Shell IGCC Plant With Carbon Capture & Sequestration

Plant Overview

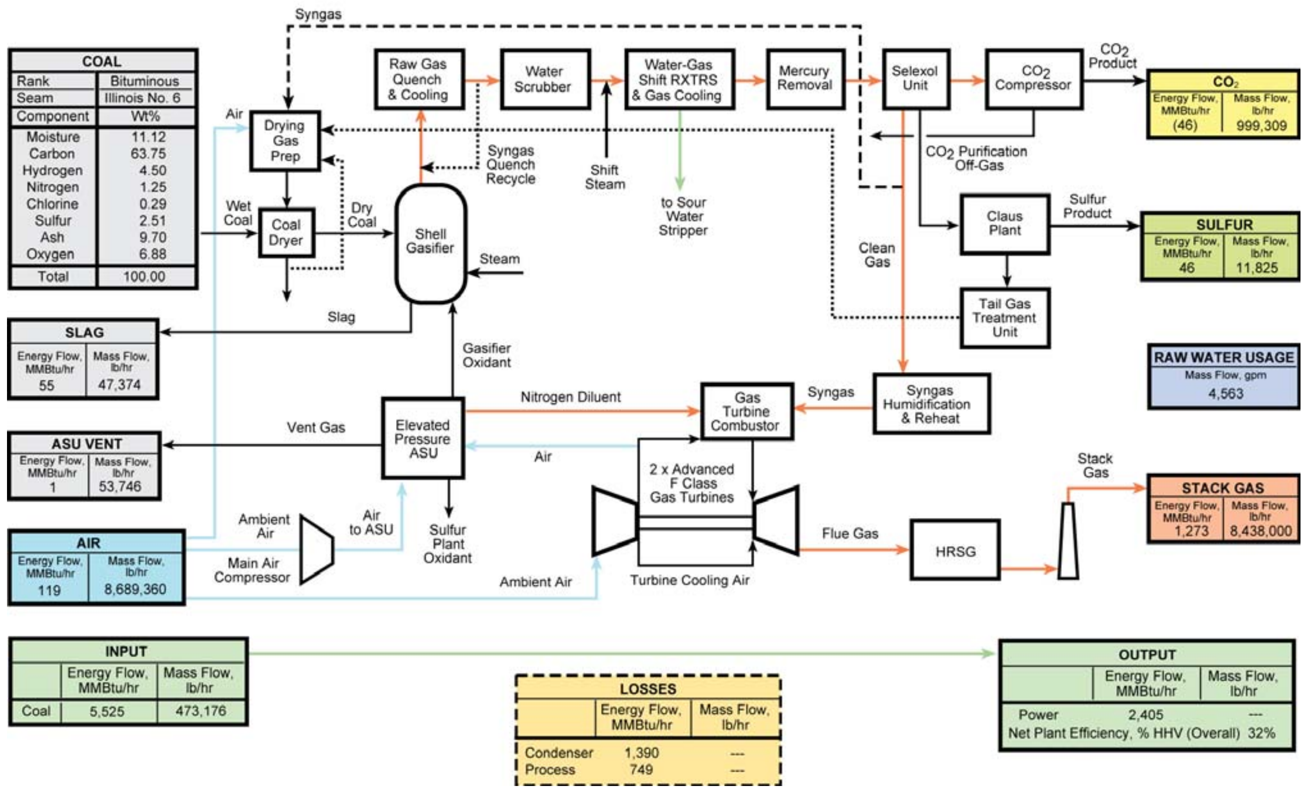
This analysis is based on a 517 MWe (net power output) Integrated Gasification Combined-Cycle (IGCC) plant using Shell Global Solutions gasification technology located at a greenfield site in the midwestern United States. The plant utilizes carbon capture and sequestration (CCS). Two pressurized, dry-feed, entrained–flow gasification trains feed two advanced F-Class combustion turbines. A quench reactor is utilized to provide a portion of the water required for the water gas shift. 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 Shell IGCC plant with CCS is shown in Figure 1. The primary fuel is an Illinois No. 6 bituminous coal with a 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 Shell IGCC plant with CCS is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	Shell IGCC
Carbon capture	Yes
Gross power output (kWe)	517,135
Net plant HHV efficiency (%)	32.0
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 80% capacity factor	110.4
Total plant cost ($ x 1,000)	$1,379,524
Cost of CO_2 avoided[1] ($/ton)	42

[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
Shell 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 the Shell gasification technology. All technology selected for the plant design is assumed to be available to facilitate a 2010 startup date for a newly constructed plant. However, because certain processes like the combustion turbine operating on a high-hydrogen content syngas and the two-stage Selexol process for CO_2 capture either have no commercial or limited commercial operating experience, a process contingency was included in this case. A summary of performance for the Advanced Gas Turbine for the Shell 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 5,678 tons of coal per day. Dry coal is introduced to the gasifier via lockhoppers. Oxygen (O_2) is produced in a cryogenic air separation unit. Coal, steam, and O_2 react in the gasifier at about 4.2 MPa (615 psia) at a temperature of 1,427°C (2,600°F) to produce syngas. The gas from the gasifier is quenched to 399°C (750°F) with water to provide a portion of the water required for water-gas-shift (WGS) reactions. The syngas passes through a cyclone and a raw gas candle filter where a majority of the fine particles are removed. The ash that is not carried out with the gas forms slag and runs down the interior walls, exiting the gasifier in liquid form.

The raw syngas is cooled to 260°C (500°F) and then enters a scrubber for removal of chlorides and remaining particulate matter (PM). Following the scrubber, the raw syngas is reheated to 285°C (545°F) and fed through two sour gas shift reactors for converting carbon monoxide (CO) to CO_2 and also hydrolyzing Carbonyl Sulfide (COS), eliminating the need for a separate COS hydrolysis reactor. The syngas is then cooled to about 35°C (95°F) before passing through a carbon bed to remove ninety-five percent of the Hg.

To capture CO_2, a WGS reactor containing a series of two shifts with inter-cooled stages, converts a nominal 96 percent of the CO 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. Elemental sulfur is recovered in a Claus bypass-type sulfur recovery unit utilizing oxygen instead of air. The CO_2 is dried and compressed to 15.3 MPa (2,215 psia) for subsequent pipeline transport and sequestration. 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	463.6
Steam turbine, MWe	229.9
Gross power output, MWe	693.5
Auxiliary power requirement, MWe	(176.4)
Net power output, MWe	517.1

A Brayton cycle, fueled by the syngas, is used in conjunction with a conventional subcritical steam Rankine cycle for combined cycle power generation. 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. The steam turbine operates at 12.4 MPa/538°C/538°C (1,800 psig/1,000 °F/1,000°F). The plant produces a net output of 517 MWe. The summary of plant electrical generation performance is presented in Table 3. This plant configuration results in a net plant efficiency of 32.0 percent HHV, or a net plant HHV heat rate of 10,674 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 (less than 3 ppmv in the flue gas) are achieved by capture of the sulfur in the two-stage Selexol acid gas removal (AGR) process, which removes over 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 (primarily) and syngas humidification (secondarily) in the gas turbine combustor to 15 ppmvd (as nitrogen oxide at 15 percent O_2). Filterable PM discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter 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. Approximately 90 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 Shell IGCC plant with CCS is presented in Table 4.

Table 4. Air Emissions Summary @ 80% Capacity Factor

Pollutant	Shell IGCC with CCS (90%)
CO_2	
• tons/year	361,056
• lb/MMBtu	18.7
• cost of CO_2 avoided ($/ton)	42.0
SO_2	
• tons/year	204
• lb/MMBtu	0.0105
NOx	
• tons/year	944
• lb/MMBtu	0.049
PM (filterable)	
• tons/year	137
• lb/MMBtu	0.0071
Hg	
• tons/year	0.011
• lb/TBtu	0.571

Cost Estimation

Plant size, primary/secondary fuel type, 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 the 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 14 percent of the Shell 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 3.8 percent of the Shell IGCC with CCS case TPC and have been applied to the estimates as follows:

- 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 $4.30/short ton, which adds 4.1 mills/kWh to the LCOE.

The 517 (net) MWe Shell IGCC plant with CCS was projected to have a TPC of $2,668/kWe, resulting in a 20-year LCOE of 110.4 mills/kWh.

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

Major Assumptions					
Case:	**1x517 MWe net Shell IGCC with CCS**				
Plant Size:	517.1	(MWe, net)	Heat Rate:	10,674	(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					66.6
Resulting Operating Costs (Levelized 2007 dollars)[3]					**Mills/kWh**
Fixed Operating Cost					7.2
Variable Operating Cost					9.3
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu					**Mills/kWh**
					23.2
Resulting Levelized CO_2 Cost (2007 dollars)					**Mills/kWh**
					4.1
Total Levelized Busbar Cost of Power (2007 dollars)					**Mills/kWh**
					110.4

[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.

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

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