Permitting and Emissions for Coal-Based IGCC Plants

Extended Abstract # 594 (Session: EI-2c IGCC - Current Developments)

Gary D. Brown
CH2M HILL
9193 South Jamaica St.
Englewood, Colorado 80112

INTRODUCTION

New coal-based power plant projects in the United States are now considering Integrated Gasification Combined Cycle (IGCC) technology as an option for the production of electric power in addition to pulverized coal (PC) and circulating fluid-bed (CFB) technologies. All new IGCC generating units will be required to use state of the art emission controls to meet or exceed current BACT and NSPS requirements. Some of these IGCC plants may also use CO_2 removal and sequestration techniques to reduce greenhouse gas emissions.

Coal Plant Technology Options

There are three primary technology options for a coal-fired power plant:

- Pulverized Coal (PC)
- Circulating Fluid Bed (CFB)
- Integrated Gasification Combined Cycle (IGCC)

PC plants represent the most mature of coal-based power generation technologies. Modern PC plants generally range in size from 80 MW to 1,300 MW and can use coal from various sources. Units operate at close to atmospheric pressure, reducing vessel construction cost, and allowing onsite fabrication of portions of the boilers. Subcritical, supercritical (SCPC) and ultra-supercritical (USCPC) boilers are being constructed for new coal-fired power plants.

Atmospheric CFB designs are available from multiple suppliers. CFBs are designed for the particular coal to be used. The technology is principally of value for low grade, high ash or high moisture coals which may have variable combustion characteristics. It is also suitable for co-firing coal with low grade fuels, including some waste materials. The advantage of fuel flexibility often mentioned in connection with CFB units can be misleading; the combustion portion of the process is inherently more flexible than PC, but material handling systems must be designed to handle larger quantities associated with lower quality fuels. Once the unit is built, it will operate most efficiently with whatever design fuel is specified.

IGCC coal-based power generation uses commercial coal, low rank coal or waste fuels in a reaction with steam and oxygen or air at high temperature and pressure to produce a gaseous mixture consisting primarily of hydrogen and carbon monoxide. The gaseous mixture requires cooling and cleanup to remove contaminants in order to produce a synthesis gas (syngas) suitable for use in the combustion turbine portion of a combined cycle unit. The combined cycle portion of the plant is similar to a conventional combined cycle. The most significant differences in the combined cycle are modifications to the combustion turbine to allow use of a 200 to 400 Btu/SCF gas and use of steam produced in syngas coolers in addition to that from the combustion turbine exhaust (HRSG). Specifics of a plant design are influenced by the gasification process and matching coal supply, degree of heat recovery, and methods to clean up

the gas. An IGCC facility can also be designed for co-production of synthetic liquid fuels such as diesel and naphtha or synthetic natural gas (SNG).

Key IGCC Issues

IGCC technology has the following advantages and disadvantages:

Advantages

- SO_2 & NO_X Emissions (Lb/MMBtu) lower than PC and CFB
- Reduces potential siting problems near Class I areas
- Lower water use than PC
- CO_2 removal and sequestration options may be less costly and have lower impact on plant performance
- May be favored by environmental community over PC technology

Disadvantages

- New technology, 15-40% higher capital cost than PC
- Higher capital cost required for low rank fuels
- Gas turbine output derate as elevation increases
- Maximum 85% availability without a spare gasifier train or backup natural gas for combustion turbines

IGCC Operating/Planned Facilities

The domestic IGCC facilities that are operating, permitted and with pending permit applications are as follows:

Operating

- 262 MW SG Solutions Wabash River Generating Station - 1995 to present
- 250 MW Tampa Electric Company Polk Power Station Unit #1 - 1996 to present

Permits

- 580 MW Global Energy Kentucky Pioneer
- 580 MW Global Energy Lima
- 530 MW Wisconsin Elm Road
- 285 MW OUC/Southern (Draft Permit)

Permit Applications

- 544 MW Steelhead Energy Southern Illinois Clean Energy Center w/95 MMScf/Day SNG
- 630 MW ERORA Cash Creek Generating Station (KY)
- 630 MW ERORA Taylorville Energy Center (IL)
- 629 MW AEP Great Bend (OH)
- 629 MW AEP Mountaineer (WV)
- 600 MW Energy Northwest - Pacific Mountain Energy Center (WA)
- 606 MW Excelsior Energy Mesaba (MN)
- 630 MW Duke Energy Edwardsport (IN)
- 601 MW Tondu - Nueces (TX)

IGCC Emission Sources

An IGCC plant has the potential for reduced emissions of SO_2, NO_X, Hg and particulates compared to levels produced by conventional PC and CFB units. SO_2 removal at levels greater than 98 percent and Hg removal of approximately 90 percent is possible in the syngas treatment system downstream of the gasifier. Particulates will be removed to levels approaching natural gas fired combustion turbines. NO_X emissions from the gas turbines should be similar to emissions from natural gas fired combustion turbines, if SCR is included.

There would be PM_{10} emissions from coal and ash material handling operations. There would also be other sources of air emissions from the IGCC process from the syngas/natural gas-fired auxiliary boiler used to dry the PRB coal; flaring of treated or untreated syngas during plant startups, shutdown and upsets; tank vents; thermal oxidizers; and from miscellaneous support equipment such as diesel or natural gas emergency generators and fire pumps.

The primary IGCC emission sources are as follows:

- IGCC Combustion Turbines
- Flare – Emissions during startup, shutdown and plant upsets
- Thermal Oxidizer
- Tanks Vents
- Auxiliary Boiler
- Emergency Diesel Generator / Fire Water Pump
- Material Handling – Coal, limestone (flux), slag
- Cooling Tower – High Efficiency Mist Eliminators

IGCC Combustion Turbines – SO2 Control Options

The syngas produced in the gasifier is treated to remove H_2S in order to control SO_2 emissions from the gas turbines. The following table shows the results of the syngas treatment BACT Analysis for H_2S removal from the Steelhead SICEC Permit Application.

System	lb/MMBtu SO_2	Capital Cost	Annual Operating Cost	Incremental Cost
MDEA	0.033	$20.2 Million	$2.8 Million	Base
Selexol	0.009	$37.8 Million	$10.2 Million	$20,400/ton
Rectisol	0.0044	$78.3 Million	$14.0 Million	$31,700/ton

Source: Sargent & Lundy/Steelhead Energy 1/21/05 Response to IEPA Request for Additional Information on 12/10/04.

The combustion turbine SO_2 emission limits (lb/MMBtu) from some of the domestic IGCC permits, draft permits and permit applications are as follows:

Permits

- Wisconsin Elm Road – 0.03 / 24-Hr Ave (Amine)
- Kentucky Pioneer – 0.032 / 3-Hr Rolling Ave (Amine)
- Lima Energy – 0.0219 / 12-Month Rolling Ave (Amine)

Draft Permit

- OUC/Southern – 0.0195 / 30-Day Rolling Ave (Amine)

Permit Applications

- Steelhead SICEC – 0.033 / 30-Day Ave (Amine)
- Taylorville EC – 0.0117 / 3-Hr Ave (Selexol)

IGCC Combustion Turbines – NO_X Control Options

The IGCC combustion turbines include controls to limit NOx emissions. The following table shows the results of the NO_X control BACT Analysis from the Steelhead SICEC Permit Application.

System	lb/MMBtu NO_X	Capital Cost	Annual Operating Cost	Incremental Cost
None	0.157	$0	$0	Base
Diluent Injection	0.059	$1.3 Million	$0.4 Million	$270/ton
SCR	0.011	$21.1 Million	$4.3 Million	$6,550/ton

Source: Sargent & Lundy/Steelhead Energy 5/10/05 Response to IEPA Request for Additional Information on 3/23/05.

The syngas sulfur content will have an impact on the operation of an SCR system. The treated syngas could contain from 40-75 ppm H_2S for a high sulfur coal application using an amine gas treatment process. A portion of the SO_2 formed by combustion of residual H_2S in the syngas is oxidized to SO_3 in the combustor and downstream SCR unit. The SO_3 will combine with the ammonia slip from the SCR unit to form ammonium bisulfate which can result in fouling of the heat recovery steam generator (HRSG).

Including an SCR system in the design of an IGCC plant may require Selexol gas treatment of syngas in order to achieve lower syngas sulfur content. There are existing IGCC SCR units in Japan and Italy that use advanced gas treating systems.

The combustion turbine NO_X emission limits (lb/MMBtu) from some of the domestic IGCC permits, draft permits and permit applications are as follows:

Permits

- Wisconsin Elm Rd – 0.07 / 30-Day Rolling Ave (Diluent)
- Kentucky Pioneer – 0.0735 / 3-Hr Rolling Ave (Diluent)

Draft Permit

- OUC/Southern – 20 ppmvd / 30-Day Rolling Ave (Voluntary SCR to achieve 10 ppmvd)

Permit Applications

- Steelhead SICEC – 0.059 / 30-Day Ave (Diluent)
- Taylorville EC – 0.0246 / 24-Hr Ave (Diluent & SCR)

IGCC Combustion Turbines – CO Emission Limits

The combustion turbine CO emission limits (lb/MMBtu) from domestic IGCC permits, draft permits and permit applications are as follows:

Permits

- Wisconsin Elm Road – 0.03 / 24-Hr Ave
- Kentucky Pioneer – 0.032 / 3-Hr Rolling Ave

Draft Permit

- OUC/Southern w/o Duct Burner – 0.050 / 24-Hr Rolling Ave (2-Yr DOE Test w/CO Catalyst to achieve 0.009)

Permit Applications

- Steelhead SICEC – 0.040 / Stack Test
- Taylorville EC – 0.036 / 24-Hr Ave

IGCC vs. SCPC w/CO_2 Sequestration

A comparison of the impact of adding CO_2 capture and sequestration to IGCC versus supercritical pulverized coal (SCPC) technology is shown in the following table.

Parameter	IGCC	SCPC
Net MW (pre-CO_2 Capture)	425	462
Plant Output Derating	14%	29%
Heat Rate Increase	17%	40%
Total Capital Cost Increase	47%	73%
Cost of Electricity Increase	38%	66%
CO_2 Capture Cost ($/Ton)	24	35

Source: "Environmental Footprints and Costs of Coal-Based IGCC and PC Technologies", Final Report, EPA-430/R-06/006, July 2006

IGCC Power Plant Drivers

The key IGCC power plant drivers are as follows:

Environmental

- Lower emissions compared to PC and CFB units
- Reduces potential siting problems near Class I areas
- Lower water use than PC
- CO_2 removal and sequestration options may be available with lower costs and plant impacts than PC
- May be favored by environmental community over PC technology

Government Support

- DOE Clean Coal Power Initiative funding of new IGCC units
- FutureGen program based on IGCC technology

Private Development

- Large utilities initiating development of IGCC projects
- Suppliers developing commercial IGCC technology offerings