. Thermodynamic models indicate that the trace metals are generally more volatile under the reducing conditions of gasification than in oxidizing environments, possibly because volatile gaseous compounds, such as chlorides, sulphides, and hydroxides, are more stable in reducing atmospheres.[23] In an oxidizing environment, metals tend to be converted into less volatile compounds, such as oxides and sulfates.[f]

FIGURE 2-2. TRACE ELEMENT CATEGORIZATION BASED ON VOLATILITY BEHAVIOR [25]



	Boiling Pts, °C
F_2	-188.1
Cl_2	-34.1
H_2Se	-41
Se	217
SeO_2	317
Hg	357
As_2O_3	465
As	613
ZnS	641
MoO_3	795
Zn	907
Sb_2O_3	1155
PbS	1281
B_2O_3	1800
CoO	1800
Mn	1960
Cu	2570
Ni	2730
Co	2870
Cr_2O_3	3000-4000
Mo	4660

The so-called chalcophile elements (As, Cd, Mo, Pb, Sb, Se, Zn), which are defined as those with a strong affinity for sulfur, are claimed to be mostly volatized during combustion because they occur as sulfides or within sulfide minerals.[26,27,28] It has been inferred that this is the result of the high temperature, reducing conditions near the surface of a burning coal particle that breaks the chemical bonds between metallic elements and sulfur in the sulfides.[24] Therefore, these

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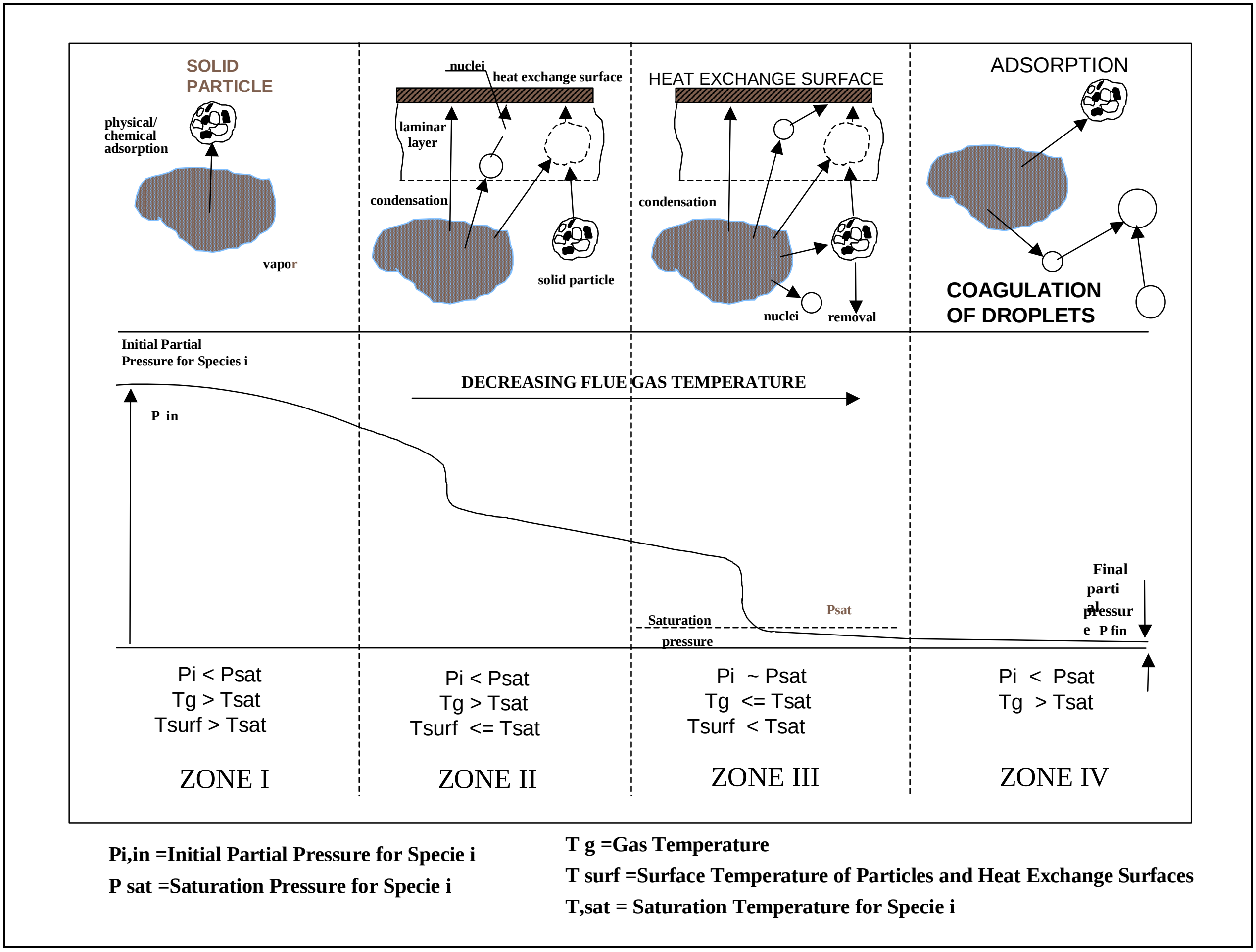
[f] This phenomenon is supported by experimental results, which compared fractional vaporization under reducing and oxidizing conditions – higher oxygen partial pressures reduced the fraction of each element vaporized.[13]

[h] It is assumed that the temperature of ash or other sorbent surface is close or equal to the local gas temperature.

elements are likely to partially or fully vaporize during combustion, which correlates with their Class II partitioning categorization.

In a combustion system operating with excess oxygen, trace metals that have been volatized, regardless of the release mechanisms, will probably be oxidized as they diffuse from the burning coal particles. However, in the reducing environment of gasification, the volatile species may be different from those that form during combustion. Gaseous species will undergo additional physical and chemical conversions as they are carried to different locations, depending on their thermodynamic properties, the fly ash/char properties, and temperature variations in the system. Once synthesis gas leaves the gasifier, the key factors influencing partitioning behavior are the conversion into various solid forms and their collection along with the fly ash and char. The former is determined by three complex and interrelated processes, namely adsorption, condensation, and chemical transformation. While these simultaneous processes occur along the entire gas pathway, conversion will be complete for all but the most volatile species before the particulate and acid gas control equipment. Understanding the complicated transformation of each volatile component can be simplified with the help of the flowchart presented in FIGURE 2-3.

FIGURE 2-3. GENERIC PARTITIONING PROCESS OF VAPOR-PHASE TRACE SPECIES IN HEAT TRANSFER AND GAS POLLUTANT CONTROL EQUIPMENT[25]



Zone 1: In this zone, the gas and heat exchange surface temperatures are higher than the dewpoint of a specified component, although adsorption may occur on the surface of fly ash and/or char.[h] Adsorption will mostly occur on the porous char/ash particles instead of smooth particles formed from condensed metals. The concentration (partial pressure) of a volatile component, as shown on Figure 2-3, initially falls slowly with decreasing temperature. Chemisorption will yield a new compound on a particle surface, which may be more stable and less volatile. Capillary condensation in the pores of fly ash (and sorbent particles) can also be a factor in removing volatile species from the gas phase. The saturation vapor pressure of most compounds is lowered in fine pores due to the **Kelvin effect**; therefore, condensation can occur in the pores even though the bulk vapor pressure is below saturation. This provides a means for capturing trace metals at relatively high flue gas temperatures.[29]

Zone 2: In this zone, the temperature of the heat exchange surface is equal to or below the dewpoint of the specified species. The process of adsorption on particulates continues in the bulk of the gas stream. However, special conditions appear in the laminar flow regime near the heat exchange surface. In this regime, the gas temperature decreases dramatically, and condensation processes become possible: 1) heterogeneous condensation on the heat exchange surface as a film, 2) heterogeneous condensation on the surface of particles whose temperature drops with that of the gas, 3) condensation of gaseous species previously adsorbed on the particle surface, and 4) homogeneous condensation/mist formation. A portion of the adsorbed component will be returned to the main gas flow due to particle and mist re-entrainment. Depending on the heat exchange surface design and other conditions, the species concentration in this zone will vary somewhat. High concentrations of some volatized-condensed trace species, such as As, have been reported for boiler tube ash deposits.[30]

Zone 3: Here the bulk gas temperature reaches the dewpoint of a particular species. Because the temperature of the heat exchange surface is usually lower than the gas temperature all along the boiler pass, all of the processes described above continue. However, condensation on ash particles and on mist droplets within the entire gas volume is now possible. Also, homogenous condensation is possible, especially if a sharp temperature drop occurs, as in the case of wet scrubbing. The component's partial pressure drops sharply to the saturation level, achieving equilibrium between the material adsorbed on particle surfaces and the vapor phase.

Zone 4: This zone is characterized by equilibrium between gaseous and condensed phases. However, if enough particles are present, the partial pressure of a species can be reduced below its saturation pressure by continued adsorption. Here the species is present as 1) an equilibrium liquid film on the surface of solid particles, 2) mist droplets, and 3) vapor. The location in the gas path where the various regimes are in control will be different for each of the volatile trace species based on their concentration levels, their thermodynamic properties and chemical reactivity potential. This simplified picture becomes much more complicated if we take into account possible chemical reactions between condensed species, between species and fly ash, and between the volatile species and other components of the gas. For example, investigation of the adsorption of mercury vapor on ash and activated carbon particles[31] has shown that the largest part of the mercury captured is not physically adsorbed, but chemically adsorbed and immobilized as more stable compounds. Immobilization of the trace species on fly ash or other adsorbents may offer an opportunity for ultimate disposal of these materials.

In summary, chemical forms and partitioning of trace elements among various gaseous, liquid and solid streams in an IGCC system ultimately depend upon coal characteristics, gasifier type (fluidized bed, slagging entrained-flow), gasifier operating conditions, operating conditions downstream of the gasifier, and the type of downstream gas treatment processes.

2.2.3.2.2 Measured Partitioning Behavior

Gasifier Bench- and Pilot-Scale Test Results

Tests conducted in a bench-scale pressurized drop-tube furnace by the Energy and Environmental Research Center have shown that gasifier temperature, pressure, and oxygen-to-carbon ratio (a proxy for reducing tendency) affect trace element partitioning, but primarily for the volatile elements.[20] The majority of trace elements were recovered with the ash and char, regardless of temperature, pressure and reducing conditions. However, the most volatile species, such as arsenic, cadmium, selenium and mercury, are affected by operating conditions, but not necessarily in an entirely consistent (or intuitive) manner. For example, increasing pressure increased the volatility of cadmium and mercury, but decreased volatility for selenium. Increasing temperature generally increased the volatility of the Class III metals. Additionally, while no significant trend was observed for the oxygen-to-carbon ratio, Hg volatility was shown to increase under more reducing (less oxidizing) operating conditions. The latter observation indicates that mercury may take a less volatile form under more oxidizing conditions (e.g., HgO versus Hg^o or HgS). As expected, the elements found to be the most volatile under all conditions were cadmium, selenium, and mercury. In contrast, nickel, chromium and, to a certain degree lead, were determined to be less volatile or nonvolatile.

In another bench-scale study reported by Helble,[13] the fate of trace elements was investigated in a device that simulated the gasification of Illinois No. 6 coal under entrained-flow conditions at atmospheric pressure and a temperature of 1450°F. The results indicated that over 40% of the elements arsenic, antimony, lead, selenium and mercury were vaporized, whereas the elements cadmium, chromium, cobalt, manganese, nickel, uranium and thorium were relatively non-volatile.

IGCC Test Results

While the bench-scale studies clearly identified the most volatile trace elements, the test results offer no information regarding the capture or escape from an IGCC facility that includes syngas cleanup equipment. Tests at representative IGCC units must be examined to garner this information.

Shell Development Company Pilot-Scale Plant

Pilot-scale test results have been reported by Shell Development Company based on operation of their SCGP-1 IGCC plant from 1987 to 1991.[32] The Shell system is a high-pressure, oxygen-blown, dry-feed, entrained-bed slagging gasification process (see Section 1.1.2.3 for more details). Extensive characterization during a long-term demonstration, while gasifying Illinois No. 5 coal, established the distribution of the major, minor, and trace elements to the slag, particulate filters, scrubber water, raw syngas, acid gas, and treated syngas.

Trace elements showing very high levels of recovery in the gasifier slag and particulate filter were: B (90%), Be (100%), Cd (74%), Co (100%), Cr (100%), Mn (100%), Mo (100%), Ni (84%), Pb (80%), U ((100%), V (100%), and Zn (90%). Elements with low levels of recovery were: As (63%, all in slag and particulate), Cd (74%, all in slag and particulate), Hg (27%, with 21% in slag and particulate and 6% removed in acid gas treatment), Sb (40%, all in slag and particulate), Se (63%, with 61% in the slag and particulate and 2% in scrubber water), and Sn

(71%, all in slag and particulate). Shell concluded that the low measured recovery of these volatile elements was related to retention within the process equipment. Analysis of the sorbent and packing material from their syngas scrubber after decommissioning of the plant showed this material to be "significantly" enriched in Hg, As, Pb, Se and Zn. Therefore, they concluded that the scrubbing step in the syngas cleanup train, upstream of the acid gas removal equipment, was, in fact, very effective at removing volatile trace elements. Volatile trace elements were not detected in the clean product syngas or the acid gas, with the exception of lead (clean syngas) and selenium (acid gas), which were present at less than 1% of the total inlet feed rate to the gasifier.

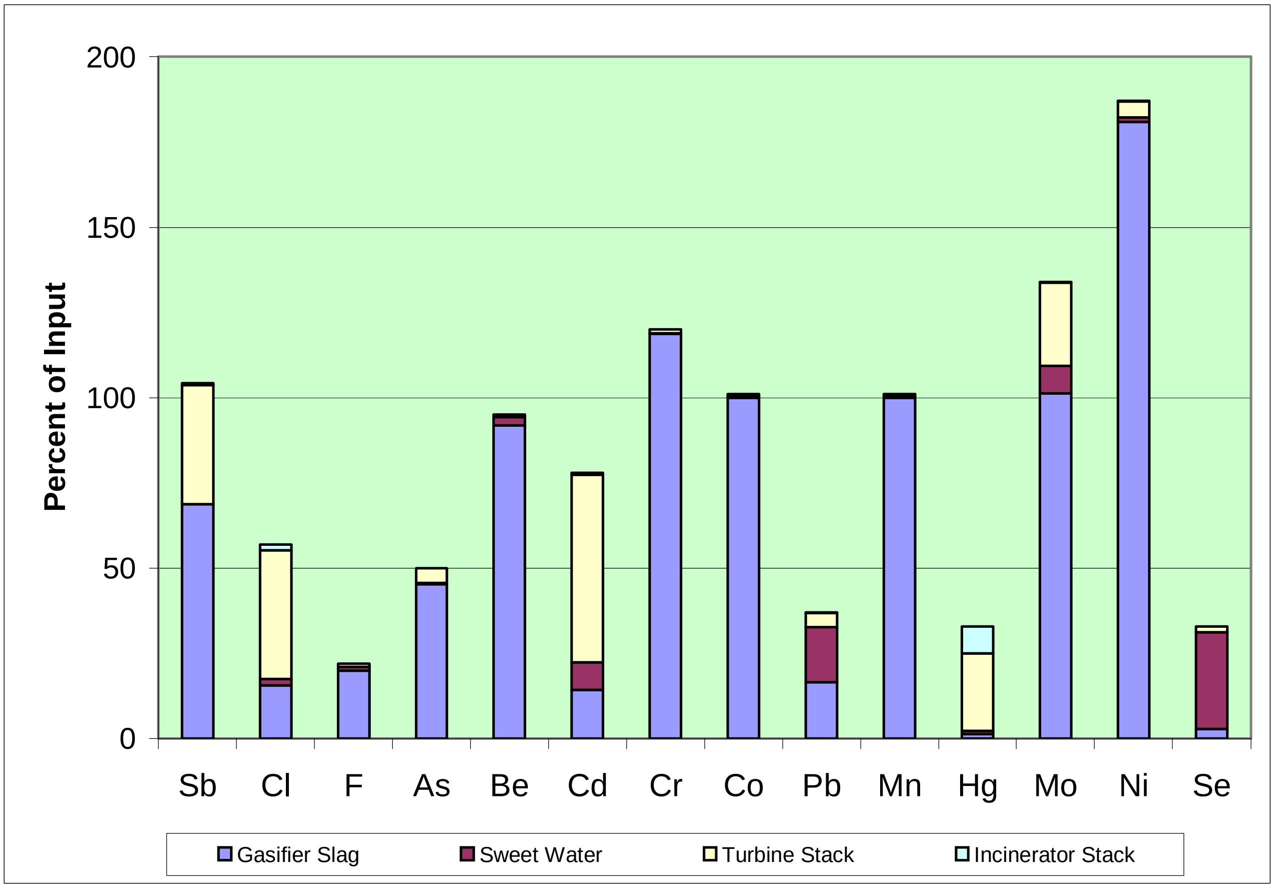
Louisiana Gasification Technology Inc (LGTI) IGCC Plant

Detailed field measurements of toxic emissions were performed at the 160 MWe LGTI IGCC power plant described in Chapter 1.[18] Sampling and measurements included all inlet and outlet streams, as well as many internal streams. In general, Radian reported that the trace substance emissions (inorganic and organic) were relatively low and comparable to a well-controlled pulverized coal-fired power plant. Material balance closures were best (70 to 130%) for the non-volatile elements (Be, Cr, Co, Mn and Ni), not as good for the semi-volatile elements (As, Cd, and Pb), but poor for the most volatile elements (Hg, Se, Cl and F). They also found that the acid gas Selectamine scrubber captured some volatile elements and organics. FIGURE 2-4 shows the partitioning of the trace elements among the major outlet streams – gasifier slag, processed "sweet" water, turbine stack gas, and incinerator stack gas. Since many of the trace elements are present at extremely low levels and since some of the metals may partially accumulate within an IGCC process, it isn't considered unusual to obtain material balance closures of less than (or more than) 100%.

Test results show that the volatile Class III elements, such as Hg and the halogens, are completely vaporized during gasification and are carried downstream with the syngas. Little to none is retained in the slag, but a portion is removed in the cleanup equipment. However, species, such as mercury, remain in the gas phase and will ultimately be discharged with the turbine exhaust gas. LGTI test data showed that the concentration in the tail-gas incinerator stack (28 $\mu g/Nm^3$) was significantly higher than in the turbine exhaust (0.71 $\mu g/Nm^3$). As discussed in the LGTI report, a possible explanation is the formation of mercuric sulfide in the syngas, which would be removed by the amine (MDEA) in the Selectamine^{TM} absorber. During amine regeneration, the mercury would desorb into the acid gas stream that is sent to the sulfur unit (Selectox^{TM} unit), and exit in the tail gas sent to the incinerator. These results definitively show that some portion of the input mercury will be discharged into the atmosphere but some mercury remains unaccounted for. This is further discussed in Section 2.2.3.3.

The semi-volatile Class II elements, such as As, Cd, Pb, and Se, were distributed partially to the slag, but were also present in the vapor phase throughout the process. The test data indicate that a small amount of each ends up in the turbine exhaust gas, but it is not clear where the remaining material goes. The Radian report suggests that some of the Class II and III metals may accumulate in the acid gas removal system, but, unfortunately, the solvent and the sludge were not sampled.

FIGURE 2-4. DISTRIBUTION OF VOLATILE, SEMI-VOLATILE, AND NON-VOLATILE TRACE ELEMENTS AS MEASURED IN LGTI IGCC DISCHARGE STREAMS[18]



As expected, the non-volatile Class I elements almost fully partition to the slag. The excess chromium and nickel found in the slag is claimed to come from the gasifier refractory material. Traces of these metals were also measured in the turbine exhaust. Radian speculates that this may be due to the reducing environment of the gasifier, which provides the potential for forming volatile carbonyl compounds.

Trace element emission factors (lb/10^{12} Btu input basis), calculated for total stack emissions from the LGTI plant, are presented in TABLE 2-11.

TABLE 2-11. TOTAL STACK EMISIONS OF TRACE ELEMENTS IN LGTI IGCC PLANT[18]

TRACE ELEMENT	EMISSION FACTOR, lb/10^{12} Btu	
	Average	**95% Confidence Level***
Antimony	4	4.7
Arsenic	2.1	1.9
Berylium	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

2.2.3.3 Detailed Evaluation of Mercury Data

Mercury is a particular problem in combustion and gasification systems, since it primarily remains in the vapor phase due to its low boiling point (357°C or 675°F). Its partitioning and speciation may vary between different gasification systems, but should be broadly similar. The likely chemical forms that may be found within a gasification-based power system are: 1) elemental mercury (Hg^o), 2) oxidized mercury (HgO and $HgCl_2$), and 3) mercuric sulfide (HgS). Other species are possible, but they should be present in only small quantities. The mercury may remain in the gaseous phase, be adsorbed onto particulates, or be removed in the liquid scrubbers. As discussed previously, both thermodynamic equilibrium modeling studies and actual test results indicate that elemental mercury is the prominent chemical form in gasification systems.

The mercury originally contained in the solid gasifier feed (e.g., coal) can be distributed in varying amounts to the following IGCC flow streams:

- **Gasifier slag/ash –** Hg discharged in solid form from the gasifier
- **HRSG stack gas –** Hg exits in gaseous form as constituent of the flue gas
- **Sulfur recovery unit tail gas –** Hg exits in gaseous form in the tail gas
- **Acid gas removal amine solvent** – Hg potentially accumulates within the gas cleanup system solvent
- **Discharge water –** Hg potentially absorbed in process water

- **Discharged process solids –** Hg contained in scrubber bottoms of flyash/char
- **Sulfur or sulfuric acid by-product –** Hg potentially captured with byproducts

2.2.3.3.1 Characterization of Probable Mercury Pollutant Emissions (Gaseous, Solids And Liquids) Based On Plant Test Results

Polk and Wabash River IGCC Plants

The U.S. EPA's Office of Air Quality and Planning (OAQP) conducted a program to collect the mercury emissions from coal-fired power systems.[33,34] As part of their Information Collection Request (ICR), EPA selected specific power plants for emissions testing to characterize speciated mercury emissions. Mercury sampling was performed on both the Polk Power and the Wabash River IGCC units. Mercury speciation testing was performed at the outlet of the combustion turbine/HRSG (in the stack) and mercury in the coal feed was also quantified to identify the mercury input to the cycles. Results of these tests are listed below in TABLE 2-12.

TABLE 2-12. MERCURY EMISSION TEST RESULTS FOR POLK AND WABASH RIVER IGCC POWER PLANTS[33,34]

	POLK			WABASH RIVER		
Flue Gas Emissions[a]	**µg/Nm³**	**lb/hr**	**% Total**	**µg/Nm³**	**lb/hr**	**% Total**
Particulate bound mercury	< 0.01	0.00003	0.25	<0.02	0.00006	0.56
Oxidized mercury	0.29	0.00087	7.08	<0.9	0.00273	25.30
Elemental mercury	3.81	0.01120	92.67	2.64	0.00800	74.14
Total	4.11	0.01210	100.00	<3.56	0.01079	100.00
Input (mercury in coal)		< 0.0207			0.016	100
Mercury partial mass balance[b]		lb/hr	Closure, %		lb/hr	Closure, %
Mercury In		0.0207			0.016	
Mercury Out		0.01210			0.01079	
Difference		0.00860	58.45		0.00521	67

[a] Average values for 3 tests, Nm³ = Normal cubic meter (0°C and 1 atm)

[b] Balance is not complete -- no results for liquid and solids effluent streams

Although a complete mercury mass balance cannot be performed, both tests clearly indicate that a large portion, at least 60%, of the mercury will exit with the combustion flue gas as elemental mercury, predominant species generated by these IGCC processes.

A significant portion of the Hg does not exit in the flue gas and is removed elsewhere. Since little mercury will be trapped with the gasifier slag (see Section 2.2.3.2.2), the most likely sinks are the water and amine scrubbers and the flyash and char particles entrained in the fuel gas. Therefore, the following partitioning of the remaining mercury is possible:

- Accumulates in the amine scrubbing loop
- Removed from the amine solvent when stripped of H_2S and partitioned to the sulfur/sulfuric acid recovery unit – discharged with the by-product
- Returned to the gasifier with excess scrubber water that is recycled for coal/water slurry preparation
- Recycled to the gasifier with char and flyash (Wabash River Plant)
- Discharged with treated water, water treatment material (e.g., activated carbon), or water scrubber bottoms.

Louisiana Gasification Technology Inc. (LGTI) IGCC Plant

A joint DOE/EPRI/LGTI project characterized trace substance emissions from this plant in 1995. Mercury was measured in the gasifier coal feed, gasifier slag, turbine stack, acid plant incinerator stack, sulfur by-product, and sweet water discharge. Mercury speciation testing distinguishes the particulate phase from the vapor phase. Results of these tests are listed in TABLE 2-13.

The LGTI test results are not consistent with the test results provided in Table 2-12 in terms of mass balance closure. However, these test results were more complete since they included data for the solid and liquid discharge streams. The mass balance is summarized in FIGURE 2-5:

FIGURE 2-5. LGTI MERCURY MASS BALANCE

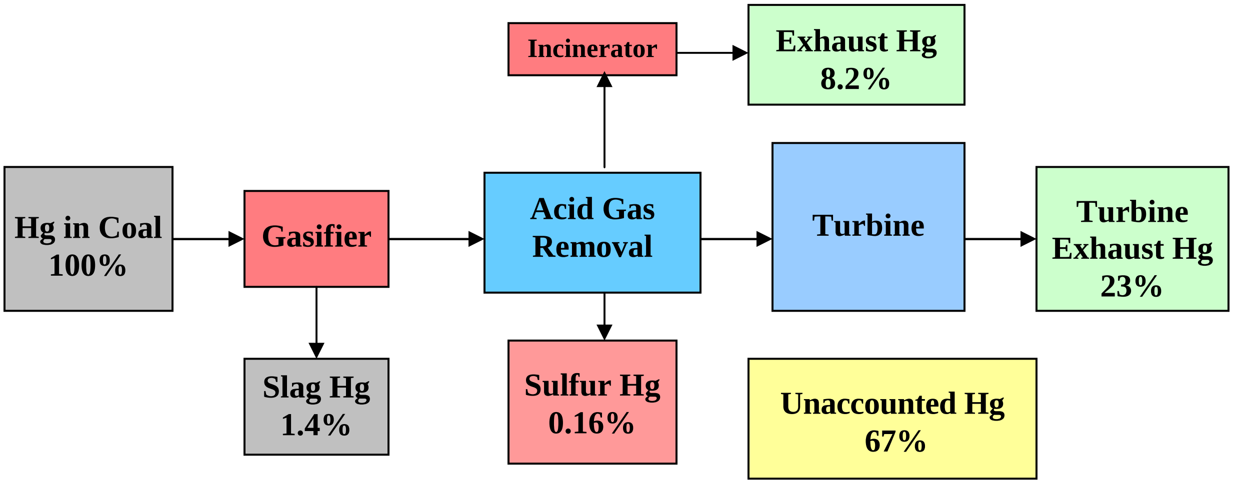


TABLE 2-13. MERCURY EMISSION TEST RESULTS FOR LGTI IGCC POWER PLANT[18]

Hg OUTPUT	**$\mu g/Nm^3$ (avg)**	**lb/hr (avg)**	**% TOTAL by WEIGHT**
Flue Gas Emissions[a]			
Turbine Stack – Particulate Phase	0.01	0.00005	1.1
Turbine Stack – Vapor Phase	0.70	0.00335	72.8
Incinerator Stack – Particulate Phase	0.015		
Incinerator Stack – Vapor Phase	28	0.0012	26.1
Total Flue Gas Emissions		**0.0046**	**100.0**
Solid Discharge Effluent Streams	**µg/g (avg)**	**lb/hr (avg)**	**% Total by Wt**
Gasifier Slag	0.02	0.00020	90
Sulfur By-product	0.095	0.000023	10
Total Solid Phase Hg		**0.000223**	**100.0**
Aqueous Discharge Streams	**Mg/L**	**lb/hr (avg)**	**% Total**
Sweet Water[b]	**<0.00003**	**N/A**	**100.0**
Hg INPUT	**µg/g (avg)**	**lb/hr (avg)**	**% Total**
Input (mercury in coal)	**0.11**	**0.015**	**100.0**
Mercury Partial Mass Balance		**lb/hr (avg)**	**Closure, %**
Mercury In		0.015	
Mercury Out		0.004823	
Difference		**0.0102**	**33**

[a] Average values for tests, Nm^3 = Normal cubic meter 0^oC and 1 atm)

[b] Mass flow of sweet water discharge not provided in report, but Hg content is very small

Approximately 31 percent of the inlet mercury is discharged in gaseous form to the atmosphere, probably as elemental mercury. About 2 percent leaves with the slag and sulfur by-product. According to these test results, the unaccounted mercury is not leaving with the solid and liquid discharge streams. Either the emissions test data are in error or the Hg is being accumulated within the system. There is some evidence that Hg may accumulate in the amine-based sulfur removal system.[35] The amine solvent is periodically regenerated to prevent excessive buildup of heat stable salts, primarily carboxylic acids. These acids, it is claimed, can keep metallic elements such as Hg in solution by chelation. The sludge layer that accumulates at the bottom of the solvent storage tank may also contain some Hg. In the tests reported here, no samples were taken that can fully confirm this result.

Mass balance closure was considerably less for LGTI than for the Polk and Wabash River plants. As a percentage of mercury input to the power plant cycle, about half as much mercury is released in the LGTI system. One conspicuous difference is the type of coal being consumed – subbituminous versus eastern bituminous, but it is unclear why this would have such a significant impact. It should be noted, however, that ICR results for PC power plants show mercury emissions and speciation differences that can be correlated with coals of different rank (e.g., bituminous versus subbituminous).

2.2.3.3.2 Mercury Emission Rates and Emission Factors

The data presented in the previous section can be used to estimate total mercury flue gas emissions and emission factors for IGCC plants, assuming that the unaccounted mercury is accumulated somewhere within the gas treatment equipment and not subsequently released to the atmosphere. TABLE 2-14 presents this information for three U.S. IGCC plants evaluated in this chapter of the report.

TABLE 2-14. ESTIMATED MERCURY EMISSION RATES AND EMISSION FACTORS FOR IGCC PLANTS[36]

	Polk Plant	Wabash River Plant	LGTI Plant
Plant Net Capacity, MWe	250	262	160
Average Load During Tests, MWe	250	177.7	160
Average Unit Heat Input, 10^6 Btu/hr	2,326.7	2,472.7	2,705.8
Coal Type	Eastern Bituminous	Midwestern Bituminous	Wyoming PRB
Mercury Input, lb/MWh	8.3×10^{-5}	9.0×10^{-5}	9.4×10^{-5}
Mercury Input, lb/10^{12} Btu	8.9	6.5	5.6
Average Measured Hg Stack Emissions, lb/hr	0.0121	0.0108	0.0046
Hg Emission Factor, lb/MWh	4.8×10^{-5}	6.1×10^{-5}	2.9×10^{-5}
Hg Emission Factor, lb/10^{12} Btu	5.2	4.4	1.7

This table highlights the conclusion drawn in the last section that the LGTI plant captures considerably more mercury than the other two plants. Mercury input (lb/MWh) is relatively similar for all three plants. LGTI input mercury is 13 percent higher than the Polk plant and 5 percent higher than the Wabash River plant. However, on the same basis, the LGTI plant emits 39% less mercury to the atmosphere than the Polk plant and 52% less than Wabash River. This inconsistent behavior may be the result of more limited testing capability in 1995 versus the 1999 to 2000 time period, and the different coal types may also be a factor.

2.2.3.3.3 Comparison of IGCC Mercury Emissions With Those of Competing Fossil-Based Power Generation Technologies

To assess the future outlook for add-on mercury control at IGCC plants, it is appropriate to compare expected emissions with those of currently operating PC plants. TABLE 2-15 compares the Polk IGCC plant test results with similar ICR results for the following power plants:

- **Widow's Creek Unit 6** – 140 MWe Wall-fired, dry bottom boiler that burns eastern bituminous coal; emission control devices include a hot-side ESP for particulate control and low-NOx burners for NOx control.
- **Bailly Generating Station Units 7 & 8** (Northern Indiana Public Service Company) – Cyclone-fired, wet bottom, balanced draft boilers with net capacities of 160 and 320 MWe, respectively. They burn a mix of Southern Illinois Bituminous and Wyoming subbituminous coals, utilize cold-side ESPs for particulate control, and share a common wet, limestone FGD unit for SO_2 control.
- **Big Bend Unit 3 (Tampa Electric Company)** – 445 MWe Opposed wall-fired, dry bottom, boiler that burns Illinois bituminous coal; emission control devices include a cold-side ESP for particulate control, low-NOx burners for NOx control, and a wet limestone FGD system for SO_2 control.
- **Lawrence Energy Center Unit 4 (Western Resources)** – 115 MWe Tangential-fired, dry bottom boiler that burns western subbituminous coal; emission control devices include a wet venturi scrubber for particulate control and wet limestone FGD for SO_2 control.
- **R.M. Haskett Station Unit B2 (Montana-Dakota Utilities)** – 78 MWe fluidized bed system that uses lignite coal; emission control devices include a cold-side ESP for particulate control and in-bed limestone injection for SO_2 control.
- **AES Hawaii (AES)** – 90 MWe fluidized bed system that uses Indonesia bituminous coal; emission control devices include a baghouse for particulate control, SNCR for NOx control, and in-bed limestone injection for SO_2 control.

While limited, these results show that Hg emissions vary considerably from plant to plant. However, the results do indicate that IGCC mercury emissions are probably no worse than PC plants that have a full compliment of emission control technologies. Results also indicate that the concentration of mercury in the flue gas from IGCC plants may be no more of a control problem than for the other types of plants, and control of mercury in the syngas prior to combustion may be a significant advantage (see Section 2.4.7).

TABLE 2-15. COMPARISON OF MERCURY EMISSION RATES AND EMISSION FACTORS BETWEEN IGCC PLANT AND COAL-FIRED POWER PLANTS[36]

	Polk Plant	**Wabash River Plant**	**Widows Creek 6**	**Bailly 7 & 8**	**Big Bend 3**	**Lawrence 4**	**R.M. Haskett**	**AES Hawaii**
TECHNOLOGY TYPE	**IGCC**	**IGCC**	**PC**	**PC**	**PC**	**PC**	**FBC**	**FBC**
Plant Net Capacity, MWe	250	262	140	160 & 320	445	115	68-85	90
Average Load During Tests, MWe	250	177.7	120	460	435	100	78	90
Average Heat Input, 10^6 Btu/hr	2,326	2,472.7	1,187	4,982	4,045	1,019.2	919	923
Coal Type	Bituminous	Midwestern Bituminous	Eastern Bituminous	Bituminous. & Sub-bituminous	Illinois Bituminous	Western Subbituminous	Lignite	Bituminous (Indonesia)
Mercury Input, lb/10^{12} Btu	8.9	6.5	2.1	5.47	10.1	4.9	7.6	1.29
Average Measured Hg Stack Emissions, lb/hr	0.0121	0.0108	0.00078	0.0111	0.0071	0.005	0.00412	0.00054
Hg Emission Factor, lb/10^{12} Btu	5.2	4.4	0.69	2.23	1.75	4.9	4.48	0.58
Hg Emission Factor, lb/MWh	4.8×10^{-5}	6.1×10^{-5}	6.5×10^{-6}	2.4×10^{-5}	1.6×10^{-5}	5×10^{-5}	5.7×10^{-5}	5.8×10^{-6}

2.2.4 Identification and Characterization of Trace Organic Compounds (HAPs)

Some of the trace air pollutants that may be associated with coal combustion and gasification are organic compounds that either originate from incomplete oxidation of the fuel or result from the chemical transformation of organic constituents in the fuel.[37] All coal conversion processes - combustion, gasification, and liquefaction - include thermal degradation of the coal as their initial step. The organic products are normally oxidized in these conversion processes to oxides of carbon, but insufficient mixing or non-uniform temperatures may prevent complete oxidation of devolatilization products. Trace organic compounds, therefore, can be released via complex, non-oxidizing, pyrolytic processes that govern the formation and transformation of these organics in high temperature environments.

Because some organic compounds may have deleterious effects on the environment or human health, the purpose of this section is to identify their chemical forms and determine the extent of their possible release from IGCC technology. TABLE 2-16 lists the classes of organic species that may be found in the stack gases of coal-fueled power plants. The 1990 Clean Air Act Amendments identify eight volatile and semi-volatile organic compounds that have been found in the stack gases of conventional fossil fuel power plants. These are benzene, toluene, phenol, naphthalene, biphenyl, benzo[a]pyrene, formaldehyde, and acetylaldehyde.

TABLE 2-16. CLASSES OF ORGANIC COMPOUNDS THAT MAY BE PRESENT IN COAL-FIRED POWER PLANT STACK GASES[37]

ORGANIC COMPOUND CLASS	EXAMPLES
n-Paraffins	n-alkanes of carbon number C_{15} – C_{34}
Aldehydes and Ketones	Acetylaldehyde, Benzaldehyde, Formaldehyde
Aromatics (Volatile Organic Compounds)	Benzene, Toluene, Carbon Disulfide
Polycyclic Aromatic Hydrocarbons (PAHs)	Benzo[a]anthracene, Benzo[e]pyrene, Napthalene
Polychlorinated Furans, Dibenzo-p-dioxins	2,3,7,8-tetrachlorodibenzodioxin, 2,3,7,8-tetrachlorodibenzofuran
Phenols	Tert-butyl phenol
Sulfur Heterocycles	2-ethyl-5-isoamylthiophene
Nitrogen Heterocycles	Dibenzo[c,g]carbazole

This section also compares IGCC's trace organic emissions with those produced by conventional coal-fired power plants, as well as natural gas-fired combustion turbines. The latter comparison is made here because IGCC technology incorporates a combustion turbine (CT) in the power cycle, which accounts for most of the air emissions, and its environmental performance is inevitably compared with that of a natural gas-fired combustion turbine, either a simple cycle or a natural gas combined cycle (NGCC) plant.

2.2.4.1 IGCC Plant Operating Data

While little corroborating data is available on individual trace organic releases to the air from gasification systems, detailed test results from the LGTI IGCC plant provide perspective on the types and levels likely to be seen.[18] LGTI's incinerator and turbine stack gases were measured for about 114 different organic species. TABLE 2-17 presents calculated emissions factors for some of the key species measured at LGTI. These are compared with median emission factors derived from test data from 52 coal-fired units subjected to extensive emission tests by EPRI, DOE, the Northern States Power Company, and EPA.[38] In general, the results indicate extremely low levels of trace organic emissions, in-line with emissions expected from conventional coal-fired plants. Data from the Wabash River IGCC plant, while higher than measured LGTI emissions, also supports relatively low levels of emissions; total average VOCs (for 1997 and 1998) are reported to be 0.00205 lb/10^6 Btu or 0.01635 lb/MWh.[39] These emissions represent about one-half the emissions of the original coal-fired plant that was replaced.

The LGTI test results did not identify any significant dioxin or furan emissions in the stack gas. This is in agreement with the belief that dioxins and furans are not likely to be formed in gasification systems. The high temperatures in the gasifier should destroy any dioxin/furan compounds or precursors, and the lack of oxygen in the reducing environment should limit the formation of free chlorine. Without free chlorine, the formation of polychlorinated species downstream of the gasifier is unlikely. Measurements taken at Shell Coal Gasification Plant-1 (see Sections 1.1.2.3 and 2.2.3.2.2) also corroborate these expectations. Dioxins and furans were not present at the detection limit of 1 part per billion by volume in the synthesis gas, nor were there any precursors at the same detection level.[40] Shell estimates that, due to the effects of dilution and combustion, the concentration of dioxins and furans in the HRSG stack gas should be less than one part per trillion by volume.

It is important to note that the above results are based on IGCC systems that use single-stage, entrained-flow gasification processes, such as ChevronTexaco and E-Gas. IGCC power systems that utilize other types of gasification processes may yield different HAPs emissions.

2.2.4.2 Comparison of Organic HAPs Emissions from IGCC and Gas Turbines Firing Natural Gas

While the primary pollutant from a natural gas-fired turbine is NOx, as discussed in Section 2.2.1.3.1, some concern has been raised about the aggregate impact of trace organic emissions resulting from the increased use of gas-fired CTs to meet rising electricity demand. Such concern makes it worthwhile to compare IGCC turbine HAPs emissions with those from natural gas-fired CTs. Emissions data indicate that formaldehyde is the most significant organic compound emitted from combustion turbines, albeit at very low concentrations. For natural gas-fired turbines, formaldehyde accounts for about two-thirds of the total HAPs, while polycyclic aromatic hydrocarbons (PAHs), benzene, toluene, xylenes, and other organics account for the remaining one-third.[41] TABLE 2-18 identifies HAPs emission factors for compounds contained in EPA's Emission Inventory for combustion turbines. In its Utility Air Toxics Report to Congress,[42] EPA concluded that emissions of HAPs from gas-fired electric utilities are of no significant public health concern. In its Executive Summary, EPA states that, "The impacts due to HAP emissions from gas-fired utilities are negligible based on the results of this study; therefore, the EPA feels that there is no need for further evaluation of the risks of HAP emissions from natural gas-fired utilities."

TABLE 2-17. COMPARISON OF ORGANIC HAPs MEASURED AT THE LGTI IGCC PLANT WITH MEDIAN EMISSIONS FROM DIFFERENT TYPES OF COAL-FIRED PLANTS

ORGANIC POLLUTANT	COMBINED INCINERATOR AND TURBINE STACK EMISSION FACTORS FROM LGTI		MEDIAN EMISSION FACTORS PROJECTED FOR ORGANIC HAPS FROM COAL-FIRED UNITS,[38] lb/10^{12} Btu
	Average, lb/10^{12} Btu	95% Confidence Level,* lb/10^{12} Btu	
ALDEHYDES			
Acetaldehyde	1.8	1.5	6.8
Benzaldehyde	2.9	2.6	Not available
Formaldehyde	17	7.5	4.0
Benzene	4.4	1.7	2.5
Carbon Disulfide	46	14	4.3
Toluene	0.033	0.02	3.6
PAHs/SVOCs			
2-Methylnapthalene	0.36	0.55	0.024
Acenaphthylene	0.026	0.0075	0.0042
Benzo[a]anthracene	0.0023	0.0002	0.0021
Benzo[e]pyrene	0.0056	0.0007	0.0012
Benzo[g,h,i]perylene	0.0096	0.0005	0.0032
Napthalene	0.4	0.12	0.77
Benzoic Acid	140	65	Not available

* The confidence interval represents the range around the average where the true mean lies with a probability of 95%

TABLE 2-18. RANGE OF HAP EMISSION FACTORS [AVERAGE, (MIN-MAX)] FOR NATURAL GAS-FIRED COMBUSTION TURBINES IN EPA's SECTION AP-42

HAP	# TESTS	AVERAGE EMISSION FACTOR ($lb/10^6$ Btu)	RANGE MIN - MAX ($lb/10^6$ Btu)
Acetaldehyde	7	9.12E-05	(1.10E-05 – 3.50E-04)
Acrolein	2	5.49E-06	(4.90E-06 – 6.08E-06)
Benzene	11	1.03E-05	(1.34E-06 – 3.91E-05)
Ethyl Benzene	1	4.10E-05	---
Formaldehyde	22	7.13E-04	(2.21E-06 – 5.61E-03)
Naphthalene	3	1.46E-06	(5.11E-07 – 3.31E-06)
PAH	4	2.23E-06	(1.44E-07 – 7.32E-06)
Toluene	7	1.42E-04	(1.05E-05 – 7.60E-04)
Xylene	5	4.59E-05	(1.19E-05 – 1.20E-04)

As discussed previously, limited data from IGCC power plants has shown their organic emissions to be extremely low (see TABLE 2-17 in Section 2.2.4.1). Detailed HAPs measurements taken at the LGTI IGCC plant are compared in TABLE 2-19 with the average emission factors presented in TABLE 2-18. This limited comparison indicates that IGCC, based on entrained-flow gasification, generally performs better than a natural gas-fired turbine from the standpoint of HAPs emissions. The LGTI emissions are typically an order-of-magnitude lower than the average AP-42 HAP emission factors.

2.2.5 Characterization of Carbon Dioxide Generation

The carbon contained in the coal fed to an IGCC power plant is initially converted into a combination of CO and CO_2 in the syngas that exists the gasifier. Figure 1-3 (located in Section 1.1.2) shows that the CO typically ranges from 30 to 60% (by volume), while the CO_2 typically ranges between 5 to 15% (by volume). TABLE 2-20 presents the syngas analysis for the Wabash River and Polk IGCC plants. Upon combustion in the gas turbine, the CO is oxidized to CO_2. The total CO_2 content of the flue gas that exits the HRSG is approximately 6 to 8% by volume).

TABLE 2-19. COMPARISON OF LGTI HAPS EMISSIONS WITH AP-42 GAS TURBINE EMISSION FACTORS[41]

HAP	AVERAGE EMISSION FACTOR FOR GAS TURBINE FIRING NATURAL GAS ($lb/10^6$ Btu)	AVERAGE EMISSION FACTOR FOR GAS TURBINE FIRING SYNGAS ($lb/10^6$ Btu)
Acetaldehyde	9.12E-05	1.8E-06
Acrolein	5.49E-06	-
Benzene	1.03E-05	4.4E-06
Ethylbenzene	4.10E-05	< 2.0E-06
Formaldehyde	7.13E-04	1.7E-05
Naphthalene	1.46E-06	0.4E-06
PAH	2.23E-06	-
Toluene	1.42E-04	3.3E-06
Xylene	4.59E-05	< 2.0E-06

TABLE 2-20. PRODUCT SYNGAS ANALYSIS FOR POLK AND WABASH RIVER PLANTS

SYNGAS CONSTITUENT	WABASH RIVER ANALYSIS, VOLUME %	POLK ANALYSIS, VOLUME %
Nitrogen	1.9	3.3
Argon	0.6	0.9
Carbon Dioxide	15.8	14.4
Carbon Monoxide	45.3	42.7
Hydrogen	34.4	38.3
Methane	1.9	0.1
Water	-	0.3
Other	0.1	-
TOTAL	100	100

In TABLE 2-21, CO_2 emissions from the Polk and Wabash River IGCC plants are put into perspective by comparing them (on an energy output basis) with other coal-based technologies. While still substantially higher than gas-fired plants, IGCC's improved energy efficiency reduces CO_2 emissions relative to other coal-based plants. Repowering the Wabash River plant reduced CO_2 emissions by approximately 20% on a per kWh basis.[11] IGCC emissions can be further reduced by improving plant thermal efficiency (e.g., reducing plant heat rate). Possible ways (among others) to accomplish this are:

- Development of an effective high-temperature syngas cleaning system in which all contaminants are removed without significant gas cooling;
- Development of advanced gas turbines with higher inlet temperatures and higher pressure ratios.

TABLE 2-21. COMPARISON OF UNCONTROLLED CO_2 EMISSIONS FROM GASIFICATION-BASED AND COMBUSTION-BASED POWER GENERATION TECHNOLOGIES

POWER GENERATION TECHNOLOGY	HEAT RATE,[a] Btu/kWh	CO_2 EMISSIONS,[b] lb/kWh
Conventional Pulverized Coal Plant with FGD	9,800	2.00
Polk IGCC Plant	9,350	1.87
Pressurized Fluidized Bed Combustion Plant	8,700	1.81
Wabash River IGCC Plant	8,900	1.78
Natural Gas Combustion Turbine Plant	11,000	1.27
Advanced Gasification Fuel Cell Plant	6,000	1.20
Natural Gas Combined Cycle	7,500	0.86

[a] Net heat rate of plant based on higher heating value (HHV) of fuel. Includes all ancillary power requirements.
[b] Accounts for CO_2 emissions produced via fuel conversion within the power plant and emitted at the plant site. Generation rate depends on the fuel type (e.g., coal, petroleum coke) and the type of fuel conversion system.

2.2.6 Assessment of Emission Control Technologies for NOx, Mercury and CO_2

2.2.6.1 NOx Emissions Control

Although NOx emissions from operating IGCC power plants are quite low, stricter regulations may require control to levels as low as 3 ppm in the HRSG stack gas. The purpose of this section is to review both combustion-based and post-combustion NOx control methods.

2.2.6.1.1 Turbine NOx Control

Available combustion-based NO_x control options for syngas-fired turbines are more limited than those available for natural gas-fired turbines. The so-called Lean-Premix Technology,[i] which permits the latter to achieve emissions as low as 9 ppm (at 15% O_2), is not applicable to IGCC gas turbines. Differences between syngas and natural gas composition and combustion characteristics are the source of the problem.[43] Gasification-derived syngas differs from natural gas in terms of calorific value, gas composition, flammability characteristics, and contaminants. An oxygen-blown, entrained-flow 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 1000 Btu/ft^3 for natural gas. This yields a significant flow rate increase compared with natural gas (~14% more), resulting from the need to maintain a specified heat input to the combustor. Furthermore, whereas the combustible composition of natural gas is primarily methane (CH_4), the syngas combustible components are carbon monoxide (CO) and hydrogen (H_2), with an H_2/CO ratio generally ranging from 0.6 to 0.8.[9] When compared to natural gas, the H_2 component of syngas exhibits a higher flame speed and broader flammability limits. The latter means that the syngas should have a stable flame at leaner conditions than natural gas, while the former indicates that the kinetics (chemical reaction speed) of H_2 combustion are much quicker than that of natural gas. This very fast flame speed of the hydrogen component of the syngas prevents the use of the lean-premix technology. Finally, coal gasification-derived syngas will likely contain higher concentrations of H_2S than natural gas, which may impact post-combustion NOx control technologies.

The use of a diluent to lower flame temperature, such as nitrogen or steam, is currently the preferred method for minimizing NOx generation from a syngas-fired turbine. Nitrogen is usually available from the cryogenic air separation unit, so it can conveniently be employed in the IGCC process. This control method can reduce NOx emissions levels from syngas-fired turbines to approximately 15 ppm (at 15% O_2). GE is currently targeting development of combustors to reliably achieve below 10 ppm NOx with syngas, which would be comparable to the NOx emission levels achieved through use of the lean-premix technology on gas turbines firing natural gas.

2.2.6.1.2 Post-Combustion NOx Control

The only methods currently available to achieve single-digit NOx concentrations in the stack gas require treatment of the flue gas to reduce the NOx to nitrogen. Selective catalytic reduction (SCR) is a fully commercial technology that has been applied to natural gas-fired turbines to minimize NOx, while the SCONOX process is a newer technology that is being developed to compete with SCR.

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[i] The lean-premix combustion process goes by a variety of names, including the Dry Low-NOx (DLN) process of General Electric, the Dry-Low Emissions (DLE) process of Rolls-Royce/Allison, and the SoLoNOx process of CATERPILLAR/Solar Turbines. Most of the commercially available systems are guaranteed to reduce NOx emissions to the 9 to 25 ppm range, depending on the manufacturer, the particular turbine model, and the application. A few manufacturers have guaranteed NOx emissions in the range of 9 ppm (e.g., GE). As the NOx emission level is lowered, some manufacturers have experienced problems with combustion vibration (dynamic pressure oscillations) and premature combustor deterioration. These technologies may result in an increase in CO and UHC by as much as 50 ppm.

Selective Catalytic Reduction (SCR)

SCR technology is generally considered the best available add-on NOx control for stationary combustion turbines that fire natural gas or fuel oil and, therefore, it is the most likely candidate for use in IGCC. SCR selectively reduces NOx emissions by injecting ammonia (NH_3) into the exhaust gas upstream of a catalyst. The NOx reacts with NH_3 and O_2 to form N_2 and H_2O, primarily according to the following equations:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$$

The catalyst's active surface is usually a noble metal, base metal (titanium or vanadium) oxide, or a zeolite-based material. Metal-based catalysts are typically applied as a coating over a metal or ceramic substrate, while zeolite catalysts are typically a homogeneous material that forms both the active surface and the substrate. The geometric configuration of the catalyst body is designed for maximum surface area and minimum obstruction of the flue gas flow path to maximize conversion efficiency and minimize back-pressure on the turbine. The most common configuration is a monolith, "honeycomb" design. An important factor that affects the performance of SCR is the operating temperature. Base-metal catalysts have an operating temperature window for clean fuel applications of approximately 400° to 800° F. The upper range of this temperature window can be increased using a zeolite catalyst to a maximum of 1,100° F. Due to the required operating temperature range for conventional SCR catalyst (600-750^{o}F), integration into the HRSG normally requires splitting of the HP evaporator (or boiler) section to accommodate the SCR catalyst bed and ammonia injection equipment.

An ammonia injection grid, designed to disperse the ammonia uniformly throughout the exhaust flow, is located upstream of the catalyst body. In a typical 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 5 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.

The ammonia-to-NO_x (NH_3:NO_x) ratio can be varied to achieve the desired level of NO_x reduction. It takes one mole of ammonia to reduce one mole of NO, and two moles of ammonia to reduce one mole of NO_2. Higher NH_3:NO_x ratios achieve higher NO_x emission reductions, but can result in increased unreacted ammonia being emitted into the atmosphere. This unreacted ammonia is known as ammonia slip. SCR catalysts degrade over time, which changes the quantity of NH_3 slip. Catalyst life will typically range from 3 to 10 years depending on the specific application. IGCC applications, with exhaust gas that is relatively free of contaminants, should yield a significantly longer catalyst lifetime than for a conventional coal-fired application.

Installation of SCR in an ICCC's HRSG, for what amounts to NOx polishing, requires consideration of the environmental impacts of ammonia slip. Ammonia slip is typically limited to less than 5 ppm in most SCR applications, but may be higher when the NOx level entering the catalyst bed is so very low. Such operation may require more excess ammonia than is typically used. While the tradeoffs between NOx and ammonia are not simple, from a qualitative perspective they are both acutely toxic; both contribute to the formation of fine particles of ammonium sulfate ($(NH_4)_2SO_4$) and ammonium nitrate (NH_4NO_3), acid deposition, eutrophication, and nitrogen enrichment of terrestrial soils; and both may ultimately be converted to nitrous oxide (N_2O), a powerful greenhouse gas. In addition, NOx (as NO_2) is a chronic toxin and an essential precursor to the formation of tropospheric ozone. The contribution of NOx or ammonia emissions from a single facility to any of these environmental problems is primarily determined by existing levels of NOx and ammonia in the area and the concentration of other pollutants in the atmosphere that react with the NO_x or NH_3. In terms of the range of influence or potential for long-range transport, nitric acid or organic nitrate (peroxyacetylnitrate, PAN) derived from NOx emissions, and ammonia have similar lifetimes in the atmosphere and, thus, similar potential for long-range transport. PAN and ammonium sulfate, however, are longer-lived and can spread the influence of both NOx and ammonia over a wide area.

Disposal of salt deposits and spent catalyst are also potential environmental issues. SCR catalysts typically contain heavy metal oxides, such as vanadium and/or titanium, thus creating a potential human health and environmental risk related to the handling and disposal of spent catalyst. Vanadium pentoxide, the most commonly used SCR catalyst, is on the EPA list of Extremely Hazardous Materials. The quantity of waste associated with SCR is quite large, although the actual amount of active material in the catalyst bed is relatively small. This requires the use of licensed transport and disposal facilities and compliance with RCRA. It is conceivable that facilities in some states may face added costs by having to dispose of these materials out of state due to a lack of licensed disposal facilities that will handle these materials. This responsibility may not be born by the plant since catalyst suppliers often collect and recycle spent catalyst as part of their contract.

An additional environmental issue related to SCR is that of occupational safety. Permit applicants need to be aware of ammonia safety concerns as an issue, which in itself may mitigate the benefit of using SCR to control NOx. The EPA characterizes ammonia as an extremely hazardous substance. It is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose or throat. Vapors may form an explosive mixture with air. Nonetheless, ammonia is a commonly used material. OSHA regulations require that employees of facilities where ammonia is used be trained in safe use of ammonia (under 29 CRF 1910.120). Facilities that handle over 10,000 pounds of anhydrous ammonia or more than 20,000 pounds of ammonia in an aqueous solution of 20 percent ammonia or greater must prepare a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases. The costs for training, meeting appropriate Federal, State and local safety codes, and the preparation and approval of the RMP and Emergency Preparedness Plan must be taken into consideration when assessing the technology. All this said, ammonia is a broadly used in a variety of applications, especially agriculture, and with appropriate preparation can be handled and used safely.

There are two major operational impacts resulting from the installation of an SCR system in the HRSG of an IGCC plant. First, the pressure loss across the SCR catalyst bed increases the turbine back-pressure, thereby decreasing gas turbine output by approximately one-half percent. The ammonia storage and transfer equipment consumes some additional power. Second, unwanted chemical reactions may negatively impact and interfere with the operation of the plant. Although IGCC fuel gas cleanup equipment efficiently removes more than 95% of the sulfur constituent (as H_2S), the residual sulfur in the syngas passes to the combustion turbine where it is oxidized to both SO_2 and SO_3. Ammonia slip from the SCR process can react with the SO_3 to form ammonia salts, such as ammonium sulfate or ammonia bisulfate. Ammonium bisulfate is a very corrosive and sticky material that can plug downstream heat transfer equipment, reducing performance or even causing plant shutdown. The additional back-pressure caused by the fouling will also reduce the gas turbine output. The ammonium sulfate, if not deposited with any bisulfate formed, is discharged to the atmosphere as fine particulate matter ($PM_{2.5}$), since no particulate control is typically installed downstream of the HRSG. This problematic behavior represents another important difference between a natural gas-fired plant and the IGCC power plant.

In order to prevent ammonia salt formation, either the ammonia slip or the SO_3 must be greatly minimized. Since some ammonia slip is inevitable, IGCC suppliers recommend that a maximum sulfur oxide level of 2 ppm be allowed to enter the HRSG with the fuel gas. Installation of a zinc oxide or activated carbon polishing reactor, upstream of the gas turbine, is one method to control the residual SO_2 (with the added benefit of some added mercury control). Unfortunately, this further increases parasitic power consumption and significantly raises the cost of the SCR installation.

SCONOx^{TM} Oxidation/Absorption Cycle[44]

This post-combustion catalytic system removes both NOx and CO from the gas turbine exhaust through the use of a platinum catalyst. Unlike SCR, it does not require the use of ammonia injection, and the active NOx removal reagent is potassium carbonate. The exhaust gases from a gas turbine flow into the reactor and react with potassium carbonate that is impregnated onto the platinum catalyst surface. The CO is oxidized to CO_2 by the platinum catalyst. NO is oxidized to NO_2 and then reacts with the potassium carbonate coating on the catalyst to form potassium nitrites and nitrates at the surface of the catalyst. These chemical reactions, shown below, are referred to as the "Oxidation/Absorption Cycle."

$$CO + 1/2\ O_2 \rightarrow CO_2$$
$$NO + 1/2\ O_2 \rightarrow NO_2$$
$$CH_2O + O_2 \rightarrow CO_2 + H_2O$$
$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3$$

When the carbonate becomes saturated with NOx, it must be regenerated. The effective operating temperature range is 280^o to 750^o F, with 500^o to 700^o F being the optimum range for NOx removal. The optimum temperature range is approximately the same as that of SCR.

The regeneration of the catalyst is accomplished by passing a dilute hydrogen reducing gas across the surface of the catalyst in the absence of oxygen. The hydrogen reacts with nitrites and nitrates to form water and elemental nitrogen. CO_2 in the regeneration gas reacts with potassium nitrites and nitrates to reform potassium carbonate. This cycle is referred to as the "regeneration cycle," as shown below.

$$KNO_2 + KNO_3 + 4H_2 + CO_2 \rightarrow K_2CO_3 + 4H_2O + N_2$$

Water vapor and elemental nitrogen are exhausted up the stack instead of NOx, and potassium carbonate is once again present on the surface of the catalyst, allowing the oxidation/absorption cycle to begin again.

Because the regeneration cycle must take place in an oxygen-free environment, the catalyst undergoing regeneration must be isolated from exhaust gases. This is accomplished using a set of louvers, one upstream of the section being regenerated and one downstream. During the regeneration cycle, these louvers close and a valve opens allowing regeneration gas into the section. A typical SCONOx^{TM} system has five to fifteen sections of catalyst. At any given time eighty percent of these sections are in the oxidation/absorption cycle, and twenty percent are in the regeneration cycle. Because the same numbers of sections are always in the regeneration cycle, the production of regeneration gas proceeds at a constant rate. A regeneration cycle typically is set to last for three to five minutes, so each section is in the oxidation/absorption cycle for nine to fifteen minutes.

Several critical issues associated with the use of this technology are:

- Catalyst is very sensitive to sulfur, including trace quantities that are typically found in IGCC exhaust gas;
- Reliability of moving parts over time is an operational and maintenance concern;
- Use of hydrogen for regeneration could be a serious safety concern, since it is hard to contain;
- Scale-up issues for large gas turbines;
- SCONOx™ has about twice the pressure drop of SCR; and
- The initial capital cost is about three times the cost of SCR, although this may come down once there are more systems in operation.

In 1997, the EPA monitored the application of SCONOx™ on a natural gas-fired turbine at the Federal Cogeneration facility in Los Angeles, where it established a 3.5 ppm (at 15% oxygen on a 3-hour rolling average) standard for NOx. The SCONOx^{TM} control system has typically achieved average NOx emissions of approximately 2 ppmv. This resulted in being designated as having achieved a LAER (lowest achievable emission rate) at 3.5 ppmv, which set the standard for future control technology for similar facilities per Section 173(a)(2) of the Clean Air Act. The South Coast Air Quality Management District designated SCONOx^{TM} as the Best Available Control Technology (BACT) for natural gas-fired turbine engines. A further improvement in reductions was certified in 1998, when the EPA found that SCONOx^{TM} had achieved a LAER of 2.5 ppmv.

2.2.6.2 Mercury Emissions Control

This report's review of the environmental performance of coal-fired IGCC technology indicates that vapor-phase mercury emissions may need to be further reduced to comply with future EPA mercury regulations. The purpose of this section is to examine both commercial and near-commercial methods for integrating such control into a typical IGCC system.

Two basic approaches for control are: 1) turbine exhaust gas treatment and 2) syngas treatment. While vapor-phase mercury can potentially be removed from the flue gas exiting the gas turbine/heat recovery steam generator (HRSG), it is more effective in IGCC systems to remove Hg from the syngas prior to combustion. This may already occur, to some extent, via the acid gas scrubbing system, but more data are required to verify this. Syngas removal has the advantage of elevated mercury concentration (although still very low), lower mass flow rates, and higher pressure than the stack gas. Disadvantages include operation in a reducing environment (more corrosive environment), possible operation at a high temperature if part of a hot gas cleanup system, possible presence of other contaminants, and greater safety issues related to premature combustion. A review of syngas control options revealed that several commercially available technologies, using sorbents such as activated carbon, have already been successfully applied to gasification applications, as well as other gaseous hydrocarbon streams. These are discussed below.

UOP Corporation has a commercial product that is in wide use in natural gas/NGL and LNG (liquified natural gas) plants called HgSIV. It is a molecular sieve (MS) that removes very low levels of elemental mercury from natural gas or syngas via a regenerable adsorption process. It uses a 2-bed thermal-swing MS adsorption system. The gas flows through one adsorbent bed to adsorb Hg, while the temperature of the other bed rises to desorb Hg. After regeneration, the beds are reversed. Hg removal is needed in NGL or LNG plants to protect the braised aluminum heat exchangers in the cryogenic section from mercury attack. HgSIV has been successfully operated in about 30 plants for almost 10 years.[45]

Eastman Chemical Company has developed and successfully applied activated carbon-based mercury control technology at their Chemicals from Coal Facility located in Kingsport, Tennessee.[46] Eastman has been operating ChevronTexaco gasifiers at this facility since 1983 to provide syngas for the production of acetyl chemicals. They utilize Calgon's HGR-P sulfur-impregnated, pelleted activated carbon beds with the following performance characteristics:

- Operating conditions: Approximately 30^{o} C (86^{o} F) and 900 psi
- Gas contact time in bed: Approximately 20 seconds (based on total packed volume)
- Removal efficiency: Ranges from 90 to 95%
- Carbon lifetime: 12 to 18 months based on a buildup in pressure drop, a buildup in water in the bed, or a buildup of other contaminants.

Eastman Chemical operates their carbon beds ahead of the sulfur recovery unit. The use of dual beds, (i.e., two beds in series) should be capable of achieving carbon removal levels of greater than 99%.

Sorbents for Mercury Capture

A number of companies produce activated carbons that have been used commercially for mercury removal from combustion flue gas, with most of the applications being for incinerator stack gas. Norit's DARCO FGD is a lignite-derived activated carbon manufactured specifically for the removal of heavy metals and other contaminants typically found in incinerator flue gas.[47] It has been proven in numerous full-scale facilities to be highly effective for the removal of gaseous mercury, dioxins (PCDD) and furans (PCDF). Its open pore structure and fine particle size permit rapid adsorption, which is critical for high performance in gas streams where contact times are short. It is a free flowing powdered carbon with minimal caking tendencies that makes it appropriate for automatic wet or dry injection systems. It has a very high ignition temperature, which permits safe operation at the elevated temperatures inherent in incinerator flue gas. This material has also been successfully used in a number of R&D programs focused on evaluation of mercury removal from coal-fired power plant stack gas.

UOP has developed a new line of HgSIV zeolite-based desiccants, with enhanced mercury removal capability. Zeolites are crystalline structures not unlike sponges on a molecular scale. They have a solid framework defining large internal cavities where molecules can be adsorbed. These cavities are interconnected by pore openings through which molecules can pass. Because of their crystalline nature, the pores and cavities are all precisely the same size, and depending on the size of the openings, they can adsorb molecules readily, slowly, or not at all, thus functioning as molecular sieves -- adsorbing molecules of certain sizes while rejecting larger ones. UOP indicates that their HgSIV products have proven to be reliable in removing mercury from natural gas, natural gas liquids, and other process streams such as ethylene. They can be used to dry and remove mercury to less than 0.01 micrograms per normal cubic meter.[48]

Calgon Carbon's family of FluePac^{TM} powdered activated carbons is specially manufactured for use in flue gas treatment.[49] Their high effective surface area and large pore volume make them extremely effective in removing common contaminants, including mercury, dioxins, furans, and VOC's. Typical applications include municipal waste combustors, hazardous waste combustors, hospital waste incinerators, coal-fired power plants, cement kilns, and industrial boilers. These coal-derived powdered activated carbons have a high minimum Iodine Number (measurement of available surface area) with up to twice the amount of high-energy adsorption sites compared to other adsorbent carbons. With proper dosing levels, Calgon claims that over 95 percent reduction in mercury/dioxin is achievable. This sorbent has been used by Eastman Chemical Company in their gasification facility to control mercury.

Use of these sorbents for mercury control may also provide the added side benefit of residual H_2S removal, which could improve IGCC integration with add-on NOx control technologies such as SCR. However, their effectiveness for this purpose has to be verified.

Cost of Mercury Control Based on Activated Carbon Adsorption

Parsons Corporation, in a project sponsored by NETL, recently estimated costs for applying a packed-bed carbon adsorption system to an IGCC plant.[50] The cost format was based on the methodology used in the EPA Mercury Study Report to Congress,[51] while the cost estimate (capital and O&M) was based on Parsons in-house data and experience. This study assumes treatment of approximately 400,000 lb/hr of syngas, an eighteen-month carbon replacement cycle and 90% reduction of mercury emissions.

The purchased equipment costs were scaled from Parson's in-house data for pressure vessels used in a syngas application. The installation cost, which includes foundations and piping, was estimated to be 50% of the purchased equipment costs. The total capital cost came to $834,350 or $3.34 per kilowatt.

O&M costs were based on factors for labor, material and overhead. Carbon costs were based on Calgon Carbon Corporation's list price for sulfur-impregnated carbon of $6.43/lb. Carbon costs were by far the largest O&M cost factor amounting to over 67% of the O&M costs. Disposal costs of $500/ton were estimated assuming hazardous waste disposal. The total O&M came to $320,683. Based on a 15% capital recovery factor, the total cost per year would be $445,836 or 0.254 $/MWh (or mills/kWh). Therefore, this study estimates the cost of mercury reduction to be approximately $3,412 per pound of mercury removed.

2.2.6.3 Carbon Dioxide Control Methods

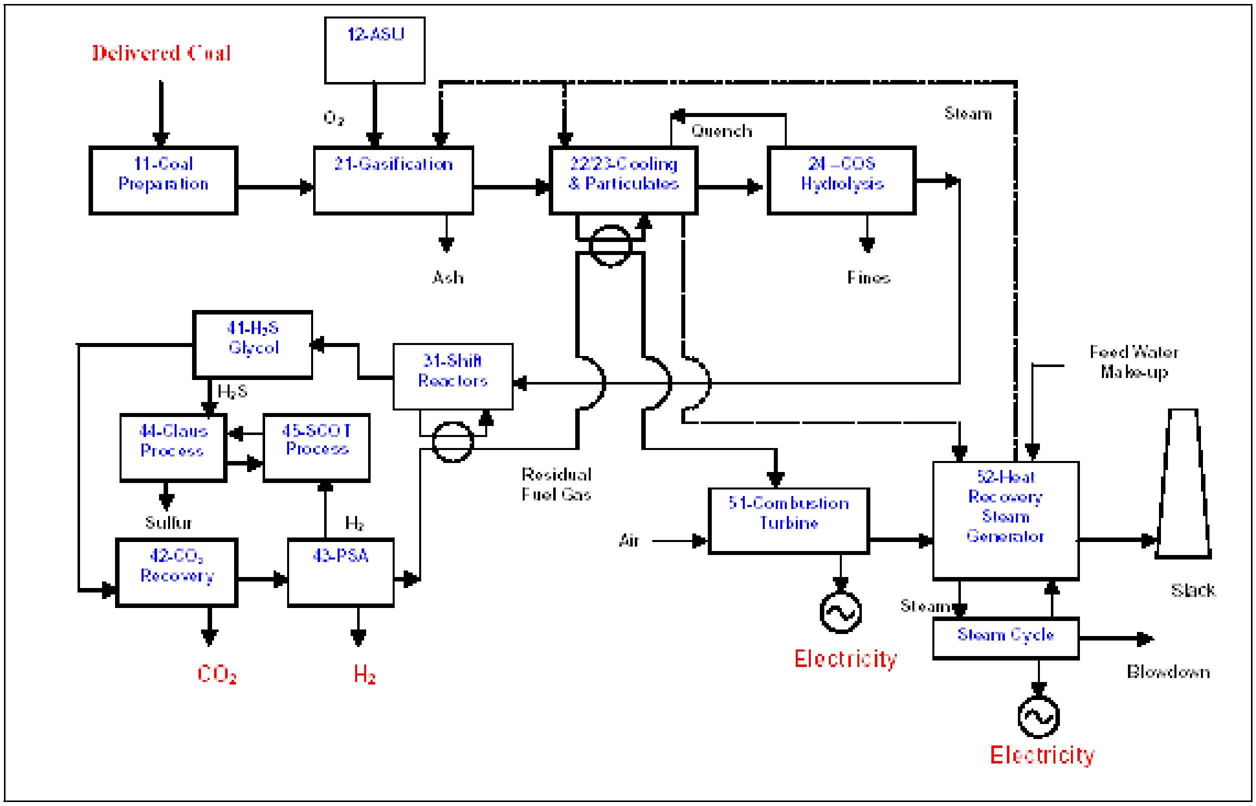
IGCC has two major operating advantages that can be exploited to capture CO_2 more efficiently than is possible with combustion technology. First, the syngas, as previously shown in TABLE 2-20, has a very high CO_2 concentration, which can be made much higher by further converting the CO to CO_2 prior to combustion. Second, IGCC gasifiers typically operate under relatively high pressure (~400 psig in the Wabash plant). Both of these conditions make recovery of the CO_2 from the syngas much easier than capture from the flue gas.

Recovery of CO_2 from the syngas requires that *shift reactors* be added the treatment train. In these commercially available reactors, the following exothermic reaction occurs:

$$CO(g) + H_2O(g) \rightarrow CO_2(g) + H_2(g) + Heat$$

The concentration of CO_2 in the shifted gas should be about 40%. This high concentration, combined with the high pressure of the syngas, yields a high CO_2 partial pressure that permits use of physical absorption rather than the more energy-intensive chemical absorption required at lower partial pressures. FIGURE 2-6 shows a simplified schematic of oxygen-blown IGCC with the added equipment.[52] This configuration also includes an optional pressure-swing absorber to remove some of the hydrogen as a valuable by-product.

FIGURE 2-6. SCHEMATIC OF OXYGEN-BLOWN IGCC WITH CO_2 RECOVERY



Maximum conversion of CO to CO_2 can be achieved by utilizing both high (~350° C) and low (~200° C) temperature shift reactor in series.[53] Since the high temperature reactor is upstream of the acid gas removal system, a sufur-resistant catalyst is utilized (e.g., $Co/MoO_4/Al_2O_3$ catalyst). This shift catalyst also promotes COS hydrolysis, thereby eliminating the need for a separate COS converter. After the first reactor, the syngas is cooled and fed to the second shift reactor, after which it is further cooled and sent to a physical absorption process, such as Rectisol™, Purisol™ or Selexol™, to remove both H_2S and CO_2. The CO_2 stream from the regenerator is dried and compressed to approximately 1,600 psi, which results in liquid CO_2 for transport to a utilization site (e.g., enhanced oil recovery) or a sequestration site (e.g., abandoned oil well). The fuel to the combustion turbine consists largely of hydrogen and water vapor, the carbon having been removed.

A DOE/NETL-EPRI engineering assessment examined the effect of CO_2 removal on the performance and cost-of-electricity (COE) for pulverized coal, natural gas-fired combined cycle, and IGCC plants. This study showed a decided advantage for the IGCC plants.[54] FIGURE 2-7 confirms data previously presented in TABLE 2-21, which shows that coal technologies produce substantially more uncontrolled CO_2 (about twice as much) than natural gas technologies. CO_2 scrubbing captures about 90% of the uncontrolled CO_2 for all technologies, but scrubbing coal-fired plants results in capturing about twice as much CO_2 as from natural gas fired power plants. While IGCC CO_2 emissions to the atmosphere are drastically cut, they are still about twice that of a gas-fired combined cycle plant.

FIGURE 2-8 shows that IGCC CO_2 capture results in the lowest parasitic energy consumption, almost one fourth that of NGCC, because IGCC produces a more concentrated CO_2 stream at higher pressure. The lower energy consumption for CO_2 capture means that less additional generation capacity is needed to make up for the parasitic loss. Since additional CO_2 will likely be generated by any added fossil-based capacity, IGCC minimizes this effect.

The capital cost associated with applying CO_2 capture is shown in FIGURE 2-9. IGCC technology was found to incur the smallest increase in capital cost, primarily due to more effective CO_2 scrubbing. As shown, CO_2 capture increases capital cost of NGCC by 90%, while IGCC and PC increase by only 30% and 73%, respectively. While the advantage of cost-effective syngas CO_2 removal helps minimize the impact on the IGCC's capital cost expenditure, the NGCC technology still maintains a substantially lower capital cost than IGCC.

Finally, the study looked at the cost of electricity of all technologies with CO_2 capture. Since coal prices are projected to remain stable for the next 20 years, coal cost was assumed fixed, but natural gas price was assumed to be variable. With volatile gas prices, IGCC is the most stable and cost-effective CO_2 capture option, based on gas prices above $\$4/10^6$ Btu. This is shown in FIGURE 2-10.

Another recent engineering study, performed for ChevronTexaco by Jacob's Engineering in cooperation with General Electric, evaluated the design concept of incorporating CO_2 capture capability into a new IGCC facility without requiring it to be used.[55] They developed a process flow scheme that can operate without CO_2 removal, but that could be readily upgraded through some minor modifications that they estimated would cost between \$5 and \$10 million. The evaluation is based on the logic that IGCC units built today may not have a commercial need to capture CO_2, unless there was the potential for using enhanced oil recovery (EOR) through CO_2 injection or a future regulatory requirement for sequestration in an in a suitable repository (e.g., an aquifer).

FIGURE 2-7. COMPARISON OF POWER PLANT CO_2 GENERATION, CAPTURE AND EMISSIONS

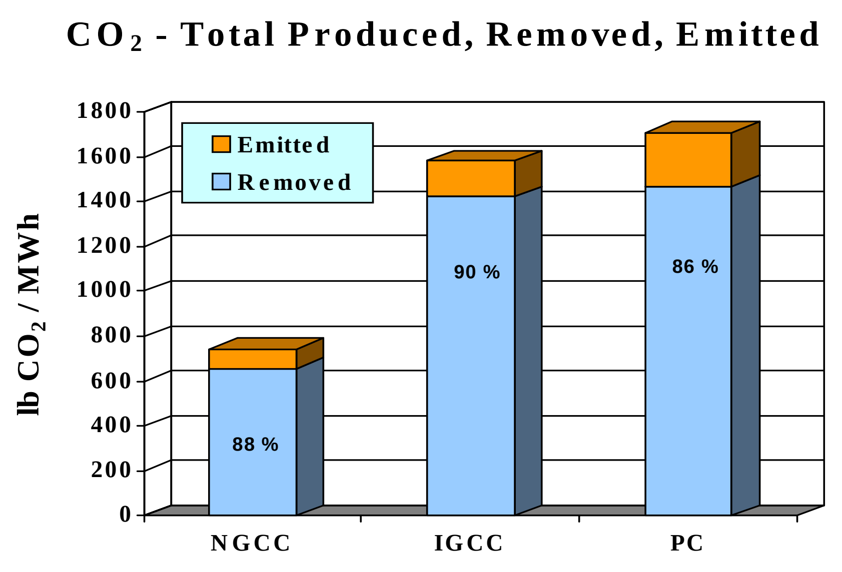


FIGURE 2-8. COMPARISON OF POWER PLANT PARASITIC POWER LOSS

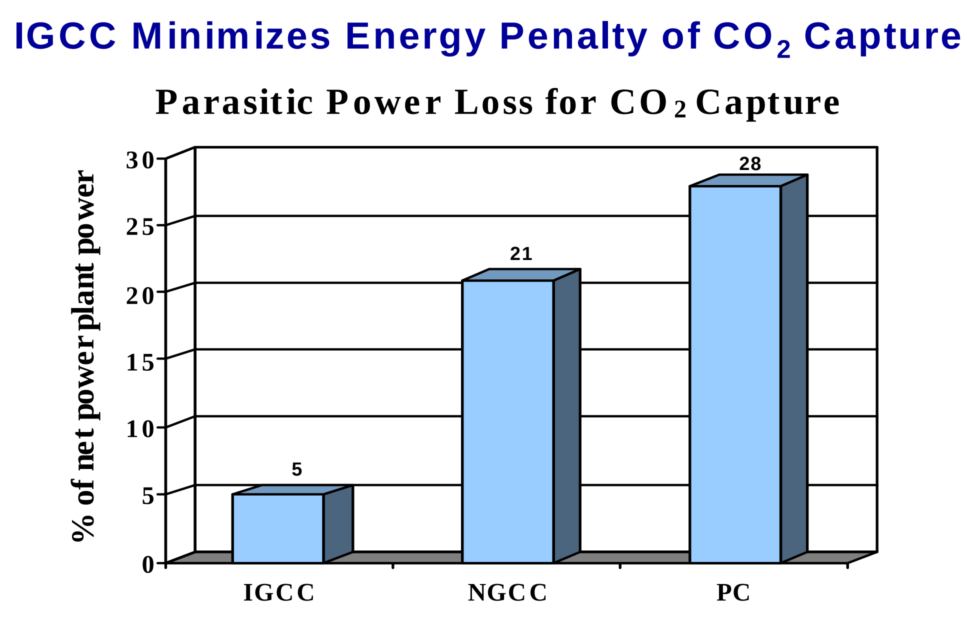
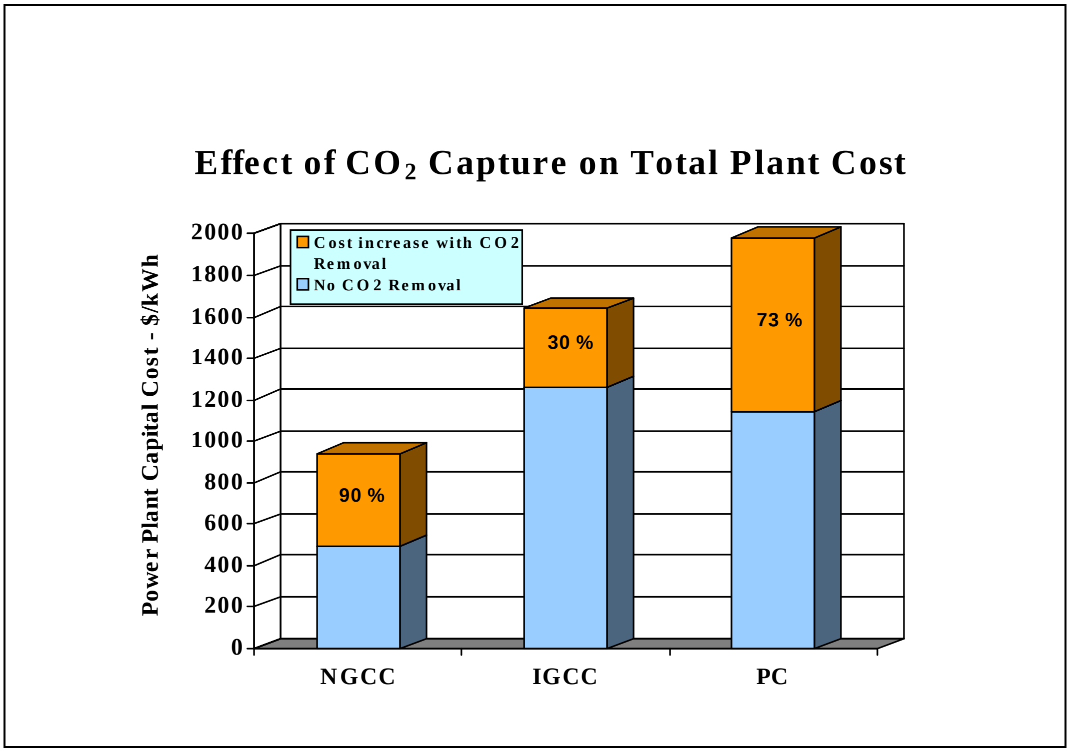
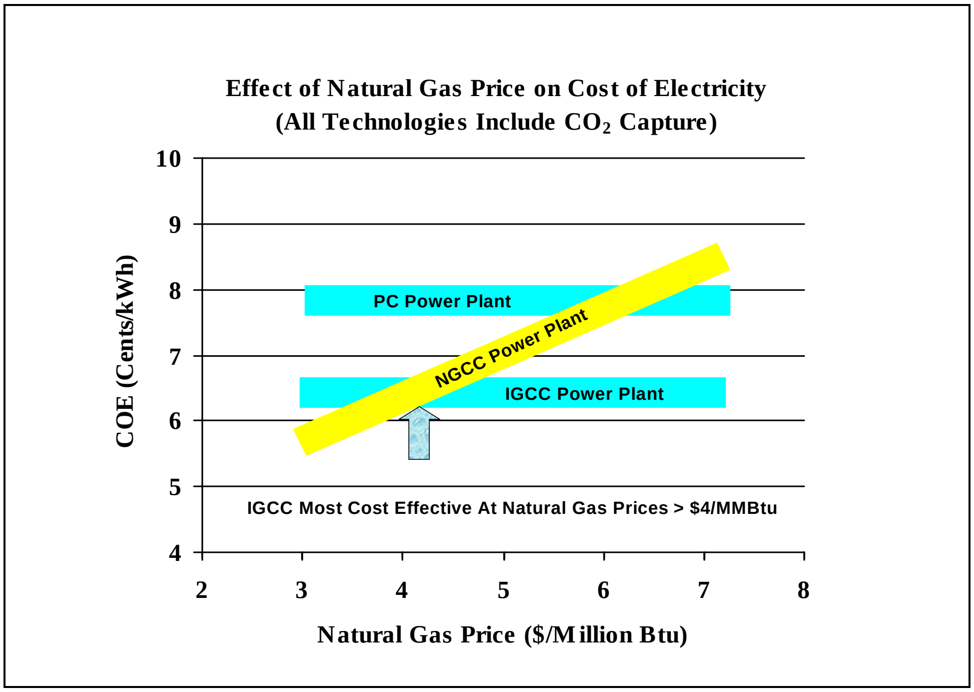


FIGURE 2-9. COMPARISON OF THE CAPITAL COST IMPACT OF CO_2 CAPTURE



Basis: Plants operating at 65% capacity factor, 20 year life and 2000 $.

FIGURE 2-10. EFFECT OF NATURAL GAS PRICE ON COST OF CO_2 CAPTURE



The plant design uses ChevronTexaco Quench gasifiers followed by syngas shift reactors, physical absorption acid gas removal (e.g., Selexol), a sulfur recovery system, and a combined cycle unit consisting of two GE 9FA gas turbines, a HRSG, and a single steam turbine. A quench gasifier utilizes the heat of the gasification reaction to provide a very high level of water saturation that is ideal preparation for a shift reactor. Another important design feature, different from that shown in Figure 2-6, is the use of a Selexol™ system capable of removing either H_2S selectively, or both H_2S and CO_2. Jacob's estimated the capital cost for a 900 MWe IGCC system (excluding the add-on equipment needed for CO_2 recovery) to be $974/kW (mid-2001 $U.S.). After modification, such a unit would be capable of capturing 75% of the feed carbon as CO_2. The relatively low cost of this design appears to be, in part, due to economies of scale.

Some of the important results of this study are:

- The capture of 75% of the carbon in the coal results in a loss of efficiency of only two percent (41% to 39%) and a decrease in net output of only 3%, which is one-half the energy penalty in the NETL-EPRI study
- The cost for the equipment to capture CO_2 is estimated to be between $5 and $11/kW. There would also be additional costs associated with CO_2 compression, which largely depends on the specific sequestration/utilization application.
- The IGCC design demonstrates that the economic impact of CO_2 capture can be a lot less than previously thought. The flexibility to build and operate a conventional IGCC plant that can be converted later to CO_2 capture enhances the likelihood that power developers will seriously consider such plants.
- The plant design makes use of commercially proven equipment.

2.2.7 Comparison of the Environmental Performance of IGCC with Pulverized Coal and Fluidized Bed Power Plants

This section compares the environmental performance of an IGCC plant with a modern, conventional PC plant, an atmospheric, circulating fluidized bed power plant (AFBC), and a pressurized fluidized bed plant (PFBC). The modern PC plant incorporates advanced emission control technology in the form of wet, limetone flue gas desulfurization (FGD) for SO_2 control (95%+ removal), low-NOx burners and selective catalytic reduction (SCR) for high-efficiency NOx control, and an electrostatic precipitator (ESP) for particulate control. The AFBC technology utilizes in-bed SO_2 capture with a limestone sorbent (up to 95% removal), relatively low bed temperature (1400^o - 1700^o F) to minimize NOx formation, ammonia injection for further NOx reduction, and a fabric filter to control particulate to very low levels. The PFBC technology utilizes in-bed SO_2 capture with a limestone sorbent (up to 95% removal), relatively low bed temperature (1400^o - 1700^o F) to minimize NOx formation, and a fabric filter to control particulate to very low levels. Section 1.4 compares the design characteristics and expected performance of these technologies.

TABLE 2-22 and FIGURE 2-11 compare the major air emissions from the PC, AFBC and PFBC plants with that of the IGCC plant. Stringent emission requirements favor IGCC over PC and fluidized-bed combustion steam power plants.

TABLE 2-22. COMPARISON OF AIR EMISSIONS FROM GASIFICATION-BASED AND COMBUSTION-BASED POWER GENERATION TECHNOLOGIES

CRITERIA POLLUTANTS, IONIC SPECIES AND CARBON DIOXIDE	CONVENTIONAL PC-FIRED PLANT WITH ADVANCED POLLUTION CONTROLS[a]	AFBC[b] (WITH SNCR)	PFBC[c] (WITHOUT SNCR)	IGCC PLANT[d] (WITHOUT SCR)	COMBUSTION-BASED REGULATORY LIMIT
SO_2, lb/10^6 Btu (lb/MWh)	0.2 (2.0)	0.4 (3.9)	0.2 (1.8)	0.08 (0.7)	1.2 (N/A)
NOx, lb/10^6 Btu (lb/MWh)	< 0.15 (< 1.6)	0.09 (1.0)	0.2 – 0.3 (1.7 – 2.6)	0.09 (0.8)	0.5 (N/A) (after 1978) 0.15 (1.6) (after 1997)
PM10, lb/10^6 Btu (lb/MWh)	< 0.03 (< 0.3)	0.011 (0.12)	0.015 – 0.03 (0.13 – 0.26)	0.011 (0.10)	0.03 (N/A)
Chloride as HCl (lb/MWh)	0.01	0.71	0.65	0.007	None
Fluoride as HF (lb/MWh)	0.003	0.05	0.05	0.0004	None
Cyanide as HCN (lb/MWh)	0.0003	0.005	0.005	0.00005	None
Ammonia (lb/MWh)	0	0.001	0.001	0.004	None
CO_2, lb/kWh	2.0	1.92	1.76	1.76	None

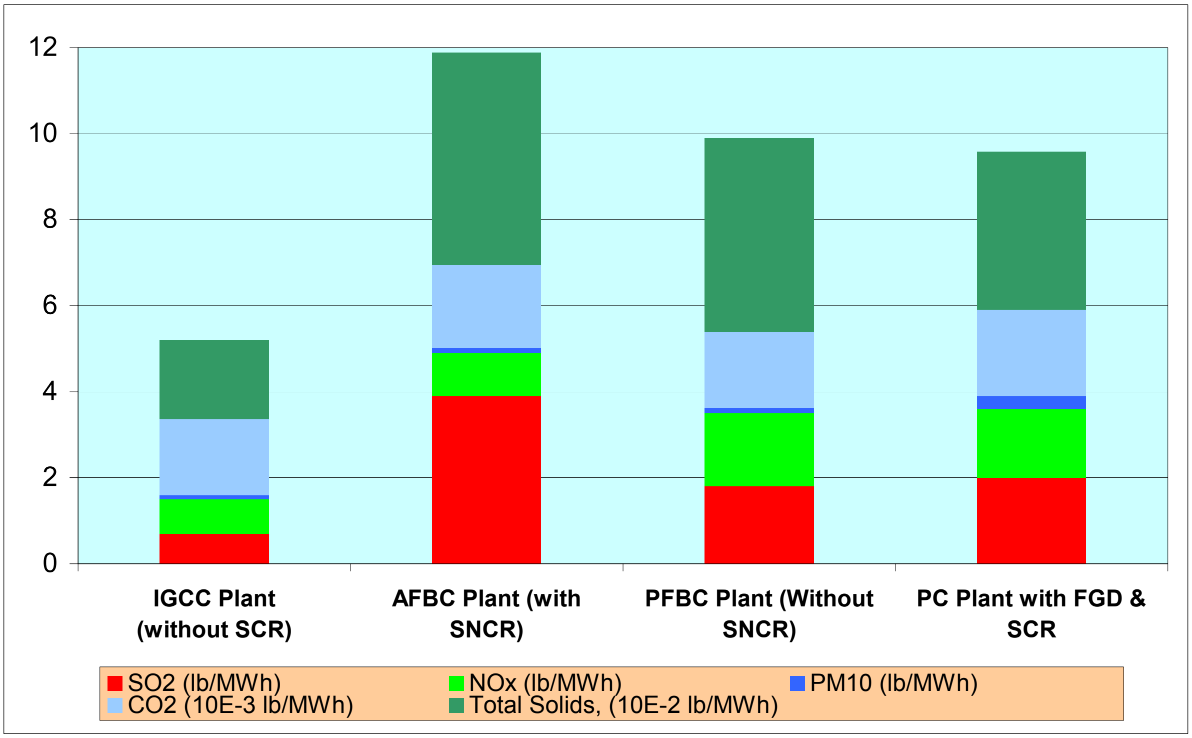
[a] PC with SCR, ESP, FGD. Heat rate equals 9,750 Btu/kWh (35% efficiency). SO_2 emissions based on 2.5% sulfur, 12,000 Btu/lb coal, and 95% reduction via wet limestone FGD. NOx emissions are based on control with SCR and uncontrolled emissions of 0.45 lb/10^6Btu. PM10 emissions are based on actual ESP experience. Ionic species emissions based on average of DOE-sponsored toxic emissions tests at three power plants: Bailly (NIPSCO), Coal Creek (Cooperative Power), and Yates (Georgia Power). CO_2 emissions are based on coal with 67% total carbon content.

[b] AFBC plant. Heat rate equals 9,400 Btu/kWh (36% efficiency). Performance source is Final Environmental Impact Statement for The JEA Circulating Fluidized Bed Combustor Project, DOE/EIS-0289, June 2000. SO_2 emissions are based on 2.5% sulfur, 12,000 Btu/lb coal, and 90% reduction via in-bed limestone. NOx emissions are based on low-NOx combustion and control with SNCR. PM_{10} emissions are based on Nucla demonstration plant experience. Ionic species emissions are not presented since they weren't measured in Nucla demo plant. CO_2 emissions are based on coal with 67% total carbon content.

[c] PFBC plant. Heat rate equals 8,600 Btu/kWh (40% efficiency). Performance source is Tidd PFBC Demonstration Project - A DOE Assessment, DOE/NETL-2001/1159, August 2001. SO_2 emissions are based on 2.5% sulfur, 12,000 Btu/lb coal, and 95% reduction via in-bed limestone. NOx emissions are based on low-NOx combustion. PM_{10} emissions are based on Tidd demonstration plant experience. Ionic species emissions based on DOE-sponsored toxic emissions tests at the Tidd PFBC demonstration plant. CO_2 emissions are based on coal with 67% total carbon content.

[d] IGCC plant. Heat rate equals 8,600 Btu/kWh (40% efficiency). SO_2 emissions based on 2.5% sulfur, 12,000 Btu/lb coal, and 98% reduction via acid gas removal system. NOx emissions are based on turbine combustor that achieves 15 ppm NOx (15% O2, dry). CO_2 emissions are based on coal with 67% total carbon content. PM10 emissions based on 1998 Wabash River plant experience. All other emissions based on measured performance of LGTI plant.[18]

FIGURE 2-11. COMPARISON OF EMISSIONS FROM GASIFICATION-BASED AND COMBUSTION-BASED POWER GENERATION TECHNOLOGIES



2.2.7.1 Acid Gas and Halogen Emissions

The emissions of sulfur dioxide and nitrogen oxides, gases linked to acid rain, are a small fraction of allowable limits. SO_2 originates from the sulfur in the fuel, so utilizing a coal that is low in sulfur content will minimize overall emissions without added control. However, this is not always possible and almost always involves an increase in fuel cost and does little to make efficient use of existing coal resources, some of which are high in sulfur. Sulfur emissions from a PC plant can only be reduced by treatment of either the fuel prior to combustion or the flue gas. Flue gas desulfurization (FGD) applied to a PC plant reduces the overall SO_2 emissions by up to 98%. This technique is especially useful for retrofitting an existing plant, but it is expensive and reduces the overall plant efficiency. AFBC's and PFBC's operate at a much lower temperature than PC systems, and this permits a more integrated approach to sulfur control by using in-bed desulfurization with a calcium-based sorbent. This is a practical option only at temperatures ranging between 1400^{o} to 1700º F. In-bed desulfurization produces about the same reduction in SO_2 emissions as FGD, but the capital cost is much lower.

The approach to sulfur control in an IGCC plant is fundamentally different than that used with other power plants. Emission control strategy usually is focused on the fuel gas, which is pressurized (typically 300 to 500 psi) and has a substantially lower volumetric flow rate than combustion flue gas, which flows near atmospheric pressure. Furthermore, the sulfur in the fuel gas is in a reduced form (mostly H_2S) which can be removed by a variety of commercial processes such as the Selexol® process previously mentioned. H_2S and COS are removed and the concentrated acid gas is then processed for elemental sulfur recovery. Up to 99% of the sulfur can be removed.

As discussed in Section 2.2.1.3, NO_x emissions originate mainly from two sources, thermal NO_x and fuel NOx. PC technology gives the highest level of uncontrolled NO_x emissions because of the very high temperatures involved. However, SCR technology can be used to reduce NOx emissions by up to 90%. With fluidized bed combustion, the quantity of NO_x is significantly reduced because of the much lower operating temperature. However, care is required in the design of the fluid bed system to minimize the N_2O content of the NO_x, which is a much more potent greenhouse gas. In IGCC, the fuel gas produced is virtually free of fuel-bound nitrogen. NOx formation is primarily the result of thermal NOx. Diluting the syngas in an IGCC to achieve lower combustion temperatures should be able to achieve emissions as low as 15 ppm (0.09 lb/10^6 Btu or 0.8 lb/MWh) in gas turbines firing low-Btu syngas.

2.2.7.2 Particulate Emissions

All of the technologies make use of highly efficient particulate control equipment to limit PM_{10} emissions. Conventional particulate control devices also effectively control non-volatile trace elements. Since almost all of the fly ash is removed from the flue gas, trace organic and inorganic species that selectively condense on fine particles are also removed to become constituents of the sold waste. However, some of the semi-volatile and volatile species may not be removed in the particulate collection equipment.

2.2.7.3 Trace Metal Emissions

Section 2.2.3 identifies, characterizes, and discusses the partitioning of the trace metal constituents of coal. FIGURE 2-12, FIGURE 2-13, and FIGURE 2-14 compare the emissions for 15 key trace metals. The following data sources were used:

- IGCC Plant – Based on field measurements of toxic emissions at LGTI’s 160 MWe gasification-combined cycle plant in Plaquemine, Louisiana. Quality assurance and quality control for all of the exit emissions data is considered very good, since the sampling and analytical protocols were employed at previous EPRI and DOE test sites. However, sampling and analytical protocols for internal streams are not considered adequate. A key limitation is that detailed data was only available for this plant. Similar information was not available for the Polk and Wabash River plants.

- PC Plant -- Based on average of DOE-sponsored toxic emissions tests[56] at three power plants: Northern Public Service of Indiana’s Bailly plant, Cooperative Power Associates’ Coal Creek plant, and Georgia Power’s Yates plant. Bailly units 7 & 8 (480 MWe) are wet-bottom, cyclone furnace designs that feed a common advanced wet FGD system, and use ESPs for particulate control. Coal Creek (506 MWe) is a dry-bottom, tangential-fired furnace design that uses an ESP for particulate control and a wet, lime-based FGD to treat 60% of the flue gas. Plant Yates (105 MWe) is a wet-bottom, tangential-fired furnace design that uses an ESP for particulate control and an advanced bubbling reactor-type FGD system. QA/QC for these tests was extensive. However, these tests, which showed quite a lot of data variability resulting from fuel variability and sampling/analytical precision limitations, demonstrated the difficulty involved in quantifying trace element emissions from coal-fired systems. The calculated emission factors ranged from one order-of-magnitude (Mn) to nearly four orders-of-magnitude (Se).

- AFBC Plant – no data were available, so the figures do not include AFBC data.

- PFBC Plant -- Based on DOE-sponsored toxic emissions tests at the Tidd PFBC demonstration plant.[57] The boiler at Plant Tidd is a bubbling bed, PFBC rated at 70 MWe. A slurry of Pittsburgh No. 8 bituminous coal (3.4% sulfur) is fed to the PFBC unit along with dolomite sorbent to control SO_2 emissions. Particulate matter is controlled by primary and secondary cyclones in series with an ESP. Overall, QA/QC data associated with this program indicated that measurement data were acceptable and could be used with confidence. The QA/QC results indicated that the quality control mechanisms were effective in ensuring measurement data reliability within the expected limits of sampling and analytical error. However, sampling and analytical protocols have improved since the early 1990's, when these tests were performed. Some metals proved difficult relative to data accuracy, namely antimony, calcium, nickel, potassium, selenium, sodium, and selenium. A key limitation is that detailed data was only available for this one plant.

This is a difficult comparison to make based on the limited data available, the inherent limitations of the sampling and analytical protocols, and the different testing organizations involved. However, generally, the results of this comparison indicate that trace metal emissions are quite low for all technologies, and that IGCC emissions appear to be comparable to other well-controlled coal-fueled power plants.

FIGURE 2-12. TRACE METAL EMISSIONS COMPARISON FOR Sb, As, Ba, Be, and Cd

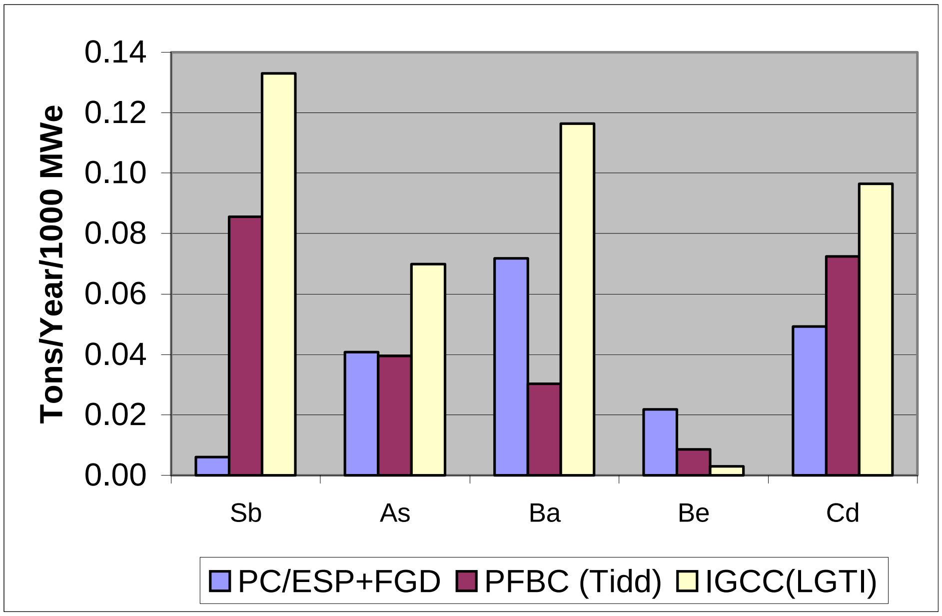


FIGURE 2-13. TRACE METAL EMISSIONS COMPARISON
FOR Co, Pb, Mo, and V

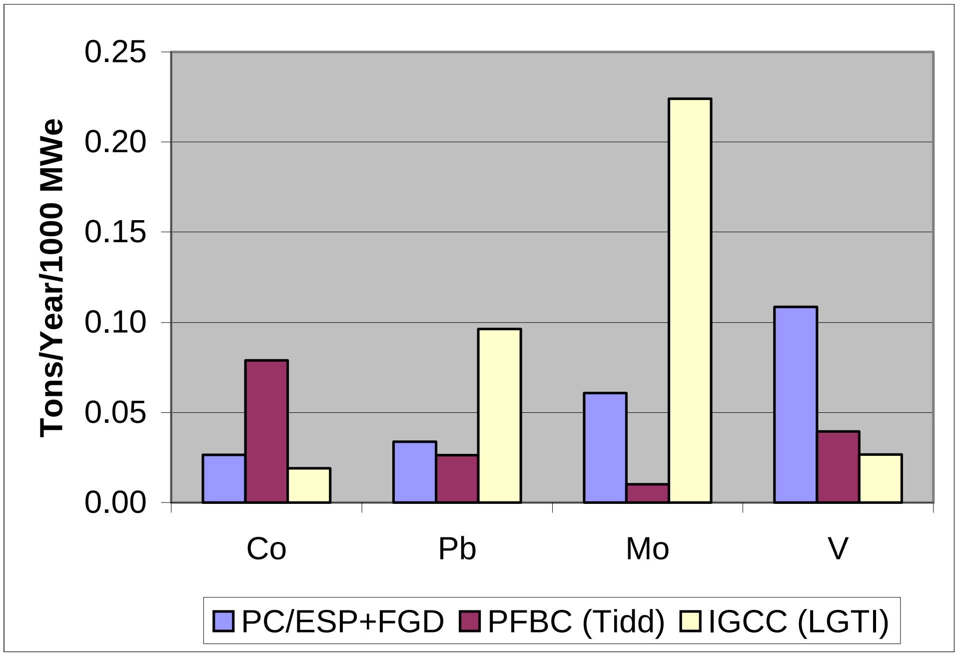
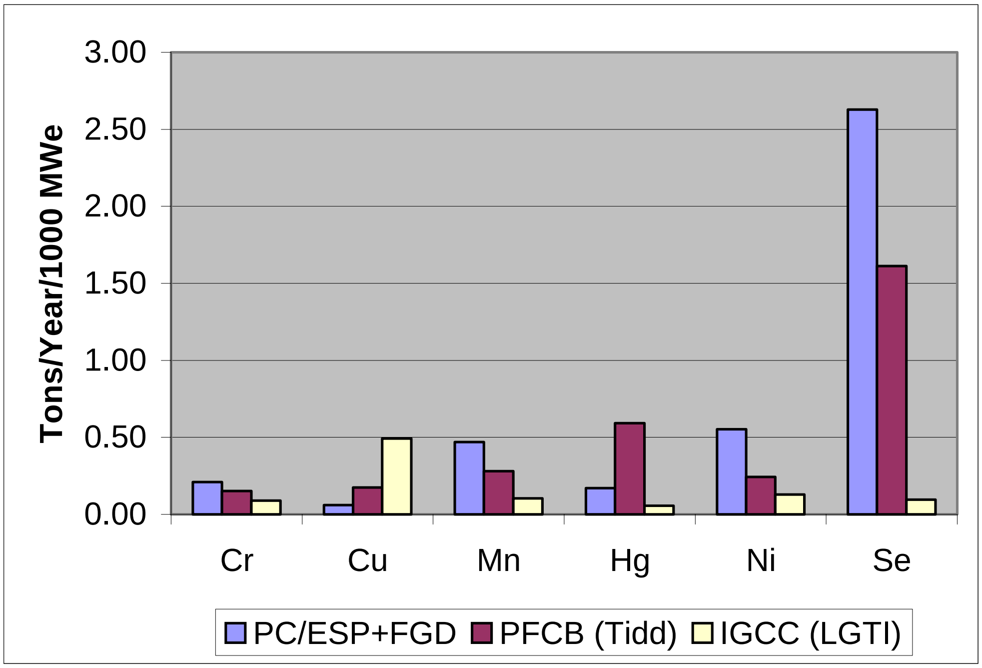


FIGURE 2-14. TRACE METAL EMISSIONS COMPARISON
FOR Cr, Cu, Mn, Hg, Ni, and Se



2.2.7.4 Trace Organic Emissions

In general, available data indicates that emissions of organic pollutants attributable to all coal-fueled power plants (aldehydes and ketones, VOCs, SVOCs, and PAHs, and chlorinated dioxins and furans) are very low. The low concentrations of most of the organic compounds found in the stacks are typically within an order of magnitude of the concentrations reported by the EPA for ambient air. TABLE 2-17, in Section 2.2.4, compares calculated emissions factors for some of the key species measured at LGTI with median emission factors derived from test data from 52 coal-fired units subjected to extensive emission tests by EPRI, DOE, the Northern States Power Company, and EPA.

2.3 Aqueous Effluents -- Identification, Characterization, and Control

This section presents detailed information covering aqueous effluents generated by IGCC plants. The physical and chemical characterization of these large-volume wastes, compared with the wastes generated by conventional, and more familiar, coal-fueled power plants, is an important issue in determining their relative safety and environmental impacts.

2.3.1 IGCC Water Consumption

Water is primarily required for the plant's steam cycle as boiler feedwater (BFW) and cooling water (CW), as well as for process operations, such as syngas emissions control. While the steam cycle in an IGCC plant typically produces less than 50% of the power plant's total power output, its water consumption is not proportionately lower (compared with a similarly sized conventional steam plant), since the gasification process itself can consume considerable quantities of BFW.[58] BFW consumers in IGCC systems, depending upon gasification technology and design, are:

- Instrument tap purges, pump seals, and intermittent flushes
- Direct steam injection to serve as a reactant and/or temperature moderator
- Saturator for NOx abatement (if steam is used as a diluent)
- Losses.

Because of these BFW needs, an IGCC plant may consume as much, or more, BFW than a conventional steam plant of comparable output, even if it is well designed, operated, and maintained.[58] On the other hand, the steam cycle CW requirement will be proportionately lower than the conventional steam plant due to its reduced share of the total plant power output. Also helping to reduce water consumption, coal gasification processes recover most of the water associated with the raw feed coal via condensation during syngas cleanup. This is not practical for combustion-based plants due to their low-pressure operation.

The other large water requirement, process water, is used to cool and clean the syngas to remove fly ash, halogens and trace organic and inorganic components. The concentration level of specific contaminants depends upon the fuel characteristics and the type of gasifier employed in the design. The quantity of water required depends on the capacity of syngas treated, the degree of gas cooling required, and the contaminants to be removed.

Coal-fueled plants also often use wastewater to control the dust and bulk density of the solid waste. The net process water bleed stream is usually of higher quality than the cooling-water blowdown. In fact, some plants use process water effluent as part of the cooling-water makeup.[59]

IGCC plants normally consume between 6 to 9 gpm of water per MW of electricity generated, depending upon the specific design.[4] In contrast, a PC plant, utilizing a wet limestone desulfurization process for SO_2 control, consumes about 10 to 11 gpm of water per MW of electricity generation.[4]

2.3.2 Aqueous Effluents

Based on the water requirements described above, coal gasification plants have two principal water effluent streams that are similar to those in direct-fired power plants. The first is wastewater from the steam cycle, including blowdowns from the boiler feedwater purification system and the cooling tower (if direct cooling is not used). The amount of this wastewater effluent depends on the hardness of the raw water and the power generated by the steam cycle. These effluents contain salts and minerals that have been concentrated from the raw feedwater. Gasification processes, with the exception of moving-bed gasifiers, such as Lurgi and British Gas/Lurgi, purify and recycle raw process streams, and the net discharge process water is normally only a blowdown.

The second aqueous effluent is process water blowdown. These streams are typically high in dissolved solids and gases including trace metals, trace organics, and the following commonly found ionic species: chloride, fluoride, sulfide, formate, nitrogen species, cyanide, thiocyanate, and bicarbonate.[60] As discussed in Section 2.2.2, almost half of the chlorides and all of the fluorides in the syngas should end up in the blowdown. Under the reducing conditions that exist in a gasifier, ammonium (NH_4^+) and ammonia (NH_3^0) are likely to dominate the nitrogen-containing aqueous species found in both untreated and treated process water, which differs from a direct-fired power plant whose oxidizing environment virtually ensures that the dominant species is the NO_3^- ion.

Blowdown streams are typically recycled to the coal feed preparation area, to the scrubber after entrained solids have been removed, to a zero discharge water system, or to a wastewater treatment system. However, recycling of water has its limitations, as dissolved salts accumulate to levels incompatible with the process or its metallurgy. Make-up water is added as process water is blown down to wastewater treatment. Zero-discharge process water systems have no wastewater discharges, however, these systems must address disposal of salts resulting from brine evaporation. Purification removes most of the organic compounds, before the water is recycled.

Finally, as with all coal-fueled plants, a secondary effluent stream is run-off from the coal and slag storage areas and the process area. TECO Energy, the owner/operator of the Polk plant indicates that control of this effluent can involve significant effort and cost.[58]

2.3.3 Wastewater Treatment

While IGCC wastewater control technology varies significantly,[61,62] essentially all the necessary control technologies are commercially available and have found wide use in various industries, such as chemical, pulp and paper, oil, and steel. The more complex the gasification process, the more complex is the wastewater-processing scheme. On this basis, the moving-bed technologies (Lurgi and British Gas/Lurgi) typically require the most complex wastewater-processing scheme, while the entrained-flow gasifiers (Dow, Shell, and ChevronTexaco) require a relatively simple processing scheme. In either case, wastewater-processing facilities have been developed and are currently in operation. Extensive data have demonstrated the satisfactory performance of these systems at the South Africa Coal, Oil and Gas Corporation (SASOL),[59] the Cool Water IGCC, the LGTI project,[11] and the Polk and Wabash River plants. Some of these facilities utilize a zero water effluent design, as opposed to the blowdown approach mentioned above. For example, the Cool Water IGCC system utilized a simple evaporation pond to accomplish zero discharge.

One method of treatment for process water offers an additional opportunity to recover sulfur. Process water taken directly from high temperature and pressure systems can be "flashed" in a vessel at low or negative pressure to release dissolved gases. The flash gas is routed to the sulfur removal unit with the raw synthesis gas, and the water is either recycled to the system or it is blown down to a conventional wastewater treatment unit before discharge. Gas condensate, also known as sour water, may also be steam-stripped to remove ammonia, carbon dioxide, and hydrogen sulfide. The stripper overhead can be routed to the sulfur recovery unit or incinerated, subject to permit limitations for NOx and SO_2 emissions. The sour water stripper recovers water suitable for recycling to the process as make-up. A portion of the recovered water from the sour water stripper may be discharged to a conventional wastewater treatment system.

At the Wabash River plant, process wastewater is steam stripped to remove dissolved gases before recycling to slurry preparation or being discharged. An ammonia stripper is used to remove ammonia and remaining trace components. Water leaving the treatment system is purified sufficiently to allow reuse or discharge within permit limits. Holding tanks were also constructed for discharges that are not within acceptable limits.

Polk's zero-discharge water treatment system reflects the current state-of-the-art. The process water blowdown stream goes to a vapor compression concentrator followed by crystallization of the brine into a salt consisting mostly of ammonium chloride. The clean condensate from this system is recycled to the process. The size of the blowdown stream which must be treated in this manner is determined by one of two factors: 1) process water balance and distribution – is the water consumed by the process (the gasifier) more or less than the water coming in with the coal, purges, etc., and 2) salt (chloride) build-up in the process water loop. This buildup, which also sets the blowdown rate for wet scrubbing systems in conventional direct-fired plants, is almost entirely a function of the chloride in the coal. The plant also operates an ammonia stripper to purge the system of cyanides and ammonia that are produced in the gasifier. So, although the plant has no process water discharge, this comes at a price of operating several treatment systems.[58]

2.3.4 IGCC Operating Experience and Plant Data

Detailed analyses have been conducted on process wastewater discharged at the Wabash River IGCC power plant. Results were reported for metals, cyanide, ammonia, and water quality (e.g., pH), but excluded sulfides, other anions, and organic compounds. Streams included were cooling tower blowdown; gasification plant process waste water; regeneration waste water from the demineralizer in the power block; rainwater collected in both the gasification and the power blocks; equipment purges (blowdowns) and water wash-downs during maintenance preparation procedures; and un-recycled condensed water from the process cooling water was not tested. Results are presented in TABLE 2-23.

TABLE 2-23. WABASH RIVER PROCESS WASTE WATER DISCHARGE[63]

PARAMETER/ CONSTITUENT	UNIT	PERMIT LEVEL MONTHLY AVERAGE	PERMIT LEVEL DAILY MAXIMUM	1997 MONTHLY AVERAGE	1998 MONTHLY AVERAGE	1999 MONTHLY AVERAGE
Ammonia (as Nitrogen)	mg/l	27.14	54.29	3.93	6.56	8.8
Arsenic	mg/l	0.018	0.043	0.0077	0.0199[a]	<0.01
Cadmium	mg/l	0.010	0.025	<0.0038	<0.008	<0.01
Chromium	mg/l	3.47	8.07	<0.006	<0.0108	<0.0167
Hexavalent Chromium	mg/l	0.014	0.032	<0.01	<0.0120	<0.01
Copper	mg/l	0.040	0.093	<0.01	<0.0145	0.0185
Cyanide	mg/l	0.019	0.044	0.107[a]	0.2798[a]	0.1438[a]
Lead	mg/l	0.260	0.606	<0.08	<0.08	<0.08
Mercury	mg/l	0.0005	0.001	<0.005	<0.0005	<0.0006
Nickel	mg/l	2.91	6.78	<0.02	<0.0236	<0.1140
Selenium	mg/l	0.017	0.040	0.0714[a]	0.230[a]	0.1380[a]
Zinc	mg/l	0.241	0.560	0.05	0.0414	0.1363
pH	mg/l	6.0 to 9.0	6.0 to 9.0	7.99	8.4	7.5

[a] Originally out of permit compliance, but later corrected

Process water from the Wabash facility originally demonstrated out of compliance levels for arsenic, cyanide and selenium. While not included in the table, daily maximums routinely exceeded permit levels for cyanide and selenium and occasionally for arsenic. However, installation of a wastewater mechanical vapor recompression (MVR) system in 2001, like the system described earlier for the Polk plant, has apparently solved this problem. This treatment method strips and dehydrates (to a salt) the majority of the contaminants in a selected process wastewater stream with beneficial water re-use of the condensed vapor.[39]

Similar tests were conducted on the treated wastewater from the LGTI IGCC plant. Results are presented in TABLE 2-24 for many of the same analytes listed in TABLE 2-23. The major differences between LGTI results and those at Wabash deal with lead and cyanide. Both are an order of magnitude higher at LGTI. The Wabash facility, however, is more representative of current state-of-the-art performance of wastewater treatment equipment. The LGTI plant also has experienced elevated cyanide levels in their wastewater discharge. Total average cyanide levels were measured to be 1.5 mg/l, with a 95% confidence interval of 0.3 to 2.7 mg/l. Average ammonia content (as nitrogen) was measured to be 7.3 mg/l in the treated process wastewater, which corroborates the levels measured at the Wabash River plant.

TABLE 2-24. LGTI RIVER PROCESS WASTE WATER DISCHARGE ANALYTES – AMMONIA, CYANIDE, METALS, WATER QUALITY[63]

ANALYTE	UNITS	AVERAGE	95% CONFIDENCE LEVEL
Ammonia (as Nitrogen)	mg/l	7.3	3.6
Arsenic	mg/l	0.0038	0.0024
Berylium	mg/l	0.0006	0.0013
Cadmium	mg/l	0.005	0.0024
Chloride	mg/l	0.88	0.15
Chromium	mg/l	0.0087	0.003
Hexavalent Chromium	mg/l	-	-
Copper	mg/l	0.015	0.0044
Cyanide	mg/l	1.5	1.2
Lead	mg/l	0.33	0.25
Manganese	mg/l	0.0024	0.0034
Mercury	mg/l	<0.00003	-
Nickel	mg/l	0.022	0.042
Selenium	mg/l	0.032	0.02
Zinc	mg/l	-	-
pH	mg/l	8.75	-
Chemical Oxygen Demand	mg/l	53	3.9

Organic analytes were also measured in the treated wastewater discharge with results indicating very low concentrations of aldehydes, volatile organic compounds, and semi-volatile compounds.[18] TABLE 2-25 provides a partial listing of the reported results. Note that these results will differ depending on the gasifier type, fuel, and water treatment methods employed in an IGCC plant.

TABLE 2-25. LGTI RIVER PROCESS WASTE WATER DISCHARGE ANALYTES – ORGANIC COMPOUNDS[63]

ANALYTE	UNITS	AVERAGE	95% CONFIDENCE LEVEL
ALDEHYDES			
Acetaldehyde	mg/l	<0.01	Not Calculated
Acrolein	mg/l	<0.01	Not Calculated
Benzaldehyde	mg/l	<0.01	Not Calculated
Formaldehyde	mg/l	<0.01	Not Calculated
VOLATILE ORGANIC COMPOUNDS			
1,1,1-Trichloroethane	µg/l	<0.87	Not Calculated
1,1-Dichloroethane	µg/l	<0.59	Not Calculated
Benzene	µg/l	<0.46	Not Calculated
Carbon disulfide	µg/l	<0.49	Not Calculated
Chlorobenzene	µg/l	<0.32	Not Calculated
Vinyl acetate	µg/l	<0.64	Not Calculated
SEMI-VOLATILE COMPOUNDS			
1,2,4 -Trichlorobenzene	µg/l	<0.53	Not Calculated
1,2-Dichlorobenzene	µg/l	<0.64	Not Calculated
2-Fluorobiphenyl	µg/l	61.2	15
Anthracene	µg/l	<0.70	Not Calculated
Benz(a)pyrene	µg/l	<0.70	Not Calculated
Benz(a)anthracene	µg/l	<0.77	Not Calculated
Pyrene	µg/l	11	5.6

2.3.5 Comparison of the Environmental Performance of IGCC with Pulverized Coal and Fluidized Bed Power Plants

The water required to operate an IGCC plant is approximately one-half to two-thirds that needed to operate a PC plant with FGD or an FBC plant. Approximate estimates are shown in TABLE 2-26. An IGCC plant generally produces fewer water effluents than the PC and FBC plants. The amount of process water blowdown is about the same for these plants. However, the steam cycle in IGCC power plants yields much lower amounts of wastewater blowdown since less than 50% of the total power generated comes from the steam cycle.

TABLE 2-26. WATER CONSUMPTION ESTIMATE –IGCC VERSUS PC AND FBC PLANTS[1]

	CONVENTIONAL PC-FIRED PLANT WITH ADVANCED POLLUTION CONTROLS	FBC PLANT	IGCC PLANT
Water Consumption, gallons/MWh	600 – 660	570 - 625	360 – 540

2.4 Solid Wastes and By-products -- Identification, Characterization, and Control

Power plants that combust or gasify solid fossil fuels generate large quantities of solid residues, principally ash, slag and desulfurization/sulfur byproducts. The quantities generated depend upon the ash and sulfur content of the solid fuel consumed. Plant operators commonly add or leave 20–30% water in the solid waste for dust control and optimum bulk density. If this water is part of the plant water effluents it may contain dissolved salts and minerals. Some plants, practicing zero water discharge, may add a small amount of solid salts and minerals (from water effluent evaporation) to the solid residues.

Coal-consuming electric utilities now produce over 100 million tons of coal utilization byproducts (CUBs) annually in the United States. Since 1966, the American Coal Ash Association (ACAA) has prepared annual surveys of CUB production and consumption by its members, which consist primarily of coal-burning electric utilities. These surveys generally cover the highest-volume CUBs: fly ash, bottom ash, boiler slag, and flue gas desulfurization (FGD) by-products. The data reported in the ACAA survey comes primarily from plants that use conventional PC boilers or cyclone boilers. TABLE 2-27 shows the production and use figures for the period between 1988 and 1999:

TABLE 2-27. CUB PRODUCTION AND USE, 1988-1999 (Million Short Tons)[64]

Year	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Production	83.7	87.5	86.8	88.8	82.0	88.5	89.0	92.2	101.8	105.1	107.7	107.1
Total Use	20.4	17.6	21.2	22.2	20.3	19.3	22.1	22.8	25.2	29.2	31.2	33.0
% Used	24.6	20.2	24.5	24.9	24.8	21.8	24.8	24.7	24.7	27.8	29.0	30.8

Review of the ACAA data shows that fly ash and bottom ash have consistently accounted for about 58% and 16%, respectively, of all CUBs produced since 1988. Boiler slag production has dropped consistently from about 6-7% in 1988-93 to about 2.5% in 1996-99. Conversely, desulfurization by-products have increased from about 16% in 1988 to about 22% in 1996-99. The total percent of CUBs utilized hovered below 25% prior to 1996, then increased steadily to over 30% in 1999. However, the remaining 70% are disposed of in ponds and landfills. Because constituents can subsequently leach from disposed wastes, there is potential for components to migrate to surface and ground waters. Groundwater contamination can occur when rainwater percolates through waste, separates (or leaches) hazardous constituents from wastes, and carries the hazardous constituents into the groundwater supply. Regulating land disposal is one of the most important strategies used by the EPA to protect groundwater.

A recent review of 46 power plant disposal sites from 12 states in the USA and abroad (offshore marine and India) demonstrated that a number of different waste disposal sites had one to several constituents exceed the EPA MCL, SMCL or WQC[j] limits by an order of magnitude or more in downgradient wells, ash pond effluents, aquatic receiving systems, etc.[65] U.S. sites with the greatest number (three or more) of excessive contaminants included two in Indiana; one in Arizona, Illinois, Massachusetts, South Carolina and Virginia; two in North Dakota and Tennessee, and four in Wisconsin.

Given the types of problems cited above, in the Spring of 2000, EPA reached its final decision on whether federal regulations should be established to set the minimum safeguards required at all power plant waste disposal sites (see Section 3.2.3). EPA initially decided that federal regulations were needed due to some evidence of contamination from power plant wastes, the significant inconsistencies in disposal standards between states, and different disposal methods being used (storage in landfills vs. strip mines), and strong public support for such standards. Instead of federal regulations, however, EPA determined that voluntary Subtitle D (non-hazardous) national standards would need to be developed for CUBs disposed in landfills or surface impoundments and used in filling surface or underground mines. They also determined that no additional regulations were warranted for CUBs that are used beneficially (other than for minefilling). In the regulatory determination, EPA supported increases in beneficial uses of CUBs, such as additives to cement and concrete, waste stabilization, and use in construction products.[k] Thus, the current state of regulations and the need to better protect the environment, as well as public sentiment, clearly favors power generation technologies that can demonstrate safe disposal or beneficial use of solid by-products.

2.4.1 Identification of Major IGCC Solid Byproducts

The largest solid waste/by-product streams produced by IGCC systems are coal ash (in various forms) and sulfur. The quantity of each is a direct function of the ash and sulfur contents of the feed fuel. Coal gasification processes can produce three types of ash: fly ash (including char or unreacted fuel), bottom ash, and slag. Most prominent coal gasification processes incorporated into IGCC, such as ChevronTexaco, E-Gas and BGL, are slagging systems that operate at high pressure. Therefore, most ash is in the form of slag, which can be likened to wet-bottom pulverized coal boiler slag. Non-slagging gasification produces a coarse bottom ash and fine fly ash. While the amount of fly ash varies according to the type of gasification process, it is often recycled to consume the char and minimize the quantity of fly ash produced. Therefore, the ratio of slag or bottom ash to fly ash is usually much higher in IGCC plants than it is in combustion-based plants. As an example, dry-bottom PC boilers produce about 20% bottom ash and 80% fly ash, whereas almost all of the ash is recovered as an inert vitreous slag in the Wabash River IGCC plant. This large difference in fly ash quantities is an advantage for coal gasification because fly ash is more difficult to handle, use, and dispose of than bottom ash or slag.

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[j] Maximum Contaminant Levels (MCL) and Secondary Maximum Contaminate Levels (SMCL) from the Safe Drinking Water Act, US EPA health advisories for children and adults, and the US EPA Water Quality Criteria (WQC). The WQC are used as water quality standards under the Clean Water Act for protection of aquatic life from acute and chronic levels of toxicity.

[k] More detailed background information and updated documents on USEPA's determination can be obtained from http://www.epa.gov/epaoswer/other/fossil/index.htm.

Slag is an inert glass-like material, and is a potentially marketable solid by-product. The physical form of slag is the result of gasifier operation at temperatures above the fusion, or melting temperature of the mineral matter. Under these conditions, non-volatile metals are bound together in molten form until the slag is cooled in a water bath at the bottom of the gasifier, or by natural heat loss at the bottom of an entrained bed gasifier. Volatile metals, such as mercury, are typically not recovered in the slag, but may be removed from the raw syngas during cleanup. Slag production is a function of ash content, so coal produces much more slag than petroleum coke. Regardless of the feed, as long as the operating temperature is above the fusion temperature of the ash, slag will be produced. Its physical structure is sensitive to changes in operating temperature and pressure, and physical examination of the slag's appearance can often be a good indicator of carbon conversion in the gasifier.

A second potential large-volume solid stream is sulfur (or sulfuric acid). It is typically produced as a high-purity liquid that is a highly marketable by-product. The volume of sulfur from a gasifier is significantly less than that of the gypsum produced by wet limestone-based FGD processes.

2.4.2 Chemical and Leachate Characterization

As mentioned above, the primary concern associated with disposal or utilization of CUBs, according to the EPA, is the potential for ground water contamination. Noteworthy toxic trace elements include arsenic, barium, cadmium, chromium, lead, mercury and selenium, the semi-volatile and volatile trace elements that preferentially deposit on fly ash (see Section 2.2.3). Without proper handling of CUBs (see Section 2.4.5), the potential hazard of ground water contamination has a multi-dimensional impact upon human and recreational health, croplands and aquatic life.[65] The public may consume contaminated water from wells, creating a human health hazard. Groundwater used to irrigate croplands may adversely affect sensitive crops and bioaccumulate through animal and plant products bought by the consumer. Runoff from irrigated fields can infiltrate into aquatic systems to become a threat to aquatic life and eventually again to human health.

The chemical characterization of fossil fuel CUBs is based on the total concentration of primary constituents of concern. Leachate characterization focuses on the results of leaching analyses of CUB materials. The primary analyses used are the Toxicity Characteristic Leaching Procedure (TCLP) and extraction procedure (EP) analysis. These were the analyses used to characterize waste leachate for use in the risk assessment portion of EPA's 1999 Report to Congress.[66] TCLP and EP toxicity are determined from laboratory procedures that simulate leaching from a disposal site under actual disposal conditions. These results can then be compared with regulatory standards to ascertain if a waste is hazardous or non-hazardous. Table 3-24, in Chapter 3, lists selected TCLP regulatory levels for various metals.

The TCLP is designed to simulate the leaching a waste will undergo if disposed of in a sanitary landfill. The extraction fluid employed is a function of the alkalinity of the solid phase of the waste. A sub-sample of a waste is extracted with the appropriate buffered acetic acid solution for a specified time period. The extract obtained from the TCLP (the "TCLP extract") is then analyzed to determine if any of the thresholds established for the 40 Toxicity Characteristic (TC) constituents (listed in Table 3-24) have been exceeded or if the treatment standards established for the constituents listed in 40 CFR §268.41 have been met for the Land Disposal Restrictions (LDR) program. If the TCLP extract contains any one of the TC constituents in an amount equal to or exceeding the concentrations specified in 40 CFR §261.24, the waste possesses the characteristic of toxicity and is deemed a hazardous waste. If the TCLP extract contains LDR constituents in an amount exceeding the concentrations specified in 40 CFR §268.41, the treatment standard for that waste has not been met, and further treatment is necessary prior to land disposal. However, as discussed in detail in Section 3.4, coal combustion wastes have generally been found to be non-hazardous. Applicable TCLP limits are RCRA standards or the Universal Treatment Standards (UTS) if the waste is classified as a “decharacterized” hazardous waste (see report Section 3.4.1.2).

TABLE 2-28 includes a comparison of IGCC solid waste material with boiler slag from PC plants, and TABLE 2-29 presents Wabash River gasifier slag[63] analysis, which includes analytes not presented in TABLE 2-28. The data obtained represents a variety of feedstock from lignite through petroleum coke. As indicated in the table, this material has been determined to be a non-leachable, non-hazardous material. As noted in the endnote to TABLE 2-28, barium was the only constituent that demonstrated leachable characteristics. The TCLP measurement for the total gasification slag is less than that measured for direct-combustion slag.

TABLE 2-30 presents detailed Wabash River IGCC coal slag analysis for specific metal constituents and organics, and compares the TCLP results with the RCRA and UTS standards identified in Section 3.4.1. The data indicates that the Wabash River slag has superior leachability characteristics. Data obtained from EPRI’s Cool Water Project tend to support the results obtained at the Wabash River Facility. These results are presented in TABLE 2-31.

In summary, the data presented in TABLE 2-29 and TABLE 2-30 (Wabash River Gasifier Slag) essentially agrees with the Cool Water results (TABLE 2-31) in the sense that both demonstrate that the gasifier slag is highly non-leachable. This behavior demonstrates that gasifier slag need not be treated any differently than coal combustion waste material that is classified as non-hazardous. Note, however, that the information presented in this section is limited to slagging-type gasifiers that consume coal or petroleum coke, and does not necessarily apply to plants that use other feedstocks, such as MSW, or non-slagging gasification processes. Also it needs to be pointed out that even if slag is classified as non-hazardous, local regulations may require disposal in a different class of landfill.

2.4.3 IGCC By-product Handling and Storage Stability

Laboratory analysis of slag from the Wabash River gasifier, as discussed previously, has been determined to be non-leachable, non-hazardous material with regard to inorganic species; since gasifier slag is in a vitrified state, it rarely fails the TCLP protocols for metals. Various feedstocks (lignite, subbituminous coal, bituminous coal, and petroleum coke) processed through the E-Gas™ gasification process have consistently demonstrated a non-hazardous classification based on TCLP (total) test results. Since slag is not a good substrate for binding organic compounds, it is usually found to be non-hazardous, exhibiting none of the characteristics of a hazardous waste. Consequently, it may be disposed of in a non-hazardous landfill, or sold as an ore for metals recovery. Slag’s hardness also makes it suitable as an abrasive or roadbed material, as well as an aggregate in concrete formulations. Further evidence of the long-term stability of this material is supported in an EPRI publication entitled *Long-Term Leaching Tests with Coal Gasification Slag*.[67]

TABLE 2-28. COMPARISON OF IGCC SLAG WITH SLAG FROM PC PLANTS

CONSTITUENTS		**PC UTILITY BOILER SLAG**		**GASIFICATION SLAG**
	Units	**Mean**	**Range**	
Carbon	wt %	--	--	0.21-15.67[11]
Moisture	wt %	--	--	0.11-30.17[11]
MAJOR COMPOSITION, CARBON FREE BASIS[74]				
SiO_2	wt %	--	45.9-70.0	42.5
Al_2O_3	wt %	--	15.9-28.3	29.0
Fe_2O_3	wt %	--	2.0-14.3	21.2
CaO	wt %	--	0.4-15.3	4.6
MgO	wt %	--	1.9-5.2	1.1
Na_2O	wt %	--	0.6-1.0	0.5
K_2O	wt %	--	0.1-0.3	1.8
TRACE ELEMENTS[68,72]				
Antimony	wt ppm	0.7	0.25 - 1.0	4.8 - <10
Arsenic	wt ppm	23	0.01- 254.0	6.39 - <10
Barium	wt ppm	698.7	6.19 - 1720	37.9 - 80
Beryllium	wt ppm	7	7.0 - 7.0	2.03 - 10.9
Boron	wt ppm	31.7	0.1 - 55.0	128 - 283
Cadmium	wt ppm	22.4	0.01 - 40.5	<50 - 0.76
Chromium	wt ppm	592.1	1.43 – 5981[b]	29.6 - 120[c]
Copper	wt ppm	52	1.37 - 156	12 - 54.1
Lead	wt ppm	34.6	0.40 - 120.0	8.19 - 97
Mercury	wt ppm	5.1	0.016 - 9.5	<0.08
Nickel	wt ppm	81.4	3.3 - 177	22.9 - 146.7
Selenium	wt ppm	4.8	0.010 - 14.0	<10.0
Silver	wt ppm	22.2	0.01 - 74.0	<1.0 - 3
Thallium	wt ppm	37.3	33.5 - 40.0	<0.4 - 16
Vanadium	wt ppm	146.1	75.0 - 320.0	25.1 - 156
Zinc	wt ppm	79.2	4.43 - 530	32.97 - 213
TCLP-Total	mg/L	1.28[d]	--	<0.682[e]

[a] Represents range of 1997, 1998, and 2001 average analysis.
[b] Identified as Cr^{+6}
[c] Chromium species not identified
[d] Sum of calculated average of all reported TCLP data.
[e] Values represent total leachate present in the analyzed sample. Barium was the only constituent that demonstrated leachable characteristics.

TABLE 2-29. WABASH RIVER GASIFIER SLAG CHEMICAL ANALYSIS

CONSTITUENT	UNITS	1997 AVERAGE ANALYSIS[11]	1998 AVERAGE ANALYSIS[11]	2001 AVERAGE ANALYSIS[39]
Carbon Content	wt%	15.67	7.91	0.21
Moisture Content	wt%	30.17	28.04	0.11
Group I Metals				
Antimony	mg/kg	<10.0	4.8	<4
Arsenic	mg/kg	<10.0	6.39	<4
Cadmium	mg/kg	<0.50	0.76	<2
Chromium[1]	mg/kg	29.6	120	290
Cobalt	g/kg	5.35	1.017	17 mg/kg
Manganese	mg/kg	33.3	67	1140
Mercury	mg/kg	<0.08	<0.01	0.03
Nickel	mg/kg	22.9	146.7	45
Selenium	mg/kg	<10.0	3.02	-
Group II Metals				
Aluminum	mg/kg	8,527	49,600	129,200
Barium	mg/kg	37.9	80	
Beryllium	mg/kg	2.03	10.9	40
Boron	mg/kg	128	283	1230
Calcium	mg/kg	9253	3246	187,100
Copper	mg/kg	12	54.1	50
Iron	mg/kg	17,267	105,333	20,000
Lead	mg/kg	8.19	97	34
Magnesium	mg/kg	1383	2783	33,000
Molybdenum	mg/kg	3.30	8.63	<20
Phosphorus	mg/LP	<39	2.0	
Potassium	mg/kg	1687	7623	5900
Silicon	mg/kg	1207	2000	162,300
Silver	mg/kg	<1.0	3.0	<2
Sodium	mg/kg	743	1037	25,200
Thallium	mg/kg	<0.4	16	<4
Vanadium	mg/kg	25.10	156	530
Zinc	mg/kg	32.97	213	3
TCLP (Total)	mg/l	<0.682[3]	<0.12[3]	-

Notes:
Chromium species not identified

mg/LP = milligrams/L as Phosphate

Values represent total leachate present in the analyzed sample. Barium was the only constituent that demonstrated leachable characteristics.

Based on 100% Coal feed (i.e. no waste or biomass in feed at this point). Independent lab report.

TABLE 2-30. WABASH RIVER COAL SLAG ANALYSIS LEACHABILITY RESULTS FOR TRACE METALS AND SELECT ORGANICS[39,69]

COMPONENT	RCRA LIMIT (mg/l)	UTS LIMIT (mg/l)	WABASH TCLP RESULTS
Antimony	--	2.1	< UTS
Arsenic	5.0	5.0	< UTS
Barium	100.0	7.6	< UTS
Beryllium	--	0.014	< UTS
Cadmium	1.0	0.19	< UTS
Chromium (Total)	5.0	0.86	< UTS
Cyanides (Total)	--	590 mg/g^3	< UTS
Mercury (non WW)	0.2	0.2	< UTS
Mercury (all other)	0.02	0.025	< RCRA
Nickel	--	5.0	< UTS*
Selenium	1.0	0.16	ND
Silver	5.0	0.3	< UTS
Thallium	--	0.078	ND
Vanadium	--	0.23	< UTS*
Zinc	--	5.3	< UTS
1,1,1,2-Tetrachloroethane		6.0	ND
1,1,2,2-Tetrachloroethane		6.0	ND
Tetrachloroethylene		6.0	ND
2,3,4,6-Tetrachlorophenol		7.4	ND
Acenaphthylene		3.4	ND
Acenaphthene		3.4	ND
Acetone		160	ND
Acetonitrile		38	ND
Acetophenone		9.7	ND
2-Acetylaminofluorene		140	ND
Acrolein		NA	ND
Aniline		14	ND
Anthracene		3.4	ND
Benzene		10	ND
Benz(a)anthracene		3.4	ND
Carbon Disulfide		4.8 mg/lTCLP	< UTS
Diethyl phthalate		28	< UTS
Fluoranthene		3.4	< UTS
Toluene		10.0	ND
Vinyl chloride		6.0	ND
1,1,1-Trichloroethane		6.0	ND
1,1,2-Trichloroethane		6.0	ND
Trichloroethylene		6.0	ND

Single pass and recycle (* single pass only)
WW – Wastewater
ND –Not Detected

TABLE 2-31. RCRA GASIFIER SLAG TEST RESULTS FOR COOL WATER GASIFICATION PLANT

RCRA EXTRACTION PROCEDURE COMPONENT	LEACHATE CONCENTRATION (mg/l)	RCRA LIMIT (mg/l)	DETECTION LIMIT (mg/l)
Arsenic	ND	5.0	(<0.06)
Barium	0.32	100.0	
Cadmium	ND	1.0	(<0.002)
Chromium[a]	ND	5.0	(<0.005)
Lead	ND	5.0	(<0.08)
Mercury	ND	0.2	(<0.0004)
Selenium	ND	1.0	(<0.08)
Silver	ND	5.0	(<0.002)

ND = Not Detected

[a] Chromium species not identified

In contrast with IGCC, the amount of solid waste discharged from direct coal combustion can increase by a factor of 2 to 3 with the use of throw-away desulfurization systems and high-sulfur coals. Coal gasification avoids this problem totally by recovering the fuel's sulfur as a pure, by-product that is readily marketable or as marketable sulfuric acid. Most direct coal combustion processes recover the sulfur as wet scrubber sludge or a dry or semi-dry spent sorbent, or gypsum. These forms of sulfur have significantly larger mass and volume than pure sulfur. Furthermore, they are more difficult to handle, market, and dispose of. If the gypsum is pure enough, it can be marketed for a variety of applications.

2.4.4 IGCC By-Product Handling Experience

2.4.4.1 Wabash River IGCC Plant[63]

Solid byproducts from the gasification process at the Wabash facility primarily consist of gasifier slag, entrained particulate in the syngas exiting the gasifier, and elemental sulfur. The slag from the gasifier is removed in a slag/water slurry and directed to a dewatering system. The dewatered slag is loaded into a truck or railcar for transport to market or a storage site. Clear water from the settled slurry is returned to the gasifier quench section and the slurry of fine particulates from the bottom of the settler is recycled to the slurry preparation area. The entrained particulates are collected from the cooled syngas and recycled to the gasifier. The slag produced is a black, glassy sand-like material, which is inert (e.g., passes TCLP). It generally contains 3-10% unconverted carbon and is marketed for asphalt, construction backfill, and landfill cover applications. Slag production is proportional to ash & flux content in feed.

The plant also produces 99.99% pure elemental sulfur that leaves plant in railcars. It is sold to a broker for agricultural applications, with over 40,000 tons to sold to-date.

2.4.4.2 Polk IGCC Plant[70]

Similar to the Wabash facility, solid wastes from the Polk facility consist primarily of gasifier slag and entrained particulates in the syngas. In the gasification system, coarse solids and some fine solids are flushed from the radiant cooler into a concrete slag-dewatering bin. Dewatered slag is then loaded into trucks for offsite use or temporary onsite storage. Water removed is pumped to the gasification process black water handling and processing system. The temporary storage units are designed to provide for up to five years of waste from the IGCC unit operating at 100-percent capacity. The slag storage area includes a storm water runoff collection basin and surrounding berm to prevent runoff from entering the area. Both the slag storage area and runoff collection basin are lined with a synthetic material or other materials with similar low permeability characteristics. The runoff basin is designed to contain runoff water volumes equivalent to 1.5 times the 25-year, 24-hour storm event. Water collected in the runoff basin is routed to the industrial wastewater treatment facility.

Particulate removal from the syngas occurs in both the conventional cold gas cleanup unit (CGCU) and a demonstration hot gas cleanup unit (HGCU). The solids from both gas cleanup units are collected as slurry. The slurry is collected and processed in the blackwater handling system. The solids from the slurry are stored at an onsite brine storage area, a lined landfill with a leachate collection system. In the HGCU, sodium bicarbonate is used as a sorbent for halogen removal. A secondary cyclone captures the injected sodium bicarbonate, which is also sent to the onsite brine storage area. A small amount of non-hazardous sorbent fines are collected in a high efficiency barrier filter and are sent offsite for disposal. Larger fines are sieved on screens, and fugitive fines are collected in filter bags and recycled to the catalyst supplier.

All blackwater from the gasification and syngas cleanup process is collected, processed, recycled to the extent possible, and contained within the process. The separated water is recycled for slurrying the coal feed.

A by-product handling issue reported at the Polk plant is related to the ash/char recycle stream. Polk’s ChevronTexaco gasifier generates char that is mixed with a very fine glassy frit, which requires separation prior to re-injection. The separated frit must be washed with clean water before it can be disposed of economically or used commercially. However, this process water must then be treated to remove contaminants, which increases water consumption and treating costs.[58]

Another byproduct issue at the Polk plant deals with slag disposal. Although the slag is classified as non-hazardous, local regulations require disposal in a different class of landfill. Polk must use a Class I landfill that is double-lined with leachate extraction/control versus a much less expensive and more available Class III landfill. The difference in disposal cost between the two is about $20/ton.

2.4.5 Assessment of Disposal Options for IGCC Solid By-Products

Solid material disposal requirements for IGCC are expected to be similar to those for direct combustion of coal. An extensive study was conducted in preparation for the 1999 EPA Report to Congress on Wastes from the Combustion of Fossil Fuels (EPA 530-R-99-010, March, 1999).[71] Recommendations resulting from the study concluded that disposal of CUBs should remain exempt from RCRA Subtitle C hazardous waste management practices. Additionally, EPA has determined that national Subtitle D regulations are warranted and are to be handled through the Land Disposal Restrictions (LDR) revised in August 2001. The LDR program identifies treatment standards for hazardous wastes and specifies requirements that generators, transporters, and owners or operators of treatment, storage, and disposal facilities (TSDFs) that manage restricted wastes destined for land disposal must meet (see Section 3.4.1).

2.4.5.1 Types of Waste Management and Control Measures[71]

Current management practices for solids typically consist of onsite surface impoundments and landfills. Because of the economic value of IGCC slag, the use of temporary surface impoundments is the more likely storage practice.

Surface impoundments are natural depressions, excavated ponds, or diked basins. UCCWs managed in surface impoundments typically are sluiced with water from the point of generation to the impoundment. The solid UCCWs gradually settle out and accumulate at the bottom of the impoundment. This process leaves a standing layer of relatively clear water at the surface, which is commonly termed “head.” The distance between the surface and the top edge of the impoundment is known as “freeboard” and indicates the remaining capacity of the impoundment. The amount of freeboard in an impoundment may fluctuate as wastes are added, rainfall accumulates, and liquids are removed for discharge to surface water or recirculated to sluicing operations. Solids that accumulate at the bottom of a surface impoundment may be left in place as a method of disposal. The impoundment also may be periodically dewatered and the solids removed for disposal in another unit, such as a landfill.

Landfills are facilities in which wastes are placed for disposal on land. Landfills usually are constructed in sections called “cells.” Wastes are placed in the active cell and compacted until the predetermined cell area is filled. Completed cells are sometimes covered with soil or other material, and then the next cell is opened. Cells may be constructed on top of a layer of previously completed cells, called a “lift.” Landfills are usually natural depressions or excavations that are gradually filled with waste, although construction of lifts may continue to a level well above the natural grade. UCCWs managed in landfills may be transported dry from the point of generation, or they may be placed after dredging from a surface impoundment. Some residual liquids may be placed along with the dredged solids. Also, liquids may be added during the construction of the landfill for dust control.

Specific storage and environmental control requirements are currently the responsibility of the states. Typical control measures include liners, covers, leachate collection systems and groundwater monitoring systems.

A **Liner** is a barrier placed underneath a landfill or on the bottom and/or sides of a surface impoundment. Depending on their construction, liners can slow or prevent the release of leachate from a landfill or liquids from a surface impoundment to underlying soils and ground water. Liners can consist of compacted soil, compacted clay, a synthetic material or membrane, or a combination of barrier types.

A **cover**, or cap, is a barrier placed over the top of a waste management unit. Covers can prevent precipitation runoff from becoming contaminated by contact with waste, prevent or slow percolation of precipitation into the unit, and prevent windblown transport of waste. Like liners, covers can consist of compacted clay, synthetic materials or membranes, or a combination of materials. Covers also may be a layer of soil or sand. Final covers are those placed upon closure of a unit. Intermediate covers also may be placed on closed or inactive portions of a unit, particularly completed cells of a landfill. Daily covers are sometimes placed at landfills at the end of a day's operation.

A **leachate collection system** is a series of drains placed beneath a unit, typically a landfill. These systems collect leachate for treatment or disposal, thus preventing it from reaching soils, ground water, or surface water.

Ground-water monitoring systems consist of one or several wells drilled in the vicinity of a unit. Samples from these wells are periodically collected and analyzed. Groundwater monitoring is not strictly an environment control but rather a warning system. Groundwater samples that display contamination may trigger regulatory requirements to mitigate or eliminate the source of contamination.

TABLE 2-32 provides a summary of the prevalence of regulatory requirements in the United States. These controls are applicable to newer landfills and surface impoundments. Recent trends suggest that states are increasingly applying their regulatory authority as new units are introduced.

TABLE 2-32. CURRENT STATE REGULATORY CONTROLS[72]

	CCW LANDFILLS			CCW SURFACE IMPOUNDMENTS		
	Number of States[b]	Percent of States[c]	Percent of Capacity[d]	Number of States[b]	Percent of States[c]	Percent of Capacity[d]
Hazardous Waste Exemption[a]	44	88%	96%	44	88%	96%
Permit Onsite	41	82%	77%	45	92%	87%
Permit Offsite	48	96%	95%	45	94%	88%
Siting Controls	46	96%	92%	41	87%	81%
Liner	43	86%	87%	45	92%	91%
Leachate Collection	42	84%	79%	33	73%	68%
Ground-Water Monitoring	46	92%	89%	44	96%	94%
Closure	45	90%	91%	43	91%	88%
Cover and Dust Controls	49	98%	96%	No Data		

[a] Exempt from state hazardous waste regulations for CCWs.

[b] Number of states with authority to impose requirement, either by regulation or on a case-by-case basis.

[c] Percent of surveyed states with authority.

[d] Percent of surveyed utility generating capacity represented by states with authority.

2.4.6 Assessment of IGCC By-Product Utilization

A 300-MWe IGCC power plant using 2,500 tons of 10% ash coal per day may generate 250 tons/day of slag or bottom ash, the disposal of which represents a significant operating cost. Commercial application of coal gasification technologies can be greatly enhanced if the solid by-product can be utilized, rather than disposed of in a landfill. Data presented in Sections 2.4.2, 2.4.3, and 2.4.4 show that gasification slag is similar to the material produced in wet-bottom PC plants and has as good or better leachability characteristics. It also has low bulk density, high shear strength, good drainage and filtering characteristics. Unfortunately, due to the relatively small quantities of boiler slag produced in the U.S., relative to fly ash and FGD material,[1] the markets for this type of material are not yet fully developed. There is also relatively little experience using coal gasification slag.

This section reviews the potential markets for utilizing slag material generated by IGCC power plants, examines the utilization experience for slag produced by wet-bottom PC plants, and discusses some of the limited utilization experience associated with currently operating IGCC plants.

2.4.6.1 Potential Markets for IGCC Slag

Current large-volume markets for slag can mainly be found in those states that make use of wet bottom boilers, such as Ohio, New York, Illinois and Indiana. In the areas where slag is produced, it is utilized to a high extent. U.S. utilization of slag from coal-fired boilers is estimated to be about 94%, according to the American Coal Ash Association (ACAA), and over 89% in ACAA Region 3, which includes Illinois, Indiana, Kentucky, Michigan, Ohio, and Wisconsin.

Identified markets for IGCC slag include:

- Construction structural backfill
- Asphalt paving aggregate - hot mix and seal coat aggregate
- Portland cement aggregate
- Asphalt shingle roofing granules
- Pipe bedding material
- Blasting grit
- Snow and ice control
- Mineral filler
- Road drainage media
- Water filtering medium
- Water-jet cutting - a new application for boiler slag
- Slag lightweight aggregate (SLA) and ultra-lightweight aggregate (ULWA)

In the State of Ohio, while only 3.8% of the CUBs produced in 1997 were boiler slag, slag represented approximately 13.4% of the CUB utilized. TABLE 2-33 identifies the primary markets for boiler slag in Ohio in 1997.[73] While utilization of boiler slag amounted to almost 75%, use of fly ash/bottom ash was estimated at just over 23% and use of FGD material at 21%. Of course, the much larger quantities of ash and FGD material produced helps account for its more limited utilization.

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[1] Coal-burning electric utilities now produce over 100 million tons of CUBs annually in the United States. However, boiler slag production, as a percentage of total CUB production, has dropped consistently from about 6-7% in 1988-93 to about 2.5% in 1996-99.

TABLE 2-33. ESTIMATED BOILER SLAG UTILIZATION IN OHIO BY TYPE OF USE –1997

TYPE OF USE	QUANTITY USED, Short Tons	PERCENT OF TOTAL USED
Cement/Concrete/Grout	4,700	1.8
Structural Fills	18,400	7.1
Road Base/Subbase	300	0.1
Snow and Ice Control	11,800	4.5
Blasting Grit/Roofing Granules	223,200	85.9
Misc./Other	1,500	0.6
TOTAL	**260,000**	**100**

Production of lightweight aggregates from slag, used to make roof tile, lightweight block, and structural concrete, appears to represent an excellent opportunity to develop a high-value market for IGCC slag. A project funded by the DOE, the Electric Power Research Institute (EPRI), and the Illinois Clean Coal Institute (ICCI), along with considerable industry involvement, has demonstrated the technical and economic feasibility of commercial production and utilization of slag lightweight aggregates (SLA) and ultra-lightweight aggregates (ULWAs).[74] A sample from an Illinois basin coal slag generated at the Wabash River IGCC plant was included in the project.

The economic incentive for developing this technology depends on the market prices of target applications: conventional LWAs made from expansible clays sell for $40/ton, and ULWAs made from expanded perlite sell for $150/ton. The results indicate that SLA is an excellent substitute for conventional LWA in roof tile, block, and structural concrete production. In addition, slag-based near-ultra-lightweight material may also be used as a partial substitute for expanded perlite in agricultural and horticultural applications. The preliminary economics indicate that SLA costs would be considerably lower than those of conventional materials due to the absence of mining costs and significantly lower temperature of expansion (1400-1600^{o}F vs. 1800-2000^{o}F for conventional clays). Production costs were calculated at $24.40 and $21.87 per ton of product (1998 dollar basis), respectively. These costs compare very favorably with current LWA production costs of about $30/ton. When these numbers are modified to reflect a possible $15/ton avoided costs of slag disposal, the economics of SLA production become even more attractive. The technology demonstrated under this project indicates a good opportunity for developing value-added products from IGCC slag.

2.4.6.2 Benefits of Slag Utilization

Some of the perceived advantages of using the slag by-product, instead of the current practice of landfilling are:

- Decreased need for expensive landfill space
- Conserves natural resources
- Uses a better by-product with significant technical benefits (such as uniformity)
- Reduces the cost of energy production
- Provides substantial cost savings for end-users
- Helps the economic competitiveness of coal, in general, and IGCC in particular.

The interest in using slag is largely driven by the avoided landfill cost.[73] Avoided landfill costs can be significantly different for utilities with and without captive landfills. For slag producers with captive landfill, use of any by-product results in 100% savings of operating costs but only partial savings of the capital of the landfill. On the other hand, utilities without captive landfills have zero capital cost but high operational costs. Thus, any material not sent to the landfill results in much higher cost savings for IGCC plants without captive landfills, than those with captive landfills. CUB landfilling costs (capital and operating) in the State of Ohio, for example, can range from about $3 to $35 per ton for plants with and without captive landfills. CUB producers with captive landfills have low landfill costs (approximately $3 to $15 per ton). However, CUB generators without captive landfills generally have much higher landfilling costs (about $10 to $35 per ton) due to high tipping fees and longer haulage distance.

Another benefit associated with CUB utilization can be quantified as the intrinsic value of land not needed for disposal purposes. It is presumed that almost any tract of land will have a lesser environmental quality if it is used as a disposal site rather than left in its natural state. The mere operation of a large disposal site over a long period of time increases the potential for accidental environmental damage due to loss of vegetation, surface runoff, airborne dust from trucks, etc. It is, therefore, assumed that the environmental benefit of diverting CUBs from disposal sites takes the form of a value assigned to each acre of landfill space "avoided." This benefit accrues to any use of CUB, assuming that there is no additional environmental disturbance at the utilization site merely to accommodate the CUBs.[75]

2.4.6.3 Barriers to Slag Utilization

The principal barriers to IGCC slag utilization can be classified into three main categories: 1) institutional, 2) regulatory, and 3) legal. The institutional barriers include restrictions on use of CUBs through requirements, standards, specifications, policies, procedures, or attitudes of organizations and agencies involved in CUB use or disposal. This can also include economic, marketing, environmental, public perception, and technical barriers. Some examples are local material transport requirements, opposition from established raw material marketers, unknown long-term effects on products made from slag, and product durability concerns.

Regulatory barriers include federal, state, and local legislation and permitting requirements. Regulatory and permitting factors are discussed in Section 3.4 and 3.5. Most states currently do not have specific regulations addressing the use of CUBs, and requests for specific uses are handled on a case-by-case basis or under generic state recycling laws or regulations.

Legal barriers include contract, patent, liability and some regulatory issues. Critical to overcoming the barriers and creating successful IGCC slag uses will be demonstrating that such practices are technically safe, environmentally sound, socially beneficial, and commercially competitive. Improved specifications, fact sheets, design manuals, and testing procedures need to be developed and widely distributed in collaboration with government and university researchers and standard-setting organizations.

Efforts to educate regulators, policy-makers, engineering consultants, potential end-users, and the general public are very important. The educational efforts should focus on neutralizing the association of the term "waste" with IGCC by-products, and should emphasize their environmental safety (non-toxicity) and their potential uses, benefits and drawbacks. The public in particular should be made aware of the environmental costs of landfilling and the environmental and social benefits resulting from reclamation and other efforts using IGCC by-products.

2.4.6.4 Current IGCC Experience with Slag Utilization

In addition to the successful assessment of Wabash slag to produce lightweight aggregate, as discussed in Section 2.4.6.1, the Polk plant has successfully processed slag for use in cement production. In order to meet the required slag specification, the size of the fines handling system was doubled, and additional slag handling equipment was installed to deal with unconverted carbon in the fines. As a result, Polk produced 2000 tons of slag in the summer of 2001 that was used by the cement industry at lower cost than Class I landfill disposal. Some further process modifications, during an outage in the fall of 2001, have enabled the plant to better separate unconverted carbon and produce slag that is more consistently suitable for the cement industry.[76] Not only does the slag meet specifications, but also the unconverted carbon can be recycled back to the plant or used elsewhere. However, a negative impact of the improved slag generation capability is that the plant must operate at reduced load. Load reduction is necessary, because more oxygen is needed to gasify the fines, but the oxygen plant, specifically the main air compressor, cannot supply the required capacity. In order to eliminate the load restrictions and ensure Polk’s long-term viability, another source of air for the oxygen plant is needed. This problem is specific to the Polk plant and not inherent in IGCC technology. A new design would not have this problem.

Note that this particular problem with complete carbon conversion does not generally apply to all gasifiers. For example, the BGL gasifier has not demonstrated this problem due to the nature of its slag removal system.[58]

2.4.7 Comparison of the Environmental Performance of IGCC with PC and Fluidized Bed Power Plants

TABLE 2-34 compares the quantity of solid waste and byproducts produced by IGCC, FBC, and PC plants. The basis for this comparison is a 300 MWe size plant using an Illinois bituminous coal with 4% sulfur content. The IGCC plant is shown to generate significantly less total solids than the other plants, roughly one-half that of the PC plant and one-third that of the FBC plant. Selection of lower coal sulfur content for this analysis will provide a more favorable comparison for the PC and FBC plants relative to the IGCC plant.

TABLE 2-34. SOLID WASTE AND BYPRODUCTCOMPARISON FOR 300 MWe PLANTS –IGCC VERSUS PC AND FBC PLANTS

PLANT DATA	PC PLANT WITH ADVANCED WET FGD	FBC PLANT	IGCC PLANT
PLANT OPERATING DATA			
Plant Size, MWe	300	300	300
Annual Capacity Factor, %	65	65	65
Heat Rate, Btu/kWh	9,750	9,400	9,000
Carbon Conversion, %	99	98	99
Feed Fuel, tons/day	3,480	3,360	3,216
Feed Limestone, tons/day	466	1,104	-

PLANT DATA	PC PLANT WITH ADVANCED WET FGD	FBC PLANT	IGCC PLANT
FUEL PROPERTIES			
HHV, Btu/lb	10,100	10,100	10,100
Sulfur, Weight %	4	4	4
Ash, Weight %	16	16	16
Carbon, weight %	57.6	57.6	57.6
SULFUR REMOVAL			
Removal Efficiency, %	95	95	98
Sorbent	Limestone	Limestone	MDEA
Limestone Purity, %	95	95	-
Ca/S Molar Ratio	1.02	2.5	-
Water on Dry Waste, %	25	25	25
SOLIDS GENERATED, tons/day			
Ash (Dry)	557	538	0
Slag (Dry)	0	0	515
Carbon in Ash (Dry)	20	19	19
Elemental Sulfur	0	0	126
$CaSO_4$ (Anhydrite)	562	542	0
Water in $CaSO_4 \bullet 2H_20$	149	144	0
CaO (Dry)	10	363	0
Water in $Ca(OH)_2$	3	117	0
Inerts from Limestone	23	55	0
TOTALS			
TOTAL BY-PRODUCTS, tons/day	**747**	**0**	**126**
TOTAL SOLID WASTE, tons/day (Dry)	**577**	**1,778**	**534**
TOTAL SOLIDS GENERATED, tons/day	**1,324**	**1,778**	**660**
TOTAL SOLIDS GENERATED, lb/MWh	**367**	**494**	**183**
TOTAL SOLID WASTE GENERATED, lb/MWh	**172**	**494**	**148**

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3. EXISTING AND FUTURE ENVIRONMENTAL REGULATIONS AFFECTING THE SITING AND OPERATION OF GASIFICATION-BASED POWER SYSTEMS

3.1 Introduction and Summary of Information Presented

The assurance of a healthy environment for the American public is one of the greatest drivers for the regulation of emissions and byproducts generated by electric power producing facilities. Substantial regulation already exists for the assessment and control of pollutants by means of air, water, and solid discharges generated from fossil-fueled utility and industrial plants. The regulations fall into three general categories: 1) ***environmental quality standards*** that establish acceptable levels or concentrations of pollutants in the environment, 2) ***performance standards*** that limit discharges of specific pollutants to the environment (air, water and land), and 3) ***control standards*** that prescribe particular control methods that should be utilized to achieve the required performance.[1] Environmental quality standards usually serve as the basis for the enforceable performance and design standards specified in environmental permits, and they also usually necessitate pollutant monitoring and reporting to a regulatory organization.

Since these regulations apply to the IGCC technology, this chapter examines existing and future environmental regulations that may impact the siting, environmental permitting, and operation of gasification-based power plants. These federal, state, and local regulations deal with criteria air pollutants, organic and inorganic hazardous air and water pollutants, and solid wastes/byproducts in all media – air, water and land. Increasingly restrictive regulatory requirements for coal-based power generation are a critical factor impacting selection, acceptability, and operability of competing technologies.

3.1.1 Chapter Organization

This chapter is divided into three major sections (in addition to this introductory section) that exclusively cover air in Section 3.2, water in Section 3.3, and solid wastes/byproducts in Section 3.4, respectively. Each provides the following information:

- Description of Federal Regulations
- Federally-Mandated Operating Permits for Commercial IGCC Plants
- Recent Permitting Experience with Planned IGCC Plants
- Review of Existing State Regulations and Permitting Applicable to IGCC Plants
- Overview of Future Pollution Regulations Potentially Applicable to IGCC Plants

Section 3.5 is also included to provide summary information on miscellaneous regulatory and industrial permitting issues that may be applicable to greenfield construction of IGCC facilities, but can't be distinctly categorized. The chapter concludes by listing cited references in Section 3.6. The rest of this introductory section summarizes the information presented in Sections 3.2 to 3.4. The summary begins with a brief overview of the methodology used to regulate and permit large-scale fossil-based power generation systems like IGCC.

3.1.2 Overview of the Regulatory and Permitting Process

TABLE 3-1 provides an overview of key elements of current regulatory policy impacting all fossil-based power plants in the U.S. The table identifies those media-specific regulations that have been developed to comply with federal and state laws, as well as the pollutants regulated.

TABLE 3-1. SUMMARY OF KEY REGULATORY ELEMENTS IMPACTING ALL COAL-FUELED POWER PLANTS IN THE U.S.

ENVIRONMENTAL MEDIA AND APPLICABLE REGULATIONS	POLLUTANTS REGULATED	REGULATORY BASIS
Air Pollution • National Ambient Air Quality Standards (NAAQS) • Federal New Source Performance Standards (NSPS) • Federal New Source Review (NSR) • Title IV, 1990 CAAA – Acid Deposition Control • Title III, 1990 CAAA – Hazardous Air Pollutants • Title I, 1990 CAAA – Attainment Maintenance of NAAQS, Regional Programs – NOx SIP Call • State Implementation Plans (SIPs) • Local Standards (air quality, emission limits, control methods)	SO_2, NOx, PM10, Pb, O_3, CO, HAPs	Clean Air Act, Clean Air Act Amendments, State and local laws
Water Pollution • Federal Safe Drinking Water Standards (SDWS) • National Pollutant Discharge Elimination System Limits (NPDES) • State Pollutant Discharge Elimination System (SPDES) • Toxic and Hazardous Waste Regulations (Federal and State) • State and Local Standards (stream quality, effluent limits, treatment methods)	Priority Pollutants: arsenic, benzene, cyanide, mercury, naphthalene, selenium, other organics, and trace metals	Clean Water Act, Safe Drinking Water Act, Resource Conservation and Recovery Act (RCRA) State and local laws
Solid Waste Discharge • RCRA Subtitle C Toxic and Hazardous Waste Regulations • RCRA Subtitle D Non-Hazardous Waste Regulations • State and Local Standards (Classification, Disposal Methods)	Fly Ash, Bottom Ash, Slag, Pollution Control Waste, By-products	Solid Waste Disposal Act as amended by the Resource Conservation and Recovery Act (RCRA)

Since inception, the environmental regulatory structure has been largely media-specific, with separate regulations covering air and water pollutants and solid waste/byproduct discharges. Regulations are based on health-related impacts to humans and wildlife, sustaining the national landscape, and the preservation of waterways to provide for both commercial and recreational use. Laws exist to provide public access to information on potentially hazardous substances that are produced or utilized at regulated facilities. The regulations also necessitate that proper siting procedures are carried out and that appropriate permits be obtained before any environmental compromise is likely to occur. Additionally, the major environmental laws call for investments and operating incentives to enhance current technology, develop new and innovative technology, and ensure that progress is made in improving the nation's air, water, and other natural resources.

The legal instrument used in the U.S. to ensure compliance with these environmental regulations is the environmental permit. A permit may specify in considerable detail how a facility may be constructed or operated and, therefore, must be obtained prior to commencement of any activity, including construction. Industrial and municipal facilities are required to obtain these permits to control their pollutant emissions to the air, land, and water. Various federal permitting programs have been established by EPA under the Clean Air Act, such as the New Source Review and Titles V of the 1990 Clean Air Act Amendments for air emissions, the National Pollutant Discharge Elimination System (NPDES) for discharges of pollutants into surface water, and the Resource Conservation and Recovery Act (RCRA) for waste management. In general, permit programs are defined in the regulations to ensure that the requirements of the original statute are properly implemented. Rather than issuing most permits itself, EPA generally has established programs to authorize state, tribal, and local permitting authorities to perform most permitting activities. Once EPA has delegated its authority for a permitting program to a state or tribe, they can then implement their own version of the permit program as long as it meets the minimum requirements stated in the governing statutes and regulations. EPA has delegated authority to most states for implementing part or all of the major permit programs. Some states have enacted provisions that are more stringent than federal requirements, while other states have adopted the federal requirements without revision.

The permitting process for the siting of a gasification-based power system is a complex and lengthy process, especially due to the increasing number of applicable regulations and associated permits required. A large-scale IGCC facility for utility power generation will almost certainly qualify as a major emissions source within the permitting process. The actual paper process of obtaining the necessary environmental permits is very similar to the siting of a traditional utility electric generation facility. Permit applications may take several months to prepare and can take an additional twelve months for approval, as for a PSD permit. The permit process usually includes air, water and solid waste impact assessments, assessment of need for additional generating capacity, and other impact analysis. In addition to the various state permitting agencies that are involved, there is also a public participation component that can significantly effect the time required to obtain the permit. Furthermore, NEPA analysis is required for facilities that have some degree of federal agency involvement, as has often been the case throughout the Department of Energy's clean coal technology demonstrations of IGCC. Many states are developing outlines for the siting process for power plants, including but not limited to the Florida Power Plant Siting Act, the Article X process of New York State, and the Ohio process overseen by the Ohio Power Siting Board.

3.1.3 Summary of Air-Related Regulations and Permitting

Section 3.2 describes air pollution regulations and environmental permitting requirements relevant to IGCC systems. Air emissions from a coal-fueled plant are effectively required to comply with two major regulatory programs required by the Clean Air Act, New Source Performance Standards (NSPS) and New Source Review (NSR), to achieve national ambient air quality standards (NAAQS). NSPS specifies maximum emission limits on criteria air pollutants, but can be superseded by provisions of NSR that impose emission limits on individual sources, such as a coal-fired power plant. Other regulatory limits are based on Titles I, III and IV of the 1990 Clean Air Act Amendments (CAAA) covering ozone and PM10 nonattainment, hazardous air pollutant emissions and aggregate emissions of acid rain precursors, respectively. Theses CAAA titles result in a national cap on SO_2 emissions and regional caps on NOx emissions, as well as maximum source limits on specific hazardous air pollutants. These regulations are all described in detail in Sections 3.2.1 (criteria pollutants) and 3.2.2 (air toxics).

The current requirements of the NSPS and NSR programs are summarized below in TABLE 3-2, along with the recent limits imposed on IGCC technology. As the table indicates, actual permitted emissions levels may be significantly less than required by NSPS based on a requirement to use Best Available Control Technology (BACT) in attainment areas and Lowest Achievable Emissions Reduction (LAER) technology in nonattainment areas. BACT/LAER requirements are determined by a permitting agency on a case-by-case basis, considering the most stringent emission limits imposed on similar facilities and certain project-specific factors. Therefore, it is not possible to forecast precisely what BACT/LAER would require for any particular plant installation, but recent BACT/LAER determinations provide an indication of likely requirements. The air emission regulations that will likely have the biggest impact on the introduction of IGCC technology are those that limit NOx and mercury emissions. EPA's "top-down-approach" for determining BACT has resulted in the lowering of allowable natural gas-fired turbine NOx emission levels to values significantly less than NSPS. BACT levels as low as 9 ppm (equivalent to 0.04 lb/10^6 Btu) can be achieved using combustion controls, and flue gas treatment equipment, such as selective catalytic reduction (SCR), can further lower NOx levels.

LAER may require emission levels as low as 2 or 3 ppm (equivalent to 0.01 lb/10^6 Btu) for natural gas-fired turbines in some states. Therefore, if combustion turbine technology is used as the basis for a new source review of an IGCC plant, it is very important for regulators to distinguish between the different performance capabilities of a combustion turbine that fires syngas versus one that fires natural gas. Syngas-fired turbines, as part of an IGCC system, have not been proven capable of matching the NOx emissions levels achieved with natural gas-fired turbines, either with combustion control or flue gas control technologies. NOx regulations are presented in detail in Section 3.2.1.1.2.

Future mercury emission limits, to be finalized by EPA by December 2004 as a result of their affirmative mercury determination for coal-fueled power plants, will definitely impact future IGCC implementation. As discussed in Section 3.2.2, the EPA determination concluded that there was a "plausible link" between emissions of mercury from coal-fired electric utility steam generating units and the bioaccumulation of methyl-mercury in fish and other animals that eat fish. Since human exposure to mercury occurs primarily through consumption of contaminated saltwater or freshwater fish, further control of coal- and oil-fired power plants was deemed necessary. Compliance will be required within three years after the regulations go into effect.

TABLE 3-2. NSPS AND NSR REQUIREMENTS FOR AIR POLLUTANTS FROM COAL-FUELED POWER PLANTS

POLLUTANT	NEW SOURCE PERFORMANCE STANDARD (NSPS)	RECENT NSR BACT/LAER EMISSION LIMIT	RECENT BACT/LAER CONTROL TECHNOLOGY	RECENT BACT/LAER CONTROL EFFICIENCY	RECENT LIMITS FOR IGCC
Sulfur Dioxide, SO_2	0.6 to 1.2 lb/10^6 Btu and 70% to 90% Removal	0.12 to 0.2 lb/10^6 Btu	Low to Medium Sulfur Coal, FGD	90 to 95%	< 0.2 lb/10^6 Btu or < 360 ppmvd, 0.01 lb/10^6 Btu H_2SO_4 mist
Nitrogen Oxides, NOx as NO_2	1.6 lb/Megawatt-hour and 0.15 lb/10^6 Btu	0.05 to 0.1 lb/10^6 Btu	Selective Catalytic Technology with Low-NOx Burners	50 to 90%	0.02 - 0.15 lb/10^6 Btu, 5 to 25 ppmvd
Particulates, TSP or PM10	0.03 lb/10^6 Btu and 99% Removal	0.01 to 0.015 lb/10^6 Btu	ESP, Fabric Filter	>99.5%	<0.015 lb/10^6 Btu
Opacity	20% Opacity (6 minute average)[a]	10% opacity	ESP, Fabric Filter	99.9% TSP	20%
Carbon Monoxide	None	0.1 to 0.15 lb/10^6 Btu	Combustion Control	--	15 ppm based on 15% O_2
Volatile Organic Compounds, VOCs	None	0.005 to 0.03 lb/10^6 Btu	Combustion Control	--	--
Hazardous Air Pollutants (HAPs)	To be set for Mercury in 12/2004	None	None	None	None

a May emit 27% opacity for one 6-minute period per hour

The Clean Air Act requires that mercury regulations reflect Maximum Achievable Control Technology (MACT). In addition, for existing sources, the Act also requires that these MACT regulations be no less stringent than the average emission level achieved by the best performing 12% of similar, existing sources. For new sources, the Act requires that these MACT regulations be no less stringent than the emissions level achieved by the best similar source. Data, presented in Chapter 2 of this report, shows that uncontrolled mercury emissions emitted by operating IGCC plants are apparently similar to that of coal-fired boilers, but that control technology is already commercially available to effectively limit mercury emissions from IGCC plants.

IGCC environmental permitting requirements and experience, as discussed in Sections 3.2.3 and 3.2.4, indicates that air permitting is by far the most time-consuming and complex aspect of developing an IGCC project. New plants have to go through NSR and BACT or LAER determinations. If a proposed plant site is a designated nonattainment area, requiring LAER treatment, cost or cost-effectiveness cannot be used by a project developer as a criterion for control technology selection. For attainment areas, most of the emissions sources and BACT determinations for a new IGCC plant are not expected to be problematic, since most of the balance-of-plant equipment and emissions (e.g., cooling towers, flares, material handling) are well defined and understood. However, since the IGCC process fundamentally differs from combustion-based fossil power generation technology, its unique, innovative technology may raise some questions concerning gas turbine pollutant emissions of NOx, SO_2, and CO and will require the most detailed analysis to avoid permitting difficulties. Further complicating this process is the possibility that state and local governments will be more restrictive than the federal requirements. Section 3.2.6 presents a review of states with a large base of existing coal-fueled electric power generation that indicates, in general, that the states follow federal regulations with respect to criteria and hazardous air pollutants.

Section 3.2.7 discusses potential emission regulations that may impact future IGCC installations. Currently, future regulations are being prepared to deal with revised NAAQS for ozone and fine particulate matter (PM2.5). The primary pollutants from coal-fueled power plants that are believed to contribute to ambient PM2.5 are sulfates due to sulfur dioxide emissions, nitrates due to NOx emissions, and fine fly ash particulates that escape particulate matter collection devices. Only a further reduction in the NOx limit would be expected to impact IGCC technology, since SO_2 and particulate matter emissions are already at extremely low levels. Since NOx emission levels ranging from 0.06 to 0.1 lb/10^6 Btu are being considered, this could necessitate development of advanced, combustion-based NOx reduction technologies specific to turbines that fire syngas or further modifications to IGCC systems to potentially accommodate flue gas cleaning technologies, such as SCR. Additional future legislation appears to favor technologies that can simultaneously minimize SOx, NOx, and mercury emissions, while also limiting carbon dioxide (CO_2) production. Proposed legislation, unrelated to the EPA mercury determination, calls for as much as a 90% reduction of emissions from individual sources, while other legislation is geared toward reducing aggregate mercury emissions from about 48 tons per year to much lower levels. The extent to which this may affect IGCC versus other coal-fueled technologies is more completely discussed in Chapter 2 of the report.

CO_2 control may also be required further into the future, and proposed legislation calls for reduction of emissions to 1990 levels. While significant CO_2 emission limitations would impact the cost-competitiveness of all coal-based technologies, two key factors make IGCC less vulnerable than combustion-based systems. First, the lower heat rates achieved by IGCC yield lower CO_2 emissions per unit of electricity production. Second, high-pressure, oxygen-blown gasifiers yield syngas with a relatively high concentration of CO_2 that can be readily removed in the acid gas removal system. Of course, any CO_2 removed must be either utilized in some fashion or transported to a sequestration site, such as an aquifer or depleted oil wells.

3.1.4 Summary of Water- and Solid Waste/Byproduct Related Regulations

Applicable water and solid waste/byproduct discharge regulations and permitting requirements are discussed in Sections 3.3 and 3.4, respectively. None of these regulations would appear to limit the introduction of IGCC technology any more than coal combustion-based technology. Wastewater discharges normally are permitted under the National Pollutant Discharge Elimination System (NPDES) program and State Pollutant Discharge Elimination System (SPDES) programs, which may be more stringent than NPDES. The design of cooling systems and wastewater treatment facilities must ensure that their discharges are permittable under the applicable program.

A particularly critical water issue that impacts all fossil-fueled plants deals with the construction of surface water intake and discharge structures. Issues such as the disturbance of shoreline and bottom habitats and the protection of fish and aquatic wildlife are often raised during the permitting process. Therefore, the location and design of proposed intake/discharge structures is an important consideration in the permitting process. As discussed in Section 3.3.4, EPA is currently developing regulations required by the Clean Water Act (CWA) for fish protection at cooling water intake structures (CWA 316(b)). New facilities that will be required to comply are those that require a NPDES permit and withdraw two million gallons or more per day (MGD) from waters in the U.S. Facilities that require a NPDES permit, but withdraw less than 2 MGD, will be evaluated on a case-by-case basis.

With regard to solid byproducts, 45 states, representing 96% of coal-fueled utility generating capacity, duplicate the federal exemption of coal combustion byproducts from being categorized as a hazardous waste. Therefore, as long as IGCC's solid byproduct material is shown to have similar (or better) toxicity characteristics compared to wastes/byproducts from combustion-based plants, then IGCC will be no more impacted than any other coal-based technology. Results of data presented in Chapter 2 show that IGCC slag is, indeed, comparable to that produced in wet-bottom, PC-fired power plants, and should fall under the classification of non-hazardous waste. This has important implications for both landfill disposal and waste utilization.

A landfill must comply with specific requirements for lining, leachate collection, ground water monitoring, and other environmental protection measures, to prevent groundwater contamination. Waste disposal landfills typically are regulated by state agencies, and in some states obtaining approval for the location and design of a landfill can be a very difficult and time-consuming process, but is certainly easier with non-hazardous waste material. Even better, is to select or design a new power generation system that produces solid wastes suitable for commercial use. As discussed in Chapter 2, IGCC's solid byproduct material has been tested as non-leachable and non-hazardous, and may be quite useful for a variety of industrial applications.

3.2 Air Pollution Regulations and Environmental Permitting

3.2.1 Description of Pollution Regulations for Criteria Air Pollutants

The Clean Air Act (CAA, 42 U.S.C.A. §§ 7401 to 7671q) designates six pollutant species as "criteria pollutants" and EPA has established specific ambient air concentration levels of these pollutants as (primary and secondary) national ambient air quality standards (NAAQS). These pollutants are carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), ozone[a] (O_3), particulate matter (PM10), and sulfur dioxide (SO_2). The NAAQS are achieved by each state through the implementation of a State Implementation Plan (SIP) that imposes emission limits on individual sources, such as a coal-fueled IGCC power plant. Although developed initially by state and local air pollution control officials, SIPs must be adopted by municipal and state governments and then approved by EPA. Once a SIP is fully approved, it is legally binding under both state and

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[a] Ozone itself is not emitted directly into the air, but rather is formed through a series of complex physical and chemical reactions in the atmosphere. Effectively, volatile organic compounds (VOCs) react with NOx in the presence of sunlight to form so-called ground-level ozone.

federal law, and may be enforced by either government. A geographic area that meets or does better than the NAAQS primary standard for a criteria pollutant is called an **attainment area**; areas that don't meet the primary standard are called **nonattainment** areas.

New Source Performance Standards (NSPS, 40 CFR 60) outline performance requirements for new or modified source units,[2] but other regulations may ultimately establish the actual performance level required. Although it does not apply to IGCC, Subpart Da addresses requirements for fossil-fuel-fired electric utility steam generators greater than 73 MW (>250 million Btu/hr) for which construction commenced after September 18, 1978 (or an alternative date as modified). In addition, NSPS requirements for stationary gas turbines are outlined by 40 CFR 60 Subpart GG. These requirements apply to all stationary gas turbines with a heat input (at peak load) equal to or greater than 10.7 gigajoules or 10 million Btu per hour. The language of the regulation includes combined cycle gas turbines defined as "any stationary gas turbine, which recovers heat from the gas turbine exhaust gases to heat water or steam" (40 CFR 60.331). Together, these regulations outline specific compliance requirements for SO_2, NOx, PM, and opacity.

Since IGCC plants may employ either a sulfuric acid plant or a Claus sulfur recovery plant to convert captured hydrogen sulfide (H_2S) into sulfuric acid (H_2SO_4) or elemental sulfur, respectively, NSPS for these facilities may also be applicable. Standards of Performance for Sulfuric Acid Plants (40 CFR 60.82, Subpart H) limits sulfur dioxide emissions in discharge gases. The existing NSPS limit(s) on sulfur emissions from Claus sulfur recovery plants of greater than 20.32 Mg (22.40 ton) per day capacity is stated in 40 CFR 60, Subpart J - Standards of Performance for Petroleum Refineries.

New source review (NSR) requirements are outlined by 40 CFR 52.21(b)(1)(I)(a)-(b) and apply to all new major emission sources and may apply to expansions or modifications of existing facilities. Triggers for NSR compliance typically vary depending on the designated status of the location where the source will be located (i.e., whether the location is attainment or nonattainment). Areas classified as attainment or unclassifiable must comply with regulations outlined under the Prevention of Significant Deterioration (PSD) program. Because NOx is a precursor for ozone formation, area status of NAAQS for both NOx and VOC pollutants must be considered. On June 13, 2002, the EPA Administrator submitted a Report to the President detailing New Source Review Recommendations that summarize actions to improve and streamline the NSR program. However, the key provisions of the recommendations are primarily targeted at existing plants that will undergo major modifications, maintenance, repair and replacement, and will not greatly affect new plants.

For areas that are designated as attainment or unclassifiable, the major source threshold for most sources is 250 tons per year of the applicable pollutant. For fossil-fueled steam electric plants, the trigger is 100 tons per year of the applicable pollutant. For areas designated as nonattainment, the compliance threshold ranges from 100 tons per year of the designated pollutant down to 10 tons per year, depending on the severity of the air quality compromise where the source is located. For companies that own or operate multiple sources within a single operating area, most often within a single plant site, the compliance thresholds can be interpreted with respect to total emission from all sources within the area or plant site. This allows the company to reduce emissions at another source and have a "net" emission increase within the operating area, including the new or modified source, of less than the NSR trigger. This process is known as "netting out." [3]

The NSR process is typically conducted on the state level in accordance with their SIP. Compliance plans for PSD include technological requirements such as Best Available Control Technology (BACT) and may include air quality dispersion modeling, using models such as EPA's CALPUFF non-steady-state modeling system.[4] Pre-startup air quality monitoring is required for new sources. BACT is an emissions limit based on the maximum degree of emissions reduction for a pollutant based on application of the best available control technology, and allows the consideration of energy, environmental, and economic impacts (42 U.S.C.A. §§ 7475, 7479(3)). Because BACT is a case-by-case decision, specific requirements may vary from one location to another. Sources subject to PSD are not typically required to offset emission increases.

In nonattainment areas, environmental permits may be issued requiring new sources to meet lowest achievable emission rate (LAER) standards (42 U.S.C.A. § 7503 (a)(2)) based on a numerical emission standard or a specific equipment design or operational requirement. These standards are based on technological factors and cannot consider energy or economic issues. Significant progress in the U.S. Department of Energy's (DOE) Advance Turbine System (ATS) program, along with technological development of post combustion NOx control technology, has allowed lowest achievable NOx emission levels in the single digit ppm range for stationary combustion turbines firing natural gas. However, syngas-fired turbines cannot yet achieve this emissions level, requiring higher NOx LAER requirements for the turbine section of an IGCC facility. In addition to LAER requirements, operators of facilities must obtain "emission offsets" of the same pollutant from other sources within the nonattainment area to ensure equivalent or lower total emissions in that area. These offsets typically are an equivalent 1:1 offset, but may require greater reductions depending on the severity of the air quality compromise.[5] Thus, source control required under NSR can be significantly more stringent than required by the PSD rules.

Prior to commencing new construction or major modification, major stationary sources are required to obtain a permit from the authorized state air pollution agencies (CAA Title V, 42 U.S.C.A. § 7661a(a)). Subsequent permitting requirements for NAAQS compliance are outlined by individual state generated SIPs as required under Title I of the CAA. The permits outline all relevant CAA requirements for an applicable facility.

Title IV acid rain provisions of the 1990 Clean Air Act Amendments (CAAA Title IV – Acid Deposition Control, 42 U.S.C.A. § 7651) further regulate SO_2 and NOx emissions from electric utility plants and outline specific reduction targets for existing plants. The program includes traditional regulatory mechanisms along with an allowance trading system and a cap on future annual emissions of SO_2 of 8.9 million tons. In addition to SO_2 and NOx emission compliance, Title IV requires continuous emission monitoring (CEM) that includes measurement and recording of SO_2, NOx and CO_2 emissions, as well as volumetric flow, opacity and diluent gas levels.[6]

Title I NAAQS attainment provisions of the 1990 Clean Air Act Amendments (CAAA Title I – Provisions for Attainment Maintenance of NAAQS, 42 U.S.C.A. § 7407d) requires reductions in ground-level ozone and its precursors, including NOx. Ground-level ozone is a major ingredient of smog. Since NOx is a major ozone precursor, it is necessary to control NOx to comply with ambient ozone standards. Effective July 16, 1997, the NAAQS for ozone is 0.08 ppm (8-hour average). At this level, many large- and medium-sized urban areas are classified as being in nonattainment, and many power plants are situated within these nonattainment areas.

Nonattainment of ozone standards result not only from NOx emissions in a given locality, but also from significant amounts of NOx transported by winds over a wide geographical area. To account for the regional transport issue, the CAAA also provided for the establishment of ozone transport regions.

The Ozone Transport Assessment Group (OTAG), established in 1995 to undertake an assessment of regional pollutant transport problems in the eastern half of the United States, concluded that regional reductions in NOx emissions are needed to reduce the production and transport of ozone and its precursors. OTAG recommended that major sources of NOx emissions (utility and other stationary sources) be controlled. Based on OTAG's analysis, findings, and recommendations, EPA ultimately issued a rule under Title I on September 24, 1998, to establish a cap for NOx emissions. It is applicable to electric power generating units within an area covering 22 states east of the Mississippi River[b] plus the District of Columbia (EPA, 1998), although this area was later reduced to 19 states plus DC. These jurisdictions are required to submit SIPs to meet target emissions levels under the EPA NOx SIP Call. The cap applies to the five-month ozone season from May 1 through September 30. Both existing and new plants within the SIP Call region will be required to meet reduced NOx emissions levels that may be even more stringent than required by Title IV, NSPS or NSR.

A key dilemma facing IGCC, as well as other gasification-based power generation systems, is the applicable performance standards that must be met. IGCC represents a coal/solid fuel-based technology, but produces a gaseous intermediate fuel that is combusted in a stationary gas turbine. As in a gas-fired combined cycle plant, the hot exhaust gas from the turbine is fed to a HRSG to produce steam for a steam turbine. Therefore, should emissions be governed by the coal-fired standard, the natural gas-fired standard, or a new gasification or syngas standard? The specific applicability of gas turbine NSPS to IGCC facilities will likely depend upon how the facility configuration is interpreted relative to fossil-fuel-fired steam electric generation and stationary gas turbine regulations, as well as plant siting in attainment or nonattainment locations. It is also important to keep in mind that state and even local air quality regulations and requirements can be more stringent and must be more comprehensive than federal requirements. It is, in fact, the responsibility of individual states to identify state-specific air quality issues and develop appropriate regulations to deal with them.

3.2.1.1 Criteria Pollutant Ambient and Source Emission Standards

This section identifies specific criteria pollutant control levels required by the Federal regulations discussed above in order to meet the NAAQS. TABLE 3-3 lists the NAAQS for the six criteria pollutants, expressed as both micrograms per cubic meter ($\mu g/m^3$) and parts per million (ppm).

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[b] The SIP Call area consists of Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

TABLE 3-3. NATIONAL AMBIENT AIR QUAILITY STANDARDS

POLLUTANT	MEASURING CRITERIA	STANDARD VALUE	STANDARD TYPE
Carbon Monoxide (CO)	8-hour Average	9 ppm (10,000 µg/m^3)	Primary
	1-hour Average	35 ppm (40,000 µg/m^3)	Primary
Lead (Pb)	Quarterly Average	1.5 µg/m^3	Primary & Secondary
Nitrogen Dioxide (NO_2)	Annual Arithmetic Mean	0.053 ppm (100 µg/m^3)	Primary & Secondary
Ozone (O_3)	1-hour Average	0.12 ppm (235 µg/m^3)	Primary & Secondary
	8-hour Average*	0.08 ppm	Primary & Secondary
Particulate (PM10) *Particles with diameters of 10 µm or less*	Annual Arithmetic Mean	50 µg/m^3	Primary & Secondary
	24-hour Average	150 µg/m^3	Primary & Secondary
Particulate (PM2.5)* *Particles with diameters of 2.5 µm or less*	Annual Arithmetic Mean	15 µg/m^3	Primary & Secondary
	24-hour Average	65 µg/m^3	Primary & Secondary
Sulfur Dioxide (SO_2)	Annual Arithmetic Mean	0.030 ppm (80 µg/m^3)	Primary
	24-hour Average	0.14 ppm (365 µg/m^3)	Primary
	3-hour Average	0.5 ppm (1,300 µg/m^3)	Secondary

* Proposed standards for ozone 8-hour average and PM2.5 included for information only.

The current regulation for particulate matter is the PM10 standard that applies to emitted particles with diameters of 10 µm or less (small enough to be inhaled). EPA has proposed more stringent NAAQS for ozone and particulate matter applicable to emitted particles of 2.5 µm or less (PM2.5). A 1999 federal court ruling blocked the implementation of these NAAQS. In May 1999 EPA asked the U.S. Supreme Court to reconsider the ruling, and in June 1999 a petition for rehearing was filed with the U.S. Court of Appeals D.C. Circuit.[7] In 2000, the U.S. Supreme Court unanimously affirmed EPA's ability to set national ambient air quality standards. Currently, EPA is determining the appropriate approach for implementing the ozone standard, and is also in the process of collecting the required three years of fine particulate monitoring data prior to determining attainment area status. Area attainment and nonattainment status designations are expected to begin in 2004.

3.2.1.1.1 SOx

While not directly applicable to IGCC, Federal NSPS for SO_2 compliance of fossil fuel-fired steam generators are based on the type of fuel burned and the potential combustion concentration[c] in the flue gas. For solid fuel or solid-derived fuel, sulfur dioxide limits are 520 nanograms per joule (ng/J) (1.20 lb/10^6 Btu) heat input and 10 percent of the potential combustion concentration (90 percent SO_2 reduction), or 30 percent of the potential combustion concentration (70 percent SO_2 reduction) when emissions are less than 260 ng/J (0.60 lb/10^6 Btu) heat input (40 CFR, Part 60 **§** 60.43a – standard for sulfur dioxide – 39 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976; 52 FR 28954, Aug. 4, 1987). For combustion of combined fuels, the requirements are based on percentage contribution of solid, liquid and gaseous fuels. NSPS for stationary gas turbine SO_2 compliance (40 CFR, Part 60 **§** 60.333 - standard for sulfur dioxide), which (as currently written) is applicable to the gas turbine in an IGCC, requires no discharge into the atmosphere from any stationary gas turbine gases that contain sulfur dioxide in excess of 0.015 percent by volume (15 percent oxygen on a dry basis) or prohibit the burning of any fuel that contains sulfur in excess of 0.8 percent by weight.

While not directly applicable to IGCC, Standards of Performance for Sulfuric Acid Plants (40 CFR 60.82, Subpart H) limits sulfur dioxide emissions in discharge gases to no more than 2 kg per metric ton of acid produced (4 lb per ton), the production being expressed as 100 percent H_2SO_4. The limit on sulfuric acid mist is 0.15 lb per ton of sulfuric acid produced (40 CFR 60.83 Subpart H). The existing NSPS limit(s) on sulfur emissions from Claus sulfur recovery plants of greater than 20.32 Mg (22.40 ton) per day capacity is stated in 40 CFR 60.104 (Part J - Standards of Performance for Petroleum Refineries):

- Any Claus sulfur recovery plant using an oxidation control system or a reduction control system followed by incineration may not emit any gases greater than 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. This is comparable to the 99.8 to 99.9 percent control level for reduced sulfur.
- Any Claus sulfur recovery plant using a reduction control system not followed by incineration may not emit any gases greater than 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H2S), each calculated as ppm SO2 by volume (dry basis) at zero percent excess air.

CAAA Title IV acid rain compliance plans require that an affected unit hold enough allowances to cover annual SO_2 emissions and that it will comply with applicable Title IV SO_2 limits. Each sulfur dioxide allowance permits a unit to emit 1 ton annually. For each ton of SO_2 emitted in a given year, one allowance is permanently retired. The number of allowances an affected facility receives is based on past fuel consumption and relevant emission rate.

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[c] Potential combustion concentration is defined in the NSPS as the theoretical emissions that would result from the combustion of a fuel in an uncleaned state without emission control systems.

Additional allowances are allocated annually to units in high growth states (42 U.S.C.A. §7651d(i)) and certain municipally owned power plants. Also, for states with 1985 SO_2 emission rates below 0.8 lb/10^6 Btu, emission allowances are available upon the discretion of that State's Governor. Most important to plants that will be installed in coming years, any new fossil-fired plant will have to fall under the overall SO_2 cap of 8.9 million tons of SO_2 per year. A utility will have to have either banked or purchased SO_2 allowances for the plant to operate. It is this cap on SO_2 emissions that most impacts construction of new plants and will likely require strict SO_2 emissions limits.

The CAAA provided special incentives for the "repowering" of a facility using specific clean coal technologies, including integrated gasification. The deadline for demonstrated intent was December 31, 1997. Utilities that underwent repowering were granted an extension of the deadline for emission limitation compliance and issued non-transferable SO_2 allowances specifically for the operation of the repowered unit.

3.2.1.1.2 NOx

Federal NSPS for fossil-fuel-fired steam generator NOx compliance were revised in September 1998. The change only applies to units for which construction, modification, or reconstruction began after July 9, 1997. The pollutant standard for newly constructed sources built after this date is quantified on a basis of energy output rather than the former heat input basis. The standard is 200 nanograms NOx (as NO_2) per joule (ng/J) or 1.6 lb/megawatt-hour (MWh) gross energy output on a 30-day rolling average, regardless of fuel type (40 CFR, Part 60 § 60.44a – standard for nitrogen oxides – 44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 63 FR 49453, Sept. 16, 1998; 66 FR 18551, Apr. 10, 2001). For existing sources that undergo a modification or reconstruction after the prescribed date, the standard remains on a heat input basis, but is lowered to 65 ng/J or 0.15 lb/10^6 Btu as NO_2.

NSPS standards for stationary gas turbine NOx compliance requirements are determined by calculations based on fuel characteristics and turbine heat rate (kilojoules per watt-hour) at manufacturer's rated load, or actual measured heat rate based on the lower heating value (LHV) of fuel as measured at actual peak load for the facility (40 CFR, §60.332 – standard for nitrogen oxides). Certain exemptions, on a case-by-case basis, are available for NOx emissions for several specific situations including turbine research and development, the potential for NOx control measures, such as water or steam injection, to cause localized impairment of visibility that impacts local traffic patterns, and periodic drought conditions. The lowest NOx emissions level required by NSPS for electric utility stationary gas turbines, with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, is 75 ppm by volume (15 percent oxygen and on a dry basis).

In December 1987, EPA's "top-down-approach" for determining BACT became a new PSD requirement. The first step in this approach is to determine, for the power generation unit in question, the most stringent control available for a similar or identical unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. This methodology has resulted in the lowering of allowable gas turbine NOx emission levels to values significantly less than NSPS.[5]

Currently, this top-down BACT typically requires a new natural gas-fired turbine to achieve a NOx output level in the range of 3 - 4 ppm NOx, and often requires the use of both combustion controls and flue gas treatment equipment, such as SCR. However, new units in ozone nonattainment areas are required to install LAER technology, without cost consideration, to reach emission levels as low as 2.5 ppm NOx. In addition, under the NSR program, increases in emissions from new or modified sources in nonattainment areas must be offset by greater than 1:1 emission reductions at other sources.

The Title IV Acid Rain provisions for NOx reductions, like those for SO_2, required a two-phase program, **but most importantly did not cap overall emission limits**. Phase I began in 1996 and Phase II in 2000. Affected units have four compliance options.[8]

- *Standard Emission Limitations*: Specific units covered by Phase I include dry bottom-wall fired boilers and tangentially fired boilers with emission limits of 0.50 lb/10^6 Btu and 0.46 lb/10^6 Btu respectively, on a heat input basis. Phase II includes further restrictions on dry bottom-wall fired boilers (0.46 lb/10^6 Btu) and tangentially fired boilers (0.40 lb/10^6 Btu) while adding limits to cell burner boilers (0.68 lb/10^6 Btu), cyclone boilers (0.86 lb/10^6 Btu), vertically fired boilers (0.80 lb/10^6 Btu), and wet bottom boilers (0.84 lb/10^6 Btu).
- *NOx Emissions Averaging*: The owner or operator of two or more units subject to one or more of the applicable emission limitations may petition the permitting authority for alternate contemporaneous annual emission limits for such units that ensure that the actual annual emission rate in lb/10^6 Btu averaged over the units in question is less than or equal to the Btu-weighted average annual emission rate for the same units if they had been operated for the same time period in compliance with applicable emission limitations (42 U.S.C.A. § 7651f(e)).
- *Alternative Emission Limitations:* If a boiler is unable to meet it's standard limits after proper installation and operation of appropriate NOx control technology, the owner and operator may petition EPA and the permitting authority for a less stringent NOx emission limit.
- *Early Election:* A Phase II affected unit with a dry bottom wall-fired or tangentially fired boiler that complied with Phase I emission limits by January 1, 1997, is exempt from Phase II limits until 2008.

Ultimately, the NOx emission limit imposed on a specific gasification-based power system depends upon its location and treatment by regulatory authorities. It is possible that regulatory authorities could view a coal gasification-based power system as similar to a coal/solid fuel-based facility, a natural gas-fired unit (if a combustion turbine is part of the power cycle), or possibly as some unique gasification or syngas-fired unit. The location determines whether ozone attainment or nonattainment regulations apply, as well as conditions that could be imposed by the NOx SIP Call or other local requirements. Clearly, emission limits imposed on coal-fueled plants by Title IV are far less restrictive than the BACT or LAER regulations that are applied to natural gas-fired combustion turbines.

Recent Determinations By EPA And States:

TABLE 3-4 presents information on some recent determinations by states for combined cycle stationary gas turbine projects that are permitted to burn synthesis gas produced from coal or petcoke. Most important, a recent NOx BACT determination in Florida applies to Tampa Electric's Polk IGCC plant. In mid 2001, based on its original PSD air permit, the Polk plant was required to submit a NOx BACT analysis to the Florida Department of Environmental Protection (FDEP) as if it were a new source. The basis was to be actual operating data, data from other similar facilities and the manufacturer's research.

TABLE 3-4. RECENT LIMITS FOR NITROGEN OXIDES FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS THAT COMBUST SYNGAS[9]

PROJECT LOCATION	POWER OUTPUT, MWe	NOx EMISSION RATE*	GASIFICATION TECHNOLOGY	APPLICATION & MATERIAL GASIFIED
Polk; Polk County, FL	260	25 ppmvd - original (0.126 lb/10^6 Btu) **15 ppmvd –revised (0.076 lb/10^6 Btu)**	ChevronTexaco pressurized oxygen-blown entrained-flow	Power generation, Coal
Wabash River; Terra Haute, IN	262	25 ppmvd (0.096 lb/10^6 Btu)	Destec two-stage pressurized oxygen-blown entrained flow	Power generation, Coal
Kentucky Pioneer (Clark County, KY and Lima, OH)	580	20 ppmvd (0.07 lb/10^6 Btu)	British Gas / Lurgi slagging fixed bed	Power generation, Coal & MSW (Proposed project)
Motiva; Delaware City, DE	240	16 ppmvd (0.1lb/10^6 Btu)	ChevronTexaco pressurized oxygen-blown entrained-flow	Refinery, Petroleum Coke

* Some of the plant's permitted rates may change due to pending BACT determinations (i.e., Polk and Kentucky Pioneer)

Based on a final BACT determination by FDEP, a new PSD permit was issued in February 2002 (# 1050233-007-AC for the Polk Power Station IGCC unit, emission unit 001).[10] The permit significantly lowers the syngas-fired turbine NOx emission limit from 25 ppm to 15 ppm (15% O_2 basis and ISO conditions) on a 30-day rolling average (via CEMS) effective July 1, 2003. The control basis is application of an N_2 diluent. The determination's rationale for reaching its final decision were given as:

- Polk IGCC is not a greenfield unit, and additional controls effectively result in a retrofit,
- Other (similar) domestic IGCC units are able to comply with an emission limit of 15 ppmvd, and
- The process of gasification is likely to expand to renewable fuels, possibly complicating the application of more stringent controls.

3.2.1.1.3 Particulates

Federal NSPS standards for PM10 for a fossil-fuel-fired steam generator are based on heat input and potential combustion concentration of the solid fuel. The particulate levels for fossil fuel fired steam generating units are 13 ng/J (0.03 lb/10^6 Btu) on a heat input basis and 1% of the potential combustion concentration. Opacity requirements are set at 20% for a six-minute average and an allowance of one 6-minute period per hour of no more than 27% opacity.

3.2.1.1.4 CO

Carbon monoxide emissions result due to the incomplete combustion of carbon-based fuels. The primary contributor to national carbon monoxide pollution is highway and off-highway transportation sources. Carbon monoxide emissions are a potential issue from any combustion source, including the gasifier and combustion turbine used in the combined cycle of IGCC. TABLE 3-3 lists the NAAQS for CO. NSPS does not regulate emissions of carbon monoxide from utility boilers or gas turbines.

3.2.1.1.5 Ozone

Ground level ozone results when emitted ozone precursors react under the influence of sunlight. Two ozone precursors of particular concern in the fossil-fuel-based electric generation industry are NOx and volatile organic compounds (VOCs). While ozone levels are regulated explicitly, in practice, regulating NOx and VOCs controls ozone pollution. Volatile organics emissions are primarily an issue with automobiles, but are present in detectable levels from coal-fired burners and combustion turbine exhaust gas. TABLE 3-3 lists the NAAQS for ozone.

3.2.2 Description of Pollution Regulations for Air Toxics

Title III hazardous air pollutants provisions (HAPs) of the 1990 Clean Air Act Amendments (CAAA Title III – Hazardous Air Pollutants, 42 U.S.C.A. § 7412) identified 189 pollutants as potentially hazardous or toxic and required EPA to evaluate their emissions by source, health and environmental implications, and the need to control these emissions. These pollutants are collectively referred to as air toxics or hazardous air pollutants (HAPs). Control requirements are technology-based and established by the top performing existing sources. Triggers for compliance are dependent on yearly emission quantities for one or more HAPs (10 tons/year for any one HAP or 25 tons/year for any combination of HAPs).

The provisions in Title III specific to electric power generation units were comprehensively addressed by DOE’s National Energy Technology Laboratory (NETL) and the Electric Power Research Institute (EPRI) in collaborative air toxic characterization programs conducted between 1990 and 1997. This work provided most of the data supporting the conclusions found in EPA’s Congressionally mandated reports regarding air toxic emissions from coal-fueled utility boilers: the Mercury Study Report to Congress[11] (1997) and the Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report to Congress[12] (1998). The first report identified coal-fired power plants as the largest source of man-made or anthropogenic mercury emissions in the U.S., and the second concluded that mercury from coal-fired utilities was the HAP of “greatest potential concern” to the environment and human health that merited additional research and monitoring.

Subsequent to these findings, data were gathered during EPA’s 1999/2000 Information Collection Request (ICR), in cooperation with NETL, to refine the total mercury emission inventory from coal-fueled plants and ascertain the mercury control capabilities of existing and potential emission control technologies. Results of this work, plus an independent evaluation of mercury health impacts by the NAS, culminated in EPA’s regulatory determination, in December 2000, to regulate mercury emissions from coal-fueled power plants. In their regulatory determination, EPA concluded that there was a "plausible link" between emissions of mercury from coal-fired electric utility steam generating units and the bioaccumulation of methylmercury in fish and other animals that eat fish. Since human exposure to mercury occurs primarily through consumption of contaminated saltwater or freshwater fish, further control of coal- and oil-fired power plants was deemed necessary.

EPA is now required to propose regulations by December 15, 2003, and issue final regulations by December 15, 2004. Compliance will be required within three years after the regulations go into effect. The Clean Air Act requires that the regulations reflect Maximum Achievable Control Technology (MACT). For existing sources, the Act also requires that these regulations be no less stringent than the average emission level achieved by the best performing 12% of similar, existing sources. For new sources, the Act requires that these regulations be no less stringent than the emission level achieved by the best similar source. Future installations of coal gasification-based power systems will thus have to deal with the EPA regulations for mercury emissions, and potentially other HAP emissions.

Currently, EPA has established National Emission Standards for Hazardous Air Pollutants (NESHAPs) for four mercury source categories: mercury ore processing facilities, mercury cell chlor-alkali plants, sewage sludge driers, and hazardous solid waste incinerators and kilns. In addition, EPA has now established MACT standards, under Section 129 of the CAA, for municipal waste combustors and hospital, medical and infectious solid waste incinerators.

3.2.3 Federally-Mandated Air Operating Permits for Commercial IGCC Plants

The permitting process for the siting of a gasification-based power system is a complex and lengthy process, especially due to the increasing number of air permits required. A large-scale IGCC facility for utility power generation will almost certainly qualify as a major source within the permitting process. TABLE 3-5 identifies many of the critical government air permit approvals that are likely to be required by such a power generation facility. The actual paper process of obtaining the necessary environmental permits is expected to be very similar to the siting of a traditional utility electric generation facility.

TABLE 3-5. PROBABLE AIR PERMIT APPROVALS REQUIRED FOR IGCC[13]

PERMIT TYPE	PERMIT APPROVAL AUTHORITY	PERMIT APPROVAL REQUIREMENT	RELATED REPORT SECTION
PSD Air Permit	State Environmental Agency	Prior to Construction/ Mobilization	3.2.3
Title IV Acid Rain	State Environmental Agency	24 Months Before Operation	3.2.3
Title V Operating Permit	State Environmental Agency	12 Months Before Operation	3.2.3
NOx SIP Call Budget Permit	State Environmental Agency	Prior to Construction/ Mobilization	3.2.3

While each state's permitting program is unique in its specific requirements, most follow a similar process for permit application submittal, agency review, and final decision. In general, there are four major milestones in the permitting process:

- The permitting authority receives and reviews the permit application (pre-application activities are included in this milestone);
- A draft permit or notice of intent to deny the permit is issued by the permitting authority;
- A public comment period of at least 30 days is provided to allow the public to comment on the draft permit; and
- The permitting authority makes a final determination on the permit application.

Methods of implementing federal regulations in state programs vary among the state agencies. Generally, environmental standards are adopted by reference to federal standards, while procedures for permit application and review are detailed in state regulations. Agencies typically control fees, review times and application processes. In some cases, federal law requires public hearings; in other cases, hearings are at the discretion of the agency boards, which set guidelines regarding their direct involvement in individual permits or classes of permits.

Major sources of air pollution are required to obtain an air operating permit. Major sources are defined as those that emit greater than 100 tons/year of any single criteria air pollutant, 10 tons/year of a hazardous air pollutant, and/or 25 tons/year of a combination of hazardous air pollutants. The CAA established two different types of permits for air pollution sources - pre-construction permits for new and modified sources and operating permits for existing sources. The purpose of the **CAA's New Source Review (NSR) permit programs** for new or modified sources is to ensure that a new or modified source installs the appropriate control technologies, that they do not interfere with or violate the control strategy for meeting the NAAQSs, and that they do not contribute to new or existing air pollution problems, such as violations of the NAAQSs.[14] There are four different permit programs for new and modified air pollution sources:

- The NSR program for major sources located in areas that are attaining the NAAQS for the particular pollutant being discharged is commonly referred to as the Prevention of Significant Deterioration (PSD) program (see Section 3.2.1). PSD air permit applications are reviewed by the Federal Land Manager to assess potential impacts on National Parks and Monuments, especially regional haze;
- The NSR program for major sources locating in areas designated as nonattainment for the particular pollutant (see Section 3.2.1);
- Minor source NSR programs for non-major sources; and
- Review of new and reconstructed sources of air toxics.

Title V of the 1990 Clean Air Act Amendments developed minimum national air permitting standards (see Section 3.2.1). It requires permitting authorities to adopt permit programs (often called Part 70 programs) for all major sources of air pollution and many smaller sources of hazardous air pollutants in order to improve compliance with and enforcement of CAA requirements. All stationary sources are required by federal law to get operating permits that incorporate the rules that apply to the day-to-day operations at a facility. A detailed set of federal regulations, which sets standards for permitting programs, is found at 40 CFR Part 70.

The Title V program provides for the compliance and enforcement of CAA goals in several ways. The program enhances compliance and enforcement by including all of the CAA's requirements that apply to a facility in one document — the operating permit. For example, terms from the facility's pre-construction permit and requirements from the SIP that apply to the facility are included in the permit, along with all federal standards that apply. Additionally, although the operating permit generally does not create emissions limits, where necessary, the permit will add monitoring, record-keeping, and reporting requirements. The permit will require the facility to regularly provide the permitting agency with information that establishes whether or not the facility is in compliance with all of its applicable requirements. In other words, the facility must submit reports that contain the results of the facility's monitoring (e.g., monitoring the levels of pollutants emitted) or other required record-keeping at least semiannually. Some states have, and other states are moving toward combining their new source air pollution permit programs with the operating permit program under Title V of the Clean Air Act. Thus, a notice of a permit action might not specifically state that the permit is being issued under one of the new source programs, but that the source must meet all applicable new source requirements.

Title V permits undergo stringent review and public comment. It is likely that enforcement of air quality rules will be more stringent for facilities with Title V Operating Permits. Most power plants likely exceed at least one major applicability threshold and are subject to the program. Facilities must meet the terms of the Title V Operating Permit, including all emission and operating limitations. Because it is difficult for a facility to plan for future activities during application preparation, in most states the Title V application contains the opportunity to define Alternate Operating Scenarios (AOS) to anticipate future growth or changes to operation. If emission rates listed in a proposed AOS (due to new equipment, a change in fuel, etc.) comply with all applicable air quality regulations, then a facility can switch to that AOS without pre-approval from the agency. AOSs may be interpreted differently, however, by different states.

Title IV of the Clean Air Act Amendments helps govern permitted release of Acid Rain constituents, SO_2 and NOx (see Section 3.2.1.1). An acid rain permit is required by large-scale fossil fuel-fired power plants. A Designated Representative (DR), whose responsibilities are considerable and absolute, must administer each permit. As discussed in Section 3.2.1.1, one-for-one offsets of SO_2 and NOx emissions must be purchased, or otherwise obtained, each operating year. For SO_2, the offsets are obtained by a deadline following the calendar year totals of emissions. The offsets for NOx must be obtained and deposited with U.S. EPA by November of each year following the May to September ozone season.

In addition to acid rain permitting for NOx, power plants in 19 states east of the Mississippi, plus DC, are also subject to the NOx SIP Call (see Section 3.2.1). NOx is monitored during the ozone season (May to September) and emission offsets must be acquired from others or purchased on the commodities market, by the following November, to meet the required NOx budget. A continuous emission monitoring system (CEMs) is mandatory at each plant to constantly monitor emissions, and it is connected directly to EPA's data collection system. CEMs are required on turbine stacks for NOx, CO, SOx, oxygen, and PM (as opacity). Their maintenance and certification is critical to permitted compliance.

Based on detailed pollution modeling, EPA has allocated a budget (CAP) for the total NOx emissions from affected large plants within each state. States have typically been assigning 95% of this budget to existing sources and 5% to new projects in the first 3-year cycle (sources operating by May 1, 2004). This will change to 98% and 2% in subsequent control cycles. The implications of this are clear – many future projects will only receive a small fraction their budget allocations.

3.2.4 Recent Air Permitting Experience with Operating and Planned IGCC Plants[13]

As discussed in Chapter 1, there are currently two operating IGCC plants in the U.S. that were designed and constructed solely for power generation, both of which use coal and petroleum coke feedstocks. Tampa Electric's Polk power plant is a 250 MWe unit, located in Polk, County, Florida, that initiated operation in 1996, and the PSI Energy/Global Energy Wabash River Plant is a 262 MWe unit, located in West Terre Haute, Indiana, that began operating in 1995. Their operating air permit limits for criteria pollutants is presented in TABLE 3-6. The Polk NOx limit accounts for the recent BACT determination that reduced their turbine NOx emissions from 25 ppm to 15 ppm (see Section 3.2.1.1.2).

Recent environmental permitting of several IGCC projects by Global Energy Inc. is also reviewed in this section to provide insight into the IGCC permitting process. Global Energy Inc. is an Independent Power Producer (IPP) that owns and operates the Wabash River IGCC power plant and is currently developing IGCC projects in Kentucky and Ohio (EPA Regions 4 and 5, respectively). The two projects are mostly identical 520 MWe (net) IGCC plants based on the fixed-bed British Gas/Lurgi (BGL) gasification technology and use of two GE 7FA gas turbines.

Kentucky Pioneer will be located in Clark County, Kentucky on 300 acres leased from East Kentucky Power Cooperative (EKPC). The site is essentially a greenfield location, but EKPC has completed some infrastructure development at the site. The companion Lima Energy project is to be located in Lima, Ohio on a 63-acre brownfield site that dates to the late 1800s. Remediation of this site was undertaken by the City of Lima in anticipation of its development. Both Ohio EPA and USEPA have approved the remediation. Since both coal and refuse-derived fuel (RDF) will be fired at these plants, their permitting must also account for possible MSW regulations. While not covered here, the important issue of co-consumption of waste materials with coal in utility power plants is discussed in detail in Section 3.2.5.1.

TABLE 3-6. OPERATING IGCC AIR PERMIT LIMITS

CRITERIA POLLUTANT	POLK IGCC OPERATING PERMIT LIMIT[a]	WABASH RIVER IGCC OPERATING PERMIT LIMIT[b]
SO_2	1.43 lb/MWh (357 lb/hr)	1.25 lb/MWh[d] (315 lb/hr)
NOx	0.53 lb/MWh (15 ppm or 132 lb/hr)	1.35 lb/MWh (25 ppmvd or 0.15 lb/10^6Btu)
PM10, Particulate and H_2SO_4 Mist	0.288 lb/MWh[c] (72 lb/hr)	0.25 lb/MWh[e] (64 lb/hr)
CO	0.392 lb/MWh (98 lb/hr)	2.2 lb/MWh (1,660 tons/yr)[f]

[a] Values provided by TECO Energy.

[b] Basis: permit limits specified in final technical report for Wabash River Coal Gasification Repowering Project.

[c] Basis: 0.068 lb/MWh for particulate-only (17 lb/hr, excluding H_2SO_4 mist) and 0.22 lb/MWh (55 lb/hr H_2SO_4).

[d] Basis: 252 MWe @ 6000 hrs/year, 1,512,000 MWh/year.

[e] Basis: limits specified for combustion turbine (20% max opacity, 0.01 lb/10^6Btu H_2SO_4) and tail gas incinerator (6.8 tons/yr).

[f] Based on limits specified for flare, combustion turbine, and tail gas incinerator.

Due to the scale and complexity of the IGCC plants, as well as their uniqueness, Global Energy has indicated that the air permitting process was the most time consuming of the various permits. The Kentucky permit application took about eight months to prepare and file, and 20 months until final approval. It received its PSD permit from the state of Kentucky on June 7, 2001. The Ohio process, even though it benefited from the prior Kentucky effort, had taken 20 months through December 2001. The permit schedules were reported to be slowed by various factors, such as:

- An evolving design basis;
- Significant environmental agency staff turnover (4 to 6 months lost);
- Global Energy's "efforts to lobby against many agency 'default' assumptions and regulatory applicability determinations"; and
- Additional regulatory requirements were required as a result of incorporating co-processing of MSW/RDF and other renewable wastes, like biomass.

The Kentucky Pioneer plant will be constructed in an EPA-designated attainment area and is, therefore, subject to the PSD/BACT process. This process requires a plant to install the best available control technology that is in use elsewhere on the same or similar application, or can be reasonably determined to be applicable and technologically feasible (see Section 3.2.1). TABLE 3-7 identifies the PSD air permit emission limits required for the Kentucky and Ohio facilities.[13]

TABLE 3-7. PSD AIR PERMIT EMISSION LIMITS AT PROPOSED GLOBAL ENERGY IGCC PLANTS FOR SYNGAS FUEL[13]

POLLUTANT	lb/ 10^6 Btu	lb/MWh	COMMENT
NOx	0.0735	0.45	● 15 ppm – Syngas Primary Fuel ● 25 ppm – Natural Gas Backup Fuel ● No SCR ● Natural Gas Fuel – Annual Use Limit
CO	0.032	0.19	● 15 ppm – Syngas ● 25 ppm – Natural Gas ● Limit on Natural gas – Slightly Higher
SOx	0.032	0.19	● Basis is 40 ppm H_2S in Syngas
PM	0.011	0.067	● KPE Stacks of Two CTs are Within One Internal Diameter – Due to Terrain
VOC	0.0044	0.0267	
Beryllium	6.0×10^{-7}	3.6×10^{-6}	Kentucky only
Formaldehyde	3.55×10^{-4}	0.0022	Ohio only

Notes:

BACT analysis for Kentucky Pioneer must be redone as a new plant after 18-24 months of operation
Nitrogen and H_2O diluent results in ~ 10 ppm H_2S as-fired
Transient (i.e., start-up, shut-down, and upset) NOx emissions are included in Annual Limit
PM was most challenging pollutant to resolve in modeling
Formaldehyde is a concern with natural gas, but is less so with syngas

An important aspect of the BACT determination has focused on NOx emissions and the use of SCR technology to minimize those emissions. Global Energy has argued against the use of SCR for reasons of "expected performance and costs in this unique application." Their arguments have currently resulted in a PSD permit that does not require use of SCR, but the permit contains the requirement to re-evaluate BACT after two years of operation. Section 2.2.6 of this report discusses the feasibility and cost of using SCR in IGCC systems. Note also that the January 2002 NOx BACT determination for the Polk IGCC plant did not require the use of SCR.

Global Energy's experience also indicates that SO_2 stack emissions is another permitting issue that must deal with uncertainty as to the stringency of BACT. They point out that an existing plant, which has been effectively retrofitted with IGCC technology (e.g., Wabash River), can avoid the PSD process by reducing emissions from the original boiler by shutting it down ("netting-out"). However, a new plant cannot use this approach to avoid PSD. Their experience indicates that a likely range for BACT for IGCC SO_2 emissions would be:

- Least stringent – +99% removal of sulfur from IGCC synthesis gas (< 160 ppm H_2S).
- Most Stringent – Approximately 40 ppm total sulfur (expressed as H_2S) in the synthesis gas. This is approximately equivalent to 8 ppm SO_2 emissions in the turbine exhaust gas.

The minimum limit is based on the NSPS level that refineries have to achieve (40 CFR 60 Subpart J) for their internally generated fuel. The most stringent level is based on the current practical capability of commercially available solvent-based acid gas control systems and catalytic conversion systems (to convert COS to H_2S), along with sulfur conversion processes (e.g., sulfur or sulfuric acid plants). From a broader perspective, TABLE 3-8 provides Global Energy's list of likely BACT determinations for most of the key air emissions and sources typically found at an IGCC facility.

TABLE 3-8. POSSIBLE BACT DETERMINATIONS - IGCC AIR EMISSION SOURCES

EMISSION SOURCE	AIR POLLUTANT	POTENTIAL BACT
GE 7FA Gas Turbines, Primary Fuel – Clean syngas from coal gasification	NOx	Steam/diluent injection to 15 ppm @ 15% O_2 or SCR to 3-6 ppm (see Section 2.2.6.1.1)
	SO_2	Acid gas removal (>99%) with sulfur recovery, 40-160 ppm H_2S (equivalent) in Syngas (see Section 2.2.1.1)
	CO	Good combustion techniques or possibly use of oxidation catalyst (see Section 2.2.1.4)
	PM10	Good engineering design and proper operation (see Section 2.2.1.2)
	VOCs	Good engineering design and proper operation (see Section 2.2.4)
	Trace Metals	Not mentioned by Global Energy, but add-on controls for mercury may be a future need
Flare	NOx, SO_2, CO, PM10, VOCs	Good flare design, consistent with NSPS Subpart A, and treatment of flared syngas in acid gas removal system
Material Handling Operations	PM10	Conveyor hood covers, chutes, covered trucks, pave roads, water spray, maintain moisture, and bag houses
Cooling Tower	PM10	High efficiency drift eliminators

3.2.5 Gasification of Alternative Feedstocks –Pertinent Air Regulations and Permitting

This report focuses on coal as the primary fuel for IGCC power plants. However, other feedstocks may be co-gasified with coal (or gasified as the primary feedstock) due to the flexibility offered by various gasifier designs, and the need to improve economics through use of alternative low-cost feedstocks. Of course, in order to capitalize on feedstock versatility, the plant would need to be designed to handle the feedstock variability. Potential non-hazardous feedstocks include renewable fuels, such as municipal solid waste (MSW), biomass, and organic agricultural waste, as well as non-renewable fuels like petroleum coke, tires and plastics. Besides the technical complications that may result from a multi-fuel capability, a project developer must also address potential regulatory and permitting requirements that can differ from coal-only gasification. Existing laws and regulations deal with "co-fired combustion" of non-hazardous MSW materials. Applicability to gasification and IGCC is subject to interpretation of EPA rules.

Federal and state laws and regulations may establish either incentives or barriers for implementing co-gasification projects, depending on how they relate to current environmental constraints on coal combustion. In general, key environmental statutory constraints on any combustion/gasification process, including co-gasification, relate to both present implementation and plant design/operation. The former refers to project siting and environmental permit approval procedures and requirements, which are usually complex and may not be well coordinated in many states. Additionally, these permit requirements and procedures may vary depending upon the type and mix of fuels consumed at a facility, particularly when wastes constitute a portion of the fuel supply. Constraints on plant design and operation deal with the following:

- **Flue gas emissions** - control of criteria pollutants and HAPs
- **Waste and byproduct disposal/utilization** - control of soil and groundwater contamination
- **Fuel handling and storage** - provide for facility safety and prevent site contamination

Electric utilities (municipal- and investor-owned) and Independent Power Producers (IPPs) are almost always affected by these constraints, while so-called Qualifying Facilities (e.g., small power producers or cogenerators) may be impacted somewhat differently.

3.2.5.1 Co-Gasification of Coal and Waste Materials

Currently, few Federal or state regulations specifically govern co-consumption of waste materials in fossil-based utility power plants, be they gasifiers or combustors. However, two regulations that may apply are EPA's Municipal Waste Combustor (MWC) New Source Performance Standard rules for large units that consume more than 250 tons/day [40 CFR, Chapter I, Subchapter C, Part 60, Subpart Eb] and for small units that consume between 35 to 250 tons/day [40 CFR, Chapter I, Subchapter C, Part 60, Subpart AAAA]. Both define applications in which MSW or refuse-derived fuel (RDF) is "co-fired" with non-municipal solid waste fuel (e.g., coal). Depending upon the percentage (by weight) of MSW utilized, co-consuming installations could be regulated as either "coal burning facilities" or as "municipal waste combustors."

EPA defines a municipal waste combustor unit as "equipment that combusts solid, liquid, or gasified municipal solid waste including, but not limited to, field-erected incinerators (with or without heat recovery), modular incinerators (starved-air or excess-air), boilers (i.e., steam generating units), furnaces (whether suspension-fired, grate-fired, mass-fired, air curtain incinerators, or fluidized bed-fired), and pyrolysis/combustion units." A pyrolysis/combustion unit is defined as a "unit that produces gases, liquids, or solids through the heating of municipal solid waste, and the gases, liquids, or solids produced are combusted and emissions vented to the atmosphere. While this rule does not specifically define gasification technology as subject to its requirements, the current EPA interpretation is that gasification technology "gasifies the waste" and the gas turbine is effectively the combustor.[13]

The Clean Air Act of 1990 (Section 129g - definitions) stipulates that "utility combustors" that burn a fuel stream comprised, in aggregate, of equal to or less than 30% MSW or RDF, by weight on a 24-hour basis, are not considered to be municipal solid waste combustors. Such combustors are required to only submit reports quantifying the amount of MSW and other fuels burned. This implies that coal gasification facilities such as IGCC, that consume less than 30% MSW, are likely to be treated the same as units that consume only coal. In this case, all of the coal-related regulations and permitting issues discussed in this section are applicable. However, if the MSW (or RDF) content exceeds 30% capacity, and capacity is greater than 250 tons per day of MSW, then the EPA Municipal Waste Combustor New Source Performance Standard rule [40 CFR 60, Subpart Eb] may be triggered. If the MSW content exceeds 30% capacity, and capacity is between 35 to 250 tons/day of MSW or RDF, then EPA's MWC New Source Performance Standard rule for small MWC units [40 CFR 60, Subpart AAAA] may be triggered. This brings into play different NSPS, materials handling requirements, and operator certification/training requirements associated with these rules.

Other key features of the Clean Air Act that can impact co-consumption of fuels in new and retrofit IGCC plants appear to be:

- Significant reconstruction at an existing coal-fired plant for the purposes of adding co-firing capability could trigger the reconstruction rule that would require the facility to meet the NSPS for criteria pollutants. Furthermore, BACT and LAER apply to certain "modified" generation sources. A source is considered modified if its air pollutant emissions are increased by a physical or operational change, including the use of a new fuel. Additionally, a source can be considered reconstructed irrespective of any change in emission rate, if the fixed capital cost of new equipment exceeds 50% of the cost of replacing the unit, and if it is technologically and economically feasible to meet the NSPS.[15]

- The NSPS for Industrial-Commercial-Institutional steam generating units [40 CFR 60 Part Subpart Db] effectively provides an incentive for consuming waste fuels by imposing less stringent emission limits for boilers that restrict the amount of coal that they consume. For example, a unit that limits the combustion of coal to 30% or less of its annual rated capacity is exempt from the 90% SO_2 reduction requirement, although it still must meet the coal-fired emission limit of 1.2 lb/10^6 Btu. The particulate emission standards are also relaxed for sources co-firing other fuels with coal; the 0.05 lb/10^6 Btu limit is relaxed to 0.10 lb/10^6 Btu for units that burn more than 10% of fuels other than coal.

- BACT determinations often require more stringent pollution control than NSPS, since the EPA has held that a permitting agency must not only consider the environmental impact of regulated pollutants, but also the environmental impact of unregulated pollutants (e.g., air toxics) that might be affected by the choice of control technology. Co-firing may represent such a case.

3.2.5.2 Siting and Permitting of Co-Gasification Facilities Based on Experience with Co-Combustion Facilities

Investigation of siting and permitting issues related to existing co-fired combustion facilities (not co-gasification facilities) revealed that many of these facilities were originally sited and permitted as coal-fired power plants. When these facilities were converted to co-firing, new permits were obtained. In general, the new permits were awarded based on the modified plant's ability to meet the emissions specifications for which they were originally permitted. These existing facilities did not face any siting requirements.

Following the 30% MSW rule discussed earlier, new greenfield utility plants that are designed for co-consumption of less than 30% waste material and coal will probably face the siting and permitting issues involved in constructing a coal-fueled facility, since coal is the primary fuel. However, differences that may come into play will surely involve waste transportation, storage, fugitive emissions, and odor, which will depend upon the quantities of waste being transported, the distances involved, mode of transportation, and transportation across state boundaries.

However, if characterized as a “waste combustor,” the unit is subject to specific siting requirements (§60.57b and §60.1125) that require a detailed siting analysis of the affected facility’s impact on ambient air quality, visibility, soils, and vegetation. It must also consider air pollution control alternatives that “minimize, on a site-specific basis, to the maximum extent practicable, potential risks to the public health or the environment.” Specified pollutant emission limits are listed in TABLE 3-9.

TABLE 3-9. STANDARDS FOR MUNICIPAL WASTE COMBUSTOR METALS, ACID GASES, ORGANICS, AND NITROGEN OXIDES (40 CFR §60.52B, 40 CFR §60.1465)

POLLUTANT	SMALL & LARGE MWC LIMITS (@ 7 % O_2)
Carbon Monoxide (CO)	150 ppm
Sulfur Oxides (SOx)	30 ppm or 80% sulfur removal, whichever is less stringent
Nitrogen oxides (NOx)	180 ppm – 1st year 150 ppm after 1st year
Particulate Matter	24 mg/Nm^3 (dry) and < 10% opacity (6-minute average)
Dioxin and Furan	30 ng/Nm^3 (dry)
Hydrogen Chloride (HCl)	25 ppm or 95% reduction, whichever is less stringent
Mercury (Hg)	0.08 mg/Nm^3 (dry) or 85% reduction by weight, whichever is less stringent
Cadmium (Cd)	0.02 mg/Nm^3 (dry)
Lead (Pb)	0.2 mg/Nm^3 (dry)

Unlike the NSPS for coal-fired units, NSPS for MWC plants sets limits for trace organics and metals air emissions. The capability to meet these limits will depend upon the particular fuels chosen, their constituent make-up, and the proportions fired. Mercury emission control may be required, but control technologies are available (see Chapter 2, Section 2.2.6).

3.2.5.3 State Regulations, Laws, and Policies

No information has been found to indicate that any state has formal regulations, laws, or policies that specifically govern co-consumption of coal and waste fuels. Discussions with different states indicate the following requirements for co-firing coal and waste materials (assuming that the plants do not exceed the 30% MSW rule):[16]

- Siting and permitting are likely to be handled on a case-by-case basis
- Air permitting is likely to be based on coal-only operation
- Solid waste permitting and regulation is likely to be based on coal-only operation, but toxicity testing of the ash or slag may be required
- Preparation of environmental impact statements (EIS) for certain types of projects are required by the environmental policy acts of some states
- Health risk assessments are required by some states for some combustion facilities, especially those combusting wastes
- Specific site characteristics can subject facilities to additional permitting requirements. Co-combustion projects on sites with wetlands, in flood plains, or in coastal areas may be subjected to additional regulations.

State and local regulation of fuel storage facilities tends to be less uniform than air pollution and hazardous waste regulation. State and local agencies are usually concerned with fugitive air emissions and water quality impacts from storm water runoff or leachate. The environmental impacts of waste fuel storage and handling will differ from that of coal piles; therefore, state and local regulation can be expected to be customized to mitigate specific concerns related to combustible waste materials. Such concerns may involve 1) odor from waste decomposition, 2) fire risks from spontaneous combustion, and 3) organic contamination from leachate and runoff.

Co-consumption of solid wastes in utility power plants that have only burned coal may add additional permitting requirements, as imposed by state solid waste laws. In addition to air and water pollution, state regulation of solid waste facilities typically focuses on fire and explosion hazards, public health concerns involving disease, rodents and insects, objectionable odors, and issues concerning disposal capacity. Solid waste disposal issues may dominate any other issues for plants seeking permission to co-combust or co-gasify refuse with coal.

3.2.5.4 Recent IGCC Experience with Waste Co-Gasification

Global Energy intends to utilize renewable fuels, in addition to coal, at its planned IGCC projects in Kentucky and Ohio (see Section 3.2.4).[13] RDF pellets will initially be the alternate fuel of choice. Based on the plant's size and MSW content, EPA has imposed the NSPS Subpart Eb requirement, as discussed previously. While Global Energy has stated publicly that they do not agree with this action, because they "oppose the association of gasification with conventional waste combustion," they have included the requirements of the subpart into their Kentucky permit application. TABLE 3-10 compares the expected maximum performance levels of the IGCC air pollutants with the Subpart Eb emission standards. As shown, the expected environmental performance is projected to be significantly better than required by the MWC regulation.

TABLE 3-10. COMPARISON OF PROJECTED IGCC PERFORMANCE WITH MWC NSPS[13]

POLLUTANT	Modeled PSD & HAP Limit			MWC LIMIT (@ 7 % O_2)
	mg/Nm^3	ng/Nm^3	ppmv	
Carbon Monoxide (CO)			39	150 ppm
Sulfur Oxides (SOx)			15	30 ppm or 80% sulfur removal, whichever is less stringent
Nitrogen oxides (NOx)			Not provided - Likely to be much lower than limit	180 ppm – 1st year 150 ppm after 1st year
Particulate Matter	8.2			24 mg/Nm^3 (dry) and < 10% opacity (6-minute average)
Dioxin and Furan		0.01		30 ng/Nm3 (dry)
Hydrogen Chloride (HCl)			< 1	25 ppm or 95% reduction, whichever is less stringent
Mercury (Hg)	0.0006			0.08 mg/Nm^3 (dry) or 85% reduction by weight, whichever is less stringent
Lead (Pb)	0.008			0.2 mg/Nm^3 (dry)
Cadmium (Cd)	0.004			0.02 mg/Nm^3 (dry)

3.2.6 Review of Existing State Air Regulations and Permitting Applicable to Gasification-Based Power Systems

The CAAA requires the submission of SIPs by each state to provide for the regulation of air pollutants. As stated previously, individual states have the option to outline standards and regulations that are at least as stringent as federal standards, and may be more stringent. While complete analysis of state and county regulatory plans is beyond the scope of this report, information is included to provide summary state level regulatory information as it may apply to gasification-based power systems. Primary attention is focused on the major aspects of key regulatory issues, including emission and performance standards for criteria pollutants and HAPs, new source review (including PSD and nonattainment issues), and acid rain provisions of the CAAA. Particular focus is directed at states that currently have IGCC facilities. An attempt is also made to indicate where state standards differ from federal standards.

No attempt is made to analyze the permitting process or enforcement provisions in individual state summaries. While every attempt is made to include the most recent regulatory status, interested parties should contact the appropriate state regulatory agency for more information.

3.2.6.1 Florida

Tampa Electric Company (TEC) is responsible for the operation of the Polk Power Station, which includes a 250 MWe IGCC plant firing syngas or No. 2 fuel oil. This facility is located in Polk County, Florida. Appendix 1B, Section 1B.3 provides a description of the Polk plant.

Currently, SIP approval has not been given to Florida for power plants that are subject to the Power Plant Siting Act (PPSA).[17] The PPSA provides for certification of steam-electric or solar power plants 75 MW or larger in size and is intended to consolidate and streamline the permitting process. Because the SIP is not approved, Florida Department of Environmental Protection (FDEP) is acting on behalf of the EPA. Information on existing Florida SIP air quality regulations is provided as a guideline to possible future applicability to those sources in which the SIP is not currently applicable.

3.2.6.1.1 Criteria Pollutants

NAAQS – 62-204.240 Florida Administrative Code (F.A.C.) adopts all of the Federal NAAQS, except for 24-hour and annual arithmetic mean standards for SO_2. Florida requires more stringent ambient air quality standards, setting the levels as follows:

- Maximum 24-hour Concentration – 0.1 ppm (260µg/m^3)
- Annual Arithmetic Mean – 0.02 ppm (60µg/m^3)

NSPS – 62-204.800 F.A.C. adopts Federal 40 CFR 60 Subparts Da and GG, which is applicable to Electric Utility Steam Generators and Stationary Gas Turbines.

Pre-Construction Review (NSR)

As of August 2 2001, Florida had no areas of nonattainment.

Prevention of Significant Deterioration (PSD) – Specifically applicable to IGCC, under certain circumstances the installation or operation of a permanent Clean Coal Technology Demonstration Project that constitutes repowering shall not be subject to the NSR review process. For facilities that undergo NSR, BACT is required for subject pollutants. Additionally, Florida has several National Parks and Wilderness areas that are designated Federal Class I areas requiring additional restrictions for sources located outside the Class I area but have a potential for significant impact on that Class I area. Therefore, sources located within 100 kilometers of a Class I area must also consider impairment of area visibility. 62-212.500(2)(f) F.A.C. provides for sources located in PSD areas which influence nonattainment areas (areas of influence on nonattainment areas) to comply with requirements applicable to sources located in nonattainment areas. Specific provisions are included for exemption of nonattainment compliance requirements of VOC and NOx emissions from sources located within areas of influence of nonattainment source regulations (62-212.500(2)(f)2.a).

Nonattainment Areas (if applicable) – In addition to LAER, pollutant specific offsets are required. For all criteria pollutants, except for NOx and VOCs, offsets of greater than a 1:1 ratio are required and must be from the nonattainment area that the source is located. NOx and VOC offsets may be obtained from another nonattainment area of equal or higher classification or another area that contributes to the nonattainment area in which the source is located. Emission offsets for NOx and VOCs in areas that are nonattainment for ozone are as follows:

Marginal	1.1:1
Moderate	1.15:1

Areas that are transitional for ozone must be at least 1:1 for VOCs and emission offsets are not required for NOx. Federal Class I visibility considerations also apply.

Pre-Construction Review provisions also exist for sulfur storage and handling facilities with an annual throughput of 5,000 or more tons of elemental sulfur. Depending on sulfur production at IGCC facilities, compliance may be required. Specific emission and deposition analysis may be required.

Acid Rain Provisions

Florida Code (62-214.100 F.A.C. and 62-204.800 F.A.C.) adopts Federal Acid Rain regulations outlined by 40 CFR 72, 73, 75 and 76. 62-214 F.A.C. includes certain additional administrative and exemption requirements, including provisions for submission of the Acid Rain Part of an operation permit application of formerly exempt sources.

3.2.6.1.2 Hazardous Air Pollutants (HAPs)

Florida Code (62-204.800 F.A.C.) adopts by reference multiple provisions and standards of 40 CFR 61 and 63 regarding HAP emission requirements.

3.2.6.2 Indiana

The Wabash River Coal Gasification Repowering Project, sited at PSI Energy's Wabash River Generating station in West Terra Haute, Indiana, successfully demonstrated commercial application of Global Energy's E-GAS^{TM} coal gasification technology with a 262 MWe IGCC system. The gas turbine fires syngas for operations, and No. 2 fuel oil for startup, but the turbine is currently being converted to replace the fuel oil with natural gas. Appendix 1B, Section 1B.4 provides a description of the Wabash River plant.

The project is a joint venture of Global Energy Inc. (Global acquired Destec Energy's gasification assets from Dynegy in 1999) and PSI Energy, part of Cinergy Corporation.[18] While an administrative distinction is made between the two operations, Indiana Department of Environmental Management (IDEM) and Vigo County Air Pollution Control (VCAPC) refer to the gasifier and combustion turbine as a single source. IDEM and VCAPC had issued separate Part 70 Title V permits to both facilities. The coal gasification stationary source emission components are identified as Manufacturing, Chemical and Allied Products, Industrial Organic Chemicals, Not Elsewhere Classified (SIC 2869) and include the following: an acid gas recovery unit, a sour water treatment system, a tank venting system, a tail gas incinerator, a flare, and fugitive equipment leak emissions. The primary electricity generating components are identified as Electric Services (SIC 4911) and include a boiler, fuel preheater, and the combustion turbine.

3.2.6.2.1 Criteria Pollutants

NAAQS – 326 Indiana Administrative Code (IAC) 1-3-4 adopts all Federal primary and secondary NAAQS outlined by 40 CFR 50. Additionally, Indiana is also included in the SIP Call area for NOx review.

NSPS – 326 IAC 12-1-1 incorporates by reference all portions of federal NSPS regulations outlined by 40 CFR 60.

Pre-Construction Review (NSR)

As of August 2, 2001, Indiana had four counties that are nonattainment for ozone. Of those four, a portion of one county is nonattainment for PM10 and SO_2.

Prevention of Significant Deterioration (PSD) – For facilities that undergo NSR, BACT is required for subject pollutants. Currently Indiana has no Federal Class I or Class III areas. Indiana also requires that any air quality analysis demonstrate that increased emissions by the proposed major stationary source or source modification will not exceed 80% of maximum allowable increases over baseline SO_2, NOx and PM10 concentrations (326 IAC 2-2-6). Sources located in attainment areas but significantly influence air quality of a nonattainment area must comply with LAER requirements and participate in the emission offset program for nonattainment areas for the specific pollutant (326 IAC 2-3-2(e)).

Nonattainment Areas – Sources located in nonattainment areas must comply with LAER requirements for the specific pollutant (326 IAC 2-3-2). Additionally, emission offsets are required such that a ratio greater than 1:1 is achieved. Both VOCs and NOx compounds are considered for areas designated nonattainment for ozone. For those areas, the minimum offsets are as follows:

- Marginal 1.1:1
- Moderate 1.15:1
- Serious 1.2:1
- Severe 1.3:1

Emission offsets may be obtained from the same area or other nonattainment areas of equal or higher nonattainment status that directly contribute to the air quality of the nonattainment area where the new or modified source is located (326 IAC 2-3-5).

Acid Rain Provisions

Indiana adopts Federal requirements of CAA Title IV, incorporating by reference 40 CFR 72 through 40 CFR 78, along with various sections of the Federal Register. Indiana is identified as the permitting authority (326 IAC 21-1-1).

3.2.6.2.2 Hazardous Air Pollutants (HAPs)

326 IAC 2-4.1-1 outlines new source toxic control requirements CAA § 112(g)(2)(B), implementing provisions of 40 CFR 63 along with 61 FR 68384, December 27, 1997, *Hazardous Air Pollutants; Regulations Governing Constructed or Reconstructed Major Sources.* Indiana specifically exempts electric utility steam generating units until they are added to the source category list under CAA § 112(c)(5). Indiana does not adopt 40 CFR 63.43(c), (f), or (h) but sets forth its own administrative and public notice procedures in 326 IAC 2-1.1 and 326 IAC 2-5.1.

Indiana Code 326 IAC 14-1 specifically addressed HAP regulations and has several additional provisions for the regulation of the following HAPs: asbestos, beryllium, mercury, vinyl chloride, fugitive equipment leaks of volatile HAPs, fugitive benzene leaks, and benzene emissions from coke oven by-product recovery plants. Indiana adopts all 40 CFR 61 emission standards applicable to individual HAPs except for several provisions for fugitive volatile HAPs, benzene from coke oven byproduct recovery plants and asbestos from demolition and recovery operations.

3.2.6.3 Louisiana

Louisiana Gasification Technology Incorporated (LGTI) operated a Clean Coal Technology demonstration plant at the Dow Louisiana Division chemical complex in Plaquemine, Louisiana. The plant produced 160 MWe, co-firing syngas with natural gas at a ratio of approximately 63% syngas to 37% natural gas. The success of the LGTI plant led to the Wabash Repowering demonstration project. Both plants utilized the same E-GAS^{TM} coal gasification technology. This plant is described in Appendix 1B, Section 1B.2.

3.2.6.3.1 Criteria Pollutants

NAAQS – Louisiana Administrative Code (LAC) 33:III.Chapter 7§ 705 adopts all Federal primary and secondary NAAQS outlined by 40 CFR 50.

NSPS – LAC 33:III.Chapter 30 incorporates, by reference, all portions of federal NSPS regulations outlined by 40 CFR 60, with modifications addressing administrative and reporting issues.

Pre-Construction Review (NSR)

As of August 20, 2001, Louisiana has seven parishes that are nonattainment for ozone only. All parishes are designated as attainment for all other pollutants.

Prevention of Significant Deterioration (PSD) – LAC 33:III.Chapter 5§509 outlines specific Louisiana PSD permitting requirements. For facilities that undergo NSR, BACT is required for subject pollutants. Currently, Breton National Wildlife Refuge, located in Louisiana, is designated a Federal Class I area requiring additional restrictions for sources located outside the area that have a potential for significant impact on that Class I area. Therefore, sources located within 100 kilometers of a Class I area must also consider impairment of area visibility. LAC 33:III.Chapter 6 provides for the participation of emission sources located in ozone attainment areas in an Emission Reduction Credits Banking Program.

Nonattainment Areas – Sources located in nonattainment areas must comply with LAER requirements for the regulated pollutant (LAC 33:III.Chapter 5§504.D.2). For ozone areas designated as incomplete data, transitional nonattainment, marginal, moderate, serious or severe nonattainment for ozone, VOCs are the regulated pollutant. Emission offsets of a ratio greater than 1:1 are required in addition to LAER. Emission offsets for ozone nonattainment areas are as follows (LAC 33:III.Chapter 5§504.D.5):

Marginal	1.1:1
Moderate	1.15:1
Serious	1.2:1 w/ LAER
Severe	1.3:1

Louisiana also includes emission offset requirements for areas of transitional ozone status and areas that are designated incomplete data for ozone. These areas require a 1.1:1 emission offset. Additionally, for areas designated as serious for nonattainment for ozone, LAER requirements can be avoided for major sources emitting greater than 100 tons per year of VOCs by obtaining internal offsets of 1.3:1 or greater (LAC 33:III.Chapter 5§504.D.3).

Emission offsets may be obtained from the same area or other nonattainment areas of equal or higher nonattainment status that directly contribute to the air quality of the nonattainment area where the new or modified source is located (LAC 33:III.Chapter 5§504.D.9). Additionally, emission impacts on Federal Class I areas must be considered.

Acid Rain Provisions

Louisiana provides Acid Rain Program requirements in LAC 33:III.Chapter 5§505. Additionally, Louisiana specifies that Federal requirements of CAA Title IV supersede Louisiana regulations in any situation in which federal regulations are inconsistent with Louisiana code (LAC 33:III.Chapter 5§505.A.4).

3.2.6.3.2 Hazardous Air Pollutants (HAPs)

In the 1987 Toxic Release Inventory Report, Louisiana was ranked among the top five states in totals of toxic air emissions. In response, the state legislature enacted Louisiana Revised Statute 30:2060 in 1989. Among other mandates, the law called for: 1) the establishment of a “toxic air pollutant emission control program,” 2) the development of a 1987 toxic air pollutant (TAP) emission baseline, and 3) the reduction of statewide TAP emissions by 50 % from 1987 levels by December 31, 1996. The program aggressively achieved a 60% reduction by 1998. The Comprehensive Toxic Air Pollutant Emission Control Program (LAC 33:III.Chapter 51) became one of the most stringent state air toxics rule in the nation. In addition to incorporating Federal MACT standards, the law includes emission-reporting requirements for all major sources of toxic air pollutants and sets an ambient air standard for each pollutant. Furthermore, in addition to the toxic air pollutants identified in the CAAA, Louisiana regulates several additional compounds, bringing the list to over 200 pollutants.[19]

TAPs regulated by Louisiana, but not on the Federal HAP list are:[20]

- Ammonia
- Barium and barium compounds
- N-Butyl alcohol
- Chlorine dioxide (chlorine peroxide)
- Copper and copper compounds
- Diaminotoluene
- 2,6-Dinitrotoluene
- Hydrogen sulfide
- Nitric acid
- Pyridine
- Sulfuric acid
- Toluene-2,6-Diisocyanate
- Zinc and zinc compounds

3.2.6.4 Other States With a Large Base of Existing Coal-Fueled Electric Power Generation

TABLE 3-11 presents summary information of state level environmental regulations for selected states that currently have a significant number of coal-fueled electric generating units. These states are Alabama, Georgia, Illinois, Kentucky, New York, Ohio, Pennsylvania, Tennessee, Texas, and West Virginia. Qualitative generalizations are provided for the major air pollution regulations (including hazardous air pollutants). More detailed information is provided in Appendix 3A.

3.2.7 Overview of Future Air Pollution Regulations Potentially Applicable to Gasification-Based Power Systems

3.2.7.1 Multiple Pollutant Control

In the past several years, lawmakers have introduced legislation for multiple pollutant control that would limit emissions of criteria pollutants SO_2 and NOx, as well as CO_2 and mercury from electric power plants. While the current Administration has made it clear that the United States would neither participate in the Kyoto Protocol nor require mandatory CO_2 source emission reductions, the current interest in multi-pollutant legislation indicates foreseeable regulatory changes for fossil-based utility power producers.

TABLE 3-11. AIR REGULATIONS FOR SELECTED STATES

STATE	CRITERIA POLLUTANTS	HAPS
Alabama	Generally follows federal regulations.	Incorporates by reference.
Georgia	Generally follows federal regulations.	Incorporates by reference.
Illinois	Generally follows federal regulations.	Generally follows federal regulations Additional requirements include Organic Materials Emissions Standards and an emission banking and trading program for volatile organic material sources located in the Chicago nonattainment area.
Kentucky	Generally follows federal regulations.	Generally follows federal regulations. Kentucky has set state air quality standards for hydrogen fluoride and hydrogen sulfide.
New York	New York has developed numerous state specific air quality regulations. Additionally, several counties have developed their own unique requirements.	Incorporates by reference.
Ohio	Generally follows federal regulations.	Generally follows federal regulations.
Pennsylvania	Generally follows federal regulations. A NOx budget and allowance trading system has also been established.	Generally follows federal regulations. Pennsylvania has set state air quality standards for beryllium, hydrogen fluoride, and hydrogen sulfide.
Tennessee	Generally follows federal regulations.	Generally follows federal regulations.
Texas	Texas air pollution regulations have a number of significant variations from federal standards. Texas also imposes an emission fee based on annual tonnage emissions of regulated pollutants.	Generally follows federal regulations.
West Virginia	Generally follows federal regulations. LAER required for new major sources located in attainment areas that will impact a nonattainment area.	Incorporates by reference.

Four multi-pollutant control legislative proposals were introduced in the 107th Congress:

- Clean Smokestacks Act of 2001 (H.R. 1256 – Rep. Henry Waxman, et al.)
- The Clean Power Act of 2001 (S.556 – Jeffords, et.al.)
- The Clear Skies Act of 2002 (S.2815 – Bush Admin/Smith and H.R. 5266 – Barton & Tauzin)
- The Clean Air Planning Act of 2002 (S.3135 – Carper, Breaux, Baucus, & Chafee)

Only the last three proposed Acts are currently under serious deliberation, and they significantly differ on matters such as compliance methods, emissions targets, deadlines, compliance regions, and inclusion of mandatory CO_2 reductions. This proposed legislation is discussed below.

3.2.7.1.1 Legislation proposed in the 107th Congress

S. 556 - Clean Power Act of 2001 (Sen. Jim Jeffords, I-VT)

This proposed legislation amends the Clean Air Act to reduce emissions from electric power plants and for other purposes (see TABLE 3-12 and associated baselines in TABLE 3-13).

TABLE 3-12. S. 556 CLEAN POWER ACT OF 2001 –EMISSION GOALS

Pollutant	Reduction Target	Yearly Cap for All Power Plants	Yearly Cap for Coal Plants	Schedule
SO_2	Aggregate reduction of 75% beyond Phase II requirements under title IV	2.24 million tons	2.13 million tons	January 1, 2007
NOx	Aggregate reduction of 75% from 1997 emissions levels	1.55 million tons	1.4 million tons	January 1, 2007
CO_2	Stabilize at 1990 levels	476.7 mmtC (525.47 million tons C)	408.8 mmtC (450.62 million tons C)	January 1, 2007
Mercury	Aggregate reduction of 90% from 1999 levels	4.8 tons	4.8 tons	January 1, 2007

TABLE 3-13. S. 556 CLEAN POWER ACT OF 2001 -- BASELINES

Pollutant	Standard for Measurement	Baseline Emissions All	Baseline Emissions Coal	Source
SO_2	Phase 2 Title 4	8.95 million tons	8.5 million tons	EPA http://www.epa.gov/airmarkets/arp/overview.html#phases
NOx	1997	6191 thousand tons	5.6 million tons	EPA (www.epa.gov/oar/aqtrnd98/tables/tablea-4.prn)
CO_2	1990	476.7 mmtC = 525.47 million tons C	408.8 mmtC = 450.62 million tons C	EIA: Emissions of Greenhouse Gases in the United States, 1985-1990
Mercury	1999	48 tons	48 tons	EPA: National emission inventory of electric utility mercury (NATEMIS)

S.2815 and H.R. 5266 - The Clear Skies Act of 2002 (Bush Admin/Smith and Barton & Tauzin)

The legislation proposes nationwide caps for SO_2 and mercury and regional caps (east-west) for NOx. It differs from other proposed legislation primarily in targeted emission reductions and proposed compliance dates, as shown in TABLE 3-14. While the final NOx and SO_2 targets are close to those proposed in S.556 and H. R. 1256, mercury reductions are not as stringent. The proposed legislation provides for market-based cap and trade emission programs for NOx and SO_2, although it also provides for mercury emission trading. Absent are any mandatory CO_2 emission regulations.

TABLE 3-14. CLEAR SKIES ACT - ANNUAL POWER PLANT EMISSION TARGETS

Pollutant	Current	Mid-Term 2008-2010	2018
SO_2	11 million tons	4.5 million tons	3 million tons
NOx	5.4 million tons	2.1 million tons	1.7 million tons
Mercury	48 tons	26 tons	15 tons

S.3135 - The Clean Air Planning Act of 2002 (Carper, Breaux, Baucus, & Chafee)

Introduced late in 2002, the legislation sets national caps on SO_2, NOx, CO_2, and mercury emissions from electric power plants. It is to be implemented in phases as detailed in TABLE 3.15.

EPA would revisit the emissions targets for all four emissions 15 years after the date of enactment and could change the targets starting 20 years after the date of enactment. NO_X, mercury and CO_2 allowances would be allocated based on electricity generated during a rolling 3-year period. SO_2 allowances are allocated using the methodology of the existing Title IV Acid Rain program, but with provisions for allowances for new sources.

TABLE 3-15. CLEAN AIR PLANNING ACT - ANNUAL POWER PLANT EMISSION TARGETS

Pollutant	Current Baseline	2008	2012	2015
SO_2	11 million tons	4.5 million tons	3.5 million tons	2.25 million tons
NOx	5.4 million tons	1.87 million tons	1.7 million tons	-
Mercury	48 tons	24 tons	5-16 tons (EPA to set cap)	5-16 tons (EPA to set cap)
CO_2	2.4 Billion Tons	~2.6 Billion Tons	~2.3 Billion Tons	-

Caps would be implemented using a market-based cap-and-trade program so that reductions may occur where they may be most efficiently achieved. Facilities that achieve early reductions or reduce emissions below the norm would benefit from being able to sell their excess allowances. To avoid toxic hot spots, mercury trading would be limited by requiring each plant to either reduce mercury by 50% by 2008 (70% by 2012) or limit emissions to 4 lb per TBtu (EPA to set 2012 rate). EPA would be required to impose additional controls in 8 years if these limits do not adequately protect public health, and to report to Congress on the adequacy of controls on recaptured mercury.

The CO_2 cap may be achieved through reducing carbon emitted by power plants or with allowances earned through carbon sequestration and off-sector efficiency projects. An Independent Review Board would be created to certify projects as eligible for allowances.

3.2.7.1.2 Comparison of Legislation Proposed in the 107th Congress

TABLE 3-16 presents a comparison of emission targets and reduction schedules for the three Acts described in the previous section. The Clean Power Act of 2001 is the most stringent and least flexible from an implementation perspective, while the Clear Skies Act of 2002 is the least restrictive and most flexible in that it does not require full compliance until 2018. The former requires CO_2 stabilization at 1990 levels, while the latter does not include CO_2 emissions targets at all. The Clean Air Planning Act of 2002 appears to represent a compromise between the other Acts in terms of emissions targets, compliance scheduling, and CO_2 emissions.

TABLE 3-16. SUMMARY OF NATIONWIDE ANNUAL U.S. EMISSION CAPS UNDER PROPOSED MULTI-POLLUTANT LEGISLATION OF THE 107TH CONGRESS

	Pollutant[a]	**2007**	**2008**	**2010**	**2012**	**2015**	**2018**
Clear Skies Act of 2002	**NOx**		2.1 million tons				1.7 million tons
	SO_2			4.5 million tons			3 million tons
	Mercury			26 tons			15 tons
	CO_2	No mandatory CO_2 provisions					
Clean Air Planning Act of 2002	**NOx**		1.87 million tons		1.7 million tons		
	SO_2		4.5 million tons		3.5 million tons	2.25 million tons	
	Mercury		24 tons		~5 to 15 tons[b]		
	CO_2[c]		~ 616.9 million metric tons C		~ 611.6 million metric tons C		
Clean Power Act of 2001	**NOx**[d]	1.55 million tons					
	SO_2[d]	2.24 million tons					
	Mercury[d]	4.8 tons					
	CO_2[c]	~ 476.7 million metric tons C					

Notes:

[a] 2000 EIA Baseline power plant emission rates: NOx – 5.1 million tons, SO_2 – 11.2 million tons, mercury – 47.8 tons, CO_2, 621.1 million metric tons of carbon.

[b] Emission rate based on yet to be determined reduction (79% - 91%) from 1999 baseline mercury content of delivered coal.

[c] CO_2 emission rates are based on EIA CO_2 emission rates for reference year. S. 3135 – 2005, 2001; S. 556 – 1999.

[d] S.556 emission targets are based on % reduction from reference years. NOx – 1997, SO_2 – full implementation of Title IV acid rain provisions, mercury – 1999.

Each of the proposed acts provides for emission trading programs, but only the Clear Skies Act (S.2815/H.R.5266) allows for full trading of mercury emissions to meet targets. While the Clear Air Planning Act (S.3135) includes a trading program for mercury, it also requires mandatory reductions at individual affected units. Furthermore, each proposed act also includes various degrees of NSR reform, ranging from more stringent compliance with the existing program (S.556 has 40 year "birthday provision") to potential exemption from both existing NSR and the

Regional Haze best available retrofit technology (BART) requirements (S.2815/H.R.5266 – affected units either in compliance with regional/national caps or meets specific technology and performance requirements).[d]

3.2.7.2 Revised NAAQS for Ozone and Particulate Matter

EPA finalized revisions to the national ambient air quality standards for ozone and particulate matter in 1997. The revisions made the existing standard for ozone more stringent and established a new standard for very fine particulate matter designated as PM2.5. Implementation of these revised standards was delayed by a series of court cases, but the Supreme Court largely upheld them in February 2001, with implementation now proceeding. However, a number of uncertainties currently exist about how the standards will be implemented. Nonattainment areas for the revised standards have not yet been designated, and state plans for bringing those areas into attainment have not yet been developed.

Currently, it appears that non-attainment areas will be designated some time between 2003 and 2005, and SIPs will have to be submitted to the EPA 2 to 3 years beyond that date. Emission sources identified in a SIP probably will not be required to reduce emissions until after the SIP is approved by the EPA. Therefore, it appears that emission reductions will likely not be required until some time between 2007 and 2010. The revised ozone standard probably will be implemented toward the earlier portion of this timeline, while the PM2.5 standard could be implemented later on. Since NOx and VOCs are considered ozone precursors, power plants in ozone nonattainment areas may be required to reduce their emissions of these pollutants. However, it is unlikely that a new plant would be required to meet any requirements more stringent than the BACT/LAER limits discussed previously. The primary pollutants from coal-fueled power plants that are believed to contribute to ambient PM2.5 are sulfates due to sulfur dioxide emissions, nitrates due to NOx emissions, and fine fly ash particulates that escape particulate matter collection devices. For IGCC, no additional measures, other than increased NOx control, are anticipated to be required due to the very high levels of control already attained for SO_2 and particulates.

3.2.7.2.1 SO_2/Sulfate Emissions

EPA has suggested that it may consider a call for further control of SO_2 emissions as a possible response to its proposed revisions to the NAAQS for PM2.5, as well as its on-going regional haze program. Such actions would address the potential link between power plant sulfate emissions and ambient PM2.5 nonattainment. Using Title IV of the 1990 CAAA as a baseline for SO_2 control compliance, it is anticipated that the electric utility industry would again have to consider similar options to those used to meet Title IV – Phase I and II requirements. EPA could call for an incremental 50% reduction in SO_2 emissions beyond that required by Phase II of Title IV.

3.2.7.2.2 NOx/Nitrates

The need to limit ambient air nitrates may result in further regulation of NOx (below CAAA Title IV acid rain program or the Title I ozone nonattainment SIP program levels). The Title IV

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[d] Source: Energy & Environment Daily Special Report: “Clean Air Overhaul” (http://www.eenews.net/sr_cleanair.htm). Last accessed 12/17/02.

NOx limitations may be further reduced to 0.06 to 0.1 lb/10^6 Btu, which would in many cases require the addition of SCR technology to existing plants, including IGCC (if possible). However, if new coal-fueled plants are designed with SCR units sized to limit NOx emissions to 0.05 lb/10^6 Btu, future regulation of PM2.5 precursors will not require additional NOx control because these SCRs will already be operating below the expected PM2.5-related NOx limit.[21]

3.2.7.2.3 Fine Particulates

Future regulations for control of fine particulates may result in regulations that require further reduction of overall particulate emissions. Future limits for particulate emissions may be in the range of 0.015 to 0.03 lb/10^6 Btu. However, a new plant permitted for 0.015 lb/10^6 Btu (or less) as PM10 will probably not be subjected to further increased regulation, because the plant will already be operating below the expected PM2.5-related particulate limit. Since IGCC's fine particulate emissions are so low, it should not be impacted by any new requirements.

3.2.7.3 Air Toxic Emissions

EPA is currently conducting a National-Scale Air Toxics Assessment. The completed project will include a subset of HAPs identified by the CAAA. Sixteen of these 33 Urban Air Toxics (UAT) are emitted by electric utilities, as shown in TABLE 3-17. The assessment is based on 1996 emission data and consists of a national emission inventory of air toxic emissions from outdoor sources, estimates of ambient concentrations of air toxic across the contiguous U.S., estimating population exposure and characterization of the potential public health risk due to inhalation of air toxics. As of June 28, 2001, reports of the individual steps were either in draft form or under peer review. The expected result of this assessment is that priorities will be set concerning those toxics that present the greatest potential concern. Additional monitoring of emissions and ambient data of priority toxics will follow.[22] It is likely that subsequent regulations directly applicable to the electric generation industry will result from this study.

TABLE 3-17. CAAA LISTED HAPS AND URBAN AIR TOXICS FOUND IN UTILITY FLUE GAS EMISSIONS [23]

COMPOUND	UAT	COMPOUND	UAT
Acetaldehyde	x	Formaldehyde	x
Antimony Compounds		Hexachlorobenzene	x
Arsenic Compounds	x	Hydrochloric acid	
Benzene	x	Hydrogen fluoride (Hydrofluoric acid)	
Beryllium Compounds	x	Lead Compounds	
Biphenyl		Manganese Compounds	x
Bis(2-ethylhexyl)phthalate (DEHP)		Mercury Compounds	x
Cadmium Compounds		Naphthalene	x
Carbon disulfide	x	Nickel Compounds	
Carbon tetrachloride		Pentachlorophenol	x
Carbonyl sulfide	x	Phenol	
Chlorine		Phosphorous	
Chlorobenzene		Selenium Compounds	
Chloroform		2,3,7,8-Tetrachlorodibenzo-p-dioxin	x
Chromium Compounds	x	Tetrachloroethylene	
Cobalt Compounds	x	Toluene	
Dibenzofurans		Trichloroethylene	x
1,4-Dichlorobenzene		2,4,5-Trichlorophenol	

3.3 Water Pollution Regulations and Environmental Permitting

3.3.1 Description of Federal Water Pollution Regulations

3.3.1.1 The Clean Water Act

The Clean Water Act (FWPCA, 33 U.S.C.A. §§1251 to 1387) outlines the regulation of discharges into U.S. waters. The National Pollutant Discharge Elimination System (NPDES) program is called out by 33 U.S.C.A. § 1342 and limits the concentration of various pollutants in water discharges. States may submit State Pollutant Discharge Elimination System (SPDES) plans to the Administrator of the EPA for approval. SPDES may outline more stringent regulations but must be at least as stringent as the NPDES. NPDES plans differentiate between process wastewater and storm water runoff and regulate the two independently.[24]

Process wastewater requirements for steam electric point sources are outlined by 40 CFR Part 423 (facilities "primarily engaged in the generation of electricity for distribution and sale"). Each discharge requires a separate NPDES permit with limitations based on industry specific control technologies, such as Best Practicable Control Technology Currently Available (BCT), Best Technology Economically Achievable (BAT), or New Source Performance Standards (NSPS). Facilities that discharge to publicly owned treatment works (POTWs) must comply with Pretreatment Standards for Existing Sources (PSES) or Pretreatment Standards for New Sources (PSNS). Permits may also include water quality based limitations and pollution monitoring requirements. While the technology-based standards take into account economic impact of the implementation, water quality based standards typically do not.

Although water effluent standards vary significantly by application, industry, and location, the EPA Water Quality Standard [25,26] presented in TABLE 3-18 is the most common standard. Pollutants are grouped into three categories and designated as a conventional, non-conventional, or priority pollutants.[27]

3.3.1.1.1 Conventional Pollutants

Conventional pollutants include but are not limited to five-day biochemical oxygen demand (BOD_5), total suspended solids (TSS), pH, fecal coliform, oil and grease.

3.3.1.1.2 Priority Pollutants

Section 307(a)(1) of the CWA required the establishment of a published list of priority pollutants considered to be toxic chemicals or compounds. These are listed in Appendix 3-A of 40 CFR 423. Included in this list are several elemental, organic and inorganic species that are present in wastes produced by steam electric generating plants. Among these are arsenic, benzene, cyanide, mercury, naphthalene and selenium.

3.3.1.1.3 Non-Conventional Pollutants

Pollutants considered neither conventional pollutants, nor toxics identified as priority pollutants, are considered "non-conventional." These include, but are not limited to, ammonia, nitrogen, trace metals, chemical oxygen demand (COD) and whole effluent toxicity (WET). Chemical oxygen demand is a measure of the oxygen required to oxidize all compounds, both organic and inorganic, in water.

Whole Effluent Toxicity is a term used to quantify the impact a discharge has on the water quality of the receiving body of water. WET is based on the aggregate toxic effect of an aqueous sample (e.g., whole effluent wastewater discharge or ambient receiving water) as measured according to an organism's response upon exposure to the sample (e.g., lethality and impairment to growth or reproduction).

TABLE 3-18. EPA WATER QUALITY STANDARDS

CONSTITUENT	DISCHARGE STANDARD (mg/l, Average Monthly Limit)
Biochemical Oxygen Demand (BOD)	15
Chemical Oxygen Demand (COD)	50 to 200
Total Suspended Solids (TSS)	10
Ammonia	10
Cyanide	1.0
Phenols (4AAP)	0.025
Sulfide	0.1
Nitrate	100
Fluoride	100
Arsenic	5.0
Barium	100
Boron	50
Cadmium	1.0
Chromium	5.0
Lead	5.0
Mercury	0.2
Selenium	1.0
Silver	5.0
Zinc	20

Particular water discharge criteria are outlined in NPDES permits generated by the state permitting authority. For existing sources, conventional pollutants are controlled using BCT standards, while priority and non-conventional pollutants are controlled by BAT standards. Federally mandated NSPS outline the baseline for minimum control requirements for new sources. Additionally, NSPS requires zero discharge for fly ash handling water. Thermal properties of the discharged water are also called out on NPDES permits. Furthermore, EPA has reserved NPDES limitations for non-chemical metal cleaning wastes and FGD waters for future rulemaking.[24]

3.3.1.1.4 Storm Water Discharges

Storm water discharge requirements exist for steam electric power generating facilities, and are called out under 40 CFR 122.26(b)(14)(vii). Compliance with storm water requirements can be included within an individual NPDES permit or a Multi-Sector General Permit (MSGP) in areas where the EPA is the NPDES permitting authority.[28] Requirements under individual NPDES permits require the facility to fulfill control and monitoring requirements subject to the judgment of the permit writer. Coverage under a general stormwater permit requires the implementation of a stormwater pollution prevention plan, "reasonable and appropriate" control measures, and 1 or 2 years of monitoring and reporting. General permit requirements include recommended best practices for stormwater at steam electric facilities, landfills, treatment works, and construction areas greater than five acres. Requirements are additive across industrial sectors, requiring a facility with operations that fall under more than one category (i.e. a utility with onsite ash landfill) to comply with all requirements for each appropriate industry sector.[24]

3.3.1.2 Safe Drinking Water Act

The Safe Drinking Water Act (SDWA) requires that EPA establish health-based regulations to protect humans from contaminants in national drinking water. The act requires EPA to set national drinking water standards and create a joint Federal-State system to ensure compliance. EPA is also required to protect underground drinking water sources by regulating and controlling the underground injection of liquid waste. The provisions of the SDWA apply directly to public water systems in each state.

Drinking water standards are included here because electric power generation results in waste streams that contain detectable levels of elements or compounds that have established drinking water standards. Regulations under the Resource Conservation and Recovery Act (RCRA) for ground water contamination resulting from the disposal of solid wastes are tied to the contaminant levels established under the SDWA. Furthermore, deposition of emissions from the atmosphere may result in increased ambient contaminant levels in surface waters. Together, these conditions may hinder the ability of a public water system to meet the Federal or State standards and may result in additional effluent regulations at point sources.

EPA has set primary and secondary drinking water standards. Primary drinking water standards are contaminant specific and consist of maximum contaminant level goals (MCLGs), which are non-enforceable health based goals, and maximum contaminant levels (MCLs), which are enforceable limits set as close to MCLGs as economically and feasibly possible. These are presented in TABLE 3-19.

Additionally, even properly operated cooling towers have the potential to breed microorganisms, therefore routinely requiring the addition of disinfectants. Measures to address water quality issues resulting from recycled cooling water include MCLs for common chlorinated water treatment chemicals, along with treatment requirements for *Legionella* and heterotrophic plate count (HPC), a quantitative measure of the amount of bacteria present in the water.

National Secondary Drinking Water Regulations (NSDWRs or secondary standards) are non-enforceable guidelines regulating contaminants that may cause cosmetic effects (such as skin or tooth discoloration) or aesthetic effects (such as taste, odor, or color) in drinking water. EPA recommends secondary standards to water systems but does not require systems to comply. However, states may choose to adopt them as enforceable standards.[29]

TABLE 3-19. SELECTED NATIONAL PRIMARY DRINKING WATER STANDARDS

CONTAMINANT	MCLG (mg/l)	MCL (mg/l)
Inorganic Chemicals		
Antimony	0.006	0.006
Arsenic	None	0.01
Barium	2	2
Beryllium	0.004	0.004
Cadmium	0.005	0.005
Chromium (total)	0.1	0.1
Cyanide	0.2	0.2
Fluoride	4.0	4.0
Lead[a] (treatment requirement)	Zero	0.015 (action level)
Mercury	0.002	0.002
Selenium	0.05	0.05
Organic Chemicals		
Benzene	Zero	0.005

[a] Lead is regulated by a treatment technique that requires systems to control the corrosiveness of the water. If more than 10% of tap water samples exceed the action level, water systems must take additional steps.

3.3.2 Water Permitting Requirements for Commercial IGCC Plants

3.3.2.1 Federally-Mandated Water Permitting Requirements [14]

The permitting process for the siting of a gasification-based power system is a complex and lengthy process, especially due to the increasing number of permits required. A large-scale IGCC facility for utility power generation will almost certainly qualify as a major source within the permitting process. TABLE 3-20 identifies many of the critical government water permit approvals that could be required by such a power generation facility. The actual paper process of obtaining the necessary environmental permits is expected to be very similar to the siting of a traditional utility electric generation facility.

EPA implements two permit programs under the Clean Water Act (CWA), the objective of which is to restore and maintain the chemical, physical, and biological integrity of the Nation's waters: *Section 404* permits, and *National Pollution Discharge Elimination System (NPDES)* permits. Section 404 of the Clean Water Act establishes a program to regulate the discharge of dredged (or fill) materials into waters of the United States, including wetlands. Section 404 permits prohibit the discharge of dredged or fill material if there is a practicable alternative that is less damaging to the aquatic environment or if the discharge would result in significant degradation of waters of the United States.

TABLE 3-20. PROBABLE ENVIRONMENTAL PERMIT APPROVALS REQUIRED FOR IGCC [13]

PERMIT TYPE	PERMIT APPROVAL AUTHORITY	PERMIT APPROVAL REQUIREMENT	RELATED REPORT SECTION
NPDES Wastewater Discharge Permit	State Environmental Agency	180 Days Prior to Discharge	3.3.2.1, 3.3.3
Clean Water Act – Section 404 Wetlands Permit	U.S. Army Corps of Engineers	Prior to Construction/ Mobilization	3.3.1.1
NPDES – Storm Water Notice of Intent (NOI) for Construction General Permit	State Environmental Agency	Prior to Construction/ Mobilization	3.3.2.1, 3.3.3
NPDES – Multi-Sector General Storm Water Notice of Intent Permit for Operations	State Environmental Agency	Prior to Operation	3.3.2.1, 3.3.3
Storm Water Pollution Prevention Plan (SWPPP) for Construction Activities	State Environmental Agency	Prior to Construction/ Mobilization	No Information Provided
Storm Water Pollution Prevention Plan (SWPPP) for Operations	State Environmental Agency	Prior to Operation	No Information Provided
Beneficial Use Permits to Divert or Withdraw Groundwater	Permit Board/ State Environmental Agency	Prior to Installation of Wells	No Information Provided

NPDES permits regulate wastewater discharges with the goals of (1) protecting public health and aquatic life, and (2) assuring that every regulated point source complies with applicable technology based effluent limits and at a minimum treats wastewater. To achieve these ends, permits may include the following terms and conditions: site-specific discharge (or effluent) limits; standard and site-specific compliance monitoring and reporting requirements; and enforcement provisions in cases where the regulated facilities fail to comply with the provisions of their permits. Under the NPDES program, all facilities that discharge pollutants from any point source into waters of the United States are required to obtain a NPDES permit. The term "pollutant" is defined very broadly by the NPDES regulations and includes industrial, municipal, or agricultural waste discharged into water. Where such pollutants are discharged from a point source, that discharge is subject to NPDES regulation.

The Safe Drinking Water Act (SDWA) provides for control of contaminants in public water systems and also provides authority to regulate underground injection wells. The SDWA uses **Underground Injection Control (UIC)** permits to regulate construction, operation, and closure of wells in order to protect public sources of drinking water. The UIC permit program regulates the underground injection of wastes or other fluids with the goal of protecting underground sources of drinking water (USDW) from endangerment. A USDW is defined as an aquifer capable of supplying a public water system now or in the future and containing water with a concentration of 10,000 mg/l of total dissolved solids or less.

The UIC program defines five classes of wells. For Class I-IV wells, all injection activities, including construction of an injection well, are prohibited until the owners or operators of these injection wells receive a permit. Most Class V wells are currently authorized by rule as long as they do not endanger underground sources of drinking water and the well owners submit basic inventory and assessment information (40 CFR 144.24). Existing Class II enhanced recovery wells and hydrocarbon storage wells are authorized by rule for the life of the field project or until a permit is issued (40 CFR 144.22). Class IV wells, those that inject hazardous waste into or above USDWs, are prohibited unless they are part of an aquifer cleanup operation (40 CFR 144.13).

3.3.2.2 Recent Water Permitting Experience with Planned IGCC Plants

Recent environmental permitting of several IGCC projects by Global Energy Inc. is reviewed in this section to provide insight into the process. These projects have been described earlier in the report in Section 3.2.4. Global Energy has not yet applied for their water permits at the Kentucky and Ohio plants, but rather has investigated their requirements. In Kentucky, the IGCC plant will use the Kentucky River for water supply and discharge. An advantage for this facility will be that EKPC, which already withdraws water for its need as a public utility, plans to withdraw additional water under its existing permit and sell it to the Kentucky Pioneer plant. While the IGCC plant wastewater discharge will be mixed with EKPC's existing discharge, their effluent will be independently monitored upstream of the tie-in to the existing discharge line. However, based on new discharge conditions, the Kentucky River Authority and Kentucky Water Resources has told Global Energy that thermal and mixing zone limits may necessitate the addition of a diffuser to the existing wastewater discharge line.

The Ohio project has explored water supply and treating requirements with the City of Lima. Wastewater discharge will be by permit under the Industrial Pretreatment Program of Ohio EPA, with City of Lima approval, and flow into the city's POTW.

3.3.3 Review of Existing State Water Regulations and Permitting Applicable to Gasification-Based Power Systems

Individual states have the option to outline standards and regulations that are at least as stringent as federal standards, and may be more stringent. Water discharge permits may be issued under SPDES approved by the Administrator. States will sometimes permit individual counties to outline specific standards that are more stringent than both state and federal levels.

Complete analysis of state and county regulatory plans is beyond the scope of this report. This information is included to provide summary state level regulatory information as it may apply to gasification-based power systems. Primary attention is focused on the major aspects of water discharge issues. Particular focus is directed at states that currently have IGCC facilities. An attempt is made to indicate where state standards differ from federal standards. However, no effort is made to analyze the permitting process or enforcement provisions in individual state summaries. While every attempt is made to include the most recent regulatory status, interested parties should contact the appropriate state regulatory agency for more information.

3.3.3.1 Florida [30]

The Florida Department of Environmental Protection is authorized by EPA to administer the NPDES permitting program. The Department assumes permitting and enforcement authority for NPDES permits issued by EPA. While the federal program covers discharges to surface waters, the state wastewater program issues permits to facilities that discharge to either surface or groundwater. Water quality standards for Florida vary for usage category and compare closely to EPA published national recommended water quality criteria. In 1996, approximately 75% of rivers and almost all lakes greater than ten acres in area and estuaries are classified as fishable and swimmable.[31] Resulting water quality based effluent limits (WQBELs) for point sources discharging to these waters require the maintenance of water quality standards intent on providing high levels of control. In addition to FDEP standards, several counties in Florida impose specific wastewater management, permitting and monitoring requirements of their own. Florida's pretreatment program follows the federal program with one additional requirement. For a business that uses reclaimed wastewater in its processes, with no potential for public access to the reclaimed water, state pretreatment regulations are not applicable.

3.3.3.2 Indiana [30]

The Indiana Department of Environmental Management's Office of Water Management (OWM) is authorized by EPA to implement and enforce NPDES programs. Effluent limits can be based upon the more stringent of water quality or technology based standards. Models used to calculate water quality-based limits include parameters such as discharge flow rate, along with receiving water body properties such as background pollutant concentration, average minimum seven consecutive day low flow which occurs once in ten years, and hydrologic characteristics. Indiana has 45 EPA approved pretreatment cities that run local pretreatment programs, each program doing its own permitting, inspecting, sampling and enforcement for all discharges within its area. All categorical dischargers not located in a pretreatment city must apply to IDEM for an Industrial Wastewater Pretreatment (IWP) permit and must meet the specific requirements in an issued permit.

3.3.3.3 Louisiana[30]

Louisiana is authorized by EPA to administer the NPDES permit program. Louisiana storm water regulations require that industrial facilities meet numerical limitations for discharges of total organic carbon and oil and grease. Louisiana industrial pretreatment regulations reflect the federal pretreatment requirements with several modifications, including the definition of major POTW.

3.3.3.4 Other States With a Large Base of Existing Coal-Fueled Electric Power Generation

TABLE 3-21 presents summary information of state level environmental regulations for selected states that currently have a significant number of coal-fueled electric generating units. These states are Alabama, Georgia, Illinois, Kentucky, New York, Ohio, Pennsylvania, Tennessee, Texas, and West Virginia. Qualitative generalizations are provided for the major water pollution regulations. More detailed information is provided in Appendix 3A.

3.3.4 Overview of Future Water Pollution Regulations Potentially Applicable to Gasification-Based Power Systems

3.3.4.1 Cooling Water Intake Structures (CWA § 316(b))

Clean Water Act § 316 outlines requirements for the protection of fish and aquatic wildlife. Specific regulations are required under CWA § 316(b) for fish protection measures at cooling water intake structures (CWIS). 316(b) requires that the best technology available (BTA) be used to minimize adverse environmental impact. BTA allows for economic considerations in the determination of appropriate implementation. Additional environmental impact studies may be required by and under the funding of the facility seeking compliance.

TABLE 3-21. WATER REGULATIONS FOR SELECTED STATES

STATE	WATER REGULATIONS
Alabama	Generally follows federal regulations.
Georgia	Generally follows federal regulations. State water quality standards are typically more stringent than federal effluent limits.
Illinois	Generally follows federal regulations. State water quality standards are typically more stringent than federal effluent limits. Illinois has imposed more stringent mercury and cyanide concentration based standards.
Kentucky	Generally follows federal regulations. State requires more stringent water quality based standards when federal effluent limits are considered not sufficiently protective.
New York	Generally adopts federal regulations by reference.
Ohio	Generally follows federal regulations.
Pennsylvania	Generally follows federal regulations. Industrial wastewater requirements include limitations for oil content, acidity, and heat content.
Tennessee	Generally follows federal regulations. Additional requirements authorizing more stringent water quality standards based on water body’s intended use.
Texas	Generally follows federal regulations. Texas also has several more stringent provisions and limitations for discharges. Additionally, Texas also imposes a waste treatment fee for all permit holder or authorized discharger.
West Virginia	Generally follows federal regulations. West Virginia includes ground water in the definition of “waters of the state.”

EPA is in the process of developing specific 316(b) regulations. An Amended Consent Decree submitted on November 21, 2000 by EPA and plaintiffs in Riverkeeper, Inc. v. Whitman and signed by the U.S. District Court, Southern District of New York, revised an existing court order that set EPA final action and regulation deadlines. The Amended Consent Decree divides the rulemaking into three phases. Phase I applies directly to new electric generating plants and manufacturing facilities that employ a CWIS. Phases II applies to existing utility and non-utility power producers and Phase III applies to other industrial facilities that utilize a CWIS. Phase II requirements are to be proposed by February 28, 2002, with final action by August 28, 2003.

In December 2001, EPA issued Phase I CWIS standards that establish location, construction and design aspects of intake structures. Phase I regulations are applicable only to new “greenfield” or “stand-alone” facilities as defined in 40 CFR 122.2 and 122.29(b)(1), (2), and (4) and commence construction after January 17, 2002. Phase I regulations are only applicable to a newly constructed CWIS or one modified to increase intake capacity, and may not be required for a “repowering” or modification to an electric generating facility that has an existing CWIS, so long as no modifications are required to increase capacity at the CWIS. For sources that meet the new source definition, the regulations are directly applicable to facilities that withdraw more than 2 MGD from waters of the U.S. and use more than 25% of the intake for cooling purposes. Facilities that withdraw less than 2 MGD are to be regulated on a case-by-case basis.

The final ruling presents two options to new facilities. For certainty and fast permitting, a new facility can accept set standards that limit intake capacity and velocity. Facilities that locate near fisheries are required to use additional fish protection measures including screens, nets, or other similar devices. No reductions of intake capacity are required for facilities that withdraw less than 10 MGD but must employ fish protection measures. Facilities also have the option of conducting site-specific studies that may allow for alternative fish protection measures so long as they provide comparable protection. All facilities must limit intake relative to a defined proportion of the source water body.[32]

Because of the large water intake associated by the steam cycle portion of utility scale IGCC applications, 316(b) requirements for installations that meet the new source definition essentially require closed circuit cooling systems of some kind and prohibit the practice of once-through cooling.[33] During the rulemaking process, EPA has also considered a "zero intake" flow requirement as for BTA. The baseline is derived from dry cooling technology, which uses air for cooling rather than water. Fundamental physical property differences associated with wet and dry cooling systems (e.g., heat transfer properties and wet bulb temperature vs. dry bulb temperature), along with parasitic power losses due to recirculating pumping and ancillary equipment, results in decreased net power output and therefore increased air emissions for the affected plant. As part of the determination, EPA considered these energy penalties and increased air emissions resulting from the application of the new CWIS regulations.

TABLE 3-22 presents comparative estimates of national annual energy penalties for three possible cooling system configurations (once-through, wet cooling tower, and dry cooling tower). The national energy penalty was determined as an average of annual energy penalties for facilities modeled for power plants located in four metropolitan areas (Boston, Chicago, Jacksonville, and Seattle) to represent a range of climate differences. As would be expected, the energy penalty was greatest in Jacksonville.[34] Subsequently, air emissions would rise as a result of increased generation capacity needed to compensate for parasitic power losses.

TABLE 3-22. NATIONAL AVERAGE ANNUAL ENERGY PENALTY SUMMARY TABLE

COOLING TYPE	67% MAXIMUM LOAD		100% MAXIMUM LOAD	
	COMBINED-CYCLE PERCENT OF PLANT OUTPUT[a]	FOSSIL-FUEL PERCENT OF PLANT OUTPUT[b]	COMBINED-CYCLE PERCENT OF PLANT OUTPUT[a]	FOSSIL-FUEL PERCENT OF PLANT OUTPUT[b]
Wet Tower vs. Once-Through	0.4	1.7	0.4	1.7
Dry Tower vs. Once-Through	2.1	8.6	2.8	10.0
Dry Tower vs. Wet Tower	1.7	6.9	2.4	8.4

[a] Energy penalty is applicable only to the energy output of the steam plant component
[b] Represents coal-fueled plants

3.3.4.2 Total Maximum Daily Load

The Clean Water Act also requires that states identify pollution impaired water bodies and develop total maximum daily loads (TMDLs) that set the maximum amount of pollution from all sources that a particular body may take on and not violate water quality standards. For States that fail to identify impaired water bodies, EPA is required to develop the list and make it's own TMDL determination.

For several reasons, implementation of TMDL requirements has not been carried out. Since the late 1980s, citizen groups have filed more than 40 lawsuits in 38 states against EPA and various states for failure to comply with TMDL requirements of the CWA.[35] As a result of court orders requiring prompt development of TMDL standards, EPA proposed regulatory changes in 1999 and issued a final rule in July 2000 (65 FR 43586).

EPA's ruling requires the identification of impaired waters along with the development of a cleanup schedule and implementation plan. TMDLs will include key elements such as water body name; location and pollutant water quality standard; amount of pollutant allowable to meet standards; load reductions required to meet standards; and several measures for the addition of new TMDLs and public comment periods. States will maintain flexibility to determine which sources of pollution to clean up and in what manner the clean up should be carried out.[36] The new TMDL requirements will also include greater focus on "non-point" sources of pollutants. The "non-point" source category includes surface water pollution resulting from the suspected contribution due to deposition from the atmosphere of emitted pollutants. It is quite possible that under the revised TMDL program, plans to restore the water quality of polluted lakes or streams may include requirements for further controls on emissions from electric utility generators.[37]

3.3.4.3 Clean Water Act Reauthorization

Authorizations for most current program funding expired September 30, 1990, but Congress has continued to appropriate funds to carry out the act. Several attempts to formally complete the reauthorization process, and several bills introduced to Congress as part of that process may change the current regulations governing water discharges.[35] Specific proposed changes include a ban and/or discharge tax on all mercury discharges.

3.4 Solids-Related Regulations for Coal Combustion Wastes

3.4.1 Description of Federal Solid Waste Pollution Regulations

Solid waste regulations are outlined in the Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act (RCRA, 42 U.S.C.A. §§ 6901 to 6992k). The term solid does not specifically limit regulations solely to wastes that are not liquid and gaseous, but includes waste in any physical state that meets the statutory definition as any material that is discarded by being either abandoned (disposed of, burned, or incinerated), inherently waste-like, certain military munitions, or recycled. Regulated wastes are characterized as either hazardous or non-hazardous wastes with regulations specific to the pertinent waste type. The facility owner or operator must determine if a waste is hazardous in all cases in which a waste is not specifically excluded from the definition of hazardous or solid waste or is exempt from Subtitle C hazardous waste regulations.

A significant policy issue affecting electric utilities that use coal has been the question of whether or not coal utilization by-products (CUBs) should be regulated at the Federal level as hazardous wastes under RCRA Subtitle C. Specifically, Subtitle C of RCRA imposes requirements on the generation, transportation, storage, treatment and disposal of "hazardous" wastes. Wastes that are not considered hazardous under Subtitle C fall under Subtitle D of RCRA, and are subject to regulation by the states as solid waste. As originally drafted in 1976, RCRA did not specifically address whether CUBs fell under Subtitle C as a hazardous waste or

Subtitle D as a solid waste. In 1980, Congress enacted the Solid Waste Disposal Act Amendments to RCRA. Under the amendments, certain wastes, including CUBs, were temporarily excluded from Subtitle C regulation. This regulatory exemption, introduced by Congressman Bevill of Alabama, is commonly referred to as the “Bevill Exemption.” As a result, CUBs fell under Subtitle D and became subject to regulation under state law as solid waste.

The RCRA amendments directed that the EPA collect information and produce a report that recommended appropriate regulations regarding CUBs. Extensive data on CUB leaching characteristics and information on potential environmental damage cases involving CUBs were collected and analyzed by EPA. The subsequent report to Congress, issued by EPA in 1988, concluded that CUBs generally do not exhibit hazardous characteristics, damage to the environment from existing CUB disposal sites was minimal, and that regulation of CUBs should remain under state Subtitle D authority. A final regulatory determination, effective September 2, 1993, stated that regulation of CUBs generated by coal-fueled electric utilities and independent power producers as hazardous waste was unwarranted, and that EPA will continue to exempt these materials from regulation as a hazardous waste under RCRA.

EPA narrowly interpreted the scope of the 1993 rulemaking; the exemption applied only to fly ash, bottom ash, boiler slag and flue gas desulfurization (FGD) by-products that were produced by coal fired electric utilities and independent power producers, and were managed independently of any other wastes. The exemption did not apply to CUBs that were placed in the same waste stream as low volume utility wastes (boiler blowdown, coal pile runoff, cooling tower blowdown, demineralizer regenerant rinses, metal and boiler cleaning wastes, and pyrites). This narrow interpretation was important to the electric utility industry because these low-volume wastes were mixed with the high-volume CUBs in the vast majority of utility waste management scenarios. Fluidized bed combustion (FBC) wastes and CUBs that were generated at any industrial activity other than electric utilities and independent power producers were also outside the rule.

On March 31, 1999, EPA issued another report to Congress to establish a factual basis for EPA decision-making regarding the appropriate regulatory status of the “remaining wastes” under RCRA. In this report, EPA found that: (1) FBC wastes and co-managed CUBs generally do not exhibit hazardous characteristics; (2) no damage to human health had ever been associated with CUB disposal or use; (3) damage to the environment from existing CUB disposal sites was minimal; (4) no damage to the environment had occurred from any CUB beneficial use activity; and (5) existing State CUB regulatory programs had been significantly strengthened over the last decade. As a result, EPA recommended in the March 1999 report that disposal and most beneficial uses of CUBs should not be regulated under RCRA Subtitle C. However, EPA was still considering the possibility of establishing some form of Subtitle C regulation for agricultural application of CUBs because of a concern over the potential of long-term human exposure to arsenic. Mine filling was also being considered for some form of Subtitle C regulation because of EPA’s lack of data on the environmental effects of mine-filling scenarios and the uncertainty in their ability to accurately model such scenarios. In response to the March 1999 report, EPA received a great deal of comment from the utility industry, State and Federal government agencies, and the general public.

On April 25, 2000, EPA issued a Regulatory Determination that concluded that FBC wastes and CUBs that are co-managed with other wastes do not warrant regulation as hazardous wastes under Subtitle C of RCRA. EPA also concluded that, except for mine filling, no additional regulations are warranted for coal combustion wastes that are used beneficially. The initial concern expressed by EPA over agricultural applications of CUBs was alleviated upon reconsidering its modeling assumptions in view of comments and information received after its March 1999 report, particularly the information received from the U.S. Department of Agriculture. However, EPA also determined that national regulations under Subtitle D of RCRA are warranted for coal combustion wastes when they are disposed in landfills or surface impoundments, and that regulations under Subtitle D of RCRA, and/or possibly modifications to existing regulations established under authority of the Surface Mining Control and Reclamation Act (SMCRA), are warranted when these wastes are used to fill surface or underground mines. So that coal combustion wastes are consistently regulated across all waste management scenarios, EPA also intends to make these Subtitle D regulations applicable to large volume coal combustion wastes that had previously been exempted under the 1993 regulatory determination. The process of developing these specific Subtitle D regulations for disposal and minefilling of CUBs has just begun.

The April 2000 regulatory determination is important in that it marks the first time EPA had stated its intent to develop nationwide regulations for disposal of CUBs; prior to this, all regulations governing CUB disposal and use had come from individual states. Even though the regulations are being developed under RCRA Subtitle D (rather than the more rigorous Subtitle C), the uncertainty caused by the possibility of having to comply with National regulations, which may not coincide with current disposal practices, is causing a great deal of concern within the utility industry. The possibility of a separate set of nationwide regulations regarding placement of CUBs in mines is also causing a great deal of uncertainty. Finally, the April 2000 regulatory determination also states "there are several factors that might cause us (EPA) to rethink our current determination." One of those factors is that "the agency will consider the results of a report of the National Academy of Sciences regarding the adverse human health effects of mercury, one of the constituents in fossil fuel combustion wastes." This consideration raises the possibility that all CUBs may yet be considered for regulation under RCRA Subtitle C because of concerns over mercury.

3.4.1.1 Hazardous Waste

Hazardous waste status is determined by either a listing of a particular waste as hazardous or if a waste exhibits one of the four characteristics of hazardous wastes: ignitability, corrosivity, reactivity or toxicity. Facilities must also determine if a waste demonstrates a hazard characteristic for listed hazardous wastes.

Four lists of hazardous wastes exist. The lists are designated as F, K, P, and U and each list is process-specific, industry-specific, or chemical compound-specific. To be placed on a list, a substance must demonstrate harmful biological or environmental effects, exhibit one or more of the four characteristics of hazardous wastes, or cause EPA to believe that the waste fits within the statutory definition of hazardous waste. These are defined in TABLE 3-23.

TABLE 3-23. DEFINITION OF HAZARDOUS WASTE CATEGORIES

LIST DESIGNATION	CHARACTERISTIC	GENERAL DESCRIPTION
F	Wastes from non-specific sources.	Wastes generated in common industrial and manufacturing processes.
K	Wastes from specific sources	Wastes generated by specific industries.
P	Acutely toxic chemicals – lethal chemicals that are fatal to humans in small doses or that cause serious irreversible or incapacitating illness.	Pure or commercial grades of certain chemicals being disposed of.
U	Toxic chemicals and those specific chemicals that demonstrate characteristics of hazardous wastes.	Pure or commercial grades of certain chemicals being disposed of.

Characteristic wastes are wastes that demonstrate measurable properties of any of the four hazardous waste categories that, when present in the waste, can cause death or illness in humans or lead to ecological damage. Listed wastes that also demonstrate one or more hazardous waste characteristic may be subject to additional regulatory requirements. Ignitability differs for each physical form (solid, liquid, or gas). The general characteristic identifies wastes that can readily catch fire and sustain combustion. The corrosivity characteristic identifies wastes that are acidic or alkaline ($pH<2$ or $pH>12.5$) and will readily dissolve or corrode flesh, metal, or other materials. The reactivity characteristic identifies wastes that readily explode or undergo violent or toxic reactions. Because no reliable test method exists to determine a wastes reactive behavior, EPA uses narrative criteria and often requires the best judgment of the waste handler to determine if a substance should be identified as hazardous.

Toxicity characteristics are determined by a waste's tendency to leach toxic chemicals into the ground water. The reference test for determining a substance's tendency to leach is the Toxicity Characteristic Leaching Procedure[e] (TCLP). The testing procedure requires a facility to create a liquid leachate on waste samples. The leachate produced is assumed similar to the leachate generated by a landfill of the waste being tested. The TCLP requires the facility to conduct tests on waste samples to create a liquid leachate and test for any of 40 regulated toxic chemicals. Various leachate concentration levels exist for the listed toxics presented in TABLE 3-24.

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[e] Toxicity Characteristic Leaching Procedure (TCLP): Introduced in the November 7, 1986 Solvents and Dioxins rule, this testing procedure was specifically initiated for evaluation of the solvent- and dioxin-containing wastes. When a waste extract is tested, EPA requires that the TCLP be used to determine whether a waste requires treatment. Additionally, the TCLP is used to determine whether a waste is hazardous and serves as a monitoring technique to determine whether a treated waste meets the applicable waste extract treatment standard.

TABLE 3-24. SELECTED TCLP REGULATORY LEVELS (40 CFR §261.24)

WASTE CODE	CONTAMINANT	REGULATORY LEVEL (mg/l)
D004	Arsenic	5.0
D005	Barium	100.0
D018	Benzene	0.5
D006	Cadmium	1.0
D021	Chlorobenzene	100.0
D007	Chromium	5.0
D027	1,4–Dichlorobenzene	7.5
D027	1,4 – Dichlorobenzene	7.5
D032	Hexachlorobenzene	0.1
D008	Lead	5.0
D009	Mercury	0.2
D037	Pentachlorophenol	100.0
D010	Selenium	1.0
D011	Silver	5.0
D039	Tetrachloroethylene	0.7
D040	Trichloroethylene	0.5
D041	2,4,5–Trichlorophenol	400.0
D041	2,4,5 – Trichlorophenol	400.0

Handling and disposal requirements for material designated as hazardous wastes is a cradle-to-grave process, with the generating facility responsible for ensuring appropriate procedures are carried out as outlined in 40 CFR § 262. Specific regulations include hazardous waste identification, site-specific EPA identification numbers, shipping preparation and manifest generation, on-site management and storing limits, and biennial reporting requirements. Additionally, record-keeping, waste disposal tracking requirements, and import/export regulations exist. For disposal, wastes must meet certain pretreatment standards as outlined in 40 CFR § 268.[38]

More pertinent to the topic of IGCC wastes are the requirements for treating characteristic waste that is "decharacterized." When a characteristic waste is "decharacterized" it no longer exhibits a hazardous waste characteristic. However, these decharacterized wastes may still contain underlying hazardous constituents.[f] Therefore, EPA promulgated standards for characteristic wastes to ensure that the concentrations of all underlying hazardous constituents in characteristic wastes have been minimized. These **Universal Treatment Standards** (UTS) list over 200 constituents for which LDR (Land Disposal Restrictions) treatment standards have been developed. UTS standards apply to underlying hazardous constituents in decharacterized wastes and to constituents for which treatment standards are applicable in listed hazardous wastes. Characteristic wastes cannot be land-disposed until they meet the applicable treatment standards for the waste characteristic and underlying hazardous constituents that apply to the waste. Even if a characteristic waste no longer exhibits a characteristic, it cannot be land disposed until the waste is in compliance with the treatment standards. Importantly, in most cases, characteristic waste cannot be merely diluted to meet specified treatment standards. TABLE 3-25 lists UTS limits for potentially hazardous slag and ash constituents, and compares the standards with the TCLP limits. Note that the UTS limits are generally more restrictive for the trace metals.

3.4.1.2 Non-Hazardous Waste

Non-hazardous wastes are handled under applicable regulations outlined in RCRA Subtitle D and are called out in 40 CFR § 257. Federal regulations address siting requirements based on floodplain characteristics, disposal adjacent to food chain agricultural lands, and impact on endangered species. The regulations also prohibit discharge into surface waters that is in violation of NPDES requirements and addresses contaminant leaching into underground drinking water with regulatory contaminant levels that are tied to the MCLs, as promulgated under the Safe Drinking Water Act. Furthermore, measures are required to minimize disease vectors such as rodents, flies and mosquitoes. Additional regulations exist for the disposal of conditionally exempt small quantity generator wastes (CESQG) as defined by 40 CFR § 261.5. These include additional siting requirements, ground water sampling and analysis, record keeping, and corrective measures for the detection of statistically significant levels exceeding ground-water protection standards.

Specific handling requirements for Subtitle D wastes are typically the responsibility of individual states. For landfills and surface impoundments, state permit requirements and siting control measures usually include groundwater monitoring, leachate collection systems, liners, and covering requirements, along with closure and fugitive dust controls. Waste management alternatives are permissible, subject to demonstration that they are at least as effective as currently accepted control measures. Certain units may obtain exemption to specific control requirements provided it can be demonstrated that there is no danger to human health or environment.[24]

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[f] **Underlying Hazardous Constituents** are any constituents listed in the universal treatment standards (UTS) table (40 *CFR* 268.48), except fluoride, selenium, sulfides, vanadium, and zinc, which can reasonably be expected to be present at the point of generation of the hazardous waste, at a concentration above the constituent-specific UTS treatment standards.

TABLE 3-25. SELECTED UNIVERSAL TREATMENT STANDARDS (40 CFR §268.40)

WASTE CODE	CONTAMINANT	RCRA TCLP LIMIT (mg/l)	UTS LIMIT (mg/l)
	Antimony	--	2.1
D004	Arsenic	5.0	5.0
D005	Barium	100.0	7.6
	Beryllium	0.82	--
D006	Cadmium	1.0	0.19
D007	Chromium (Total)	5.0	0.86
	Cyanides (Total)	--	590 mg/kg
D008	Lead	5.0	0.37
D009	Mercury	0.2	0.025
D010	Selenium	1.0	0.16
D011	Silver	5.0	0.3
	Thallium	--	0.078
	Vanadium	--	0.23
	Zinc	--	5.3
D018	Benzene	0.5	10
D021	Chlorobenzene	100.0	6.0
D027	1,4 – Dichlorobenzene	7.5	6.0
D032	Hexachlorobenzene	0.1	10
D037	Pentachlorophenol	100.0	7.4
D039	Tetrachloroethylene	0.7	6.0
D040	Trichloroethylene	0.5	6.0
D041	2,4,5 – Trichlorophenol	400.0	7.4

When subjected to hazardous waste testing criteria, fossil fuel combustion (FFC) wastes rarely are characterized as hazardous. To facilitate and expedite the beneficial use and large volume disposal of FFC wastes, EPA has conducted several studies of the physical properties of electric utility solid wastes. EPA has subsequently determined (65 FR 32214) that all FFC wastes, including large volume utility coal combustion wastes (fly ash, bottom ash, boiler slag and flue gas emission control wastes) and low volume process-related wastes co-managed with these large volume wastes (i.e., boiler blowdown, cleaning waste, air heater and precipitator washwater, and other equipment and facility wastes), are exempted from federal hazardous waste categorization. EPA is conducting further analysis and characterization of certain co-managed wastes, including pyrite coal pile runoff, which may result in future determinations altering current storage and/or disposal practices.

3.4.2 Federally-Mandated Solid Waste Permits[14]

As mentioned previously, the permitting process for the siting of a gasification-based power system is a complex and lengthy process, especially due to the increasing number of permits required. A large-scale IGCC facility for utility power generation will almost certainly qualify as a major source within the permitting process. TABLE 3-26 identifies the critical government solid waste permit approvals that could be required by such a power generation facility, as well as some of the other permits not previously identified. The actual paper process of obtaining these permits is expected to be very similar to the siting of a traditional utility electric generation facility.

TABLE 3-26. PROBABLE SOLID WASTE (AND OTHER) PERMIT APPROVALS REQUIRED FOR IGCC[13]

PERMIT TYPE	PERMIT APPROVAL AUTHORITY	PERMIT APPROVAL REQUIREMENT	RELATED REPORT SECTION
SOLID WASTE PERMITS			
Waste Disposal Facility Permit	State Environmental Agency	Prior to Construction/ Mobilization	3.2.3
Notice of Intent to Construct a Sanitary Septic System	Local Health Department	Prior to Installation	No Information Provided
OTHER PERMITS			
Endangered Species Clearance Letter & Permit	U.S. Fish and Wildlife	Prior to Construction/ Mobilization	3.5
National Historical Preservation Act Clearance Letter	State Historic Preservation Office (SHPO)	Prior to Construction/ Mobilization	3.5

The Resource Conservation and Recovery Act (RCRA) was enacted to ensure safe disposal of the huge volumes of solid waste generated nationwide. The broad goals of RCRA are to protect human health and the environment, to conserve energy and natural resources and to reduce or eliminate the amount of waste generated, including hazardous waste. Several categories of permits are issued and regulatory standards for each category define operating requirements and various provisions specific to the permitting need. Categories include: operating permits, research, development, and demonstration permits; post-closure permits; emergency permits; permit-by-rule permits; combustion permits, land treatment demonstration permits, and remedial action plans. As discussed previously, IGCC wastes are generally expected to be permitted under Subtitle D, as non-hazardous waste.

3.4.3 Review of Existing State Coal Combustion Byproducts Regulations and Permitting Applicable to Gasification-Based Power Systems

As stated previously, individual states have the option to outline standards and regulations that are at least as stringent as federal standards, and may be more stringent, and they will sometimes permit individual counties to outline specific standards that are more stringent than both state and federal levels. Solid waste handling for Subtitle D non-hazardous waste materials is typically handled at the state level.

Currently 45 states duplicate the federal exemption of FFC wastes from hazardous wastes. Five states (California, Kentucky, Maine, Tennessee, and Washington) do not categorically exempt FFC wastes from hazardous waste requirements and either regulate as "special" waste or subject those wastes to hazardous waste characteristic tests and appropriate state handling and disposal procedures. For the handling of hazardous wastes, states may determine their own permitting and siting requirements but must be at least as stringent as those outlined by Subtitle C (42 U.S.C.A. § 6929).

Most states currently do not have specific regulations addressing the use of CUBs and requests for CUB uses are handled on a case-by-case basis or under generic state recycling laws or regulations. Many states have "generic" laws and regulations that authorize limited reuse and recycling of hazardous and/or solid wastes. These generic laws do not apply specifically to CUBs or any other materials. Classification of combustion wastes as CUBs and the allowable beneficial uses can vary widely from state to state. Some states include the same fossil fuel wastes as in the federal definition of CUBs while other states exclude a particular component or include co-burned wastes including tire derived fuels and/or wood. Often, regulation may fall under one or several state regulatory agencies, depending on the specific use or application of CUBs.

Complete analysis of state and county regulatory plans is beyond the scope of this report. This information is included to provide summary state level regulatory information as it may apply to gasification-based power systems. Primary attention is focused on the classification and utilization of CUBs, and particular focus is directed at states that currently have IGCC facilities. An attempt is made to indicate where state standards differ from federal standards. However, no attempt is made to analyze the permitting process or enforcement provisions in individual state summaries. While every effort is made to include the most recent regulatory status, interested parties should contact the appropriate state regulatory agency for more information.

3.4.3.1 Florida[39]

The primary solid wastes of concern for coal-based gasification power systems are large volume CUBs and the co-management of small volume wastes with CUBs. Florida regulations adopt the federal regulations which exempt fly ash, bottom ash, slag and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels from regulation as hazardous waste (40 CFR 261.49(b)(4), 62-730.030 F.A.C.). CUBs are regulated as solid waste if disposed of and may be regulated as industrial byproducts if the CUBs are utilized within one year, if there is no release or threat of release into the environment, and if the facility is registered with the Department of Environmental Protection to allow for such recovery of CUBs (FAC 62-701.220(2)(c) F.A.C.). Reuse of all CUBs is not specifically authorized under Florida law. However, ash residue from CUBs is specifically authorized for use in concrete under Florida statute 336.044(2)(b). Until national regulations are promulgated, Florida will continue to be responsible for implementation of Subtitle D disposal of CUBs.

3.4.3.2 Indiana[39]

Indiana Code IC 13-11-2-109.5 defines industrial wastes as a solid waste that is not 1) a hazardous waste, 2) a municipal waste, 3) a construction/demolition waste or 4) an infectious waste as defined elsewhere in Indiana Code. The disposal of such wastes is subject to Federal Subtitle D regulations specified in 40 CFR §228, with certain provisions for small quantities and specially permitted disposal sites (IC 13-20-7.5-1). Any waste determination required for non-exempt wastes are the responsibility of the generator, and specific guidelines are outlined in 326 IAC 10.

Indiana Code (IC 13-19-3-3) specifically exempts coal combustion wastes from solid or hazardous waste regulations, if the waste is not included in the definition of hazardous wastes and meets the Federal exemption under 42 U.S.C.A. § 6921. In order to maintain the categorical exemption the waste must also be disposed of at a facility regulated as a surface coal mining facility. Additional exemptions from solid waste regulations are also provided for specific beneficial uses of coal combustion fly or bottom ash alone or in mixture with flue gas desulfurization byproducts generated by coal combustion units, or the use of boiler slag. The allowable uses include:

- Use of bottom ash as anti-skid material
- Use of the waste as a raw material for manufacturing another product
- Use in mine subsidence, mine fire control, and mine sealing
- Use as structural fill when combined with cement, sand, or water to produce a controlled strength fill material
- Use as a roadbase in construction
- Extraction or recovery of materials and compounds from the coal ash.

3.4.3.3 Louisiana[39]

Under Louisiana regulations, fly ash, bottom ash, slag and flue gas emission control waste generated solely from the combustion of coal or other fossil fuels are exempt from regulation as hazardous waste (LAC 33:V.105(D)(2)(d)). Additionally, Louisiana specifically exempts from regulation as hazardous waste gasifier ash and process waste water resulting from coal gasification, categorizing this ash as solid waste resulting from the processing of ores and minerals (LAC 33:V.105(D)(2)(h)(ii)). These materials are, however, regulated as industrial solid wastes (LAC 33:VII.115). Louisiana does not specifically address the reuse of coal combustion by-products, but does require beneficial-use permits for land application of any solid waste (LAC 33:VII.1103(A)). Additional site analysis, disposal and record keeping requirements also exist. Louisiana code outlines recycling regulations (LAC 33:VII.Subpart 2) that may be applicable to the reuse of CUBs as raw material or product.

3.4.3.4 States With a Large Base of Existing Coal-Fueled Electric Power Generation

TABLE 3-27 presents summary information of state level solid waste regulations for selected states that currently have a significant number of coal-fueled electric generating units. These states are Alabama, Georgia, Illinois, Kentucky, New York, Ohio, Pennsylvania, Tennessee, Texas, and West Virginia. Qualitative generalizations are provided for the classification and disposal of CUBs. More detailed information is provided in Appendix 3A.

3.4.4 Overview of Future Solid Waste Pollution Regulations Potentially Applicable to Gasification-Based Power Systems

Continued interest in trace level hazards and toxics, including mercury, may impact the reuse and disposal of fossil fuel combustion waste. EPA has continued to support the Bevill exemption for large volume fossil-fuel wastes and the recent ruling of exemption for associated fossil-fuel process wastes has demonstrated support for the beneficial reuse of these wastes. National level RCRA Subtitle D requirements for the disposal of fossil fuel combustion wastes are expected to be proposed in the near future and will have a direct effect on the onsite storage and subsequent disposal of these wastes.

TABLE 3-27. CUB REGULATIONS FOR SELECTED STATES

STATE	COAL COMBUSTION BYPRODUCT REGULATIONS
Alabama	Exempt from regulation as hazardous waste. Also provisions for exemption from designation as industrial solid waste. No specific provisions for reuse.
Georgia	Incorporate by reference federal exemption of CUBs from hazardous designation. No specific provisions for reuse.
Illinois	Exempt from regulation as hazardous waste. Also provisions for exemption from designation as industrial solid waste. Illinois law specifically authorizes reuse. Provides a distinction between coal combustion waste and coal combustion by-product with separate regulations for reuse.
Kentucky	Exempt from regulation as hazardous waste. Fly ash, bottom ash, and scrubber sludge from coal-fueled electric generating units are classified as special waste. Kentucky specifically authorizes reuse with certain provisions.
New York	Exempt from regulation as hazardous waste. New York regulations specifically include provisions for CUB reuse.
Ohio	Exempt from regulation as hazardous waste. Additionally, non-toxic fly ash, bottom ash and slag are regulated as exempt waste. The reuse of CUBs that are regulated as solid waste is not specifically authorized. The reuse of non-toxic exempt waste is however authorized.
Pennsylvania	Adopts federal hazardous waste exemption by reference. Beneficial reuse is authorized with certain provisions outlined.
Tennessee	Exempt from regulation as hazardous waste. Fly ash, bottom ash, and boiler slag may be reused under “permit by rule” regulation.
Texas	Adopts federal hazardous waste exemptions by reference. Texas has issued a CUB reuse guidance that provides that under certain circumstances, CUBs are not subject to designation as waste and are designated as “co-products”.
West Virginia	Exempt from regulation as hazardous waste. West Virginia includes specific provisions for the reuse and disposal of CUBs.

3.5 Additional Regulatory and Permitting Requirements

There are a variety of regulatory and permitting requirements that aren't media-specific or apply across media categories. Permits are typically required for construction and operation of industrial facilities, and states frequently have statutes unique to each state. Many permit requirements are included in an Environmental Impact Statement (EIS) if NEPA requirements are applicable. In order to stay within the scope of this report, significant categories of permits and regulations are only mentioned here in the context that they may be required.

3.5.1 Miscellaneous Industrial Permitting Requirements

The placement and use of industrial structures in navigable waters may require permitting under the River and Harbor Act of 1899, along with certain provisions of the Clean Water Act. Land use permits may be required under federal and state level statutes. Wetland and floodplain regulations may also require permitting. Compliance with Federal and local air navigation statutes and regulations are likely required due to the presence of high structures. Noise ordinances may also require consideration and possibly permitting. Additionally, likely biological impacts, including the impact on endangered and indigenous species, may require permit compliance. Further, cultural resource impact considerations are required under federal and state historic preservation statutes.

Local permits and approvals are also required for an IGCC project. These requirements typically pertain to local zoning and building codes, comprehensive land use and shoreline plans, and local development policies. Requirements will vary by jurisdiction. Operation of a solid waste facility (landfill, transfer station, recycling facility, etc.) requires a Solid Waste Permit. These permits are issued by local health departments, and are conditioned to ensure that these facilities meet state and local laws governing solid waste. Requirements will vary by jurisdiction.

Development on tribal-reservation land may be subject to tribal laws. The appropriate tribal planning office needs to be contacted prior to conducting activities on tribal land. When a project is on non-tribal lands, but may affect treaty-reserved resources or areas of tribal significance, agencies have an obligation and responsibility to consult with tribal governments during the project review process. Mitigation may be required to protect treaty rights. Prevention of damage to Indian graves or artifacts is required. Unlawful removal or mutilation of artifacts or burial sites is typically punishable as a felony under state law.

3.5.2 Reporting and Emergency Planning Regulations

In addition to control and handling measures outlined in the specific pollution control acts, several regulations outline reporting requirements. Electric utilities that "burn" coal and/or oil are required (62 FR 23834) to report under the Emergency Planning and Community Right-to-Know Act (EPCRA, 42 U.S.C.A. §§ 11001 to 11050). Under 42 U.S.C.A. §11023, subject industries are required to complete a toxic chemical release form for each toxic chemical listed on the Toxic Release Inventory (TRI) and was manufactured, processed or otherwise used in quantities beyond a threshold amount in the previous calendar year. Certain compounds, including mercury, are categorized as a reportable persistent bioaccumulative toxic (PBT)(64 FR 58666) and require compliance regardless of the amount emitted. Industries required to report under 42 U.S.C.A. §11023 are also required to comply with the Pollution Prevention Act (PPA, 42 U.S.C.A. §§ 13101 to 13109). The PPA focuses attention on source reduction of pollution through cost effective changes in the product production, facility operation and raw material use.

Additionally, EPCRA requires the generation of emergency response plans and requires emergency notifications for releases of hazardous and highly hazardous substances outside the perimeter of the facility (42 U.S.C.A. §§ 11003 and 11004). These regulations are linked closely to the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA, 42 U.S.C.A. §§ 9601 to 9675). 42 U.S.C.A. §§ 9601 and 9602 outline what compounds constitute a highly hazardous substance. Compounds of known emitted hazardous elements (compounds of mercury for example) may require compliance with these statutes. Additionally, facilities subject to OSHA required MSDS preparation for hazardous chemicals are also required to comply with reporting requirements outlined by EPCRA Subchapter II.

3.5.3 NEPA Requirements for Federally Funded Facilities

The National Environmental Policy Act of 1969 (NEPA) applies to all Federal Agencies and to Federal Actions that may significantly effect the environment. The types of Federal activities that subject NEPA requirements to fossil fuel electric power generating facilities include siting, construction, and operations of federally owned facilities, federally issued NPDES, RCRA, and air permits, and federally issued operating licenses. NEPA requires that each Federal activity follow certain environmental review procedures. Depending on the information available, either an environmental impact statement (EIS) or an environmental assessment (EA) must be prepared. The outcome of the detailed statements determines whether there is no significant impact, or whether alternative actions are required. For outcomes of no significant impact, the preparation of a finding of no significant impact (FONSI) is required.

3.6 Section 3 References

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APPENDIX 1A

DESCRIPTION OF COMMERCIAL GASIFICATION SYSTEMS

1A DESCRIPTION OF COMMERCIAL GASIFICATION SYSTEMS

Gasification-based power generation systems can incorporate any one of a number of different gasifier designs. This appendix reviews those gasification technologies that are predominantly used in commercial applications for power generation and have been extensively evaluated and tested. These are listed below in TABLE 1A-1, and are identified by vendor, type, form of fuel feed and oxidant, along with some major installations that use coal, petcoke, RDF, and heavy oil feedstocks. The sections that follow provide a detailed description of these gasifiers.

TABLE 1A-1. GASIFIER TECHNOLOGY SUPPLIERS

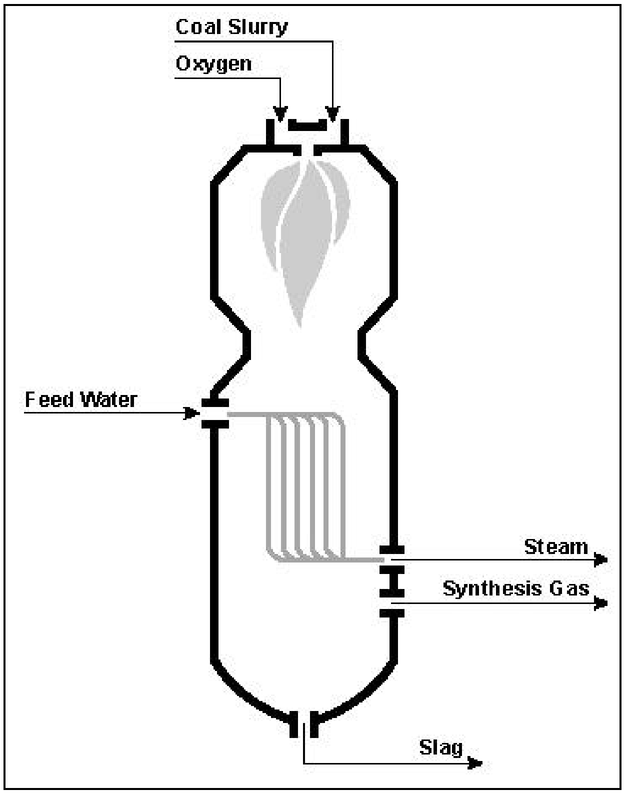
TECHNOLOGY SUPPLIER	GASIFIER TYPE	SOLID FUEL FEED TYPE	OXIDANT	POWER INSTALLATIONS
ChevronTexaco, USA	Entrained Flow	Water Slurry	O_2	Tampa Electric IGCC Plant, Cool Water IGCC Plant, ChevronTexaco-Eldorado IGCC Plant, Eastman Chemical, Ube Industries, Motiva Enterprises, Deer Park
Global Energy E-GAS, USA	Entrained Flow	Water Slurry	O_2	Wabash River IGCC Plant and Louisiana Gasification Technology IGCC Project
Shell, USA/The Netherlands	Entrained Flow	N_2 Carrier/Dry	O_2	Demkolec IGCC plant, (Buggenum, Netherlands), Shell-Pernis IGCC Plant (Netherlands), Harburg
Lurgi, Germany	Moving Bed	Dry	Air	Sasol Chemical Industries and Great Plains Plants
British Gas/Lurgi, Germany/U.K.	Moving Bed	Dry	O_2	Global Energy Power/Methanol Plant (Germany)
Prenflo/Uhde, Germany	Entrained Flow	Dry	O_2	Elcogas, Puertollano IGCC Plant (Spain), Fürstenhausen in Saarland
Noell/GSP, Germany	Entrained Flow	Dry	O_2	Schwarze Pumpe, Germany
HT Winkler (HTW), RWE Rheinbraun/ Uhde, Germany	Fluidized Bed	Dry	Air or O_2	None
KRW, USA	Fluidized Bed	Dry	Air or O_2	Sierra Pacific (Nevada, U.S.A.)

1A.1 ChevronTexaco Entrained-Flow Gasifier[1]

ChevronTexaco gasification technology uses a single-stage, downward-feed, entrained-flow gasifier (see FIGURE 1A-1) in which fuel/water slurry (e.g., 60-70% coal) and 95% pure oxygen (from an air separation unit) are fed to a hot, pressurized gasifier. Slurried feedstock is pumped to a specially designed injector mounted at the top of the refractory-lined gasifier. The fuel and oxygen react exothermally at a temperature ranging from 2200° to 2700°F (1204° to 1482° C), and a pressure greater than 20 atmospheres, to produce raw fuel gas (syngas) and molten ash (slag). Operation at the elevated temperatures eliminates the production of hydrocarbon gases and liquids in the syngas. In the syngas cooler design-type, the hot gas flows downward into a radiant syngas cooler where high-pressure steam is produced. The syngas cooler is specifically designed to meet the conditions of high thermal gradients and the ability to handle soot. The syngas passes over the surface of a pool of water at the bottom of the radiant syngas cooler and exits the vessel. The slag drops into the water pool and is fed from the radiant syngas cooler sump to a lock hopper. The black water flowing out with the slag is separated and recycled after processing in a dewatering system. The slag is eventually removed through a lockhopper. This design configuration maximizes heat recovery for steam production, as well as CO production, which is appropriate for an IGCC application.

Upon exiting the gasifier, a water scrubber further cools and cleans the syngas, and the fine particulate matter and char may be recycled to the gasifier. A sulfur recovery system may also be added. After the gasifier converts organic materials into syngas, the cooled, water-scrubbed syngas, consisting mainly of hydrogen and carbon monoxide, essentially contains no hydrocarbons heavier than methane. Metals and other ash constituents become part of the glassy slag.

FIGURE 1A-1. ChevronTexaco GASIFIER



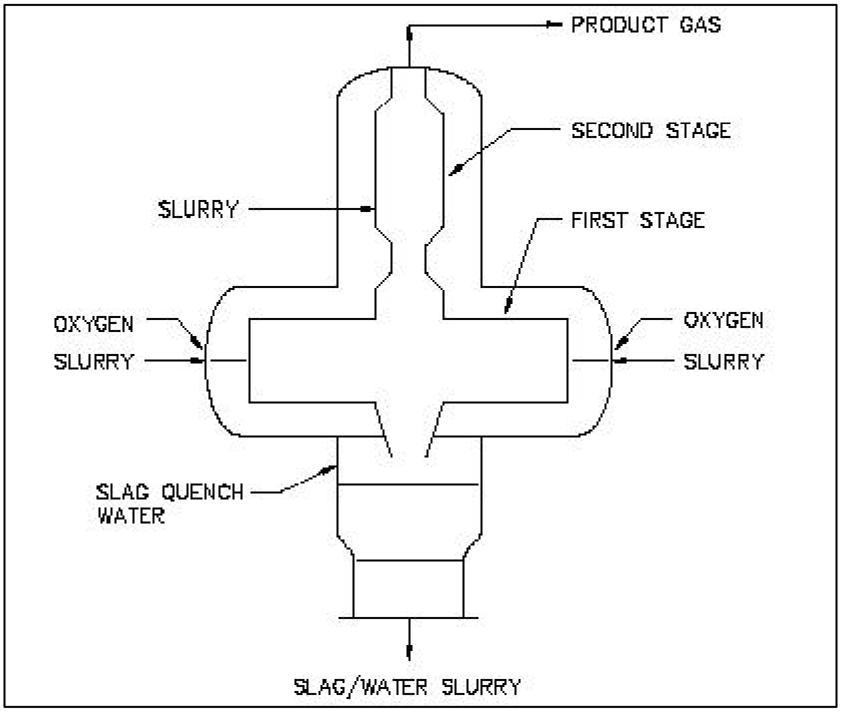
An alternate design to the use of a radiant syngas cooler is the use of an exit gas quench. In this design mode, the hot gas exiting the reaction chamber is contacted with water via a quench ring followed by immersion into the water in the lower portion of the gasifier vessel. The syngas is cooled by direct contact, exits the gasifier saturated with water, and enters a scrubber for particulate and soot removal. This design provides an effective mechanism to add water to the syngas to promote the water-gas shift reaction and maximize hydrogen production. The quench design mode is often used to accommodate heavy hydrocarbon feedstock.

The ChevronTexaco technology has operated commercially for over 40 years with feedstocks such as natural gas, heavy oil, coal, and petroleum coke. There are currently 60 commercial plants in operation: 12 using coke and coal, 28 using oil, and 20 using a gas feedstock. This technology was used in the groundbreaking Cool Water IGCC project, the first large-scale IGCC power plant, and it is incorporated into Tampa Electric's Polk IGCC power plant.

1A.2 E-GAS Entrained-Flow Gasifier[2]

The E-GAS (formerly Destec) coal gasifier, depicted in FIGURE 1A-2, is a slurry-feed, pressurized, upflow, entrained slagging gasifier whose two-stage operation makes it unique. Wet crushers produce slurries with the raw feed coal. Dry coal slurry concentrations range from 50 to 70% by weight, depending on the inherent moisture and quality of the feed coal. About 75% of the total slurry feed is fed to the first (or bottom) stage of the gasifier. This slurry is combined with 95% pure oxygen (from an air separation unit) in mixer nozzles and injected into the first stage of the gasifier, which operates at 2600°F and 400 psig. This stage is best described as a horizontal cylinder with two horizontally opposed injectors. The highly exothermic gasification/oxidation reactions take place rapidly at temperatures of 2400° to 2600° F (1315° to 1427° C). Operation at the elevated temperatures eliminates the production of hydrocarbon gases and liquids in the product gas.

FIGURE 1A-2. E-GAS GASIFIER



The hot raw gas from the first stage enters the second (top) stage, which is a vertical cylinder perpendicular to the first stage. The remaining 25% of the coal slurry is injected into the hot raw gas. The endothermic gasification/devolatilization reactions in this stage reduce the final gas temperature to about 1900°F and add some hydrocarbons to the product gas. Char is produced in the second stage. However, the yield of this char is relatively small because only about 25% of the coal is fed to the second stage. Char yield is dependent on the reactivity of the feed coal and decreases with increasing reactivity. The char is recycled to the hotter first stage, where it is readily gasified.

The 1900° F (1038° C) hot gas leaving the gasifier is cooled in a fire-tube product gas cooler (high temperature heat recovery unit or HTHRU) to 1100° F, generating saturated steam, which is sent to the steam turbine. After cooling in the HTHRU, particulates and chlorides in the syngas are removed in a wet scrubber and the char is recycled to the gasifier where the carbon in the char is converted to syngas. The syngas is then treated to remove carbonyl sulfide and hydrogen sulfide prior to being sent to an energy conversion device, such as a gas turbine.

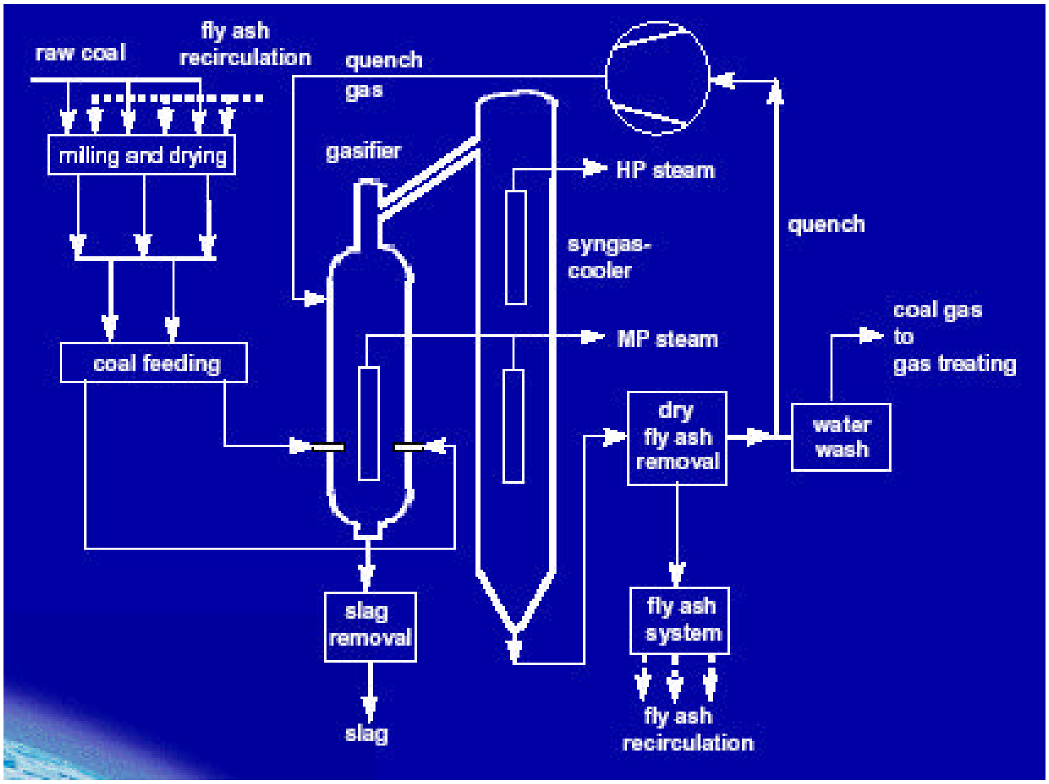
The E-Gas technology was originally demonstrated at the LGTI IGCC plant, sometimes called the Dow Syngas Project, but is no longer operated. It is currently incorporated into the Wabash River IGCC plant, which began operation in 1995 and has gasified over two million tons of bituminous coal (up to 5.9% sulfur) and petroleum coke (up to 7% sulfur) during its nearly seven years of operation.

1A.3 Shell Entrained Flow Gasifier[1]

The Shell Gasification Process, as shown in FIGURE 1A-3, is a dry-feed, pressurized, entrained slagging gasifier that can operate on a wide variety of feedstocks.[3] Feed coal is pulverized and dried with the same type of equipment used for conventional pulverized coal boilers. The coal is then pressurized in lock hoppers and fed into the gasifier with a transport gas by dense-phase conveying. The transport gas is usually nitrogen; however, product gas can be used for synthesis gas chemical applications, where nitrogen in the product gas is undesirable. The oxidant, 95% pure oxygen from an air separation unit, is preheated to minimize oxygen consumption and mixed with steam as moderator prior to feeding to the fuel injector. The coal reacts with oxygen at temperatures ranging from 2700° to 2,900°F (1500° to 1600° C), and pressures ranging from 350 to 650 psi, to produce a syngas principally composed of hydrogen and carbon monoxide, with little carbon dioxide. Operation at the elevated temperatures eliminates the production of hydrocarbon gases and liquids in the product gas.

The high-temperature gasification process converts the ash into molten slag, which runs down the refractory-lined water wall of the gasifier into a water bath, where it solidifies and is removed through a lock hopper as slurry in water. Some of the molten slag collects on the cooled walls of the gasifier to form a solidified protective coating. The crude raw gas leaving the gasifier at 2,500-3,000°F contains a small quantity of char and about half of the molten ash. To make the ash non-sticky, the hot gas leaving the reactor is partially cooled by quenching with cooled recycle product gas (not shown in figure). Further cooling takes place in the waste heat recovery (syngas cooler) unit, which consists of radiant, superheating, convection, and economizing sections, where high-pressure superheated steam is generated. The syngas is further cooled before particle removal in a wet scrubber. The syngas is then treated to remove carbonyl sulfide and hydrogen sulfide prior to being sent to an energy conversion device, such as a gas turbine.

FIGURE 1A-3. SHELL GASIFICATION PROCESS [3]



Shell's experience with gasification dates back to the 1950s, when the first Shell Gasification Process (SGP) units were commissioned.[4] In 1972, Shell started development work on a gasification process for coal (SCGP). Following experience with a 6 ton/day pilot plant in Amsterdam, in 1978, Shell started operation of a 150-ton/day demonstration plant operated by Deutsche Shell at Harburg near Hamburg, Germany. Shell used the experience gained to construct a plant at its existing petrochemicals complex at Deer Park in Houston, USA. This plant was sized to gasify 250 tons/day of bituminous coal or 400 tons/day of high-moisture, high-ash lignite.

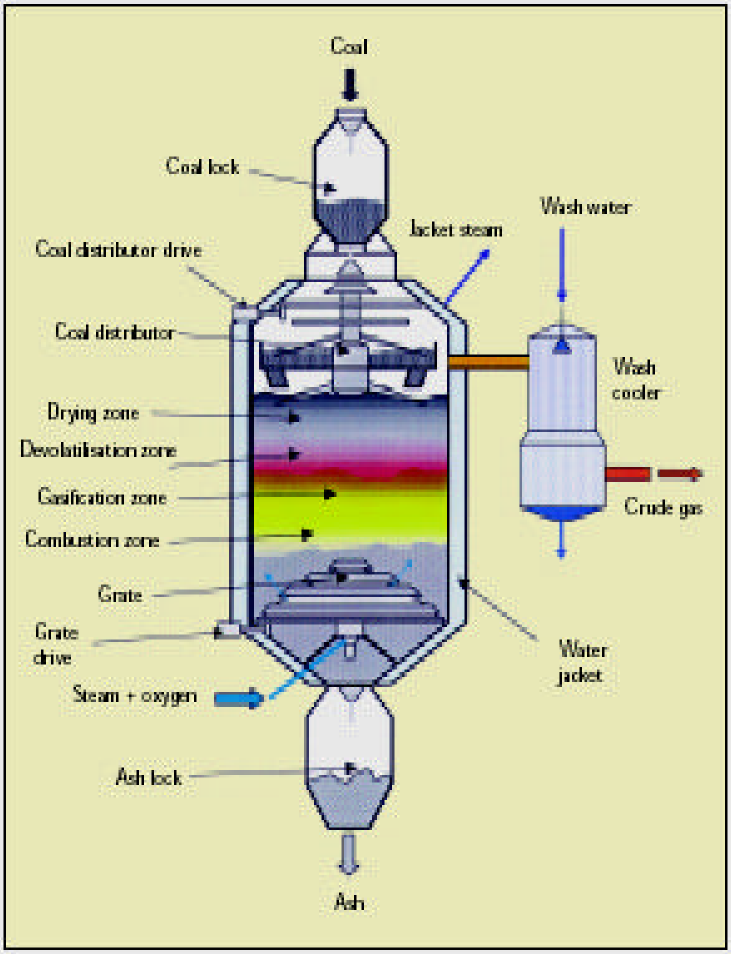
The Deer Park gasifier went into operation in 1987, and proved the ability of the SCGP to gasify a wide range of coals. In 1989 the SCGP was chosen for a 250 MWe IGCC plant at Buggenum, The Netherlands, and has been in operation since 1993. The Shell-Pernis IGCC plant, using heavy oil as a feedstock, started operation in 1997. It produces 127 MWe of power, as well as hydrogen.

1A.4 Lurgi Dry Ash Gasifier

The Lurgi dry-ash gasifier, shown in FIGURE 1A-4, is a pressurized, dry ash, moving-bed gasifier. Its major features are that it is a moving bed process that uses steam and (normally) O_2 as the oxidants. Like the BG/L gasifier (see Section 1A.5), it runs on lump coal rather than pulverized fuel and, like the BG/L system, it produces tars. The major difference between the

Lurgi dry-ash gasifier and the BG/L slagging gasifier is that the former uses a much greater ratio of steam to O_2 as oxidant (perhaps 4-5:1 for the former compared with ~0.5:1 for the latter). The result of this is that the temperature in the dry-ash system is kept sufficiently low at all points that the ash does not melt but is removed as a dry ash. The lower temperature of the dry-ash system means that it is suited more to reactive coals, such as lignites, than to bituminous coals.[4]

FIGURE 1A-4. LURGI DRY-ASH GASIFIER[4]



Sized coal enters the top of the gasifier through a lock hopper and moves down through the bed. A rotating coal distributor ensures even distribution of coal around the reactor. Steam and oxygen enter at the bottom and react with the coal as the gases move up the bed. Ash is removed at the bottom of the gasifier by a rotating grate and lock hopper. The coal moves slowly down the gasifier. As its does so, it is warmed by the syngas flowing upwards through the bed; thus the coal is sequentially dried and devolatilized (the devolatilisation forms tars and phenols), then gasified. The countercurrent operation results in a temperature drop in the reactor. Gas temperatures in the drying and devolatization zone near the top are approximately 500° to 1000° F (260° - 538° C). The very bottom of the bed, immediately above the grate, is the hottest part of the gasifier (~1000° C or 1832° F) and there any remaining coal is oxidized. The CO_2 produced there reacts with carbon higher in the bed to form CO.

The raw syngas produced exits the gasifier at a temperature of 570° to 932° F (300 to 500° C) and is cooled and quenched using recycle water quench to condense tar/oil. A water jacket cools the gasifier vessel and generates part of the steam to the gasifier. Sufficient steam is injected into the bottom of the gasifier to keep the temperature below the melting temperature of ash.[1] Ash is removed by a revolving grate and depressurized in a lockhopper.

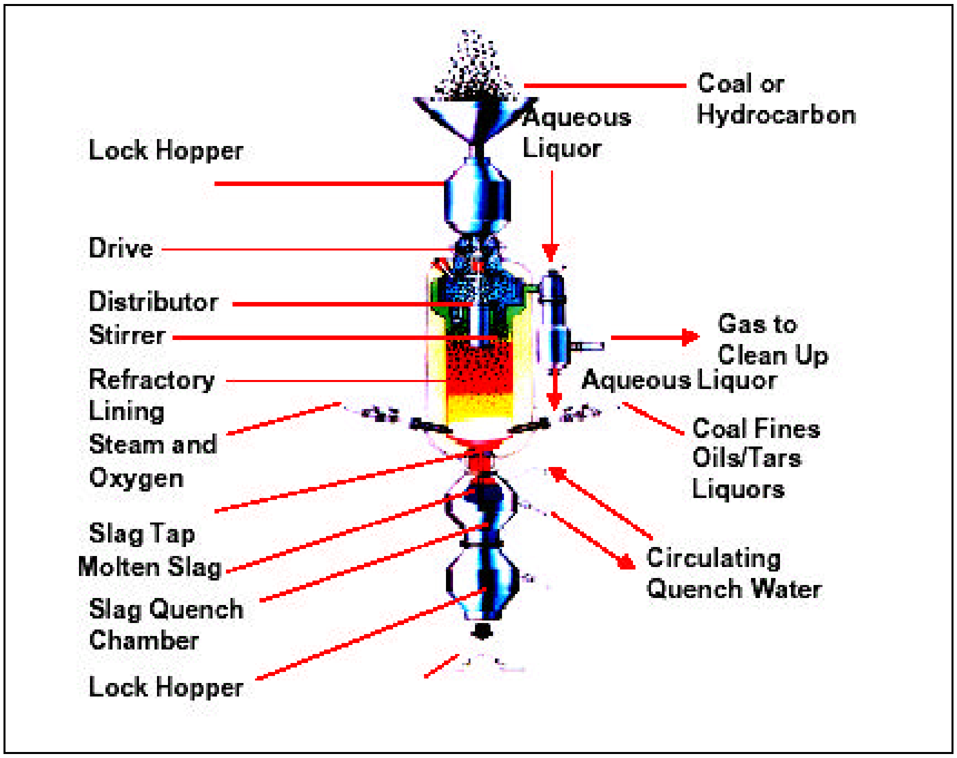
Lurgi GmbH developed the technology in the early 1930s as a means of producing so-called town gas. The first commercial plant was built in 1936. Until 1950, the process was mostly restricted to lignites, but in the 1950s Lurgi and Ruhrgas collaborated to develop a process suitable for bituminous coals as well. Since then the Lurgi gasification process has been widely used worldwide for producing Town Gas and syngas for a variety of purposes (e.g., NH_3, methanol, liquid fuel production). Significant installations using this technology are the Great Plains SNG plant in North Dakota, USA, and the SASOL synfuels plant in South Africa.

1A.5 British Gas/Lurgi Moving-Bed Gasifier

The British Gas/Lurgi (BG/L) coal gasifier, shown in FIGURE 1A-5, is a dry-feed, pressurized, moving bed, slagging gasifier. The BG/L technology offers the following features:

- High gasification efficiency (carbon conversion), typically over 92%
- Use of run-of-the-mine coal or other carbon-based feedstock
- High thermal efficiency and simple heat exchanger for convenient heat recovery
- High gasifier throughputs, and
- A closed-loop system with no primary stack and no ash residue.

FIGURE 1A-5. BRITISH GAS/LURGI MOVING BED GASIFIER[5]



The reactor vessel is water-cooled and refractory-lined. The gasifier is provided with a motor-driven coal distributor/mixer to stir and evenly distribute the incoming coal mixture. Oxygen and steam are introduced into the gasifier vessel through sidewall-mounted tuyeres (lances) at the elevation where oxidation and slag formation occur.

The coal mixture (coarse coal, fines, briquettes, and flux), which is introduced at the top of the gasifier via a lock hopper system, gradually descends through several process zones. Coal at the top of the bed is dried and devolatilized. The descending coal is transformed into char, and then passes into the gasification (reaction) zone. Below this zone, any remaining carbon is oxidized, and the ash content of the coal is liquified, forming slag. Slag is withdrawn from the slag pool by means of an opening in the hearth plate at the bottom of the gasifier vessel. The slag flows downward into a quench chamber and lock hopper in series. The pressure differential between the quench chamber and gasifier regulates the flow of slag between the two vessels.

Syngas exits the gasifier at approximately 1050°F through an opening near the top of the gasifier vessel and passes into a water quench vessel and a boiler feed water (BFW) preheater designed to lower the temperature to approximately 300°F. Entrained solids and soluble compounds mixed with the exiting liquid are sent to a gas-liquor separation unit. Soluble hydrocarbons, such as tars, oils, and naphtha are recovered from the aqueous liquor and recycled to the top of the gasifier and/or reinjected at the tuyeres.

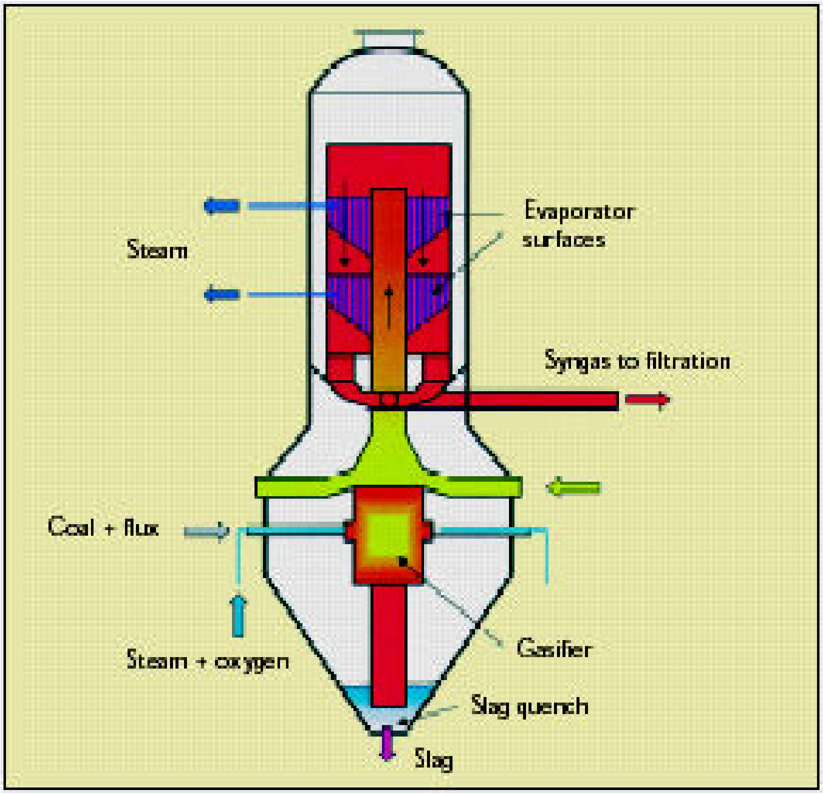
The BG/L gasifier was originally developed in the 1970s to provide a syngas with high methane content in order to provide an efficient means of manufacturing SNG from coal. It was developed over about 15 years at British Gas' Westfield Development Centre in Fife, Scotland, initially to test the process for applicability to SNG manufacture and later for IGCC. BG/L-based IGCC plants include two at Fife Power in Scotland, one plant that generates 120 MWe from coal and sewage sludge, and a second, larger 400 MWe plant that gasifies coal and refuse derived fuel (RDF). Global Energy intends to use BG/L gasifiers in two IGCC projects it is currently developing in Kentucky and Ohio. The BG/L gasifiers were selected based on their capability to fire a combination of coal and refuse-derived fuel (RDF).

1A.6 Prenflo Entrained Bed Gasifier

The Prenflo gasification process, developed by Uhde (formerly Krupp Uhde) of Germany, is a pressurized, dry feed, entrained-flow slagging process. The gasifier is shown in FIGURE 1A-6.

Coal is ground to approximately100µm and pneumatically conveyed by nitrogen to the gasifier. The gasifier structure is unusual in that it incorporates both the gasifier itself and the syngas cooler, with the internal surface of the wall being lined with refractory to protect the metal vessel from the hot syngas. The coal is fed through injectors located in the lower part of the gasifier, together with O_2 and steam. Syngas is produced at a temperature of up to 2900° F (1600° C). However, it is quenched at the gasifier outlet with recycled cleaned syngas to reduce its temperature to about 1470° F (800° C). The syngas then flows up a central distributor pipe and down through evaporator stages before exiting the gasifier at about 716° F (380° C). The slag formed during the gasification process flows down the gasifier walls to be quenched in a water bath and granulated before removal through a lockhopper system. The slag provides a critical protective layer, which prevents diffusion of the gas through the refractory coating.

FIGURE 1A-6. PRENFLO ENTRAINED FLOW GASIFIER



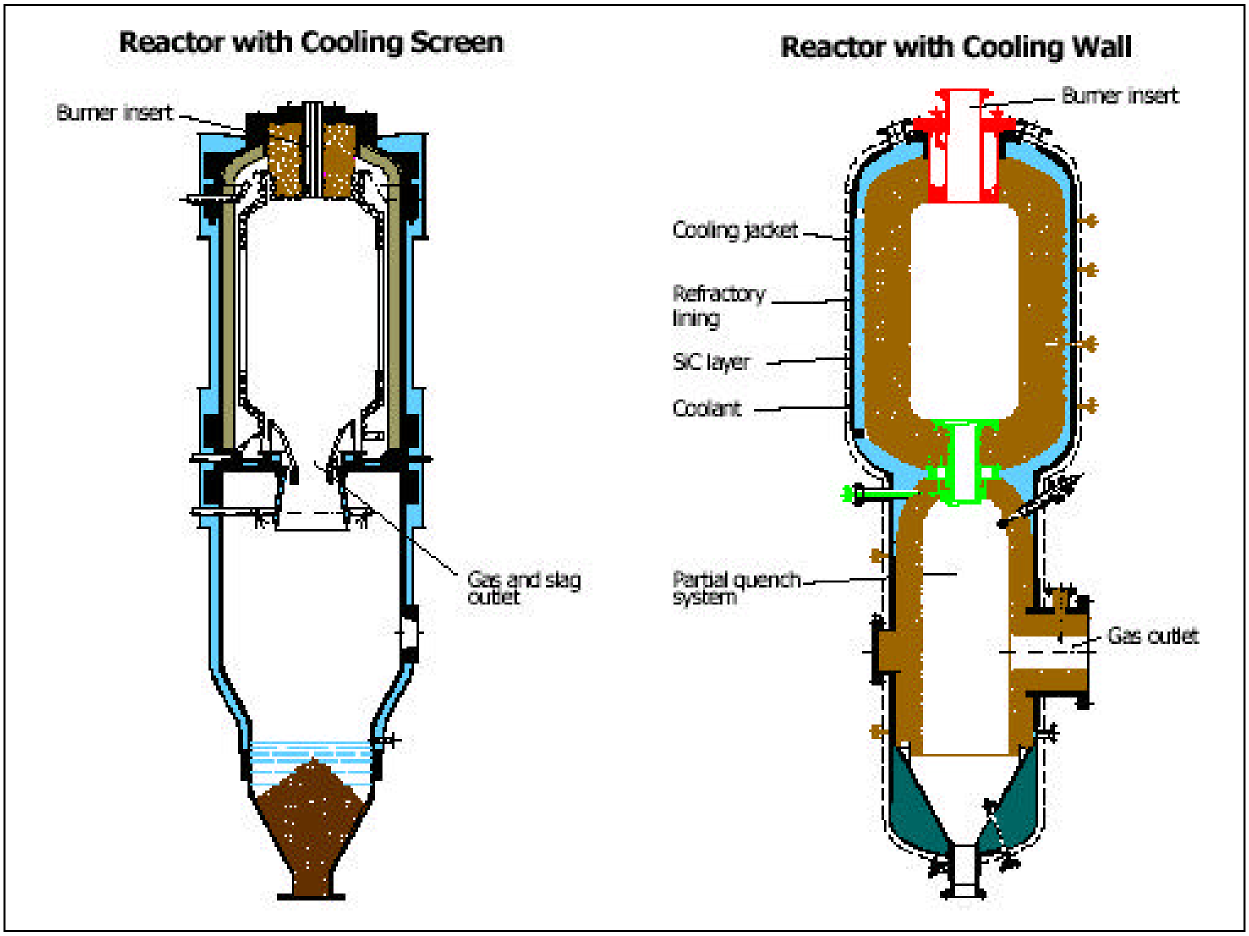
Uhde built a 48 metric ton/day unit at Fürstenhausen in Saarland, Germany. Following this work, the Prenflo process was selected for the 318 MWe Puertollano IGCC plant in Spain, which uses coal and coke feedstocks.

1A.7 Noell Entrained Flow Gasifier

The Noell gasification process, originally developed by Deutsches Brennstoffinstitut Freiberg for the gasification of pulverized brown coal, is a pressurized, dry feed, entrained-flow slagging process. The gasifier is shown in FIGURE 1A-7. As shown, the reactants are fed in at the top of the gasifier. The oxygen-to-fuel ratio is trimmed to keep the gasification temperature at a level at which the inorganic matter melts, flows vertically downward in parallel with the gasification gas and leaves the gasifier through a special discharge unit. The gasification chamber is enclosed by a cooling screen, which consists of a gas-tight membrane wall structure that is studded and refractory-lined with a thin layer of a special silicon carbide (SiC) ramming mass for protection. The liquid slag, which is thrown from the gasification chamber onto this cooling screen, cools down and solidifies, thus, forming a compact slag layer. This solidified slag layer continues to grow in thickness until the ash fusion temperatures are exceeded. Then, slag hitting the wall remains in liquid condition, flows down the wall, and discharges at the bottom together with the syngas.

A reactor design that makes use of the above-described cooling screen requires gasification feeds with ash content of more than 1% by weight, thus allowing the solidified slag layer to regenerate continually. The cooling screen is not incorporated if the ash content is lower than 1%. In such a case, a cooled-wall reactor design is used, whereby a refractory lining replaces the missing slag layer. A water-cooling jacket is substituted for the tube screen inside the pressure vessel. The syngas outlet zone, where small quantities of ash may concentrate, is designed as a discharge unit of the cooling-screen type. Low ash quantities enable partial quenching to temperatures of 1470° F (800 ° C), with heat recovery steam generation.

FIGURE 1A-7. NOELL ENTRAINED FLOW GASIFIER[6]

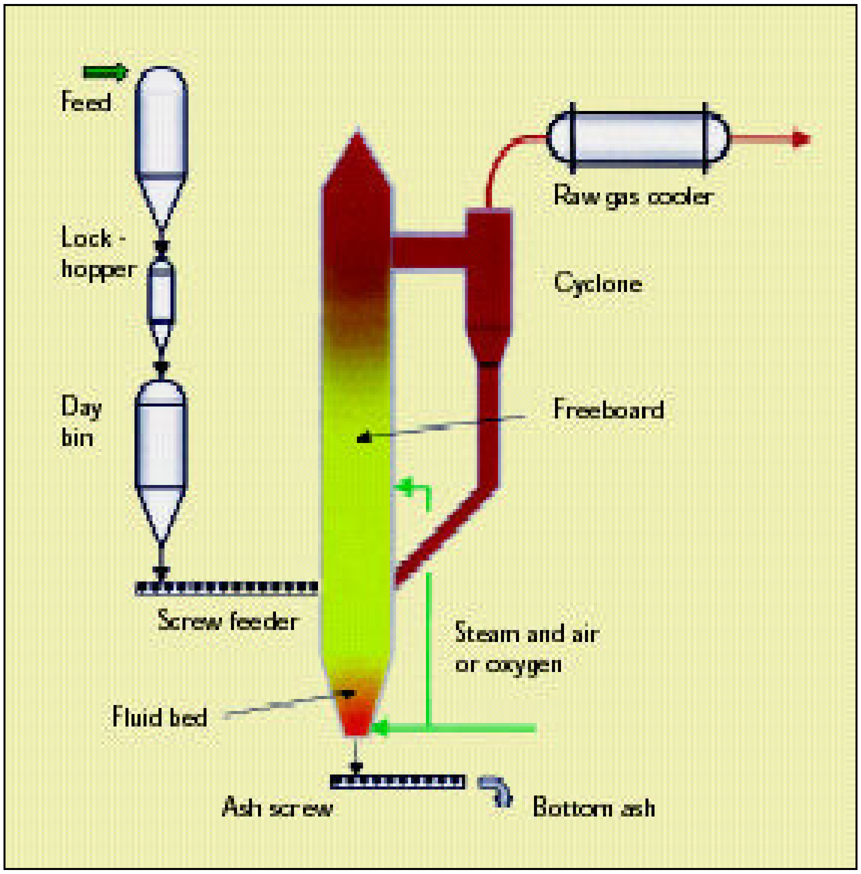


Carbon conversion rates of more than 99 % have been achieved in the gasifier. Depending on the intended use of the syngas produced, a direct-contact water spray quench system or an indirect-cooling heat recovery steam generator system may be installed downstream of the gasifier (not shown in figure). This type of gasifier has been successfully operating at SVZ Schwarze Pumpe since 1984, first on brown coal and then on sludge, ash-containing oils and slurries. A 40 MWe IGCC unit, fueled with coal and oil, has been operating at Schwarze/Pumpe (Germany) since 1996.

1A.8 High Temperature Winkler Gasifier

The High Temperature Winkler (HTW) gasifier, developed by Rheinbraun and shown in FIGURE 1A-8, is a dry-feed, pressurized, fluidized-bed, dry ash gasifier. A key advantage of the technology is the capability to gasify a variety of different feedstocks, including all grades of more reactive low-rank coals with a higher ash softening temperature (i.e., brown coal, more reactive grades of black coal, both caking and non-caking types), and also various forms of biomass. Also, due to the high outlet temperature, the syngas does not contain any higher hydrocarbons, such as tars, phenols and other heavy and substituted aromatics.[4]

FIGURE 1A-8. HT WINKLER FLUIDIZED BED GASIFIER[4]



Fuel (e.g., fine-grained coal) is pressurized in a lockhopper and then stored in a day- or charge-bin before being fed continuously by screw-type feeder into the gasifier. The bottom part of the gasifier comprises a fluidized-bed, the fluidizing medium being air or O_2 and steam. The bed is formed by particles of ash, semi-coke and coal, and is maintained in the fluidized state via upward flow of the gasification agent (e.g., air). Gas plus elutriated solids flow up the reactor, with further air/O_2 and steam being added in this region to complete the gasification reactions. Fine ash particulate and char, entrained in the crude syngas, is removed in a cyclone and cooled. The solids removed in the cyclone are returned to the gasifier base to maximize carbon conversion. Ash is removed from the base of the gasifier by means of an ash screw.

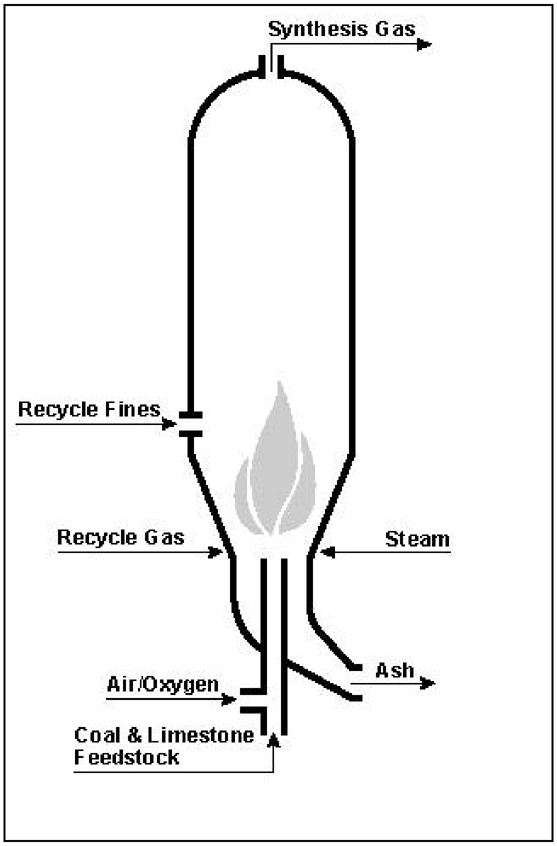
The temperature in the base of the gasifier is kept at about 1470° to 1650° F (800° to 900° C); this is controlled to ensure that the temperature does not exceed the ash softening point. The temperature in the freeboard above the bed itself can be significantly higher (1650° to 2000° F or 900° to 1100° C). The operating pressure can vary between 145 psi (10 bar) for syngas manufacture and 360 to 435 psi (25-30 bar) for an IGCC application.

The HTW process was developed by Rheinbraun, which owns and operates several lignite mines in Germany's Ruhr region. Rheinbraun is still responsible for the development of the HTW process, but Uhde (formerly Krupp Uhde) is undertaking the marketing and supply. The HTW gasifier has been applied commercially at 145 psi (10 bar) pressure for the gasification of Rhenish lignite to syngas for methanol synthesis and for peat gasification in Finland for ammonia synthesis. An IGCC project is planned with the HT Winkler technology in Vresova, Czech Republic, utilizing the local lignite.[4]

1A.9 KRW Fluidized Bed Gasifier

The KRW gasification process, originally developed by M.W. Kellogg Company, is a pressurized, dry feed, fluidized bed slagging process. The gasifier design is shown in FIGURE 1A-9. The KRW IGCC technology is capable of gasifying all types of coals, including high-sulfur, high-ash, low rank, and high-swelling coals, as well as bio- or refuse-derived waste, The only solid waste from the plant is identified as a mixture of ash and calcium sulfate, a non-hazardous waste.[1]

FIGURE 1A-9. KRW FLUIDIZED BED GASIFIER[1]



Coal and limestone, crushed to below 1/4", are transferred from feed storage to the KRW fluidized-bed gasifier (Figure 1-7) via a lock hopper system. Gasification takes place by mixing steam and air (or oxygen) with the coal at a high temperature. The fuel and oxidant enter the bottom of the gasifier through concentric high velocity jets, which assure thorough mixing of the fuel and oxidant and of the bed of char and limestone that collects in the gasifier. Upon entering the gasifier, the coal immediately releases its volatile matter, which oxidizes rapidly, supplying the endothermic heat of reaction for gasification. The oxidized volatiles form a series of large bubbles that rise up the center of the gasifier, causing the char and sorbent in the bed to move down the sides of the reactor and back into the central jet. The recycling of solids cools the jet and efficiently transfers heat to the bed material. Steam, which enters with the oxidant and through a multiplicity of jets in the conical section of the reactor, reacts with the char in the bed, converting it to syngas. At the same time, the limestone sorbent, which has been calcined to CaO, reacts with H_2S released from the coal during gasification, forming CaS.

As the char reacts, the particles become enriched in ash. Repeated recycling of the ash-rich particles through the hot gas of the jet melts the low-melting components of the ash causing the ash particles to stick together. These particles cool when they return to the bed, and this agglomeration permits the efficient conversion of even small particles of coal in the feed. The velocity of gases in the reactor is selected to maintain most of the particles within the bed. The smaller particles that are carried out of the gasifier are recaptured in a high efficiency cyclone and returned to the conical section of the gasifier, where they again pass through the hot gas jet. Eventually, most of the smaller particles agglomerate as they become richer in ash and gravitate to the bottom of the gasifier. Since the ash and spent sorbent particles are substantially denser than the coal feed, they settle to the bottom of the gasifier, where they are cooled by a counter-flowing stream of recycled gas, which both cools and classifies the material, sending lighter particles containing char back up into the gasifier jet.

The char, ash, and spent sorbent from the bottom of the gasifier flow to the fluid-bed sulfator, where both char and calcium sulfide are oxidized. The CaS forms $CaSO_4$, which is chemically inert and can be disposed of in a landfill. Most of the spent sorbent from the gasifier contains unreacted CaO. Sulfur released from burning residual char in the sulfator is also converted to $CaSO_4$.

Sierra Pacific Power Company installed a 99 MWe (net) IGCC demonstration at its Tracy Station near Reno, Nevada that incorporated KRW's air-blown pressurized fluidized-bed gasifier and hot-gas cleanup to produce low-Btu syngas. Construction on the Pinon Pine project was completed in early 1995 and start-up occurred in mid-1996. However the scale-up of the air-blown KRW gasifier to the 100 MW size has not been operationally successful. Problems have been attributed to the high degree of new technology, high scale-up factors on auxiliary components, and some design and engineering deficiencies.[7] However, the ability of the KRW coal gasification process to produce syngas of the quality predicted by design was successfully demonstrated.

1A.10 Appendix 1A References

[1] http://www.netl.doe.gov/coalpower/gasification/description/gasifiers.html#Lurgi.

[2] Wabash River Coal Gasification Repowering Project, Final Technical Report, prepared for U.S. DOE/NETL, by Wabash River Energy Ltd., August 2000.

[3] Krupp Uhde, Gasification Technology: Shell Gasification Process, Gasification Brochure, ThyssenKrupp Technologies 1999.

[4] "Gasification of Solid And Liquid Fuels For Power Generation - Status Report," U.K. Department of Trade and Industry, December 1998. http://www.dti.gov.uk/cct/pub/tsr008.pdf.

[5] Olliver, R., "Application Of BGL Gasification Of Solid Hydrocarbons For IGCC Power Generation," Global Energy, Inc technical paper presented at 2000 Gasification Technologies Conference, San Francisco, California, October 8-11, 2000.

[6] Gaudig, U., "Experience During Erection and Commissioning the Gasification Plant Seal Sands, UK," Technical paper presented at 2001 Gasification Technologies Conference, San Francisco, California, October 7 – 10, 2001.

[7] Cargill, P., et al., "Pinon Pine IGCC Project - Final Technical Report to the Department of Energy," Sierra Pacific Resources, Reporting Period August 1, 1992 to January 1, 2001, January 2001.

APPENDIX 1B

DESCRIPTION OF COMMERCIAL-SCALE IGCC POWER PLANTS

1B DESCRIPTION OF COMMERCIAL-SCALE IGCC POWER PLANTS

This appendix to Section 1 provides a description of the IGCC power plants identified in Section 1.3. These plants are listed below in TABLE 1B-1, which is the same as Table 1-4.

TABLE 1B-1. COMMERCIAL-SCALE IGCC POWER PLANTS

PLANT NAME	PLANT LOCATION	OUTPUT (MWe)	FEEDSTOCK	GASIFIER TYPE	POWER ISLAND	OPERATION STATUS
U.S. IGCC PLANTS						
Texaco Cool Water	Daggett, CA USA	120	Bituminous Coal (1,000 tpd)	Texaco	CCGT – GE 7FE	1984 - 1988
Dow Chemical/Destec LGTI Project	Plaquemine, LA USA	160	Subbituminous Coal (2200 tpd)	E-Gas® (formerly Destec)	CCGT – Westinghouse 501	1987 – 1995
Tampa Electric Polk Plant	Polk County, FL USA	250	Bituminous Coal (2200 tpd)	ChevronTexaco	CCGT – GE 7FA	1996 - Present
PSI Energy/Global Energy Wabash River Plant	West Terre Haute, IN USA	262	Bituminous Coal and Petroleum Coke (2544 tpd)	E-Gas® (formerly Destec)	CCGT – GE 7FA	1995 - Present
FOREIGN IGCC PLANTS						
NUON/Demcolec/ Willem-Alexander	Buggenum, The Netherlands	253	Bituminous Coal	Shell	CCGT – Siemens V94.2	1994 - Present
ELCOGAS/ Puertollano	Puertollano, Spain	318	Coal and Petroleum Coke (2500 tpd)	Prenflo®	CCGT – Siemens V94.3	1998 - Present

CCGT – Combined Cycle Gas Turbine, tpd – short tons per day

1B.1 Description of the Cool Water IGCC Project

The Cool Water IGCC project, operated at Southern California Edison's Cool Water generation station, successfully demonstrated the use of the Texaco coal gasification process for IGCC applications while achieving a high level of operability, availability, and environmental performance. The plant was the first of its type to be operated by conventional electric utility staff, and was the first commercial-sized Texaco gasifier used with a syngas cooler. The successful performance of this first-generation IGCC plant was a highly significant factor in moving the technology towards commercialization. The major sponsors of this project were EPRI, Southern California Edison, Texaco, General Electric, Bechtel and a Japanese Consortium (Toshiba, CRIEPI, IHI and Tokyo Electric).[1] Appendix 1A, Section 1A.1 provides a description of the ChevronTexaco (formerly Texaco) gasification process.

The gross combined cycle power generation capacity of the plant was 120 MWe, with a net production capacity of 96 MWe based on auxiliary power demand of 7 MW and oxygen plant power of 17 MW. The net heat rate of the plant was 11,300 Btu/kWh. The relatively high heat rate primarily resulted from use of a combustion turbine that had a low firing temperature (1,985°

F or 1,085° C), and a steam cycle that operated at a high condenser temperature with no reheat. FIGURE 1B-1 presents a process flow diagram for the Cool Water plant. ChevronTexaco gasification technology uses a single-stage, downward-feed, entrained-flow gasifier. The plant's two gasifiers were similar in design, but differed in the way they recovered sensible heat from the hot raw synfuel. The operating gasifier included syngas heat exchange cooling, while the spare gasifier utilized a direct water quench to cool the syngas. Appendix 1A.1 describes the operation of both types of ChevronTexaco gasifiers. A description of the plant's operation is provided below.

1,000 tons per day of bituminous feed coal was initially crushed to 100% minus ¾ inch by cage mills, followed by final crushing in wet rod/ball mills. Coal-water slurry was prepared with a maximum concentration of about 60-65 weight percent solids in a wet grinding process. The slurry was introduced with oxygen into the Texaco gasifier (FIGURE 1B-1), where partial oxidation of the coal took place at about 600 psig and 2500°F (1371° C). The gasifier yielded a mixture of mainly carbon dioxide, carbon monoxide, and hydrogen gases, with sulfur primarily in the form of hydrogen sulfide. A relatively inert slag containing most of the mineral matter of the coal passed from the gasifier into a pool of water in the bottom of the radiant cooler. The slag was taken out periodically through a lockhopper system. The seal at the bottom of the radiant cooler was maintained by water, which was recycled. The syngas, after cooling in the radiant and convective coolers, passed through a carbon scrubber, where a water spray removed most of the particulates and further cooled the gas. After additional cooling to ambient temperature, the gas flowed to a sulfur-removal unit, where a solvent removed the hydrogen sulfide and, therefore, most of the sulfur from the stream. The relatively particle-free and sulfur-free syngas, at 265 Btu/scf (dry), was saturated with hot water for NOx control purposes, preheated, and then fired in a GE frame 7E combustion turbine at 1,985° F. The water-quenching process suppressed NO_x formation by reducing the gas combustion temperature, and it also increased the turbine power output by adding to the mass flow in the gas turbine combustor. The combustion turbine generated about 65 MW of electricity (54% of gross generation). Hot combustion gases from the gas turbine then passed through the heat recovery steam generator (HRSG), where they produced additional steam as they dropped in temperature to about 400°F (227° C). The steam turbine generated about 55 MW of electricity.

The Cool Water system was unique in that it was designed to accommodate the gasification and processing of both low-sulfur and high-sulfur coals. When operating with a high-sulfur coal, acid gas removal was accomplished via the Selexol process, with a hydrolysis unit used to convert COS to H_2S. A Claus unit, equipped with a SCOT tailgas process, converted the H_2S leaving the Selexol unit to elemental sulfur. When operated with low-sulfur coal, which yielded an acid gas with only about 4% H_2S, a second, low-pressure amine removal process was also used, thereby requiring an extra absorber and a large stripper. Overall recovery of sulfur was 97% for low-sulfur coal and 99% for high-sulfur coal. The Cool Water plant was operated successfully with Utah run-of-mine coal with 0.4% sulfur, Illinois #6 coal with 3.1% sulfur, and Pittsburgh #8 coal with 2.9% sulfur. The sulfur removal process in the plant yielded about 99.6% pure elemental sulfur. Average HRSG stack emissions are presented in TABLE 1B-2 for the different coal-types tested at the plant.[2]

FIGURE 1B-1. COOL WATER IGCC PLANT PROCESS FLOW DIAGRAM [3]

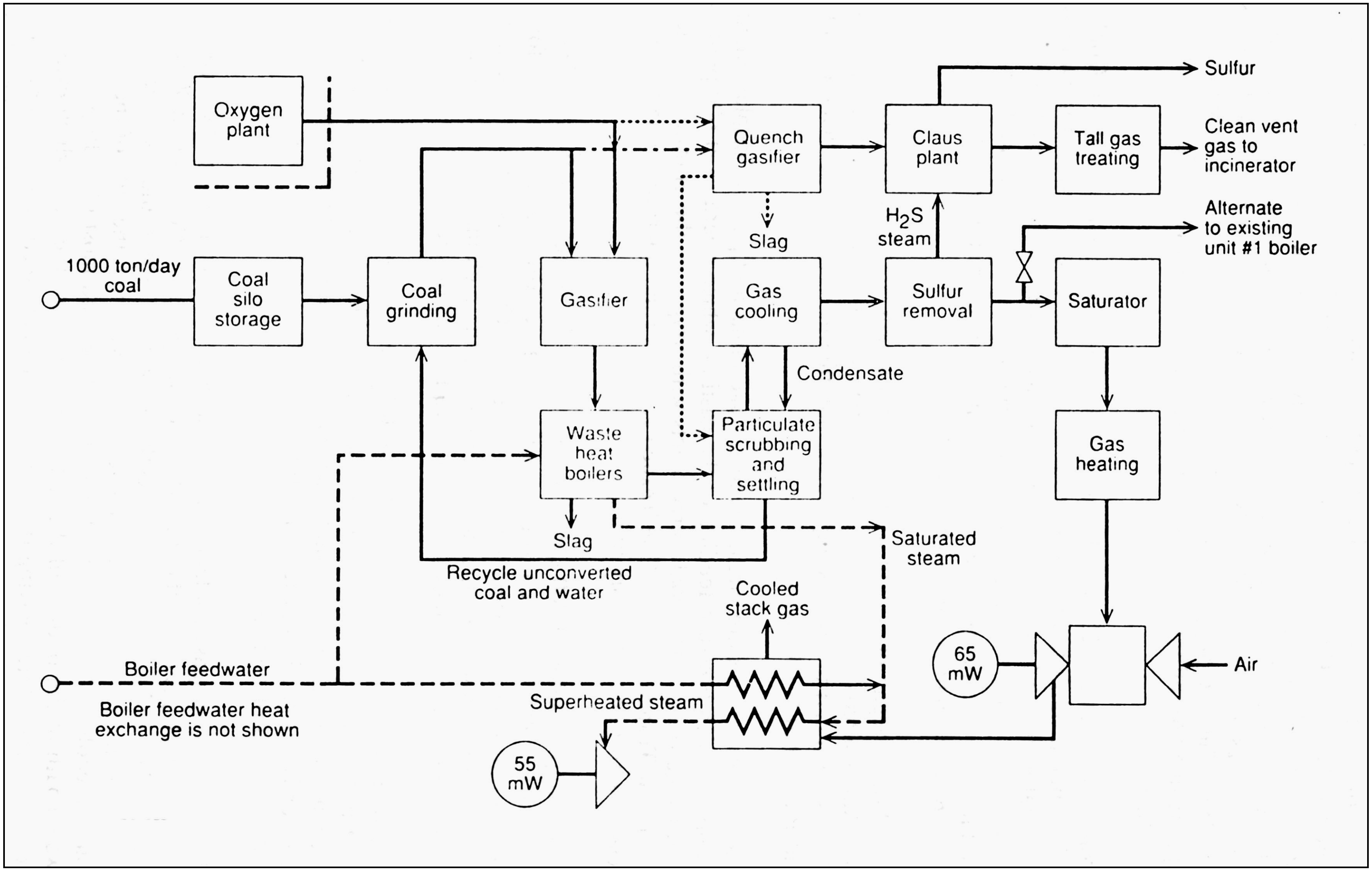


TABLE 1B-2. EMISSIONS FROM THE COOL WATER PLANT HRSG[2] (lb/10^6 Btu)

	High Sulfur Coal SO_2	Low Sulfur Coal SO_2	NOx	CO	Particulate Matter
Permit and Regulatory Limit	0.16	0.033	0.13	0.07	0.01
Utah coal	-	0.018	0.07	0.004	0.001
Illinois #6	0.068	–	0.094	0.004	0.009
Pittsburgh #8	0.122	–	0.066	<0.002	0.009
Federal NSPS	0.6	0.24	0.6	–	0.03

1B.1.1 Cool Water Plant Status

Southern California Edison (SCE) operated the Cool Water plant between May 1984 and December 1988. Low natural gas prices and over-capacity made it uneconomical for them to continue to operate commercially. In 1990, the plant was sold to Texaco.[4]

1B.2 Description of the Louisiana Gasification Technology Plant

The Louisiana Gasification Technology Incorporated (LGTI) plant, located within the Dow Chemical complex in Plaquemine, Louisiana, was selected by the U.S. Synthetic Fuels Corporation in 1987 to demonstrate the E-GAS^{TM} (formerly Destec) coal gasification process. At full capacity, the plant produced 30,000 MMBtu of equivalent syngas per day, producing 161 MWe of net power at a net heat rate of 10,500 kWh (HHV basis). The successful construction and operation of the LGTI plant led to the DOE-sponsored Wabash River Repowering demonstration project. Both plants utilized the same E-GAS system. Appendix 1A, Section 1A.2 describes the E-Gas entrained flow gasifier.

The LGTI plant coal feed was about 2,200 tons/day of Wyoming Powder River Basin subbituminous coal,[a] which was sent to wet crushers to prepare a coal/water slurry. The water used to prepare the coal slurry was recycled water from raw gas cooling, along with makeup water. The gasifier was a two-stage, high-temperature, oxygen-blown, upflow, entrained slagging gasifier. The process flow diagram is shown in FIGURE 1B-2.

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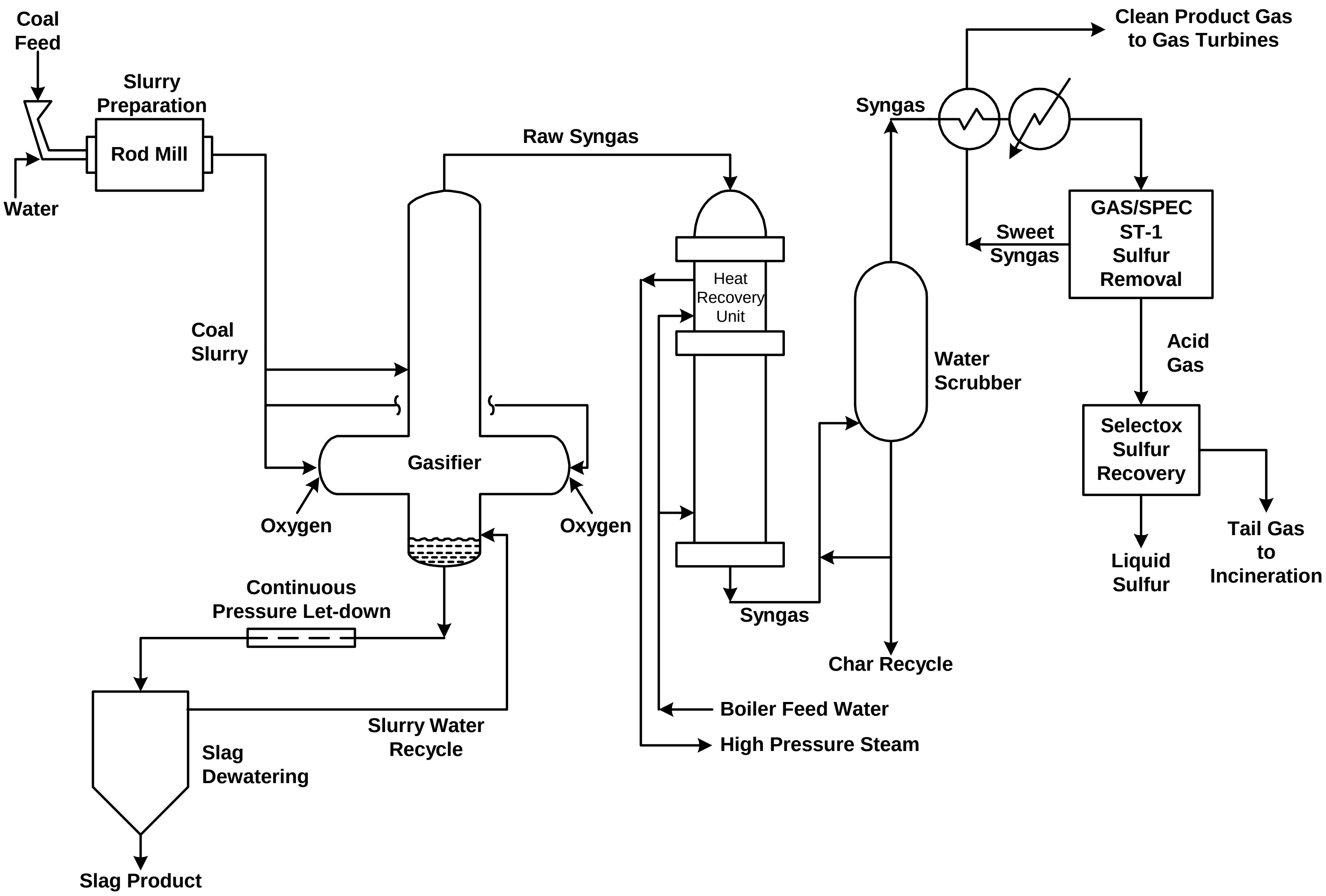
[a] The project also tested low-sulfur Sufco coal from southern Utah, as well as high-sulfur Illinois #6 bituminous coal.

FIGURE 1B-2. LGTI PLANT PROCESS FLOW DIAGRAM[4]



Coal slurry is mixed with oxygen in the gasifier burner nozzles. About 75% of the coal slurry is sent to the first stage of the gasifier, where exothermic gasification/oxidation reactions take place at 2,400–2,700 °F. The coal ash converts to a molten slag, which flows through a taphole to a water-quench removal system, which uses a novel continuous-pressure letdown/dewatering system. The hot raw gas from the first stage enters the second stage of the gasifier where the remaining 25% of the coal slurry is added. Endothermic gasification/devolatilization reactions in this stage reduce the hot raw gas temperature to 1,900 °F. A relatively small amount of char is produced in the second stage, which is then recycled to the first stage for gasification.

Hot raw syngas leaves the gasifier and passes through several gas cooling and cleaning systems. A convection-type cooler cools the gas through heat exchange with water to produce steam. After cooling, entrained particulate matter is removed in a venturi scrubber system. Particulate matter removed from the scrubber water is recycled to the gasifier with the second stage slurry feed. The syngas is further cooled to condense moisture, and then sent to the acid gas removal process. More than 97% of the sulfur from the sour syngas is removed using methyl diethanolamine (MDEA) absorber/stripper columns and sent for sulfur recovery. The Selectox process (a modified Claus plant) converts the H_2S into elemental sulfur byproduct. The sour off-gas and the sulfur recovery tail gas are incinerated. Overall sulfur recovery was about 87%, leaving less than 100 ppm (by volume) of sulfur in the clean, medium-Btu syngas.

The sweet syngas is then piped to the gas turbine. The cleaned syngas is co-fired with natural gas in two Westinghouse WD501-D5 gas turbines at a ratio of about 63% syngas to 37% natural gas.[4] Heat recovery steam generators produce 1,250 psig and 950^o F superheated steam from the combustion turbine flue gas. Dow Chemical used the steam for process applications, as well as power generation in a steam turbine. Average plant emissions are presented in TABLE 1B-3.

TABLE 1B-3. EMISSIONS FROM THE LGTI PLANT[5]

	SO_2 (lb/10^6 Btu)	**NOx (lb/10^6 Btu)**	**Hg (lb/hr)**	**Particulate Matter (lb/10^6 Btu)**
Wyoming Powder River Basin Subbituminous Coal	<0.15	0.26	0.004823	<0.01

1B.2.1 LGTI Plant Status

The LGTI plant was operated very successfully on the design subbituminous coal, as well as other coal types, from 1987 to 1995 and accumulated about 34,000 hours of operating experience. In 1995, the plant participated in a DOE and EPRI-sponsored project to fully characterize trace substance emissions from power systems.[5] Results of this comprehensive study are presented in Chapter 2 of the report. The plant has since been shut down.

1B.3 Description of Polk Power Plant

In December 1989, DOE’s Clean Coal Technology (CCT) Demonstration Program selected the Tampa Electric Integrated Gasification Combined-Cycle Project at the Polk Power Station as a project under Program Round III. Construction was started in October 1994 and operation began in September 1996. This plant has successfully demonstrated advanced IGCC technology using an entrained-flow gasifier, integrated with a combined-cycle turbine system for power generation. Net power production meets the target goal of 250 MWe at a high stream factor and plant availability. Carbon conversion exceeds 95%, and emissions of SO_2, NOx, and particulates are below the original regulatory limits set for the Polk plant site.[6]

This IGCC system utilizes commercially available, oxygen-blown, entrained-flow coal gasification technology licensed by ChevronTexaco Development Corporation (ChevronTexaco). Coal is ground with water to the desired concentration (60-70% solids) in rod mills. The gasifier is designed to utilize about 2200 tons per day of coal (dry basis). Appendix 1A, Section 1A.1 describes the ChevronTexaco gasification process. FIGURE 1B-3 provides a process flow diagram for the Polk Plant.

An ASU separates ambient air into 95% pure oxygen for use in the gasification system and sulfuric acid plant; nitrogen is sent to the advanced GE MS 7001F combustion turbine (CT). The addition of nitrogen in the CT combustion chamber has dual benefits. First, this additional mass flow has the advantage of producing higher CT power output. Second, the nitrogen acts to control potential NOx emissions by reducing the combustor flame temperature, which, in turn, reduces the formation of thermal NOx in the fuel combustion process.

The coal/water slurry and the oxygen are mixed in the gasifier process feed injector. The subsequent gasification reactions produce syngas with a heat content of about 250 Btu/scf (LHV). The gasifier is designed to achieve greater than 95% carbon conversion in a single pass. The gasifier is a single vessel feeding into a radiant syngas cooler (RSC) which is designed to reduce the gas temperature to 1400°F while producing 1650 psig saturated steam. The gas stream from the RSC is split in two and sent to parallel convective syngas cooler boilers (CSC), where the temperature is further reduced to less than 800°F and additional high pressure steam is produced. The syngas is then further cooled in gas-to-gas exchangers, where the heat in the raw ash-laden syngas is exchanged with either clean, particulate free syngas or nitrogen.

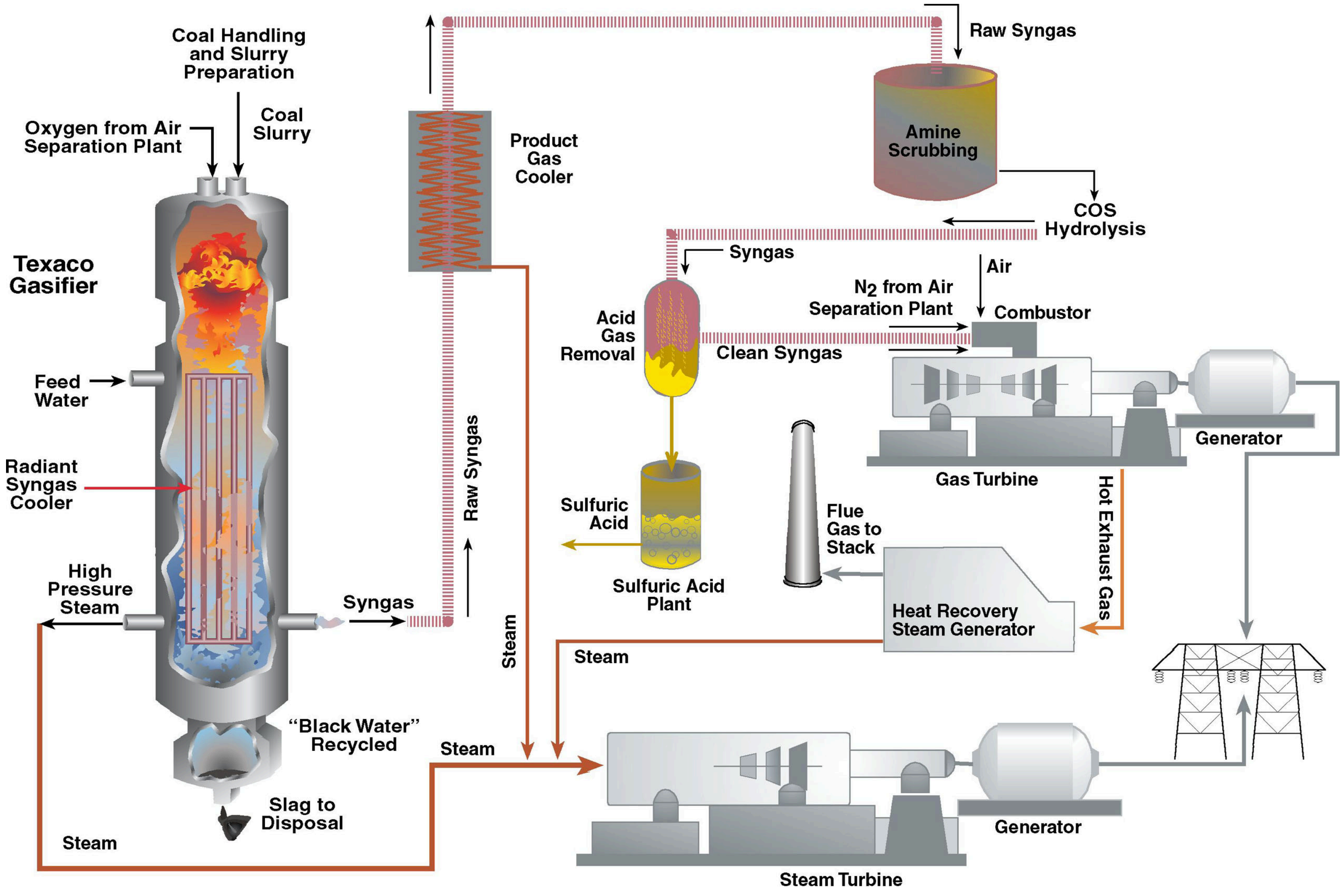
Next, particulates and hydrogen chloride are removed from the syngas in water scrubbers. Most of the remaining sensible heat is recovered in low temperature gas coolers by preheating clean syngas and heating steam turbine condensate. A final trim cooler reduces the syngas temperature to about 100°F for the cold gas clean-up (CGCU) system. The CGCU system is a traditional amine scrubber type that removes most of the sulfur from the syngas. Sulfur is recovered in the form of sulfuric acid that has a ready market in the phosphate industry in the central Florida area.

Most of the material not gasified in the coal exits the bottom of the RSC into the slag lock hopper where it is mixed with water. These solids generally consist of slag and char. These non-leachable products are saleable for blasting grit, roofing tiles, and construction building products. All of the water from the gasification process is cleaned and recycled, thereby creating no requirement for discharging process water from the gasification system. To prevent build-up of chlorides in the process water system, a brine concentration unit removes them in the form of marketable salts.

1B.3.1 Polk Power Plant Status

The Polk Power Plant will complete six years of operation in September 2002. Over 25,700 hours of operation have been accumulated. In year 5, ending in September 2001, the plant generated 1,826,644 kWh of electricity from its coal feed. Gasifier availability was 84.2%, the ASU availability was 90.5%, and the power block's availability was 94.4%.

FIGURE 1B-3. POLK POWER PLANT PROCESS FLOW DIAGRAM



The ChevronTexaco gasifier at Polk has generally shown a lower than design carbon conversion; there is approximately twice as much unconverted carbon from Polk's gasifier as initially expected. This unconverted carbon makes Polk's slag unsuitable for all current applications unless it is further processed. In response, the Teco Energy has doubled the size of the fines handling system and installed additional slag handling equipment to deal with the unconverted carbon, which is contained in the smaller slag particles (the fines). By reducing plant load and modifying the slag handling equipment, the plant has produced slag that is consistently suitable for the cement industry with lower cost than Class I landfill disposal. Load reduction is necessary because more oxygen is needed to gasify the fines, and the oxygen plant (specifically the main air compressor), cannot supply it. The plant is seeking a source of more air for the oxygen plant to eliminate the load restrictions.

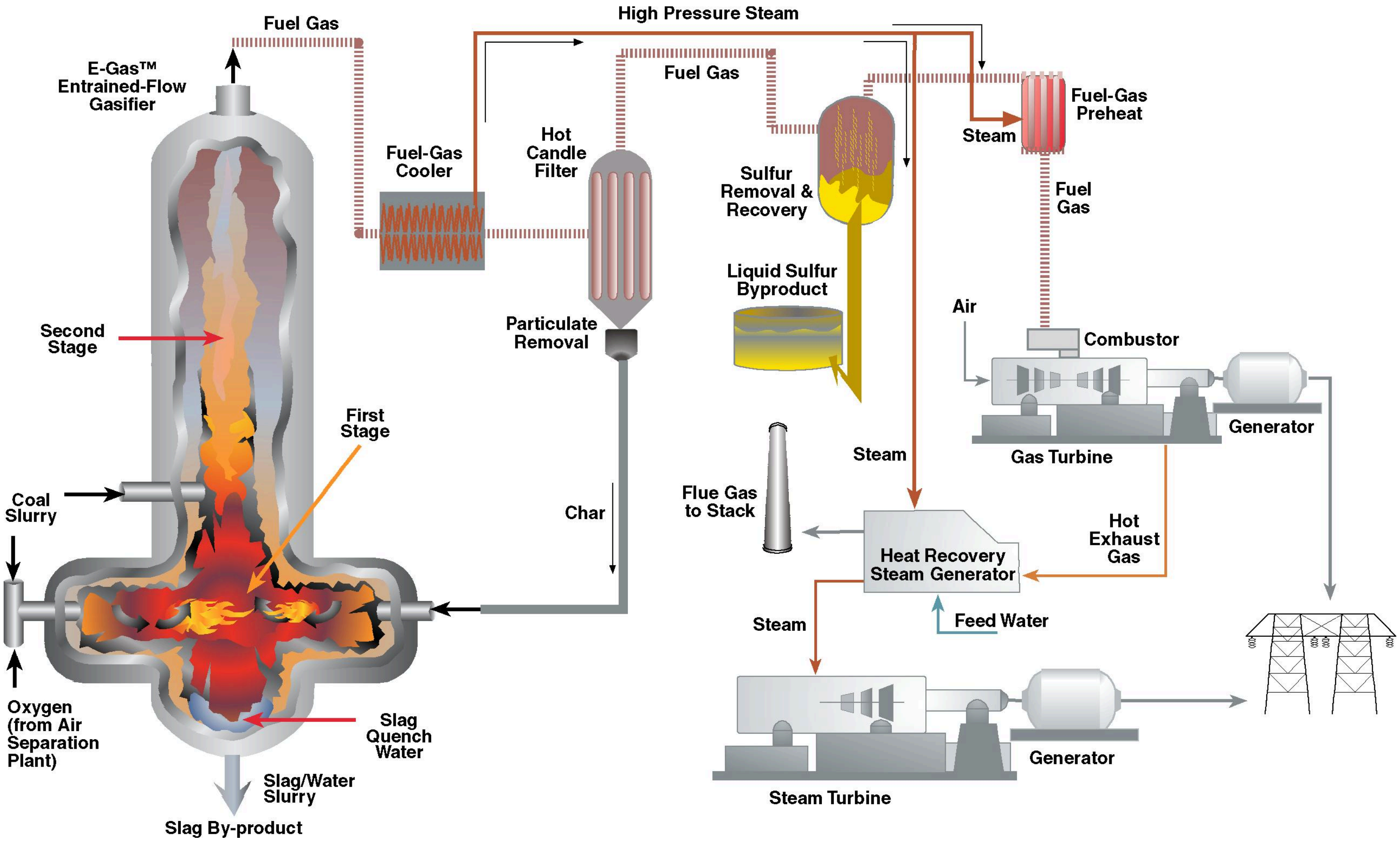
1B.4 Description of Wabash River IGCC Power Plant

In December 1991, DOE's Clean Coal Technology (CCT) Demonstration Program selected the Wabash River Coal Gasification Repowering Project at the Wabash River Generating Station as a project under Program Round IV. Construction was started in July 1993 and operation began in November 1995. This plant has successfully demonstrated advanced IGCC technology using an entrained-flow gasifier, integrated with a combined-cycle turbine system for power generation. Repowering for this project involved refurbishing the steam turbine to both extend its life and withstand the increased steam flows and pressures associated with combined-cycle operation. The repowered steam turbine produces 104 MWe, which combined with the combustion turbine generator's 192 MWe and the systems auxiliary load of approximately 34 MWe, adds 262 MWe (net) to the Cinergy grid. Gasifier carbon burnout exceeds 95%, and emissions of SO_2, NOx, and particulates are below the original regulatory limits set for the Wabash River plant site.

The Wabash IGCC E-GAS^{TM} gasification process features an oxygen-blown, continuous-slagging, two-stage, entrained-flow gasifier, which uses natural gas for startup. Coal is milled with water in a rod mill to form a slurry. The slurry is combined with oxygen in mixer nozzles and injected into the first stage of the gasifier, which operates at 2600°F and 400 psig. Oxygen of 95% purity is supplied by a turnkey 2,060-ton/day low-pressure cryogenic distillation facility. The process flow diagram is shown in FIGURE 1B-4. Appendix 1A, Section 1A.2 provides a description of the E-Gas gasification process.

In the first gasifier stage, slurry undergoes partial oxidation at temperatures above the melting point of the ash. The fluid ash flows through a taphole at the bottom of the first stage into a water quench, forming an inert vitreous slag. The syngas flows to the second stage, where additional coal slurry is injected. This coal is pyrolyzed in an endothermic reaction with the hot syngas to enhance syngas heating value and to improve overall efficiency. The syngas then flows to the high-temperature heat recovery unit (HTHRU), essentially a firetube steam generator, to produce high-pressure saturated steam. After cooling in the HTHRU, particulates in the syngas are removed in a hot/dry filter and recycled to the gasifier where the carbon in the char is converted into syngas. The syngas is further cooled in a series of heat exchangers, water scrubbed for chlorides removal, and passed over a catalyst that hydrolyzes carbonyl sulfide into hydrogen sulfide. Hydrogen sulfide is removed using MDEA-based absorber/stripper columns. The "sweet" syngas is then moisturized, preheated, and piped to the power block.

FIGURE 1B-4. WABASH RIVER PLANT PROCESS FLOW DIAGRAM



The key elements of the power block are the General Electric MS 7001 FA high-temperature combustion turbine/generator, the HRSG, and the repowered steam turbine. The GE 7FA is a dual-fuel turbine (syngas for operations and No. 2 fuel oil for startup) capable of a nominal 192 MWe, when firing syngas, attributed to the increased mass flows associated with syngas. Steam injection is used for NOx control, but the steam flow requirement is minimal compared to that of conventional systems because the syngas is moisturized at the gasification facility, making use of low-level heat in the process. The HRSG for this project is a single-drum design capable of superheating 754,000 lb/hr of high-pressure steam at 1010°F, and 600,820 lb/hr of reheat steam at 1010°F when operating on design-basis syngas.

1B.4.1 Wabash River IGCC Plant Status

The Wabash River IGCC Power Plant will complete seven years of operation in November 2002. In 2001, average product syngas availability was 83% and the power block's availability was 89.9%. Reliability data for each of the gasification system's key sub-systems is presented in TABLE 1B-4.

TABLE 1B-4. WABASH RIVER IGCC RELIABILITY BY GASIFICATION SUBSYSTEM – 2001 OPERATION

IGCC SUB-SYSTEM	RELIABILITY	IGCC SUB-SYSTEM	RELIABILITY
1st Stage Gasifier	99.5%	**Acid Gas Removal**	100%
2nd Stage Gasifier	100%	**Sulfur Recovery**	96.6%
Raw Syngas Conditioning	100%	**Sour Water Treatment**	100%
Syngas Cooling	94.2%	**Fuel Hopper System**	100%
Particulate Removal	99.9%	**Rod Mill System**	100%
Chloride Scrubbing	100%	**Slurry Storage System**	99.9%
COS Hydrolysis	100%	**Slurry Feed System**	99.4%
Low Temp Heat Recovery	100%	**Slag Removal System**	100%
Syngas Moisturization	100%	**Cooling Tower System**	100%

Reported environmental control performance for 2001 was:

SO_2: 1.08 lb/MWh (0.08 lb/10^6 Btu)
NOx: 1.09 lb/MWh (0.15 lb/10^6 Btu)
CO: 0.37 lb/MWh (0.05 lb/10^6 Btu)
Particulates: Zero particulates

1B.5 Description of NUON/Demkolec/Willem Alexander IGCC Plant

The Demkolec plant at Buggenum was one of the first successful IGCC plants in the world. The project was ordered in 1990 by SEP (Samenwerkende Elektriciteits-Produktie-Bedrijven), the former collective body for Dutch power producers, with capital & operating cost sharing from The Netherlands government. Construction was completed at the end of 1993, and the plant was commissioned in 1994.[7] The project, built and operated by Demkolec BV, is located in Buggenum, The Netherlands. Plant ownership has been transferred from SEP to NUON.[8]

The 253 MWe Buggenum IGCC is built around a Shell SCGP gasifier and a CCGT supplied by Siemens (V94.2 gas turbine). The Shell gasifier, an oxygen-blown, continuous-slagging, entrained-flow process, is described in detail in Appendix 1A, Section 1A.3. The plant, which is designed to accept a wide range of imported coals, contains a number of advanced design features that differ from the U.S. plants. The most significant differentiating feature is that the air separation unit (ASU) and the gas turbine are very closely coupled together, with the gas turbine compressor supplying all the air to the ASU. This increases efficiency at the cost of making the plant more complex and less easy to start. Plant design efficiency is 43% (LHV basis).

1B.5.1 Demkolec/Buggenum IGCC Plant Status

This plant has been operating on a coal feed since 1994. More than 23,000 operating hours on coal-based syngas have been accumulated through 2000. This includes continuous operation of nearly 3,000 hours between June and October 1998. The plant changed from demonstration into commercial operation in January 1998. The Shell gasifier has generally performed well and has achieved its design cold gas efficiency.

Since the plant has been put into operation it has suffered from two major types of problems: operability problems connected with the high level of integration between the gas turbine and ASU, and gas turbine problems associated with burning the low-Btu syngas in the gas turbine. Both of these have now been solved, but required significant time to fully rectify. The integration problem has led SEP to recommend only partial integration for future installations. The main problem encountered in the early years of operation at the Buggenum plant (also later encountered at Puertollano) has been combustion-induced vibrations and overheating in the gas turbine combustors. Design changes made in early 1997 have markedly improved the vibration problem, with significantly improved availability (often over 80 percent).

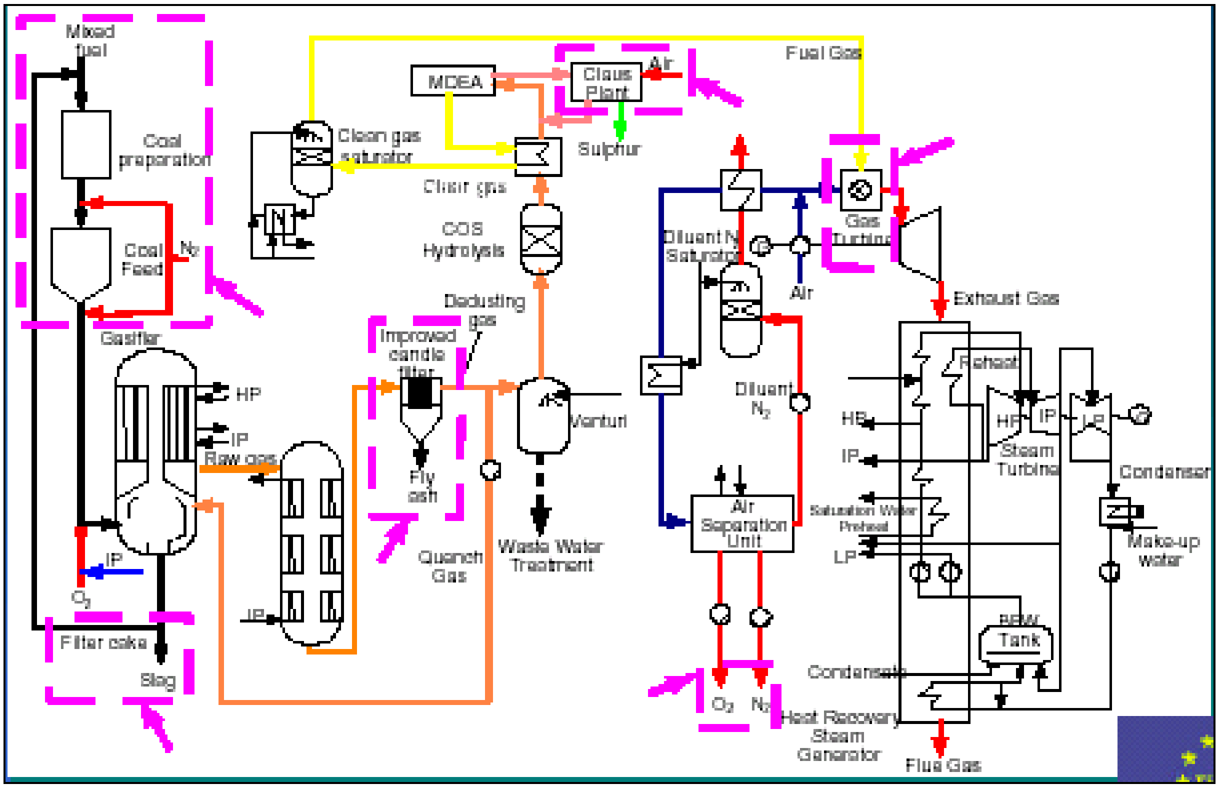
Sulfur removal efficiency has been reported to be greater than 99% in 2001. Emissions of SO_2, NOx, and particulate matter have been reported to be:[9]

SO_2: 0.44 lb/MWh (0.2 g/kWh)
NOx: 0.7 lb/MWh (0.318 g/kWh)
Particulates: 0.01 lb/MWh (0.0045 g/kWh)

1B.6 Description of the Elcogas/Puertollano IGCC Plant

The Puertollano plant, located in south-central Spain, is a 318MWe IGCC owned and operated by Elcogas, a consortium of eight major European utilities and three technology suppliers. This project was the first targeted project funded under the European Commission's Thermie-programme, in 1992. Puertollano features a Prenflo gasifier and a Siemens V94.3 gas turbine. The plant is very similar in design to Demkolec/Buggenum and, like Buggenum, has full integration of the gas turbine and ASU. It is designed to use 50/50 mix of local hard coal and petroleum coke. Design efficiency (net) is 45% (LHV basis). This facility is currently the world's largest solid feedstock-based IGCC plant. FIGURE 1B-5 shows a process flow diagram of the plant.

FIGURE 1B-5. ELCOGAS/PUERTOLLANO IGCC POWER PLANT PROCESS FLOW DIAGRAM[10]



The Gasification Unit was supplied by Uhde and is based on their Prenflo system, an entrained-flow system with dry feeding. A detailed description of the Prenflo gasification process is provided in Appendix 1A, Section 1A.6. The syngas is produced by reaction of coal with oxygen at high temperatures up to 2912° F (1600° C). The Prenflo process is capable of gasifying a wide variety of fuel types, and qualities of coal, for the production of synthetic gas. The 'design' fuel of Puertollano power plant is a 50% mixture, by weight, of local high ash coal and high sulfur petroleum coke. The hot syngas exits the top of the gasifier, where it is quenched to approximately 1472° F (800° C) with cooled recirculated gas. The quenched gas then enters the high-pressure steam heat exchanger, located in the same pressure vessel as the gasifier and the quenching zone, and then to an intermediate pressure exchanger located in a separate vessel. The gas cleaning unit (GCU) treats the gas at the outlet of the intermediate pressure boiler removing the solid particles (using candle filters), and incorporates a water wash step (Venturi scrubber) for ammonia, HCl, HCN and trace component removal. The sulfur removal unit consists of a fixed bed catalyst (99.9% efficiency). The cleaned gas is then passed through a conditioning phase (saturation with water), before delivery to the gas turbine.[10]

The power block is designed around a Siemans V94.3 gas turbine, a triple-pressure heat recovery boiler supplied by Babcocks Wilcox Espanola and a Siemans reheat generator. This equipment produces steam that is used to generate additional electric power in a conventional steam turbine with condensation cycle. The gas turbine is able to operate with both syngas and natural gas allowing greater plant flexibility. The ASU supplied by Air Liquide, uses air extracted as a bleed from the gas turbine air compressor to generate oxygen of high purity (85%) to feed to the gasifier and nitrogen for pneumatic transportation of the fuel. Nitrogen is also used as a safety purge system. The gross power output of the gas turbine generator is 182.3 MWe and that of the steam turbine generator is 135.4 MWe, for a total gross output of 317.7 MWe.

1B.6.1 Elcogas/Puertollano IGCC Plant Status

The initial gasifier firing on design feedstock took place in December 1997. Between February and March 2000, ELCOGAS proved the flexibility of the gasification process by carrying out four tests using different coal/coke mixtures in over 525 hours of operation. Through March 2001, 6,752 hours of gasifier operation have been accumulated, and 5,005 hours with the gas turbine firing syngas. The commensurate net electricity production with coal gasification is 1,210,796 MWe, and the gas turbine maximum achieved load for syngas operation was 197.6 MWe. The longest gasifier run was 689 hours. Planned outages were 8% and unplanned outages were 7%. Annual syngas production as a percentage of design output was about 60%.[8]

Sulfur removal efficiency has been reported to be 99.9%. Emissions of SO_2, NOx, and particulate matter have been reported to be:[11]

SO_2: 0.145 lb/MWh (0.066 g/kWh)
NOx: 0.88 lb/MWh (0.397 g/kWh)
Particulates: 0.044 lb/MWh (0.02 g/kWh)

1B.7 Appendix 1B References

[1] Simbeck, D.R., et al., “Coal Gasification Guidebook: Status, Applications, and Technologies,” TR-102034, Final Report, Prepared for Electric Power Research Institute, December 1993.

[2] Watts, Donald H., Dinkel, Paul W., and McDaniel, John E., "Cool Water IGCC Performance to Date and its Future in the Electric Utility Industry," U.S. Utility Symposium, Palm Springs, California., October 1987.

[3] “Cool Water Coal Gasification Program: Final Report.” Palo Alto, California: Electric Power Research Institute, December 1990. GS-6806.

[4] “A Study of Toxic Emissions from a Coal-fired Gasification Plant,” Final report, Radian Corp., Austin, TX, Report Number: DOE/PC/93253-T2, December 1995.

[5] Williams, A., B. Wethorold, and D. Maxwell, “Summary Report: Trace Substance Emissions from a Coal-Fired Gasification Plant,” EPRI DCN 96-643-004-09 and DOE/PC/93253-T3, October 16, 1996.

[6] “Clean Coal Technology – Tampa Electric Integrated Gasification Combined-Cycle Project – An Update”, DOE Topical Report Number 19, July 2000.

[7] Power Technology Web Site, http://www.power-technology.com/projects/willem/

[8] Zuideveld, P., “Overview of Shell Gasification Projects,” Gasification Technology Conference, October 2001.

[9] Smeers, Y., “Coal Options - Evaluation of Coal-Based Power Generation in an Uncertain Context,” OSTC - Global Change and Sustainable Development 1996-2000 Sub-Programme 2 "Scientific Support for Belgian Policy on Climate Change" Contracts CG/DD/231 and CG/DD/232, September 2001.

[10] CARNOT Online Case study: Conversion of Solid-Fuels -- Puertollano IGCC Power Plant, http://enpov.aeat.com/carnot/case_studies/pdf/Puertollano.pdf.

[11] Trevino, M., “The Puertollano Demonstration Plant and IGCC Prospects in Spain, VGB PowerTech Magazine, January 2002.

APPENDIX 2A

ASSESSMENT OF TRACE POLLUTANT MEASUREMENT/MONITORING AND DATA UNCERTAINTY

2A ASSESSMENT OF TRACE POLLUTANT MEASUREMENT/MONITORING AND DATA UNCERTAINTY

2A.1 Trace Pollutant Analytical Measurement Techniques

Determining the amount and chemical form of trace constituents of the gaseous, solid and liquid effluents and residues of a gasification-based power generation system requires proper sampling, sample recovery, awareness of potential contamination errors, choice of appropriate reference materials, and appropriate analytical techniques.[1] The type of sampling performed depends on the physical state of the target species. For example, since trace elements in flue gas may be present in both solid and vapor phases, both must be sampled. The volatile Class III elements must either be measured directly in the gas phase or trapped in liquid or solid form. Class II elements are present in a semi-volatile form, and, therefore, the sampling conditions (especially temperature) will determine the physical state of each element. It is, therefore, necessary to define the sampling conditions and maintain them identical to actual conditions.[2] More in-depth information regarding sampling techniques can be found in reference [2].

The selection of the analytical method is dependent upon the specific trace species to be analyzed, the medium, and the concentration. Other factors to consider are the sample type, size of sample, equipment operator's expertise, cost-effectiveness and timeliness. TABLE 2A-1 identifies the analytical methods that have been used to quantify critical ananlytes. Several reports are excellent sources for describing appropriate analytical methods and instrumentation.[3,1] A report by Radian Corporation (now called URS), which details trace substance emissions from the LGTI IGCC plant, provides the most detailed information with respect to the monitoring locations and the analytical procedures that have been used for quantitative analyses in an IGCC. (A detailed description of the LGTI plant is provided in Appendix 1B.2 of this report.) Also, the Energy and Environmental Research Center (EERC) performed a long-term project for DOE to evaluate trace element transformations in entrained gasification systems. Their report reviews a variety of analytical techniques for trace metals in solids and gases. EERC also prepared a report for EPRI and DOE/NETL that evaluated flue gas mercury measurement methods,[4] and another report that more generally evaluated toxic emissions from coal-fired power plants.[5]

The LGTI IGCC project represents a good example of the particular sampling techniques used to quantify and characterize trace species. FIGURE 2A-1 is a simplified block diagram of the LGTI plant showing sampling locations. TABLE 2A-2 lists the sampling location (the numbers refer to the location on FIGURE 2A-1), the stream, and the analytes that were measured. Analytical techniques used to determine constituents are presented in TABLE 2A-3, TABLE 2A-4, and TABLE 2A-5. The reader should refer to the cited references and the ASTM web site (http://www.astm.org/cgi-bin/SoftCart.exe/index.shtml?E+mystore) to obtain more specific information on the analytical methods listed here.

TABLE 2A-1. ANALYTICAL TECHNIQUES USED TO DETECT AND QUANTIFY CRITICAL ANALYTES[4,5]

ANALYTE TYPE	ANALYTICAL TECHNIQUE
Major Elements Al, Ca, Fe, Mg, K, Na, Si, Sr, Ti Trace Elements As, B, Ba, Be, Cd, Cr, Co, Cu, Hg, Mn, Mo, Ni, Pb, Sb, Se, V	Inductively Coupled Plasma – Atomic Emission Spectroscopy, ICP-AES Graphite Furnace – Atomic Emission Spectroscopy, IGF-AAS Cold Vapor – Atomic Emission Spectroscopy, CV-AAS Inductively Coupled Plasma -- Mass Spectroscopy (ICP-MS) Instrumental Neutron Activation Analysis (INAA) Gold Amalgam – Cold-Vapor Atomic Absorption (GA-CVAA) Double Gold Amalgam – Cold-Vapor Atomic Absorption (DGA-CVAA) Cold-Vapor—Atomic Fluorescence (CV-AF) X-Ray Fluorescence (XRF)
Be, Pb, P	ASTM D3683
As, Cd, Se	ASTM D3684
F	ASTM D3761
Hg speciation in flue gas	EPA Method 29, Ontario Hydro, EPA Draft Method 101B
Moisture	ASTM D3173
Ash	ASTM D3174
C, H, N, O	ASTM D3176/D5373
S	ASTM D4239
Volatile Matter	ASTM D3175
Radionuclides	Gamma Emission Spectroscopy Alpha-Ray Counting Beta-Ray Counting
Anions Phosphates, HCl, HF, Sulfates	Ion Chromatography Specific Ion Electrode Colorimetry
Reduced Species Ammonia Cyanide	EPA 350.2, Colorimetry EPA 9012, Colorimetry
Organics Benzene, Dioxins, Formaldehyde, Furans, Toluene, POCs	High-Performance Liquid Chromatography (HPLC) Gas Chromatography—Mass Spectroscopy (GC-MS) Selective Ion Monitoring Spectroscopy (SIMS) Method 23 APA 8270

FIGURE 2A-1. BLOCK FLOW DIAGRAM IDENTIFYING STREAM SAMPLING LOCATIONS AT LGTI

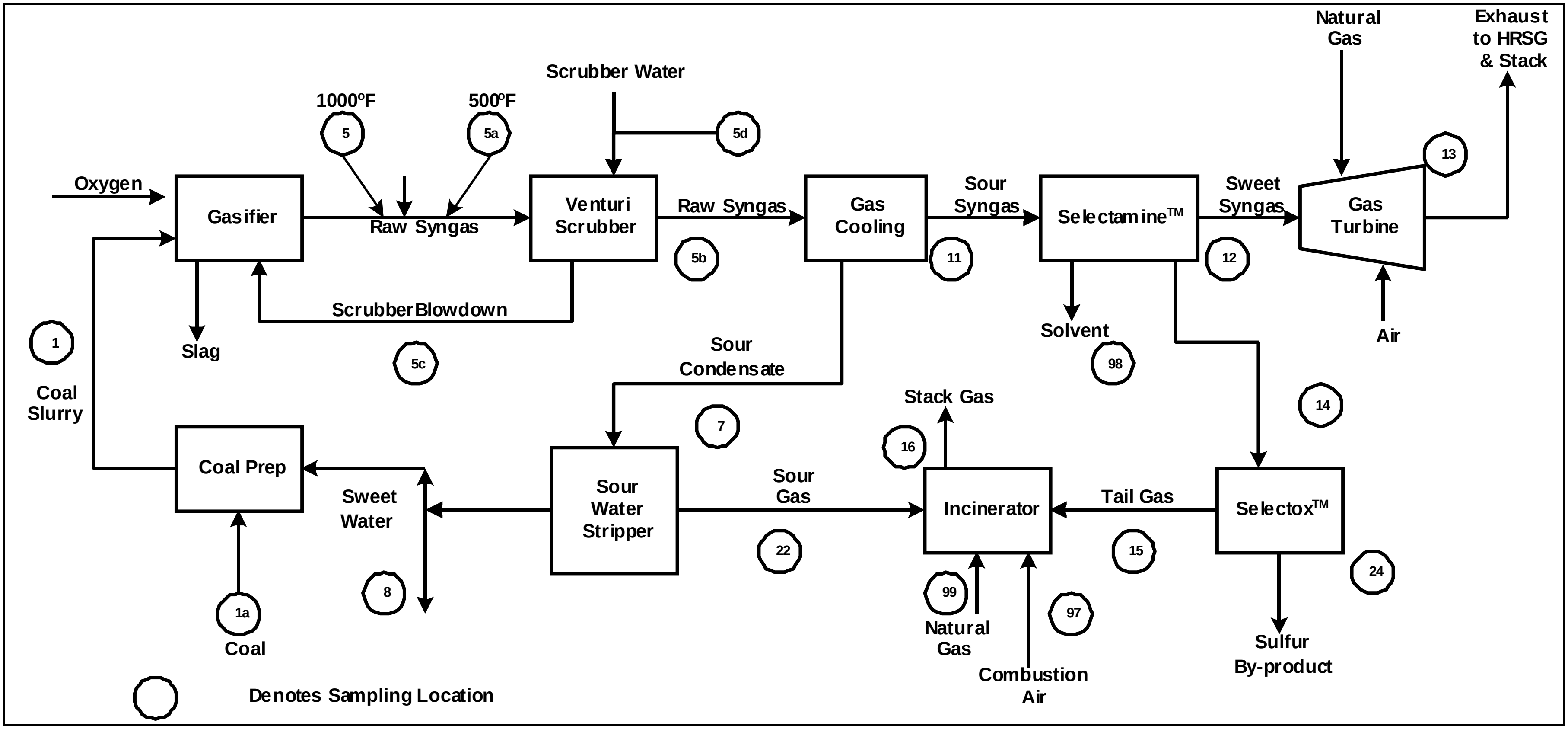


TABLE 2A-2. LGTI SAMPLING LOCATIONS AND ANALYTES

LOCATION	STREAM	ANALYTES
1	Coal slurry	Metals, ultimate, proximate, anions
1a	Coal pile	Metals, ultimate, proximate, anions Radionuclides
4	Slag	Metals, ultimate, proximate, anions Radionuclides
5	Raw gas, 1,000˚F	Vapor: metals, Cl, F, NH_3, HCN Particulate: metals
5a	Raw gas, 500°F	Metals, C_1-C_{10}, Cl, F, NH_3, HCN Particulate: metals
5b	Raw gas, scrubbed	Metals, C_1-C_{10}, Cl, F, NH_3, HCN
5c	Scrubber blowdown (char)	Metals, ultimate, proximate, anions,
	(filtrate)	Metals, ultimate, proximate, anions, ammonia, cyanide, suspended solids
5d	Scrubber water	Metals, ultimate, proximate, anions, ammonia, cyanide
7	Sour condensate	Metals, cyanide, volatile/semivolatile organics, aldehydes, anions, ammonia, phenol, sulfide, water quality
8	Sweet water	Metals, cyanide, volatile/semivolatile organics, aldehydes, anions, ammonia, phenol, sulfide, water quality
11	Sour syngas	Particulates, metals, C_1-C_{10}, volatile organics, major gases, sulfur species, semivolatile organics, aldehydes, Cl, F, NH_3, HCN
12	Sweet syngas	Particulates, metals, C_1-C_{10}, volatile organics, major gases, sulfur species, semivolatile organics, aldehydes, Cl, F, NH_3, HCN
13	Turbine exhaust	Particulates, PM-10, metals, VOST, semivolatile organics, aldehydes, Cl, F, NH_3, HCN, H_2SO_4, CEM gases
14	Acid gas	Metals, C_1-C_{10}, major gases, sulfur species, semivolatile organics, Cl, F, NH_3, HCN
15	Tail gas	Metals, C_1-C_{10}, major gases, sulfur species, semivolatile organics, NH_3, HCN, CEM gases
16	Incinerator stack	Particulates, PM-10, metals, VOST, sulfur species, semivolatile organics, aldehydes, Cl, F, NH_3, HCN, H_2SO_4, CEM gases
22	Sour gas	C_1-C_{10}, major gases, NH_3, HCN
24	Sulfur	Metals, ultimate, proximate
97	Combustion air	C_1-C_{10}, major gases, sulfur species, NH_3, HCN
98	Selectamine™ solvent	Metals, ash, volatile organics, heat stable salts
99	Natural gas	Metals, C_1-C_{10}, sulfur species

TABLE 2A-3. ANALYTICAL METHODS SUMMARY - GASEOUS STREAMS

SAMPLE MATRIX	SAMPLE METHOD	ANALYTE	SAMPLE PREPARATION AND ANALYTICAL METHOD
Filter and probe rinse solids[a]	EPA Method 29 (draft)	Al, Sb, Ba, Be, Ca, Cr, Co, Cu, Fe, Mg, Mn, Mo, Ni, P, K, Si, Na, Ti, V, & Zn.	Mixed-acid microwave digestion/ICP-AES (SW6010)
		As, Cd, Pb, & Se.	Mixed-acid microwave digestion/GFAAS (SW7060, 7131,7421,7740)
		Hg	Mixed-acid microwave digestion/VAAS (SW7470)
HNO_3/H_2O_2 impinger solutions	EPA Method 29 (draft)	Al, Sb, Ba, Be, B, Ca, Cr, Co, Cu, Fe, Mg, Mn, Mo, Ni, P, K, Si, Na, Ti, V, & Zn.	Digestion (SW3005)/ICP-AES (SW6010)
		As, Cd, Pb, & Se.	Digestion (SW3020)/GFAAS (SW7060,7131,7421,7740)
		Hg	Peroxide reduction/CVAA (SW7470)
		Sb, As, Ba, Be, Cd, Cr, Co, Cu, Pb, Mn, Mo, Ni, Se, & V.	ICP/MS (SW6020)
4% $KmnO_4$/10% H_2SO_4 impinger solution[1]	EPA Method 29 (draft)	Hg	CVAA (SW7470)
1N KCl-HNO_3/H_2O_2-10% H_2SO_4/4% $KmnO_4$ impinger solutions	Ontario Hydro	Hg	CVAAS with $SnCl_2$ as reducing agent
Charcoal Sorbent[b]	Radian	Al, Sb, Ba, Be, Ca, Cr, Co, Cu, Fe, Mg, Mn, Mo, Ni, P, K, Si, Na, Ti, V, & Zn.	Nitric acid microwave digestion/ICP-AES (SW6010)
		As, Cd, Pb, & Se.	Nitric acid digestion/GFAAS (SW7060, 7131,7421,7740)
		Hg	Nitric acid digestion/CVAA (SW7470)
H_2SO_4 impinger solutions	EPA Method 26 (modified)	Ammonia	Colorimetric (EPA Method 350.2, 350.1)
		Chloride	Ion Chromatography (EPA Method 26)
		Fluoride	Specific Ion Electrode (EPA Method 340.2)
2% $Zn(C_2H_3O_2)_2$ impinger solution	Texas Air Control Board	Total Cyanide	Colorimetric (EPA Method 335.2)
Filter and FH rinse[a]	EPA Method 0010	SVOCs/PAHs	GC/MS (SW8270)[a] HRGC/MS (CARB 429)[1]

SAMPLE MATRIX	**SAMPLE METHOD**	**ANALYTE**	**SAMPLE PREPARATION AND ANALYTICAL METHOD**
XAD, condensate, and BH rinse		SVOCs/PAHs	GC/MS (SW8270) HRGC/MS (CARB 429)[a]
2,4 – DNPH impinger solution	EPA Method 0011	Aldehydes	HPLC (EPA Method 0011)
VOST[a]	EPA Method 0030	Volatile organic compounds	GC/MS (SW8240)
4% $KmnO_4$/10% NaOH impinger solution[a]	EPA Method 7D	NO_x	Ion Chromatography

a Turbine stack and incinerator flue gas samples only.
b Internal process streams only.

TABLE 2A-4. ANALYTICAL METHODS SUMMARY - SOLID STREAMS

MATRIX	SAMPLE HANDLING	ANALYTE	SAMPLE PREPARATION & ANALYTICAL METHOD
Coal/Char/ Slag	Composite samples are air-dried and ground to pass a 60-mesh sieve.	Carbon, Hydrogen, Nitrogen	ASTM D5373
		Sulfur	ASTM D4239
		Ash	ASTM D3174
		Volatile Matter [a]	ASTM D3175
		Fixed Carbon[a]	ASTM D3172
		HHV [a]	ASTM D2015
		Chlorine (as Cl^-)	ASTM D4208 (adapted for IC analysis)[a] HNO_3 acid leach/potentiometry[2]
		Fluorine (as F^-)	ASTM D3761/SIE[a] NaOH fusion/SIE[b] ASTM D4208 (adapted for IC analysis)[a]
		Major ash minerals: Al, Ca, Fe, Mg, P, K, Si, Na, Ti	ASTM D4326 (XRF)
		Ba, Ni, Zn	ASTM D3683/ICP-AES
		Sb, As, Be, Cd, Cr, Co, Cu, Pb, Mn, Mo, Se, V	ASTM D3683, mixed-acid microwave digestion (HF, HCI, HNO_3), and EPA SW3020. Analysis by ICP/MS.
		Boron	Na_2CO_3, fusion/ICP-AES
		Mercury	Double gold amalgamation/CVAAS
Sulfur	Grab samples were ground and mixed	Sulfur	ASTM D4239
		Ash	ASTM D3174
		Sb, Ba, Be, Cr, Co, Cu, Mn, Mo, Ni, V	ASTM D3683/ICP-AES
		As, Cd, Pb, Se	ASTM D3683/GFAAS
		Boron	Na_2CO_3, fusion/ICP-AES
		Mercury	Double gold amalgamation/CVAAS

Notes:

a Coal and char samples only.

b Slag samples only.

c IC – Ion chromatography, XRF – x-ray flourescence, ICP-AES – inductively coupled plasma absorption spectroscopy, ICP/MS – Inductively coupled plasma/mass spectroscopy, CVAAS – cold vapor atomic absorption spectroscopy, GFAAS – graphite furnace atomic absorption spectrophotometry.

TABLE 2A-5. ANALYTICAL METHODS SUMMARY - LIQUID STREAMS

PROCESS STREAM	SAMPLE HANDLING	ANALYTE	SAMPLE PREPARATION & ANALYTIC METHOD
Sour Condensate, Sweet Water, Scrubber Inlet Water, and Recycle Char Filtrate	On-site analysis.	pH	EPA 150.1
		Specific Conductance	EPA 120.1
		Total Suspended Solids (TSS)	EPA 160.2
		Sulfide	Orion SIE
	Composite samples cooled to 4°C. Filtered prior to analysis.	Fluoride	EPA 340.2
		Chloride, Sulfate	EPA 300.0
		Formate	EPA 300.0 (modified)
		Phosphate	EPA 365.1
	Grab samples treated with $PbCO_3$, filtered, and pH adjusted >12 with CaO.	Total Cyanide	EPA 335.2
		Free Cyanide	EPA 335.1
		Thiocyanate	SM 412K
	Composite samples treated with H_2SO_4 to pH < 2.	Ammonia	EPA 350.2, 350.1
		COD	EPA 410.1
		Phenol	EPA 420.1
	Composite samples treated with HNO_3 to pH < 2.	Al, Sb, Ba, Be, B, Ca, Cr, Co, Cu, Fe, Mg, Mn, Mo, Ni, P, K, Si, Na, Ti, V, Zn	SW3005/SW6010
		As, Cd, Pb, Se	SW3020/SE7060, 7131,7421,7740
		Mercury	SW7470
	Grab samples cooled to 4°C.	Semivolatile Organic Compounds	SW8270
		Aldehydes	SW8315 (proposed)
		Volatile Organic Compounds	SW8240
Selectamine™ Solvent	Grab samples stored in amber glass bottles at room temperature.	Heat Stable Salts	Union Carbide-Titration with NaOH
		Ash	ASTM D3174
		Total Suspended Solids (TSS)	EPA 160.2

2A.2 Data Uncertainty

There are a number of problems that lead to data uncertainty and inadequate mass balances for trace inorganic and organic species produced by the gasifier. These problems can be been categorized as follows.[2]

- Low concentrations of species being measured
- Inaccurate identification of all input and output streams and deposition locations, solid and liquid
- Inaccurate plant operating assumptions
- Inaccuracies in the measurement methods.

Most trace inorganic and organic species are quite low, and often below the detectable limits; however, this can make it very difficult to obtain accurate measurements. This is compounded by the fact that losses can occur through condensation and/or absorption in parts of the gas train. For example, arsenic tends to deposit on heating surfaces, which can lead to significant material imbalances. As discussed earlier, poor mercury balances may also be the result of deposition within the process equipment. This can be further exacerbated by loss (or contamination) within sampling equipment. Heated Teflon sampling tubing, for example, has been reported to absorb $HgCl_{2,}$ and stainless steel sampling tubes may add to the concentrations of Cr, Ni and Zn.[2]

Significant variation in the coal, and other feeds, is an inherent problem. Partial remediation involves consistent operation, understanding that operations, such as soot blowing, can affect sampling, and maintaining fuel (and other inputs) composition for a specified period of time prior to sampling. Nevertheless, intrinsic coal variations must be considered when evaluating results. This variability is demonstrated by a 1997 USGS analysis of eight Premium Coal samples to determine the concentration of 68 elements.[6] A multi-technique approach for major and trace element analysis was taken to provide a high degree of reliability.[a] Each sample was analyzed in triplicate for the 68 elements, and 51 elements were determined by more than one technique. TABLE 2A-6 presents the results for 8 trace elements in the Illinois #6 coal sample. The deviation in the results not only reflects coal property heterogeneity, but also the variability of the different measurement techniques.

Inaccuracies in the measurement methods may be the most important problem. Some sampling and analysis methods are known to be prone to error. This coupled with coal variability, and the very low concentrations of trace species in effluents and residues, can lead to significant measurement uncertainties. Under these circumstances, mass balances between 70 and 130% have been deemed acceptable.

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[a] The analyses were performed by energy- and wavelength-dispersive X-ray fluorescence spectrometry, instrumental neutron activation analysis, inductively coupled argon plasma-atomic emission spectroscopy, atomic absorption spectrometry, inductively coupled argon plasma-mass spectrometry, and direct-current arc spectrographic analysis.

TABLE 2A-6. USGS TEST RESULTS FOR TRACE ELEMENT CONCENTRATIONS IN AN ILLINOIS #6 COAL SAMPLE

Element	**Be**	**B**	**Cr**	**Ni**	**As**	**Se**	**Cd**	**Sn**	**Sb**	**Pb**	**U**	**Zn**
Mean Concentration (ppm)	0.8	140	38	24	4.2	4.2	0.7	2	0.84	9	5	190
Standard Deviation (ppm)	0.16	23	7.7	6.7	0.53	0.45	0.14	1.1	0.062	3	1.2	60
Relative Standard Deviation (%)	19.6	16.5	19.9	28.2	12.6	10.7	19.4	67.7	7.45	32.6	23.1	32.3

Unfortunately, balances on IGCC systems for possibly the most important trace element, mercury, have not even been this good, as discussed in Section 2.2.3.3. Measurement problems appear to be a combination of process variability and lack of precision associated with measurement methods. Imprecision can only be reduced by taking more samples. For example, EERC recommends that manual wet chemistry methods, such as Ontario Hydro and Method 29, be performed in triplicate and, preferably be backed up with real-time measurements (CEM analyses) where possible.[1]

Measurement capabilities for gasifier internal syngas streams require significant improvement. The poor experience at the LGTI plant is evidence that current sampling and analysis protocols can only be considered as semi-quantitative.[7] The most accepted sampling and analytical methods available, Ontario hydro and EPA Method 29, were developed for oxidizing gas environments (flue gases) and are not full functional in reducing environments. It is important to consider the effects of components, typically in a reduced and reactive form, on the sampling technique commonly used for flue gas sample collection. Apparently, the mercury oxidizing capacity of the potassium permanganate impingers is rapidly depleted by H_2S in syngas. A more direct mercury measurement technique is therefore required.

The overall impact of data uncertainty is that it seriously hampers efforts to fully understand trace pollutant behavior in coal-fired power generation systems, including IGCC. This is extremely important for mercury due to the future emission standards expected to be imposed by EPA on coal-fired plants (see Section 3.2.2). Assessing of mercury control will require improved measurement capabilities.

2A.3 Appendix 2A References

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APPENDIX 3A

DETAILED INFORMATION ON AIR, WATER AND SOLIDS REGULATIONS FOR SELECTED STATES WITH A LARGE BASE OF EXISTING COAL-FIRED ELECTRIC POWER GENERATION

3A DETAILED INFORMATION ON AIR, WATER AND SOLIDS REGULATIONS FOR SELECTED STATES WITH A LARGE BASE OF EXISTING COAL-FIRED ELECTRIC POWER GENERATION

3A.1 Alabama

3A.1.1 Air Regulations[1]

Alabama has received SIP approval for implementation of CAA by U.S. EPA. Additionally, the City of Huntsville and Jefferson County have been authorized by the state of Alabama to regulate air regulations within their areas of jurisdiction.

Alabama air regulations generally follow the federal structure with several administrative differences. NSR for nonattainment areas and PSD are similar to the federal guidelines. Currently most of Alabama is classified as attainment for all NAAQS with the exception of two counties that are classified as marginal nonattainment for ozone. For these counties, in addition to LAER, VOC emission offsets of 1.1:1 are required, unless certain conditions are met. Alabama also has one Federal Class I designated area. Furthermore, the neighboring states of Florida, Georgia, and Louisiana have Class I designated areas that, due to their proximity, may require PSD permitting consideration for sources located in Alabama.

Alabama has incorporated by reference EPA hazardous air pollution regulations. Alabama NSPS requirements parallel federal requirements.

3A.1.2 Water Regulations[1]

Alabama is an NPDES delegated state with NPDES permits administered by the Alabama Department of Environmental Management (ADEM). ADEM's wastewater program is essentially the same as the federal EPA program under the CWA and the Underground Injection Control (UIC) component of the SDWA. Certain requirements beyond federal regulations include pollutant load allocation studies for the determination of discharge effluent limits and Discharge Information Zone (DIZ) studies for major sources that discharge to estuarine or marine waters. The Alabama pretreatment program reflects the federal regulations. Local limits on industrial dischargers are developed on a case-by-case basis as needed to protect POTWs from pass through or interference, as well as to protect receiving water bodies.

3A.1.3 Solid Waste Regulations[2]

Fly ash, bottom ash, boiler slag, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels are exempt from regulation as industrial solid waste (335-13-1-.03(12)). Additionally, fly ash, bottom ash, boiler slag, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels, along with gasifier ash resulting from gasification of coal and process waste water resulting from coal gasification are specifically exempt from regulation as hazardous waste (335-14-2-.01(4)(b)). Fly ash and bottom ash may be considered special wastes that require specific handling (335-13-1-.03(12)). Reuse of CCBs is not specifically authorized under AL state law, but may be authorized pursuant to the reported Alabama Department of Environmental Management interpretation of CCBs as non-regulated solid wastes (ALA.ADMIN.CODE R.335-13-1-.03).

3A.2 Georgia

3A.2.1 Air Regulations[1]

The Georgia Department of Natural Resources, Environmental Protection Division (EPD), Air Protection Group, manages Georgia's air quality programs.

A 13-county region in the greater Atlanta area has been designated as serious nonattainment for ozone. In addition to LAER, offsets are required for new and modified major sources of NOx and VOCs. Sources located in nonattainment areas, as well as sources with the potential to emit greater than 100 tons per year of VOCs, are required to comply with specific VOC control rules, including Reasonably Available Control Technology (RACT) requirements. Georgia PSD program requirements are identical to the federal program. Georgia has three areas designated as Class I Federal areas requiring visibility consideration for permitting requirements.

Georgia has incorporated by reference EPA hazardous air pollution regulations and federal NSPS requirements.

3A.2.2 Water Regulations[1]

The Georgia Department of Natural Resources, Environmental Protection Division (EPD), Water Quality Management Program, manages Georgia's water quality and wastewater management issues.

The authority to administer and enforce the NPDES program is established in the Georgia Water Quality Control Act. The state's wastewater regulations generally mirror the federal CWA, with a few additional wastewater requirements. Typically the state's water quality standards are more stringent than federal effluent limits. Georgia stormwater regulations generally follow the federal storm water regulations, with several differences; including administrative, monitoring and pollution prevention plan requirements. Georgia's industrial pretreatment regulations reflect the National Pretreatment Program with several differences, including certain discharge prohibitions for radioactive and warfare agent wastes, public notice requirements, and the approval for the use of mass based limits where federal regulations do not specifically require concentration-based numbers.

3A.2.3 Solid Waste Regulations[2]

Georgia regulations adopt by reference the federal regulation that exempts CCBs (including fly ash, bottom ash, slag, and flue gas emission control waste generated primarily from the combustion of coal) from classification as hazardous waste (GA.COMP.R. & REGS. r. 391-3-11-.07(1)). CCBs are classified under Georgia law as industrial solid waste (Georgia Code 12-8-22(12.1)). Reuse of CCBs is not specifically authorized under Georgia law. Informal ash reuse applications appear to primarily involve concrete and gypsum wallboard applications. The Department of Transportation has reportedly been conducting experimental asphalt projects including the use of ash.

3A.3 Illinois

3A.3.1 Air Regulations[1]

Illinois' air pollution control programs are managed through the Illinois Environmental Protection Agency (IEPA), Bureau of Air, Division of Air Pollution Control.

Illinois' air regulations primarily adopt the federal structure and requirements with additional significant requirements. Illinois has a number of nonattainment areas for criteria pollutants, including the Chicago area, covering eight counties, classified as severe nonattainment for ozone, three counties designated as moderate nonattainment for ozone, and one county designated as moderate nonattainment for PM10. Specific additional requirements for sources located in these areas include Organic Materials Emissions Standards and an emission banking and trading program for sources located in the Chicago nonattainment area that emits greater than 10 tons of volatile organic material (VOM) during the ozone season. Illinois has adopted the federal PSD program. Currently there are no federal Class I areas in the state.

Illinois' HAP requirements primarily adopt the federal structure and requirements, with an additional reporting requirement for large manufactures (>25, 000 pounds/year) and users (>10,000 lbs/year) of certain HAPs. Illinois also adopts the federal structure and performance requirements of the federal NSPS.

3A.3.2 Water Regulations[1]

The Illinois Environmental Protection Agency (IEPA), Bureau of Water, addresses water quality and wastewater management issues in Illinois.

Illinois has been delegated authority to administer the NPDES program. Illinois follows federal regulations related to wastewater discharges with a few additional provisions. Typically the states water quality criteria are more stringent than EPA's technology based effluent limitations. For discharges into the Lake Michigan Basin, Illinois regulations conform to federal guidance for the Great Lakes System. Illinois industrial pretreatment regulations adopt by reference the National Pretreatment Standards while imposing more stringent prohibitions and concentration-based standards. Illinois also prohibits the discharge of pollutants that would cause safety hazards to personnel operating the treatment works, pollutants that would cause damage to POTWs, sewers or other structures, and pollutants that would cause effluents from treatment works to violate applicable effluent standards. Illinois has also imposed more stringent concentration-based standards for mercury and cyanide.

3A.3.3 Solid Waste Regulations[2]

Under Illinois regulations, fly ash, bottom ash, slag, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels, along with gasifier ash and process waste water from coal gasification, are exempt from regulation as hazardous waste (35 ILL. ADMIN. CODE §721.104(b)). Illinois law specifically authorizes the reuse of CCBs, classified into two different groups: coal combustion waste (CCW) and coal combustion byproduct (CCB). CCW reuse is regulated more stringently than CCB. CCW can be classified as CCB under certain conditions and reused based on the classification. Allowable CCB uses are 1) for the extraction and recovery of materials and compounds within the ash; 2) as a raw material in the manufacture of cement and concrete products; 3) for roofing shingles; 4) in plastic products, paints, and metal alloys; 5) in conformance with the specifications and with approval from the Illinois Department of Transportation (IDOT); 6) as anti-skid material, athletic tracks or foot paths (bottom ash); 7) as a lime substitute for soils so long as the CCBs meet the IDOT specifications for agricultural lime as a soil conditioner; 8) in non-IDOT pavement base, pipe bedding, or foundation backfill (bottom ash); 9) as structural fill when used in an engineered application or combined with cement, sand, or water to produce a controlled-strength material; and 10) for mine subsidence, mine fire control, mine sealing, and mine reclamation (must meet requirements of both the Illinois Environmental Protection Agency and Department of Mines and Minerals). Other CCB applications may be authorized by IEPA (415 ILCS 5/3.94).

3A.4 Kentucky

3A.4.1 Air Regulations[1]

Kentucky's air pollution control programs are managed through the Kentucky Department for Environmental Protection, Division of Air Quality (DAQ). For the Louisville area, regulations are implemented directly by the Air Pollution Control District of Jefferson County (APCDJC). The state's air pollution control regulations generally follow federal requirements with some state specific differences.

Currently, portions of Kentucky are classified as nonattainment for ozone. Additionally, part of Boyd County is nonattainment for SO_2. APCDJC imposes certain additional requirements due to the nonattainment status for ozone. Jefferson County has adopted all relevant state and federal requirements and has instituted specific regulations to restrict major source VOC emissions. Specific operations associated with major sources have VOC standards included in Kentucky regulations. Additionally, RACT may be required for major source VOC emissions, evaluated on a case-by-case basis. The Kentucky PSD program parallels the federal program and the Jefferson County PSD program is essentially the same as the federal PSD program also. Kentucky has one Federal Class I designated area.

The Kentucky and Jefferson County HAP program closely follows the federal requirements. In addition, Kentucky has set State Ambient Air Quality Standards for hydrogen fluoride and hydrogen sulfide. The Kentucky NSPS program follows the federal standards.

3A.4.2 Water Regulations[1]

Wastewater is regulated by the Kentucky Department for Environmental Protection (KDEP), Division of Water Quality. The Kentucky Pollutant Discharge Elimination System (KPDES) Branch is authorized by U.S. EPA to administer and enforce the NPDES program and the National Pretreatment program for industrial wastewater discharged to POTWs.

In addition to federal NPDES regulations, Kentucky adds several requirements. These requirements include the requirement of more stringent water quality based effluent guidelines when EPA effluent guidelines are considered not sufficiently protective. Also, Kentucky incorporates mixing zones into water quality based effluent guideline calculations. The Kentucky stormwater program is similar to the federal program. Sampling requirements for certain industries are different than those outlined in the federal requirements.

3A.4.3 Solid Waste Regulations[2]

Under Kentucky regulations, fly ash, bottom ash, slag, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels, along with gasifier ash and process waste water from coal gasification, are exempt from regulation as hazardous waste (401 KAR 31:010§4(2)). CCBs (including fly ash, bottom ash, and scrubber sludge produced by coal-fired electrical generating units) are classified as special waste (KRS § 224.50-760; 401 KAR 45:010§(4)). Excluded from the definition of CCBs are boiler slag and residues of refuse-derived fuels such as municipal waste, tires, and solvents (KRS 350.010 (24)). Under Kentucky law, CCBs (as defined above) may be reused under permit by rule regulation 1) as an ingredient in manufacturing a product; 2) as an ingredient in cement, concrete, paint, and plastics; 3) as an anti-skid material; 4) as highway base course; 5) as structural fill; 6) as blasting grit; and 7) as roofing granules. Specific conditions for reuse of CCBs include: 1) the CCB reuse may not create a nuisance; 2) erosion and sediment controls must be undertaken; 3) the CCB reuse must be at least 100 feet from a stream and 300 feet from potable wells, wetlands, or flood plains; 4) the ash must be "non-hazardous;" and 5) the generator must submit an annual report (401 KAR 45:060). Also allowable is the disposal in an active mining operation if the mine owner/operator has a mining permit, issued by the Department for Surface Mining, Reclamation and Enforcement authorizing disposal of special waste (KRS 350.270). Specific disposal and analysis requirements apply.

3A.5 New York

3A.5.1 Air Regulations[1]

The New York State Department of Environmental Conservation (NYSDEC), Division of Air Resources, regulates air quality in New York. Several counties have their own unique requirements administered in addition to those of New York State.

NYSDEC has developed numerous state-specific air quality regulations. Those that are most notably distinct from federal requirements are permit and registration conditions and the NYSDEC's General Process Emission Sources - Part 212. The General Process Emission Sources (6 NYCRR Part 212) has traditionally been used by NYSDEC to regulate all air contaminant sources that are not addressed by categorical standards. Under these regulations, each air contaminant is addressed individually, classified into an environmental toxicity category, and controlled based on category and source emission potential.

New York has a number of counties designated as nonattainment for criteria pollutants. Twenty-two counties are nonattainment for ozone, seven counties are nonattainment for carbon monoxide, and one county designated as nonattainment for PM10. When a proposed source project or a proposed major facility is subject to NSR for any nonattainment contaminant, LAER is required for any emission source included in that project or facility that emits that nonattainment contaminant. New York implements and parallels the federal PSD program. For its PSD program, New York has developed a four-category air quality classification system based on population density and land use. New York currently has no Federal Class I designated areas.

New York has incorporated federal HAP and NSPS regulations by reference.

3A.5.2 Water Regulations[1]

The New York State Department of Environmental Conservation (NYSDEC), Division of Water, regulates wastewater in New York and handles the states SPDES permit program.

New York has been delegated authority to administer the NPDES program. For wastewater discharges, New York does not allow state rules to be more stringent than the corresponding federal regulations. In most cases federal rules are adopted by reference or the federal text is used verbatim. New York includes ground water in its definition of state waters. New York's storm water regulations are similar to federal storm water regulations, with additional requirements for general storm water discharge permits for construction sites and industrial facilities. New York is not authorized by the U.S. EPA to implement the National Pretreatment Program, with EPA Region II regulating the pretreatment program for industrial water discharges to POTWs. While New York is not authorized to administer its own state pretreatment program, it does regulate industrial sources that discharge to POTWs without EPA-approved pretreatment programs, incorporating the permitting into the SPDES program. The permit program reflects federal requirements with federal industrial pretreatment regulations adopted by reference, while imposing less stringent reporting requirements.

3A.5.3 Solid Waste Regulations[2]

Under New York regulations, fly ash, bottom ash, slag, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels, along with gasifier ash and process waste water from coal gasification, are exempt from regulation as hazardous waste (6 NYCRR Chapter IV, Subchapter B, § 371.1(e)(20)). Bottom ash may be used as a component in the manufacture of roofing shingles or asphalt products, or as a traction agent on roadways, parking lots, or other driving surfaces. Fly ash or "gas scrubbing products" may be used as an ingredient in producing lightweight block, lightweight aggregate, low strength backfill material, manufactured gypsum, or manufactured calcium chloride. Fly ash or bottom ash may be used as a cement or aggregate substitute in concrete or concrete products, as raw feed in the manufacturing of cement, or as structural fill within building foundations when placed above the seasonal high groundwater table. Certain reporting requirements also exist. Other proposed beneficial reuses may be approved by the State on a case-by-case basic (6 NYCRR Chapter IV, Subchapter B, § 360-1.15).

3A.6 Ohio

3A.6.1 Air Regulations[1]

Ohio's air quality programs are managed through the Ohio Environmental Protection Agency (OEPA), Division of Air Pollution Control.

Ohio's air pollution control regulations generally follow the federal requirements, although the state has developed specific regulations covering other areas of air quality management and air emissions control. Ohio currently has two counties that are nonattainment for sulfur dioxide. Ohio regulations for nonattainment area NSR and PSD programs are very similar to federal rules. Ohio currently has no Federal Class I designated areas.

Ohio has been delegated authority from EPA to implement the federal program for HAPs and NSPS. The regulations closely follow the federal requirements.

3A.6.2 Water Regulations[1]

Ohio's water quality and wastewater management programs are overseen by the OEPA, Division of Drinking and Groundwater or the Division of Surface Water.

Ohio has been delegated authority to administer the NPDES program and the National Pretreatment Program for industrial wastewater discharges to POTWs. Permits are issued by the OEPA Division of Surface Water. Ohio has adopted the federal wastewater regulations and has included a few additional provisions, including categories for the issuance of general wastewater permits and the inclusion of groundwater in the definition of the waters of the state. Ohio storm water regulations parallel federal EPA construction and multi-sector general permits with several additional provisions, also including categories for the issuance of general storm water permits, administrative provisions, and additional stabilization requirements included in construction general permits. State industrial pretreatment regulations adopt federal regulations by reference.

3A.6.3 Solid Waste Regulations[3]

Under Ohio regulations, fly ash, bottom ash, boiler slag, and flue gas emission control by-products (FGD material) generated primarily from the combustion of coal or other fossil fuels, along with gasifier ash and process waste water from coal gasification, are exempt from regulation as hazardous wastes (Ohio Administrative Code, §3745-51-04-B). Fly ash, bottom ash, boiler slag, and FGD are regulated as solid wastes. Non-toxic fly ash, bottom ash, and slag are regulated as exempt wastes, i.e.; they are excluded from the statutory definition of solid waste. FGD material is considered to be an air pollution control waste and is regulated as a residual solid waste (Ohio Administrative Code, §3745-30-01-B-1).

The reuse of CCBs is not specifically authorized under Ohio law or regulations, but the reuse of non-toxic fly ash and bottom ash is authorized under a policy document (Ohio Environmental Protection Agency (OEPA) Policy DSW 0400.007). Non-toxic CCBs may be reused 1) as a raw material in manufacturing a final product; 2) as a stabilization/solidification agent for other wastes that will be disposed; 3) as a part of a composting process; 4) in uses subject to USEPA procurement guidelines; 5) for extraction or recovery of materials and compounds in CCBs; 6) as an anti-skid material or road preparation material; 7) for use in mine subsidence stabilization, mine fire control, and mine sealing; 8) as an additive in commercial soil blending operations, where the product will be used for growth of ornamentals (no food crops or grazed land); 9) as daily cover at a landfill; 10) as structural fill, defined as an engineered use of waste material as a building or equipment supportive base or foundation and does not include valley fills or filling of open pits from coal or industrial mineral mining; 11) as pipe bedding, for uses other than transport of potable water; 12) as a construction material for roads or parking lots (sub-base or final cover); and 13) other single beneficial uses of less than 200 tons. Certain reporting and analysis guidelines may apply to the above uses.

3A.7 Pennsylvania

3A.7.1 Air Regulations[1]

Pennsylvania's air quality programs are managed through the Pennsylvania Department of Environmental Protection (DEP), Bureau of Air Quality.

Pennsylvania has adopted and is implementing federal air quality requirements and has introduced a number of important additions. In addition to the NAAQS for criteria pollutants, Pennsylvania has set ambient air standards for beryllium, hydrogen fluoride, and hydrogen sulfide. Pennsylvania has many counties that are nonattainment for regulated pollutants. Thirty-two counties or portions thereof are nonattainment for ozone, three are nonattainment for SO_2, and one is nonattainment for PM10. Portions of one county are designated as nonattainment (unclassified) for CO. Pennsylvania also requires new or modified sources that impact a nonattainment area, are located within an ozone transport region and meeting certain emission criteria, or facilities located in an unclassifiable area or within a marginal nonattainment area located within an ozone transport region be subject to NSR requirements. Pennsylvania has adopted the federal PSD program, although local authorities may adopt requirements that are more stringent. Pennsylvania has no areas of federal Class I designation.

Pennsylvania has adopted the federal HAP, MACT and NSPS standards, with the addition of the ambient air standards mentioned for beryllium, hydrogen fluoride, and hydrogen sulfide.

Pennsylvania has also established a NOx budget and allowance trading system, which includes monitoring, reporting, and record keeping requirements.

3A.7.2 Water Regulations[1]

The Pennsylvania Department of Environmental Protection (DEP), Bureau of Water Quality Protection, Office of Wastewater Management has the responsibility for water quality and wastewater management issues in the state.

Pennsylvania has been authorized by the U.S. EPA to administer the NPDES program. Pennsylvania has not, however, been authorized to implement the National Pretreatment Program. Therefore, EPA Region III regulates the pretreatment program for wastewater discharges to POTWs. Pennsylvania follows the federal requirements for wastewater NPDES permitting while adding a few rules of its own. Effluent guidelines may be more stringent based on state water quality standards or local wastewater requirements. Also, industrial wastewater discharges are subject to standards and limitations for oil content, acidity, and heat content. The state storm water permits add a few additional provisions beyond the federal requirements, including administrative and erosion and sediment control plan requirements.

3A.7.3 Solid Waste Regulations[2]

Pennsylvania adopts the federal hazardous waste exemptions by reference (25 Pa. Code §261.A.1.4). Therefore, fly ash, bottom ash, slag, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels, along with gasifier ash and process waste water from coal gasification, are exempt from regulation as hazardous waste. The beneficial use of coal ash, defined as fly ash, bottom ash, and boiler slag resulting from the combustion of coal (25 Pa. Code § 287.1), is regulated under the Solid Waste Management Act and the residual waste management regulations (25 Pa. Code § 287.661-287.666), which authorize the use of coal ash 1) as a structural fill; 2) as a soil substitute or additive; 3) for reclamation at an active surface coal mine site, a coal refuse reprocessing site, or a coal refuse disposal site; 4) for reclamation at an abandoned coal or an abandoned non-coal (industrial mineral) mine site; 5) in the manufacture of concrete; 6) for the extraction or recovery of one or more materials and compounds contained within the coal ash; 7) as an anti-skid material or road surface preparation material (bottom ash or boiler slag only); 8) as a raw material for a product with commercial value; 9) for mine subsidence control, mine fire control, and mine sealing; 10) as a drainage material or pipe bedding; and 11) the use of fly ash as a stabilized product where the physical or chemical characteristics are altered prior to use or during placement so that the potential of the coal ash to leach constituents into the environment is reduced. Some uses must comply with specific state regulations.

3A.8 Tennessee

3A.8.1 Air Regulations[1]

The Tennessee Department of Environment and Conservation (TDEC), Division of Air Pollution Control, manages air quality programs in Tennessee.

The Tennessee state air pollution program generally follows the federal requirements although it includes a number of state specific provisions. Tennessee currently has part of one county designated as nonattainment for lead. While there are no areas that are currently designated nonattainment for ozone, Tennessee regulations include emission offset requirements for NOx and VOCs, should any area be designated nonattainment in the future. The offsets are as follows:

Marginal	1.1:1
Moderate	1.15:1
Serious	1.2:1
Severe	1.3:1
Extreme	1.5:1

Tennessee has adopted the federal PSD program, with state requirements that parallel federal regulations. The owner or operator of a proposed major source or major modification may request approval from the permitting agency for the use of innovative control technology in lieu of BACT. Tennessee has three areas that are Class I designation.

Tennessee has been delegated authority for the implementation of HAP, MACT and NSPS regulations, with standards that generally follow the federal requirements.

3A.8.2 Water Regulations[1]

The Tennessee Department of Environment and Conservation (TDEC), Division of Water Pollution Control, manages water quality and wastewater issues in Tennessee.

TDEC has been delegated authority to administer the NPDES permit program, including stormwater discharges. TDEC has also been authorized by U.S. EPA to implement and enforce the National Pretreatment Program for wastewater discharges to POTWs in the state. The state wastewater regulations generally follow the federal regulations, with additional requirements outlining the authorization of more stringent numerical limits based on state water quality standards, derived from the water body's intended use, along with narrative and numeric criteria for dissolved oxygen, pH, hardness, total dissolved solids, solids, turbidity, temperature, and fecal coliform. The state storm water regulations include construction and multi-sector general permits that follow federal storm water permit conditions. Tennessee has incorporated the federal industrial pretreatment standards for industrial discharges to POTWs.

3A.8.3 Solid Waste Regulations[2]

Under Tennessee law, fly ash, bottom ash, slag, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels, along with gasifier ash and process waste water from coal gasification, are not considered hazardous waste (TENN.COMP. R. & REGS. 1200-1-11-.02(1)(d)(2)(xiii) and (xv)). Fly ash, bottom ash, and boiler slag may be reused under permit by rule regulation: 1) in engineered structures for a highway overpass, levee, runway, or foundation backfill; and 2) in other proposed beneficial uses approved on a case-by-case basis (TENN.COMP. R. & REGS. 1200-1-7-.02(1)(c)(1)(ii)). Certain restrictions and requirements apply to "permit by rule" uses and proper written notification of the beneficial use must be submitted to the Tennessee Department of Environmental Conservation and approved.

3A.9 Texas

3A.9.1 Air Regulations[1]

The Texas Natural Resource Conservation Commission (TNRCC), Office of Air Quality is responsible for implementing air quality programs in Texas.

Texas air pollution regulations have a number of significant variations from federal standards. In Texas, all sources of emissions constructed or modified after September 1, 1971 must have a state NSR permit, unless they meet all requirements of codified standard exemptions. Texas currently has sixteen counties designated as nonattainment for ozone and one county that is also nonattainment for CO and PM. TNRCC has imposed additional requirements for sources located in nonattainment areas. New sources located in nonattainment areas that result in an increase in VOC emissions of 5 TPY or more may trigger new source review. The major source threshold for VOC and NOx emissions from new sources located in moderate nonattainment areas is 100 TPY and for major modifications is 40 TPY. The major source threshold for VOC and NOx emissions from new sources located in serious nonattainment areas is 50 TPY and for major modifications is 25 TPY. The major source threshold for VOC and NOx emissions from new sources and modification of existing sources located in severe nonattainment areas is 25 TPY. In addition to permit record keeping and reporting requirements, TNRCC requires facilities to submit an annual inspection fee along with an emission fee based on annual tonnage emissions of each regulated pollutant, with a maximum of 4,000 tons for each pollutant.

TNRCC also imposes flow rate and effective stack requirements for facilities that emit PM greater than 3.5 pounds / hour. TNRCC also provides for specific sulfur emissions for solid fossil fuel fired steam generators, which includes continuous emission monitoring systems for facilities equipped with SO_2 emission control equipment. Additionally, TNRCC has imposed NOx emission control and monitoring requirements applicable to existing facilities located in the Houston/Galveston and Beaumont/Port Arthur areas, specifically applicable to commercial, institutional, or industrial boilers with a maximum rated capacity of 40 10^6 Btu/hour or greater, stationary combustion turbines with a 1 MW or greater rating, or stationary internal combustion engines (in the Houston/Galveston area only) with a 150 horsepower rating or greater. Furthermore, TNRCC defines a pollution episode as "a widespread condition of air pollution as specified in the Texas Water Code, §5.514, that requires immediate action to protect human health or safety. An episode may be declared for one or more air contaminants and will apply to any geographical area affected by the generalized condition of air pollution." TNRCC requires that major stationary sources of 100 TPY or more of any criteria pollutant and located in El Paso, Galveston, Harris, Jefferson, and Orange Counties prepare and maintain an emission reduction plan which includes action plans and impact analysis of operational curtailment. TNRCC also outlines specific monitoring requirements, including reporting requirements of upset conditions, including control equipment malfunctions.

Texas has adopted by reference the federal PSD program. Texas has also been delegated authority and implements federal HAP and MACT standards, along with federal NSPS standards.

Texas also imposes a fuel oil surcharge of $\$0.20/10^6$ Btu that must be paid for fuel oil burned between April 15 and October 15 in boilers with a heat input capacity of at least 10 million Btu/hour capable of burning natural gas by facilities located in a consolidated metropolitan statistical area or in a nonattainment area.

3A.9.2 Water Regulations[1]

The TNRCC Office of Water Resources Management helps manage the state’s water resources. Texas has been delegated authority by U.S. EPA to administer the NPDES program, including storm water discharges. TNRCC has also been authorized authority to administer the National Pretreatment Program for industrial discharges to POTWs in the state.

Texas issues TPDES permits, which include several additional requirements beyond federal requirements. TNRCC uses the more stringent 7-day, 2-year flow rate for the mixing zone in the determination of water quality-based effluent limits. An annual waste treatment fee is required for each person holding a permit or other authorization issued under Chapter 26 of the Water Code, not to exceed $25,000 for TPDES permit holders. Facilities that operate waste water land applications or discharge to surface waters in the Edwards Aquifer recharge zone must comply with additional requirements which include the preparation of a water pollution abatement plan, the prohibition of treatment facility bypass, the prohibition of discharge of untreated or partially treated wastewater, and the application of additional standards for carbonaceous biochemical oxygen demand, total suspended solids, ammonia nitrogen, and phosphorous. Texas assumed administration of the federal multi-sector industrial stormwater permits. TNRCC issued a draft stormwater general permit that contains provisions similar to the federal multi-sector storm water permit and is expected to become final in the summer of 2001. Industrial pretreatment regulations adopt by reference the federal pretreatment requirements except that the Upset Provision (40 CFR 403.16) has not been adopted by the state.

3A.9.3 Solid Waste Regulations[2]

Texas adopts the federal hazardous waste exemptions by reference (30 TAC §335.1). Therefore, fly ash, bottom ash, slag, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels, along with gasifier ash and process waste water from coal gasification, are exempt from regulation as hazardous waste. Under Texas regulations, CCBs may be classified as industrial solid wastes. The Texas Natural Resource Conservation Commission issued CCB reuse guidance, under which CCBs are not subject to classification as a waste and are designated as "co-products" when used in: 1) concrete, concrete products, cement/fly ash blends, pre-cast concrete products, lightweight and concrete aggregate, roller compacted concrete, soil cement, flowable fill, roofing material, insulation material, artificial reefs, and as mineral filler (fly and bottom ash); 2) as a raw feed for concrete manufacture and in masonry (fly ash, bottom ash, and FGD material); 3) in oil well cementing and waste stabilization and solidification (fly ash); 4) as roadbase when covered by a wear surface; 5) as an unsurfaced road construction material, road surface traction material, and blasting grit (bottom ash); and 6) in wall board and sheetrock (FGD material).

3A.10 West Virginia

3A.10.1 Air Regulations[1]

West Virginia's air quality programs are managed through the West Virginia Department of Environmental Protection (DEP)

West Virginia's air quality regulations generally follow federal requirements. Currently, portions of two counties are designated nonattainment for PM10 and a portion of one county is designated nonattainment for SO_2. West Virginia nonattainment requirements impose LAER for new major sources and major source modifications for sources located within the nonattainment areas along with sources located in attainment areas that will have an impact on a nonattainment area. West Virginia's PSD parallels the federal PSD program. Additionally, West Virginia has two areas designated as Class I requiring visibility impact considerations.

West Virginia adopts by reference 40 CFR Parts 61 and 63 for regulation of HAPs and 40 CFR Part 60 for New Source Performance Standards.

3A.10.2 Water Regulations[1]

The West Virginia Department of Environmental Protection (DEP), Office of Water Resources has been delegated authority by U.S. EPA to administer the NPDES program, including storm water management, and the National Pretreatment Program for industrial discharges to POTWs.

West Virginia wastewater regulations follow applicable federal regulations with several additional requirements. West Virginia regulations include groundwater in its definition of "waters of the state." Other additions include the preparation of a fact sheet for every draft NPDES permit for a major facility or activity, for every general permit, and certain other permit submissions, along with the certification of laboratories that analyze samples of waste or waste water, and notification requirements for spills and non-permitted discharges into navigable waters. West Virginia storm water regulations mirror the federal multi-sector and construction general permits, also adding several additional requirements. Included in these additional requirements are submission deadlines prior to onset of activities, monitoring and analysis of an initial storm water event, and the preparation of both a Storm Water Pollution Prevention Plan and a Groundwater Pollution Prevention Plan. West Virginia's industrial pretreatment regulations mirror federal pretreatment requirements with an additional application provision for certain POTWs prior to acceptance of increased industrial flows.

3A.10.3 Solid Waste Regulations[2]

West Virginia regulations adopt by reference the federal regulation that exempts CCBs (including fly ash, bottom ash, slag, and flue gas emission control waste generated primarily from the combustion of coal) from classification as hazardous waste. West Virginia provides specific regulations for the use and disposal of CCBs, including closure and analysis requirements (33 CSR 1-5.5.b). Under West Virginia regulations, CCBs may be reused: 1) as a material in manufacturing another product or as a substitute for a product or natural resource; 2) for the extraction or recovery of materials and compounds contained within the CCBs; 3) as a stabilization/solidification agent for other wastes if used singly or in combination with other additives or agents to stabilize or solidify another waste product; 4) under the authority of the West Virginia Abandoned Mine Lands and Reclamation Act and the Surface Coal Mining and Reclamation Act; 5) as pipe bedding or as a composite liner drainage layer; 6) as an anti-skid material (bottom ash, boiler slag); 7) as a daily or intermediate cover for certain solid waste facilities; 8) as a construction base for roads or parking lots that have asphalt or concrete wearing surfaces.

3A.11 Appendix 3-A References

[1] Specialty Technical Publishers “Environmental State Differences - Regulatory Differences Summary” [CD-ROM] Version 2001-3.

[2] “State and Federal Environmental Framework Governing the Use of Coal Combustion Products (CCPs),” American Coal Ash Association (ACAA), 2000.

[3] Butalia, T., Wolfe, W., “Market Opportunities For Utilization Of Ohio Flue Gas Desulfurization (FGD) And Other Coal Combustion Products (CCPs) Volume 2 – Findings, Recommendations, and Conclusions,” Department of Civil and Environmental Engineering and Geodetic Science, Ohio State University, May 2000.

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