Conditions in Advanced Turbines for IGCC Power Plants with Carbon Capture

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Motivation

Lack of turbine condition information available for setting research boundary conditions including:

- Anticipated moisture levels
- Anticipated sulfur levels
- Anticipated particulate concentrations, sizes, and compositions

Approach

- Reviewed plant conditions for 5 existing IGCC plants, 2 IGCC plants with carbon capture in the planning/construction phase, and system studies by DOE and OEMs
- Data and conclusions reviewed by industry experts

DOE Baseline System Study Cases

3 cases of interest

Case	Unit Cycle	Steam Cycle, psig/°F/°F	Combustion Turbine	Gasifier/Boiler Technology	Oxidant	H_2S Separation/ Removal	Sulfur Removal/ Recovery	CO_2 Separa-tion
1	IGCC	1800/1050/1050	2 x Advanced F Class	GEE Radiant Only	95 mol% O_2	Selexol	Claus Plant	
2	IGCC	1800/1000/1000	2 x Advanced F Class	GEE Radiant Only	95 mol% O_2	Selexol	Claus Plant	Selexol 2nd stage
3	IGCC	1800/1050/1050	2 x Advanced F Class	CoP E-Gas™	95 mol% O_2	Refrigerated MDEA	Claus Plant	
4	IGCC	1800/1000/1000	2 x Advanced F Class	CoP E-Gas™	95 mol% O_2	Selexol	Claus Plant	Selexol 2nd stage
5	IGCC	1800/1050/1050	2 x Advanced F Class	Shell	95 mol% O_2	Sulfinol-M	Claus Plant	
6	IGCC	1800/1000/1000	2 x Advanced F Class	Shell	95 mol% O_2	Selexol	Claus Plant	Selexol 2nd stage

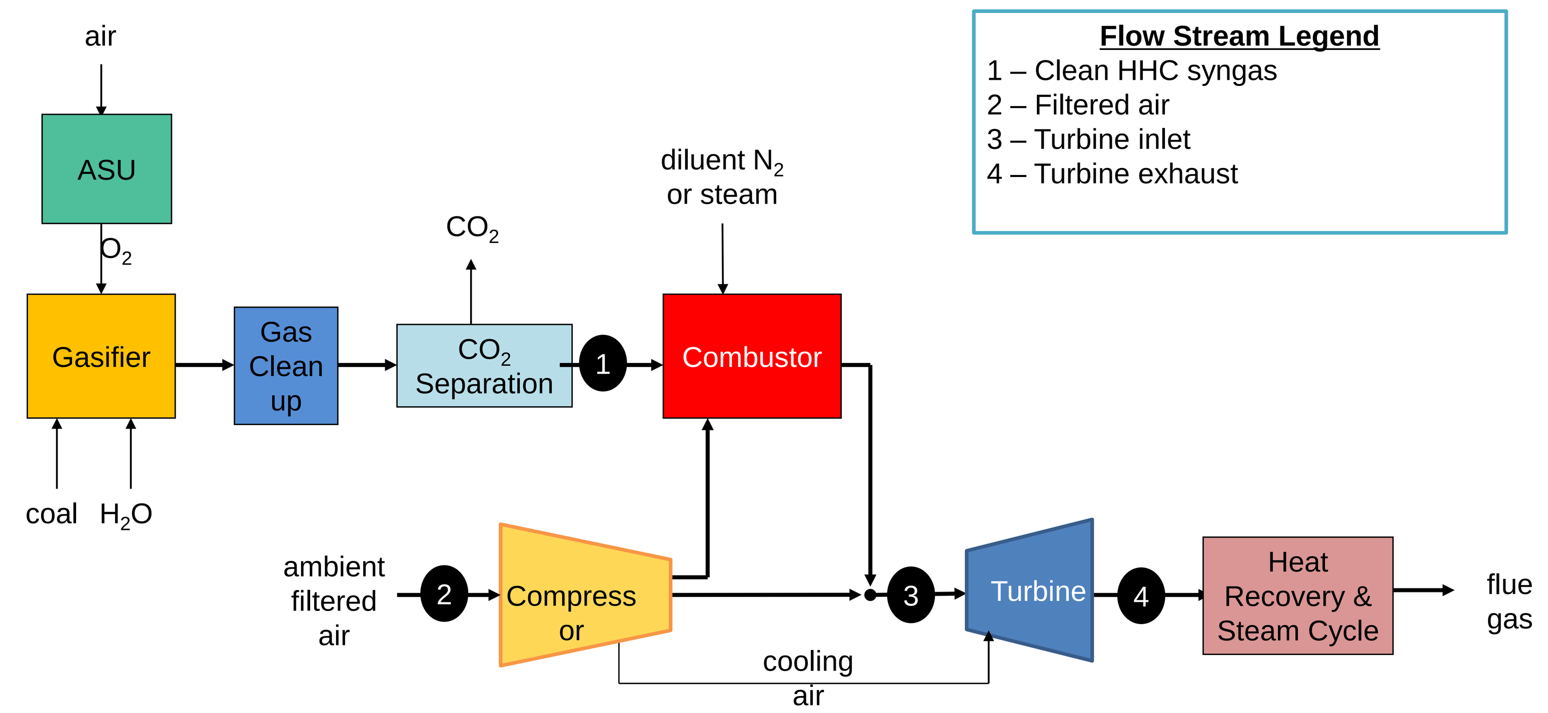
Sulfur

- Sulfur contents in the clean, shifted syngas of existing IGCC plants ranges from less than 10ppm (dry coal feed) to 257 ppm (slurry coal feed). Sulfur is less than 100 ppm in most existing IGCC plants
- Sulfur concentrations < 20 ppm should be anticipated in IGCC plants with carbon capture (Industry feedback and DOE baseline study)
- Sulfur in the hot gas path will significantly lower than in the clean shifted syngas due to dilution of the combusted sulfur products by the main working fluid (air) plus NOx suppressing combustion diluents prior to entering the turbine section. ~22 ppm sulfur concentrations in the clean shifted syngas corresponds to ~3 ppm in the exhaust

Plant Class	Plant Name	Clean, Shifted Syngas - Total Sulfur	Total Sulfur Stack Emissions	Calculated Turbine Section Sulfur Concentration*	Comments	References
Existing IGCC plants without carbon capture	Tampa Electric	257 ppmv	1.17 lb/MWh	87 ppm	COS catalyst, Amine AGR	DOE Final Technical Report[1]
	Wabash Repowering	100 ppmv	1.08 lb/MWh	74 ppm	COS catalyst, Amine AGR	DOE Final Technical Report[2]
	Buggenum	< 10 ppmv	0.06 lb/MWh	4 ppm	COS catalyst, Sulfinol AGR	Presentations found on-line, NETL website, EPRI availability report[3]
	Puertollano	12-24 ppmv	0.10 lb/MWh	8 ppm	COS catalyst, Amine AGR	Presentations found on-line, NETL website, EPRI availability report[3]
Planning/Construction Phase IGCC plants with carbon capture	Texas Summit	< 100ppb	0.14 lb/MWh	13 ppm	WGS CO-shift (COS->H_2S), Rectisol AGR	EIS[4]
	Kemper	<10ppmv	0.0040 lb/MMBtu	1 ppm	2 WGS reactors in series, COS catalyst if needed, AGR not specified	EIS[5]
System Studies with carbon capture	DOE Baseline IGCC - Case 2 GE gasifer	23 ppmv	< 3 ppmv (0.010 lb/MMBtu)	3 ppm	2-stage Selexol designed for 95 % CO_2 capture resulted in >99.7 % sulfur capture	DOE Baseline Study[6]
	DOE Baseline IGCC - Case 4 CoP E-Gas gasifer	22 ppmv	< 3 ppmv (0.0085 lb/MMBtu)	2 ppm	2-stage Selexol designed for 95 % CO_2 capture resulted in >99.7 % sulfur capture	DOE Baseline Study[6]
	DOE Baseline IGCC - Case 6 Shell gasifer	22 ppmv	3 ppmv (0.0105 lb/MMBtu)	3 ppm	2-stage Selexol designed for 95 % CO_2 capture resulted in >99.7 % sulfur capture	DOE Baseline Study[6]
Industry Anticipated Conditions	GE	< 10 ppm	Not Specified		Not Specified	GE Communication
	Siemens	20 ppmv				Siemens Communication
New Source Performance Standards (NSPS)	Calculated assuming generic 2x1 711 MW Gross Plant		1.4 lb/MWh	118 ppm	0.162 lb/MMBtu (based on heat rate of 8,640 Btu/kWh)	

*Calculated Turbine Section Sulfur Concentration was calculated using the Total Sulfur Stack Emissions for the various plants while assuming exhaust flow rates of 4,219,005 lb/hr for 1 x 1 configurations and 8,438,010 lb/hr for 2 x 1 plants, consistent with IGCCs based on F-class turbines and a steam bottoming cycle. Also assumed 1 MWh = 3.412 MMBtu where needed.

Simplified IGCC Power Plant Layout



1. Clean high-H_2 content (HHC) syngas – CO_2 separated and removed. Sulfur and particulates removed with sorbents, filters, and washes
2. Ambient air is filtered and compressed, which is used for combustion, as the working fluid, and cooling
3. Air, as the working fluid, effectively dilutes the combustion products as they enter the turbine. CO_2 capture increases H_2 concentrations, resulting in moister turbine conditions but also can lower sulfur and coal-based contaminant loadings due to the extra gas cleaning
4. Turbine exhaust is sent to the Heat Recovery Steam Generator and then out the flue

Bulk Gas Characteristics

- Mass flow rates, pressures, temperatures, and gas compositions for the filtered air and turbine exhaust streams were similar for three IGCC cases with carbon capture
- Minimal turbine inlet data was available
- Moisture content ranges from 0-14.27% in clean shifted syngas depending on gasifier choice (GE, Conoco Philips, and Shell) and combustor dilution strategy (H_2O vs. N_2)
- OEMs agreed that a moisture content of 15-18% in the turbine inlet could be expected if the fuel is dry, high-hydrogen syngas, while it could increase to 30-40% if steam were used for NOx suppression
- Exhaust moisture contents were slightly lower, ranging 12-14%

		Temperature / Pressure / Mass Flow Rate					Gas Composition					
Flow Segment #	Flow Segment ID	Units	GE – Case 2	CoP – Case 4	Shell – Case 6	Average	Units	GE – Case 2 (%)	CoP – Case 4 (%)	Shell – Case 6 (%)	Range (%)	Average (%)
1	Clean High-H_2 Syngas	F	386	385	385	385	H_2	91%	76%	86%	86-91%	84%
		psia	460	453	449	454	H_2O	0%	14%	3%	0-14%	6%
		lb/hr	99,491	131,802	117,516	116,269	CO	2%	1%	3%	1-3%	2%
							CO_2	4%	2%	2%	2-4%	3%
							Ar	1%	1%	1%	1-1%	1%
							N2	1%	1%	5%	1-5%	3%
2	Filtered Air	F	59	59	59	59	N_2	77%	77%	77%	77%	77%
		psia	14.7	14.7	14.7	15	O_2	21%	21%	21%	21%	21%
		lb/hr	3,519,235	3,498,170	3,531,165	3,516,190	H_2O	1%	1%	1%	1%	1%
							Ar	1%	1%	1%	1%	1%
3	Turbine Inlet	No data available in DOE Baseline Study										
4	Turbine Exhaust	F	1,052	1,052	1,051	1,052	N_2	75%	74%	75%	74-75%	75%
		psia	15.2	15.2	15.2	15.2	H_2O	12%	14%	13%	12-14%	13%
		lb/hr	4,219,005	4,219,005	4,219,005	4,219,005	O_2	11%	10%	11%	10-11%	11%
							CO_2	1%	1%	1%	1%	1%
							Ar	1%	1%	1%	1%	1%

Particulates

Potential sources:

1. coal ash
2. syngas reactions with piping and components
3. syngas combustion by-products
4. air-borne dust that passes through intake filters

Findings:

- OEM specifications generally limit particulates:
  - sizes < 10 microns
  - concentrations < 20 ppm
- New IGCC with carbon capture plants will have particulate stack emissions less than ~7 ppm in accordance with New Source Permit Standards
- Fly ash will be collected in filtration systems, sulfur removal systems, and CO_2 removal systems and hence is not likely to be present in the turbine section
- Metallic turbine components can react with sulfur and hydrocarbons to form compounds that have been found in the turbine sections. Pipe scale filtration and the use of corrosion-resistant stainless steel can mitigate damage
- 30:1 air:fuel mass flow rate suggests air-borne dust should be more prevalent than syngas-derived particulates in turbine section
- Air-borne particulates will reflect location character and could be site-specific
- Ca-Mg-Al-Si (CMAS) should be a reasonable approximation for the melting components in generic air-borne dust
- OEMs indicated that exhaust could contain SiO_2, Fe_3O_4, CaO, and Al_2O_3

Plant Class	Plant Name	Stack Particulate Emissions	Calculated Turbine Section Particle Concentration*	Pertinent Fuel Clean Up Processes	References
Existing IGCC plants without carbon capture	Tampa Electric	0.037 lb/MWh	2.1 ppm	Particle removal system, COS catalyst, MDEA AGR, Y strainers and 10 micron filter critical for turbine protection from pipe-scale during start-ups.	DOE Final Technical Report[1]
	Wabash Repowering	0.012 lb/MMBtu	2.4 ppm	Particle removal system (99.9 % efficient), sour water scrubbing for Cl and trace metals, condenser, Amine AGR	DOE Final Technical Report[2]
	Buggenum	< 1 mg/m^3		Cyclone, ceramic candle filter, water scrub for NH_3 + halides, COS catalyst, Sulfinol M AGR	Presentations found on-line, NETL website, EPRI availability report[3]
	Puertollano	0.05 mg/m^3		Candle filter, water wash scrub, COS catalyst, MDEA AGR	Presentations found on-line, NETL website, EPRI availability report[3]
Planning/Construction Phase IGCC plants with carbon capture	Texas Summit	0.22 lb/MWh	12 ppm	Particle removal, Rectisol AGR designed for 90% CO_2 capture	EIS[4]
	Kemper	0.015 lb/MMBtu	5.4 ppm	Cyclone, filters w/ pulsing, saturator column, two WGS reactors in series, water scrub, AGR, system designed for 60% CO_2 capture. "Downstream of each filter element, a device would safegaurd the CT from particulate-related damage in event of a filter element failure"	EIS[5]
System Studies with carbon capture	DOE Baseline IGCC - Case 2 GE gasifer	0.056 lb/ MWh 0.0071 lb/MMBtu	3.7 ppm	Syngas scrubber, cyclone, and candle filters, 2-stage Selexol designed for 95 % CO_2 capture	DOE Baseline Study[6]
	DOE Baseline IGCC - Case 4 CoP E-Gas gasifer	0.057 lb/MWh 0.0071 lb/MMBtu	3.5 ppm	Syngas scrubber, cyclone, and candle filters, 2-stage Selexol designed for 95 % CO_2 capture	DOE Baseline Study[6]
	DOE Baseline IGCC - Case 6 Shell gasifer	0.057 lb/MWh 0.0071 lb/MMBtu	3.5 ppm	Syngas scrubber, cyclone, and candle filters, 2-stage Selexol designed for 95 % CO_2 capture	DOE Baseline Study[6]
New Source Performance Standards (NSPS)	NA	0.015 lb/MMBtu			

*Calculated Turbine Section Particle Concentrations were calculated using the Stack Particle Emissions for the various plants while assuming exhaust flow rates of 4,219,005 lb/hr for 1 x 1 configurations and 8,438,010 lb/hr for 2 x 1 plants, consistent with IGCCs based on F-class turbines and a steam bottoming cycle.

Potential Impact

A F-class turbine with 20 ppm of particulates in its exhaust ingests ~2,000,000 lbs of material in a standard hot gas path inspection interval (24,000 hrs)

- Assumes F-class turbine exhaust flow rate of 4,219,005 lb/hr
- Performance and lifetime impacts will depend on variables such as firing temperature, particulate size and composition, as well as aerodynamic considerations

Conclusions

- OEMs agree that turbine inlet moisture contents will range 15-18%. but will depend on level of carbon capture, fuel/air ratio, and strategies for combustor dilution and component cooling
- State-of-the-art IGCC plants have syngas with 10-20 ppm sulfur in the cleaned syngas fuel and will be less in the turbine section
- Air stream flow rates are 30X more than fuel flow rates suggesting that particulate concentrations, compositions, and sizes will strongly reflect the composition of the filtered air stream rather than the coal-derived syngas
- OEM's typically filter particle sizes to less than 10 microns
- Fe and Ni can deposit in turbine section along with air-borne dust compounds

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