Babeş-Bolyai
University

Department of Chemical Engineering

Hydrogen and electricity co-production based on gasification process with Carbon Capture and Storage (CCS)

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Content

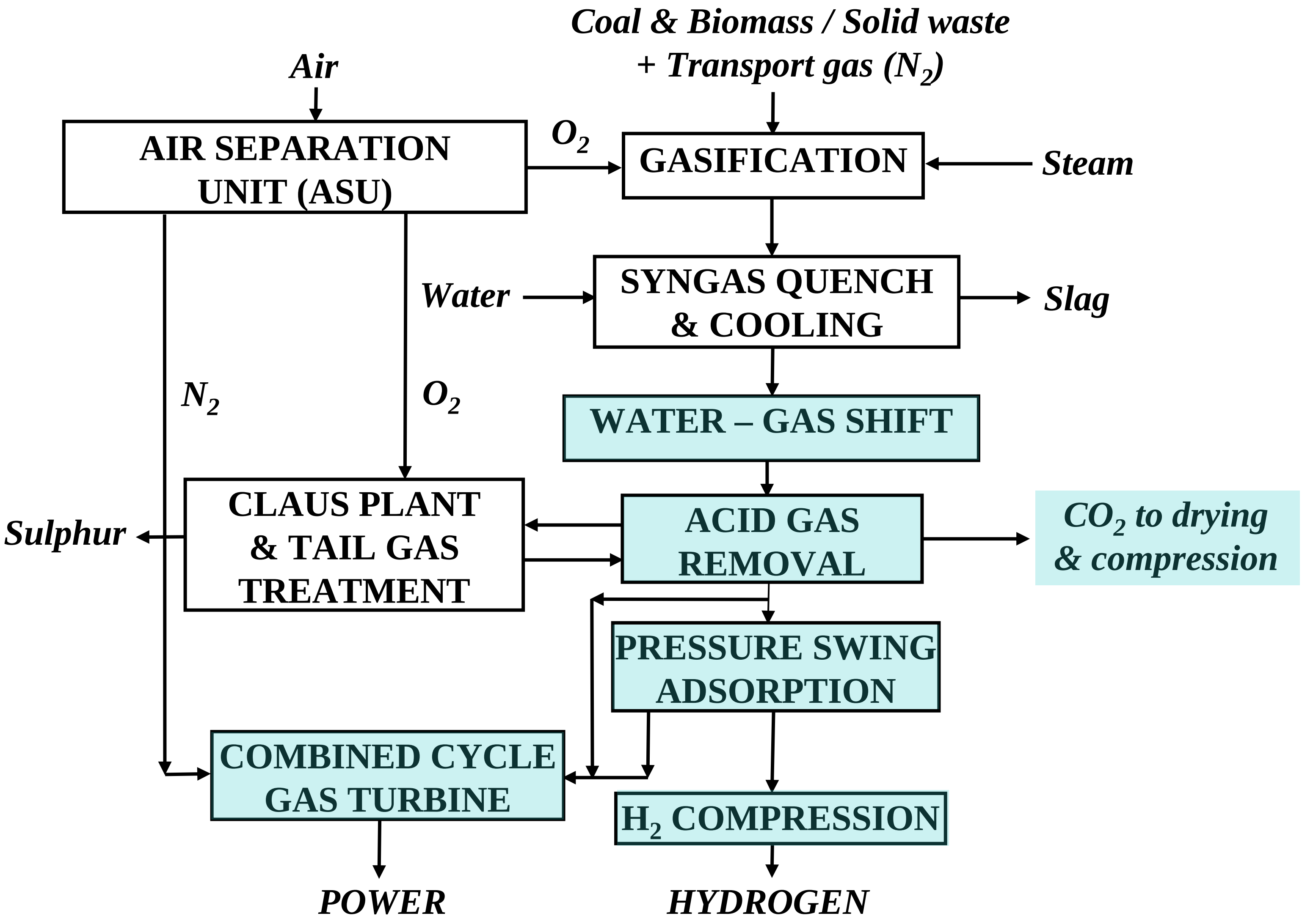
I. Introduction

The following work was performed within the project:
“Innovative systems for poly-generation of energy vectors
with carbon dioxide capture and storage
based on co-gasification processes of coal
and renewable energy sources (biomass) or solid waste”

Specific project objectives:

- Investigation of co-gasification processes
- Energy vectors poly-generation
- Evaluation of carbon capture technologies
- Techno-economical and environmental evaluations of poly-generation schemes with CCS

II. Plant Configuration of Hydrogen and Electricity Co-Production with CCS



Coal & Biomass / Solid waste + Transport gas (N_2)

Air

AIR SEPARATION UNIT (ASU)

O_2

GASIFICATION

Steam

Water

SYNGAS QUENCH & COOLING

Slag

N_2

O_2

WATER – GAS SHIFT

Sulphur

CLAUS PLANT & TAIL GAS TREATMENT

ACID GAS REMOVAL

CO_2 to drying & compression

PRESSURE SWING ADSORPTION

COMBINED CYCLE GAS TURBINE

H_2 COMPRESSION

POWER

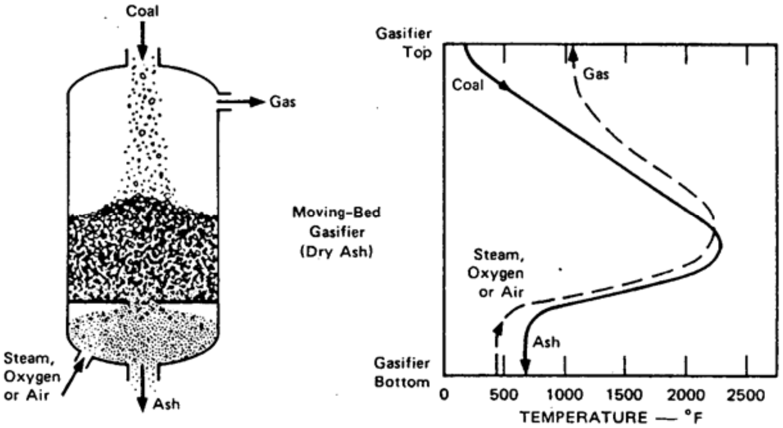
HYDROGEN

Major Design Assumptions

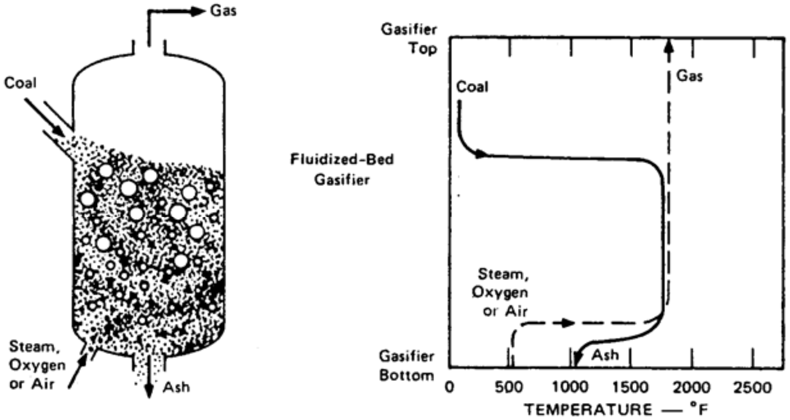
1. Plant size: ~400 $MW_{electricity}$ net, 0 – 200 MW_{H2} (LHV)
2. Gas turbine: M701G2 type (MHI)
3. Carbon capture rate: >90 %
4. H_2 purity & pressure: >99.95 % (vol.) / 70 bar
5. CO_2 purity & pressure: >98 % (vol.) / 110 bar
6. Fuel type: Coal in addition with biomass (sawdust) or solid waste (municipal solid waste - MSW, meat and bone meal - MBM), blending ratio 80 : 20 (% wt)

III. Investigation of Gasifier Options

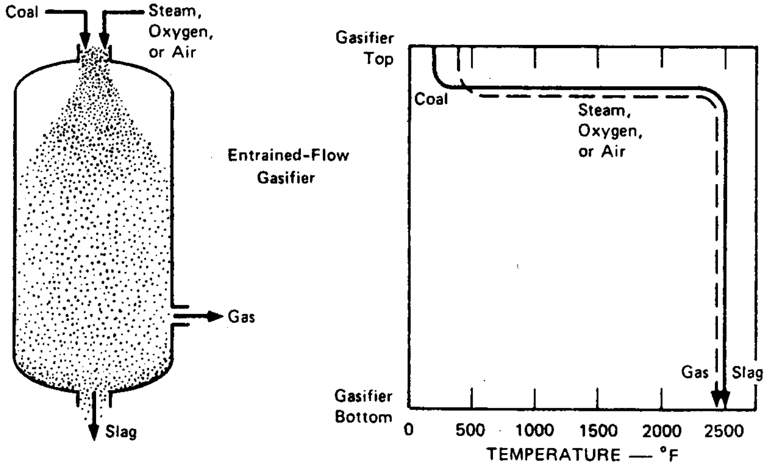
Moving-Bed



Fluidised-Bed



Entrained-Flow



Gasifier Selection Criteria

- Gasifier throughputs
- Reliability and experience
- Cold gas efficiency (CGE) and carbon conversion (CC)
- Syngas cooling options
- Oxygen purity and gasifier feed system
- Hydrogen production potential
- Downstream gas clean up issues
- Implication of gasifier selection for AGR system
- Capital cost

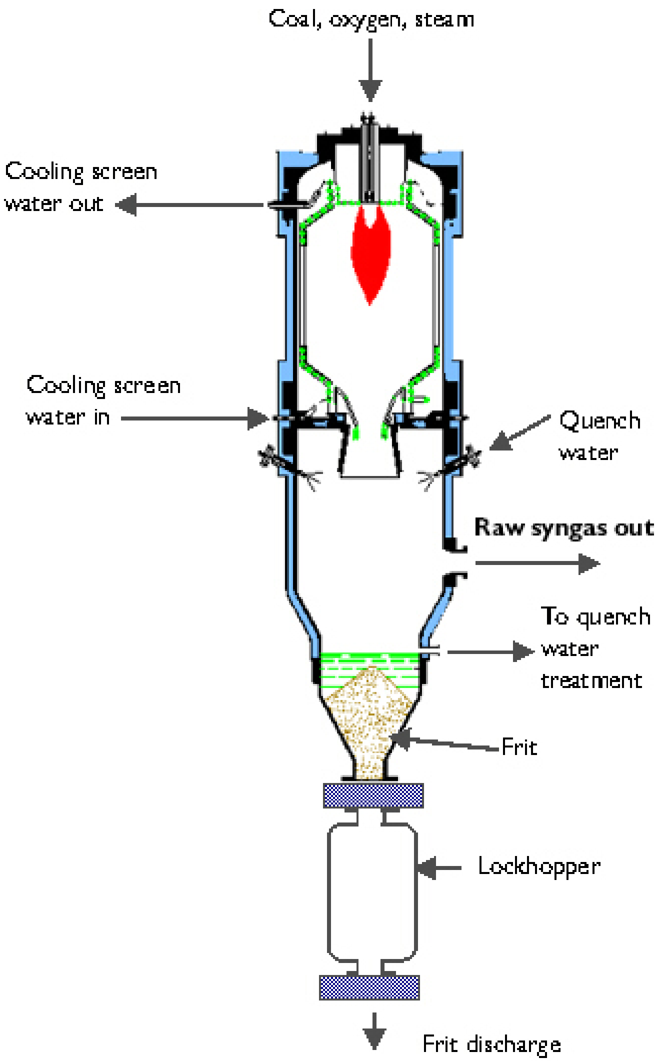
Selected Gasifiers

The most promising gasification systems (at least for coal) are all based on entrained-flow type, the following three being proposed to be investigated further:

- Shell gasifier (dry feed and heat recovery)
- Siemens gasifier (dry feed and water quench)
- GE-Texaco gasifier (slurry feed and water quench)

In the present work, Siemens gasifier was evaluated in detail, main factors for consideration being the good CGE, hydrogen production potential, dry feed design and water quench configuration

IGCC Plant with CCS



Main characteristics:

- Dry feed system (nitrogen)
- Entrained-flow gasifier (Siemens)
- Water quench configuration
- Dust / chlorine removal by quench water
- No steam raising potential
- No steam addition for shift conversion
- Sour shift conversion (2 beds)
- CO_2 and H_2S removal by Selexol® AGR
- Claus plant and tail gas treatment
- 1 MHI gas turbine (M701G2)
- 3 pressure steam cycle with MP reheat
- Steam cycle: 118 bar / 34 bar / 3 bar

IV. Fuel Selection

Fuel characteristics are important factors for the performance indicators of the gasifier (e.g. CGE, carbon conversion, oxygen consumption etc.)

For entrained-flow gasifiers, ash melting point, slag temperature – viscosity relationship and temperature corresponding to 25 Pa*s (T_{25}) are critical for operation

Temperature dependence of the slag viscosity is described by Weymann – Frenkel equation:

$$\eta = A * T * \exp^{(\frac{1000 * B}{T})}$$

Model parameters "A" and "B" are link together through the following equation:

$$-\ln(A) = m\,B + n$$

Parameter "B" is dependent of slag composition:

$$B = \sum_{i=0}^{3} b_i^0 X_S^i + \sum_{i=0}^{3}\sum_{j=1}^{2}\left(b_i^{C,j}\frac{X_C}{X_C + X_F} + b_i^{F,j}\frac{X_F}{X_C + X_F}\right) * \left(\frac{X_C + X_F}{X_C + X_F + X_A}\right)^j X_S^i$$

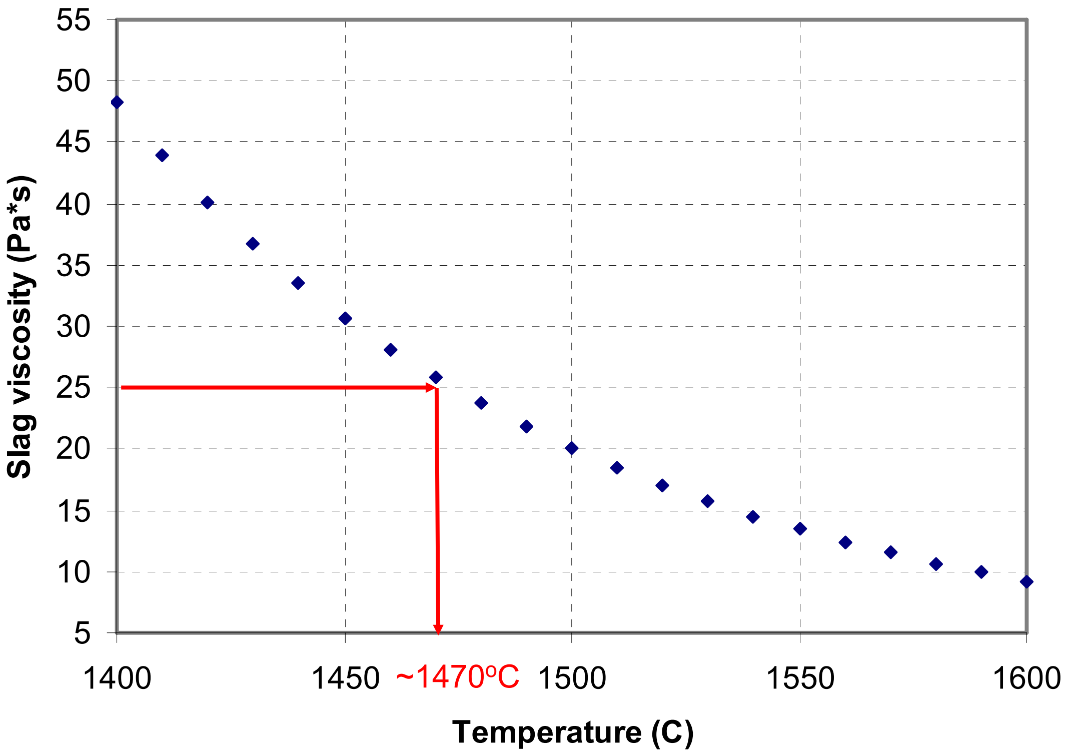
where model parameters are given below (in Poises):

$$m = m_A X_A + m_C X_C + m_F X_F + m_S X_S$$

	j	I					
		0	1	2	3		
b_i^0	0	13.31	36.98	-177.70	190.03	n	9.322
$b_i^{C,j}$	1	5.50	96.20	117.94	-219.56	m_F	0.665
	2	-4.68	-81.60	-109.80	196.00	m_C	0.587
$b_i^{F,j}$	1	34.30	-143.64	368.94	-254.85	m_A	0.370
	2	-45.63	129.96	-210.28	121.20	m_S	0.212

Evaluated fuels

Parameter	Coal	Sawdust	MSW	MBM
Proximate analysis (% wt.)				
Moisture (a.r.)	8.10	10.00	18.40	1.90
				73.40
				46.20
				6.70
				9.70
				17.07
				0.65
				0.88
				18.80
				1163.74
				9683.98
				0.00
				0.00
				2.90
				66.28
MgO	2.10	2.18	0.00	0.00
TiO_2	1.50	0.10	0.00	0.00
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Na_2O	0.30	0.61	7.25	17.82
SO_3	2.40	2.72	0.00	0.00
P_2O_5	1.30	1.23	0.00	0.00
SrO	0.00	0.15	0.00	0.00



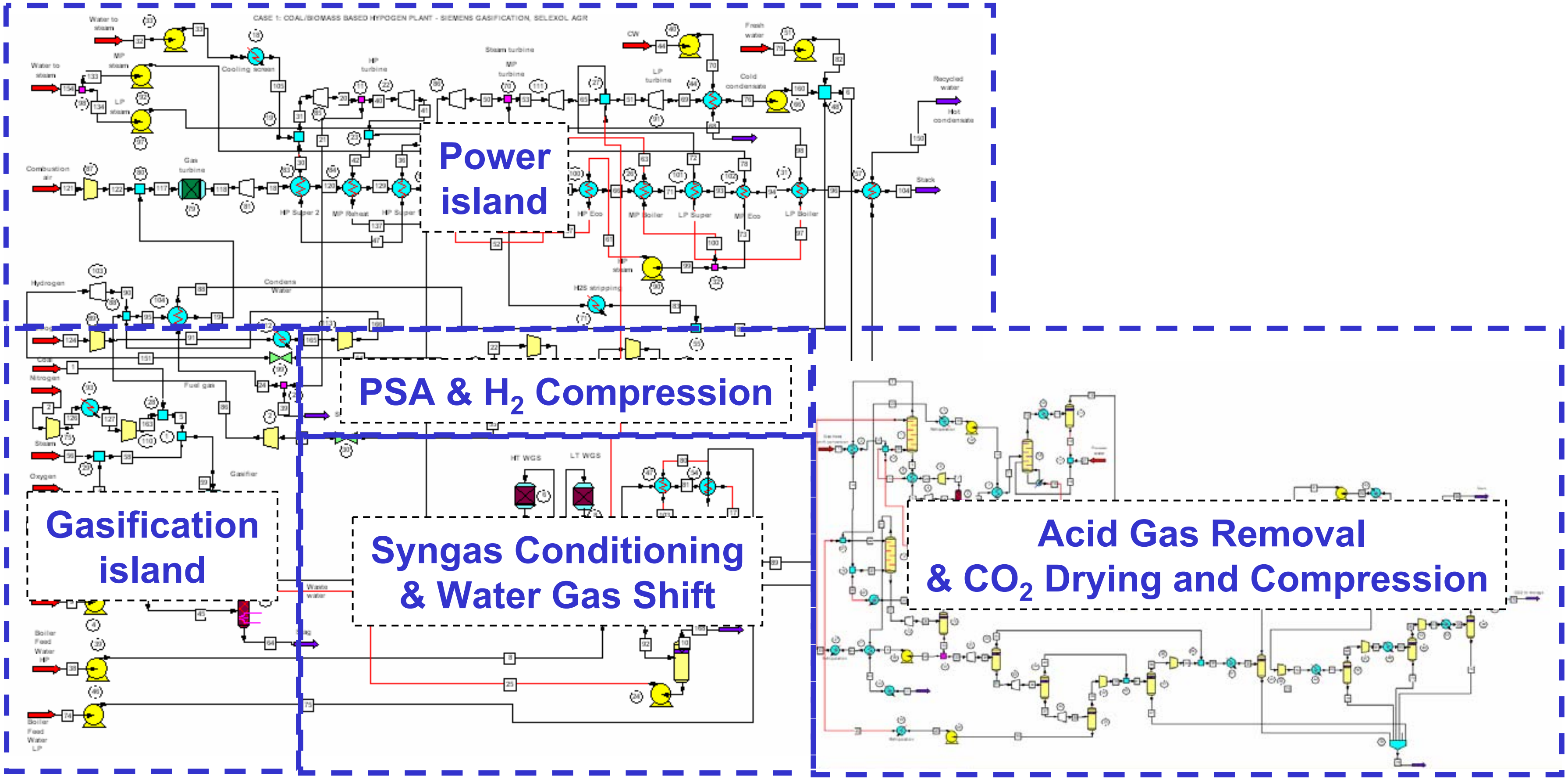
Correlation of coal slag viscosity vs. temperature

Gasification Performance

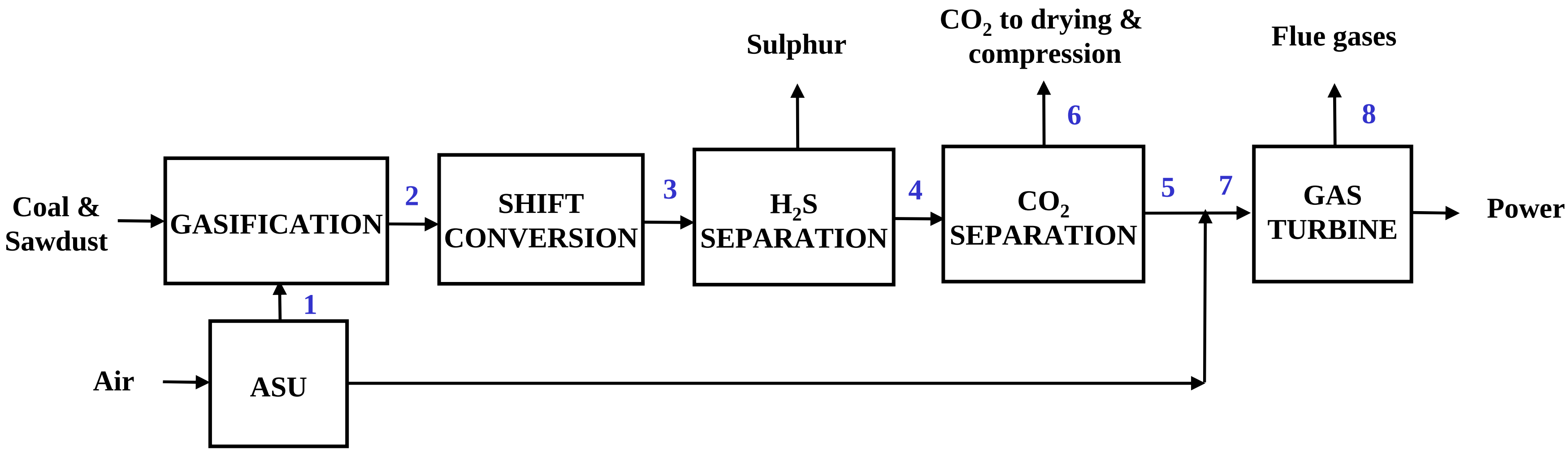
		Coal	Coal + Sawdust	Coal + MSW	Coal + MBM
Solid fuel flowrate	t/h	165.70	180.45	187.40	168.45
Coal / Sawdust / MSW / MBM (LHV ar)	MJ/kg	25.353 / 16.057 / 11.962 / 19.263			
Feedstock thermal energy (LHV)	MW_{th}	1166.98	1177.68	1180.37	1129.35
Cold gas efficiency (CGE)	%	80.10	79.33	79.26	82.52
Syngas flow	Kmol/h	15192.32	16044.55	16068.38	15198.36
CO content in syngas	% vol.	56.00	52.28	52.41	53.73
H_2 content in syngas	% vol.	25.69	25.23	25.04	28.05
Hydrogen production potential	MW_{th}	930.08	930.39	931.37	927.22
Oxygen consumption	t/h	138.66	140.00	142.00	128.72
Syngas energy / O_2 consumption	MJ/t O_2	24146.71	23924.34	23612.22	25932.15

V. Modelling and Simulation of IGCC Schemes with CCS

Investigated case studies were simulated using process flow modelling (ChemCAD software)



Process Flow Modelling Results (Case 2 – Coal with Sawdust)



Property	Stream 1	2	3	4	5	6	7	8
Temperature (°C)	20	260	37	25	30	40	150	110
Pressure (bar)	2.379	37	32.3	29.7	28	5 / 2 / 1.05	25.3	1.01
Flow (kmol/h)	4353.5	30858.6	22429.0	26919.2	13641.9	8705.8	20681.9	102491.4
Composition (vol. %):								
H_2	0	13.11	54.30	46.58	88.92	0.54	58.65	0.00
CO	0	27.18	1.15	1.03	1.83	0.08	1.20	0.00
CO_2	0	2.90	40.25	48.73	2.95	98.94	1.94	0.66
N_2	2.00	2.44	3.36	3.02	5.38	0.20	37.58	73.94
H_2O	0	53.83	0.21	0.05	0.02	0.01	0.01	12.71
O_2	95.00	0.00	0.00	0.00	0.00	0.00	0.00	11.76
Ar	3.00	0.42	0.58	0.55	0.87	0.13	0.57	0.90
H_2S + COS	0	0.08	0.12	0.00	0.00	0.00	0.00	0.00

Heat and Power Integration Analysis

Investigated plant concepts:

Case 2a – IGCC without carbon capture (syngas-fulled GT)

Case 2b – IGCC with carbon capture (H_2-fuelled GT)

Integration points among various plant sub-systems:

- Integration of LP steam (Case 2a) and HP & LP steam (Case 2b) into CCGT steam cycle (Rankine cycle)
- Steam extraction from CCGT steam cycle for AGR solvent regeneration and gasification
- Nitrogen stream from ASU integrated with gasification island and power block (fuel dilution)
- No air integration between ASU and GT compressor

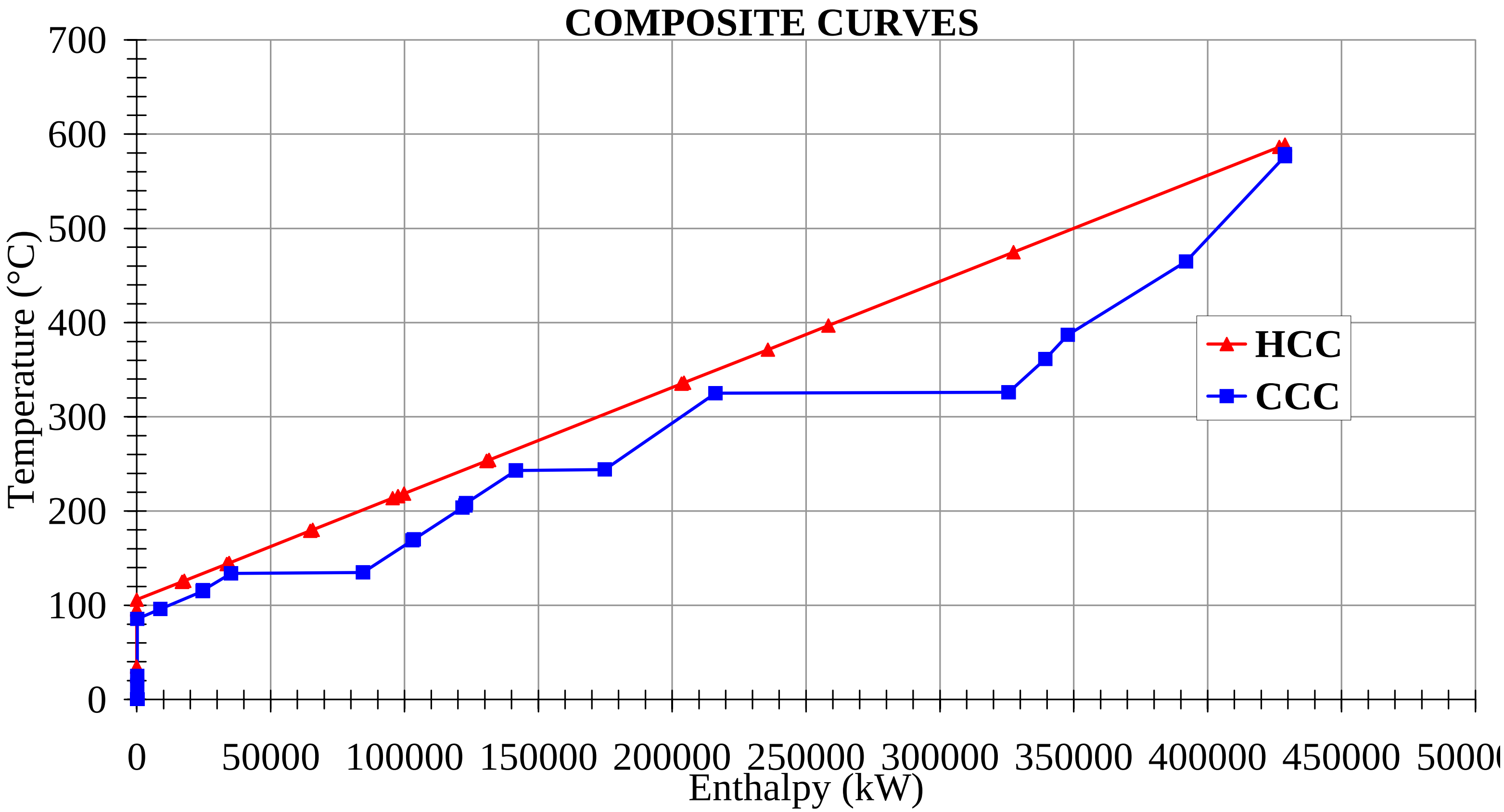
Heat and Power Consumption for IGCC Schemes with / without CCS

		Case 2a	Case 2b
HP steam from process	t/h	6.18 @ 573°C / 118 bar	135.02 @ 338°C / 120 bar
HP steam to HP Steam Turbine	t/h	339.18 @ 576°C / 118 bar	437.02 @ 574°C / 118 bar
MP steam after MP reheat	t/h	372.68 @ 465°C / 34 bar	470.72 @ 446°C / 34 bar
MP steam to process units	t/h	33.50 @ 418°C / 41 bar	35.3 @ 415°C / 41 bar
MP steam to AGR (solvent reg.)	t/h	24.00 @ 265°C / 6.5 bar	27.70 @ 265°C / 6.5 bar
LP steam from process units	t/h	219.00 @ 206°C / 3 bar	97.30 @ 200°C / 3 bar
LP steam to LP Steam Turbine	t/h	649.68 @ 196°C / 3 bar	623.32 @ 184°C / 3 bar
Cooling water	t/h	33700 @ 15°C / 2 bar	32500 @ 15°C / 2 bar
Hot condensate returned to HRSG	t/h	707.18 @ 115°C / 2.8 bar	818.70 @ 115°C / 2.8 bar
Flue gas at stack	t/h	2927.50 @ 105°C / 1.01 bar	2810.92 @ 110°C / 1.01 bar
Steam turbine generated power	MW_e	183.60	200.14

Heat and Power Consumption for IGCC Schemes with / without CCS

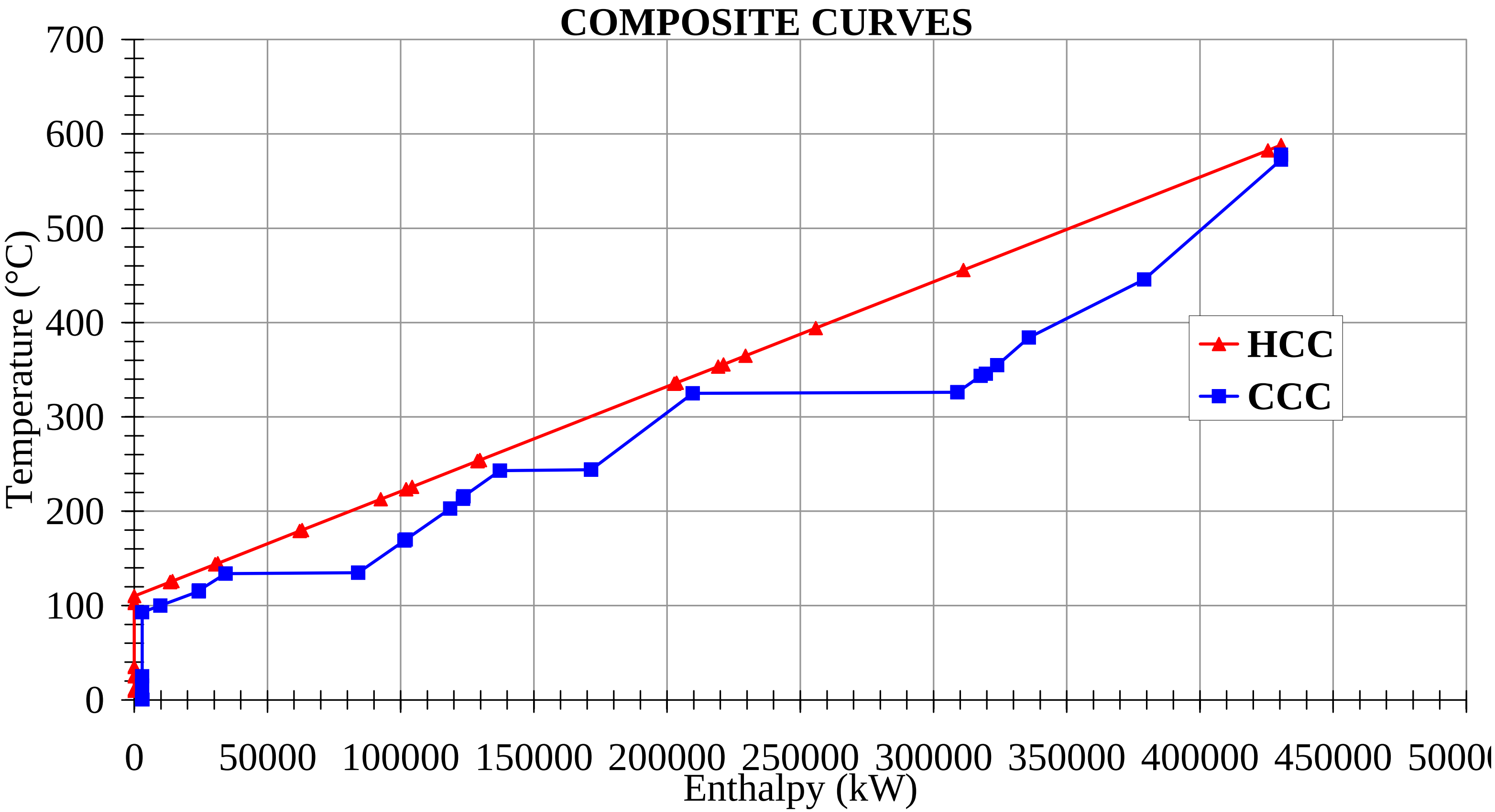
		Case 2a	Case 2b
Air Separation Unit (ASU)	MW_e	28.27	31.60
Oxygen compression	MW_e	12.10	13.53
Gasification island consumption	MW_e	6.80	8.27
Acid Gas Removal (AGR)	MW_e	7.48	13.23
CO_2 drying and compression	MW_e	0.00	27.31
Power island consumption	MW_e	20.53	19.05
Ancillary power consumption	MW_e	75.18	112.99

Optimization of Energy Efficiency by Heat and Power Integration of CCGT Unit



Composite curves for syngas-fuelled CCGT (Case 2a)

Optimization of Energy Efficiency by Heat and Power Integration of CCGT Unit



Composite curves for hydrogen-fuelled CCGT (Case 2b)

Evaluation of Power Generation Schemes with / without CCS

		Case 2a	Case 2b
Solid fuel flowrate	t/h	161.35	180.45
Feedstock thermal energy (LHV)	MW_{th}	1053.00	1177.68
Gas turbine output (1 x M701G2)	MW_e	334.00	334.00
Steam turbine output	MW_e	183.60	200.14
Ancillary power demand	MW_e	75.18	112.99
Net electric power	MW_e	443.90	421.93
Net electrical efficiency	%	42.15	35.82
Carbon capture rate	%	0.00	92.83
CO_2 specific emissions	Kg / MWh	826.05	71.19

VI. Evaluation of Hydrogen and Electricity Co-production Schemes with CCS

Investigated plant concepts:

Case 1 - Coal only as feedstock

Case 2 – Coal in addition with sawdust (80 / 20 % wt.)

Case 3 – Coal in addition with MSW (80 / 20 % wt.)

Case 4 – Coal in addition with MBM (80 / 20 % wt.)

Plant concepts were evaluated in electricity only production mode and hydrogen and electricity co-production mode

Plant Performances (electricity production only)

		Case 1	Case 2	Case 3	Case 4
Solid fuel flowrate	t/h	165.70	180.45	187.40	168.45
Feedstock thermal energy (LHV)	MW_{th}	1166.98	1177.68	1180.37	1129.35
Gas turbine output (1 x M701G2)	MW_e	334.00	334.00	334.00	334.00
Steam turbine output	MW_e	197.50	200.14	200.93	196.13
Ancillary power demand	MW_e	111.87	112.99	113.99	110.68
Net electric power	MW_e	420.41	421.93	421.72	420.23
Net electrical efficiency	%	36.02	35.82	35.72	37.20
Carbon capture rate	%	92.35	92.83	93.02	92.24
CO_2 specific emissions	Kg / MWh	76.12	71.19	70.68	72.23

Plant flexibility
Hydrogen and Electricity Co-production

Hydrogen and electricity demand from consumers is not constant (there is a need for plant flexibility)

Load Following Flexibility: 0 – 200 MW Hydrogen

- Electricity output is suitable for load following and obtained by reducing GT to 80 – 100 % of design

- Tail gas from PSA unit is either integrated in main fuel line to GT (as considered here) or used as fuel to HRSG duct burner

Complete Flexibility: 0 – 100 % Hydrogen

- Feasible, but will require some ancillary power production systems

Plant Performances
(H_2 and Electricity Co-production – Case 1)

Solid fuel flowrate (coal)	t/h	165.70			
Feedstock thermal energy (LHV)	MW_{th}	1166.98			
Gas turbine output (1 x M701G2)	MW_e	334.00	314.97	296.27	277.58
Steam turbine output	MW_e	197.50	187.44	177.38	167.40
Hydrogen output (LHV)	MW_{th}	0.00	50.00	100.00	150.00
Ancillary power demand	MW_e	111.87	111.83	111.75	111.68
Net electric power	MW_e	420.41	391.30	362.56	333.91
Electrical efficiency	%	36.02	33.53	31.06	28.61
Hydrogen efficiency	%	0.00	4.28	8.57	12.85
Cumulative efficiency	%	36.02	37.81	39.63	41.46

IGCC concept with CCS
- Pros and Cons -

Pros:

- Lower energy penalty vs. post-combustion capture
- Possibility to process lower grade coals and fuels
- Poly-generation schemes based on syngas processing
- Very low SO_x and NO_x emissions vs. steam plants
- Plant flexibility

Cons:

- Higher capital costs vs. steam plants (PF plants)
- Development needed for hydrogen-running GTs
- Significant difference for hydrogen HHV & LHV (~18%)
- Integration issues among plant sub-systems

VII. Conclusions

- Entrained-flow gasifiers are favourite for hydrogen and electricity co-production with carbon capture

- Fuel blending represent an efficient way to optimize gasifier performances (CGE, oxygen consumption, hydrogen production potential etc.)

- Modelling and simulation tools and heat and power integration studies used to asses and optimize the plant performances

- Energy penalty for IGCC plants with pre-combustion capture (6 – 7 %) are lower than for steam (PF) plants with post-combustion capture (~10%)

Thank you for your attention!

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