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AN ENVIRONMENTAL ASSESSMENT OF IGCC POWER SYSTEMS

by

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INTRODUCTION

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. IGCC 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. The technology is highly flexible and can be used for new 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 thermal efficiency, and very low pollutant emissions. The first commercial IGCC plants, put into service in the U.S., through DOE's cooperative Clean Coal Technology program, have proven capable of exceeding the most stringent emissions regulations currently applicable to coal-fueled power plants.

IGCC plants 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 hazardous air pollutants are extremely low, comparable with those from direct-fired combustion plants that use advanced emission control technologies. Discharge of solid byproducts and wastewater is reduced by roughly 50% versus other coal-based plants, and the by-products generated (e.g., slag and sulfur) are environmentally benign and can potentially be sold as valuable products. Another significant environmental benefit is the reduction of carbon dioxide (CO_2) emissions, by at least 10% per equivalent net production of electricity, due to a higher operating efficiency compared to conventional pulverized coal-fired power plants.

This paper presents an evaluation of the environmental performance of IGCC power generation technology and compares IGCC environmental performance with other competing coal-based technologies. Information presented is extracted from a DOE report entitled "Major Environmental Issues Affecting Implementation and Operation of Gasification-Based Technologies Utilized For Power Generation." For more information, please visit http://www.netl.doe.gov/coalpower/gasification/.

GASIFICATION-BASED POWER SYSTEMS

Figure 1 depicts a simplified flow chart illustrating alternative gasification-based energy conversion options that represent the next generation of solid-feedstock-based energy production systems. Various gasification and environmental cleanup technologies convert coal (and other carbon-based feedstocks) and an oxidant (e.g., O_2) to synthesis gas for further conversion into marketable products, such as electricity, other fuels, chemicals, steam, and hydrogen. Figure 2 identifies many of the basic components that make up the systems illustrated in Figure 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 the carbonaceous feedstock into gaseous products at high temperature and, usually, elevated pressure in the presence of oxygen and steam. Partial oxidation of the feedstock provides the heat. At these operating conditions, chemical reactions occur that produce synthesis gas or "syngas," a mixture of predominantly CO and H_2. Minerals in the feedstock (ash) separate and leave the bottom of the gasifier as inert slag or ash, a potentially marketable solid product. Only a small fraction of the ash is typically entrained with the syngas, which requires removal downstream in particulate control equipment.

Potential gaseous 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 an organic solvent and converted to valuable by-products, such as elemental sulfur or sulfuric acid. Nitrogen is converted to NH_3, as well as some cyanide and thiocyanate, in the gasifier's reducing environment and is readily removed via water scrubbing. Most trace pollutants are removed with 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. Gaseous mercury that escapes other control processes can be removed from the syngas via use of activated carbon beds. Additionally, 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 strategy to reduce greenhouse gas emissions.

A variety of different energy conversion devices can be incorporated into a gasification-based system to convert the syngas into the types of products identified above. The contemporary IGCC designs considered in this paper utilize a gas turbine to combust the cleaned syngas to produce about 60% of the gross power output. The hot exhaust gas from the gas turbine is sent to a heat recovery steam generator (HRSG) to produce steam for a steam turbine that generates the remainder of the plant's electricity.

Commercial-Scale Coal-Fueled IGCC Power Plants

Four commercial-scale, coal gasification-based power systems have been successfully demonstrated in the U.S. The first two units identified below were recently supported by DOE's Clean Coal Technology (CCT) Demonstration Program and are currently operated as base-load plants for their respective utility owners. The other two demonstration units, partially funded by DOE programs, were highly instrumental in demonstrating technical feasibility of IGCC, but are no longer in service.

FIGURE 1. GASIFICATION-BASED ENERGY PRODUCTION SYSTEM CONCEPTS

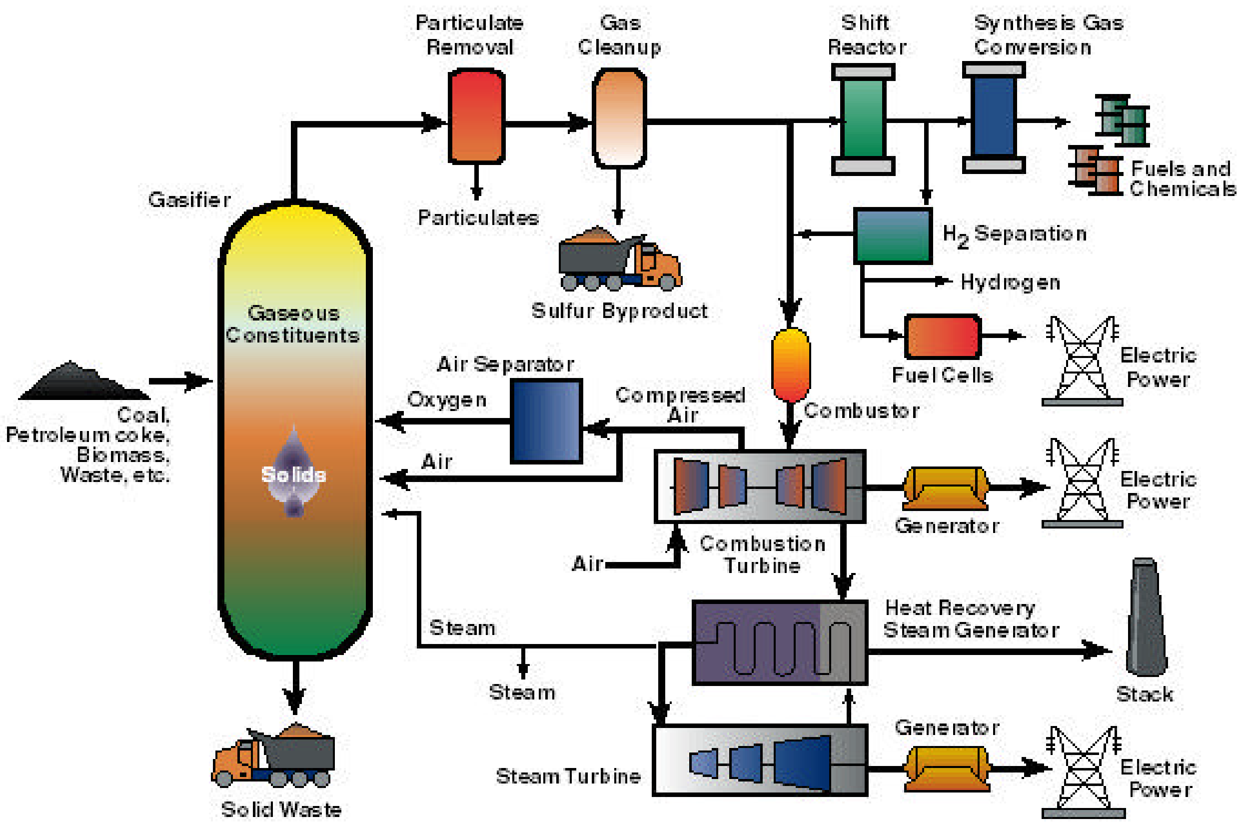
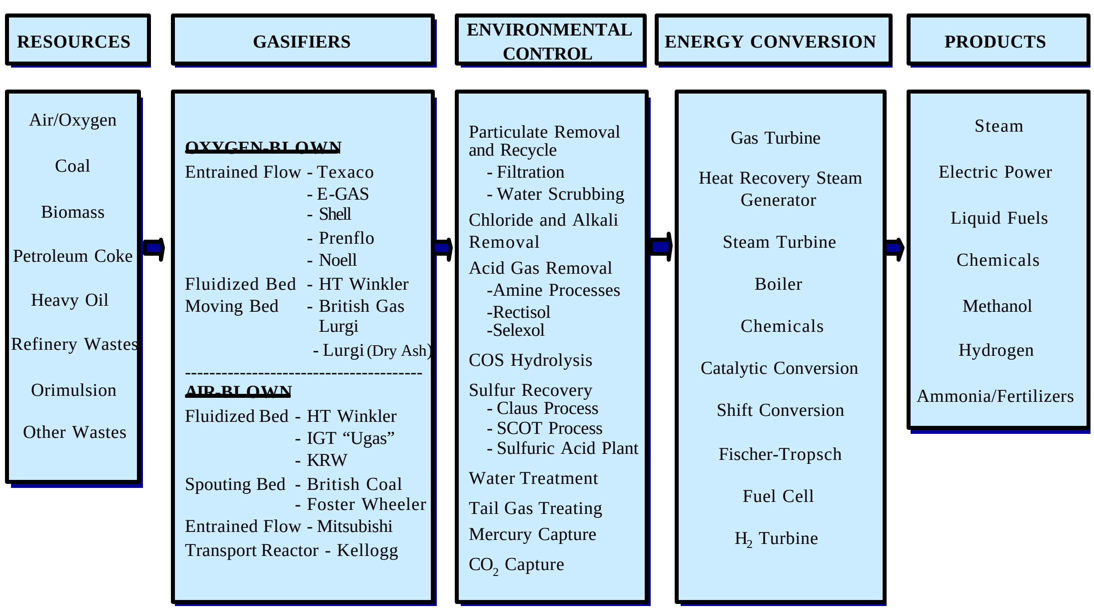


FIGURE 2. GASIFICATION-BASED ENERGY CONVERSION SYSTEM OPTIONS



- Tampa Electric's 250 MWe Polk Power Station (Tampa Electric Integrated Gasification Combined-Cycle CCT Project) – located near Lakeland, Polk County, Florida
- PSI Energy's (now Cinergy) 262 MWe Wabash River Generating Station (Wabash River Coal Gasification Repowering CCT Project) – located near West Terre Haute, Indiana
- Dow Chemical's 160 MWe Louisiana Gasification Technology Inc (LGTI) Project (Originally a U.S. Synthetic Fuels Corporation Project) – located within the Dow Chemical complex in Plaquemine, Louisiana
- Southern California Edison's 100 MWe Cool Water Coal Gasification Plant – originally located in Dagget, California (5-year R&D program was completed in 1989)

Design features of each plant are presented in Table 1. All make use of low-temperature syngas cleanup equipment, use proven sulfur recovery processes, and utilize combustion-based NO_X control methods. Information about the Polk and Wabash plants comes from DOE project reports,[1,2] 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. Information about the LGTI facility is based on a joint DOE/EPRI/LGTI project (in 1995) to characterize the trace substance emissions from advanced gasification technology.[3] However, due to the many design modifications made at the ground-breaking Cool Water IGCC plant,[4] as well as the lack of non-proprietary information, its data was not used to evaluate IGCC environmental performance. As such, only performance data for the Tampa, Wabash, and LGTI IGCC plants is listed in Table 2. This table shows that the single most compelling reason for utilities to consider coal gasification for electric power generation is superior environmental performance.[5] The superior environmental capabilities of coal gasification apply to all three areas of concern: air, water, and solid wastes, as described in detail below.

ENVIRONMENTAL PERFORMANCE OF IGCC POWER PLANTS

Criteria Air Pollutants

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 are SO_2, NOx, particulates, CO, and lead. With the exception of lead, which may be introduced into the gasifier as a constituent of the solid fuel feedstock, these pollutants are formed from constituents of the syngas and air as the syngas is fired in the combustion turbine. Upon discharge from the combustor, the hot turbine exhaust gas is cooled in a heat recovery steam generator (HRSG) before being exhausted to the stack. Therefore, these criteria air pollutants become constituents of the stack gas, and are discharged to the atmosphere. Criteria pollutants may also be emitted in much smaller amounts from equipment installed to treat the tail gas from the sulfur recovery process.

As presented in Table 3, the criteria pollutant emissions from a state-of-the-art IGCC plant will be well below the current Federal New Source Performance Standards (NSPS) for pulverized coal-fired (PC) power plants. Brief evaluations of the criteria pollutant emissions and controls are presented below.

TABLE 1. OVERVIEW OF U.S. COMMERCIAL IGCC FACILITIES

	Polk Power Station[2]	Wabash River Generating Station[1]	Louisiana Gasification Technology Inc.[3]	Cool Water Gasification Plant[4,5]
Net Power Generation Capacity (MWe)	250	262	160	96
Coal Type	High Sulfur Bituminous	High Sulfur Bituminous	Low Sulfur Subbituminous	Bituminous
Gasification Process Type/Fuel Feed	Texaco Single-Stage Entrained-Bed/ Slurry Fed	E-Gas Two-Stage Entrained-Bed/ Slurry Fed	E-Gas Two-Stage Entrained-Bed/ Slurry Fed	Texaco Single-Stage Entrained-Bed/ Slurry Fed
Oxidant	95% Pure Oxygen	95% Pure Oxygen	95% Pure Oxygen	99.5% Pure Oxygen
Gas Cleanup System Type	Low-Temperature	Low-Temperature	Low-Temperature	Low-Temperature
Particulate Control	Water Scrubber	Metallic Candle Filter System and Water Scrubber	Water Scrubber	Water Scrubber
Acid Gas Cleanup/ Sulfur By-product	Amine Scrubber and H_2SO_4 Plant/Sulfuric Acid	Selectamine™ Scrubber and Claus Plant/ Sulfur	Selectamine™ Scrubber and Selectox™ Plant/ Sulfur	Selexol Absorber
Sulfur Recovery Capability	98% Design	99% Design	85% Design	>97%
NOx Control	Nitrogen and Steam Dilution to Combustion Turbine	Steam Dilution to Combustion Turbine	Steam Dilution to Combustion Turbine	Steam Dilution to Combustion Turbine
Ammonia Control	Water Scrubber	Water Scrubber	Water Scrubber	Water Scrubber
Chloride/ Fluoride Control	Water Scrubber	Water Scrubber	Water Scrubber	Water Scrubber

TABLE 2. IGCC STEADY-STATE OPERATIONAL/ ENVIRONMENTAL PERFORMANCE

PERFORMANCE	POLK IGCC [2,5]	WABASH RIVER IGCC [1]	LGTI IGCC [3,5]
Net power output (MWe)	250	262	160
Efficiency (%, HHV basis)	38.0	39.7	N/A
Syngas Heating Value (HHV), Btu/SCF	267	280	~280
Coal Usage (tons/day)	2200	2550	2200
Availability factor, %	80	79	N/A
Emissions:			
SO_2 (lb/10^6 Btu)	0.15	0.12	<0.15
NOx (lb/10^6 Btu)	0.27	0.15	0.26
Particulates (lb/10^6 Btu)	<0.015	<0.012	<0.01
Mercury (lb/hr)	0.012	0.011	0.005
Mercury (lb/10^{12} Btu)	5.2	4.4	1.7
Sulfur removal, %	> 98	> 97	>97

TABLE 3. IGCC EXPECTED EMISSION LEVELS OF CRITERIA POLLUTANTS

CRITERIA POLLUTANT	EXPECTED IGCC EMISSION LEVELS lb/10^6 Btu (lb/MWh)	NSPS LIMIT lb/10^6 Btu (lb/MWh)
SO_2	< 0.15 (0.5)	1.2 (None)
NOx	< 0.1 (1)	0.15 (1.6)
PM10	< 0.015 (0.14)	0.03 (None)
CO	< 0.033 (0.3)	None (None)

SO_2 Emissions

During high-temperature, entrained flow gasification of coal, most of the sulfur in the coal matrix 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. These H_2S, COS and particulate contaminants are mostly removed from the syngas prior to combustion or other forms of fuel conversion (e.g., fuel cell). Acid gas removal equipment extracts 95-99% of the H_2S and COS from the fuel gas and converts it to a salable sulfur or sulfuric acid (H_2SO_4) byproduct.[6] 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 primary stack gas or in the secondary stack gas from the sulfur recovery equipment. The commercial IGCC plants, Polk and Wabash River, achieve emissions below 0.15 lb $SO_2/10^6$ Btu heat input or greater than 97% sulfur reduction. This is almost an order of magnitude lower than Federal limits on SO_2 emissions from utility plants burning solid fuels and also less than the Federal SO_2 emission limits required for stationary gas turbines.

Particulate Emissions

Particulate control in gasification processes is highly efficient, as gasifiers operate at high pressure and generate a significantly smaller gas volume than coal combustion. Not only does the gasification process provide an inherent capability to remove most ash as slag or bottom ash, but the fly ash produced is concentrated in the smaller gas volume, 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. 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.

NOx Emissions

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. 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.[7] The gasification process differs significantly from PC plants 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), as well as small amounts of hydrogen cyanide (HCN) and thiocyanate, these water-soluble species are removed during fuel gas cooling and cleaning and are usually converted to nitrogen in the sulfur recovery process.[8] Therefore, the fuel gas produced is virtually free of fuel-bound nitrogen. NOx formation is primarily the result of thermal NO produced at the high temperatures in the combustion turbine. By maintaining a low fuel-air ratio (lean combustion) and adding a diluent (e.g., nitrogen from the air separation unit or steam), the flame temperature can be lowered to reduce the potential for NOx formation. IGCC NOx emissions of less than 0.1 lb/10^6 Btu are quite low relative to the emissions of a PC plant with low-NOx burners (approximately 0.4 lb/10^6 Btu for a tangentially-fired boiler).

CO Emissions

CO emissions are typically the result of incomplete combustion, but can also result from fugitive emissions. In an IGCC system, sources are typically the gas turbine, sulfur recovery unit tail gas incinerator, and the flare system and equipment leaks. Total CO emissions from the Wabash IGCC plant for 1998 were 0.30 lb/MWh.[9] The original Wabash coal-fired plant, previous to being repowered by the IGCC plant, emitted CO at an annual average rate of 0.64 lb/MWh.[1]

Lead Emissions

Lead, a semi-volatile metal, is released from coal during combustion or gasification and partially volatizes and becomes enriched on fly ash particles of decreasing particle size.[10] Both bench-sale testing and thermodynamic equilibrium models[11,12] 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 syngas will be discharged from the combustion turbine as Pb, $PbCl_2$, or PbO. Trace metal mass balance results for LGTI's IGCC plant showed 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 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. Thus, trace amounts of lead contained in coal can be efficiently removed in an IGCC plant with minimal discharge to the atmosphere. Lead discharged with the slag can be effectively sequestered, but the form of the lead species discharged in solid or liquid streams, from the plant's water treatment facility, is not known.

Hazardous Air Pollutants

Potential trace substance emissions from coal-fueled power plants include ionic species, trace elements, and trace organic compounds. These trace substances can be emitted in flue gas, aqueous discharges, and solid effluents. Ionic species of environmental concern in the effluent streams of coal-fueled 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.[13] Chloride and fluoride, however, can exist as acids and, thus, may appear in the gas phase as well. Stack emissions of all ionic species are reduced to very low levels via particulate and acid gas control equipment.

Release of trace organic compounds is also an environmental concern, since some of these compounds, such as dioxins, furans, and formaldehyde, can have deleterious effects on the environment or human health. While there isn't much corroborating data available on trace organic releases from gasification systems, detailed test results from the LGTI plant indicate extremely low levels of trace organic emissions, in-line with emissions expected from conventional coal-fired plants. Furthermore, results from both LGTI and a Shell coal gasification pilot plant,[14] corroborate that dioxins and furans are 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. 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. Additionally, formaldehyde emissions from a syngas-fired combustion turbine appear to be more than an order-of-magnitude lower than from a natural gas-fired combustion turbine.[15] Total organic emissions from the Wabash River IGCC plant have been reported to be 2.1 x 10^{-3} lb/10^6 Btu, which is about one-half the emissions of the original coal-fired plant that was replaced.[9]

Coal contains most of the naturally occurring chemical elements in (at least) trace amounts, with specific elements and their concentrations dependent upon the rank of the coal and its geological origins.[4] Some are potentially toxic trace metals and metal compounds bound with the coal's mineral and organic matter components. These trace species may be released during gasification 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. Most of these trace metals either remain with the slag/bottom ash or are removed from the syngas in downstream process equipment. The trace metals of greatest environmental concern are reported to be arsenic, boron, cadmium, mercury, and selenium.[10] 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 may be hard to control. Of these, mercury has received the most attention from regulators.

Mercury

Mercury is a particular problem in both combustion and gasification systems, since it primarily remains in the vapor phase due to its low boiling point (357^{o}C or 180^{o}F). Its partitioning and speciation may vary between different gasification systems, but should be broadly similar. The likely chemical forms are elemental mercury (Hg^o), oxidized mercury ($HgCl_2$), and mercuric sulfide (HgS). (While other species are possible, they should be present in only small quantities.) These mercury species may remain in the gaseous phase, be adsorbed onto particulates, or be removed in the liquid scrubbers. Elemental mercury is, by far, the predominant chemical form in gasification systems.

While there is no question 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 6x10^{-5} lb/MWh (1.5 to 5 lb/10^{12} Btu). Comparison with similar tests performed at PC plants indicates that IGCC mercury emissions are of a similar magnitude.

Compared with combustion systems, 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.[16] Both molecular sieve technology and activated carbon beds have been used for this purpose, with 90 to 95% removal efficiency reported. Thus, mercury emissions control from IGCC technology is more of an economic issue than a technical one.

Aqueous Discharges and Solid Byproducts

While air emissions can affect large geographical areas and are often of greatest concern to regulators, both aqueous effluents and solid discharges from coal-fueled plants are quite important at the local level.

Aqueous Effluents

Coal gasification plants have two principal water effluents that are similar to those in PC 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 along with the various ionic species washed from the syngas, such as sulfide, chloride, ammonium, and cyanide.[7] The process water blowdown is 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.

While wastewater control technology varies significantly,[17,18] 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. Detailed analyses have been conducted on process wastewater at the Wabash River IGCC power plant, and it is representative of current, state-of-the-art performance of wastewater treatment equipment at IGCC plants. The test results have generally shown wastewater constituents to be well within environmental permits.

In general, water effluents may create fewer problems for IGCC than for PC power generation, because the steam cycle in an IGCC plant produces less than 40% of the power plant's power. Therefore, effluents from boiler feedwater preparation and cooling-water blowdown are significantly less. However, the amount of process water blowdown is about the same for both gasification and PC combustion.

Solid Byproducts

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 minimal environmental impact. The largest solid waste stream produced by recent IGCC installations is slag, a black, glassy, sand-like material that is potentially a marketable byproduct. 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 shows that gasifier slag is highly non-leachable.[9] Therefore, gasifier slag need not be treated any differently than PC combustion waste material that is classified as non-hazardous. Even more important, possible use of slag in a variety of applications may negate the need for long-term disposal. Utilization of slag from PC plants has been estimated to be about 94%, which indicates high acceptability, if material specifications are met.

The primary technical barrier to using IGCC slag for applications such as cement production is excessive carbon content, but technical solutions have already been found. The Polk IGCC plant has installed additional slag handling equipment to separate unconverted carbon. Not only does the slag meet specifications, but also the unconverted carbon can be recycled back to the plant or used elsewhere.

The other large-volume byproduct 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.

Greenhouse Gas Emissions

The largest contributor to greenhouse gas (GHG) emissions from IGCC power generation is the production of CO_2 from the carbon originally contained in the fuel fed to gasifier. The production of other GHG emissions, such as N_2O and NH_3, are small compared with CO_2. Although CO_2 emissions are higher than natural gas-fired plants, IGCC's improved efficiency reduces CO_2 emissions relative to conventional PC plants. Repowering the Wabash River plant reduced CO_2 emissions by approximately 20% on a per kWh basis.[9] On average, IGCC plants produce CO_2 at a rate of about 1.85 lb/kWh, while PC plants yield about 2 lb/kWh. However, with an IGCC plant modified to produce hydrogen, which in turn can be used to power fuel cells, a CO_2 discharge rate of 1.2 lb/kWh may be able to be achieved.

If an even lower CO_2 release rate is required in the future, IGCC has two major advantages that can be exploited to capture CO_2 more efficiently than is possible with PC combustion technology. The 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 IGCC gasifiers typically operate under relatively high pressure (~400 psig in the Wabash plant). This makes 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 percent loss in efficiency,[19] but this does not account for transport of the CO_2 to a utilization or sequestration site and further processing.

COMPARISON OF IGCC WITH PC-FIRED AND FBC POWER PLANTS

In order to put the IGCC's overall environmental assessment into proper perspective, it is appropriate to compare it with a modern, conventional PC-fired plant, as well as 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, limestone 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 - 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 - 1700^{o}F) to minimize NOx formation, and a fabric filter to control particulate to very low levels.

Table 4 compares the environmental performance of the different technologies in terms of stack emissions of criteria pollutants, ionic species and CO_2, water consumption, and solid waste/byproduct generation. As shown, IGCC's air emissions levels are generally lower than that of the others, all of which are capable of meeting current federal regulations. With respect to acid gas control, IGCC's amine-based process removes up to 99% of the sulfur, which yields the lowest SO_2 emissions among the technologies. However, the wet FGD process employed by the PC plant is also capable of very efficient removal. These effective acid gas control systems, along with efficient particulate control, also effectively limit the emissions of ionic species.

While PC technology gives the highest level of uncontrolled NOx emissions, due to the very high combustion temperatures and the combustion method, the application of SCR technology can be used to reduce NOx emissions by up to 90%. With fluidized bed combustion, the quantity of NOx 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 NOx, which is a potent greenhouse gas. In IGCC, the fuel gas produced is virtually free of fuel-bound nitrogen, and NOx formation is primarily the result of thermal NO formation in the gas turbine combustor. Diluting the fuel gas to achieve lower combustion temperatures has been proven to achieve emissions as low as 15 ppm (0.09 lb/10^6Btu or 0.8 lb/MWh) in gas turbines firing low-Btu fuel gas. Thus, IGCC matches or exceeds the NOx emissions performance of the other technologies, without the use of add-on control equipment (e.g., SCR).

All of the technologies make use of highly efficient particulate control equipment to limit PM10 emissions. These 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 solid byproduct material. However, some of the semi-volatile and volatile species, such as mercury, may not be removed in the particulate collection equipment. In general, trace metal emissions are quite low for all technologies, and IGCC emissions appear to be comparable to other well-controlled coal-fired power plant.

CO_2 emissions, compared on an electricity output basis, generally correlate directly with the thermodynamic efficiency of the respective power cycles. Thus, the IGCC plant and the PFBC plant have the lowest emissions based on a heat rate of 8,600 Btu/kWh. However, as discussed previously, the high pressure and high CO_2 concentration of IGCC's synfuel provides optimum conditions for CO_2 removal prior to combustion, if required. This capability has the potential to further set IGCC apart from the other coal-fueled power generation technologies, and would go a long way toward eliminating its contribution to possible global climate change. Depending upon a plant's location, captured CO_2 has the potential to be transported and utilized for enhanced oil or gas recovery applications.

Finally, this comparison definitively shows IGCC's advantage with respect to water consumption and solid material production. 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. Equally as important, IGCC's solids generation amounts to about 50% less than that produced by the PC plant and 63% less than that of the AFBC technology. While all of these plants produce

TABLE 4. COMPARISON OF ENVIRONMENTAL PERFORMANCE OF IGCC WITH OTHER COAL-FUELED TECHNOLOGIES

CRITERIA POLLUTANTS, IONIC SPECIES, CO_2, and BYPRODUCTS	PC-FIRED PLANT (With Advanced Pollution Controls[a])	AFBC[b] (With SNCR)	PFBC[c] (Without SNCR)	IGCC PLANT[d]
SO_2, lb/10^6 Btu (lb/MWh)	0.2 (2.0)	0.4 (3.9)	0.2 (1.8)	0.08 (0.7)
NOx, lb/10^6Btu (lb/MWh)	< 0.15 (< 1.6)	0.09 (1.0)	0.2 – 0.3 (1.7 – 2.6)	0.09 (0.8)
PM10, lb/10^6Btu (lb/MWh)	< 0.03 (< 0.3)	0.011 (0.12)	0.015 – 0.03 (0.13 – 0.26)	< 0.015 (<0.14)
CO_2, (lb/kWh)	2.0	1.92	1.76	1.76
Chloride as HCl (lb/MWh)	0.01	0.71	0.65	0.007
Fluoride as HF (lb/MWh)	0.003	0.05	0.05	0.0004
Cyanide as HCN (lb/MWh)	0.0003	0.005	0.005	0.00005
Ammonia (lb/MWh)	0	0.001	0.001	0.004
Water Usage, (gallons/MWh)	1,750	1,700	1555	750 – 1,100
Total Solids Generated, (lb/MWh)	367 (Ash and Gypsum)	494 (Ash and Spent Sorbent)	450 (Ash and Spent Sorbent)	175 (Slag and Sulfur)

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/106Btu. PM10 emissions 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 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. PM10 emissions based on Nucla demonstration plant experience. Ionic species emissions 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. PM10 emissions 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 based on turbine combustor that achieves 15 ppm NOx (15% O2, dry). All other emissions based on measured performance of LGTI plant. CO_2 emissions are based on coal with 67% total carbon content.

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.

SUMMARY

Gasification-based energy conversion systems, such as IGCC, can provide stable, affordable, high-efficiency energy production with minimal environmental impact. IGCC systems can economically meet strict air pollution emission standards, produce water effluent within environmental limits, produce an environmentally benign slag, with good potential as a salable by-product, and recover a valuable sulfur commodity by-product. Life-cycle analyses performed on IGCC power plants[20,21] have identified CO_2 release and natural resource depletion as their most significant lifecycle impacts, which testifies to the IGCC's low pollutant releases and benign byproducts. Recent studies[22] have also shown that these plants can be built to efficiently accommodate future CO_2 capture technology that could further reduce their environmental impact.

The outstanding environmental performance of IGCC makes it an excellent technology for the clean production of electricity. IGCC systems also 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. Coal-based gasification systems provide an energy production alternative that is more efficient and environmentally friendly than competing coal-fueled technologies.

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