

**The Shell Coal Gasification Process
for the US Industry**

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ABSTRACT

The Shell Coal gasification Process (SCGP) is competitive for Integrated Gasification Combined Cycle (IGCC) applications targeting highest achievable cycle efficiencies in the market in line with the DOE's Vision 21. Costs per kW_e for the SCGP can be further lowered by scaling up to 4000+ t/d units (equivalent to 550 MW_e net) and by reducing produced steam pressures and superheat levels in the Syngas Cooler. These options combined result in IGCC costs of some 1000-1100 \$/kW_e (net power, excluding Owners Costs) with an overall net cycle efficiency above 45% HHV on Pittsburgh#8. The investment for Powder River Basin with or without Petcoke co-mixing will be some 3-4% higher, while overall economics are more attractive due to lower feed costs and high efficiencies are maintained.

INTRODUCTION

The North American power generation industry is becoming more and more interested in coal gasification based solutions. Shell has been active in coal gasification in the USA in the 80's with a demonstration plant and numerous studies for EPRI and utility companies. With the advent of depleting domestic oil & gas reserves and more than three hundred billion tons of domestic coals (> 200-300 years of energy supply) readily available in the US, coal gasification is bound to be a serious option for Electric Power Companies or other owners and developers on the Power & Refinery-Petrochemical interface.

Shell's progress in China the last 3 years with 12 licensed projects in EPC phase and a JV in one gasification project has resulted in many improvements in the design and project execution leading to improved economics in both \$/kWe and \$/MWh when compared with the Demkolec project in 1993. This case study for 400-800 MW_e IGCC in the Middle of the USA assuming ISO conditions for 2 different coals (bituminous Pittsburgh #8 and sub-bituminous Powder River Basin) and a typical Petcoke mix illustrates this. EPC investment cost have been calculated at start-up date at 2004 price levels together with different inflation rates for fuels, electricity, while excluding Owners Costs.

SHELL GASIFICATION EXPERIENCE & STATUS

History

Shell started its gasification technology in 1956 with the development of oil gasifiers (SGP) also suitable for partial oxidation of natural gas. Since then some 30 syngas projects with more than 100 oil & gas gasifiers have been applied or are on order. This experience provided a sound basis for developing the Shell Coal Gasification Process which started in 1972. The first pilot plant started in the Amsterdam, which is still the home of Shell's gasification group having satellite offices in Germany, China, Singapore and Houston. The SCGP reactors were then scaled up for verification testing in Shell Harburg Germany (150 t/d) and Shell Deer Park, USA (250-400 t/d) respectively.

Demkolec Project

The 253 MW_e Demkolec Project in the Netherlands was developed after Deer Park and started up in 1993. The Dutch Electricity Board SEP and its subsidiary Demkolec selected the SCGP process for the first large-scale Integrated Gasification Combined Cycle (IGCC) project in Europe. The 2000 t/d IGCC employs a Siemens V94.2 gas turbine with a maximum integrated Air Separation Unit (ASU) from Air Products. The gas turbine, steam turbine and generator have been designed as single shaft. The coal-to-busbar efficiencies are demonstrated to exceed 43.2 %LHV (41.4 %HHV). Gas treating is accomplished with Shell Sulfinol-M (MDEA based solvent) for > 98% Sulfur removal. Coals can be switched "on-the-fly" and co-feed of biomass and bio sludge have been run successfully. Gasification pressures and temperatures are around 25 bar and 1500 °C. Solidified molten slag, fly-ash and Sulfur are recovered as saleable byproducts. The plant is presently owned and operated by NUON.

SCGP Features & Benefits in IGCC environment

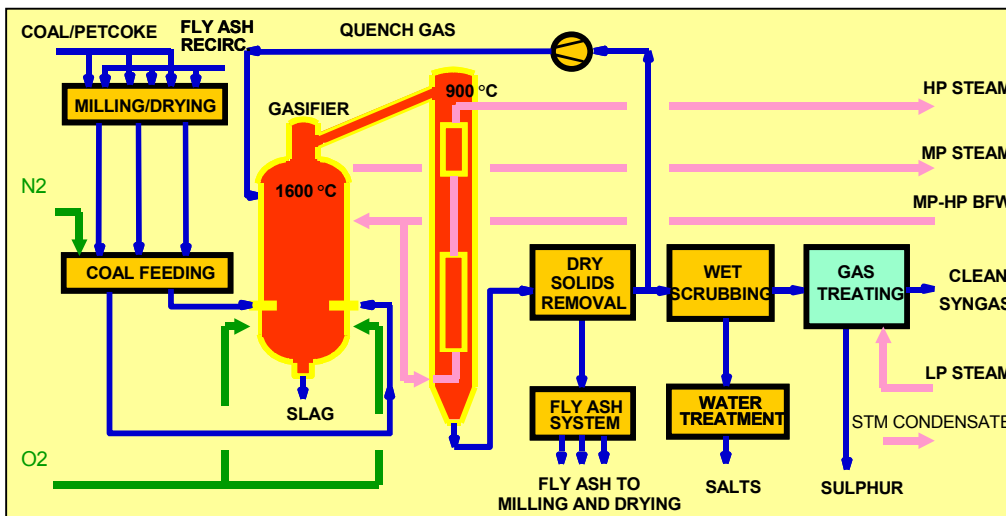


Figure 1 – SCGP process flow

The SCGP process and Gasification Island scope *) can be characterized as follows:

- Reliable dry coal feed system pressurized by N₂; milling and preconditioning like any PC boiler system, typically multiple lines per gasifier train for increased operability/reliability overall IGCC
- Oxygen blown entrained bed gasifier for high specific coal capacities up to 5000 t/d single train; ASU and gasifier scale-up potential follow each other
- Multiple co-annular burners per reactor for high turndown and scale-up (4 in NUON, maximum 6-8 burners in 2 decks for 4000 t/d gasifiers, one feed system per two burners, NUON burners > 20,000 hrs lifetimes)
- Gasification pressures up to 35-45 bara (510-655 psia) pressures
- Membrane wall slagging gasifier for high reliability and availability (NUON reactor running 10 years without membrane wall repairs); fluxing conditions assisted with fluxing agent depending on coal; gasification temperatures 1400-1700 °C (2550-3090 °F); membrane wall cooling by MP steam
- High cold gas efficiencies around 80%LHV relatively insensitive to a wide variety of coals and petcoke mixes, even mixes with biomass/wastes
- Gas quench to 800-900 °C (1470-1650 °F) followed by water-tube Syngas Cooler
- Syngas Cooler for single (MP) or multiple (HP+MP) steam pressures (typically 50-180 bara, 1470-1650 psia) with optional mild superheat; water-tube design with rappers
- Compact process and waste water handling with zero aqueous discharge
- Environmentally benign slag/ash/gaseous emissions
- Overall Gasification Island *) can have availabilities around 92% (single string) with uninterrupted coal runs > 3000 hrs:
 - 96% planned outages (3 weeks every 2 years and 1-2 weeks intermediate years)
 - 96% unplanned outages

Note *):

Gasification Island (GI) = Figure 1 scope, *excluding* Gas Treat (COS Hydrolysis, LT syngas cooling, AGR-SRU, fuel conditioning to GT/chemical process) and ASU

Syngas Manufacturing Process Plants (SMPP) = Figure 1 scope, *including* Gas Treat and ASU

SCGP Reactor & Syngas Cooler Design

The SCGP Reactor and Syngas Cooler (SGC) design as shown in Fig.1 are the center of the Gasification Island (GI) and one of the important items in the IGCC. They contribute substantially to the installed costs of the SCGP scope of plant. These costs will change depending on the process conditions (coal type, gasification temperature-pressure) and IGCC steam conditions desired.

The following assumptions have been used in Fig.2:

- Coal: Powder River Basin-Petcoke mix
- Gasification equipment scope from CMD up to wet Scrubber, including Waste Water Stripper, Slag Removal System
- Gasification equipment excluding ASU, AGR-SRU, Low-temperature Gascool/Condition
- Gasification equipment excluding Waste Water Treatment (Biotreater)
- Gasification pressure 35-40 bara
- Reactor membrane wall (MPS) and SGC steam pressure (HPS) set at 50 bara both
- Economizing and superheating in HRSG

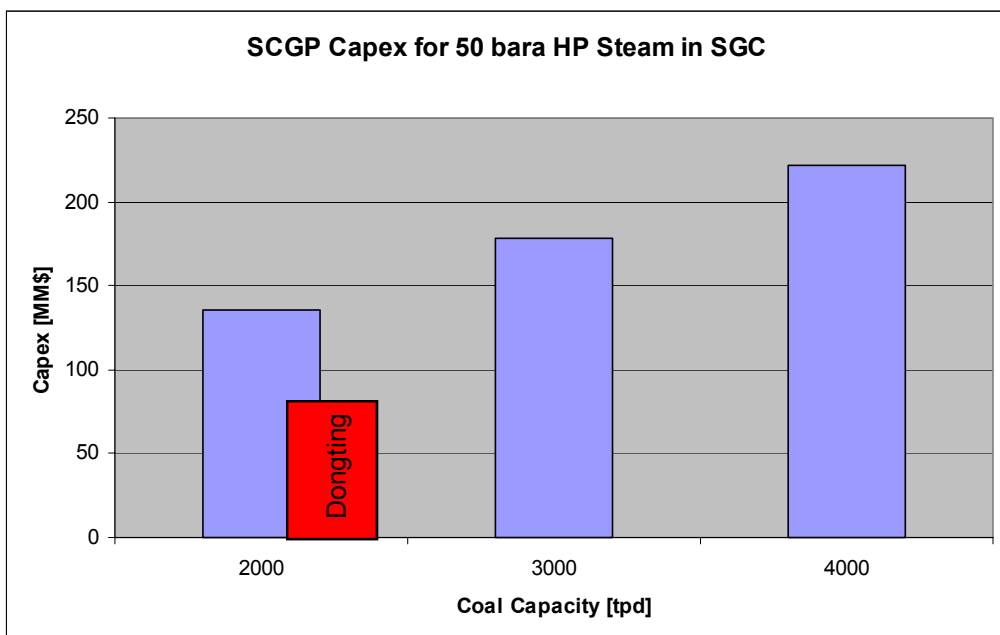


Figure 2 – SCGP Installed Equipment costs for 50 bar HP Steam vs coal capacity

Fig. 2 illustrates the economy of scale of the gasification section from coal yard to wet scrubber for 3 coal capacities. The lower capacity 2000 t/d is equivalent to the NUON project and the current reference project for Dongting, China with Shell equity. The costs for the Reactor and Syngas Cooler (R-SGC) system depends on the selected steam conditions.

The 50 bar steam pressure design will keep the SGC at lower cost as the material of construction of the coils can be low alloy Cr-Mo steel. Above 70-80 bars steam pressures the material of construction for the SGC bundles will start to require higher Cr-Ni content to mitigate high-temperature corrosion with design life times > 25 years, which inherently costs more. Selecting high steam pressures in the SGC is only economically interesting if

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corresponding IGCC efficiency improvements are offset by sufficient fuel cost reductions and higher electricity sales earnings.

The relatively low EPC costs in the Sinopec/Shell Dongting project, i.e. 57% of a normalized US design with western supply are also visualized (red bar).

Recent publications on SCGP in IGCC Environment

Recent publications by third parties have used the SCGP process in various IGCC-type environments with or without CO₂ capture, hot/cold syngas treating/conditioning and polygeneration [4] [5] [12] [15] [20] [28]. In most cases the comparisons between competing gasification technologies are using benchmark guidelines set by SFA-Pacific [6]. In many cases reference is made to the solid ground work done by DOE, NETL and EPRI in the period 2000-2002. Beyond 2002, sometimes questionable differences develop between the various gasifier technology options, which are likely caused when certain assumptions and IGCC improvement options are not credited simultaneously for each technology.

Shell concerns on use of SCGP costs in open literature may be summarized as:

- Investment costs for gasification do not cater for recent improvements in SCGP gasifier and syngas cooler design and construction, for instance the current lessons learned have allowed a > 10-20% cost reduction from NUON experience (US pricing basis)
- Installation factor for SCGP Reactor and Syngas Cooler are rather 2.3 than 3 (times FOB equipment costs results into capex) being more in line with power block installation factors due to capital intensive equipment
- SCGP scale-up potential is not utilized, i.e. 4000 t/d units are readily available for 550 MW_e plants (differentiator with single burner-reactor competition)
- High reliability of the SCGP system (>92% technically available, planned + unplanned outages combined) and corresponding low O&M costs, thus sparing reactor for power not necessary (differentiator with competition)
- IGCC integration options with SCGP not optimized, e.g. investigations for trading off efficiency with investment costs by simplifying water-steam cycle and heat recovery options with/without CO₂ capture
- Definition of ‘‘overnight IGCC investment costing’’ as compared to earlier EPRI reporting seems to be more disadvantageous for Shell technology compared to competition
- Earlier reporting by Shell through EPRI about SCGP’s relative insensitivity on \$/kW_e towards processing different coals seems neglected in some cases

IGCC Case Study Basis

Premises General

Table 2 – Site & Project Definition

Location	Holland, Michigan (ISO conditions); Random selection USA
Air	15 °C (59 °F)
Wet bulb	10.8 °C (52 °F)
Water	Make-up available for Demin Plant and Cooling Towers (option: A-frame steam condensers in case of scarce/high-cost water area's)
ASU	Partial integrated new, GT type dependent; Base Case assumes 50% air side integration as needed by ASU (options: max. - no integration) N2 return to GT at practically same mass flow as air draw-off (Base Case ~65% return)
Coal infra	New
PP infra & Requirements	HV lines available as required; new CCPP assumed; FO back-up fuel; NG for small users; Technical availability Syngas Manufacturing (GI+ASU+gastreat) > 90% Technical availability IGCC+backup fuel GT > 96%
CO₂	No capture (install CO shift and CO ₂ compression for sequestration later)

The IGCC study targets a fictive US project for either 400, 550 or 800 MW_e. Two typical US coals are used, i.e. Pittsburgh #8, Powder River Basin and a Pet Coke mix with Powder River Basin as feedstock. The 400 MW_e IGCC is single string and the 800 MW_e IGCC is double string, while not fully utilizing the economy of scale of the gasification island and ASU. The 550 MW_e plant will be double string or single string gasification island keeping the dual power block approach the same.

The project location is assumed to be a greenfield site with easy access for heavy transportation of main equipment. The infrastructure with the outside world is assumed to be available, e.g. coal unloading at the shore of Lake Michigan and a "free" connection to the HV grid is imagined enabling to design for a no-sparing (N) philosophy of gas turbines, steam turbines and gasifiers. The power block is assumed to have distillate with back-up fuel which can take-over from syngas operation "on-the-fly". Water make-up for cooling towers and demin plant is taken from Lake Michigan with no cost for intake facilities.

The total EPC cost estimate does not cater for owners soft costs such as:

- Permits, Licenses, Fees, Miscellaneous
- Land Cost
- Utility Connection Cost
- Legal & Financial Costs
- Interest During Construction
- Spare Parts & Materials
- Project Administration & Developer's Fee

In the 2002 EPRI [28] report these owners cost were included through adding some 4-5% only on the total EPC costs in their evaluation. These owners costs may be higher depending on type of owner and project definition. Each contractor/owner or financial institution has different views to calculate total costs for projects. This study has focused on the pure EPC contract cost only. The other economic assumptions are listed in the table below.

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Table 3 - Economic Premises

Source	USA	Pitts8	PRBasin	PRB/Coke	Remarks
Project life	[yrs]	25	25	25	
Economic Load	[h/a]	7008	7008	7008	Typical Base Load PP @80% year
GT Load	[%]	100	100	100	ISO/average ambient/no derating
O&M_fixed	[\$/kWe]	50	50	50	Shell S(C)GP experience
O&M_variable	[\$/kWh]	0.002	0.002	0.002	Shell S(C)GP experience
Contractor Costs	[%capex]	Typical	Typical	Typical	See remarks above
Owners Costs	[%capex]	0	0	0	Excluded, see remarks above
Depreciation	[yrs]	15	15	15	At 90% of initial investment
Debt/equity	[%]	80	80	80	US Third Party Covenant 2004
Discount rate	[%]	5.5	5.5	5.5	US Third Party Covenant 2004
Tax rate	[%]	38.2	38.2	38.2	US Third Party Covenant 2004
Inflation general	[%]	4	4	4	US Third Party Covenant 2004
Inflation fuel	[%]	0	0	0	Assumption based on history
Elec. Tariff	[\$/MWh]	40	40	40	Benchmark CCGT @4 \$/MMBtu NG
Fuel price	[\$/MMBtu]	1.24	1	0.6	Typical US coal
Fuel price	[\$/MMBtu]			0.2	Typical US coke

The economic dispatch loading in this study has been assumed conservatively at 80% like earlier EPRI studies. More optimistic assumptions may be 85% in IGCC mode with a 6% incremental loading of the GT on back-up fuel (distillate in this study or NG), which is quite achievable with one SCGP string and envisaged GT shortlist, e.g. 2*W501F or 2*7FA based power blocks for 550 MW_e net.

Some of the other economic assumptions to calculate NPV, break-even prices have been aligned with the findings from the Harvard Study report [4] targeting to reduce electricity generation costs by say 20%.

The GT load has been fixed 100% at ISO conditions neglecting fouling and aging of the blades. The syngas performance of the GT and power block have been calculated with an IGCC computer program, which has been verified with results from GE and Siemens.

Shell's O&M fixed and variable costs are expected to be superior compared to competition due to the durability and robustness of the gasifier and syngas cooler equipment. It would be unfair to apply a fixed ratio on these costs equally for each technology. A higher cost membrane wall reactor having a lifetime > 25 years would then be treated unfair compared to a refractory lined gasifier which may need to be refurbished frequently.

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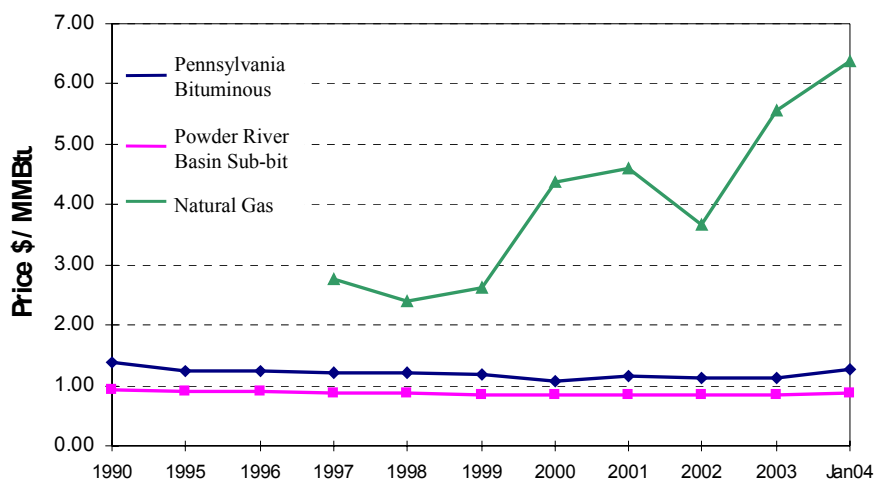


Figure 3 – SCGP coal pricing assumptions

The Powder River Basin (PRB) is a typical sub-bituminous coal and the Pittsburg#8 is a typical bituminous coal. On a weight basis the price difference may be more than double between these 2 coals due to HHV, ash and moisture differences. The PRB is also mixed with petcoke in an arbitrary 50/50 mix like in Puertollano IGCC.

Premises Power Block

Gas Turbine type

In the US there a number of GT pre-selections possible for 250-800 MW_e IGCC's. This paper uses the Siemens W501F and W501G gas turbines assuming syngas combustors are used with some pressure drop margin for possible future developments. The same Siemens GT's have been studied in previous DOE/NETL papers in 2002 while using Shell, Destec (now COP) and CVX (now GE) gasification technologies.

**Table 4 – GT Pre-selection 60 Hz Market
(Standard Design, Natural Gas, ISO Ambient Conditions)**

Vendor	Type	Power [MW _e]	GT_eff. [%LHV]	Reference Syngas-IGCC	Remarks
GE	7121EA	86.7	33.2	OPTI (new)	Std./Syngas Combustor, Mech Drive / Utility
GE	7241FA	175.4 (184->221)	37.2	Wabash River & Polk Power	Std./Syngas Combustor, IGCC demo's for Utility, (FB technology with NG-> syngas boost)
Siemens	V84.2	108.7 (110->121)	33.9 (34.0)	Buggenum (V94.2), Priolo Gargallo (V94.2K)	Vx4.2 Syngas Burner, V94.2 downsize, Mech Drive / Utility
Siemens	W501F	171.8 (198->235)	36.9 (38)	Plaquemine (W501D5)	Syngas Combustor , Utility (Latest info on NG -> syngas boost)
Siemens	W501G	253.0 (266->300)	39.3	-	Syngas Combustor , Utility (Latest info on NG -> syngas boost)
MHI	M501F	185.4	37.0	Negeshi	Syngas Combustor M701F
MHI	M501G	254.0	38.7	-	Syngas combustor under development

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Shell Coal Gasification Process Parameters

Table 5 – SCGP Typical Process Options

Source	USA	Pitts8	PRBasin	PRB/Coke	Remarks
LHV_AR	[kJ/kg]	27.68	17.44	23.88	Premises, As Received with Moisture
LHV_Dried	[kJ/kg]	29.80	24.84	28.67	Dryer spec 2-5 wt% (resp. P#8-PRB)
HHV_AR	[btu/lb]	12452	8150	10804	Premises, As Received
Sulfur	[wt%]	2.89	0.37	2.42	Premises, As Received
Ash	[wt%]	9.94	4.57	2.42	Premises, As Received, recycle as needed
Moisture AR	[wt%]	6.00	31.60	21.10	Dryer spec 2-5 wt% (resp. P#8-PRB)
Ash softening	[°C]	1168	1135	1145	IGCC Tool, slag temp. higher
Oxy/feed	[burn wrt]	0.883	0.753	0.843	Shell Gasifier Design, 99v% O2
Stm/feed	[MAF wrt]	0.08	0.04	0.1	Shell Gasifier Design Tool
Gasification press.	[bara]	35	35	35	Shell Gasifier / IGCC Design Tool
Gasification temp.	[°C]	1600	1500	1600	Shell Gasifier / IGCC Design Tool
Quench	[°C]	900	900	900	Shell Gasifier / IGCC Design Tool
Mwall stm/MF coal	[kg/kg]	0.201	0.105	0.265	50 bar, IGCC Tool to MP RH steam
SGC stm/MF coal	[kg/kg]	2.998	2.838	2.955	Base case: 125 bar, IGCC Tool
Raw syngas LHV	[MJ/kg]	12.31	11.49	11.5	Shell Gasifier Design Tool
Raw syngas HHV	[MJ/kg]	13.02	12.15	12.16	Shell Gasifier Design Tool
H2O	vol%	2.13	3.74	3.22	Shell Gasifier Design Tool
H2	vol%	29.84	27.21	26.14	Shell Gasifier Design Tool
CO	vol%	60.93	61.34	62.63	Shell Gasifier Design Tool
CO ₂	vol%	1.07	2.29	2.17	Shell Gasifier Design Tool
N2+Ar	vol%	5.07	5.18	4.94	Shell Gasifier Design Tool, +HCN/NH ³
H2S	vol%	0.82	0.16	0.77	Shell Gasifier Design Tool
COS	vol%	0.08	0.02	0.07	Shell Gasifier Design Tool
Cold Gas Eff. AR	[%LHV]	81.03	81.57	83.21	Shell Gasifier Design Tool, Raw Syngas
Cold Gas Eff. AR	[%HHV]	82.33	82.43	84.08	Shell Gasifier Design Tool, Raw Syngas

A summary of the most important IGCC plant parameters for the 3 feedstock's irrespective of plant capacity and power block have been listed in the Table 5.

The coals are moderate to low Sulfur-content and ash contents are in the order 5-10%. Much higher ash contents have been tested in Deer Park and reported to be feasible [2]. Mixing the PRB coal with Petcoke makes use of a cheap refinery residue feedstock, while the high-S content of the Petcoke is dampened by the low-S PRB so that H2S content in the syngas stay below 1v% similar to gasifying Pitts#8. Mixing a high ash containing coal (unlike PRB) with petcoke may also be considered. Details on exact amounts of ash recycle and/or possible flux to maintain proper slagging conditions have not been optimized in this study.

Drying of the coal ‘as received’ is done to 2-5% moisture with clean syngas or natural gas as heating medium, which is approximately < 0.5-3% of the total syngas produced depending on coal-petcoke, which is discarded in these scouting evaluations.

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The gasification pressure is set conservatively 35 bara for the W501F and 40 bara for the W501G. It is expected that in an optimized project this may be lowered. In case CO₂ capture is considered in the near future, pressures are likely to be correct (margin for additional CO shift unit). Gasification temperatures are subsequently selected between 1500-1600 °C to meet slagging conditions proper of the membrane wall depicting the oxidant requirements from the ASU. Fluxing agents to control slag viscosity have been neglected in this study, but this plays no role anyway for the coals in question.

The gas quench has been assumed fixed at 900 °C using syngas at 200 °C. A high quench temperature is sought to get optimal heat recovery with HP steam for power applications. The temperature is also set to solidify molten slag particles and to reduce fouling of the SGC and downstream equipment. The gas quench at NUON has proven to be a very robust solution (Elliot compressor).

Cold syngas efficiencies are relatively constant for the different feedstock's, i.e. in the order 81-83 %LHV with raw syngas heating values between 11.5 and 12.3 MJ/kg LHV. CO₂ contents of the syngas may be as low as 2 v%.

The MP steam make from the reactor membrane walls are minimized and kept at 50 bar. This typically results in 0.1-0.2 kg/kg MP steam generation per raw syngas produced which is fed directly to the Reheat superheater coil of the HRSG (pressure downgraded to 25-30 bara). It is also used as SCGP moderator steam of the gasifier itself. The bulk of the sensible heat generated in the reactor outlet is used to generate HP steam in the convective SGC. The quality of steam production in the SGC is varied in the study from 50 to 125 bar. With 125 bar HP steam some 2.8 to 3 kg/kg HP steam per raw syngas is produced. The split between MP steam and HP steam can be varied and optimized for each project. In this study HP steam is generated directly after the gas quench at 900 °C.

The higher steam pressures will rapidly result in higher skin temperatures and intolerable lifetimes for low-alloy Cr-Mo steel. A higher alloy can meet these high steam pressures but at considerable extra costs as the next alloys that be used safely have a much higher Cr-Ni content.

IGCC CASE STUDY RESULTS

Table 6 – IGCC Process Parameters (Case: 800+ MW_e 2*W501G, 125b HPS)

Source	USA	Pitts8	PRBasin	PRB/Coke	Remarks
Coal intake	[t/d]	5201	5918	5219	Dried basis
Slag/ash	[t/d]	540	378	179	Zero \$value
Sulfur	[t/d]	150	22	126	Zero \$value
CO ₂	[t/d]	13782	14036	14230	Excludes SRU
Water in	[t/d]	19829	20451	20131	Cooling towers + ZDU
Gross Power	[MW _e]	934	943	928	
Net Power	[MW _e]	819	837	818	Target 800
S removal	[%]	99	99	99	Premises
NOX	[ppm]	25	25	25	@15v% O2
Overall Eff	[%LHV]	46.9	48.5	47.2	IGCC Tool
	[%HHV]	45.3	46.8	45.6	IGCC Tool

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Sulfur recovery has been set at 99% to sustain low SO₂ emissions of the plant and to allow deep heat recovery in the HRSG stack. NO_x emissions have been set at 25 ppmv @15v% O₂ to be achieved by diluting the syngas with nitrogen and/or by saturating it with water, which means that additionally controlled with SCR, emission limits below 5 ppmv are achievable. The latter has not been added in the cost estimate.

The results table above are for a 2*W501G based 800+ MW_e IGCC with 2 gasifier-gas cleanup trains and 2 ASU's integrated for 50% on air. The steam system in this IGCC uses a 125 bar SGC and a 120 bar HRSG boiler for maximum steam pressures with superheat and reheat in the HRSG around 560-550 °C. Overall LHV efficiencies stay then in the 47-48.5 %LHV range depending on the feedstock similar to the NETL studies [12][28], but with somewhat more conservative gasification parameters.

The relatively high water intake is caused by the open recirculating CW system with forced mechanical draft Cooling Tower cells. Alternatively in more arid/dry areas A-frame steam condensers may be used at the expense of performance loss due to the higher steam condensing pressure with air.

Table 7 – IGCC Investment Costs (Case: 800+ MW_e 2*W501G, 125 bar HPS)

Source	USA	Pitts8	PRBasin	PRB/Coke	Remarks
Syngas MF gen	[MMS]	95	101	98	
Syngas MF H ₂ O	[MMS]	35	37	36	
AGR-SRU	[MMS]	63	67	67	
ASU	[MMS]	84	76	79	
Gasification	[MMS]	316	333	318	
CCPP	[MMS]	343	374	352	
Total	[MMS]	936	988	950	
Syngas MF gen	[\$/kW _e]	116	121	120	
Syngas MF H ₂ O	[\$/kW _e]	43	44	44	
AGR-SRU	[\$/kW _e]	77	80	82	
ASU	[\$/kW _e]	103	91	97	
Gasification	[\$/kW _e]	386	398	389	
CCPP	[\$/kW _e]	419	447	430	
Total specific	[\$/kW _e]	1143	1180	1161	Based on net power

Table 8 – IGCC Economics (Case: 800+ MW_e 2*W501G, 125 bar HPS)

Source	USA	Pitts8	PRBasin	PRB/Coke	Remarks
ROI	[%]	13.3	13.8	15	Harvard Report simulation
ROE	[%]	28.7	31.1	36.2	Harvard Report simulation
Payback equity	[years]	4.2	3.8	3.1	
NPV	[MMS]	278	326	326	Harvard Report simulation
Break-even P _{elec}	[\$/MWh]	31	30	27	@Input fuel price Table 3
Break-even P _{fuel}	[\$/MMBtu]	2.7	2.8	2.8	@Input electricity price Table 3

The economic results for the 800 MW_e IGCC on 3 different feedstock's are illustrated in Table 7 and 8. With electricity tariffs around 27-31 \$/MWh and NG pricing < 2.8 \$ MMBtu IGCC is not competitive, while assuming electricity and natural gas pricing are coupled as per study premises. If the electricity tariffing and NG pricing surpass the 40 \$/MWh and 4 \$/MMBtu as is currently the case in certain US states, IGCC becomes attractive indeed [24].

DISCUSSION RESULTS

Sensitivity Water-Steam cycle (ASU & heat integration) parameters

Each IGCC project will have a strong focus on optimizing the water-steam cycle, while costs including plant standardization, operability and maintainability issues stay under control:

- Keep SGC design simple at lowest steam pressure being $P_{\text{gasif}}+10$ bar for both membrane wall cooling (MP Steam) and Syngas Cooler (HP Steam)
- Supply steam requirements in Gasification Island and Syngas Manufacturing Process Plants from within resulting in practically no need for steam from the Power Block
- Optimize heat recovery between SGC-Water Scrubber and COS Hydrolysis plant and COSH-AGR plant to avoid heat losses in process water or cooling water
- Maximize N₂ return temperature from ASU to GT in feed/effluent heat exchanger with almost same mass flows and dump remaining heat GT air in condensate return loop
- Preheat syngas to maximum temperatures ~ 300 °C provided NO_x limits are not jeopardized in the GT combustor, optimize syngas saturation and/or N₂ saturation at lower temperatures respecting dew point, mass flux restriction as per GT vendor
- Verify ASU operating window on power, O₂/N₂ (im)purity and compressor drivers
- Apply highest possible superheat/reheat, e.g. 560-550 °C for W501G at ST HP admission, 25-30 & 4-5 bara cross-over pressure for MP&LP admission
- Apply lowest condenser pressure for @10% wetness in the ST with corresponding coolant design selections, e.g. cooling towers
- Ignore SO₂ dewpoint stack temperature limitation when Sulfur-removal has reached a certain threshold value
- Apply minimum HRSG stack temperature and 2p or 3p pressure boilers depending on interface with Gasifier (amount and quality of steam/BFW) and SO₂ dewpoint
- Apply Blowdown recovery; use overall condensate heat recovery between Syngas Manufacturing and Power Block islands

This study has assumed values for each of these conditions above based on earlier projects, studies and experience without trying to seek the final optimum. One parameter has been selected for further discussion, i.e. the maximum steam raising pressure in the SGC of the SCGP, while assuming this pressure is also coupled with the maximum pressure of the HRSG.

The high steam pressures in the IGCC design increases IGCC efficiency some 1.5% when comparing 125 bara vs 50 bara steam production in the Syngas Cooler. This difference may increase to 2.5% when comparing 180 bara with 50 bara steam. In this comparison the maximum steam pressure in power block (ST-HRSG interface) is assumed to follow with highest steam pressure selected in the gasification island, while maintaining the reheat feature. The reheat function is attractive as when comparing a dual pressure (HP/LP) process without reheat with a triple pressure (HP/MP/LP) process with reheat the efficiency loss is in the order of 1 percentage point, while costs on the ST-HRSG interface are marginally affected.

The 125 bar SGC case (almost similar to NUON and used in many studies as mentioned before) has a traditional 3p HRSG whereas the 50 bar SGC results in a 2p HRSG with simultaneously lower ST admission pressures. The lower ST admission design will result in marginally higher inlet pumping costs. The HRSG system will be lower in costs due to 20% lower heat transfer surface area. It is expected that a 800 MW_e system will save costs for the Power Block, however, pending on use of standardized steam turbine components.

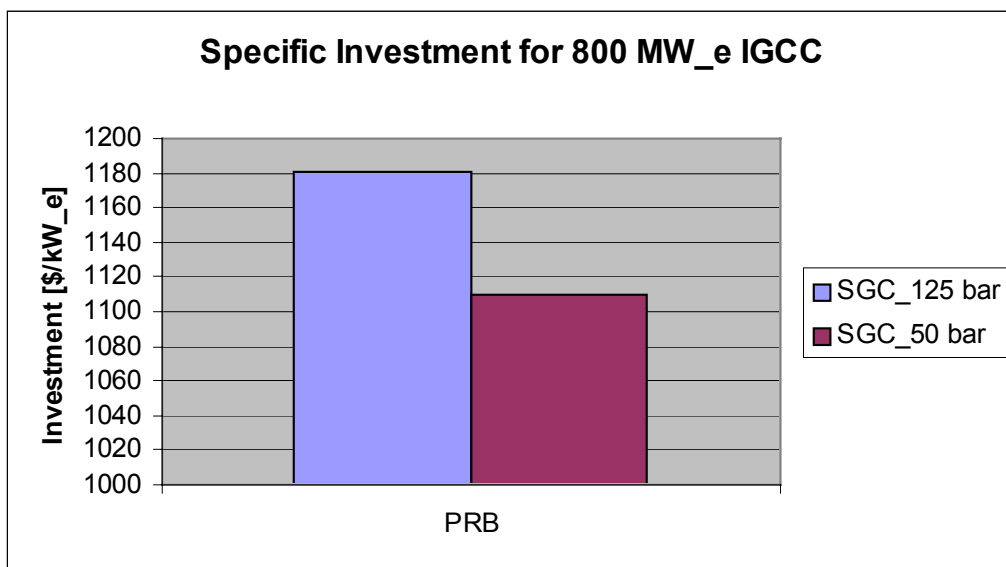


Fig. 4 - Sensitivity Maximum HP Steam Pressure of SGC and HRSG

The overall result, i.e. gasification and power island combined, shows a 5-6% drop in investment level at least due to a much cheaper Syngas Cooler, simpler HRSG (2-p in stead of 3-p and less heat transfer area).

It must be emphasized that the selected 50 bar HPS system may be higher depending on coal-petcoke as long as the high alloys in the SGC can be avoided. Alternatively, the HP steam pressure may not necessarily depict the maximum steam pressure for ST-HRSG interface. A separate superheating coil and steam admission port of the steam turbine may offer a better optimum. This needs to be checked for each project in particular. The optimum solution for a low-cost PRB based project with deferred CO₂ capture may well be in the 70-80 bara range, while the Power Block may still have a separate higher steam pressure depending on the economics of the ST-HRSG interface.

Sensitivity Economy Of Scale

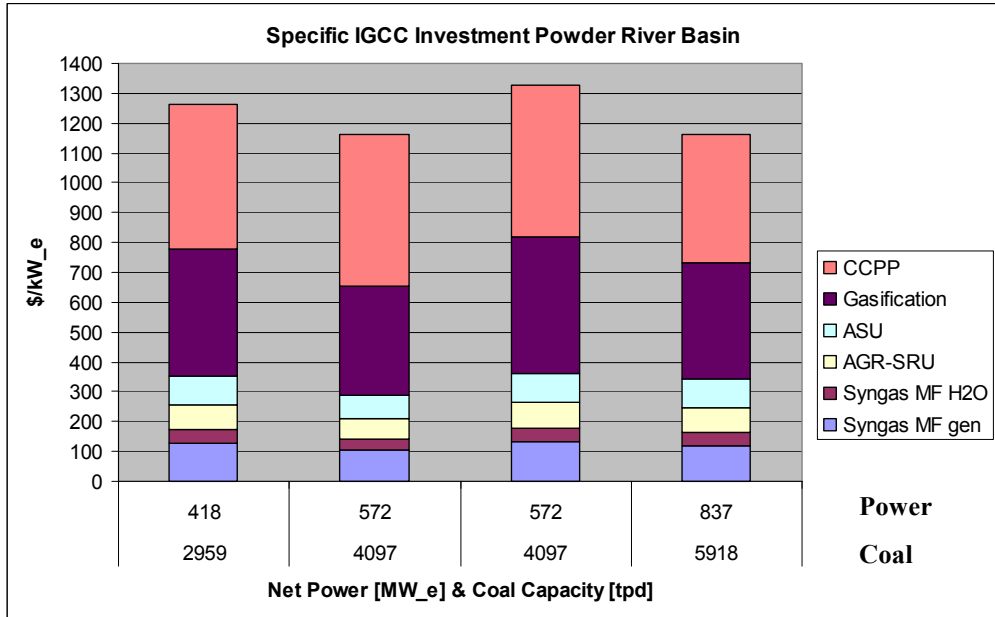


Fig. 5 – Sensitivity SCGP Scale for Specific IGCC Investment Costs

Fig. 5 illustrates the economy of scale for 3 dried coal capacities, i.e. 3000, 4000 and 6000 t/d Powder River Basin. The base case IGCC for 800 MW_e net power (Tables 6,7,8) based on 2*W501G (2*400 MW_e) is also calculated for 400 and 550 MW_e net power. The 550 MW_e IGCC has 2 configurations investigated, i.e. one with 2 string gasifiers, gas cleanup and ASU's and one with a single string gasifier, gas cleanup and ASU. Latter option provides a similar economy of scale as the 800 MW_e configuration around 1160 \$/kW_e excluding Owners Costs. The single string approach will obviously still respect sparing of critical items in the CMD, feed and filter sections.

Moreover, IGCC costs may be reduced further below 1100 \$/kW_e values with simpler steam raising conditions as discussed before. The results in Fig. 5 are still based on 125 bar steam production in the SGC and similar maximum pressure in the HRSG.

Sensitivity coal feed quality

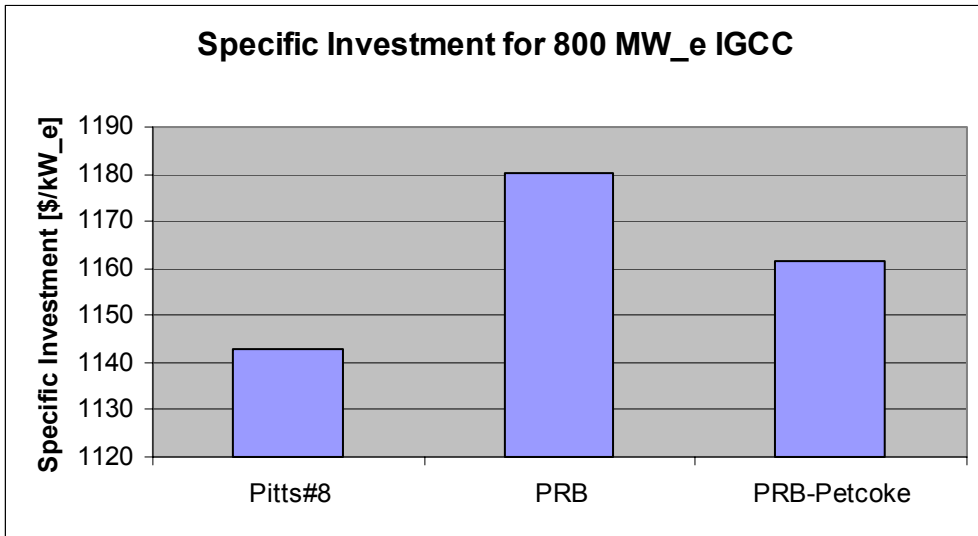


Fig. 6a - Sensitivity US coals on SCGP-IGCC investment costs

The important constituents in the study coals affecting the economics are:

- Sulfur 0.4-3 wt% (Petcoke ~4 wt% S)
- Ash 2.4-10 wt%
- Moisture 6-32 wt% (Petcoke ~20 wt% H₂O)

Contrary to the slurry feed and refractory lined competition, SCGP can handle a large variety of coals and pet coke mixes without a significant impact on the \$/kW_e, efficiency, heat rate and operating costs. The maximum variation found in this study between bituminous coal and sub-bituminous coal was 3-4%, which is much lower than the 20% reported for the competition [4].

The relatively high moisture content in PRB coal (5 times as much as Pitts#8) will obviously have a penalty on IGCC efficiency with the SCGP requirement to allow only some 5% moisture in the feed system. This may result in an efficiency drop as mentioned if syngas is taken as drying medium.

The other widely published reference coal Illinois #6 has not been studied in detail, but will show poorer results than above due to the combination of high ash content and a relatively poor heating value. Consequently results may be 4-5% more capital intensive and 2%-points less efficient than comparable PRB runs, including compensation for drying. The overall efficiency of PRB, however, will remain high ~45%HHV as the drying heat requirements are partly offset by a larger steam generation capability from the Syngas Cooler.

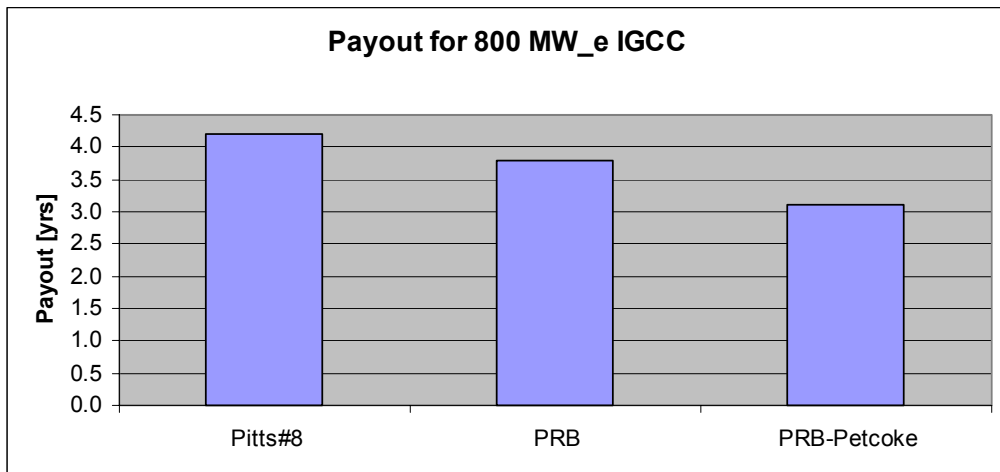
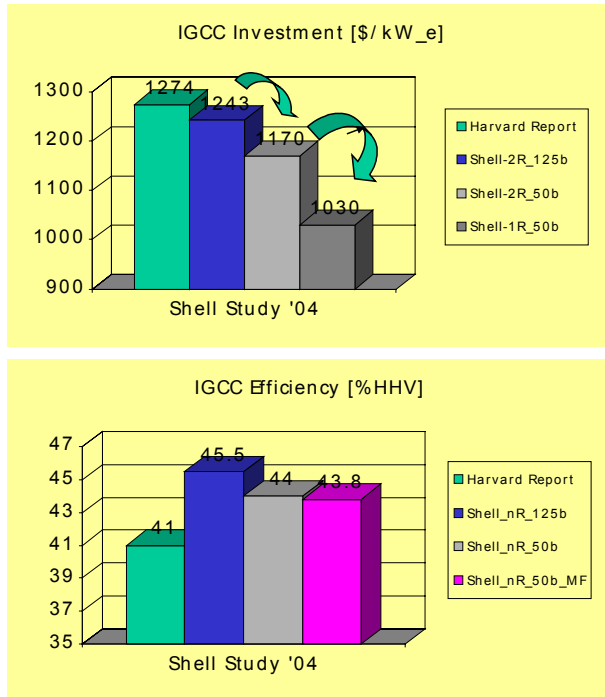


Fig. 6b - Sensitivity US coals on SCGP-IGCC economics

A 50-50 wt% mix of PRB with petcoke still has a lower Sulfur load on the SRU than Pittsburg #8 and can reduce feed drying requirements as well, while benefiting from low feed costs and high heating value (see Fig. 6b). On the other hand PRB supplies ash to the system keeping the reactor slagging with less slag recycle needed when processing petcoke alone. Optimizing such feeds is an easy task for SCGP provided that the total ash and sulfur load are designed proper for the worst case. The figure clearly shows the NPV power when mixing PRB with cokes. Similar trends may be achieved with the other coals.

CONCLUSIONS



- **Ref. Harvard Report/ EPRI Summary Cases '03:**
 - 2*7FA Power Block for 550 MW_e IGCC
 - Double Gasifier – Syngas Manufacturing FP Blocks
 - Owners Costs/ Contingency 4% included
- **Shell New Comparison [US Paper 2004]:**
 - R_SGC supply offshore (10% FOB Cost Improvement)
 - Single/ Double Gasifier – Syngas Manufacturing Blocks
 - 2*W501F Power Block for 550 MW_e IGCC
 - Shell study '04 WITHOUT Owners Costs/ Contingency
 - BOP more robust (Cooling Towers, FO back-up fuel)

Fig. 7 – SCGP Value Options for 550 MW_e IGCC with Pitts#8 coal

The Shell Coal Gasification Process (SCGP) is especially suited for Integrated Gasification Combined Cycle (IGCC) applications targeting highest achievable cycle efficiencies in the market in line with DOE's Vision 21, including high upscaling potential and high reliability.

The base case 800 MW_e IGCC with 2 power blocks based on the W501G gas turbine running on Pittsburgh #8 or Powder River Basin with 125 bara (1810 psia) steam production will cost 1143 - 1180 \$/kW_e at efficiencies 45.3 – 46.8 %HHV respectively, while excluding Owners Costs and drying fuel (net power). The scope of plant has been designed conservative on a number of aspects like higher syngas pressure (drop) assumptions and inclusion of Cooling Towers, Fuel Oil back-up. The effect of coal drying is marginal for Pittsburgh#8.

The same plant configuration can be 5-6% lower in \$/kW_e costs with a simpler Syngas Cooler system (Max. steam pressure 50-70 bara, 725-1015 psia to avoid high alloys), albeit at 1.5% lower IGCC cycle efficiency.

An alternative plant size at 550 MW_e based 2*W501F or equivalent GT size running on Pittsburgh#8 may also benefit from even larger economy scale SCGP Reactor and Syngas Coolers. A single string syngas manufacturing system can have 12% lower \$/kW_e IGCC costs compared to dual string 2000 t/d solution bringing investment down from 1243 to 1170 \$/kW_e. This system will also be in the order of 45 %HHV efficient.

Both options combined, i.e. simpler steam system and maximum scale-up SCGP in 550 MW_e capacity will result in IGCC costs around 1030 \$/kW_e with an overall net cycle efficiency of approx. 43.5% HHV on Pittsburgh#8. The investment for Powder River Basin with or without petcoke co-mixing will be 3-4% higher, albeit overall economics are more interesting due to the low feed costs and sustainable high net cycle efficiencies.

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ABBREVIATIONS

AGR	Acid Gas Removal
AR	As Received
ASU	Air Separation Unit
BOP	Balance Of Plant
CCPP	Combined Cycle Power Plant
CMD	Coal Milling & Drying
COSH	COS Hydrolysis
CT	Cooling Tower
CW	Cooling Water
DOE	Department Of Energy USA
DSR	Dry Solids Removal
ETP	Effluent Treatment Plant
EWS	Effluent Water Stripping
FO	Fuel Oil
GI	Gasification Island
EPC	Engineering, Procurement & Construction
EPRI	Electric Power Research Institute
GE	General Electric
GT	Gas Turbine
HHV	Higher Heating Value
HPS	High Pressure Steam
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
MPS	Intermediate Pressure Steam
JV	Joint Venture
LPS	Low Pressure Steam
LHV	Lower Heating Value
MAF	Moisture Ash Free
MF	Moisture Free
MPS	Medium Pressure Steam
NETL	National Energy Technology Laboratory USA
NG	Natural Gas
NPV	Net Present Value
O&M	Operating & Maintenance (Costs)
PB	Power Block
PC	Pulverized Coal (Combustion)
PRB	Powder River Basin
R	Reactor
SCGP	Shell Coal Gasification Process
SCR	Selective Catalytic Reduction
SGC	Syngas Cooler
SF	Scaling Factor
SMPP	Syngas Manufacturing Process Plants
SRU	Sulfur Recovery Unit
WS	Wet Scrubber
ZDU	Zero Discharge Unit