GE Energy IGCC Plant With Carbon Capture & Sequestration

Plant Overview

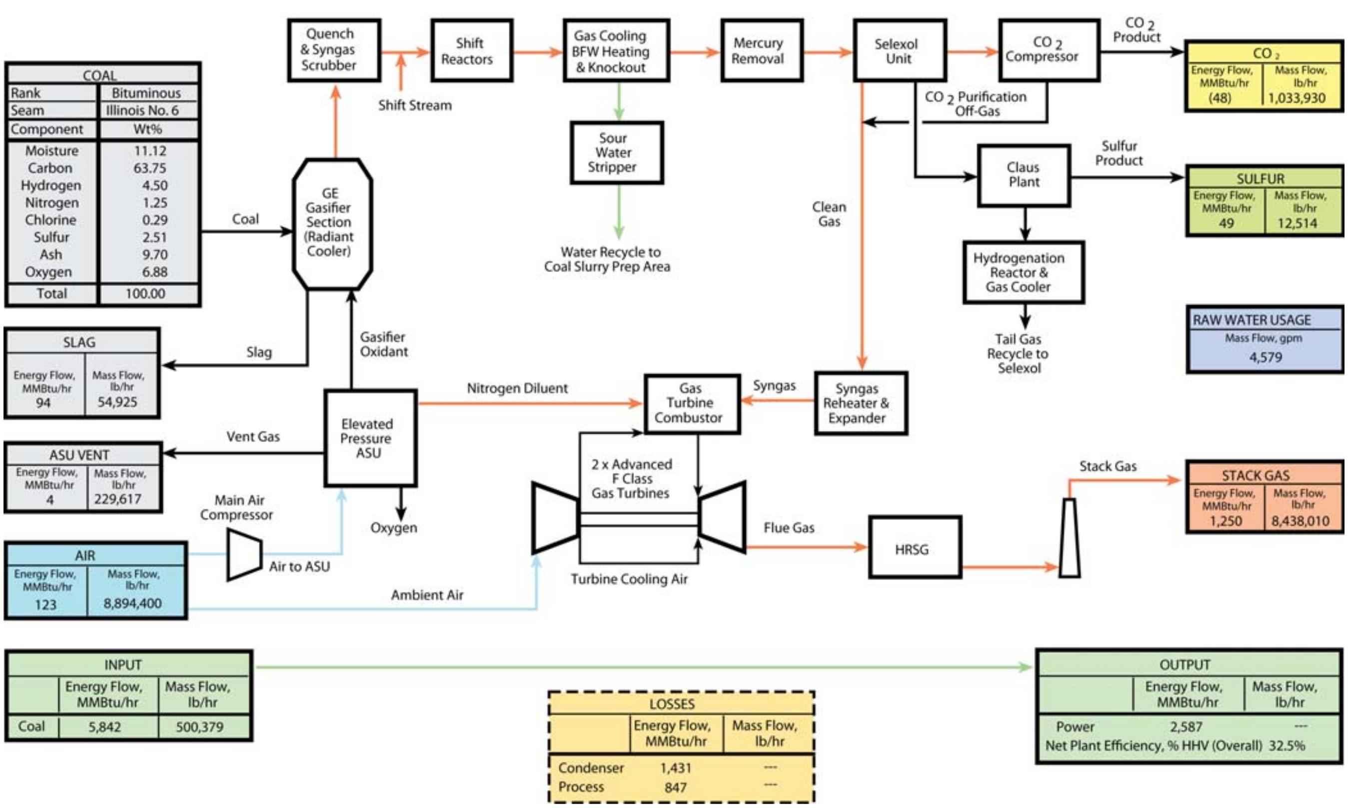
This analysis is based on a 556 MWe (net power output) Integrated Gasification Combined-Cycle (IGCC) plant, using GE Energy (GEE) radiant-only gasification technology, located at a greenfield site in the midwestern United States. The plant utilizes carbon capture and sequestration (CCS). Two pressurized, slurry-fed, entrained-flow gasification trains, utilizing water-gas–shift (WGS) reactors, feed two advanced F-Class combustion turbines. Two heat recovery steam generators (HRSGs) and one steam turbine provide additional power. Carbon dioxide (CO_2) is removed with the two-stage Selexol physical solvent process. The combination process and heat and mass balance diagram for the GEE IGCC plant with CCS case is shown in Figure 1. The primary fuel is an Illinois No. 6 bituminous coal with an assumed higher heating value (HHV) of 11,666 Btu/lb. The capacity factor (CF) for the plant is 80 percent without sparing of major train components. A summary of plant performance data for the GEE IGCC plant with CCS case is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	GEE IGCC
Carbon capture	Yes
Net power output (kWe)	555,675
Net plant HHV efficiency (%)	32.5
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 80% capacity factor	102.9
Total plant cost ($ x 1,000)	$1,328,209
Cost of CO_2 avoided[1] ($/ton)	32

[1]The cost of CO_2 avoided is defined as the difference in the 20-year levelized cost-of-electricity between controlled and uncontrolled like cases, divided by the difference in CO_2 emissions in kg/MWh.

Figure 1. Process Flow Diagram
GEE IGCC with CCS



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

Technical Description

The plant uses an improved version of the GEE gasification technology (formerly licensed by Chevron Corp. and predecessor company Texaco Inc.), which is currently in operation at the 250 MWe Tampa Electric IGCC plant in Polk County, FL. All technology selected for the plant design is assumed to be available to facilitate a 2010 startup date for a newly constructed plant. A summary of performance for the advanced F-Class combustion turbine for the GEE IGCC plant with CCS is presented in Table 2.

Table 2. Advanced Gas Turbine Performance[1]

	Advanced F-Class
Net output, MWe	185
Pressure ratio	18.5
Airflow, kg/s (lb/s)	431 (950)
Firing temperature, °C (°F)	>1,371 (>2,500)

[1]At International Standards Organization conditions firing natural gas. Performance information for syngas firing is not available.

Two gasification trains process a total of 6,005 tons of coal per day. A slurry (63 percent by weight coal) is transferred from the slurry storage tank to the gasifier with a high-pressure pump. Oxygen (O_2) is produced in a cryogenic air separation unit. The coal slurry and O_2 react in the gasifier at about 5.6 MPa (815 psia) at a high temperature (in excess of 1,316°C [2,400°F]) to produce syngas. Hot syngas and molten solids from the reactor flow downward into a radiant heat exchanger, where the syngas is cooled to 593°C (1,100°F) and the ash solidifies. Raw syngas continues downward into a quench system where most of the particulate matter (PM) is removed and then into the syngas scrubber where most of the remaining entrained solids are removed along with halogens and ammonia. Slag captured by the quench system is recovered in a slag recovery unit. The gas goes through a series of additional gas coolers and cleanup processes, including a carbon bed for mercury (Hg) removal.

To capture CO_2, a WGS reactor containing a series of two shifts with intercooled stages converts a nominal 96 percent of the carbon monoxide to CO_2. Carbon dioxide is removed from the cool, particulate-free gas stream with Selexol solvent. The dual-absorber Selexol acid gas removal (AGR) process preferentially removes hydrogen sulfide (H_2S) as a product stream, leaving CO_2 as a separate product stream. The CO_2 is dried and compressed to 15.3 MPa (2,215 psia) for subsequent pipeline transport. 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.

Table 3. Plant Electrical Generation

	Electrical Summary
Advanced gas turbine x 2, MWe	464.0
HRSG steam turbine, MWe	274.7
Sweet gas expander, MWe	6.3
Gross power output, MWe	745.0
Auxiliary power requirement, MWe	(189.3)
Net power output, MWe	555.7

A Brayton cycle, fueled by the syngas, is used in conjunction with a conventional subcritical steam Rankine cycle for combined-cycle power generation. The limiting factor that determines the use of a subcritical steam cycle is the maximum design pressure of 12.4 MPa (1,800 psig), which can be tolerated in the GEE radiant cooler. The two cycles are integrated by generation of steam in the HRSGs, by feedwater heating in the HRSGs, and by heat recovery from the IGCC process (radiant syngas cooler). The HRSG/steam turbine cycle is 12.4 MPa/538°C/538°C (1,800 psig/1,000°F/1,000°F). The plant produces a net output of 555.7 MWe. The summary of plant electrical generation performance is presented in Table 3. This configuration results in a net plant efficiency of 32.5 percent (HHV basis), or a net plant HHV heat rate of 10,505 Btu/kWh.

Environmental Performance

The environmental specifications for a greenfield IGCC plant are based on the Electric Power Research Institute *CoalFleet User Design Basis for Coal-Based IGCC Plants* specification. Low sulfur dioxide (SO_2) emissions (3 ppm in the flue gas) are achieved by capture of the sulfur in the Selexol AGR process, which removes 99 percent of the sulfur in the fuel gas. The resulting H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. Nitrogen oxides (NOx) emissions are limited by nitrogen dilution in the gas turbine combustor to 15 ppmvd (as nitrogen oxide at 15 percent O_2). Particulate discharge to the atmosphere is limited by the use of the syngas quench in addition to the syngas scrubber and the gas-washing effect of the AGR absorber. Ninety-five percent of the Hg is captured from the syngas by an activated carbon bed. Ninety percent of the CO_2 from the syngas is captured in the AGR system and compressed for pipeline transport and sequestration.

A summary of the resulting air emissions for the GEE IGCC plant with CCS is presented in Table 4.

Table 4. Air Emissions Summary @ 80% Capacity Factor

Pollutant	GEE IGCC with CCS (90%)
CO_2	
• tons/year	401,124
• lb/MMBtu	19.6
• cost of CO_2 avoided ($/ton)	32
SO_2	
• tons/year	196
• lb/MMBtu	0.0096
NOx	
• tons/year	955
• lb/MMBtu	0.047
PM (filterable)	
• tons/year	145
• lb/MMBtu	0.0071
Hg	
• tons/year	0.012
• lb/TBtu	0.571

Cost Estimation

Plant size, primary/secondary fuel type, design/construction time, total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date were used as inputs to develop capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates. Costs for the plant were based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table 5.

Project contingencies were added to each case 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 13.6 percent of the GEE IGCC with CCS case TPC.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies represent 4.2 percent of the GEE IGCC with CCS case TPC and 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 CCS cases.
- Mercury Removal – 5 percent on all IGCC cases.
- Combustion Turbine Generator – 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 calculated cost of transport, storage, and monitoring for CO_2 is $4.20/short ton, which adds 3.9 mills/kWh to the LCOE.

The 556 MWe (net) GEE IGCC plant with CCS was projected to have a TPC of $2,390/kWe, resulting in a 20-year LCOE of 102.9 mills/kWh.

Table 5. Major Financial Assumptions and Resulting Cost Summary[1]

Major Assumptions					
Case:	1x556 MWe net GEE IGCC with CCS				
Plant Size:	555.7	(MWe, net)	Heat Rate:	10,505	(Btu/kWh)
Primary/Secondary Fuel (type):	Illinois #6 Coal		Fuel Cost:	1.80	($/MMBtu)
Construction Duration:	3	(years)	Plant Life:	30	(years)
Total Plant Cost[2] Year:	2007	(January)	Plant in Service:	2010	(January)
Capacity Factor:	80	(%)	Capital Charge Factor:	17.5	(%)
Resulting Capital Investment (Levelized 2007 dollars)					**Mills/kWh**
Total Plant Cost					59.7
Resulting Operating Costs (Levelized 2007 dollars)[3]					**Mills/kWh**
Fixed Operating Cost					7.2
Variable Operating Cost					9.4
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu					**Mills/kWh**
					22.8
Resulting Levelized CO_2 Cost (2007 dollars)					**Mills/kWh**
					3.9
Total Levelized Busbar Cost of Power (2007 dollars)					**Mills/kWh**
					102.9

[1]Costs shown can vary ± 30%.

[2]Total plant cost 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.

[3]No credit taken for by-product sales.

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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