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July 30, 2009

Joseph McCarthy
Director (Projects)
Perdaman Chemicals and Fertilisers Pty. Ltd.
Level 4, 172 St. Georges Terrace
Perth, WA 6000

Dear Joe,

Following is the July 30 report.

Best Regards,

Keith J. Stokes

Review of the Technology Selections

for

Perdaman Chemical and Fertilisers Pty., Ltd.

By

Stokes Engineering Company

July 30, 2009

Contents

1.0 Scope of Work

Perdaman Chemicals and Fertilizers (PCF) asked Stokes Engineering Company to review its ammonia synthesis, urea synthesis, and urea granulation technology selections in terms of experience, efficiency, and emissions compared with the best available technologies.

2.0 Introduction

PCF's technology selections are:

Process	Licensor
Ammonia Synthesis	Topsøe
Urea Synthesis	Stamicarbon
Urea Granulation	Stamicarbon

PCF's project will include the world's largest single-train ammonia synthesis section (synloop). Topsøe's design package will include the ammonia converter, syngas compressor, refrigeration compressor, heat exchangers, knock-out drums, pumps, and piping specifications. Topsøe is a top ammonia process licensor. On the urea side, PCF's project will include two Stamicarbon urea synthesis trains and two granulation trains. Stamicarbon has the world's best urea technology. It has been the leading technical innovator since 1954.

3.0 Summary and Conclusions

Ammonia Synthesis
Topsøe can achieve 3,500 mtd using equipment that has been field-proven at effectively the required process duty. Topsøe's synloop energy efficiency equals or exceeds the industry standard. Its synloop emissions will be negligible except during plant startups and plant upsets. All pressure safety valves and vents exhaust to a flare.

Urea Synthesis
Stamicarbon's Urea2000plus Pool Condenser technology is proven. Its energy efficiency and emissions are the best in the industry.

Urea Granulation
Stamicarbon's urea granulation technology is proven. Its energy efficiency and emissions equal or exceed the best in the industry.

4.0 Ammonia Technology

4.1 Experience PCF has selected a Topsøe 3,500 mtd single-train synthesis loop.

Siuci, at 2,000 mtd, is Topsøe's largest onstream reference plant to date. It started up this year in Sohar, Oman.

Engro in Pakistan, at 2,200 mtd, is Topsøe's largest plant presently under construction. It should start up next year.

Qafco in Qatar, at 2,200 mtd x 2, is also under construction and should start up in 2011.

Siuci, Engro, and Qafco are natural-gas-based plants. PCF's gasification-based plant will have a lower inerts level in the synloop. Also, Topsøe plans to raise PCF's synloop operating pressure to achieve 3,500 mtd.

4.2 Efficiency Topsøe's synthesis loop energy efficiency equals the best available for magnetite catalyst and synloops of comparable investment cost.

4.3 Emissions PCF's ammonia plant will be designed to U.S. and European standards and its emissions will be as low as the best technology can ensure.

Continuous Emissions A header system will route all emissions to a flare. The emissions of consequence are hydrogen and ammonia. The flare will combust them.

The syngas and refrigeration compressors' dry-gas seals release small amounts of gas. The compressor vendors will make the expected flow rates available later in the project.

Intermittent Emissions Syngas is vented to flare during transient conditions. PCF might need to depressure the synloop to safeguard against fire or before doing maintenance work. Depressuring flows should not exceed 75,000 Nm^3/h and might take 15 to 30 minutes every two years. PCF may route the synloop gas to an offsite syngas header.

Refrigerant. PCF may choose to empty the circuit of 600 Nm^3 of ammonia every five years.

Table 1 Emergency Emissions						
Item	Max Flow Nm^3/h	To	Percent Gas Composition			
			H_2	N_2	NH_3	Ar
Syngas Compressor PSV	386,000	Flare	71	24	4	1
Refrigeration Compressor PSV	129,000	Flare	0.03	0.03	99.93	0.01
Chiller Tube Rupture	75,000	Flare	67.7	22.5	6.7	1.1
Water Cooler Tube Rupture	38,000	Safe Location	57.4	19.1	22.5	1.0
Fire safety PSVs, NH3 Vessels	11,000	Flare	0	0	100	0
Fire Safety PSV, Synloop	1,000	Flare	72	24	3	1
1st Let Down Drum PSV	110,000	Flare	71	24	4	1

5.0 Urea Technology

5.1 Experience

Urea Synthesis PCF has selected Stamicarbon's Urea 2000plus Pool Condenser technology. Urea producers have used this technology in new grassroots plants and plant revamps since the mid-1990s. It saves investment cost and energy.

Significant corrosion used to occur in urea plants until Stamicarbon found that small amounts of oxygen greatly alleviated the problem. The discovery led to Stamicarbon's ground-breaking oxygen patent in 1954. In 1956, DSM, Stamicarbon's parent company, began operating the first oxygen-passivated urea plant and, today, Stamicarbon has about a 66 percent share of new capacity.

However, oxygen injection is not an ideal solution and in recent years Stamicarbon, in partnership with Sandvick Steel, has developed Safurex, a proprietary, non-corrosive duplex steel. Safurex needs less oxygen to passivate and long-term testing in the field may show that no oxygen is needed. PCF has adopted the standard industry wait-and-see practice of using Safurex while continuing to inject a reduced amount of oxygen. This approach means less inerts, less purge to remove the inerts, and, consequently, more urea for the same energy. Safurex steel equipment, operating at PCF's proposed reduced oxygen level or lower, has proven satisfactory to date but is not critical because, if industry experience warrants (over the next 10 to 30 years), PCF can revert to normal oxygen levels.

PCF has opted for a two-train urea scheme to produce 6,200 mtd urea. Each 3,100 mtd train will have a urea synthesis section followed by a granulation unit. Matching a single-train ammonia plant with two urea trains is accepted industry practice, especially in large-capacity projects, because it allows the ammonia plant to keep operating even when one urea unit is offline.

Yara is building a larger, single-train pool condenser plant (3,500 mtd) in Sluiskil, Netherlands. Startup is slated for 2011. Seven pool condenser plants are under construction in China and three are in successful operation.

Table 2 Stamicarbon's 2,200 mtd and Larger Plant Experience				
Capacity mtd	Owner	Location	Startup	Safurex
2,840	Hulunbeier	China	2011	Yes
3,500	Yara	Netherlands	2011	Yes
3,500 x 2	Sorfert Algerie	Algeria	2011	Yes
2,200 x 3	Pequiven	Venezuela	2011	Yes
3,250	NPC-Lordegan	Iran	2011	Yes
3,250	NPC-Golestan	Iran	2011	Yes
3,250	NPC-Zanjan	Iran	2011	Yes
2,700	Jianfeng Chem	China	2010	Yes
3,250	PIDMCO	Iran	2009	Yes
3,250	SAFCO	Saudi	2006	Yes
3,250	CNCCC	China	2004	Yes
3,250	PIDMCO	Iran	2004	Yes
3,200	QAFCO	Qatar	2004	Yes

Urea Granulation PCF has selected two trains of 3,100 mtd. Stamicarbon has demonstrated its granulation technology in several plants, including three 2,000 mtd units in Egypt. (The first unit came onstream in 2006.) Five units of 3,600 mtd to 4,400 mtd are under construction and should start up in 2010 and 2011 in Egypt, Iran, and Venezuela.

5.2 Efficiency Stamicarbon's Urea2000Pool Condenser process uses less energy per tonne of urea than conventional processes.[1]

[1] Henke Perrée, "Revamping Conventional Urea Plants," *FINDS,* Vol. XII, No. 4 (1997)

5.3 Emissions PCF's urea plant will be designed to U.S. and European standards and its emissions will be as low as the best technology can ensure.

Synthesis Because Safurex does not need oxygen protection, Stamicarbon's inerts load and, therefore, its emissions are less than one-third of the traditional amount. In addition, all pressure safety valves exhaust to a flare stack. Stamicarbon's expected maximum ammonia loss in the synthesis section is 0.15 kilogram of ammonia per tonne of urea (0.026 percent of the 567 kilograms theoretical ammonia consumption).

Granulation Stamicarbon launched its own granulator design in 2003. Stamicarbon's process uses less urea-formaldehyde and produces less dust than competing systems, without reducing the mechanical strength of the granules. Stamicarbon's film-spraying technology provides these advantages over the leading competitor and also improves granulator-cleaning cycle time. Stamicarbon's expected emissions in the granulation plant stack are 135 mg/Nm^3 ammonia and 25 mg/Nm^3 urea. The guaranteed maximum emissions in a competitor's granulation plant are 160 mg/Nm^3 ammonia and 40 mg/Nm^3 urea.

6.0 Stokes' Résumé and Publications and SEC's Job List

KEITH J. STOKES

Manchester University, BSc, Hons., Chemical Engineering
New York University, MBA
Licensed Professional Engineer

In 1986, Stokes formed Stokes Engineering Company (SEC) and started *FINDS*, a publication of SEC. Stokes mainly represents the owners and lenders on new ammonia/urea projects. The job list on pages 11 and 12 includes the new-plant projects. SEC's bank clients have included the World Bank, the Asian Development Bank, Goldman Sachs, Santander, Citicorp, JABIC, Macquarie, ANZ, National, Bank of Scotland, and Bank of Montreal. Stokes has been the lead technical evaluator, bank's engineer, and owner's engineer on numerous projects.

Stokes' Employment:

1971-1986: James Chemical Engineering. Ammonia specialist. Stokes' projects included:

New ammonia plants: Prequalified contractors, prepared ITBs, reviewed bids, supervised contractor's work for Pusri and Kujang projects, Indonesia; AFCC, Bangladesh; Fauji, Pakistan; Talkha, Egypt; Petrocorp, New Zealand.

Ammonia plant optimizations and revamps: Prepared plans for optimum stepwise investment to increase reliability, save energy, and increase capacity and helped with implementation for Petrocorp, New Zealand; Austral Pacific, Australia; Kujang and Petrokimia, Indonesia; Zuari Agro, India; SAFCO, Saudi Arabia; TVA, U.S.A.; Amocar and Petrosur, South America.

Evaluations of new ammonia-related technology: Served as arbiter for Union Carbide and Monsanto in evaluations of their new ammonia-related technology. Evaluated new petrocoke gasification process for Allied Chemical Corporation.

Market surveys: Conducted market surveys in North America and worldwide for Monsanto before the unveiling of its new product (PRISM).

Feasibility: Evaluated the feasibility of projects for New Zealand, Pakistan, and the U.S.A. Project manager for a DAP, NPK feasibility study for Pakistan.

Legal: Presented technical reports to support Mississippi Chemical's and Allied Chemical's claims before the Federal Power Commission's hearings. Technical advisor to Travelers Insurance Company in its suit against an ammonia plant designer.

Pre-1971: Scientific Design Company (U.K./U.S.A.). Projects included a gas treatment plant proposal for New Zealand and a plant commissioning in India.

Foster Wheeler, Ltd. (U.K.). Operating engineer. Projects included an ammonia plant startup in Kuwait.

Fison's Fertilizers, Ltd.(U.K.). NPK granulation plant test runs.

Publications:

"Ammonia Construction Record and Comments on Ammonia Fuel," The Iowa Energy Center's Ammonia Fuel Conference, San Francisco, October 2007.

"Nitric Acid Plant Construction and Changes in the HDAN Market," Johnson Matthey's NAUG XIV Conference, Hilton Head, South Carolina, May 2007.

"Ammonia Reinvestment Issues," BMO Nesbitt Burns' 2006 Global Fertilizer Conference, Toronto, Canada, April 3, 2006.

"A Status Report On New Worldwide Ammonia Plant Activity," Green Markets' Audio Conference, February 1, 2006.

"Urea Plant Construction Update," Wah Chang 2003 Corrosion Conference, Coeur d'Alene Resort, Idaho, September 2003. Published in *FINDS* Vol. XVIII, No.3.

"Ammonia Supply in the 21st Century," The Fertilizer Institute Outlook 2000 Conference, Waterfront Marriott Hotel, Annapolis, Maryland, November 1999. Published in *FINDS* Vol. XIV, No. 4.

"The Ammonia Plant Construction Record, and, Prices Paid for Ammonia Plants in 1990s Acquisitions, Mergers, New Construction, and Plant Relocations, " *Green Markets* 1996 Fertilizer Trends Conference, Stouffer Vinoy Resort, St. Petersburg, Florida. Published in *FINDS* Vol. XI , No. 4.

"The Urea Plant Construction Record from 1985 to 1996," *Green Markets* 1993 N/P Conference, Longboat Key, Florida. Published in *FINDS*, Vol. VIII, No.4.

"A Review of the Ammonia Plant Construction Record from 1985 to 1995," *Green Markets* 1992 Nitrogen Conference, Clearwater, Florida. Published in *FINDS*, Vol. VII, No.4.

"Energy Efficiency in Ammonia Plants," AIChE's National Meeting, Washington, D.C., November 1983. Co-authored with G. R. James. Published in *Chemical Engineering Progress*, June 1984.

"Choosing an Ammonia Plant CO_2 Removal System for Today's Conditions," British Sulphur Corporation's Fourth Annual Conference on Fertilizer Technology, London, January 1981,published in *Nitrogen*, No. 131, May/June 1981.

"Economics of CO_2 Removal in Ammonia Plants," AIChE's 72nd Annual Meeting, San Francisco, November 1979. Published in *Ammonia Plant Safety*, Vol. 22.

"Maximizing Production in Ammonia Plants," "Hydrogen '79" Seminar, London, March 1979.

"A Review of Compression Systems for Ammonia Plants," AIChE's 71st Annual Meeting, Miami Beach, November 1978, published in *Chemical Engineering Progress*, July 1979.

"Economics of Flue Gas Heat Recovery," AIChE's 83rd National Meeting, March 1977, published in *Chemical Engineering Progress*, November 1977.

United States Patents:

Recovery of Heat from Flue Gas, 1981.
Urea Condensate Hydrolyzer/Stripper, 1985.

SEC Job List 1996 to the Present

Client	Country	Category	Type of Work	From	To
Private Bank	U.S./Canada	Ammonium Sulfate	Private equity due diligence	2008	2009
IFDC	Rwanda	Ammonia,U	New Plants, feasibility	2008	2008
Urea Producer	Australia	Urea	Revamp	2008	2008
Ammonia Producer	Australia	Ammonia	Plant Relocation	2006	2009
AN Producer	Canada	AN	Valuation	2007	2007
Ammonia Producer	Canada	Ammonia	Legal	2007	2007
Insurance Company	U.S.	AN	Legal	2006	2007
Insurance Company	U.S.	Ammonia	Legal	2006	2006
Confidential	Indonesia	NA, AN	New Plants	2005	2007
Confidential	Colombia	Ammonia	New Plant	2005	2005
Confidential	Colombia	Ammonia	Acquisition diligence	2005	2005
Confidential	Australia	Ammonia	New Plant	2004	2005
Confidential	Indonesia	Ammonia	New Plant	2004	2005
Macquarie Bank	Australia	Ammonia	New Plant	2002	2005
JABIC	Oman	Ammonia, U	New Plant	2004	2004
CitiCorp	U.S.	Nitrogen producers	Performance Overview	2001	2004
USDA	U.S.	Ammonia and derivatives	Energy values	2003	2003
Private Bank	U.S.	AN	Enterprise Value	2003	2003
Pegasus (Venture Capital)	U.S.	Ammonia, UAN	Acquisition diligence	2003	2003
AN Producer	U.S.	Ammonia, AN, Urea	Acquisition diligence	2003	2003
AN Producer	U.S.	AN	Legal	2003	2003
Confidential	Uzbekistan	AN	Market	2003	2003
Fuel Cell Company	U.S.	Ammonia	Market	2003	2003
Confidential	U.S.	Ammonia, NA, AN	Appraisal	2002	2003
Private Bank	U.S.	Mixed Fertilizers	Inventory appraisal	2001	2003
WMC	Australia	Ammonia	Optimization	2002	2002
Private Bank	U.S.	Ammonia, UAN	Appraisal	2001	2002
Abocol	Colombia	Ammonia/hydrogen	Various	2000	2001
Private Bank	Mexico	Urea, AN	Acquisition	1999	1999
Confidential	U.S.	Ammonia	Legal	1999	2000
Confidential	Arab Gulf	Ammonia	Cash Costs	1999	1999
Confidential	Egypt	Ammonia	Commercial	1999	1999
Justice Depart.	U.S.	Ammonia, methanol	Legal/Taxation	1996	1999
Incitec	Australia	Ammonia, U	New Plants, various	1986	1998
Confidential	Canada	Ammonia	Legal	1998	1998
Confidential	Chile	Ammonia	Cash Costs	1998	1998
Goldman Sachs/Sant.	Venezuela	Ammonia/U	Project financing	1997	1997
Enron	India	Ammonia	LNG Feedstock	1997	1997
Confidential	Middle East	Ammonia/U	New Plants	1997	1997
Confidential	SE Asia	Ammonia	Survey	1997	1997
Incitec	Australia	Urea	New Plant	1997	1998

Abbreviations:NA=Nitric Acid; AN=Ammonium Nitrate; U=Urea; UAN=Urea, Ammonium Nitrate

SEC Job List 1986 to 1996

Client	Country	Category	Type of Work	From	To
Confidential	Confidential	Ammonia, UAN	New Plants	1996	1997
Minter Ellison	Australia	Ammonia	Legal/Taxation	1996	1998
Confidential	Confidential	AN	Legal	1995	1997
Simplot	U.S.	Ammonia	New Plant	1995	1996
Agrium	Argentina	Ammonia,U	New Plants	1994	1995
IFC	Ukraine	Ammonia,U,UAN	Privatization	1994	1995
Oman Oil Company	Oman	Ammonia,U	New Plants	1994	1997
IFDC	Albania	Ammonia, U, AN	Technical	1994	1994
HB/ADB	China	Ammonia	Technical Survey	1994	1994
Afpenn	Zimbabwe	Ammonia	Feasibility	1993	1993
UNOCAL	U.S.	NA	Commercial	1992	1992
World Bank	Bénin	Blending	Privatization	1992	1992
Mississippi CC	U.S.	NA	Commercial	1991	1991
Petrokimia Gresik	Indonesia	Ammonia,U	New Plants	1991	1994
Roundup Powder	U.S.	NA,AN	New Plants	1991	1991
Confidential	Middle East	Ammonia	Commercial	1991	1991
Petrokimia Gresik	Indonesia	Phosphate	Plant Mods.	1990	1990
Simplot	Canada	AN	New Plant	1990	1991
Simplot	Canada	Urea	Revamp	1990	1990
World Bank	Indonesia	Ammonia,U	Bid Evaluation	1990	1990
Kujang	Indonesia	Ammonia	Commercial	1989	1989
NKFV	Hungary	Ammonia,U,NA	Privatization	1989	1989
Simplot	Canada	Ammonia,AN	New Plant	1989	1991
AECI	South Africa	Ammonia	Commercial	1988	1989
CEPEX	U.S.	UAN	Plant Pricing	1988	1988
Koneba	Indonesia	Ammonia	Process	1988	1989
Kujang	Indonesia	Ammonia	Process	1988	1988
Simplot	U.S.	Ammonia,U,NA	Technical	1987	1987
World Bank	Poland	U	New Plant	1987	1987
World Bank	U.S.	Ammonia	Technical	1987	1987
Petrocorp	New Zealand	Ammonia	Technical	1986	1992

Abbreviations:NA=Nitric Acid; AN=Ammonium Nitrate; U=Urea; UAN=Urea, Ammonium Nitrate

Technical Evaluation Report
on
Process Configuration of the Syngas Generation Block (consisting of the Shell Coal Gasification technology and Shell ADIP and SRU technology along with Haldor Topsoe CO Shift and UOP PSA technology) for Collie Coal to Urea Project in Australia

Chiyoda Corporation

July 30 2009

Contents :

1. Summary

This report has been prepared by Chiyoda Corporation for Perdaman Chemical and Fertilisers Pty Ltd to evaluate the package of technologies consisting of Shell Coal Gasification Process (SCGP), Haldor Topsoe CO shift, Shell ADIP for gas cleanup, Shell Paques for SRU and UOP PSA for the H_2 purification for Collie Urea Project in Australia. The technology package has been selected with confidence compared with their competitive technologies in the international market, in terms of experience, efficiency, economic and environmental.
The detailed discussions are made in the relevant paragraph in this report.

2. Process Configuration and the Licensed Technologies

Overall process configuration of this project is composed of two (2) blocks, i.e. the Syngas Generation Block and the Fertiliser Production Block.
The Attachment-1 shows the Block Flow Diagram of Coal Gasification to Fertiliser (Urea) Production with IGCC for the Collie Coal Gasification to Urea Project.
The selected licensed process of each block are as follows;

Syngas Generation Block :	
Composed process of Syngas Generation Block	Process Licensor
Coal Gasification	Shell SCGP
CO Shift	Topsoe Sour Shift
AGR (Acid Gas Removal)	Shell ADIP
SRU (Sulphur Recovery Unit)	Shell Paques
PSA (Pressure Swing Absorption)	UOP

Fertiliser Production Block :	
Composed process of Fertiliser Production Block	Process Licensor
Ammonia Process	Topsoe
Urea Synthesis Process	Stamicarbon
Urea Granulation Process	Stamicarbon

3. Comparison of the Licensed Technology of Syngas Generation Block and Technology Selection

3.1 Coal Gasification Technology

3.1.1 Comparison of Gasification Technologies and Suppliers

Table-1 provides the comparison of gasification technology data for the Shell SCGP Technology, Uhde Gasification (Prenflo) Technology, GE (former Texaco) Gasification Technology and COP (former E-Gas) Technology which has already been proven and commercialized technology and actually in operation.

3.1.2 Gasification Technology Selection

Among above four (4) proven gasification technologies, it is evaluated that the Shell gasification technology is the best selection for this project with the following aspects.

- SCGP has high cold gas efficiency (ratio of Higher Heating value of Synthesis Gas and Higher Heating value of Coal Feed) because the coal feed is injected into the gasifier dry. In competing technologies the feed is 'slurry' of coal in water. As a result the cold gas efficiency for the Shell dry coal feed process is about 3 percent higher than the coal water slurry feed gasification process.
- Due to the dry feeding system, SCGP is able to gasify virtually every coal type: low quality coals (lignite or brown coal) to anthracite and petcoke. The competitive technology of slurry fed system cannot process low rank coals like lignite or brown coal.
- SCGP has a high carbon conversion of over 99% versus 96-98% for slurry fed competing technologies.
- SCGP uses less oxygen consumption compared to slurry fed competing technologies to produce the same amount of syngas, resulting in a smaller Air Separation Unit capacity.
- Key component of SCGP – the coal burner has long lifetime. Long-term operation in Nuon's Buggenum Plant has a proved lifetime of the burners for different coals of over 20,000 hours. In competing technologies the burners need replacing every 1,500 – 4,500 hours.
- A key technology differentiator is the gasifier membrane wall, which was developed avoiding a refractory lined vessel not withstanding and slagging operating conditions for coal and especially petcoke gasification. The membrane wall surrounding the gasification chamber and therefore protecting the gasifier vessel is designed for long operating lifetime exceeding for standard application

25 years. Refractory lined competitive designs need regular yearly (or depending on application even more frequent) maintenance and part replacement. Eventually Shell's O&M fixed and variable costs are expected to be superior to the competitive technologies due to the long lifetime and robustness of the gasifier and burner.

- SCGP technology has a multiple burner design (4-8 burners), which allows for significant scale-up and turn down operation with associated capital cost advantages. A single gasifier can process more than 4,000 t/d of coal.
- A single train unit is expected to achieve over 90% reliability. The NUON IGCC power plant in Buggenum, the Netherlands, operating since 1993, and recently attains to 97.5% reliability. This plant was designed as a demonstration plant. Numerous improvements have been identified and engineered into new designs. Competing technologies using slurry fed systems and refractory lined gasifiers typically achieve only 80% reliability in a single train unit set up and 75% in an IGCC set-up.
- Shell Gasification Technology (SCGP & SGP) has proven experience as shown in the table below.

List of Gasification Plants Sorted by Licenser

	SHELL SCGP/SGP		Uhde Prenflo		GE (former Texaco)		Conoco Phillips (former E-Gas)	
		FEED		FEED		FEED		FEED
Reference Projects								
Operating	56	Coal/Heavy oil/Vac residue	1	Petcoke/coal mixture	71	NG/Crude oil/Vac	1	Petcoke
Planning	15	Coal/Pitch/Petcoke			15	Coal/Petcoke	9	Coal/Petcoke/ Bitumen

(Reference : SFA Pacific Gasification May 2007)

3.2 CO Shift Technology

3.2.1 Comparison between Sweet CO Shift and Sour CO Shift

The CO Shift reaction, also known as the water gas shift reaction, is as follows - :

$$CO + H_2O = CO_2 + H_2 + \text{heat (exothermic)}$$

The reaction is carried out over a catalyst. Steam is added to the syngas before the reactor, as needed to achieve the desired increase in H_2 content and decrease in CO content. If the syngas has been scrubbed upstream with water, it may already contain sufficient steam for the shift. In this case, the syngas can be fed directly to a sour shift reactor, which employs a sulphur-tolerant catalyst.

The following general flow scheme shows a simplicity of process configuration in case Sour CO Shift application.

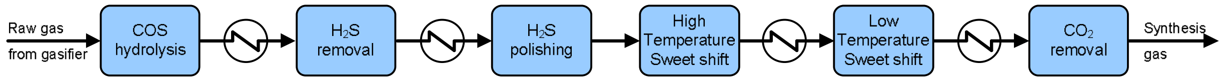


Figure 1 : The sweet shift process

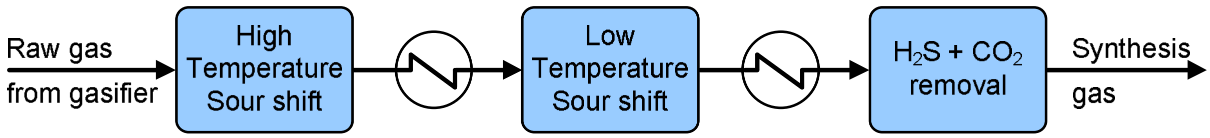


Figure 2 : The sour shift process

The following table is the summary of advantages of each process.

Summary of Advantages

Sour CO Shift - Pros	Sweet CO Shift - Pros
▪ Simpler system configuration	▪ Less stringent material selection for CO Shift section
▪ Lower H_2O / DG(Dry Gas) ratio result in lower energy consumption (H_2O/DG = 1.1 for Sour CO Shift H_2O/DG = 1.5 (min.) for Sweet CO Shift)	
▪ Higher range of operation temperature	
▪ Lower CAPEX and OPEX	

3.2.2 Application of Sour CO Shift for this Project

For this Coal Gasification to Urea production project, the application of Sour CO Shift is more attractive than the Sweet CO Shift for the following reasons;

1) More energy efficient, because - i) lower steam requirement and ii) Sour CO Shift Converter can be located at the upstream of the acid gas removal unit. On the contrary, Sweet CO Shift Converter is located at the downstream of acid gas removal unit and the gasifier product syngas saturated with steam first have to be cooled and the free water separated and again heating to the required

temperature for CO Shift is required.

2) Less reactor required, because COS Hydrolysis is done by sour shift catalyst then COS Hydrolysis Reactor with catalyst can be eliminated.
3) Lower investment cost, due to simpler system configuration and lower operating cost due to higher energy efficiency

3.2.3 CO Shift Technology Selection

Application of Haldor-Topsoe's Sour CO Shift technology including proprietary catalyst to this project is recommendable because it offers a number of the following client's benefits.

1) superior shift activity in a sulphur-containing syngas, resulting in significant process simplification and reduced energy consumption compared to the traditional sweet shift catalyst
2) the catalyst can operate in a broad temperature range and a wide range of steam to carbon monoxide ratios, resulting in increased flexibility in the operation of the water-gas shift section
3) flexible shift trains consisting of one or multiple reactors with inter-cooling either for maximum carbon monoxide (CO) conversion or for production of syngas with a wide range of hydrogen to CO ratios
4) conversion of carbonyl sulphide to hydrogen sulphide by hydrolysis
5) conversion of hydrogen cyanide to carbon monoxide and ammonia by hydrolysis
6) the use of simple adiabatic shift reactors reduces capital cost and ensures simple operation
7) Haldor-Topsoe can guarantee the process performance as CO Shift whole system including the performance of Topsoe's proprietary catalyst.

3.3 AGR (Acid Gas Removal) Technology

3.3.1 Comparison of AGR Technologies and Suppliers

There are four (4) of the most widely used AGR technologies for coal-derived syngas AGR,

i) ADIP ii) MDEA iii) Selexol iv) Rectisol.

Table-2 provides the comparison of characteristics of each licensed technology.

3.3.2 AGR Technology Selection

Among above four (4) proven AGR technologies, it is evaluated that the MDEA based AGR (Shell ADIP or Sulfinol) technology is the proper selection for this project in the following aspects.

1) Acid gas treatment process selection begins the acid gas reduction required to meet downstream process. And the deep removal of H_2S and CO_2 by means of physical absorption such as Selexol and Rectisol are not necessary for this project. And the H_2S and CO_2 removal by amine solution base is adequate, because the PSA unit is provided at the downstream for H_2 purification.

2) Lower energy consumption because of absorption at ambient temperature level (while refrigeration is required in the Selexol and Rectisol processes)

3) The next step is to determine which AGR technology is the most economically attractive. As can be shown in the Table-2, MDEA based AGR technology of Shell ADIP or Sulfinol is the least investment cost rather than those of Selexol and Rectisol.

4) CO_2 capture can be realized with the integration of SRU (Sulphur Recovery Unit) technology of Shell Paques process.

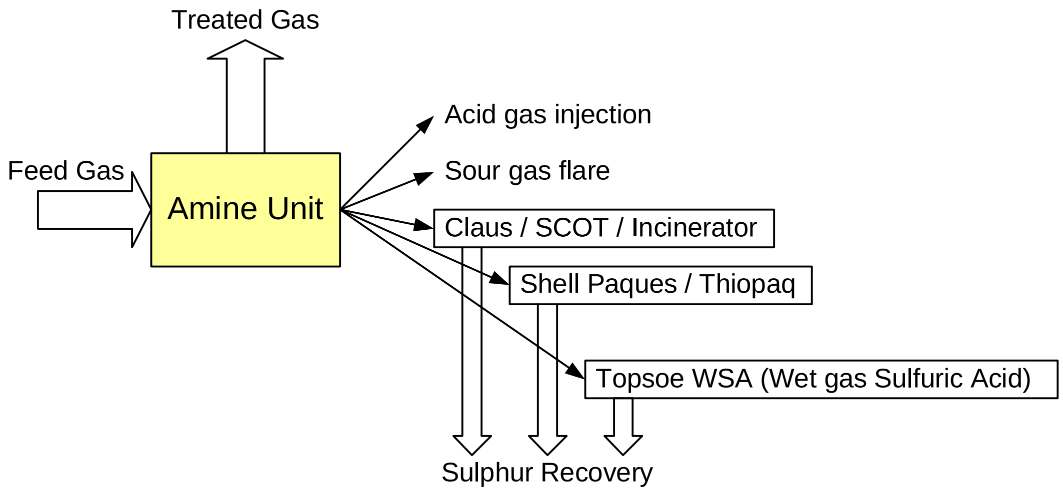
5) As shown in the Table-2, proven technology which has many experienced projects in the world. A comparable scale AGR has been delivered for the Woodside Pluto LNG project in Western Australia.

3.4 SRU (Sulphur Recovery Unit) Technology

3.4.1 Comparison of SRU Technologies and Suppliers

The following sketch shows the Sour Gas Treating Building Blocks.

Sour Gas Treating Building Blocks :



Whichever the Claus / SCOT / Incinerator system or Shell Paques / Thiopaq are used to recovery sulphur as elemental sulphur. While to recovery sulphur as sulphuric acid, Topsoe WSA (Wetgas Sulphuric Acid) technology will be used.

Table-3 compares SRU technologies among Claus, Paques and WSA.

3.4.2 SRU Technology Selection

For this project, sulphur is recovered as the elemental sulphur then the technology selection is whichever - i) conventional Claus or ii) Paques.

<u>For the sulphur recovery as elemental sulphur, the selection of Shell Paques process is proper with the following performance features</u>

- Achieves essentially complete H_2S removal and recovery as elemental S;
- Simple process configuration and control with stable operation;
- Low operating and chemical costs;
- Wide and flexible operating range with short system start-up and shut downtimes;
- Environmentally friendly process based on a naturally occurring Thiobacilli biocatalyst;
- Recovered sulphur is hydrophilic and directly usable for fertiliser/agriculture applications;
- Inherently safe operation – no free H_2S exists after the absorber inlet;
- CO_2 capture makes sense;

<u>And eventually the Paques process can deliver the economic saving compared with the Amine + Claus + SCOT, due to i) lower chemical make-up and ii) less</u>

equipment to operate and maintain.

3.5 PSA (Pressure Swing Absorption) Technology

3.5.1 Comparative Overview of H_2 Purification Processes

PSA, Membrane separation and Cryogenic separation are the three (3) principle options for purification of hydrogen.

Table-4 “Hydrogen Purification Technology Selection Criteria” provides the comparison among three technologies and major considerations in the selection of technologies.

3.5.2 PSA Technology Selection

The selection of PSA for H_2 purification is the best with the following aspects.

1) PSA is the dominant recovery technology used in new hydrogen plants. For example, PSA is the recovery technology of choice in North America, where about 40% of the world refinery hydrogen capacity is located.

2) An older but less effective purification technology, which has been largely supplanted by PSA, but is still in limited use, employs amine scrubbing to remove most of the CO_2 – followed by reacting the CO and residual CO_2 with H_2 over a catalyst to form methane. This type of methanation process is also the basis for H_2 purification. The purity after methanation is 97-98 mol% H_2, the remainder being methane and nitrogen introduced with the feed coal or the oxygen.
And these impurities in the H_2 product result in higher energy consumption in the ammonia synthesis due to higher ammonia synthesis pressure requirement due to compensate the partial pressure of the inert components (CH_4, N_2, Ar) and in higher investment cost due to provision of PGRU (Purge Gas Recovery Unit) where the purge gas continuously is purged from the ammonia synthesis loop to avoid the accumulation of inert component.

3) Among three (3) principle H_2 purification process (PSA, Membrane, Cryogenic), PSA is the best choice with the following reasons, a) highest H_2 Purity b) CO + CO_2 (which are poisonous to ammonia synthesis catalyst) removal c) higher H_2

Production pressure d) higher reliability e) no major utility requirements at all f) capital cost advantageous considering not only PSA cost but also cost caused by higher energy consumption and other additional equipment requirement in other Membrane and Cryogenic cases. (Details are referred to the Table-4 Hydrogen Purification Technology Selection Criteria)

4) Proven technology which has many experienced projects in the world.

3.6 Syngas Cleaning Technology

The syngas produced from the coal gasification is treated via the each cleaning technology as follows;

(1) Particle Removal
Dry solids removal systems use ceramic filters that can remove all solids from the gas at temperatures between 300 and 500 °C. Above 500 °C, alkali compounds may pass the filters. Below 300 °C, the filters may be blinded of deposits of ammonium chloride (NH_4Cl). Including cyclones upstream will reduce the loading on the filters and therefore also the risk of breakage.

(2) Chloride (HCl) and Ammonia (NH_3) Removal
Even if an IGCC plant has ceramic filter it usually also adds a water scrubbing system for removal of remaining impurities such as chloride (HCl) and ammonia (NH_3). It is noted that the coal has a modest chloride content, well within the standard design.

(3) Metal Carbonyls Removal
Iron and nickel carbonyls (Fe(CO)5 , Ni(CO)4) are both undesirable trace components in synthesis gases.
Metal Carbonyls are existed as vapor phase in the syngas from the Syngas cooler and can be absorbed in the organic solution of the downstream AGR.
Also in the IGCC case, nickel carbonyls are damaging to combustion turbines but can be removed from syngas by activated carbon.

(4) Mercury Removal
Mercury content in the syngas is depend upon the quality of coal feedstock.
In case the content of mercury in the syngas is higher than the environmental

specification, activated carbon will be provided so that it removes 90-95% of the mercury from coal derived synthesis gas. Mercury sulfide on the spent carbon is stable and currently the best option is to dispose of it at certified storage sites. Regeneration with mercury recovery is complex and expensive.

4. Safety and Environmental in Shell Coal Gasification Process (SCGP) Technology

4.1 Safety Aspects of Materials Consumed /Produced

The SCGP design information is prepared according to oil and petrochemical design, construction and operating regulations, guidelines, procedures and practices.

The following materials are consumed/produced and will be briefly discussed:

Coal

In general non-toxic, but repeated inhalation of high concentrations of coal dust particles could result in pneumoconiosis. Equipment design will prevent such concentrations during normal operation. In case of leakages, appropriate equipment and work practices will prevent inhalation. Two other properties of pulverized coal which affect storage and handling are its tendency to undergo spontaneous combustion in air and the possibility of forming explosive mixtures of coal dust and air. The SGCP process uses nitrogen to inertize all the equipment in which pulverized coal is handled.

Oxygen

Oxygen is a strong oxidizing agent and greatly accelerates normally non-hazardous conditions. Selection of proper materials and proper installation, cleaning and operating techniques will prevent this.

Nitrogen

Nitrogen being physiologically virtually inert can cause asphyxiation. Entry into confined spaces should therefore always be proceeded by proper procedures (e.g. oxygen concentration measurements).

Carbon Monoxide

Carbon Monoxide is a toxic gas. Long-term exposures should not exceed the T(hreshold) L(imit) V(alue) of 50 ppm. Vent gases potentially containing CO are flared, therefore. Gas detectors in strategic locations will give an early warning of leakages and the use of proper procedures and safety equipment during maintenance will prevent inhalation.

Hydrogen

Hydrogen is not toxic gas, but is highly flammable.

Hydrogen Sulfide

Hydrogen Sulfide is a toxic gas. Although it has a strong unpleasant odor initially, it anesthesizes the senses quickly so smell is not a reliable indicator. Exposure should not exceed the current TLV of 10 ppm. Gas detectors in strategic locations will give an early warning.

Sulphur Dioxide

Sulphur Dioxide is a toxic gas. Traces of sulphur dioxide is produced only in the gas turbine, the flare and incinerator and can be produced by burning sulphur. Exposure should not exceed the current TLV of 2 ppm.

Sulphur

Sulphur is an inert material present in liquid form within the plant. Three properties are relevant here:

1) Its melting point of 113 °C, which can potentially cause plugging in lines, etc. (to be resolved by “steaming”) and,
2) Its (low) “inflammability”, producing sulphur dioxide.
3) Sulphur can contain traces of H_2S. A toxic vapour can therefore be formed above non-stripped liquid sulphur.

Inflammable Materials

The SCGP does not use any highly inflammable materials which require more than common sense in storage, use, etc.

Corrosive Reagents

A number of corrosive reagents are used in the process, e.g. caustic, acid, solvents, etc. These materials create no hazards if used as prescribed/designed and if protective clothing is used if they are handled.

4.2 Safety in Design

During the design phase, the Process Safety Flow Schemes (PSFS) and the safety memorandum have to be developed. The PSFS's and safety memorandum give a comprehensive overview and description of all the safety requirements. During the development of the P(process) F(flow) S(Schemes) the following philosophy, besides standard equipment design/material selection requirements, is used:

- Instrumentation used for control should not be used for safeguarding. Separate instruments are thus required for the safeguarding.
- Incompatible gaseous environments should be separated by double block and bleeder systems.
- Different pressure levels of similar environments are separated by double block valves (batchwise discharge after pressure equalization) or control valve plus automated emergency shut-off valve (continuous discharge). Moreover, a pressure relief valve is installed on the lower pressure equipment for ultimate protection in case of "breakthrough".
- Pressure relief valves or rupture discs with relief to a safe location are installed on all equipment which can be isolated and can build up pressure internally (e.g. heat of reaction).
- Where more appropriate, pressure reliefs are installed on the supply/discharge lines to/from equipment.
- Standard safety procedures (purging, flame eyes, etc.) for fired equipment.
- Minimum operating pressures for nitrogen/steam/hot water systems used for purging and/or heat transfer are higher than the maximum reachable pressure (relief valve pressure setting) of the oxygen and/or syngas systems being purged/heated.
- Relief systems/vents (potentially) containing highly flammable and/or toxic gases will be connected to the flare system (others will be atmospheric vents, where required, e.g. HP steam - with silencers).
- Adequate depressurising valves are installed for depressuring in case of fire.

Coolers with high-pressure syngas on the process side require special attention if they are connected to a cooling water system at a lower pressure. Also coolers of HP water, in contact with an HP syngas environment, require special attention if they are connected to a cooling water system at a lower pressure (e.g. scrubber water cooler).

4.3 Environmental

4.3.1 Gaseous Effluent

The gas products from the Shell Coal Gasification Process Demonstration Plant in Deer park, Texas, are environmentally clean. A series of scrubbing steps removes dust, sulphur compounds, and other impurities from the syngas, producing a medium-Btu fuel gas product that contains only 10 to 20 ppmw sulphur compound, essentially all as carbonyl sulfide (Perdaman specification max. 50 ppmw). Acid gas from the Sulfinol® stripper and the sour slurry stripper contains hydrogen sulfide and carbon dioxide, together with minor traces of a few volatile organic compounds; the inorganic impurities in the acid gas are not expected to affect the marketability of the sulphur product from the Paques sulphur recovery process. As part of an overall research and development effort to improve the gas cleanup process still further, the performance of two selective amine solvents in treating syngas has been demonstrated in a slip-stream gas treating process development unit.

For this Collie Coal to Urea project, Shell ADIP as AGR and UOP PSA for H_2 purification system have been selected. Shell ADIP absorbs the CO_2 and H_2S generated in the Sour Shift Unit. Acid gas (CO_2 + H_2S) is sent to the Shell – Paques unit.
Shell-Paques unit, which converts the H_2S in both the CO_2 stream to Urea Plant and the AGR Acid Gas stream into biosulphur. The CO_2 rich gases contain less than 4 ppmv of H_2S. Excess CO_2 is vented with the remainder sent to the Urea manufacturing plant through an H_2S guard bed to ensure an H_2S content meeting the required specifications.
The treated syngas via AGR contains H_2S (< 10 ppmv) and PSA (at downstream of AGR) has capability to remove H_2S which is poisonous to the catalyst at downstream.

Environmental information obtained during a 1,528-hour demonstration run in which Illinois No. 5 coal was gasified, together with results from continuing studies on other coals and from gas treating studies in slip-stream process development unit, indicate that the <u>Shell Coal Gasification Process will meet all current and foreseeable future environmental regulations on gaseous effluent streams. Shell has in hand design options to provide full-scale plants with the capability to gasify economically a wide variety of coals, even lignites and sub-bituminous coals, while meeting applicable environmental regulations at any site.</u>

4.3.2 Liquid Effluent

This paragraph, contains the results of chemical and toxicological characterizations of the complete aqueous effluent from the SCGP demonstration plant during gasification of high-sulphur, bituminous coals. Results from the demonstration plant, along with studies from a slipstream process development unit, confirm that the treated aqueous effluent from the Shell Coal Gasification Process (SCGP) is environmentally clean.

The untreated aqueous bleed stream consists of water condensed from the raw product gas, water from raw gas cleaning and slurry pumping of wet scrubbed solids, condensate from sour slurry stripping, bleed water from slag cooling, and bleed water from acid gas solvent stripping.

Steps in the treatment of the process blowdown water to produce clean effluent include: collection and stabilization of wash water from gas scrubbing; pressure let-down; steam stripping for removal of dissolved gases; flocculation, clarification and thickening of suspended, fine particulates; and biological oxidation of inorganic salts of nitrogen and sulphur. Wash water containing suspended particulate matter from process cleaning operations is also combined with the process blowdown during clarification.

Gasification at very high temperature (over 1500 °C) ensures the destruction of tars, phenols, and other hydrocarbons heavier than methane. This feature provides a significant environmental advantage for SCGP. Results of extensive analyses verify that no hydrocarbon heavier than methane, nor any other volatile or semi-volatile organic compound is detectable in the process gas or aqueous blowdown.

Biological treatment provides oxidization for the small amounts of inorganic nitrogen and sulphur species that remain in the water, and produces an effluent suitable for discharge. Complete chemical characterization of the biologically treated effluent is provided. The biological oxidation of nitrogen and sulphur species results in a very low biomass yield. Several types of biological treatment reactors, suitable for operation at low-yield conditions, have been demonstrated. These biological treatment reactors have provided ample design data for a commercial facility.

The treated effluent contains fully oxidized products from biological treatment and very low concentrations of trace metals. Both acute and chronic toxicity testing of the treated effluent indicate that no adverse impact on receiving waters would result from a commercial facility that discharges biologically treated effluent. For example, no acute toxicity was detectable, and any detectable chronic toxicity could be eliminated by installation of a discharge diffuser providing only a minor amount of dilution.

The ability to remove the trace amounts of non-toxic, total cyanide that remains after conventional biological treatment has been demonstrated by means of enhanced biological treatment and by means of physical and chemical treatment. Also the ability to remove non-toxic, nitrate salt has been demonstrated by means of biological denitrification.

The slipstream process development unit provides a flexible and efficient means of data collection, applicable to commercial scale design, over a wide range of operating conditions. The slipstream process development unit continues to operate during gasification of other coals, including sub-bituminous coal and lignite. Data from this operation supports the claim that SCGP can be designed to gasify a wide range of feedstocks in an environmentally acceptable manner.

5. Attachment

Attachment-1 : Block Flow Diagram of Coal Gasification to Fertiliser Production with IGCC
Table-1 : Comparison of Gasification Technologies among Shell, Uhde, GE and COP
Table-2 : Comparison of AGR Technologies among ADIP, MDEA, Selexol and Rectisol.
Table-3 : Comparison of SRU Technologies among Claus, Paques and WSA
Table-4 : Hydrogen Purification Technology Selection Criteria

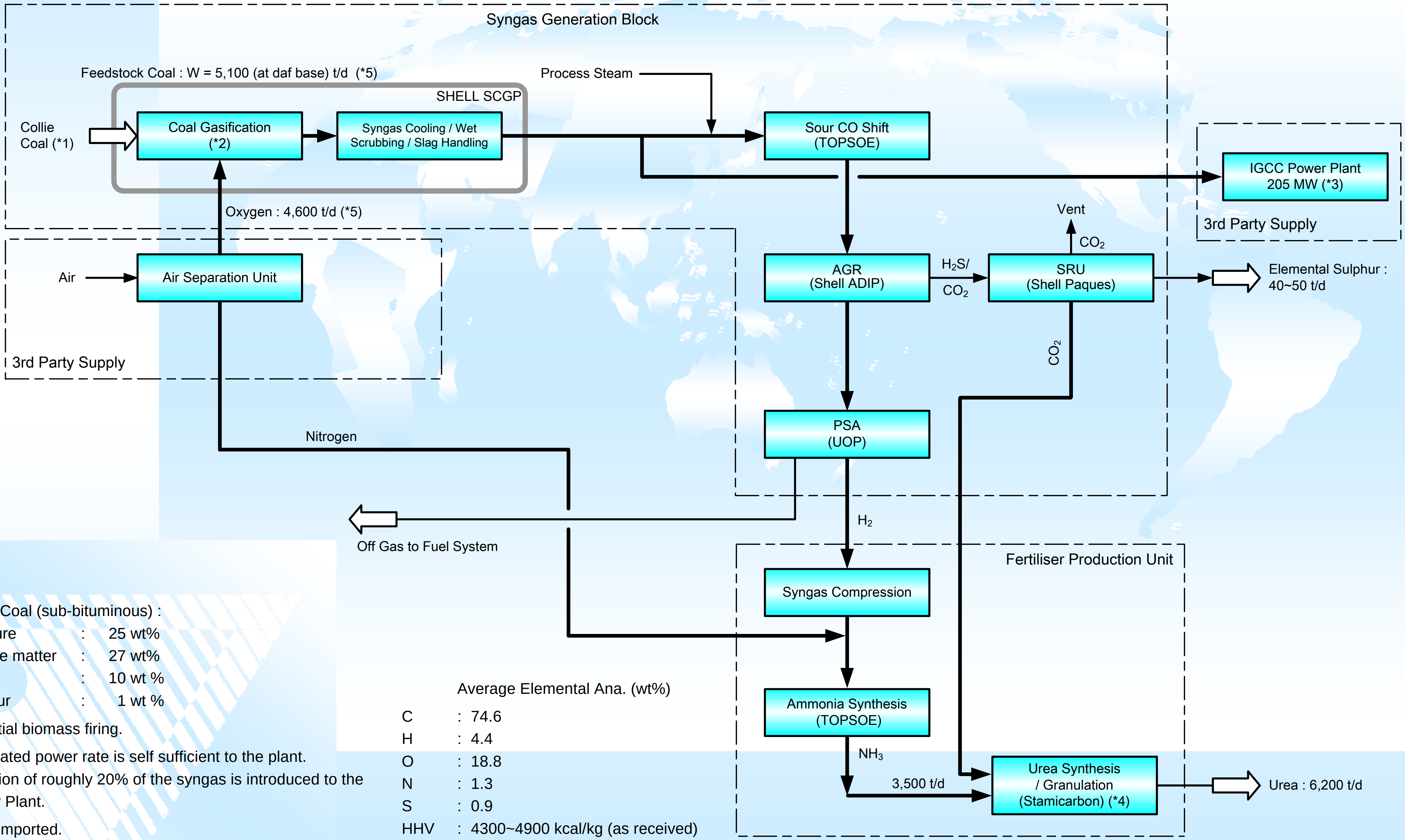
6. Reference

(1) SFA Pacific, Inc, GASIFICATION Critical Analysis of Technology, Economics, Markets, May 2007
(2) SRI PEP Report No. 154/154A/154B/216
(3) Chemsystems PERP Coal Gasification Technologies 03/04S11
(4) DOE/NETL-2007/1281 Cost and Performance Baseline for Fossil Energy Plants (Aug-2007)
(5) 8th European Gasification Conference 2007

(6) 9th European Gasification Conference 2009
(7) Topsoe's paper held at "Sulphur 2004" and International Platinum Conference in 2006.
(8) Shell's brochure titled as "Shell-Paque process-biological removal of hydrogen sulphide from gas streams" and Paper for the LRGCC, 23-26 Feb. 2003 USA, titled as "Biological Process for H_2S Removal from Gas Streams the Shell-Paques/Thiopaq Gas Desulphurization Process"

CHIYODA CORPORATION

Attachment -1 : BFD of Coal Gasification to Fertiliser Production with IGCC



Average Elemental Ana. (wt%)

C	: 74.6
H	: 4.4
O	: 18.8
N	: 1.3
S	: 0.9
HHV	: 4300~4900 kcal/kg (as received)

(*1) Collie Coal (sub-bituminous) :

Moisture	:	25 wt%
Volatile matter	:	27 wt%
Ash	:	10 wt %
Sulphur	:	1 wt %

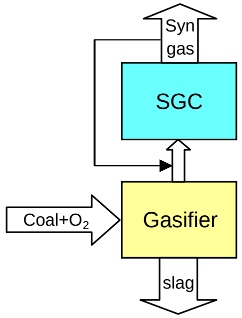
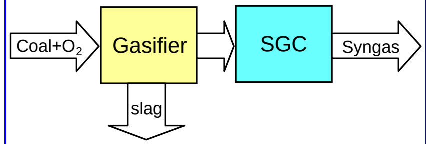
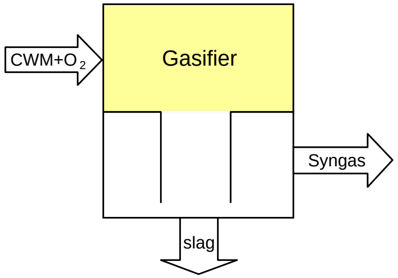
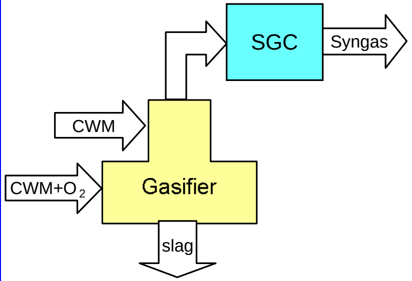
(*2) Potential biomass firing.

(*3) Generated power rate is self sufficient to the plant. A portion of roughly 20% of the syngas is introduced to the Power Plant.

(*4) UF is imported.

(*5) Feedstock coal rate and O_2 consumption are indicative only.

Table -1 : Comparison of Gasification Technologies among Shell , Uhde , GE and COP

Process Licensor	Shell	Uhde	GE (former Texaco)	COP (former E-Gas)
Gasifier Sketch				
Coal feed system	dry feed	dry feed	water slurry feed	water slurry feed
Cold gas efficiency	80% (generally 3% higher than water slurry feed)		as base	
O2 consumption	generally 20% lower than water slurry feed		as base	
Syngas cooling	both WHB and WQ type available	both WHB and WQ type available	both WHB and WQ type available	only WHB type available
Gasifier internal design	cooled membrane wall	cooled membrane wall	refractory lined	refractory lined
Gasifier maintenance requirement	long lifetime over 25 years then free maintenance		refractory lined designs need replacing regular yearly maintenance	
Burner design	multi-burner design	multi-burner design	single-burner design	multi-burner design
Burner life	long lifetime over 20,000 hours	burners need replacing every 1,500-4,500 hours		
Reliability (on-stream factor) (*1)	90 - 95% (*3)	data at Puertollano Spain IGCC in 2007 : 79%	recent actual at GE representative plant : 95%	recent data at Wabash IGCC : 90%
Syngas Product	H2 + CO (H2/CO≒0.5)	H2 + CO (H2/CO≒0.5)	H2 + CO (H2/CO≒1)	H2 + CO + CH4 (H2/CO≒1)
Sparing philosophy	no sparing philosophy is required	Sparing philosophy shall be discussed between Company and Process Licensor contemplating the plant reliability factor (on-stream factor) (*4)		
Experience (*2)	many (56 in operation)	only 1 in operation	many (71 in operation)	only 1 in operation

(*1) Reference : Gasification Technologies Conference 2008
(*2) Reference : SFA Pacific Gasification May 2007
(*3) On-stream factor of recent actual operation at Nuon Buggenum IGCC plant is 97.5%.
(*4) The availability of the plant is improved by using 2 trains approach with spare capacity.

Table-2 : Comparison of AGR (Acid Gas Removal) Technologies among ADIP , MDEA , Selexol and Rectisol

AGR Process	ADIP	MDEA	Selexol	Rectisol
Process Licensor	Shell	Shell Sulfinol-M , etc	UOP	Lurgi, Linde
Solvent	ADIP-X : aqueous DIPA or MDEA with additive (typical absorption temp. : amb.）	Sulfinol-M : mixture of aqueous MDEA and Sulfolane (typical absorption temp. : amb.）	mixture of DME + PEG (typical absorption temp. : 0 ～ 15 ℃）	Methanol (typical absorption temp. : - 35 ～ - 55 ℃）
H_2S/CO_2 Removal	H_2S/CO_2 bulk removal	H_2S/CO_2 bulk removal	H_2S/CO_2 separate removal	H_2S/CO_2 separate removal
H_2S/CO_2 spec. in the treated gas	H_2S : < 10 ppmv CO_2 : < 50 ppmv	H_2S : < 4 ppmv CO_2 : < 50 ppmv	H_2S : 0.1～1 ppmv CO_2 : < 500 ppmv	H_2S + Organic S : 0.1～1 ppmv CO_2 : 10～50 ppmv
Application to CO_2 Capture	Applicable by combination with Shell Paques system (*1) (*2)	Applicable by combination with Shell Paques system (*1)	Applicable	Applicable
Energy Consumption	low	low	mid (*3)	high (*3)
Experienced plants	Adequate (more than 400)	Adequate (more than 200)	Adequate (more than 55)	Adequate (more than 100)
CAPEX (*4)	set as 100		250	400

(*1) It is generally said that MDEA process like Shell ADIP and Shell Sulfinol-M are not suitable for CO_2 capture requirement. The combination with Shell Paques process makes sense it.

(*2) Shell will design to 5 - 10 barA CO_2 recovery by Shell Paques system. The final CO_2 pressure at battery limit shall be finalised after technical work is done based on specifications for the CO_2 for use such as storage or EOR.

(*3) Depend on refrigeration level.

(*4) Reference : "Shell Water Quench Gasifier SCGP for IGCC with CCS" at 8th European Gasification Conference 2007

Table - 3 : Comparison of SRU (Sulphur Recovery Unit) Technologies among Claus , Paques and WS

Comparison Items / Licensed Technology	Process Licensor	Product	Product Capacity (application range) per train	Energy Consumption	Experiences	Performance		Reference
						Sulphur recovery(%)	Purity	
Conventional Claus	Jacobs, Parsons, Lurgi	Elemental Sulphur	range widely from only 5 t/d to multiple trains of thousands of tons per day, and Chiyoda's experienced max. capacity is 670 t/d.	Elec. : 215kw/ton S C.W. : 38 ton/ton S Steam gene. : 4 ton/ton S	many reference projects since 1950s	2 stage reactors : 95% 3 stage reactors : 97%	H2S of 250 ppmwt is included into the product Sulphur.	(*1)
Paque Bio-Sulphur	Shell	Elemental Sulphur	0.1 to 50 t/d	There is no exact figures in the open paper. Qualitatively, lower operating cost will be obvious compared with the Claus + SCOT due to i) lower chemical make-up ii) less equipment to maintain and operate	Actual experience : 6 Under design,construction and start-up : 7 At planning : 7	99.8	99 wt%	(*2)
WSA (Wetgas Sulfuric Acid)	Topsoe	Sulphuric Acid	4 to 1,140 t/d	Elec. : 60kw/ton H2SO4 C.W. : 11 ton/ton H2SO4 Steam gene. : 0.2 ton/ton H2SO4 (*5)	approx. 45 units (*3)	96	commercially quality , usually 96 - 98 wt% H2SO4	(*4)

(*1) SRI Consulting PEP Report No. 216

(*2) Shell's brochure titled as "Shell-Paque process-biological removal of hydrogen sulphide from gas streams" and Paper for the LRGCC,23-26 Feb. 2003 USA ,titled as " Biological Process for H2S Removal from Gas Streams the Shell-Paques/Thiopaq Gas Desulphurization Process"

(*3) The Topsoe WSA technology has been industrially applied since 1980. With reference plants worldwide and within a wide range of different industries, the WSA process has fully proven its operational benefits and diversity. This was further confirmed by the European Commission's nomination of WSA as the "Best Available Technique for the Manufacturer of Large Quantity Inorganic Chemicals " in Dec. 2006.

(*4) Topsoe's paper held at "Sulphur 2004" and International Platinum Conference in 2006

(*5) The WSA process has a high energy efficiency because not only the heat of SO2 oxidation but also the heat of reaction between gas phase SO3 and H2O (to form H2SO4 vapor) , the heat of condensation of H2SO4 vapor and the cooling duty of the process gas to approx. 100 deg.C are made useful. These energies are recovered partly in the form of high pressure steam and partly in the form of hot air that can be used e.g. as combustion air. Only the cooling duty of the produced sulphuric acid is lost with cooling water.

Table-4 Hydrogen Purification Technology Selection Criteria

	PSA	Membrane	Cryogenic
Feed stream range, MMscf/d	1-200	1-50+	10-75+
Minimum Feed H_2, %	50	15	15
Feed pressure, psig	150-600	300-2,300	75-1,100
H_2 purity, %	99.9+	<98	<97
H_2 recovery, %	75-92	85-95	90-98
Maximum turn-down, %	20	30	50
CO + CO_2 removal	Yes	No	No
H_2 product pressure	~ feed	<< feed	~ feed
Feed pretreatment	No	Minimum	CO_2, H_2O removal
Byproduct availability	No	Possible	Liquid Hydrocarbons
Reliability	High	High	Average
Flexibility	Very high	High	Average
Capital cost	Medium	Low	High
Economy of scale	Moderate	Modular	Good
Ease of expansion	Average	High	Low

Source: SFA Pacific, Inc. Gasification Critical Analysis of Technology , Economics , Markets May 2007