IGCC Plants With and Without Carbon Capture and Sequestration

Technology Overview

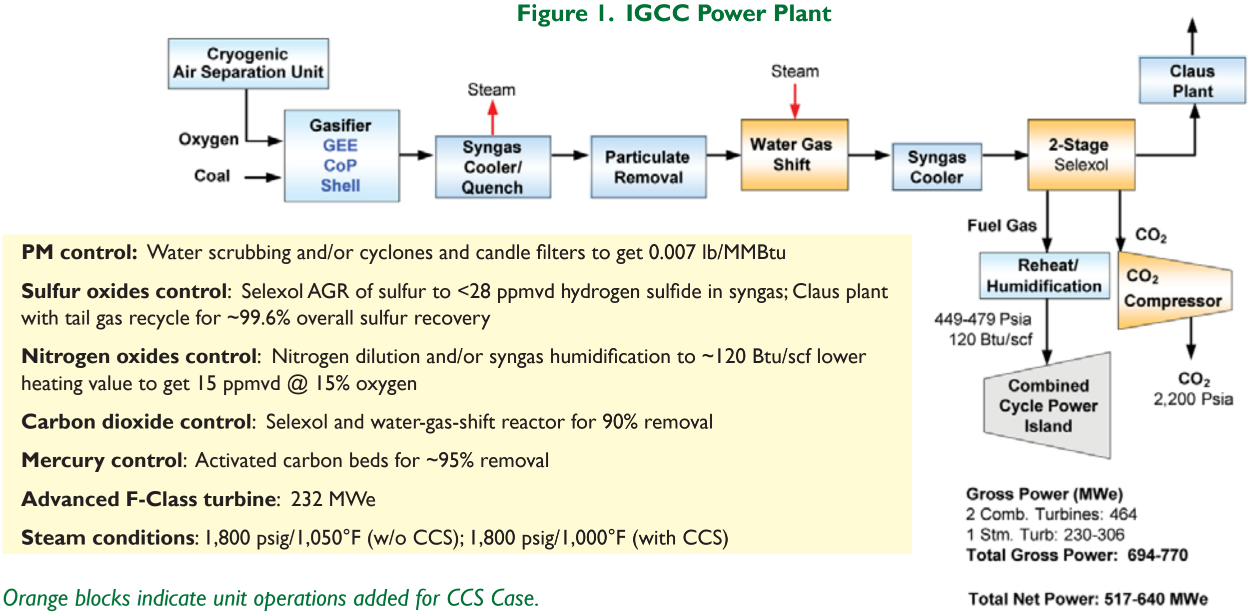
Six Integrated Gasification Combined-Cycle (IGCC) power plant configurations operating on bituminous coal were evaluated and the results are presented in this summary sheet. All cases were analyzed on the same basis, using a consistent set of assumptions and analytical tools. Each gasifier type was assessed with and without carbon capture and sequestration (CCS). The individual configurations are as follows:

- GE Energy (GEE) IGCC plant.
- GEE IGCC plant with CCS.
- ConocoPhillips (CoP) E-Gas™ IGCC plant.
- CoP IGCC plant with CCS.
- Shell IGCC plant.
- Shell IGCC plant with CCS.

Each IGCC design is based on a market-ready technology that is assumed to be commercially available in time to support a 2010 startup date. In cases where equipment or processes have little or no commercial operating experience, a process contingency was added to the cost analysis. The IGCC plants are built at a greenfield site in the midwestern United States and are assumed to operate at 80 percent capacity factor (CF) without sparing of major train components. Nominal plant size (gross rating) is 750 MWe without CCS and 700 MWe with CCS. All designs employ state-of-the-art gasifier technology. The primary fuel is an Illinois No. 6 bituminous coal with a higher heating value (HHV) of 11,666 Btu/lb. Syngas generated in the oxygen (O_2)-blown gasifier is cooled and cleaned prior to being fed to two advanced F-Class combustion turbines. The Brayton cycle is combined with two heat recovery steam generators (HRSGs) and a steam turbine for Rankine cycle power generation. For the CCS cases, a water-gas-shift (WGS) reactor converts carbon monoxide (CO) to carbon dioxide (CO_2), and a two-stage Selexol Acid Gas Removal (AGR) unit separates the hydrogen sulfide and CO_2. After compression, the CO_2 is transported for storage and monitoring.

See Figure 1 for a generic block flow diagram of an IGCC plant. The orange blocks in the figure represent the unit operations added to the configuration for CCS cases.

Figure 1. IGCC Power Plant



Orange blocks indicate unit operations added for CCS Case.

Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

Oxygen-blown, dual-gasifier trains are supplied with Illinois No. 6 bituminous coal. Cryogenic air separation units supply 95 mole percent oxygen to the gasifiers. After being cleaned of particulate matter (PM), mercury (Hg), and sulfur compounds, the syngas is fed to two combustion turbines. The combustion turbines are based on an advanced F-Class design that generates 232 MWe on syngas. With two combustion turbines, the combined gross gas turbine output is 464 MWe.

Nitrogen dilution is used to the maximum extent possible in all cases, and syngas humidification and steam injection are used only if necessary to achieve a syngas lower heating value (LHV) of approximately 120 Btu/scf. The Brayton cycle is integrated with a conventional subcritical steam Rankine cycle consisting of two HRSGs and a steam turbine, operating at 12.4 MPa/566°C/566°C (1,800 psig/1,050°F/1,050°F) in cases without CCS. The two cycles are integrated by use of the combustion turbine exhaust heat for generation of steam in the HRSGs, by feedwater heating in the HRSGs, and by heat recovery from the IGCC process. Recirculating evaporative cooling systems are used for cycle heat rejection. The average efficiency of the cases without CCS is 39.5 percent HHV for a plant with a nominal gross rating of 750 MWe.

The CCS cases require a significant amount of auxiliary power and extraction steam for the process, which reduces the output of the steam turbine in those cases due to a reduction in steam conditions to 12.4 MPa/538 °C/538°C (1,800 psig/1,000°F/1,000°F). The lower main and reheat steam temperature is due to reduced turbine firing temperature. Although the reduced firing temperature allows for more reliable operation with a high-hydrogen content fuel, it also results in a lower turbine exhaust temperature. This results in a lower nominal gross plant output for the CCS cases of about 700 MWe, for an average net plant efficiency of 32 percent (HHV basis).

The nominal 90 percent CO_2 reduction is accomplished by adding sour-gas-shift (SGS) reactors to convert CO to CO_2 and using a two-stage Selexol process with a second stage CO_2 removal efficiency of up to 95 percent, a number that was supported by vendor quotes. In the GEE CO_2 capture case, two stages of SGS and a Selexol removal efficiency of 92 percent were required, which resulted in 90.2 percent reduction of CO_2 in the syngas. The CoP capture case required three stages of SGS and 95 percent capture in the Selexol process, which resulted in 88.4 percent reduction of CO_2 in the syngas. In the CoP case, the capture target of 90 percent could not be achieved because of the high syngas methane content (3.5 volume percent (vol%) compared to 0.10 vol% in the GEE gasifier and 0.04 vol% in the Shell gasifier). The Shell capture case required two stages of SGS and 95 percent capture in the Selexol process, which resulted in 90.8 percent reduction of CO_2 in the syngas.

Once captured, the CO_2 is dried and compressed to 15.3 MPa (2,215 psia). The compressed CO_2 is transported via pipeline to a geologic sequestration field for injection into a saline aquifer, which is located within 50 miles of the plant. Therefore, CO_2 transport, storage, and monitoring costs are included in the analyses.

Fuel Analysis and Costs

All IGCC coal-fired cases were modeled using Illinois No. 6 coal, characterized by the proximate analysis shown in Table 1.

Table 1. Fuel Analysis

Rank	Bituminous	
Seam	Illinois No. 6 (Herrin)	
Source	Old Ben Mine	
Proximate Analysis (weight %)[1]		
	As Received	Dry
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile matter	34.99	39.37
Fixed carbon	44.19	49.72
Total	**100.00**	**100.00**
Sulfur	2.51	2.82
Higher heating value, Btu/lb	11,666	13,126
Lower heating value, Btu/lb	11,252	12,712

[1]The above proximate analysis assumes sulfur as a volatile matter.

A cost of $1.80/MMBtu (January 2007 dollars) was determined from the Energy Information Administration AEO2007 for an eastern interior high-sulfur bituminous coal.

Environmental Design Basis

The environmental approach for this study was to evaluate each of the IGCC cases on the same regulatory design basis. The environmental specifications for a greenfield IGCC plant are based on the Electric Power Research Institute (EPRI) *CoalFleet User Design Basis for Coal-Based IGCC Plants* specification. Table 2 provides details of the environmental design basis for IGCC plants built at a midwestern location. The emission controls assumed for each of the six IGCC cases are as follows:

Table 2. Environmental Targets

Pollutant	IGCC
SO_2	0.0128 lb/MMBtu
NOx	15 ppmvd @ 15% Oxygen
PM (filterable)	0.0071 lb/MMBtu
Hg	>90% capture

- Selexol, Sulfinol-M, or refrigerated methyldiethanolamine AGR in combination with a Claus plant are used for sulfur dioxide (SO_2) control in the GEE, Shell, and CoP cases without CCS, respectively.
- A two-stage Selexol process was used for AGR and CO_2 control in all CCS cases.
- Nitrogen dilution is used for nitrogen oxides (NOx) control to the maximum extent possible, and humidification and steam injection are used to obtain the required syngas heating value, if required.
- Water scrubbing and/or cyclones and candle filters were used for PM control.
- Activated carbon beds were used for Hg removal.

Major Economic and Financial Assumptions

For the IGCC cases, estimates of capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates were developed for each plant based on adjusted vendor-furnished and actual cost data from recent design/build projects. These costs resulted in determination of a revenue requirement for a 20-year LCOE based on the power plant costs and assumed financing structure. Listed in Table 3 are the major economic and financial assumptions for the IGCC cases.

Table 3. Major Economic and Financial Assumptions for IGCC Cases

Major Economic Assumptions	
Capacity factor	80%
Costs per year, constant U.S. dollars	2007 (January)
Illinois No. 6 coal delivered cost	$1.80/MMBtu
Construction period	3 years
Plant startup date	2010 (January)
Major Financial Assumptions	
Depreciation	20 years
Federal income tax	34%
State income tax	6%
After tax weighted cost of capital	9.67%
Capital structure:	
Common equity Debt	55% (Cost = 12%) 45% (Cost = 11%)
Capital charge factor	17.5%

Project contingencies were added to each of the cases to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was an average of 13.4 percent for the IGCC cases without CCS and an average of 13.8 percent for the IGCC cases with CCS.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies have been applied to the estimates as follows:

- Slurry Prep and Feed – 5 percent on GE IGCC cases.
- Gasifiers and Syngas Coolers – 15 percent on all IGCC cases.
- Two Stage Selexol – 20 percent on all IGCC cases with CCS.
- Mercury Removal – 5 percent on all IGCC cases.

- Combustion Turbine Generator – 5 percent on all IGCC cases without CCS; 10 percent on all IGCC cases with CCS.
- Instrumentation and Controls – 5 percent on all IGCC cases.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 80 percent for IGCC cases. The assumed capacity factor for IGCC is 80 percent.

For the IGCC cases that feature CCS, capital and operating costs were estimated for transporting CO_2 to an underground storage field, associated storage in a saline aquifer, and for monitoring beyond the expected life of the plant. These costs were then levelized over a 20-year period.

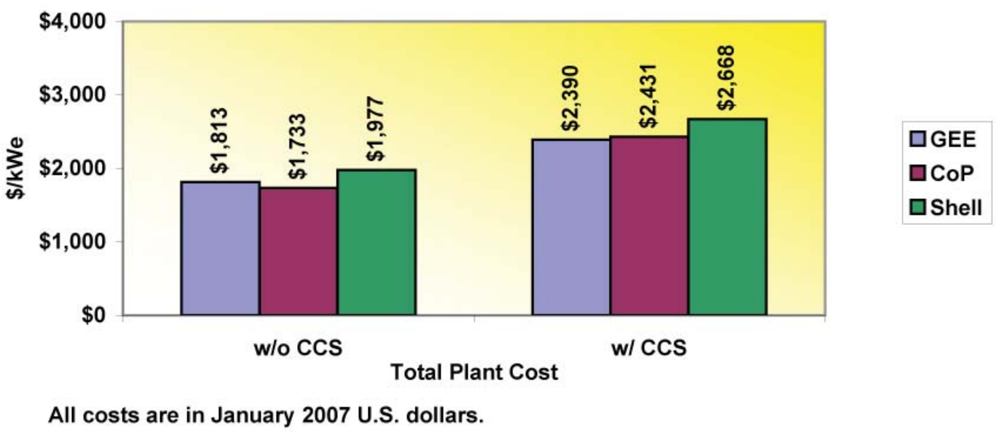
Results

An analysis of the six IGCC cases is presented in the following subsections.

Capital Cost

The total plant cost (TPC) for each of the six IGCC cases is compared in Figure 2. The TPC includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

Figure 2. Comparison of TPC for the Six IGCC Cases



The results of the analysis indicate that the Shell IGCC costs about $244/kWe more than the CoP IGCC without CCS. With CCS, the TPC increases by roughly 32–40 percent for the range of IGCC cases, resulting in a spread of capital costs from $2,390/kWe to $2,668/kWe. The Shell IGCC still remains the highest capital cost configuration.

Efficiency

The net plant HHV efficiencies for the six IGCC cases are compared in Figure 3. This analysis indicates that, in the cases without CCS, the Shell plant efficiency of 41.1 percent HHV is almost 3 percentage points higher than the GEE case. With CCS cases, the efficiency penalty is a 5.7 to 9 percentage point HHV drop in all IGCC plant cases, resulting in an average efficiency of roughly 32 percent HHV.

Figure 3. Comparison of Net Plant Efficiency for the Six IGCC Cases

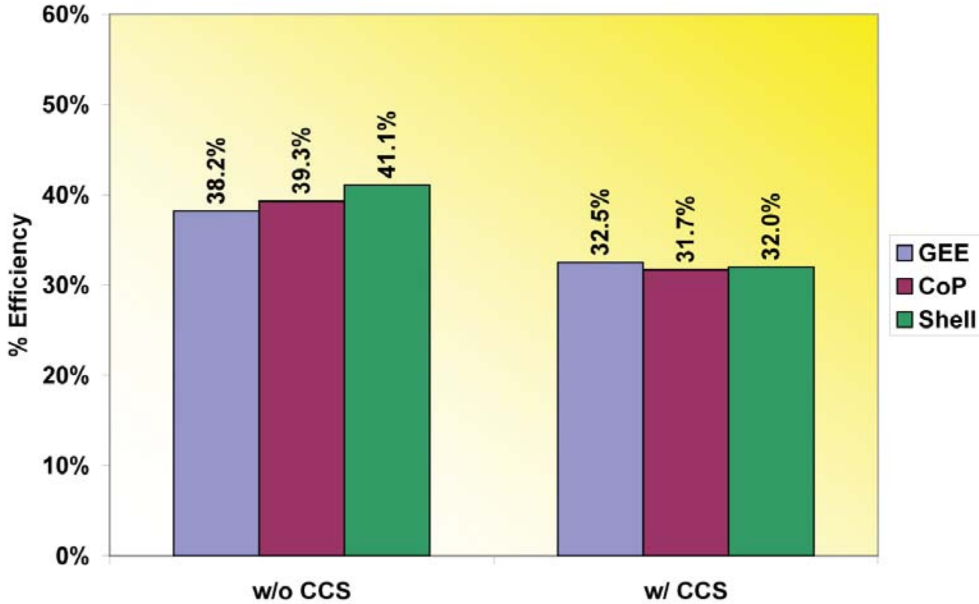
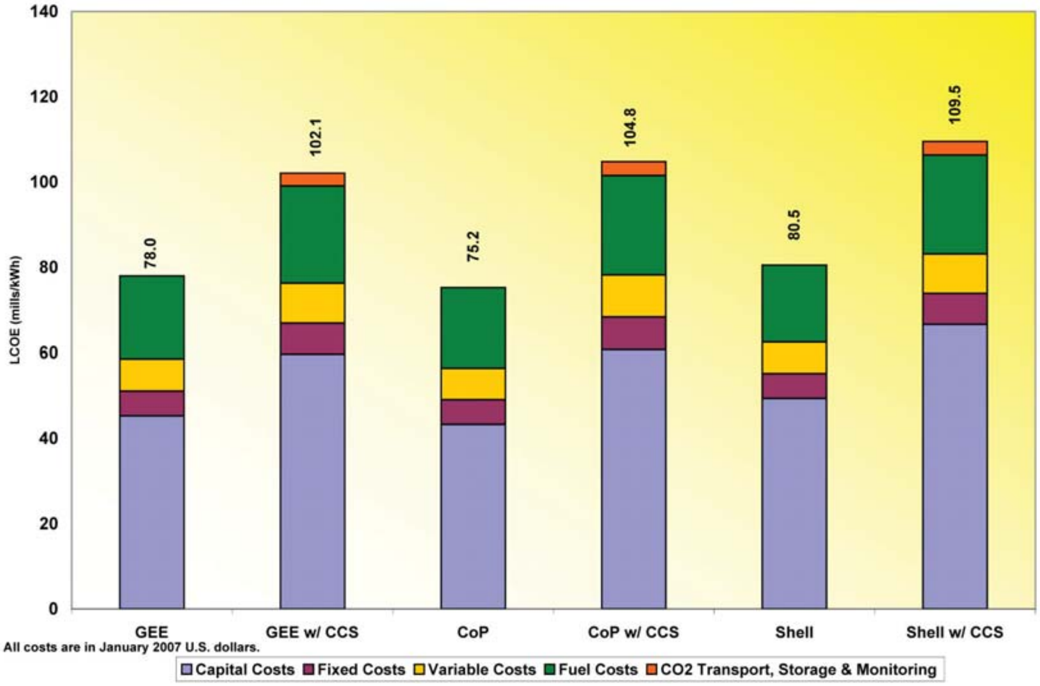


Figure 4. Comparison of Levelized Cost-of-Electricity for the Six IGCC Cases



The LCOE is a measurement of the coal-to-busbar cost of power, and includes the TPC, fixed and variable operating costs, and fuel costs levelized over a 20-year period. The calculated cost of transport, storage, and monitoring for CO_2 is about $4.30/short ton, which adds an average of 4 mills to the LCOE.

The IGCC plants generate power at an LCOE of about 78 mills/kWh at a CF of 80 percent. When CCS is included, the increased TPC and reduced efficiency result in a higher LCOE of roughly 106 mills/kWh.

Environmental Impacts

Table 4 indicates that the emissions from all six IGCC plants evaluated meet or exceed EPRI's *CoalFleet User Design Basis for Coal-Based IGCC Plants* specification. Carbon dioxide emissions are reduced by 90 percent in the capture cases, resulting in less than 460,000 tons/year of CO_2 emissions. The cost of CO_2 avoided is defined as the difference in the 20-year LCOE between controlled and uncontrolled like cases, divided by the difference in CO_2 emissions in kg/MWh. In these analyses, the cost of CO_2 avoided ranges from $32/ton to $42/ton. Raw water usage in both cases with and without CCS is roughly 4,000 gpm.

Table 4. Comparative Emissions for the Six IGCC Cases @ 80% Capacity Factor

Pollutant	IGCC					
	GEE		CoP		Shell	
	Without CCS	With CCS (90%)	Without CCS	With CCS (90%)	Without CCS	With CCS (90%)
CO_2						
• tons/year	3,937,728	401,124	3,777,815	460,175	3,693,990	361,056
• lb/MMBtu	197	19.6	199	23.6	200	18.7
• cost of CO_2 avoided ($/ton)	---	32	---	41	---	42
SO_2						
• tons/year	254	196	237	167	230	204
• lb/MMBtu	0.0127	0.0096	0.0125	0.0085	0.0124	0.0105
NOx						
• tons/year	1,096	955	1,126	972	1,082	944
• lb/MMBtu	0.055	0.047	0.059	0.050	0.058	0.049
PM						
• tons/year	142	145	135	139	131	137
• lb/MMBtu	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071
Hg						
• tons/year	0.011	0.012	0.011	0.011	0.011	0.011
• lb/TBtu	0.571	0.571	0.571	0.571	0.571	0.571
Raw water usage, gpm	4,003	4,579	3,757	4,135	3,792	4,563

Contacts

Julianne M. Klara
Senior Analyst
National Energy Technology Laboratory
626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236
412-386-6089
julianne.klara@netl.doe.gov

John G. Wimer
Systems Analysis Team Lead
National Energy Technology Laboratory
3610 Collins Ferry Road
P. O. Box 880
Morgantown, WV 26507
304-285-4124
john.wimer@netl.doe.gov

Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.
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