

# PPRP

## IGCC: Opportunities for Alternative Energy Technologies in Maryland

June 2010

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**MARYLAND POWER PLANT  
RESEARCH PROGRAM**

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John R. Griffin, Secretary  
Maryland Department of Natural Resources

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# IGCC: Opportunities for Alternative Energy Technologies in Maryland

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June 2010

## *FOREWORD*

This report was prepared under the direction of Dr. John Sherwell of the Maryland Department of Natural Resources, Power Plant Research Program (PPRP) by Environmental Resources Management, Inc. (ERM) under contract to PPRP (Contract #K00B520075). The following individuals from ERM were responsible for conducting the work associated with this report: Patrick Flynn and Julie Ross.

## *ABSTRACT*

Integrated Gasification Combined Cycle (IGCC) is a state-of-the-art technology for generating power and producing fuels and other chemical products using coal or other solid fuels such as petroleum coke and biomass. Because IGCC has been demonstrated to generate electricity with improved environmental performance and could play a key role in meeting our future power generation needs, the Maryland Department of Natural Resources Power Plant Research Program (PPRP) completed a technology review and feasibility analysis to:

- Evaluate the technological feasibility and commercial applicability of IGCC in Maryland;
- Outline the siting and licensing implications associated with coal-based IGCC technology relative to conventional coal-fired and natural gas-fired generation; and
- Determine the level of environmental performance and design attributes required of IGCC facilities to be competitive with natural gas-fired combined cycle power plants.

PPRP used the analysis as the basis for establishing a “Model IGCC Facility,” a conceptual, state-of-the-technology model plant design that considers key design attributes required to evaluate economic feasibility and environmental suitability and permitability of IGCC in Maryland. The intent of developing a pre-design or “Model Facility” was to provide a means to streamline the licensing process for IGCC facilities in Maryland.

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## **BACKGROUND ON INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) TECHNOLOGY**

Increasing concerns over global climate change and national energy security have provided incentives to develop more efficient ways to produce electricity with less impact on the environment. Integrated gasification combined cycle (IGCC), although not a new technology, is becoming a potentially viable alternative for power plant developers because of its demonstrated environmental performance, thermal efficiency, and ability to address carbon dioxide (CO<sub>2</sub>) emissions concerns. In fact, in recent years there has been on-going litigation in the U.S. regarding whether or not IGCC should be considered Best Available Control Technology (BACT) for new coal-fired power generation facilities because of the technology's ability to capture CO<sub>2</sub>.

Conventional coal-based IGCC technology, when primarily intended to produce electric power, generally involves a coal gasification process to produce synthesis gas or "syngas" (made up primarily of carbon monoxide, CO and hydrogen, H<sub>2</sub>) followed by a combined cycle gas turbine to burn the syngas and produce electricity. Because of the multiple processing steps involved with coal preparation, syngas production and clean-up, and chemical by-product processing, IGCC plants tend to resemble a chemical manufacturing plant or oil refinery, rather than a conventional power plant.

IGCC represents an important technology for generating power and producing fuels and other chemical products using coal or other solid fuels such as petroleum coke and biomass as a feedstock. Electricity production using IGCC technology generates less air pollutants (particularly, sulfur dioxide, SO<sub>2</sub>; nitrogen oxides, NO<sub>x</sub>; particulate matter, PM; mercury, Hg; and CO<sub>2</sub>) than conventional, pulverized coal-fired plants. In addition, the reductions in emissions observed from using IGCC technology can still be realized even while using lower grade coals like high sulfur eastern bituminous coals that are found in Maryland. Coal gasification has fundamental environmental advantages over direct coal combustion options. Commercial-scale IGCC plants (Wabash River Station in Indiana and Polk Power Station in Florida) have successfully demonstrated these advantages. The environmental benefits of coal gasification apply not only to air emissions, but also extend to water pollutant discharges and solid waste generation, among others. This report focuses primarily on the environmental advantages related to air quality.

In this project, the Maryland Power Plant Research Program (PPRP) performed a preliminary review of IGCC technology to better understand the current state of the technology, and to evaluate licensing implications and environmental performance. To accomplish these goals and understand the licensing implications and environmental parameters, a preferred conceptual facility design for a Maryland IGCC plant was created. This “Maryland Model Facility” outlines general components of an IGCC plant that would be most beneficial, if an IGCC plant were developed in Maryland.

## 1.1 *INCENTIVES FOR IGCC DEVELOPMENT*

Maryland has a need for clean, in-state power, given that Maryland is a significant importer of electricity from neighboring states. The Maryland Public Service Commission (PSC), in its December 2007 Interim Report to the Maryland General Assembly<sup>1</sup>, acknowledged that:

“unless steps are taken now, the State of Maryland faces a critical shortage of electricity capacity that could force mandatory usage restrictions, such as rolling black-outs, by 2011 or 2012,”

and states further that:

“the addition of 1200 MW of excess power . . . from combined cycle gas plants provides the most substantial benefit in the short term and intermediate term to the State.”<sup>1</sup>

Combined cycle natural gas-fired generation facilities emit about half the CO<sub>2</sub> of traditional, new coal plants on a per-megawatt basis, and even a lower percentage compared to CO<sub>2</sub> emitted by older coal plants. IGCC technology, fired by synthesis gas (syngas), has also been demonstrated to produce lower levels of CO<sub>2</sub> than conventional pulverized coal facilities.

IGCC allows for an efficient CO<sub>2</sub> capture option, making the technology competitive with combined cycle natural gas-fired facilities on a CO<sub>2</sub> emission basis. An IGCC plant can be configured during construction so that the CO<sub>2</sub> removal step can more easily be added at a later time. The cost of incorporating this flexibility has generally been estimated to be

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<sup>1</sup> Maryland Public Service Commission. “Interim Report of the Public Service Commission of Maryland to the Maryland General Assembly, December 3, 2007

about one percent<sup>2</sup> of the capital cost of the generating unit. However, the National Energy Technology Laboratory (NETL) indicates that the addition of carbon capture to a conventional pulverized coal plant would increase electricity costs by approximately 58-100%.<sup>3</sup>

A direct comparison of uncontrolled CO<sub>2</sub> emissions from gasification-based and combustion-based generation technologies is presented in Table 1-1. The table shows CO<sub>2</sub> emissions in both pounds per kilowatt-hour (lbs/kWh) and tons per megawatt-hour (tons/MWh) from actual operating facilities or demonstration projects in the U.S. having comparable heat rates and generating capacity. The data comes directly from a recent environmental performance review of IGCC technology by NETL. It should be noted that the listed IGCC facilities do not incorporate carbon capture or any CO<sub>2</sub> mitigation techniques.

In addition to demand, the promulgation and implementation of new federal and state regulations such as the Clean Air Mercury Rule (CAMR), the Maryland Healthy Air Act (HAA), and the Regional Greenhouse Gas Initiative (RGGI), acts as drivers for development of new power plants with enhanced environmental performance. Clean coal technology or IGCC may be suitable for meeting such requirements, and may also encourage public acceptance of coal-fired power plant development. RGGI is a multi-state program that addresses CO<sub>2</sub> emissions from fossil-fuel fired power plants in the Northeastern United States. Maryland joined RGGI in April 2007 and has established a CO<sub>2</sub> Budget Trading Program as outlined in COMAR 26.09.01 to .04. A newly proposed amendment to the CO<sub>2</sub> Budget Trading Program, known as the Clean Energy Set-Aside Account, proposes to allocate up to 5% (or 1.9 million allowances) of Maryland's CO<sub>2</sub> annual allocation of allowances (37,504,000) to encourage the development of new, clean electric generation plants in Maryland. The account allowances will be distributed to qualifying new generators to cover needed CO<sub>2</sub> allowances for up to the first six years of operation<sup>4</sup>.

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<sup>2</sup> J. Barth, Coal-Fired Power Production, Western Clean Energy Campaign Public Policy Issues and Recommendations, April 2004

<sup>3</sup> J. Alvey, "The Carbon Conundrum", August 2003 Public Utilities Fortnightly.

<sup>4</sup> Maryland Department of the Environment. Fact Sheet for Clean Energy Set-aside, "Facts about Subtitle 26.09 Proposed Amendment to Maryland CO<sub>2</sub> Budget and Trading Program: Clean Energy Set-Aside Account," May 2007.

**Table 1-1 Comparison of Uncontrolled CO<sub>2</sub> Emissions From Gasification-based IGCC and Other Fossil Fuel Generating Technologies<sup>5</sup>**

Power Generation Technology	Facility Heat Rate (Btu/kWh)	CO <sub>2</sub> Emissions (lb/kWh)	CO <sub>2</sub> Emissions (Ton/MWh)
Conventional Pulverized Coal Plant with Flue Gas Desulfurization (FGD)	9,800	2.0	1.0
Polk Power IGCC Plant	9,350	1.87	0.94
Wabash River IGCC Plant	8,900	1.78	0.89
Advanced Integrated Gasification Fuel Cell Plant (IGFC)	6,000	1.20	0.6
Pressurized Fluidized Bed Combustion Plant (PFBC)	8,700	1.81	0.91
Natural Gas Combustion Turbine Plant	11,000	1.27	0.64
Natural Gas Combined Cycle	7,500	0.86	0.43

Note: Technologies listed do not include carbon capture

## 1.2 CO<sub>2</sub> MITIGATION AND COAL-DERIVED POWER GENERATION

Coal-fired power plants make up a large part of the power generation portfolio in many areas of the U.S. and globally. In a well-balanced energy generation portfolio comprised of renewables, nuclear, and fossil fuels, coal has a number of attractive features:

- It is an abundant fossil fuel source;
- It is relatively easy to store and transport and can be sourced locally; and

<sup>5</sup> U.S. Department of Energy Office of Fossil Energy –National Energy Technology Laboratory (NETL), “Major Environmental Aspects of Gasification-Based Power Generation Technologies”-Final Report, December 2002.

- Coal-fired plants offer unique load carrying flexibility, are particularly useful in meeting peak demand, and in compensating for the intermittency of renewables like wind power.

However, coal-fired power plants have the disadvantage of relatively high levels of CO<sub>2</sub> emissions. CO<sub>2</sub> emissions from conventional coal combustion technologies generally amount to approximately 1 ton/MWh of electricity generated. For coal to have an environmentally acceptable future, CO<sub>2</sub> emissions from new and existing coal-fired plants will need to be mitigated to as low a level as feasible.

CO<sub>2</sub> mitigation for coal-derived power is a highly debated topic; however, there are several options that can be effective:

- Improvements in generation efficiency (providing a reduction in overall CO<sub>2</sub> emissions per megawatt of electricity generated), either through the development of new plants or upgrading existing facilities;
- Substituting a fraction of the coal with a carbon neutral fuel like biomass (biomass co-firing). Modern coal-fired boiler designs currently are capable of accommodating up to 20% biomass co-firing, with a corresponding reduction in CO<sub>2</sub> emissions; or
- CO<sub>2</sub> capture and geological storage; federal programs are beginning to provide support to validate this option.

Currently, three general methods are available to capture CO<sub>2</sub>:

- Post-combustion capture, in which CO<sub>2</sub> is separated from flue gases;
- Pre-combustion capture, in which CO<sub>2</sub> is captured prior to combustion, generally involving a shift reaction to convert synthesis gas to CO<sub>2</sub> and hydrogen (H<sub>2</sub>); or
- Oxyfuel firing, in which the fuel is fired with an oxygen/CO<sub>2</sub> mixture, thus producing a CO<sub>2</sub>-rich flue gas that is easier for CO<sub>2</sub> capture.

Oxyfuel firing methods have been demonstrated in several projects abroad. Several feasibility studies are currently underway for options using advanced supercritical (ASC) plants. Early results from ASC oxyfuel-firing studies have indicated that ASC plants incorporating CO<sub>2</sub> capture via oxyfuel firing will be competitive with gasification and pre-combustion capture methods. Both technologies can provide electricity at

a cost (inclusive of CO<sub>2</sub> capture and storage) that is less than the cost of electricity from renewable energy sources<sup>6</sup>.

In addition, new ASC coal-fired plant designs, such as the Alstom Power facility (Hemweg 8) located in the Netherlands, and the Fortum Power facility (Meri Pori) located in Finland, have a design cycle efficiency over 43% with steam conditions up to 259 bar and 568 °C. This efficiency increase, compared to subcritical designs with efficiencies between 35% to 38%, translate to an approximate 20% reduction in CO<sub>2</sub> emissions<sup>4</sup>.

Competing clean coal technologies, such as IGCC systems and circulating fluidized bed (CFB) boilers, also have cycle efficiencies comparable to ASC designs. All of such designs have a complementary role to play in new power project development, and specifically, where lower grade (high sulfur or high ash) coals are used.

Compared to other clean coal technologies, such as ASC or CFB, IGCC provides a more efficient and cost effective CO<sub>2</sub> capturing option. IGCC has two main operating advantages that can be used to capture CO<sub>2</sub> more efficiently than is possible with combustion technology. First, the syngas has a high CO<sub>2</sub> concentration, which increases by further converting the syngas CO to CO<sub>2</sub> prior to combustion. Second, IGCC gasifiers typically operate under relatively high pressure (approximately 400 psi, in the case of the Wabash River facility located in Indiana). Both of these conditions make recovery of the CO<sub>2</sub> from the syngas much easier than direct capture from the flue gas.

Recovery of CO<sub>2</sub> from the syngas requires that shift reactors be added to the treatment train. In commercially available reactors, the following exothermic reaction occurs<sup>3</sup>:



The higher concentration of CO<sub>2</sub> in the shifted gas, combined with the higher pressure, yields a high CO<sub>2</sub> partial pressure that permits the use of physical absorption, rather than the more energy-intensive chemical absorption required at lower CO<sub>2</sub> partial pressures (observed in combustion-based flue gas)<sup>3</sup>.

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<sup>6</sup> Power Engineering International – A future for Coal,

[http://pepei.pennnet.com/Articles/Article\\_Display.cfm?ARTICLE\\_ID=213346](http://pepei.pennnet.com/Articles/Article_Display.cfm?ARTICLE_ID=213346)

Maximized conversion of CO to CO<sub>2</sub> can be achieved by utilizing both high and low temperature shift reactors, configured in series. Following such a process, the stream would then be sent through a physical absorption process for removal of the CO<sub>2</sub> stream. The CO<sub>2</sub> would then be liquefied (i.e., compressed to approximately 1600 psi) for transport to a utilization site. The remaining fuel stream, directed to the power block, would consist largely of hydrogen and water vapor.

For such a carbon mitigation process to be suitable for Maryland, a local sink for CO<sub>2</sub> sequestering would need to be identified, or the captured CO<sub>2</sub> would need to be piped to an identified sink. Maryland would need to consider the economics of capturing CO<sub>2</sub> when setting the cost of CO<sub>2</sub>/ton for CO<sub>2</sub> trading purposes under RGGI. There should be some economic incentive for developers to capture and sequester the CO<sub>2</sub> generated from such facilities through the trading program.

The IGCC cycle, because of its greater thermodynamic efficiency, minimizes CO<sub>2</sub> emissions relative to other technologies. High CO<sub>2</sub> concentrations and characteristics of gasified syngas provide optimum conditions for CO<sub>2</sub> removal prior to combustion. The IGCC configuration is a less expensive CO<sub>2</sub> removal option over both state-of-the-art supercritical pulverized coal and fluidized bed combustion plant designs.

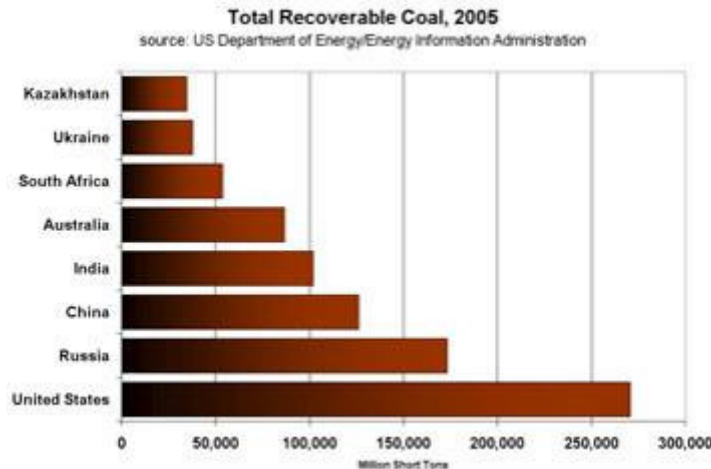
### **1.3**      ***COAL RESOURCES***

In the United States, coal is the most abundant fossil fuel resource available and is an important component in the overall portfolio of fuels needed to provide reliable electric power generation. Climate change, and the methods to mitigate its impact, mark a fundamental shift in the way we will employ coal to produce power. Such a change is required in order for U.S. coal resources to play a significant part in meeting our nation's energy dependence in an environmentally and economically acceptable manner, especially in a carbon regulated economy.

Based on reports by the Energy Information Administration (EIA), the United States currently holds an estimated recoverable coal reserve of approximately 262.7 billion tons, with a demonstrated reserve base

reaching upwards of 489.4 billion tons<sup>7</sup>. Figure 1-1 shows a comparison of estimated recoverable coal reserves for the eight most coal-rich countries. As shown, the U.S. holds the most significant known coal resources.

**Figure 1-1** *Comparison of Estimated Recoverable Coal Reserves for the Eight Most Coal-Rich Countries<sup>8</sup>*



While not one of the most coal rich states in the Mid-Atlantic region (Table 1-2), Maryland does hold reserves capable of supplying coal for power production for decades. In Maryland, there are currently 19 producing coal mines, spanning Allegany and Garrett Counties, 12 of which are located in Allegany County. Based on 2007 EIA data<sup>7</sup>, Maryland has an estimated 354 million tons of recoverable coal reserves, and a demonstrated reserve base reaching upwards of 631 million tons. Maryland produced 2.3 million tons in 2007, which was a 54.5% decline compared to production in 2006<sup>7</sup>. Based on 2007 production data, Maryland could supply coal for approximately 154 years assuming recoverable reserves in Maryland do not expand and coal demand does not change in Maryland. Table 1-2 shows 2007 production levels for the Mid-Atlantic coal producing states, including both the estimated recoverable and demonstrated coal reserves.

<sup>7</sup> Energy Information Administration (EIA) Report No: DOE/EIA 0584, Table 15 - Recoverable Coal Reserves at Producing Mines, Estimated Recoverable Reserves, and Demonstrated Reserve Base by Mining Method, Based on 2007 EIA Data & Report Release Date of September 2008.

<sup>8</sup> Source: U.S. Department of Energy/Energy Information Administration, 2005 Data.



**Table 1-2 2007 Coal Production and Estimated Recoverable and Demonstrated Coal Reserves for the Mid-Atlantic Coal Producing States (Million Short Tons)<sup>7</sup>**

	Estimated Recoverable Coal Reserve	Demonstrated Coal Reserve	2007 Coal Production	# of Producing Mines
Maryland	354	631	2.3	19
Virginia	767	1,598	25.3	118
West Virginia	17,699	32,450	153.5	282
Pennsylvania	11,621	27,228	65	264
Ohio	11,447	23,220	22.5	57

#### 1.4 CLEAN COAL IGCC TECHNOLOGY

IGCC is one of the most advanced methods for producing power from coal with low environmental impact. The environmental performance of this technology has been demonstrated through several worldwide demonstration projects, supported by both government and commercial sponsorships. A few of these projects were partially supported by the Department of Energy's (DOE) Clean Coal Technologies Program.

Conventional coal-based IGCC technology, in an application in which it is primarily intended to produce electric power, generally involves a coal gasification step to produce synthesis gas or "syngas" (primarily made up of carbon monoxide, CO and hydrogen, H<sub>2</sub>) and a combined cycle gas turbine to fire the syngas and produce power. Because of the multiple processing steps involved with coal preparation, syngas clean up and by-product processing, and the several options that can be adapted to the general process train (syngas shifting to liquid fuels and chemicals), IGCC plants tend to resemble a chemical process plant or oil refinery, rather than a conventional power plant. Such plants employ a multitude of commercially available gasification and related technologies depending on the characteristics of the coal used. Commercially available combined cycle gas turbines that have been successfully demonstrated include models such as: GE 7FA, GE 107EA, GE 107FA, GE 106FA, GE 207FB, Siemens V 94.2, and Siemens V 94.3. Table 1-3 identifies several successfully demonstrated and commercially available gasifiers (both for

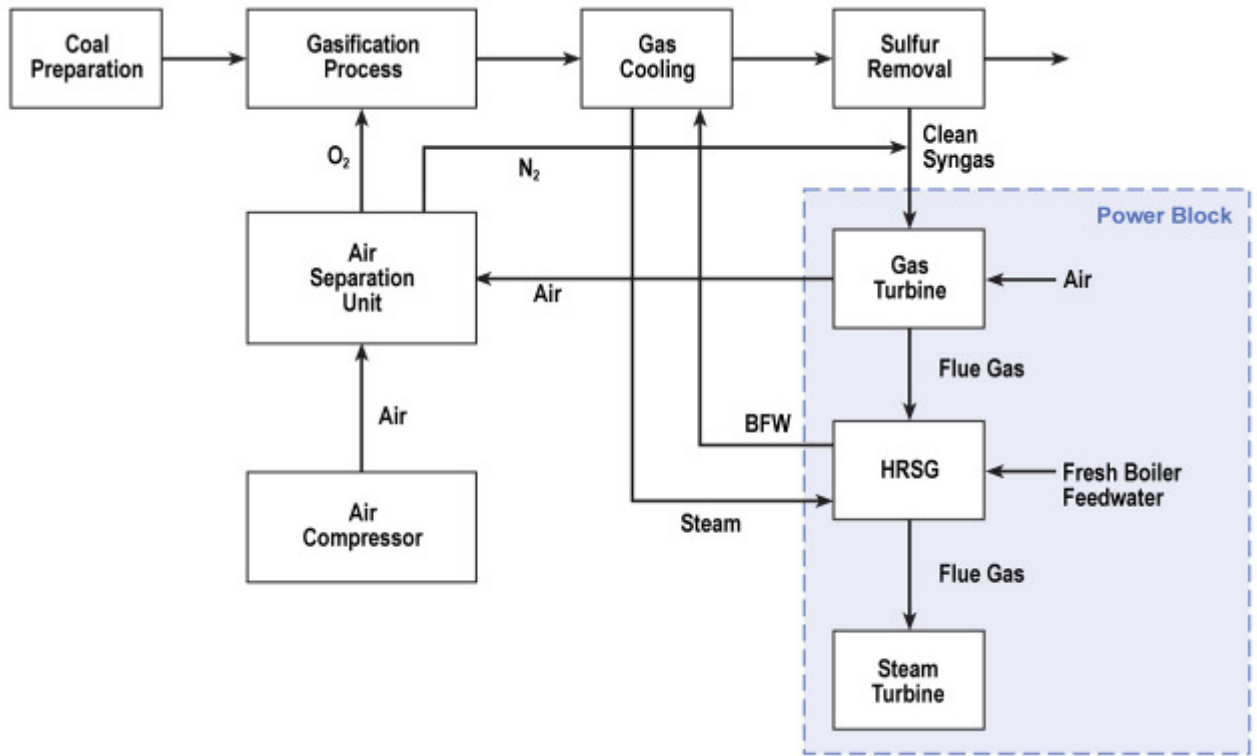
slurry feed and solid dry feed) that are commonly employed and intended for use in coal-based IGCC facilities.

**Table 1-3** *Demonstrated Commercially Available Gasifiers Intended for Coal-based IGCC Applications*

<b>Gasifiers</b>	
<b>Slurry Feed</b>	<b>Solid Dry Feed</b>
GE (formerly Chevron/Texaco) Single-stage entrained bed/slurry fed gasifier (low temperature)	Shell SCGP single-stage upflow entrained/dry fed gasifier
ConocoPhillips E-Gas (formerly Destec) two-stage entrained bed/slurry fed gasifier (low temperature)	BGL (British Gas Lurgi) fixed bed dry bottom gasifier (low Temperature)
	Prenflo single-stage upflow entrained/dry fed gasifier (low temperature)

Figure 1-2 provides a general process flow diagram for a conventional IGCC facility. Table 1-4 illustrates the many types of IGCC trains that have been installed and demonstrated both in the U.S. and abroad. The table also shows a comprehensive summary of conventional IGCC trains employed commercially by process unit.

Figure 1-2 Process Flow Diagram for Conventional IGCC Facility<sup>9</sup>



**Table 1-4 IGCC Configurations and Technology Summary for Conventional Demonstration Projects and Currently Operating Conventional Commercial-Scale IGCC Facilities<sup>9</sup>**

	IGCC Demonstration Projects		Current Operating Commercial-Scale IGCC Facilities			
Plant Name	Texaco Cool Water Project (Barstow, CA)	Dow Chemical/ Destec LGTI Project	Polk Power Station (Florida, USA)	Wabash River Generating Station (Indiana, USA)	NUON/Demkolec (Buggenum, The Netherlands)	ELCOGAS (Puertollano, Spain)
<b>Operation Status</b>	1984-1988	1987-1995	1996-Present	1995-Present	1994-Present	1998-Present
<b>Net Power Generation (MW)</b>	125	160	250	262	253	298
<b>Fuel Feed</b>	Bituminous Coal (Illinois #6, and Pittsburg #8)	Low Sulfur Sub-bituminous	High Sulfur Bituminous Coal	High Sulfur Bituminous Coal	Bituminous Coal	Bituminous Coal & Petroleum Coke
<b>Gasification Technology</b>	Chevron Texaco (now GE)	Destec E-Gas (now ConocoPhillips)	Chevron Texaco (now GE)	Destec E-Gas (now ConocoPhillips)	Shell	Prenflo
<b>Gasification Process Type/Fuel Feed Type</b>	Single-Stage Entrained Bed/Slurry Fed	Two-Stage Entrained Bed/Slurry Fed	Single-Stage Entrained Bed/Slurry Fed	Two-Stage Entrained Bed/Slurry Fed	Single-Stage Upflow Entrained /Dry Feed	Single-Stage Upflow Entrained /Dry Feed
<b>Oxidant</b>	99.5% Pure Oxygen	95% Pure Oxygen	99.5% Pure Oxygen	95% Pure Oxygen	95% Pure Oxygen	95% Pure Oxygen
<b>Slag Removal</b>	Lock Hoppers	Continuous	Lock Hoppers	Continuous	Lock Hoppers	Lock Hoppers
<b>Syngas Cooler Type</b>	Downflow Radiant Water Tube and Convective Firetube	Downflow Firetube	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
<b>Gas Cleanup System</b>	Low-Temperature	Low-Temperature	Low-Temperature	Low-Temperature	Low-Temperature	Low-Temperature

<sup>9</sup> U.S. Department of Energy Office of Fossil Energy –National Energy Technology Laboratory (NETL), “Major Environmental Aspects of Gasification-Based Power Generation Technologies”-Final Report, December 2002.

	IGCC Demonstration Projects		Current Operating Commercial-Scale IGCC Facilities			
Plant Name	Texaco Cool Water Project (Barstow, CA)	Dow Chemical/ Destec LGTI Project	Polk Power Station (Florida, USA)	Wabash River Generating Station (Indiana, USA)	NUON/Demkolec (Buggenum, The Netherlands)	ELCOGAS (Puertollano, Spain)
<b>Particulate Control</b>	Water Scrubber	Water Scrubber	Water Scrubber	Metallic Candle Filter System and Water Scrubber	Candle Filter (Operating at 230°C)	Candle Filter (Operating at 240°C)
<b>Chloride, Fluoride, and Ammonia Control</b>	Water Scrubber	Water Scrubber	Water Scrubber	Water Scrubber	Water Scrubber	Water Scrubber
<b>Carbonyl Sulfide (COS) Hydrolysis</b>	Catalytically Converted to H <sub>2</sub> S	Catalytically Converted to H <sub>2</sub> S	Catalytically Converted to H <sub>2</sub> S	Catalytically Converted to H <sub>2</sub> S	Catalytically Converted to H <sub>2</sub> S	Catalytically Converted to H <sub>2</sub> S
<b>Acid Gas Cleanup and Sulfur Recovery/Sulfur By-product</b>	Selexol Scrubber/Slaus Unit with SCOT Tailgas Unit/Sulfur	Select amine™ Scrubber and Selexol™ Plant/Sulfur	MDEA Scrubber and Sulfuric Acid (H <sub>2</sub> SO <sub>4</sub> ) Plant	MDEA Scrubber and Claus Plant / Sulfur	Sulfinol M Scrubber and Claus Plant / Sulfur	MDEA Scrubber and Claus Plant / Sulfur
<b>Sulfur Recovery Capability</b>	97% for low sulfur coal, 99% for high sulfur coal	85% design	98% Design	99% Design	99% Design	99% Design
<b>Air Separation Unit</b>	Cryogenic distillation	Cryogenic distillation	Cryogenic Distillation	Cryogenic Distillation	Cryogenic Distillation	Cryogenic Distillation
<b>Air Supply Compressor</b>	100% separate	100% separate	100% separate	100% separate	100% from gas turbine	100% from gas turbine
<b>Nitrogen Use</b>	Mostly vented	Mostly vented	GT NO <sub>x</sub> control	Mostly vented	Syngas Saturator for GT NO <sub>x</sub> Control	Syngas saturator for GT NO <sub>x</sub> control
<b>Gas Turbine</b>	GE Frame 7E	Combined cycle Westinghouse 501-D5	GE 107FA	GE 107FA	Siemens V 94.2	Siemens V 94.3
<b>Combustors</b>	Multiple cans	Multiple cans	Multiple cans	Multiple cans	Twin vertical silos	Twin horizontal silos

Plant Name	IGCC Demonstration Projects		Current Operating Commercial-Scale IGCC Facilities			
	Texaco Cool Water Project (Barstow, CA)	Dow Chemical/ Destec LGTI Project	Polk Power Station (Florida, USA)	Wabash River Generating Station (Indiana, USA)	NUON/Demkolec (Buggenum, The Netherlands)	ELCOGAS (Puertollano, Spain)
Syngas Heating Value (HHV), Btu/lb	265	260	267	280	-	-
Firing Temperature, °F (°C)	1985 (1085)	1900 (1037)	2350 (1287)	2350 (1287)	2012 (1100)	2300 (1260)
NO <sub>x</sub> Control	Syngas saturation with hot water (25% by volume H <sub>2</sub> O)	Steam dilution to combustion turbine	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	Single-pressure, natural circulation, no reheat	Single-pressure, natural circulation, no reheat	Three-pressure, natural circulation, reheat	Three-pressure, natural circulation, reheat	Three-pressure, natural circulation, reheat	Three-pressure, natural circulation, reheat
Steam Turbine	55 MW, no intermediate pressure reheat cycle	75 MW, 1250 psig/950 °F superheated steam, no reheat	1,465 psia, 1000 °F with 1000 °F Reheat	1,600 psia, 1010 °F with 1010 °F Reheat	-	-
SO <sub>2</sub> (lb/MWh)	--	--	<1.35	1.08	0.44	0.15
NO <sub>x</sub> (lb/MWh)	--	--	0.86	1.09	0.7	0.88
PM (lb/MWh)	--	--	<0.14	<0.10	0.01	0.044
Hg (lb/MWh)	--	--	4.8x10 <sup>-5</sup>	6.1x10 <sup>-5</sup>	Unavailable	Unavailable
Sulfur Removal (%)	--	--	>98	>97	>99	99.9

A conventional commercial IGCC facility involves several process steps and is configured much like a chemical plant or petroleum refinery. The main process units generally include:

- ***Coal Preparation Plant*** – Processing and transport of coal to gasifier unit;
- ***Gasification Block*** – Gasification unit, including air separation for supplying oxygen to the gasifier, gasification of coal feed to produce syngas, syngas particulate removal, and syngas cooling;
- ***Acid Gas Removal Unit*** – Syngas treatment unit, including Hg removal, amine scrubbing, and sulfur removal; and
- ***Power Block*** – Combined cycle power generation.

The newer generation clean coal IGCC technology, currently being marketed by BP and the major OEMs (original equipment manufacturers) like Shell and General Electric, enable the IGCC process train to capture the carbon entrained in the raw syngas generated from the facility gasification block and produce H<sub>2</sub> via a chemical shift. The current methodology involves converting the CO in the syngas to CO<sub>2</sub> by injecting steam and flowing the steam-injected syngas through a selective catalytic reduction (SCR) process. The process simultaneously provides additional O<sub>2</sub> to oxidize the CO to CO<sub>2</sub>, but also allows for higher yields of hydrogen to be produced through the addition of steam (H<sub>2</sub>O). The process is called a water-gas shift reaction ( $\text{CO} + \text{H}_2\text{O} \rightarrow \text{CO}_2 + \text{H}_2$ ). The CO<sub>2</sub> is then captured, leaving high yields of hydrogen gas (H<sub>2</sub> from clean syngas + H<sub>2</sub> from water gas shift) to be used to fuel the facility power block.

## 2.0 *CLEAN COAL TECHNOLOGY – CONCEPTUAL COAL GASIFICATION (IGCC) “MODEL FACILITY” FOR MARYLAND*

This section describes the development of the Maryland “Model Facility” and many of the characteristics of the facility that would be beneficial if an IGCC plant were to be developed in the State.

### 2.1 *MARYLAND “MODEL FACILITY” PLANT DEVELOPMENT*

Establishing the initial draft conceptual/pre-design for the Maryland Model Facility involved an extensive literature survey to identify the leading available technologies, including the basic process train options currently available. Publicly available information from existing IGCC plants, (including the Wabash River Repowering Plant located in Indiana; the Tampa Electric Polk Power Station in Tampa, Florida; the Shell Nuon/Demkolec Power Plant in Buggenum; and the ELCOGAS facility in Puertollano, Spain) was used to evaluate basic process and material flows, and end use product yields. The facilities were chosen for evaluation because each facility uses a different gasification technology and processes coal with different characteristics. The facilities provide a reasonable cross section of currently available technology, from which conservative estimates of environmental impacts and licensing implications could be evaluated. Based on PPRP’s review of detailed operations and performance data, and a detailed review of currently available literature, the preferred conceptual facility, noted in Figure 2-1, was developed to process western Maryland coal, as shown in Table 2-1. This design is conceptual and preliminary; improvements and adjustments will be required as more detailed technology-specific information becomes available. All process and material flows presented were based upon publicly available information through a literature survey.

After extensive review and careful consideration of Maryland’s Climate Change Action Plan, and other efforts if a coal-based IGCC technology were to be employed in Maryland, we determined that it would be preferable that some form of CO<sub>2</sub> capture be considered for environmental performance reasons. Therefore, the model facility for Maryland was configured with both a power block powered by clean syngas (Power Block B), and a power block powered by a high H<sub>2</sub>/syngas mixture (Power Block A); see Figure 2-1.



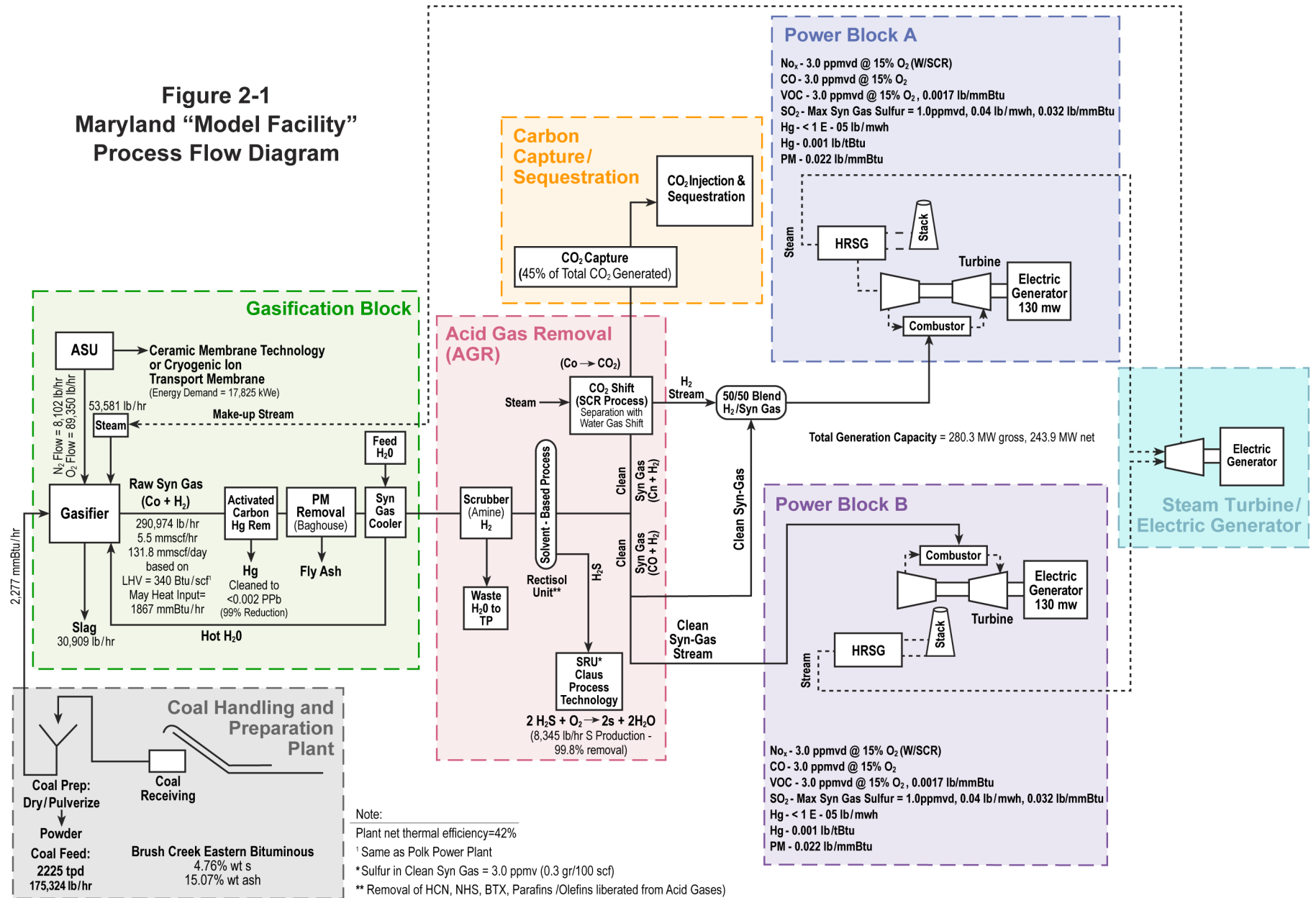
Despite several proposals (across the U.S. and abroad by various power plant developers) to fuel the power block with 100% hydrogen and up to 90% carbon capture from a single process train, American Electric Power (member of the board of directors of the FutureGen Alliance) indicated that such a design represents considerable risk for commercial power plant applications in the near-term<sup>10</sup>. AEP indicated that such a proposal would require the deployment of technology beyond that which is currently commercially available, particularly with respect to the combustion turbine. AEP also indicated that currently there are no gas turbines available in the F or G class that have been commercially demonstrated to enable utilization of high-hydrogen fuel. Currently available, high-hydrogen fueled turbine technology is thought to pose undue risk to commercial entities from a reliability standpoint.

However, if the hydrogen were blended with un-shifted syngas prior to combustion, AEP indicates that it is likely that the combustion turbine could tolerate the fuel, and such a reliability risk would be significantly reduced. AEP recommends that an effective approach for commercial consideration of IGCC with carbon capture would be one that achieves the highest level of CO<sub>2</sub> capture possible. Minimizing operational risks would be possible and thus more tolerable to utility interests. Such an approach would require no more than 45% CO<sub>2</sub> capture from the entire facility, with a staged agreement where higher levels of capture would be achievable within an agreeable time-period. Based on AEP's recommendation, the Model Facility was designed to achieve 45% capture and operate with two process trains (one with CO<sub>2</sub> capture yielding H<sub>2</sub>/syngas stream and one without CO<sub>2</sub> capture yielding clean syngas for direct combustion in a separate power block).

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<sup>10</sup> American Electric Power (AEP), Response to Request for Information on Department of Energy's Plan to Restructure FutureGen, March 3<sup>rd</sup> 2008.

**Figure 2-1  
Maryland “Model Facility”  
Process Flow Diagram**



The model facility includes the following process units:

- **Material Handling Facility (Coal/Limestone Handling and Preparation)**—handles and processes coal and possible limestone feed to the gasifier;
- **Gasification Block**—includes an air separation unit (ASU), gasifier, particulate removal, and syngas cooler;
- **Acid Gas Removal (AGR) Unit**—includes mercury removal, amine scrubbing, sulfur removal, and CO<sub>2</sub> shifting;
- **Carbon Capture/Sequestration Block**—captures shifted CO<sub>2</sub>, and sequesters such CO<sub>2</sub>;
- **Power Block A**—fired by H<sub>2</sub>/syngas mixture; and
- **Power Block B**—exclusively fired by syngas.

*Table 2-1 Coal Samples from Maryland Brush Creek Coal Seam<sup>11</sup>*

Coal Sample	Ash (% Dry)	Sulfur (% Dry)	Volatile Matter (% Dry)	Heating Value (Btu/lb)	Fixed Carbon (% Dry)
PSOC-1120	15.07	4.76	25.83	12,988	59.1
PSOC-1123	36.56	4.57	20.03	9,212	43.41
PSOC-1124	9.72	3.37	26.02	13,714	64.26
PSOC-1125	13.4	6.1	24.84	13,164	61.76

The nominal capacity of the facility, for purposes of comparison with other existing facilities, was chosen to be 280 megawatt (MW) gross, with an assumed net rating of 244 MW. Two adapted GE 106FA combined

<sup>11</sup> Source: Penn State Coal Bank, <http://datamine.ei.psu.edu/index.php>

cycle turbines, rated for syngas firing, were chosen as the plant's generating technology. Based on the selected design coal, and rated generation capacity, the facility coal throughput was calculated at 812,125 tons per year (tpy).

As part of the material handling facilities, the coal preparation plant would unload coal either by rail or by barge (depending on the location of the facility), then conveyed to either a coal stock pile or directly to a coal crusher and feed system for supply directly to the gasifier at a rate of 2,225 tons per day (tpd). In addition to coal handling, limestone may be a required constituent in the fuel feed, depending on the final selected gasifier design. Further, technology-specific data from available vendors will be required to make final determinations on the design's feed material requirements. If limestone is required, limestone would be unloaded in the same manner as the coal and prepared to feed the gasifier as flux to aid in syngas conversion. We have estimated a limestone material handling throughput of 4,487 pound per hour (lb/hr), or 19,654 tpy, based on available data for the BGL gasifier design. The maximum heat input to the gasifier was evaluated at 2,277 million British thermal units per hour (MMBtu/hr). The combined maximum heat input to the power blocks was determined to be 1,867 MMBtu/hr, assuming an average 82% gasifier conversion efficiency or 18% heat loss. Based on this assumption, the maximum feed rate of syngas to the power block would be 5.5 million standard cubic feet per hour (MMscf/hr), or 131.8 million standard cubic feet per day (MMscf/day), assuming a syngas heating value of 340 Btu per standard cubic feet (Btu/scf). The gasifier unit will generate approximately 30,909 lbs slag/hr. Fly ash would be recovered via a baghouse with  $\geq 99.8\%$  particulate matter removal efficiency. The gasifier would require O<sub>2</sub> in the amount of 89,350 lb/hr and N<sub>2</sub> in the amount of 8,102 lb/hr from an air separation unit. Approximately 53,581 lbs of steam/hr would be required.

As part of the AGR process, mercury is designed to be removed from the syngas to less than 0.002 parts per billion (ppb), or up to 99% removal. In addition, amines would be scrubbed. During the amine scrubbing process, wastewater would be generated and directed to a facility wastewater treatment plant. Sulfur in the syngas would be removed down to 1.0 ppmv. Total recovered sulfur from the Sulfur Recovery Unit (SRU) was estimated at 8,345 lbs/hr.

As noted previously, up to 45% of the total CO<sub>2</sub> generated from the facility would be captured. The facility was configured to accomplish this by effectively capturing 90% of CO<sub>2</sub> from 50% of the facility syngas stream. This would mean that 50% of the cleaned syn-gas steam flows directly to

Power Block B without CO<sub>2</sub> removal, and the other 50% of the syngas would be shifted (i.e., CO → CO<sub>2</sub>) to remove up to 90% of the CO<sub>2</sub> from this part of the stream. This achieves 45% removal of the total amount of CO<sub>2</sub> generated from the facility, assuming that all CO is converted to CO<sub>2</sub> during combustion in the power block. Based on CO<sub>2</sub> data from existing operations, a facility-wide CO<sub>2</sub> generation rate is estimated at approximately 1,894 lb/MWh or 1.9 lb/kWh. This equates to 2,023,000 tons of CO<sub>2</sub> emissions annually. With 45% carbon capture, the facility would then emit 1,041.7 lb/MWh, or 1.04 lb/kWh (1,112,650 tons), which is competitive with natural gas-fired facilities (see Table 1-1).

## 2.2 *ENVIRONMENTAL CONSIDERATIONS AND FACILITY DESIGN*

In considering switching fuels from natural gas to coal-derived syngas for existing electric generating units, or when designing new generating facilities, two major concerns would be operating reliability and environmental permitting and compliance, and in particular, air quality permitting and compliance.

Industrial facility owners (potential buyers of gas) have large fuel demands and generally require supply reliability near 100%. Typically, natural gas supplies are classified in two ways: 1) 30-day interruptible supply, and 2) firm uninterruptible gas supply. Plants that have dual natural gas/oil firing capability can obtain lower cost, 30-day interruptible natural gas and store 30-days of oil supply on-site<sup>12</sup>. According to NETL, in order to compete with natural gas supply reliability, gasification plants would require syngas supply reliability of at least 91.8%. This is thought to be achievable with today's gasification technologies. However, the plants currently requiring firm gas supply, and which could convert their equipment to dual syngas/natural gas firing would likely require a syngas production facility to provide either syngas or natural gas with 100% reliability.

Potential industrial syngas customers would need to consider seriously environmental permitting and licensing requirements, particularly, air quality permits. Permitting an IGCC facility would require the most advanced air pollution control systems to be installed. From the power block, potential emissions of SO<sub>2</sub> and Hg would be of most concern since

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<sup>12</sup> Department of Energy, National Energy Technology Laboratory (NETL), Industrial Size Gasification for Syngas, Substitute Natural Gas and Power Production, DOE/NETL-401/040607, April 2007.

it is anticipated that particulate matter, NO<sub>x</sub>, and CO emissions would be comparable to natural gas fired systems. As illustrated below, SO<sub>2</sub> and hazardous air pollutants (HAPs) would be more of concern from the syngas production process than the power block.

AGR systems that are currently used at commercial facilities like the Tampa Polk Power Station or the Indiana Wabash River facility (1995/1996 vintage MDEA scrubber technology) do not remove sulfur to comparable levels found in natural gas. Therefore, coal-derived gas cleanup systems utilizing such technology will result in higher hourly and annual emissions than from plants using natural gas, assuming operation of the plants at the same capacity factor. The level of sulfur concentration remaining in the coal-derived syngas from most of these AGR systems is on the order of 15 to 20 ppmvd<sup>12</sup> and may also result in annual SO<sub>2</sub> emissions from combustion systems exceeding the major modification threshold (40 tpy) for New Source Review (NSR) permitting purposes, based on utilization of 1,000 MMBtu/hr, or more of syngas<sup>12</sup>. Any IGCC facility having a nominal capacity of 280 MW or higher, and having a syngas heat rate exceeding 1,000 MMBtu/hr would require an AGR technology that out performs currently commercially employed technology. As noted in Figure 2-1, the Maryland Model Facility was specified at a syngas heat rate of 1,867 MMBtu/hr. Upon further review, we found that one of the few commercially available AGRs that has the ability to clean coal-derived syngas to natural gas sulfur levels is the Rectisol process (discussed further in Section 2.1.1.1) which has been chosen as the preferred AGR technology for the Maryland model facility.

Mercury reduction provisions in Maryland under the HAA require power plants to achieve an 80% minimum reduction in emissions of mercury from a baseline year for Phase I (2010), and 90 percent beginning in Phase II (2013). While the regulations cover existing coal-fired units in Maryland, there is an increased awareness of the potential for future mercury emissions regulations being promulgated that focus on combustion systems using coal-derived fuels. New power plants in Maryland will need to incorporate measures to control mercury. On a federal level, the Clean Air Mercury Rule (CAMR) established standards limiting mercury emissions from new and existing coal-fired power plants while creating a market-based cap-and-trade program to reduce nationwide utility emissions of mercury. However, on 8 February 2008, the D.C. Circuit Court vacated the rule. EPA is currently reviewing the Court's decision and evaluating the impacts of such a decision. Regardless, any new coal-fired facility, whether IGCC or more traditional technologies, would need to incorporate state-of-the art controls, such as activated carbon injection (ACI).

## 2.2.1

### *Leading Acid Gas Removal Processes*

The Rectisol process is a well known, widely used process, and involves a physical methanol-based solvent absorption process. The process operates at very low temperatures (typically less than  $-80^{\circ}\text{F}$ ). These processes have operated reliably for decades behind many types of gasification processes, including the Lurgi, BGL, Chevron/Texaco (now General Electric), and Shell technologies installed at facilities such as the Dakota Gasification facility in North Dakota, SASOL in South Africa, Schwarze Pumpe in Germany, Eastman in Tennessee, and Shell in the Netherlands. Information from Lurgi<sup>13</sup> indicates that there are about 59 gasification facilities world-wide that have Rectisol processes. About 75% of the world's syngas produced from oil residue, coal, and wastes are purified by the Rectisol process.

Rectisol has several unique operating characteristics. One feature is its ability to remove hydrogen cyanide (HCN), ammonia ( $\text{NH}_3$ ), and BTX (benzene, toluene, xylene) from the raw syngas in a prewash step. The HCN,  $\text{NH}_3$ , and BTX can be easily released from the solvent and the solvent can then be recirculated and reused within the system. The acid gases (primarily hydrogen sulfide,  $\text{H}_2\text{S}$ , and carbonyl sulfide, COS) are removed in secondary steps within the same absorber vessel. Paraffins and olefins absorbed along with the acid gases can be released from the acid gases and recombined with the "sweet gas" product (syngas not having large quantities of  $\text{H}_2\text{S}$ , or sulfur species). Another unique feature of the Rectisol process is the ability to remove both COS and  $\text{H}_2\text{S}$  and concentrate these sulfur species in a single acid gas stream for treatment in the standard Claus unit typically employed for sulfur recovery at oil refineries. In addition, the Rectisol process can remove sulfur to the low levels required to meet specifications of methanation catalysts, and can provide conversion for synthetic natural gas (SNG) production and/or deep removal of  $\text{CO}_2$  for sequestration purposes<sup>13</sup>.

There are, however, a few drawbacks to the Rectisol process. In order to reach the very low operating temperatures, which can be as low as  $-100^{\circ}\text{F}$ , the Rectisol process needs a refrigeration unit that requires auxiliary power. The process is complicated and requires several regeneration vessels in order to both release the acid gases and to facilitate the solvent

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<sup>13</sup> Lurgi AG, The Rectisol Process –

[http://www.lurgi.com/website/fileadmin/pdfs/brochures/Br\\_Rectisol.pdf](http://www.lurgi.com/website/fileadmin/pdfs/brochures/Br_Rectisol.pdf)

regeneration step. Table 2-2 summarizes some of the advantages and disadvantages of the Rectisol AGR process.

The Selexol process, another very well known and widely used technology, was also considered. Selexol is a physical acid gas removal process that uses dimethyl ether (DME) or polyethylene glycol as the solvent. The process favors high pressure operation to treat both natural and synthesis gas streams and subsequently is limited to certain gasification technologies. While the process is effective, there are several limitations that prohibit its use with certain gasification technologies. Gasifiers, yielding higher feed gas COS concentrations, would require the addition of a COS hydrolysis unit, since Selexol does not have the capability to remove COS from the raw syngas stream (See Table 2-3). BTX, paraffins, and olefins dissolve in the Selexol solvent, which can be an additional drawback. Gasification technologies using certain fuel feedstocks that yield elevated concentrations of BTX and paraffins/olefins, will dissolve in the Selexol solvent at H<sub>2</sub>S and CO<sub>2</sub> acid gas levels that are unacceptable for the Sulfur Recovery Unit (SRU) downstream. In addition, the lower operating pressures of some gasifiers (~300 pounds per square inch, PSI, range) are too low for favorable Selexol economics<sup>12</sup>.

Based on these drawbacks, we have excluded Selexol from further consideration for the initial Model Facility. Based on our review, we selected the Rectisol process because of its capability to enable competitive sulfur levels as compared to sulfur constituents found in natural gas, its ability to enable production of SNG, and its capability to enable efficient capture of CO<sub>2</sub>.



**Table 2-2** *Advantages and Disadvantages of the Rectisol Process*

<b>Advantages</b>	<b>Disadvantages</b>
Removes HCN, NH <sub>3</sub> , and BTX in the prewash step	Low operating temperatures (as low as -100 °F) and requires refrigeration system with relatively high auxiliary power load
HCN, NH <sub>3</sub> , and BTX are easily liberated from the solvent, allowing the BTX to be recycled to the gasifier and the solvent to be recycled in the AGR	Relatively complex system with several regeneration vessels to liberate acid gases and regenerate solvent, resulting in relatively high cost
H <sub>2</sub> S and COS are removed in the secondary step in the same absorption vessel and concentrated in a single acid gas stream for treatment in the Claus Unit	
Paraffins and olefins, absorbed along with acid gases, can be liberated from the acid gases and recombined with the sweet syngas product	
Significant Rectisol operating experience with fixed bed gasifiers	
Can remove sulfur to low levels required to meet methanation catalyst specifications	
Provides deep CO <sub>2</sub> removal that is required for SNG production and /or CO <sub>2</sub> sequestration purposes	

**Table 2-3** *Advantages and Disadvantages of the Selexol Process*

<b>Advantages</b>	<b>Disadvantages</b>
Well-known and widely used process	Cannot remove COS, thus requiring addition of a COS hydrolysis unit and reheating the syngas to about 400 °F before introducing it into the hydrolysis unit. Requires additional steam generation and equipment
Typically is a two-column process versus three columns required in the Rectisol process	BTX will dissolve in solvent and the Selexol process does not have a way of removing it separate from the acid gas. Concentrations will be unacceptable to the Claus Unit. BTX can be removed in

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a pretreatment process after washing but would require the addition of at least two columns likely to increase costs significantly

Paraffins and olefins will dissolve in the solvent and contaminate the acid gas going to the Claus Unit, resulting in a low-grade sulfur byproduct

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## 2.2.2 *Potential Fuels, By-products, and Waste*

Several gasifier designs were evaluated to select options that may be suitable for Maryland resources. After review of currently available information, we have selected a fixed-bed slagging gasifier design for the model facility given the broad characteristics of bituminous coal available in Maryland and throughout the Mid-Atlantic region. Fixed-bed designs can gasify a broader range of coals that are mined within the region. The limitations of a fixed-bed design are primarily determined by economics (i.e., oxygen requirements), and not by the capability of the gasifier to gasify the coal. The most typical and economical coal specification range for fixed bed designs have been reviewed and are shown in Table 2-4<sup>12</sup>.

Flux materials, such as limestone, can be mixed with the fuel to flux high ash fusion temperature fuels, resulting in acceptable slag viscosities. The process is required for some fixed-bed gasifier designs that operate at lower temperatures. However, other technologies provide for operations at higher temperatures, enabling ash in the coal to melt and drain by gravity. These designs enable the gasifier to accept higher ash coals. In addition, these designs are also capable of handling a large range of fuel sizes, minimizing coal pre-processing steps.

Other slurry-fed gasifier designs operate over a more restricted fuel envelope. Table 2-4 shows a comparison of the optimum economical fuel envelopes compatible to fixed-bed slagging gasifiers versus entrained-bed or slurry-fed designs. The Maryland coal envelope chosen for the Model Facility has a wide coal ash content ranging between 9.72% and 36.56% and a sulfur content between 3.37% and 6.1% (see Tables 2-1, 2-3). Based on the selected fuel envelope, it was determined that the fixed-bed gasifier design would be better suited for Maryland coal resources.

**Table 2-4 Economic Fuel Envelope for Fixed Bed versus Entrained Bed/Slurry Feed Gasifiers**

Coal Characteristic	Fuel Envelope Range		
	Fixed-Bed/Dry Feed	Entrained-Bed/Slurry Feed	Selected Maryland Coal Envelope**
Moisture (% by weight)*	3-28%	-	-
Ash (% by weight)	0.5-21%	Up to 14%	9.72-36.5%
Sulfur (% by weight)	0.5-5.6%	0.8 to 4%	3.37-6.1%
Chlorine	Up to 0.6%	Up to 2500 ppm (0.25%)	-

\* Coal with up to 40% moisture by weight incurs a higher oxygen consumption penalty and cost.

\*\* Source: Penn State Coal Bank, [www.energy.psu.edu/copl/coal.html](http://www.energy.psu.edu/copl/coal.html)

Given the vast flexibility in gasification technologies and process train design options, an IGCC facility provides for several product options with similar resulting by-products and waste. The main product options and resulting by-products are as follows:

- Syngas (with medium-level heating value);
- Hydrogen;
- Synthetic natural gas (SNG);
- Synthetic hydrocarbons (coal to liquids);
- Sulfur;
- Methanol, ammonia, urea;
- Tars, oils, phenols, and naphtha depending on gasifier technology and operating temperatures;
- Slag; and
- CO<sub>2</sub>.

The primary product of a gasifier system is synthesis gas that can be used as a fuel in syngas capable furnaces, boilers, and gas turbines, or further processed to co-produce hydrogen or SNG. The most common heating

value range of syngas falls between 150 – 350 Btu/scf<sup>14</sup>. We have assumed that Maryland’s Model Facility would produce syngas having a heating value of 340 Btu/scf, which is identical to the syngas produced from the existing Polk Power Generating Station located in Tampa Florida and built in 1996.

Fixed-bed gasifier designs are also known as “slagging” gasifiers, since the slag is a primary by-product from the gasification process. The slag produced from the gasification step, depending on the constituents, can be marketed for beneficial reuse in the concrete industry. Markets for a facility slag by-product are site-specific; however, if there is an absence of local concrete manufacturers near the facility, or a limited amount of major local road construction projects, the slag would likely be disposed of in a non-hazardous landfill. Existing Maryland power plants (such as CP&S’s Brandon Shores Generating Station), supply low-carbon flyash product to the cement manufacturing industry, indicating some form of market availability in Maryland. In addition, the Obama administration seems motivated to promote extensive infrastructure improvement projects as part of the federal economic stimulus package. New beneficial reuse markets for both slag and ash by-products from coal-based power plants in Maryland are expected to emerge from stimulus projects in the construction industry.

CO<sub>2</sub> may also be considered a marketable by-product for enhanced oil recovery, depending on the selected AGR process and facility location. The Rectisol AGR process not only removes sulfur from the syngas, but also removes CO<sub>2</sub>. When syngas production from the gasifier is not shifted with water to convert CO to CO<sub>2</sub> and H<sub>2</sub>, the quantity of CO<sub>2</sub> in the syngas removed by the Rectisol AGR system is quite small<sup>12</sup>. The CO<sub>2</sub> that is removed in the Rectisol system is contained in the offgas of the flash regenerator (a component of the system), and is recombined with the syngas product stream. However, when the syngas is shifted for the production of SNG, the quantity of CO<sub>2</sub> removed in the Rectisol process is significant and may remove the need for further shifting.

If the facility were to be located in the vicinity of an existing oil field and/or a CO<sub>2</sub> transport pipeline, then it may be economical to market the CO<sub>2</sub>, as does the Great Plains Synfuels Plant in North Dakota. The National Petroleum Technology Office and the Bureau of Economic

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<sup>14</sup> GE Energy – IGCC Technology Brochure,  
[http://www.gepower.com/prod\\_serv/products/gas\\_turbines\\_cc/en/igcc/technology.htm](http://www.gepower.com/prod_serv/products/gas_turbines_cc/en/igcc/technology.htm)

Geology have focused on identifying reservoirs within the states of Texas, New Mexico, North Dakota, and California that satisfy established physical and economical criteria for enhanced oil recovery (EOR)<sup>12</sup>. Based on these studies, 125 oil fields in Texas, 25 fields in New Mexico, and 52 fields in California have met such criteria. These sites are thought to have a good rate of return on investment. Public data on CO<sub>2</sub> sequestration options for the eastern states are limited.

Other by-products from the gasification system relate to the level of sulfur species in the fuel source chosen for the facility. Since syngas from the gasifier contains H<sub>2</sub>S and COS, the level of removal in the AGR is typically dictated by both emissions criteria and downstream syngas conversion requirements. The AGR process yields both a cleaned sweet gas (syngas without corrosive components like H<sub>2</sub>S), and a sour gas stream that is further processed to produce elemental sulfur or sulfuric acid depending on market conditions. The most common processing step is to produce elemental sulfur, unless there is a local market for sulfuric acid.

Based on studies performed by DOE's NETL<sup>12</sup>, the two by-products that have the most marketing potential are hydrogen and sulfur.

Hydrogen production in the U.S. has been estimated at approximately 9 million tons (3.6 trillion scf). From the 9 million tons produced, about 1.5 million tons (0.6 trillion scf) are exclusively sold to refineries and chemical plants. In addition, studies show that about 95% of the hydrogen in the U.S. is produced by steam methane reforming (SMR), currently viewed as perhaps the most economical method for production<sup>12</sup>.

Hydrogen is used by refineries across the U.S. to remove organic sulfur from crude oil, as well as to convert heavy crude to lighter, easier to refine, and more marketable products. There are a number of hydro-treating processes in a refinery, including the following<sup>12</sup>:

- **Hydrodesulfurization:** sulfur compounds are hydrogenated to H<sub>2</sub>S as the feed for the common Claus plant that provides for elemental sulfur production;
- **Hydroisomerization:** normal paraffins are converted into iso-paraffins to improve product properties;
- **Dearomatization:** aromatics are hydrogenated to cycloparaffins or alkanes; and
- **Hydrocracking:** long-chain hydrocarbons are cracked to shorter chains that are in the gasoline range.

The demand for hydrogen in the refinery setting is expected to continue to rise, as it has over the past five years, to meet mandates for low-sulfur gasoline and diesel fuel, as well as for processing higher sulfur crudes.

NETL's review of hydrogen market trends and demand data, document the following:

- The demand for hydrogen increased at a rate of about 9.5% per year between 1997 through 2002;
- The hydrogen market has remained strong, and despite the weakened economy, more favorable market conditions are expected to continue. Major industrial gas suppliers such as Air Products and Chemicals Inc (APCI), Praxair, Air Liquide, and BOC Gases have raised prices for hydrogen based on growing demand.
- With the cost of sweet crude oil increasing, refiners are processing more heavy sour crude, which requires additional hydrogen for sulfur removal. Demand for these activities is expected to grow at a rate of 4% per year through 2010 based on new low sulfur diesel requirements.
- While some refiners own and operate their own hydrogen plants, industrial gas companies have seen an increase in their business as refiners view hydrogen as a utility and allow gas companies to build, own and operate such hydrogen plants. This trend is expected to produce double-digit growth in the hydrogen supply sector.
- Aggregate hydrogen consumption has grown about 4% annually over the past several years; however, growth in hydrogen sales by industrial gas suppliers has been higher (at ~10%). In the past, refineries met hydrogen needs with recovered material, or they built, owned, and operated their own hydrogen plants. Refineries are increasingly receptive, due to economic constraints, to buying hydrogen from single and multi-user pipelines owned and operated by industrial gas companies.

Hydrogen use as a transportation fuel and as a fuel for fuel cell power generation is also expected to increase.

NETL also reports that a rule-of-thumb for pipeline hydrogen delivery to refineries is about 1.6 times the price of natural gas on a million Btu basis. Based on this assumption, hydrogen would range from \$11.20/MMBtu to \$22.40/MMBtu for natural gas costing \$7/MMBtu, depending on hydrogen plant capacity and delivery method<sup>12</sup>.

Due to the ability to produce hydrogen from syngas efficiently, the increasing need for hydrogen by refineries, the low price of coal and petcoke as a fuel, and relatively high product value of hydrogen, industrial-size gasification facilities have the potential to be economically attractive in the near future<sup>12</sup>. This assessment does not include the hydrogen fuel demand from other domestic markets that are continuing to develop.

### 2.2.3 *Facility Water Usage*

A significant concern with all power plants licensed in the U.S. and abroad is the quantity of water consumed by the facility. With IGCC facilities, water is required to produce steam for supply to the gasifier unit and subsequent downstream facility processes (e.g., for process cooling, AGR processes, combined cycle steam generation) and for facility wastewater treatment systems. Generally, the water required for the gasification process depends on the type of gasifier and the syngas cleanup requirements that typically define how much syngas cooling is required. Table 2-5 shows the estimated water usage for the Maryland Model Facility.

**Table 2-5** *Estimated Water Requirements for the Maryland Model Facility*

Facility Water Needs	Water Usage		
	gpm	gpm per 100 MMbtu/hr of Syngas Heat Input	gpm/MW of Power Generated
Process Water Makeup	643	34	1.16
Cooling Water Makeup	973	52	1.77
ASU Cooling Water Makeup	106	6	0.2
<b>Process Feed Water Supply</b>			
AGR (Rectisol System)	1	0.06	0.002
Steam System	521	28	0.9
Slag Cooling	123	7	0.24
Subtotal	645	35	1.19
<b>Circulating Water System</b>			
Gasification & Syngas Cooling	13,066	700	23.8
Rectisol	533	29	0.99
Claus unit	870	47	1.6
Wastewater Treatment	98	5	0.17
Combined Cycle CTs	54,322	2,910	98.94
Subtotal	68,890	3,690	125.46

Water requirements proportioned based on NETL Data<sup>12</sup>.

### 2.2.4 *Facility Power Block*

Upon review of available combustion turbine technology options, CO<sub>2</sub> capture options, minimum CO<sub>2</sub> capture levels, and power block reliability implications of high hydrogen rich syngas, we have selected two separate integrated power blocks (Power Blocks A and B shown in Figure 2-1) as a



preferred option. With this option, IGCC technology in Maryland could provide a consistent and reliable source of electric to the state grid. The facility is designed with a minimum CO<sub>2</sub> capture requirement of 45% and diversion of hydrogen produced from the process to an alternative power block (Power Block A). This allows for 50% of the syngas produced from the facility to be diverted to the second power block (Power Block B, fired exclusively by clean syngas). A slip stream, intended for blending with hydrogen produced via the CO<sub>2</sub> shift and recovery step is also incorporated in the design. Powerblock A, as a result, would be fired by a H<sub>2</sub>/syngas blend of approximately 50/50, depending on the final combustion turbine technology.

The air emission sources associated with the Maryland Model facility's power block include two 130-MW General Electric Frame 106FA combustion turbines (CTs) to be operated in combined cycle mode. The CTs would be equipped with heat recovery steam generators (HRSG), equipped with duct burners and arranged in a two-on-one configuration. Steam produced by the HRSGs would be combined and directed to a 20-MW steam turbine. Excess steam would be diverted to the facility gasifier to enhance the energy efficiency of the plant. The facility will have a nominal electric generation capacity of 280 MW.

In the Maryland Model Facility, the power block refers to the main source of electrical power for the plant. The facility's combined cycle configuration would use three electric generators, arranged in a "two-on-one" configuration (see Figure 2-1). One CT would burn exclusively cleaned syngas from a coal-fed gasifier system and would generate electricity directly. A second CT would fire a 50/50 high hydrogen/syngas mixture, with cleaned syngas as backup. This fuel type was selected based on our preferred requirement for the facility to achieve CO<sub>2</sub> capture at a minimum of 45% of the total CO<sub>2</sub> generated. Hot exhaust gas from each of the CTs would be directed to two consecutive HRSGs. Steam produced by both HRSGs would be directed to a single steam turbine which would be connected to the third electric generator (Figure 2-1).

Both CTs would be installed within a single turbine building. The installation will include an inlet air filter, and an inlet evaporative air cooler to reduce inlet air temperature and increase efficiency.

The CTs and duct burners will both be designed with dry low-NO<sub>x</sub> combustors, and low-NO<sub>x</sub> burners. The Model Facility would operate a selective catalytic reduction (SCR) system using aqueous ammonia downstream of the duct burners to control NO<sub>x</sub> emissions.

Pollutants from the facility power block would include:

- Criteria pollutants (NO<sub>x</sub>, SO<sub>x</sub>, CO, VOCs, PM, Pb);
- HAPs/TAPs, including low levels of Hg;
- Ammonia from SCR operation; and
- CO<sub>2</sub>

Estimated emissions from the power block are shown in Table 3-1.

**Table 3-1** *Estimated Annual Criteria Pollutant Emissions from Maryland Model Facility Combined Cycle Power Block*

<b>Pollutant</b>	<b>Power Block A (tpy)</b>	<b>Power Block B (tpy)</b>	<b>Total Emissions (tpy)</b>
NO <sub>x</sub>	46	46	92
SO <sub>2</sub>	10	10	20
CO	49	49	97
VOC	49	49	97
PM	162	162	323

The Maryland Model Facility would also include a 1,000-kilowatt (kW) emergency diesel generator (EDG), one 370-horsepower (hp) emergency firewater pump, and two electric-powered fuel gas heaters for the CTs. The model facility would also incorporate an aqueous ammonia storage tank (approximately 10,000 gallons) for the SCR system.

In addition to the CTs, the other emission sources associated with the Maryland Model Facility are shown in Table 3-2. The facility would require some form of process cooling. We have selected a wet evaporative mechanical draft cooling tower to serve this purpose. The tower would be utilized to support the steam generation system. Particulate matter emissions from cooling tower drift would be the only air-related pollutant of concern during operation of the cooling tower.

There are limited emissions sources to consider for the sulfur recovery system. The sulfur recovery system is designed to process acid gas streams into an elemental sulfur by-product. The resulting tail gas exiting the sulfur recovery system is typically recycled back to the IGCC process. A flare and thermal oxidizer would be used as part of the sulfur recovery process as control devices to provide for the safe and efficient destruction of combustible gas streams. These control devices are utilized intermittently during short-term periods of startup, shutdown, and malfunction operations. A continuous natural gas pilot would be in service on both control systems. A thermal oxidizer would also control emissions from various systems during normal operations, including a sulfur pit vent. The performance of such emission sources requires consideration during the permitting of such facilities.

The remaining air emission sources associated with the Maryland Model Facility include process heaters associated with the gasifier unit for gasifier pre-heating and startup, an auxiliary boiler to provide supplemental steam to the facility during startup and shutdown operations, and fugitive PM sources that would be associated with the facilities material handling activities. For the gasifier pre-heaters, combustion gas from the preheating process would be emitted via a vent located on the gasifier unit.

Table 3-2 lists specifications of the proposed units included in the facility design and Table 3-3 shows the projected power block emission limits representative of current state-of-the-art technology. Since further technology and process specific performance and engineering details are required (i.e., vendor recommendations and specifications for the gasifier, the AGR systems, carbon capture and sequestration units, and combustion turbines, etc.), detailed emissions quantification was not performed for each and every source identified. Due to the fact that most of the processes and components of the Model Facility are proprietary processes or equipment designs, establishing the facility mass and material balance becomes difficult without collaboration with the technology providers and vendors. Therefore, our analysis was generalized to tasks that enable a high-level technology review, and evaluation of both the licensing implications and overall environmental performance of the Model Facility.

By first understanding which facility components are emission sources, we can evaluate the regulatory and licensing constraints of such a facility without performing significant air related impact analysis tasks (emission quantification, modeling, firm regulatory determinations, etc.), which serves the purpose of our initial review of IGCC technology.

Detailed estimates of potential emissions for the sources listed in Table 3-2 require further engineering, vendor specifications, and data which are not available at this time. Rather than performing a detailed emissions analysis on each emission source, an analysis was conducted to evaluate what minimum level of performance should be expected from each process area of the Model Facility. Table 3-3 shows the initial results of our air quality assessment and identifies what we believe would be currently acceptable environmental performance levels for IGCC facilities.

**Table 3-2 Air Emission Sources Comprising the Maryland Model Facility**

Component (Number of Units)	Type/Model	Rated Capacity	Fuel	Projected Operations	Pollutants
Combustion Turbines (2)	GE Frame 106FA	130 MW (nominal)  6,250 Btu/kWh (Heat Rate)	Syngas for Turbine (1)  High H <sub>2</sub> /Syngas Turbine (2) (50/50 mixture)	8,760 hr/yr per CT	NO <sub>x</sub> , SO <sub>x</sub> , CO, VOC, PM,
Duct Burners (2)	GE	-	Syngas	-	
Emergency Diesel Generator	To be determined prior to construction	1,000 kW (~9.42 MMBtu/hr) (1,340 hp)	Diesel fuel	≤200 hours per year	
Firewater Pump Engine	To be determined prior to construction	370 hp (~2.6 MMBtu/hr)	Diesel fuel	≤100 hours per year	
Cooling Tower	Mechanical draft	-	NA	8,760 hr/yr	
Aqueous Ammonia Storage Tank	-	10,000 gallon	NA	-	
Gasifier Preheat Vents	NA	NA	Natural Gas	Startup	
Sulfur Recovery System	Rectisol/Claus Unit	99.8% Sulfur Recovery	NA	8760 hr/yr	
Auxiliary Boiler	-	-	Natural Gas	Startup/Shutd own	
Material Handling	Customized	5,000 ton/day	NA	8760 hr/yr	

**Table 3-3 Preliminary Emissions Performance Levels for the Maryland Model Facility**

Pollutant	Emission Control Option	Emission Performance
<b>Power Blocks A &amp; B</b>		
NO <sub>x</sub>	Low NO <sub>x</sub> Combustor, Low NO <sub>x</sub> Burners, Selective Catalytic Reduction (SCR)	<b>3.0 ppmvd @ 15% O<sub>2</sub></b> , 3-hr rolling avg, <b>10.5 lb/hr (BACT)</b> (Syngas & H <sub>2</sub> /Syngas firing)
SO <sub>x</sub>	Rectisol AGR	Maximum syngas sulfur content <b>0.5 ppmvd</b> , 24-hr rolling avg., excluding periods of SSM; 365-day rolling avg., w/no exclusions  <b>2.3 lb/hr, 0.04 lb/MWh, 0.032 lb/MMBtu (BACT)</b>
CO	Oxidation Catalyst	<b>3.0 ppmvd @ 15% O<sub>2</sub></b> , 3-hr rolling avg, excluding periods of SSM (Syngas & H <sub>2</sub> /Syngas firing), 365-day rolling avg., w/no exclusions  <b>11.1 lb/hr (BACT)</b> (Syngas & H <sub>2</sub> /Syngas firing)
VOC	Oxidation Catalyst	<b>3.0 ppmvd CO @ 15% O<sub>2</sub></b> , 3-hr rolling avg., excluding periods of SSM, 365-day rolling Avg., w/no exclusions (Syngas & H <sub>2</sub> /Syngas firing)  <b>0.0017 lb/MMBtu</b>
PM	Low Sulfur Syngas, H <sub>2</sub> Diluted Low Sulfur Syngas	<b>0.022 lb/MMBtu, (F&amp;C)</b> 3-hr rolling avg., excluding periods of SSM  <b>36.9 lb/hr, 0.009 lb/MMBtu (F) (BACT)</b>

Pollutant	Emission Control Option	Emission Performance
<b>Diesel Engines</b>		
NO <sub>x</sub>	Equipment Design Standard	<p><u>Emergency Generator</u> to meet combined NO<sub>x</sub>, and non-methane hydrocarbon (NMHC) standards for nonroad engines pursuant to §89.112 of NSPS Subpart IIII 40 CFR 60; 6.4 g/kWh pursuant to 40 CFR §60.4205(b) and §60.4202(a)(2)</p> <p><u>Fire Water Pump Engine</u> to meet the combined NO<sub>x</sub> and NMHC standards for nonroad engines pursuant to Table 4 of Subpart IIII; 10.5 g/kWhr for 2007 or earlier model year, or 6.4 g/kWh or otherwise, with compliance using nonroad engine testing procedures set forth in 40 CFR §89.401 to §89.424</p>
SO <sub>x</sub>	Ultra Low-sulfur Diesel Fuel	Maximum sulfur content of 15 ppmvd
CO,VOC	Equipment Design Standard	<p><u>Emergency Generator</u> to meet CO Emission standards for nonroad engines pursuant to §89.112 of NSPS Subpart IIII 40 CFR 60; 3.5 g/kWh pursuant to 40 CFR §60.4205(b) and §60.4202(a)(2).</p> <p><u>Fire Water Pump Engine</u> to meet CO emission standards for nonroad engines pursuant to table 4 of Subpart IIII; 3.5 g/kWhr with compliance using nonroad engine testing procedures set forth in 40 CFR §89.401 to §89.424</p> <p><u>Note:</u> CO limit acts as a surrogate for VOC emission because the control options for both pollutants are the same.</p>
PM	Equipment Design Standard	<p><u>Emergency Generator</u> to meet PM Emission standards for nonroad engines pursuant to §89.112 of NSPS Subpart IIII 40 CFR 60; 0.20 g/kWh pursuant to 40 CFR §60.4205(b) and §60.4202(a)(2).</p> <p><u>Fire Water Pump Engine</u> to meet PM standards for nonroad engines pursuant to Table 4 Subpart IIII; 0.54 g/kWhr for 2007 or earlier model year, or 0.2 g/kWh or otherwise, with compliance using nonroad engine testing procedures set forth in 40 CFR §89.401 to §89.424</p>
<b>Cooling Tower</b>		
PM	Drift Eliminator System	6.38 lb/hr for PM/PM <sub>10</sub> – filterable, 24-hr rolling Avg.

Pollutant	Emission Control Option	Emission Performance
<b>Gasifier Preheat Vents (Process Heaters)</b>		
NO <sub>x</sub> , SO <sub>x</sub> , CO, VOC, PM	Pipeline Quality Natural Gas	-
<b>Sulfur Recovery System, (Flare, Thermal Oxidizer)</b>		
NO <sub>x</sub>	<u>Flare:</u> Natural Gas Pilot Smokeless Flare Design Flame Detection System Auto-Ignition System Maximum Gas Velocity	59.4 lb/hr, 24-hr rolling Avg. (Flare) 8.7 lb/hr, 24-hr rolling Avg. (Thermal Oxidizer)
	<u>Thermal Oxidizer:</u> Natural Gas Pilot Minimum Operating Temperature Low NO <sub>x</sub> Burners	
SO <sub>x</sub>		684.9 lb/hr, 3-hr rolling Avg. (Flare) 150.9 lb/hr, 3-hr rolling Avg. (Thermal Oxidizer)
CO		312.9 lb/hr, 1-hr rolling Avg. (Flare) 7.4 lb/hr, 1-hr rolling Avg. (Thermal Oxidizer)
VOC		0.2 lb/hr, 1-hr rolling Avg. (Flare) 0.5 lb/hr, 1-hr rolling Avg. (Thermal Oxidizer)
PM		0.2 lb/hr, PM10 – filterable, 24-hr rolling Avg. (Flare) 0.7 lb/hr, PM10 – filterable, 24-hr rolling Avg. (Thermal Oxidizer)
<b>Auxiliary Boiler</b>		
NO <sub>x</sub>	Low NO <sub>x</sub> Burners, Flue Gas Recirculation	0.05 lb/MMBtu, 30-day rolling avg.



Pollutant	Emission Control Option	Emission Performance
SO <sub>2</sub>	Low Sulfur Fuel (NG)	0.0007 lb/MMBtu, 30-day rolling avg.
CO	Good Combustion Practices, Use of Clean Fuels (NG)	0.08 lb/MMBtu, 1-hr rolling avg.
VOC	Good Combustion Practices, Use of Clean Fuels (NG)	0.005 lb/MMBtu, 8-hr rolling avg.
PM	Good Combustion Practices, Use of Clean Fuels (NG)	0.0075 lb/MMBtu, PM <sub>10</sub> – filterable, 24-hr rolling avg.
<b>Material Handling</b>		
Fugitive PM	Forced Air Duct Control Systems, Dust Suppression Systems	<p>Periodic observations of fugitive dust sources and implementation of corrective actions (as necessary)</p> <p>Maintain records of inspections and corrective actions to be implemented (as necessary)</p>

## 4.0

### *GENERAL SITING AND LICENSING CONSIDERATIONS IN MARYLAND FOR A NEW IGCC PLANT*

Any new or modified power plant of any kind would be subject to a host of local, state, and federal environmental permitting and regulatory requirements. Table 4-1 lists general requirements for a new power plant in Maryland. Because CO<sub>2</sub> and air emissions were the primary focus of this project, we reviewed in greater detail the general air requirements a new IGCC in Maryland would need to address, but discuss other general requirements as well.

## 4.1

### *GENERAL SITING CONSIDERATIONS*

There would be significantly different siting considerations for a proposed IGCC facility compared to a traditional natural gas-fired combined cycle plant. The report focuses on air issues; however, coal-based gasification facilities must consider a broad range of site-specific characteristics similar to a conventional coal-fired power plant and a petroleum refinery or chemical plant. Some specific siting considerations are:

- Accessibility for coal delivery and ash/slag removal;
- Increased site acreage for the gasification block, coal and limestone receiving, preparation, and storage;
- Increased site acreage for ash/slag effluent storage and disposal, and flare installation;
- Source and availability for high quality water supply;
- Wastewater management;
- By-product management;
- Visual and noise impacts; and
- Other site-specific terrestrial, biological environmental and socioeconomic impacts.

The acreage required for coal storage depends on the sources of fuel, fuel consumption rate required by the specified facility, and the accessibility of the site for truck and/or rail delivery. If the site were fairly close to the coal source, and frequent delivery of coal would not adversely impact local traffic, then the storage area can be limited. Gasification systems that employ fixed bed gasifiers have minimum fuel preparation requirements

and can handle high moisture coals over a broader size range (up to 2 to 4 inches)<sup>12</sup>. Such designs require less site area for fuel preparation relative to gasifier designs which require pulverized or slurry-based coal feed. In addition, when considering particulate matter, limits may require enclosures on coal storage and transfer point locations. Such requirements may increase the facility footprint and also the capital costs.

Gasification facilities also require flaring to oxidize gases from the system during start-up, shut-down, and upset conditions. The type of flare that is incorporated into the design (i.e., elevated or enclosed flares) will have a bearing on the level of visibility from adjacent sites along with site footprint requirements. Elevated flares are the most common, but they can be quite tall (i.e., 150 ft or more) and have significant visual impacts. Elevated flares do not require a large restricted access buffer for personnel around the bases of the flare; however, if visual impacts require the lowering of the flare height, the lower the height the larger the diameter of clear area is required at the base.

Water availability is also a major issue; the amount of water required for gasification processes depends on the type of gasifier and the syngas cleanup requirement (see Table 2-2 for an overview of general water requirements). In addition, makeup water for wet cooling systems can be significant, although air-cooled systems could be employed in areas where water supply is scarcer at a higher capital cost.

## **4.2 AIR PERMITTING AND REGULATORY CONSIDERATIONS**

### **4.2.1 New Source Review: PSD and NA-NSR**

EPA has developed a complex set of regulations that govern construction of new sources and modifications or expansions of existing sources. Collectively, the regulations are referred to as New Source Review (NSR). NSR covers the construction, modification, or reconstruction of certain “major” stationary sources or “major” modifications of existing sources. In attainment areas, the NSR program is known as Prevention of Significant Deterioration (PSD). In nonattainment areas, the NSR program is referred to as Nonattainment Area New Source Review (NA-NSR).

The PSD program applies to new major sources and major modifications to existing sources. Under PSD, a source is “major” if it is one of 28 listed categories of sources with the potential to emit 100 tons or more per year of any air pollutant regulated by the Clean Air Act, or if it is any other type of source with the potential to emit 250 tons per year or more. To

comply with PSD provisions, the applicant must demonstrate during the licensing stage that the project will:

- Employ BACT
- Not cause any violations of any NAAQS or other PSD threshold concentrations known as “increments” and
- Not cause other adverse impacts to visibility, soils, and vegetation.

The set of permitting rules and regulations that applies to new or modified emissions sources in nonattainment areas, areas of the country where NAAQS are not being met, are known as NA-NSR. Restrictions on emissions and control technology requirements under NA-NSR are more stringent than under PSD, because the goal of the NA-NSR rules is to improve the air quality until the NAAQS are met. The goals of the NA-NSR provisions are to be achieved by requiring new and modified “major” sources to help improve air quality when considering new projects by:

- Demonstrating use of the most stringent level of pollution control, Lowest Achievable Emission Rate or LAER,
- Obtaining emissions offsets before operating the new source, and
- Investigating the possible use of alternate sites or technologies for the proposed project.

Because Maryland’s Model Facility is a conceptual facility, we cannot determine whether such a facility would be located in a designated attainment or nonattainment area, and so cannot make any definitive NSR determinations; however, all of Maryland is attainment or unclassifiable for most criteria pollutants (SO<sub>2</sub>, CO, PM, NO<sub>2</sub>, and lead) and parts of the State are nonattainment for ozone and/or PM<sub>2.5</sub>, and it is likely that any project of this size would trigger both PSD and NA-NSR.

As a major source for PSD and NA-NSR, the Maryland Model Facility would be subject to BACT and/or LAER for all pollutants (NO<sub>2</sub>, CO, SO<sub>2</sub>, PM, ozone, H<sub>2</sub>SO<sub>4</sub>) with emissions above significance thresholds. A challenging issue for an IGCC facility in the northeastern U.S. could be control of SO<sub>2</sub> emissions as a fine particulate matter (PM<sub>2.5</sub>) precursor.

#### 4.2.2 *New Source Performance Standards*

The New Source Performance Standards (NSPS) were established under the Clean Air Act Amendments of 1970, relatively early in the history of air quality regulation, in recognition of the fact that newly constructed

sources should be able to operate more “cleanly” than existing, older sources. The NSPS establish the minimum level of control of certain pollutants that specific categories of industrial sources constructed since 1971 must achieve. The emissions limits under NSPS are based on the best technological system of continuous emission reduction available, taking into account costs and other factors of applying the technology.

There are NSPS for several types of generating units. Applicable NSPS provisions, as they relate to the Maryland Model Facility are as follows:

- 40 CFR 60 Subpart A (General Provisions);
- 40 CFR 60 Subpart Da (NSPS for Electric Utility Steam Generating Units) applicable to the Model Facility combustion turbines;
- 40 CFR 60 Subpart Db (NSPS for Industrial-Commercial-Institutional Steam Generating Units) applicable to the Model Facility auxiliary boiler;
- 40 CFR 60 Subpart Y (NSPS for Coal Preparation Plants), directly applicable to the Model Facility material handling and processing activities and equipment; and
- 40 CFR 60 Subpart HHHH (NSPS Emission Guidelines & Compliance Times for Coal-Fired Electric Steam Generating Units) applicable to the CTs if the rule had not been vacated; on February 8, 2008, the D.C. Circuit Court vacated EPA's CAMR removing power plants from the Clean Air Act list of sources of hazardous air pollutants.

By definition, NSPS are the minimum standards that new sources must meet; BACT and LAER are at least as stringent, and are generally much more stringent than BACT for most sources and pollutants.

NSPS Subpart Da was updated on February 27, 2006 (with a final reconsideration published on June 9, 2006) and applies to electric utility steam generating units that are capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel and that commence construction or modifications after September 18, 1978. The updated rule clarifies that IGCC combustion turbines using coal-derived syngas are classified as coal-fired electric generation units and are subject to Subpart Da. Table 4-1 shows Subpart Da requirements that would apply to the proposed combustion turbines.

**Table 4-1** *NSPS Subpart Da Requirements for the Maryland Model Facility Combustion Turbines*

<b>Pollutant</b>	<b>NSPS Emission Limit</b>	<b>NSPS Monitoring Requirements</b>
NO <sub>x</sub>	1.0 lb/MWh (30-day rolling avg.)	Continuous Emissions Monitoring System
SO <sub>2</sub>	1.4 lb/MWh or 95% Reduction (30-day rolling avg.)	Continuous Emissions Monitoring System
Filterable PM	0.14 lb/MWh or 0.015 lb/MMBtu or 0.03 lb/MMBtu & 99.9% Removal	None
Opacity	20% over 6-minute Avg., except one 6-minute period per hour of no more than 27%	None
Mercury (Hg)	0.000020 lb/MWh	Continuous Emissions Monitoring System

NSPS Subpart Db applies to steam generating units with a heat input capacity greater than 29 MW (100 MMBtu/hr) and for which construction is commenced after June 19, 1984. Subpart Db states in 40 CFR 60.40b(i) that units meeting the applicability requirements of Subpart Db and constructed after June 19, 1986 are not subject to subpart D. Table 4-2 shows Subpart Db requirements that would apply to the proposed auxiliary boiler.

**Table 4-2 NSPS Subpart Db Requirements for the Maryland Model Facility Auxiliary Boiler**

Pollutant	NSPS Emission Limit	NSPS Monitoring Requirements
NO <sub>x</sub>	0.20 lb/MMBtu or 2.1 lb/MWh (30-day rolling Avg.)	Fuel Certification
SO <sub>2</sub>	0.20 lb/MMBtu (30-day rolling Avg.)	Fuel Certification
Filterable PM	Likely to be exempt per 40 CFR 60.43b(h)(5)	Fuel Certification
Opacity	Likely to be exempt per 40 CFR 60.43b(h)(5)	None

NSPS Subpart Y applies to coal preparation plants that process more than 200 tons per day. Since the coal handling capacity for the Maryland Model Facility is up to 5,000 tons per day, the coal handling operations would be subject to Subpart Y. The affected source for the proposed project is the coal crushing station, since the coal will require some form of sizing prior to its introduction to the gasifier unit. The only emission limit associated with Subpart Y for this source category is a limit on opacity to 20% or less. Subpart Y also requires that an initial performance test using EPA Reference Method 9 be conducted to demonstrate that the NSPS requirement can be achieved.

NSPS Subpart HHHH would have been EPA’s Clean Air Mercury Rule (CAMR). The Model Facility would be subject to CAMR; however, the rule was vacated on 8 February 2008, although it or a similar HAP regulation for power plants will likely be reinstated eventually. In the CAMR model rule, EPA identified an allowance allocation methodology and set up a national trading program for mercury emissions. States could adopt the model through delegation or incorporation into existing state regulations to participate in the EPA-administered trading program. The market-based cap-and-trade approach would have been implemented in two phases. Phase I reductions would have become effective in 2010, and Phase II beginning in 2018. The rule also specified mercury emissions monitoring, recordkeeping and reporting requirements. As identified in Subpart HHHH, a “unit is defined as a stationary coal-fired boiler or

combustion turbine, while a “mercury budget unit” is defined as “a unit serving at any time.... a generator with a nameplate capacity of more than 25 MW producing electricity for sale.” The IGCC combustion turbines incorporated into the Maryland Model Facility design would meet this definition and would be the mercury budget units associated with the model facility.

Both NSPS Subpart GG and KKKK include provisions clarifying that IGCC process combustion turbines are regulated as a coal-fired utility unit under NSPS Subpart Da, Db, or Dc (based on size); therefore, Subpart GG and Subpart KKKK would not apply to the Maryland Model Facility combustion turbines. The EPA states that stationary combustion turbines at integrated gasification combined-cycle electric utility steam generating units, which are subject to Subpart Da, are exempt from Subpart KKKK; however, combustion turbines fueled by gasified coal and not meeting the heat input requirements of NSPS subpart Da (more than 250 MMBtu/hr), would be covered by the stationary combustion turbine rule (subpart KKKK) under the “other” fuel category.

#### **4.2.3**      *National Emission Standards for Hazardous Air Pollutants*

Section 112 of the CAA addresses the control of HAP emissions and contains provisions for the regulation of these emissions from applicable sources through the National Emission Standards for Hazardous Air Pollutants (NESHAP) program. Provisions in 40 CFR 63 establish NESHAP requirements, including the application of Maximum Achievable Control Technology (MACT) to major sources of HAPs. Major sources of HAPs are defined as sources with the potential to emit greater than 10 tpy of any individual HAP or 25 tpy of any combination of HAPs. Emissions of HAPs from the acid gas recovery system and combustion by-products at IGCC plants would likely be above major source thresholds, requiring implementation of MACT. A detailed HAPs analysis was not completed due to limited available process data.

The NESHAP program identifies specific emission source categories that are to be regulated regardless of potential emissions. On March 29, 2005 the EPA issued a final agency action that delisted electric utility steam generating units from the applicable NESHAP/Section 112 source category list. A final reconsideration of this action was published on June 9, 2006. Instead, EPA decided to regulate coal-fired utility mercury emissions through Section 111 of the Clean Air Act, and so on March 15, 2005, EPA issued the Clean Air Mercury Rule (CAMR) to permanently cap and reduce mercury emissions from coal-fired power plants that established an overall emissions cap but would not have required



individual power plants to be controlled if the cap was met. However, as mentioned previously, in March 2008, the D.C. Circuit vacated EPA's rule that removed power plants from the Clean Air Act list of sources of hazardous air pollutants (Clean Air Act Section 112). The basis of the Court ruling was that coal-fired generating units are listed sources under Section 112, therefore regulation mercury emissions from coal-fired plants under Section 111 (as in CAMR) is prohibited. EPA has since decided to develop emissions standards for power plants under section 112 of Clean Air Act, consistent with the Court's rulings.

CAMR was a cap-and-trade program; the new MACT standards will likely involve source-specific limits. EPA has further indicated that MACT reviews apply to power plants built or reconstructed between March 29, 2005 (the date EPA removed power plants from its list of HAP sources) and March 14, 2008, when the U.S. Court of Appeals for the District of Columbia Circuit issued its CAMR vacature.

Mercury and HAPs will continue to affect any new power plant development and will need to be considered carefully. Until source-specific standards are established, any new major HAP source without an applicable MACT Standard would be subject to "case-by-case MACT" under Section 112(g)(2)(B) of the Clean Air Act.

Other sources at the Model Facility could be subject to other category NESHAP provisions (e.g., Subpart YYYY for combustion turbines, Subpart ZZZZ for stationary reciprocating internal combustion engines, Subpart DDDDD for industrial, commercial, and institutional boilers and process heaters); these sources would need to be designed to meet applicable MACT standards.

#### **4.2.4 Risk Management Program**

EPA's Risk Management Program (RMP) applies to stationary sources that have greater than a threshold quantity of a regulated flammable or toxic chemical on-site. The Model Facility is not expected to have processes containing substances in excess of applicable threshold quantities; however, further evaluations would be needed as the design process progresses. Provided that the aqueous ammonia storage proposed in the Maryland Model Facility to support the SCR system is below a 20% concentration, no RMP requirements would be applicable. Similarly, if aqueous ammonia was chosen at a concentration above 20%, the facility would only trigger RMP if the quantity of ammonia by weight amounted to 20,000 lbs or higher.

#### 4.2.5 *Acid Rain Program (40 CFR Parts 72-76)*

The Maryland Model Facility would meet the definition of an “affected unit” as defined in 40 CFR 72 and would be subject to the requirements of the Acid Rain regulations. The program would be applicable only to the Model Facility combustion turbines and includes the following requirements:

- Submittal of an Acid Rain Permit application 24 months prior to commencing operation;
- Development and implementation of an Acid Rain program compliance plan;
- Annual surrendering of SO<sub>2</sub> allowances for SO<sub>2</sub> emissions from the combustion turbines; and
- Implementation of applicable emission monitoring requirements.

Provisions of 40 CFR 75 establish monitoring requirements, which generally require the installation of continuous emission monitoring systems (CEMS). The proposed combustion turbines would meet monitoring requirements by utilizing flow monitoring and CEMS for SO<sub>2</sub>, NO<sub>x</sub>, and CO<sub>2</sub>. Under 40 CFR 74.14(C), gas-fired units are exempt from opacity monitoring.

#### 4.2.6 *Maryland State Air Requirements*

The project, like any new source, would be subject to a host of State-level air emissions limitations (e.g., PM, CO, fugitive dust, odor, visibility, etc.), operating restrictions (sulfur-in-fuel, etc.), and recordkeeping and reporting requirements. The facility would be designed to meet these requirements, which are generally less stringent than the PSD/NSR, NSPS, and NESHAP provisions to which the facility would be subject.

Increasing concerns over global climate change and national energy security have provided incentives to develop more efficient ways to produce electricity with less impact on the environment. IGCC, although not a new technology, is becoming a potentially viable alternative for power plant developers because of its demonstrated environmental performance, thermal efficiency, and ability to address CO<sub>2</sub> emissions concerns.

IGCC represents an important technology for generating power and producing fuels and other chemical products using coal or other solid fuels such as petroleum coke and biomass as a feedstock. Electricity production using IGCC technology can generate less air pollutants (particularly SO<sub>2</sub>, NO<sub>x</sub>, PM, Hg and CO<sub>2</sub>) than conventional, pulverized coal-fired plants. Pollutant reductions using IGCC technology can be realized even while using lower grade coals like high sulfur eastern bituminous coals found in Maryland. Coal gasification has fundamental environmental advantages over direct coal combustion options.

In this project, PPRP performed a preliminary review of IGCC technology to better understand the current state of the technology, and to evaluate licensing implications and environmental performance for such a technology. To accomplish these goals and understand the licensing implications and environmental parameters, a preferred conceptual facility design for a Maryland IGCC plant was created. This “Maryland Model Facility” outlines general components of an IGCC plant that would be most beneficial, if an IGCC plant were developed in Maryland.

The evaluation suggests that there is potential for IGCC technology to be implemented in the State of Maryland if appropriate State and federal incentives are provided to enable such technology to be cost competitive to natural gas-fired combined cycle facilities. We have identified, through the Maryland Model Facility, some of the design considerations that will enable IGCC technology to be competitive from an environmental perspective and that would enable power produced from the plant to be reliably delivered to the Maryland electric grid. The Maryland Model Facility could be further developed and refined to understand the actual environmental, licensing, siting, and power reliability implications of building an IGCC facility in Maryland.