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ACRONYMS

AAC – Anglo American Corporation
ASEAN- Association of South East Asia Nation
BEE – Black Economic Empowerment
CAMALA – Cape Area Municipality Local Authority
CAPEX – Capital Expenditure
CBM – Coal Bed Methane
CCGT – Combined Cycle Gas Turbine
CDM – Clean Development Mechanism of the Kyoto Protocol
CEF – Central Energy Fund
IDZ – Industrial Development Zone
IPP – Independent Power Producer
ESI – Electricity Supply Industry
EDI – Electricity Distribution Industry
EU – European Union
FDI – Foreign Direct Investment
GGP – Gross Geographic Product
GIP – Gas Infrastructure Plan
GTL – Gas To Liquid
HBI – Hot Briquette Iron
HFO – Heavy Furnace Oil
IBLC – Inbound Landed Costs
IEA – Independent Energy Agency
LNG – Liquefied Natural Gas
LPG – Liquefied Petroleum Gas
NEPAD – New Partnership For African Development
NER – National Energy Regulator
NGV – Natural Gas Vehicles
PASA – Petroleum Agency of South Africa
PETROSA- HEAVY Furnace Oil
PPIAF – Public Private Infrastructure Advisory Facility
RED – Regional Electricity Distributors
SADC – Southern African Development Community
SAPP – Southern African Power Pool
SAS – Sasol Advanced Synthol
SCADA – Supervisory Control and Data Acquisition
SCI – Sasol Chemical Industries

SSF – Sasol Synthetic Fuel

Tcf – trillion cubic feet

TPA – Third Party Access

Toe - Tonne of oil equivalent, where 1 tonne of oil equivalent = 41,868,000,000 joule

VAT – Value Added Tax

Executive Summary

Why a Gas Infrastructure Plan?

The gas infrastructure plan is intended to be a strategy for the development of the natural gas industry in South Africa. Government wishes to promote the gas industry based on its energy policy objectives as set out in the White Paper on Energy (1998). These include:

- Increasing access to affordable energy services.
- Improving energy governance.
- Stimulating economic activity.
- Managing energy-related environmental impacts.
- Securing security of supply through diversity of supply.
- Competition within and between energy carriers.
- Promoting New Partnership for African Development (NEPAD) cross-border type projects.

This Plan attempts to take this policy one step further into a practical set of options.

The Global Natural Gas Picture

Gas consumption is expected to grow at 3-4% per annum, gaining mostly against oil (down 2%) and coal (down 3%) in the process. Gas is expected to increase its share of the energy balance from 24% in 1999 to around 28% by 2020.

Gas is forecast to account for 24% of total power generation by 2010, increasing to 30% by 2020, when it is forecast to surpass nuclear and hydro combined. Gas is the only energy source for power generation that is forecast to have a growth in demand.

Natural gas has grown rapidly in the global energy balance since the 70's. It is more efficient than other fossil fuels and is the cleanest burning fossil fuel, producing far lower levels of CO₂, CO, SO₂, NO_x, and particulate matter emissions than other fossil fuels.

Natural gas occurrences are more widespread than oil and natural gas reserves are steadily increasing.

Gas in South Africa

Prior 2000, natural gas accounted for less than 2% of the primary energy demand in South Africa. This percentage is forecast to grow to approximately 7% over the next ten years, with

coal remaining the dominant energy source at 72%. Now with the gas plans in the Western Cape not materializing, and the arrival of First Gas from Mozambique on 26th March 2004 through the pipe which is 3.5% full, the gas demand is predicted to rise from 1.5% to approximately 4.3% of the primary energy demand when the pipeline is at capacity.

There are proven gas reserves offshore of Namibia and the Western Cape but these reserves are inadequate at present and further prospecting is required. Liquefied Natural Gas (LNG) is being considered for markets remote from gas fields, while coal bed methane (CBM) may become an option in the medium term.

Gas was first introduced in South Africa with the construction of the Cape Gas and Coke Company in Cape Town in 1847. Other gas plants followed in Port Elizabeth, Kimberly, Grahamstown, and eventually Johannesburg in 1892. Only the Johannesburg network has survived and it is now supplied by coal gas from Sasol.

Sasol has been selling coal gas since the 1960s and sales in 2004 amounted to 52.9 million GJ. with a total turnover of R1 522 million and an operating profit of R387million by the financial year ending on 30 June 2004 in gas sales.

The PetroSA gas-to-liquid (GTL) plant was established prior to 1994 for strategic reasons.

Sasol has been importing natural gas from Mozambique officially from 26 March 2004 and has sufficient proven reserves for 17 years. A programme is underway to prove additional reserves.

Cabinet has given a mandate to Central Energy Fund (CEF) to create a subsidiary for promoting pipeline infrastructure development (iGas), and will include investments in various gas projects.

The combined proven reserves available to the west coast amount to 2 trillion cubic feet (tcf) of gas. This is sufficient to meet the demand of PetroSA and a gas-fired power station for 16 years and exploration programmes are underway. A typical life for gas infrastructure projects is 25 to 30 years.

Governance

Most gas industries were established by vertically integrated companies (usually state owned), with exclusive supply arrangements and protection of distribution networks. This

structure is giving way to economic regulation with access to the infrastructure so that market forces can determine gas prices.

The USA has introduced gas-on-gas competition through open access to pipelines to the extent that a futures market now operates and there are daily or weekly spot prices for gas.

The European Union (EU) has been phasing in gas-on-gas competition since 10 August 2000.

In South Africa the gas industry has been unregulated, but since 1994 the following policy framework has been developed:

Legislation

Gas Act was passed by Parliament in 2001 and will come into operation during 2005 as part of a single Energy Regulator that will regulate electricity, gas and petroleum pipelines. It provides for the establishment of a Regulator and for orderly development of the gas industry. A regulatory dispensation has been negotiated to govern the Mozambique gas project and will bind the Regulator until 2014.

In terms of the Competition Act the Gas Regulator and the Competition Commission must negotiate agreements with regard to competition issues that relate to the gas sector.

Investment promotion

Government has introduced depreciation for gas pipelines for tax purposes. Job creation and training incentives are available to employers.

Standards

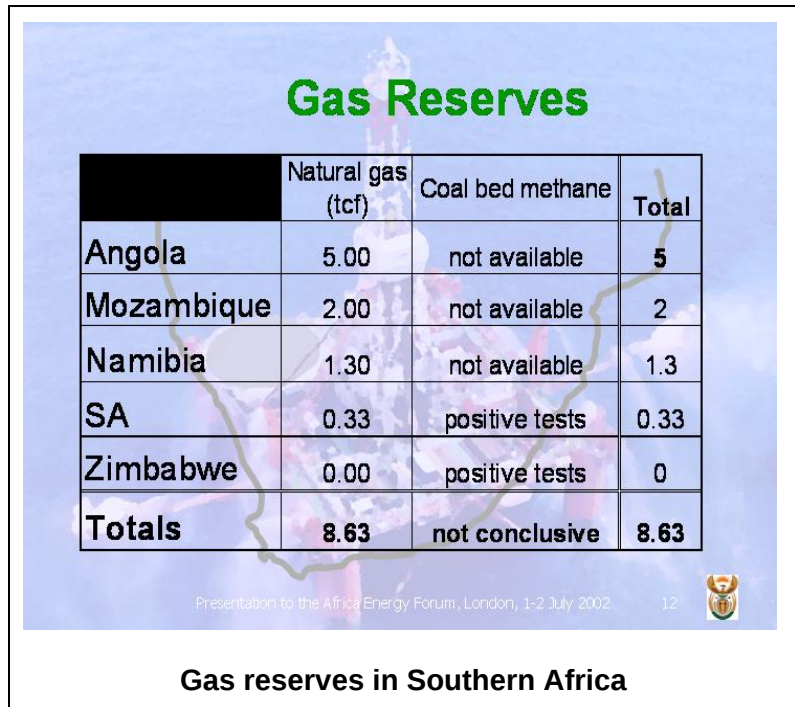
In terms of the Vessels Under Pressure regulations of the Occupational Health and Safety Act, approved recognised international standards may be adopted for gas projects.

The Gas Infrastructure Plan (GIP)

The GIP will become a tool for Government to articulate its broad policy and development aims.

Cross Border trade

Most of the viable gas reserves are in neighbouring countries, but the most viable industrial market for this gas is South Africa. There is a bi-lateral trade agreement in place with Mozambique (March 2001) and a similar agreement has been concluded with Namibia. A schedule has been established for the South African/Namibian Gas Commission 2005.



Eastern Market Analysis

Gauteng, Mpumalanga, KwaZulu-Natal gas market potential

- Chemicals and synfuels = 45 million GJ p.a.
- Industrial = 59 million GJ p.a.
- Domestic/commercial= 2 million GJ p.a.
- Power generation – minimal as most markets are close to Eskom generation sites.
- Oil refining = 7 million GJ p.a.

Western Market Analysis

Western Cape gas market potential

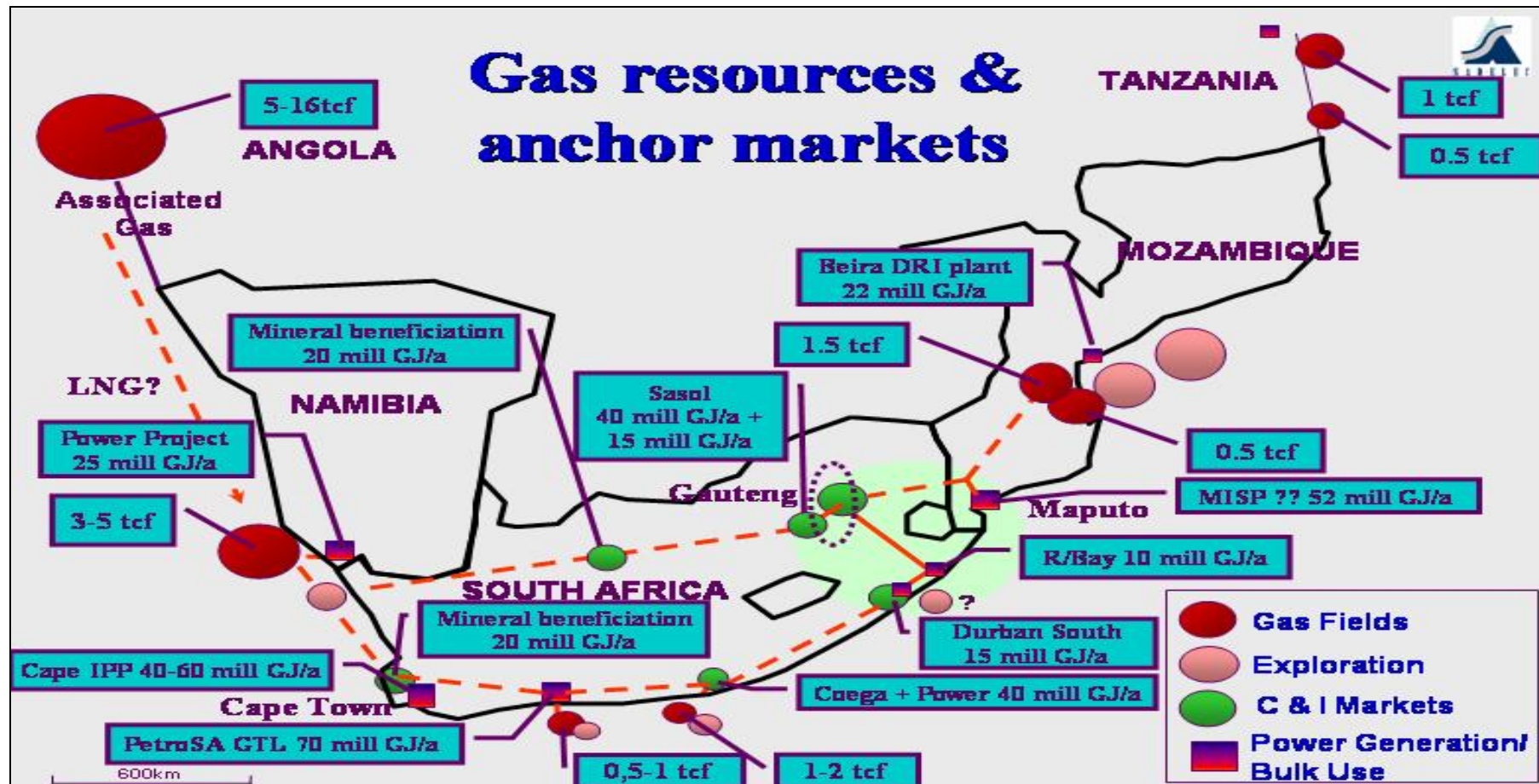
- Power generation = 40–60 million GJ p.a.
- Gas to liquids = 70 million GJ p.a.
- Minerals beneficiation = 20 million GJ p.a.
- Industrial/commercial = 15 million GJ p.a.

Eastern Cape gas market potential:

- Power generation = 20 mil GJ p.a.
- Industrial/commercial = 20 mil GJ p.a

Northern Cape gas market potential:

- Sishen mineral beneficiation = 20 mil GJ p.a



Gas resources relative to potential markets¹

¹ Adapted from the Sad-Elec presentation to the MEETI Petroleum Policy and Management course, Oct 2000

Gas demand set to increase

Sasol has sold gas since 1964, and annual gas sales have expanded from approximately 25 million Giga Joules in 1994 to 52.9 million Giga Joules in 2004 - a growth of about 27.9 million Giga Joules or 111.6% in 10 years.

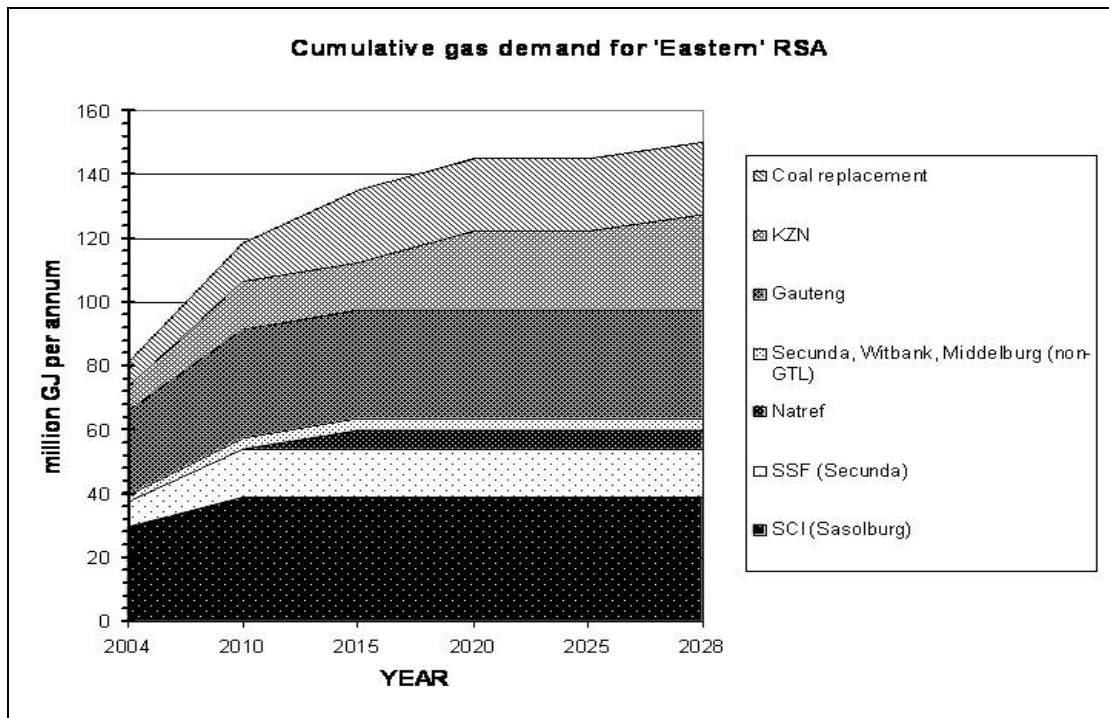
	MGJ p.a.	%
Current Nat. gas demand	70	1.6
Mozambique gas +	120	2.8
sub total	190	4.4
Namibian/lbhubesi Gas +	120	
(less the PetroSA demand)	-70	1.1
sub total	50	1.1
Total	240	5.5

This relatively small but robust, rapidly growing and profitable coal gas industry bodes well for

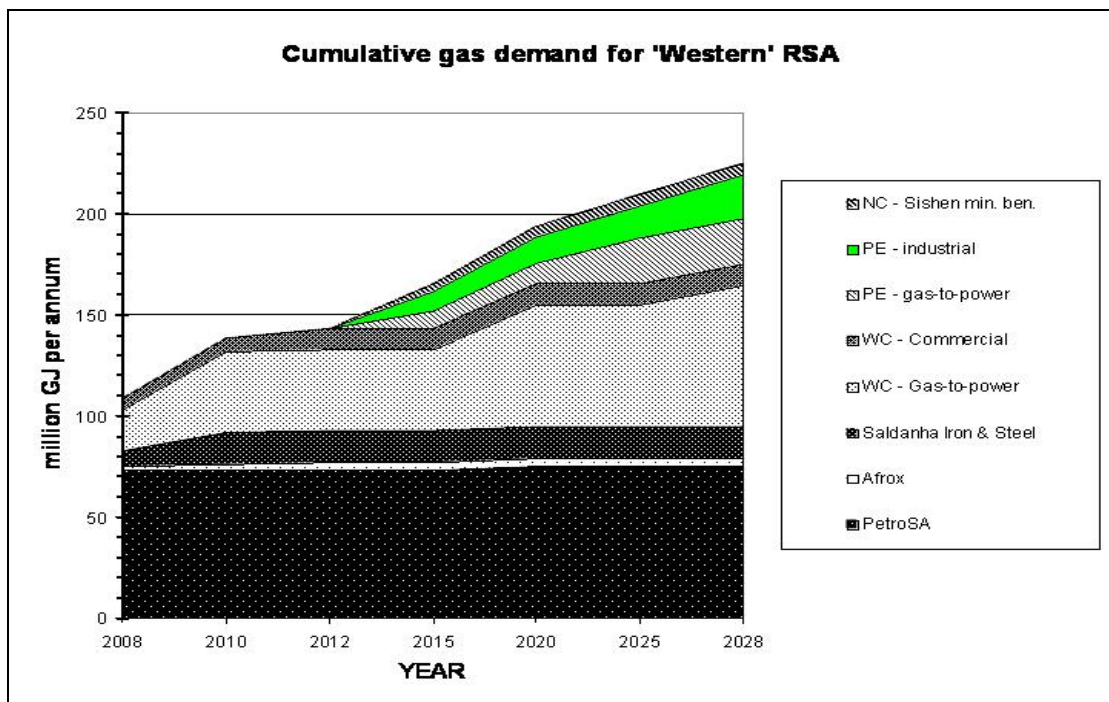
Potential gas demand, noting that initial demand is current PetroSA consumption (But Namibia/lbhubesi potential not materialising)

the future of natural gas in South Africa, especially as the traditional bulk markets such as electricity generation have not been tapped. The potential for gas sector could be realised if the energy sector is liberalised, allowing gas to compete with alternative energy carriers in an undistorted market.

If one looks at Sasol's success at penetrating a competitive market, the projection of trebling gas consumption is not unrealistic. Market research indicates that the potential demand outstrips the available proven resources. This is good news for the upstream and gas infrastructure investors.



Projected cumulative demand (150MGJ p.a) for RSA 'eastern' market



Projected cumulative demand (220 MGJ p.a) for RSA 'western' market

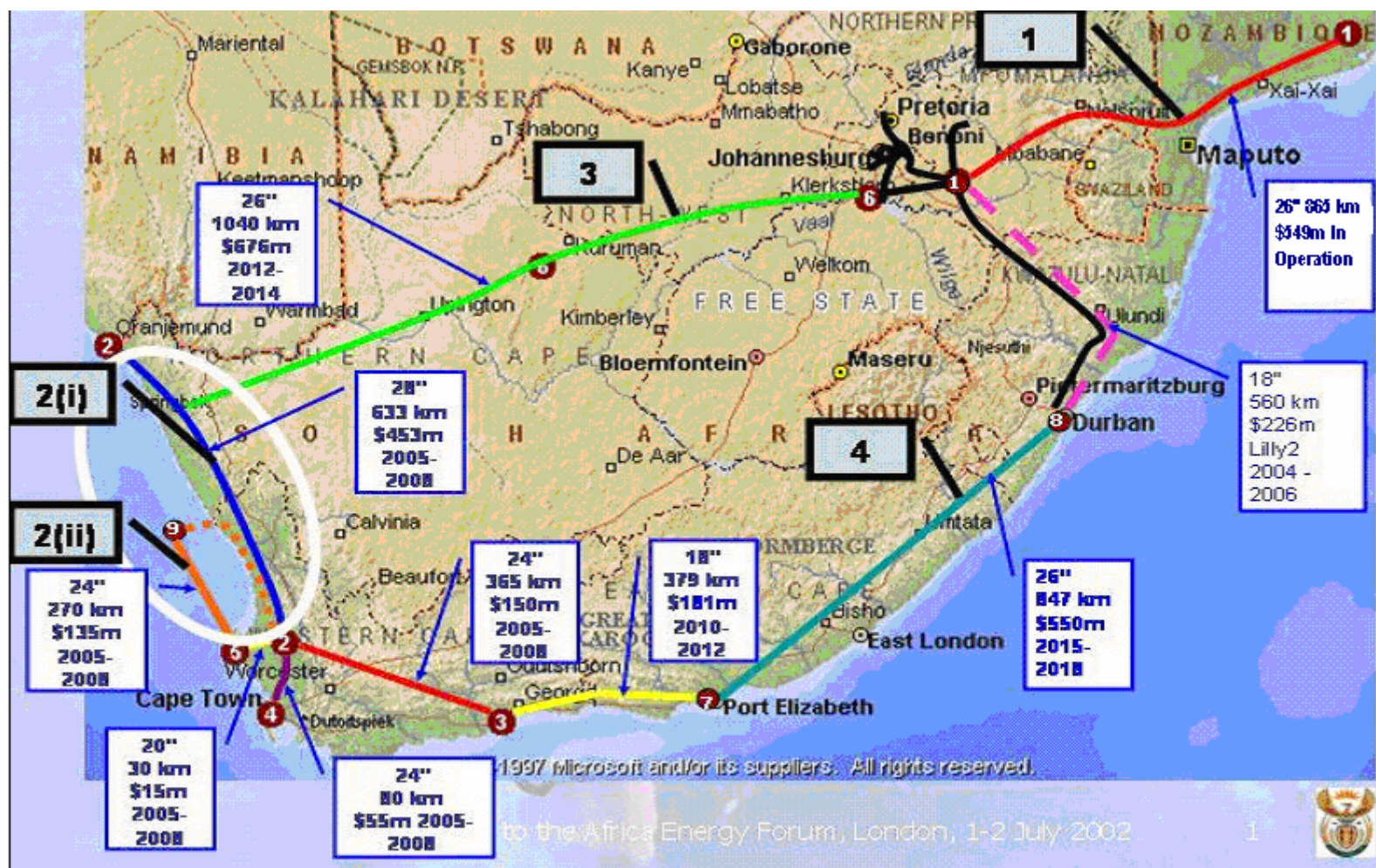
The minimum gas demand for South Africa is estimated at 240 MGJ p.a. and the projected cumulative demand is 370MGJ p.a., indicating significant opportunities to grow the market.

Infrastructure Development Plan

It is anticipated that there will be four main phases of gas infrastructure development, each with sub-phases. The phases are:

- Phase 1 = Mozambique/South Africa.
- Phase 2 = Western Cape.
- Phase 3 = Northern Cape/ Gauteng.
- Phase 4 = The coastal transmission pipeline

Once these projects are completed, there will be a fully integrated network linking the major economic centres to the upstream supplies of gas. The planned gas infrastructure is as follows:



Infrastructure development map

Phase 1 (the east coast)

The Mozambique to South Africa Gas Project

Mozambique to South Africa Gas Pipeline = 1-1 on the development map	
Project Sponsor	Sasol
Reserves	2tcf
Anchor customers	Sasol's Sasolburg and Secunda GTL plants
Market Demand	Assumed demand of natural gas for eastern South African market is constant at 120mGJ/a
Pipeline Costs	\$549 million
Distance	865 km
Construction	2002 to 2004

Sasol currently has sufficient proven reserves to supply the South African market with 120 million GJ p.a. plus 5% royalty **gas for** Mozambique for 17 years.

Petronet

The Lilly 1 gas pipeline from Secunda to Durban at present is limited to 23 mGJ/a. The present utilisation of Lily 1 is 12mGJ/a, and there is sufficient capacity to cope with the 'ramp up' from the Mozambique gas project. If the capacity were to be increased to 40mGJ/a, the cost would be approximately US\$40 million. A pipeline with a capacity of 70mGJ/a will probably be built in 2007-2009 at a cost of about US\$200 million.

Phase 2 - (the west coast) = 2(i) ad 2(ii) on the development map

The Western Cape Gas Project

The Western Cape imports majority of its energy requirements such as fossil fuels and electricity and, as a result, is an ideal region for the introduction of an alternative and cheaper energy carrier. Offshore Western Cape is considered as a gas province and the introduction of natural gas into the region is in line with the Government's policy of achieving energy security by diversifying the supply of energy carriers. It would also facilitate the establishment of different industries. The options are follows:

Map references refer to development map	Option 1 [2(i)]-Potential Kudu Gas (Namibia) - Saldanha Pipeline = 2-2 on map	Option 2 [2(ii)] – Potential Ibhubesi Gas - Saldanha Pipeline = 8-5 on map
Project Sponsor	Originally Shell before its withdrawal.	Forest Exploration International
Reserves	1.3tcf	0.216tcf
Anchor customers	Proposed 400MW Oranjemund Power PlantStation (OPP) and proposed 1600MW Cape Power PlantStation (CPP)	Forest regards PetroSA's GTL facility as a possible anchor, but first wants to sell into the switchables market so as to monetise their current upstream investment in order to prove up replacement reserves.(Limited by low Ibhubesi reserves)
Market Demand	OPP is 25 mGJ/annum CPP is 100 mGJ/annum	Switchables = 5 – 15 MGJ p.a GTL = 73 mGJ p.a
Approximate Pipeline Costs	\$453 million	\$135 million
Approximate Distance	633 km	273 km
Construction	2005 to 2008	2004 to 2006

The development of the Kudu gas field hinges on a power station in Oranjemund and a power station in Cape Town as anchor customers. Based on the above assumptions, the Kudu gas field can supply the two anchor customers for 13 years.

The alternative development is the Ibhubesi field, which involves installing an undersea transmission pipeline to Saldanha, supplying the smaller fuel replacement market in the short term (2005), and then anchor customers such as PetroSA or a gas-to-power project in the long term (2009). Once the main transmission line is installed to Saldanha, a number of other pipelines will be needed to supply the markets in and around Cape Town. These pipelines will be ring fenced for strategic planning purposes but they would be segments of the network rather than phases in construction.

Map references refer to development map	Saldanha to Cape Town 2-4 on map above	Cape Town to Mossel Bay Pipeline 2-3 on map above	Mossel Bay to Port Elizabeth Pipeline 3-7 on map above
Pipeline Costs	\$55 million	\$150 million	\$181 million
Distance	80 km	365 km	3795 km
Construction	2005 to 2008	2005 to 2008	2010 to 2012
Target market	switchable (fuel replacement) customers IPP's LPG market	PetroSA GTL facility = anchor and baseload IPP - cogeneration	Coega industrial development zone (IDZ) IPP – baseload or cogeneration

Assuming no further gas is proved up in the Bredasdorp Basin offshore of Mossel Bay then a pipeline can be planned to feed Port Elizabeth and the Coega Industrial Development Zone (IDZ.)

Phase 3 (Proposed furthest horizon for development)

Pipeline from West Coast to Gauteng via Sishen

West Coast to Gauteng Pipeline	6-6 on map above
Pipeline Costs	\$676 million
Distance	1040 km
Construction	2012 to 2014
Target markets	Sishen mineral beneficiation Gauteng fuel replacement market

Considering the upside for the Kudu gas reserves, a pipeline supplying gas to Gauteng may have the potential for gas on gas competition in the future once the Sasol dispensation expires. Poor results from Shell's recent appraisal campaign (2 dry wells) may change this picture.

The project could be marginal as the mineral beneficiation projects in Sishen will be extremely gas price sensitive and there are no markets en route to Gauteng.

Phase 4 (no plans put forward – theoretical end state)

Pipeline from Port Elizabeth to Durban via East London

East Coast to Durban Pipeline	7- 8 on development map
Pipeline Costs	\$550 million
Distance	847 km
Construction	2015 – 2018
Target markets	potential replacement fuel market potential petrochemical hub

Liquefied Natural Gas (LNG):

One of the main advantages of LNG is that it does not restrict South Africa to any one source of gas as the transportation distance has minimal impact on the gas price. Any disruption in LNG supply could be met by purchases from the world's spot market.

There have been suggestions that LNG could be introduced into the Western Cape, although this may not be viable. Shell, Coega Development Corporation and DTI conducted a study to bring LNG to Coega.

Soekor E & P has also studied the possibility of importing LNG for the Cape markets.

The average landed cost of LNG delivered to Cape Town is projected to be in the region of US\$3.16/GJ. This cost *excludes* the regasification costs.

Intended use	volume	proportion of total potential demand	alternative fuel	price threshold (US\$/GJ)
Power generation/GTL - baseload demand	> 60 MGJ p.a	40%	Coal (indirect)	1 – 2
Power generation – load balancing	20 – 30MGJ p.a	13 – 20%	Diesel	1.5 – 2.5
industrial	½ - 10MGJ p.a	5 - 10%	HFO Coal	4 – 6 3 - 5
commercial	< ½ MGJ p.a	1 – 2%	coal (anthracite) LPG	6 - 8 8 – 10

Table of the relative price thresholds for different gas consumers

Process for Compiling this Report

Since June 2001, an intensive literary review has been conducted to identify the optimal development of the natural gas industry in the context of government policy and strategic imperatives and the commercial considerations of the market development.

A limited market survey was conducted in April 2002 to test some of the market assumptions in relation to the plan for infrastructure development and the kinds of issues that may be raised during the review process.

Conclusion

With the development of the appropriate infrastructure and the realisation of the full market potential of the gas available to South Africa, the percentage of gas in the energy balance may increase from less than 2% to 7%, bringing with it investments and economic growth.

1. INTRODUCTION

Natural gas was a distant option on the energy horizon ten years ago with no definitive gas policy or legislation. The future for gas in South Africa was not promising, apart from the diminutive Sasol Gas market. Since 1994 the picture has changed dramatically, with gas policy laid down in the Energy White Paper, the passing of the Gas Act by Parliament, the conclusion of plans to transmit gas from Mozambique to South Africa, and the upstream activity off the west coast of South Africa.

1.1 Global natural gas trends over past twenty years^{2, 3, 4}

Natural gas has grown significantly since the 70's in the global energy balance. It is more efficient and environmentally friendly than coal or oil. Natural gas occurrences are more widely spread than those of oil and the proven gas reserves are steadily increasing. Oil has a reserves replacement/production ratio of 40 years against natural gas of 63 years. The downside is that natural gas is four times more expensive to transport by pipeline, and ten times more expensive by tanker (sea) when compared to crude oil.

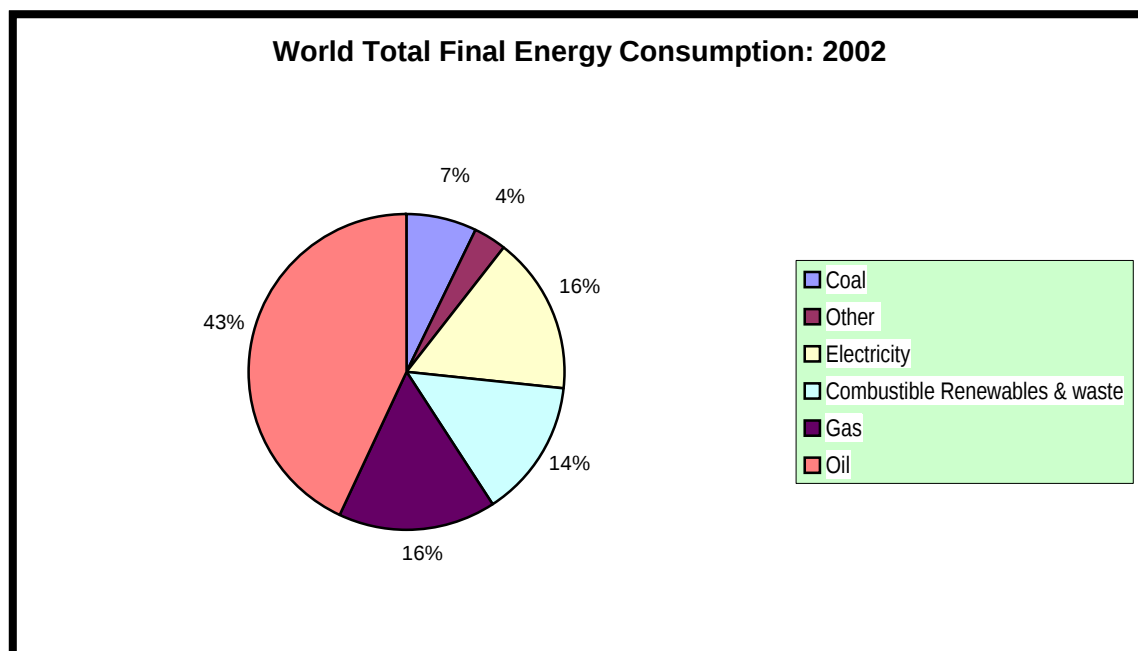


Figure 1: World Total Final Energy Consumption in 2002

² ENSPM Formation Industrie/ Economics and Management, 232 av. N. Bonaparte, 92852 Rueil-Malmaison cedex, July 2001

³ SAD-Elec inputs to the MEETI "Utilisation of Natural Gas Course" April 2002

⁴ Petrad inputs to the MEETI "Utilisation of Natural Gas Course" April 2002

⁴ Key World Statistics 2004; International Energy Agency

Natural gas demand has grown 56% over last 20 years and this demand is expected to increase at 3.2% per annum to a total of 28-30% of the global primary energy demand by 2020. The gas gains will be at the expense of crude oil (reducing by 1-2%) and coal (reducing by 2-3%).

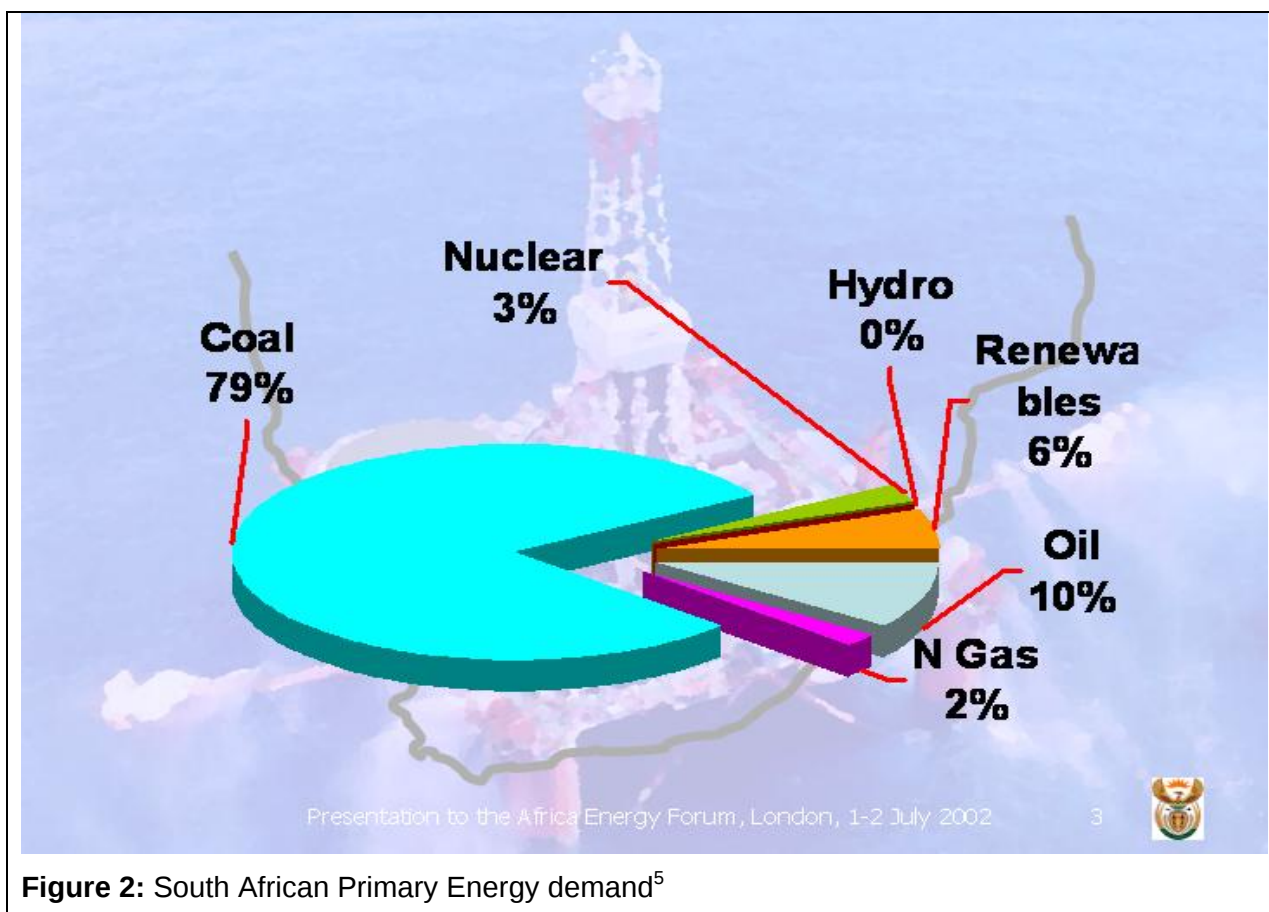
Globally, natural gas is used in gas-to-power generation (30%), spatial heating (28%), and industrial uses (26%). The most significant growth in gas demand is expected to be for power generation, with a growth of 60% by 2010 (to 24% of total power generation) followed by a further growth of 25% by 2020 (to 30% of total power generation). By 2030 the share of gas in power generation is forecast to surpass that of nuclear and hydro combined! This reflects the *only growth in demand* for power generation of any of the primary energy carriers.

The global trend is that power generation is moving from coal to gas as gas has lower operational costs and lower environmental costs, coupled with being 30 - 40% more efficient in combined cycle gas turbine (CCGT) applications. By 2020, coal and gas are expected to share equal portions of the power generation market. CCGT technology is flexible as modular generation capacity can be added as demand grows.

1.2 Natural gas in South Africa

South Africa's primary energy profile is illustrated in Figure 2. Approximately 79% of primary energy is derived from coal, as coal is the major indigenous energy resource and has a low cost of production. Imported crude oil and renewables (mainly in the form of wood and biogases) contribute almost equal amounts, and natural gas, nuclear and hydroelectric power comprises the remaining small balance.

Natural gas accounts for 2% of the primary energy demand, but this is expected to grow to approximately 7% over the next ten years but that coal will remain the dominant energy source. Natural gas can be used as a primary energy source, fuel for gas-to-power, chemical feedstock (e.g. for gas to liquids - GTL), etc. In contrast to the global demand picture, the majority of the demand for gas in South Africa in the short to medium demand will be from the GTL and industrial sectors.



1.3 Future Developments

The construction of the Mozambique to South Africa Gas transmission pipeline is complete, with official first gas delivered to Secunda 26 March 2004. When this pipeline is at capacity, the contribution of natural gas to South Africa's primary energy supply will rise from 1.5% to approximately 4.3%. There are proven gas reserves offshore of Namibia and the Western Cape but these reserves are inadequate at present and further prospecting is required. Liquefied Natural Gas (LNG) is being considered for markets remote from gas fields, while Coal Bed Methane (CBM) may become an option in the medium term.

1.4 Gas Infrastructure Plan (GIP)

This GIP is essentially a literature review of recent data on natural gas development and potential market activity and is intended to formulate the Government's view of the gas industry, taking cognisance of the following critical aspects:

- strategic considerations such as energy security and diversity, energy input costs and economic development,

⁵ Adapted from the South African National Energy Database, May 2002, Department of Minerals and Energy, Integrated Energy Planning

- policy/regulatory considerations such as infrastructure standards, pricing and competition, and
- commercial considerations such as returns on investments and protection of investments.

The GIP conforms to the relevant sections of the Integrated Energy Plan of 26 March 2003, That is "*..diversify energy supply through increase use of natural gas..*", "*..continue with existing synfuels plants and supplement with natural gas as feedstock..*", and "*..new electricity generation will remain coal-based, with potential for hydro, natural gas and nuclear..*"

Gas projects shall be undertaken on a commercial basis.

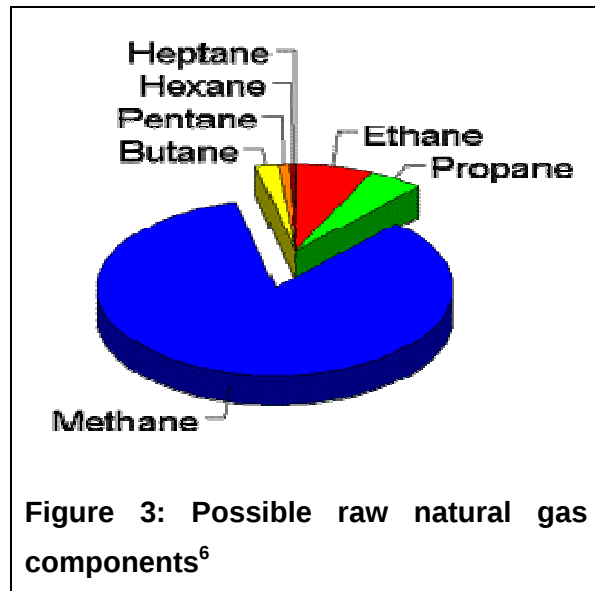
2 OVERVIEW OF THE GAS INDUSTRY

Natural gas is the cleanest burning fossil fuel and produces far lower levels of CO₂, CO, SO₂, NO_x, and particulate matter compared with other fossil fuels. Due to its superior environmental performance, gas is increasingly becoming a fuel of choice for many applications.

Natural gas is produced either from reservoirs that also produce oil (associated gas), or from reservoirs that contain gas alone (non-associated gas).

Natural gas consists mainly of methane with some ethane, propane and butane. “Wet gas” is gas that contains condensates i.e. light hydrocarbons that are liquid under atmospheric temperatures and pressures. In addition to these components, raw natural gas may also contain carbon dioxide, nitrogen, hydrogen sulphide, helium, mercury, water, and other contaminants. Gas composition differs between gas reservoirs and there is no “typical” gas composition. The following graph shows a possible composition of a particular gas reservoir.

Raw natural gas will usually undergo some form of processing to remove contaminants to very low levels to make the gas suitable for pipeline transportation and commercial use. In some instances the gas is further processed to separate ethane, propane and butane. These components have higher values as separate products instead of being utilised merely as fuel and are utilised in industries such as petrochemicals and as Liquefied Petroleum Gas (LPG). In such cases, the final gas transported and distributed will consist mainly of methane and possibly some ethane.



⁶ Graph adapted from table in *Modern Petroleum*, PennWell, 1992 as reproduced in www.naturalgas.org

2.1 Transmission – Pipelines

Gas is transmitted by pipelines at high pressure and compressor stations may be required at certain intervals to maintain the pressure within the pipeline. Compressors are fuelled by gas from the pipeline.

Pipeline companies use sophisticated systems such as Supervisory Control and Data Acquisition (SCADA) systems to monitor and control the flow of gas at various points along the pipeline electronically.

2.2 Transmission – Liquefied Natural Gas (LNG)

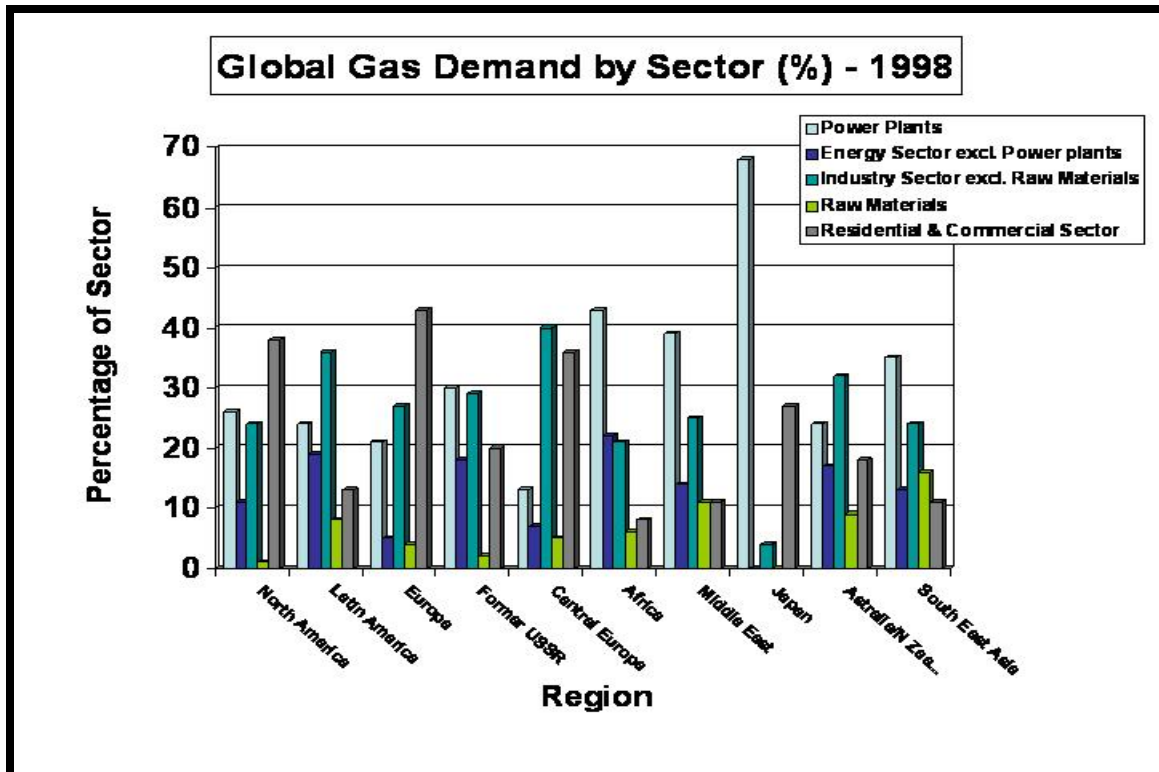
In addition to using long distance pipelines, gas is also transported over long distances in the form of Liquefied Natural Gas (LNG). The gas is cooled to around -160°C and changes to liquid. This liquefaction process results in the reduction of the volume of about one six hundred (1/600). The liquefied gas is then shipped to markets in special tankers, which maintain the required temperature to keep the gas in liquid form. The tankers discharge the LNG at terminals where the liquefied gas is re-gasified for introduction into either a gas transmission pipeline system or a local gas distribution/reticulation system. LNG is ten times more costly to transport than crude oil, and nearly three times more costly than piped natural gas. LNG becomes viable at distances in excess of 2000 km.

2.3 Distribution

While large gas users such as gas-fired power stations and large industries obtain their gas supply directly from the gas transmission pipeline, other users such as small and medium sized industries, commercial and domestic users usually obtain their gas supply from their local gas distributor. Gas distributors have extensive gas distribution pipeline networks within industrial and urban areas. For safety reasons, the gas is distributed at a lower pressure and is odorised to allow users to detect gas leaks easily.

2.4 Applications

In electricity generation, gas is used in simple open cycle gas turbines mainly for peaking purposes, or used in the more efficient combined cycle gas turbine (CCGT) mainly for baseload purposes.



	Power Plants	Energy Sector excl. Power plants	Industrial Sector excl. raw materials	Raw materials	Residential and Commercial Sector
World Total (millions toe)	560	242	511	82	547
	30%	12%	26%	4%	28%

Figure 4 - Global gas demand by sector and region.⁷

CCGT allows for a more efficient generation of electricity achieving efficiency levels of above 50% by minimising heat waste. In cogeneration applications, electricity is produced together with heat, steam, or chilled water for air conditioning applications. The efficiency achieved in cogeneration systems is higher and can achieve as high as 90% efficiency. Gas can also be used to produce electricity from fuel cells, although this application is currently not widely used. Fuel cells convert the chemical energy of the fuel directly into electricity without combustion, producing water and little or no pollution. Commercially available units have efficiencies of over 40% and the efficiency can be increased to over 80% in cogeneration applications. Widespread use of this technology

⁷ Adapted from: ENSPM Formation Industrie/ Economics and Management, 232 av. N. Bonaparte, 92852 Reuil-Malmaison cedex, July 2001

could be a boost to the domestic platinum mining industry since platinum is among the catalysts used in fuel cells. Assistance in the research and development of this technology should be considered.

In industrial applications, gas is used primarily as a fuel source, such as in boilers and furnaces. Gas is used as a feedstock in petrochemical industries in the production of liquid fuels, fertiliser, methanol etc. Natural gas can be used as a reductant for iron ore. This produces a potentially marketable secondary stream of CO₂ that could have applications in the soft drink business.

In transportation, the use of Natural Gas Vehicles (NGV) is growing in popularity as they emit less pollution than conventional petrol or diesel powered vehicles. Existing petrol or diesel-powered vehicles can be converted to run on natural gas.

Gas is used in the residential markets for space heating, water heating and cooking.

3 BACKGROUND OF GAS IN SOUTH AFRICA

Gas was first introduced in South Africa with the construction of the Cape Gas and Coke Company in Cape Town in 1847. Other gas plants followed in Port Elizabeth, Kimberly, Grahamstown, and eventually Johannesburg in 1892. These gas plants were owned by private operators from Britain and continental Europe and were run to the same standards as their European counterparts. All these gas works have since been closed down for economic reasons, although the town gas has been replaced with Sasol gas in Johannesburg and LPG/air mixture in Port Elizabeth

3.1 South Africa - 'eastern half'

Sasol was founded in 1950 as a state owned corporation. It started production in 1955 and became a private company in 1979. Sasol produces synthetic-gas from coal, and then liquid fuels and chemicals from the gas. Some of the gas is extracted and sold as pipeline gas, either as hydrogen rich gas or methane rich gas. It has sold gas since 1964, and annual gas sales have expanded from approximately 25 million Giga Joules in 1994 to 52.9 million Giga Joules in 2004 - a growth of 27million Giga Joules or 111.6% in 10 years. Sasol's gas 2004 sales amounted to R 1.522 million with an operating profit of R387 million. The market distribution of the current 'eastern' gas market is shown in Figure 5. The metals sector represented 48% of the total demand. Sales to the oil industry for refining purposes are expected to grow. This rapidly growing and profitable coal gas industry bodes well for the future of natural gas in South Africa, especially as the traditional bulk markets such as electricity generation have not been tapped.

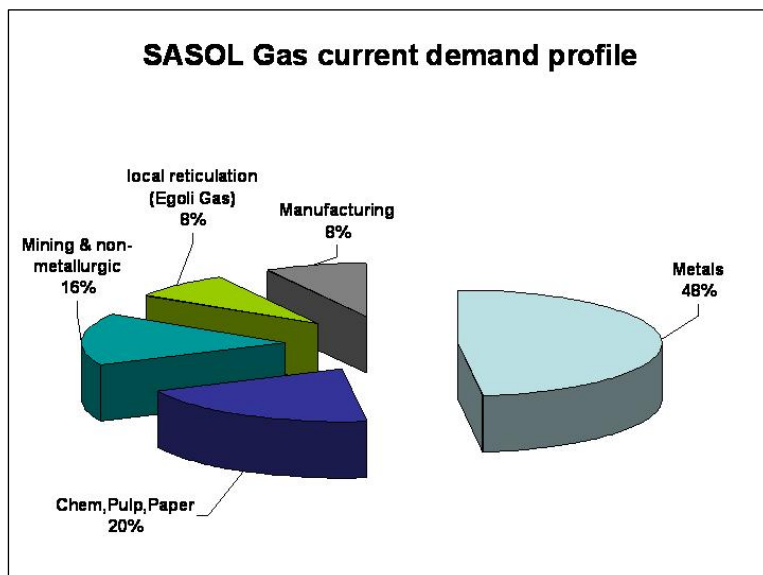


Figure 5 - Current gas demand (41.6 MGJ p.a)
'eastern' market⁸

⁸ Source – Sasol Gas, business review, 2001

Metro Gas (now Egoli Gas) has been distributing gas in Johannesburg for over 100 years. Its gas works closed during 1992, and since then Egoli Gas has been buying hydrogen rich gas from Sasol. Its present sales amount to approximately 2 million Giga Joules per annum and it has about 3000 commercial connections and 13 000 residential connections.

3.2 South Africa – 'western half'

PetroSA (previously Mossgas and Soekor), a state owned company, was established through the Central Energy Fund (CEF) in 1992 for strategic reasons. Natural gas produced from the F-A and E-M fields in the Mossel Bay area is used as feedstock to the PetroSA synthetic liquid fuels plant. The gas consumption is in the range of 75 million Giga Joules per annum, which equates to 0.069 tcf per annum. However, January 2002 gas reserves amounted to 0.414 trillion cubic feet (tcf), only sufficient for another six years of production. Long-term supply to PetroSA could theoretically come from the Kudu field offshore of Namibia, with supplementary gas from the Ibhubesi field offshore of South Africa's west coast.

Easigas (Shell) has a small LPG/air pipe network in Port Elizabeth.

4 GLOBAL DEVELOPMENT OF THE GAS INDUSTRY

The level of development of the global gas industry varies but there are generic stages of development, namely exclusive supply arrangements often with heavy state and/or regulatory involvement giving way to unbundled and deregulated value chains where economic regulation of the transmission/distribution infrastructure and gas-on-gas competition in the market has finally led to flourishing futures spot markets in major gas utilization regions. Regulation is necessary in even mature gas industries to ensure competition through mandatory third party access and non-discriminatory tariffs access.

North America has the most developed gas industry in the world. The development of the North American gas industry began with the granting of exclusive rights or franchises by local or state governments for local gas distribution companies and by the federal government for interstate pipeline companies. Pipeline projects are capital intensive and it takes time to develop gas markets. This results in the under-utilisation of pipeline capacity in the initial years. The only way for projects to be viable is to ensure that the initial sub-marginal rates of return can be offset by future profits. As such, franchises were seen to be necessary in order to reduce the risk of the investment and so stimulate the development of the gas industry.

In the 1980's, the gas industry of North America underwent deregulation and introduced open access. Today, the North American gas industry is a highly competitive with the transportation and trading functions of the major interstates pipelines separated. Industrial customers and gas distribution utilities are able to buy directly from competing gas suppliers and arrange separately for transportation by competing gas transmission systems. The price of natural gas is decoupled from oil prices and is determined by market forces. A futures market for gas also exists where buyers are able to arrange for future deliveries and hedging.

An important lesson to be learned from the deregulation of the North American gas industry was the failure to address the broader strategic issues affecting the wider energy industry. The impacts of this poorly strategised deregulation process coupled with shortsighted liberalisation of the electricity supply industry, resulted in a fragmented pipeline network that gave over emphasised control to particular pipeline connections in

the system. The resulting manipulation of the gas supply/demand dynamics caused gas prices to soar in the western US, strangling the Californian power sector with increasing inputs costs but stagnant income due to regulated electricity tariffs. These factors deterred investors from replacing generation capacity, culminating in the Californian power crisis in 2000.

The gas industry in Europe, while also mature, is not yet as competitive as the North American gas industry. Gas supplies come from within Europe, such as from the North Sea and Netherlands, as well as imported from North Africa and Russia. No single gas supplier controls sufficient quantity of gas to dictate the price and terms of supply. However, most of the gas transmission system was developed by state monopolies for both the transmission and trading functions resulting in little competition.

Since the adoption of the European Union, Gas Directive 1998, EU member states in Europe have moved towards the opening up of the European gas market beginning 10 August 2000. The aim of the directive is to create a single, unified and competitive European gas market from what was before separate markets dominated by only a few players. This entails among others, the elimination of national exclusive rights, gas supply monopolies and all cross-border restrictions allowing for gas-to-gas competition. Member states are required to gradually open up their gas markets beginning with 20% of their markets by 10 August 2000. Based on the outcome of the initial implementation of the directive, the EU is now planning to speed-up this process with the target of the formation of a fully open, single gas market by 2005. It is envisaged that eventually gas prices in Europe shall be more determined by market forces and will be decoupled from other fuel prices.

In developing countries that do have a gas industry, most of the infrastructure is still in developmental stage. The pipeline systems are less integrated and there are few cross-border pipelines, the exception being Latin America. Generally, gas pipelines are either publicly owned or are owned by companies that have been granted exclusive franchises. However, it must be remembered that this situation is very much similar to that in North America and Europe in their respective developmental stages.

In the newly industrialised countries of Association of Southeast Asia Nations ASEAN, there are already plans to integrate the separate gas pipeline systems there into an integrated Trans-ASEAN gas pipeline system. Such integrated system is seen as the next stage of the evolution of the gas industry there towards a more mature industry similar to those in Europe and North America.

5 GOVERNANCE – Legal, fiscal and regulatory regimes

5.1 Governance from a Gas perspective

The South African Government is committed to the establishment of an appropriate framework to facilitate the development of a competitive gas industry.

A number of tools are at Government's disposal to promote the gas industry in terms of a stable regulatory environment and investor friendly fiscal regime. The challenge is to use these tools in a transparent manner that protects consumers from abuse, whilst assuring investors they will receive a fair and reasonable return.

Due to the inflexible nature of pipeline infrastructure, the critical issues in regulating the gas industry are:

- To promote integration of closed networks giving alternative access to markets from different gas supplies
- Third party access, to ensure that all suppliers have equal access to markets
- Non-discriminatory tariffs to prevent monopolisation of the pipelines
- Economic regulation of the market to stimulate gas-on-gas competition.

Thus, it can be seen that regulation in the industry must manage the internal dynamics of the gas sector in the broader context of energy regulation in general.

5.2 Current legislative/regulatory tools

Energy Policy White Paper

The South African White Paper on Energy Policy 1998 has described gas as an attractive option and states that the government is committed to the development of the gas industry.

The White Paper outlined the following key energy policy objectives:

- Competition within and between energy carriers.
- Increasing access to affordable energy services.
- Improving energy governance.
- Stimulating economic activity.
- Managing energy-related environmental impacts.
- Securing security of supply through diversity of supply.
- Promoting NEPAD cross-border type projects.

The South African Government has set out the following objectives for the development of the gas industry:

- Ensure the provision of gas as soon as possible at the lowest possible price;
- Ensure the establishment of the appropriate transmission infrastructure required for industrial projects;
- Promote orderly development, operation and provision of gas services, the key being transmission infrastructure;
- Ensure that the gas industry is safe, efficient, economic and environmentally responsible;
- Ensure that gas services are provided in a non-discriminatory manner that meet the needs of the customers;
- Promote competitive markets by facilitating gas-on-gas competition through third party access (TPA) to transmission pipelines; and
- Facilitate the trade of gas between the South Africa and other countries through formal agreements, gas transmission infrastructure development, and specific projects.

The Gas Act, 2001 (Act No 48 of 2001)

The Gas Act promotes the orderly development of the South African piped gas industry. The Act envisages the granting of licenses for the construction, operation and trading for transmission, distribution, liquefaction, regasification and storage within a set framework of requirements and limitations. The Minister may promulgate regulation after consulting with the regulator and allowing for public comment.

The objectives of the Act are to:

- Promote efficient, sustainable, and orderly development and operation of the downstream gas industry;
- Facilitate investment;
- Ensure safe, efficient and environmentally responsible downstream gas industry;
- Promote historically disadvantaged firms;
- Ensure that gas services are equitable and that present and future needs are met;
- Promote competitive markets;

- Promote skills and employment equity; and
- Facilitate gas trade between the RSA and other countries; and
- Promote access to affordable and safe gas.

Section 36 of the Gas Act binds the Regulator to the Government/Sasol Agreement that pertains to the Mozambique/South Africa gas transmission pipeline and addresses derogations on the forth-coming gas regulations for a period of up to ten years, depending on the amount of gas reserves available.

The Gas Regulator

The Gas Regulator, which is in the final stages of design, is anticipated to be established in 2005 as part of a single Energy Regulator that will regulate the electricity, piped gas and petroleum pipelines industries, and will serve as a custodian and enforcer of the national and regulatory framework.

The functions of the Gas Regulator are to:

- Issue licenses
- Gather information relating to the gas value chain
- Undertake investigations and inquiries into the activities of licensees
- Consult with government departments and other bodies and institutions regarding any matter contemplated in the Act
- Consult with government departments and gas regulatory authorities of other countries
- Regulate prices;
- Expropriate land;
- Promote competition in the gas industry;
- Promote optimal use of available gas resources;
- Take decisions that are not at variance with published Government policy;
- Publish from time to time a list of other legislation applicable to the gas industry;
- Perform any activity incidental to the performance of its functions
- Exercise any power or perform any duty conferred or imposed on it under any law

Investment tools

The South African Government has introduced additional depreciation allowances for permanent structures, as outlined in the Minister of Finance's February 2000 budget speech, to encourage investment in strategic infrastructure projects:

- a. Depreciation at 10% p.a for oil and gas pipelines over 10 years (Section. 12(d) of the Income Tax Act),
- b. Depreciation at 5% p.a electricity and telephone transmission lines and railway lines over 20 years (Section. 12(d) of the Income Tax Act)
- c. Depreciation at 20% p.a of power plant (by virtue of the fact that it is a facility for use in a manufacturing process) over 5 years (Section. 12(c) of the Income Tax Act)

The proviso is that for dispensation under Section 12(d) i.e. (a) & (b) above can only be granted if the asset forms part of the core business ie the applicant owns the asset as part of its business. Dispensation under Section 12(c) can be granted to a third party such as a bank financing a power plant etc.

In specific instances there are additional investment incentives such as the promulgation of industrial development zones (IDZ's) which will have a tailored package of fiscal related tools, such as VAT exemption for production that is not entering the domestic market e.g. imported inputs for a production platform for export to the global market.

Industry standards

In terms of the Vessels Under Pressure Regulations of the Occupational Health and Safety Act 85 of 1993, approved international standards such as the American ASME standards may be adopted.

5.3 Governance from an electricity perspective

Regulation of the Electricity Industry

The Electricity Act, 1987 (No. 41 of 1987) provides for the establishment of the National Electricity Regulator to exercise control over the Electricity Supply Industry (ESI) so as to ensure order in the generation and efficient supply of electricity. The current electricity regulation framework was conceived within the context of a fully regulated ESI.

The implications of the approval to restructure both the Electricity Distribution Industry (EDI) and the ESI has profound implications on the ability of the current regulator to execute its functions. To that end, a new Electricity Regulation legislation is being developed.

The objective of the Electricity Regulation Bill is to strengthen the powers and functions of the current electricity regulator to deal with issues of distribution, transition, generation and facilitate the introduction of Independent Power Producers (foreign direct investment) in the sector.

Current ESI strategy

A number of landmark decisions were made by Cabinet during May 2001:

Firstly, the restructuring of the electricity sector was confirmed with creation of Regional Electricity Distributors (REDs).

Secondly, the restructuring will be made in the context of the following national government electricity sector policy imperatives:

- Provide low cost electricity with equitable tariffs
- Deliver reliable and quality supply
- Meeting electrification targets
- Meet economic and social objectives e.g. ISRDS, HRD, BEE
- Operate in a financially sound and efficient manner
- Debt reduction
- African Renaissance

Thirdly the establishment of Electricity Distribution Industry (EDI) Holding company was approved by Cabinet to facilitate the establishment of the REDs. The first RED expected to be in place by July 2005.

The Electricity Supply Industry (ESI) Restructuring Bill

The objective of the ESI Restructuring Bill is to facilitate the restructuring of the current ESI, which is vertically integrated, regulated industry into an unbundled market oriented industry with foreign direct investment and Black Economic Empowerment opportunities.

The restructuring framework will facilitate the attainment of key objectives:

- Introduction of Black Economic Empowerment (BEE);
- Introduction of Independent Power Producers (IPP) through Foreign Direct Investment (FDI);
- Unbundling of transmission from the generation structures;
- Unbundling and re-clustering of electricity generators;
- Introduction of electricity market traders;
- Address issues of eventuality of
 - (i) market failure
 - (II) obligation to supply Integrated Electricity Planning(IEP) within the Context of the SAPP
- Address issues of energy efficiency.

The Electricity Distribution Industry (EDI) Restructuring Bill

The objective of the Bill is to facilitate the restructuring of the current Electricity Distribution Industry (EDI), which was recognised to be in a state of disarray and being financially unsustainable. The Bill facilitates the establishment of 6 Regional Electricity Distributors (REDs) as entities under the joint ownership of current distributors in line with the Constitution. The Bill also provides for the establishment of a EDI Holding Company which will facilitate the establishment and support of the REDs to a state of financial viability. Through the transition period, the Bill facilitates the restoration of the financial standing of Municipalities which are currently benefiting from the proceeds of electricity sales.

5.4 Rationalisation of Energy Regulators

Cabinet recently approved the rationalisation of the regulators of the gas, electricity and petroleum pipelines sectors into a single National Energy Regulator(NER). This is scheduled to be undertaken during 2005 whereby gas and petroleum pipeline regulatory functions will first be undertaken by the single Energy Regulator followed by electricity regulation functions.

Combining regulatory functions will help to make energy policy implementation more efficient and integrated. One can see clearly the need for an integrated approach for gas as it impacts on other sectors of the energy industry. The electricity supply and

distribution industries (ESI and EDI) are currently undergoing restructuring and a number of bills and policy are being prepared to establish liberalised commercial entities and appropriate regulation.

A fundamental aspect of this process is the introduction of a new level of transparency of regulation of the energy sector. This will be achieved by changing the current electricity regulator status where there is no prescribed decision-making process except to appeal to the Minister of Minerals and Energy. The new procedure will involve a consultative process as prescribed in the Gas Act, 2001 (Act No 48 of 2001) to ensure that decisions are:

- Procedurally fair;
- Based on facts and evidence;
- In writing, and;
- Explained.

To provide comfort to stakeholders, there must be public meetings and the opportunity for review by the High Court. This new level of transparency is critical for an orderly and efficient delivery of energy related services.

6 A REVIEW OF THE SADC ENERGY STUDY “ECONOMICS OF NATURAL GAS UTILISATION IN SOUTHERN AFRICA”

The Southern African Development Community (SADC) Energy Study on the “Economics of Natural Gas Utilisation in Southern Africa” was released in May 1995. The aim of the study was to support regional and national policy formulation for the development of the natural gas industry. It consisted of eight technical papers covering aspects of markets, resources, production costs, transmission, supply economics, development scenarios, governance, and institutional requirements, environmental aspects, and regional benefits.

Markets

The study began with the review of possible development of gas markets in South Africa under various scenarios for economic growth and development of relative energy prices. Since then, several feasibility studies have been undertaken by various interested players, and today the Mozambique gas project is already in its implementation stage.

Key factors in determining future demand for gas found in the SADC study was economic growth, energy intensity of the economy and demand elasticity for energy in relation to economic growth. Historically, South Africa has a very energy intensive economy based on large-scale capital-intensive projects. However, it was noted that government policy has shifted to one of “strategic development” of national resources emphasising more equitable and balanced economic growth, implying a more focus on labour intensive economic growth. This shift in policy may have an impact on the growth of energy use in the future.

It was also concluded that there are four main energy consumption centres in South Africa namely Gauteng, Mpumalanga, Kwazulu-Natal, and Western Cape. These main areas provide considerable energy demand with potential for gas utilisation. The development of a gas industry in these areas may also stimulate further demand for gas. The main conclusion of the market analysis was that the identified potential gas market in South Africa appears to be substantial enough for development of a gas industry. The demand forecast indicated that a phased development of gas fields could be required as a result of the timing of primary user demand.

Electricity generation, the most likely anchor gas user, was considered in further detail. The following developments within the electricity sector will affect the gas markets –

- A likely increase in electricity prices against other energy carriers. This arises from the need to construct new power generating facilities as demand for electricity grows.
- The possible use of gas in power generation.

Based on the demand forecast of the study, industrial demand was not found to provide substantial demand to qualify it as an anchor. This however could change with the expected increase in electricity prices that would make gas more competitive.

Other potential uses of gas considered by the study included the petrochemical industries. This would provide additional demand for gas and ensure or enhance the viability of the development of the gas industry and further add value to the gas resource. Sasol will be using a third of the gas from Mozambique to convert its Sasolburg petrochemical plant entirely over to natural gas as the feedstock.

The study reviewed the existing local gas distributions system in South Africa. It was concluded that South Africa has limited experience in gas distribution and that considerable changes/investment is needed to adapt existing facilities to natural gas. For the Gauteng gas distribution system, it was found industrial and commercial users were subsidising domestic users and that the final gas prices were not cost reflective. This cross-subsidy would impact on the composition and development of the total gas demand in the area. It was also found that standards were not harmonised and were largely self-imposed. These are obvious areas to be addressed under the new regulatory regime.

The study looked into Mozambique's experience in low cost gas distribution systems and concluded that there seems to be considerable potential for such low cost gas distribution systems in South Africa. A further study of the potential for implementation of such scheme in South Africa is recommended.

Resources

In addition to natural gas, the study has also recommended further investigation into the prospects of Coal Bed Methane (CBM). Unfortunately, little investigation has been done since the study and recent attempts to obtain information from the private sector have been unsuccessful. Available data indicates that the CBM is not currently viable, although there is good potential for CBM reserves.

Transmission

An issue raised in the SADC study is the treatment of the CAPEX on pipeline assets for tax purposes. Under the previous South African tax laws, pipeline assets were classified as “permanent installations” by tax authorities and not allowed for depreciation. Since this report was compiled, straight-line depreciation of pipeline of assets was introduced. The gas transmission business is a very capital-intensive business and depreciation is normally the largest cost in a transmission company's profit and loss account. Transmission companies can now utilise the CAPEX on pipeline assets as depreciation for tax purposes, which is a strong incentive for investment in the industry.

Environment

Environmental issues may not be stressed in Southern Africa as much as in the developed world. However, the importance of gas as a cleaner fuel source will be increasingly relevant. Environmental cost is not yet incorporated in fuel pricing and this is among the several tools that should be considered. Allowing gas to compete purely on a thermal basis would in effect overlook one of the main advantages of gas, which is that it is a cleaner fuel. Several possible instruments such as environment taxation and regulations have been proposed for consideration. The aim of these instruments is to promote a more efficient utilisation of various fuel sources after factoring environmental costs.

7 DEVELOPMENT OF A GAS INDUSTRY IN SOUTH AFRICA

From the study of the development of the gas industries of North America and Europe, it is clear that the development of a gas industry is a slow process. However, the ultimate aim shall always remain the development of a mature and competitive gas industry.

The Gas Infrastructure Plan aims to provide the framework of the development of South Africa's gas industry in its infancy stage (5 or 10 years). It should be revised on a regular basis, charting the course of the gas industry based on the latest developments.

The critical issues to be assessed will involve answering the following critical questions:

- How much gas do we have, and where is it located?
- Who wants the gas and how much do we need?
- How do we get the gas from source to market?

8 CURRENT GAS RESERVES

Gas occurrences are classified in terms of reserves, contingent resources and prospective resources as shown in Table 1 below:

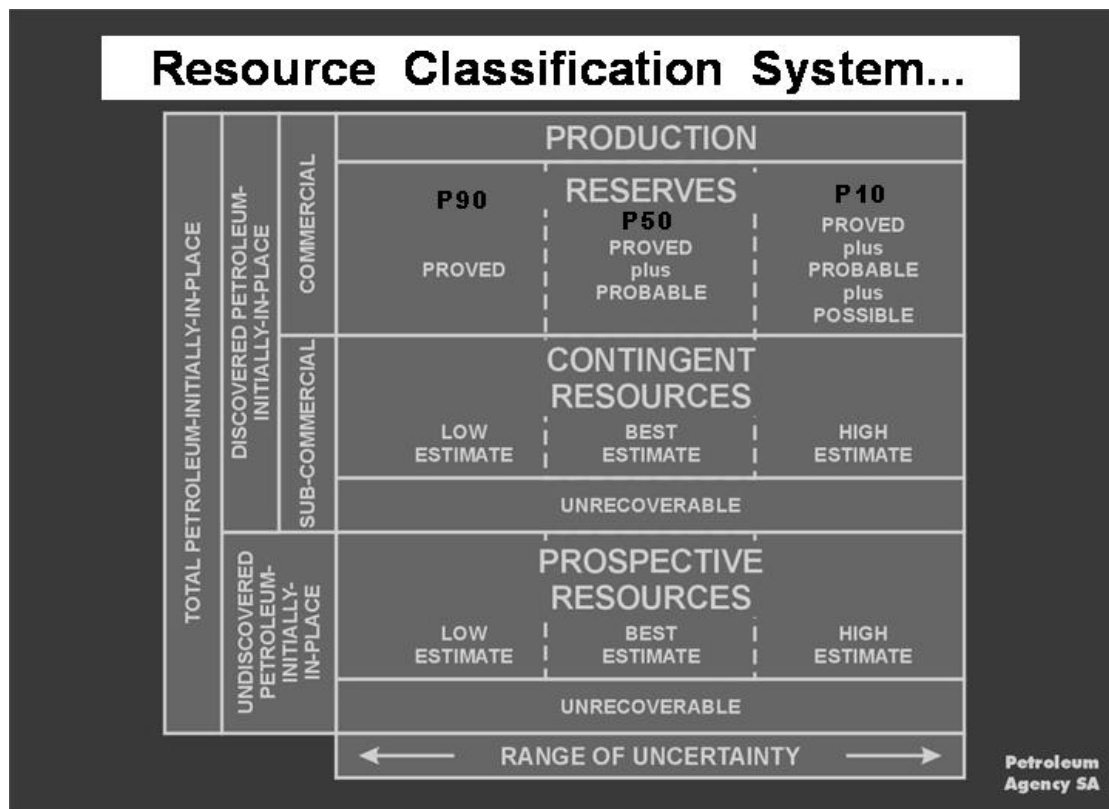


Table 1 - Universal petroleum resource classification system

The accuracy of the estimation increases as one moves from prospective resources to contingent resources and finally to proven reserves. Typically, a geological assessment would indicate the possibility of oil or gas (*prospective resources*). However, to justify further exploration seismic studies would be completed to advance the determination to *contingent resources*. Finally, a number of test wells would be drilled to prove the physical presence of gas *reserves*. The assessment of all of this data would constitute a reserve audit.

South Africa has only relatively small known natural gas reserves, mainly off its south coast (predominantly in the Bredasdorp Basin) and off the west coast. However, potential natural gas resources are being investigated and additional exploration activity is going on. Some investigations of coal-bed methane (CBM) are also taking place.

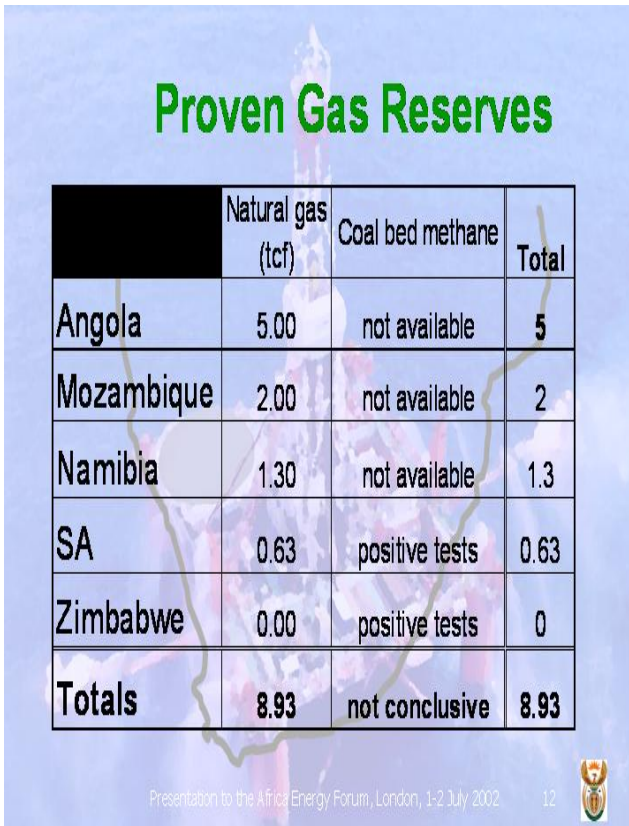
CBM could potentially become a significant source of gas for South Africa in the future if a substantial gas market develops.

Despite the relatively low level of known domestic gas reserves, it is probable that South African gas industry is on the brink of significant expansion. This is due to major natural gas discoveries and developments in the neighbouring countries of Mozambique and

Namibia and the potential utilisation of South Africa's own natural resources.

The Petroleum Agency of South Africa (PASA) is optimistic about the prospects off the west coast, especially since the Forest Oil field audit released in February 2002 includes a prospectivity estimation of the entire block 2A. Thus, the 0,216 tcf of proven reserves are small, but there is a good chance of reserves replacement being achieved.

In addition to these proven reserves, a number of upstream investors are currently conducting exploration campaigns off the coast of South Africa, including:



Proven Gas Reserves

	Natural gas (tcf)	Coal bed methane	Total
Angola	5.00	not available	5
Mozambique	2.00	not available	2
Namibia	1.30	not available	1.3
SA	0.63	positive tests	0.63
Zimbabwe	0.00	positive tests	0
Totals	8.93	not conclusive	8.93

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Table 2 - Southern African proven reserves of natural gas

- Sasol Petroleum International in Blocks 3A/4A
- Pioneer Natural Resources in Blocks 7, 9 and 10-14B
- Ranger Oil in Blocks 11B/12B.

8.1 Comparative Values

The current consumption of PetroSA's GTL facility in Mossel Bay is 75 million Giga Joules per annum (MGJ/a) and this equates to approximately 0.069 trillion cubic feet (tcf)

per annum. Thus PetroSA would require 0.69 tcf of gas for each 10 years of operation. By contrast, a 1000MW gas fired plant would require 0.55 tcf per 10 years, and a typical mineral beneficiation project would use 0.23 tcf per 10 years.

8.2 Gas Resources Off The West Coast⁹

Blocks 1, 2 and 3 are located in an area recognised as a gas province. Gas discoveries have been made in Block 1 and 4 and in Block 2. Block 5 and 6 fall within a potential oil province and Block 4 is expecting to be charged by both gas and oil provinces.

In **Block 1** four leads have been mapped. Their prospective resources add up to a low estimate of 1.1 trillion cubic feet (Tcf), a best estimate of 3.5 tcf, and a high estimate of more than 10 Tcf gas in place.

In **Block 2** several mapped leads total to prospective resources varying from 1.6 Tcf (low estimate), to 7.3 Tcf (best estimate) to more than 26 Tcf (high estimate). In February 2002, the Ibhubesi field was proven at 0.216 tcf (P90).

Several mapped leads in **Blocks 3 and 4** total to best estimates of prospective resources of 4.2 Tcf and 4.3 Tcf respectively. Minor gas potential exists in **Blocks 5 and 6**.

8.3 Gas Resources Off The South Coast

Block 7 is generally considered an oil province with wet gas potential. Prospective resources are calculated to be 1 Tcf gas in place (best estimate). All oil prospects may contain a gas cap, especially in the eastern section, which is in contact with the Bredasdorp Basin fetch area.

Block 8 has minor gas potential and prospective resources have been limited to a high estimate of 1 Tcf.

In **Block 9**, PetroSA and Pioneer Natural Resources made latest resource calculations. Best estimates of contingent resources of mapped leads are 1.7tcf, with P50 reserves at 0.8tcf. These resources are dedicated to the PetroSA GTL facility unless other gas is

⁹ extracted from the PASA data

found as feedstock, in which case this gas could be transmitted to the Eastern Cape if the market demand warrants it.

The southern parts of **Blocks 10, 11A and 12A**, in the zone adjacent to the Southern Outeniqua Basin have good potential, being proximal to the gas kitchen.

Block 11A has two gas fields, and a large 3D seismic survey has been completed over the block recently, which may exhibit substantial larger prospective resources in the nearby future with a current best estimate of 0.176 tcf.

In **Blocks 11B and 12B**, a deep-water frontier area, the total high estimate figure for 6 unmapped leads is approximately 34 Tcf. The prospective resource best estimate of mapped leads totals to 5.5 Tcf. A gas discovery demonstrated a contingent resource best estimate of 3.3 Tcf gas in place, with high estimate of more than 6 Tcf.

Blocks 13 and 14 are regarded as potential oil rather than gas provinces, but deep-seated gas potential exists within the rift succession.

8.4 Gas Resources Off The East Coast

The thin overburden in **Blocks 15 and 16** downgrades prospectivity of the area. The absence of the source rocks makes these areas risky for any hydrocarbon prospecting.

Blocks 17 and 18 are the only areas where a petroleum system still needs to be proven and are generally considered high-risk areas. Large prospects have been mapped with prospective resource best estimates exceeding 22 Tcf gas in place. These blocks were relinquished on 05 May 2001.

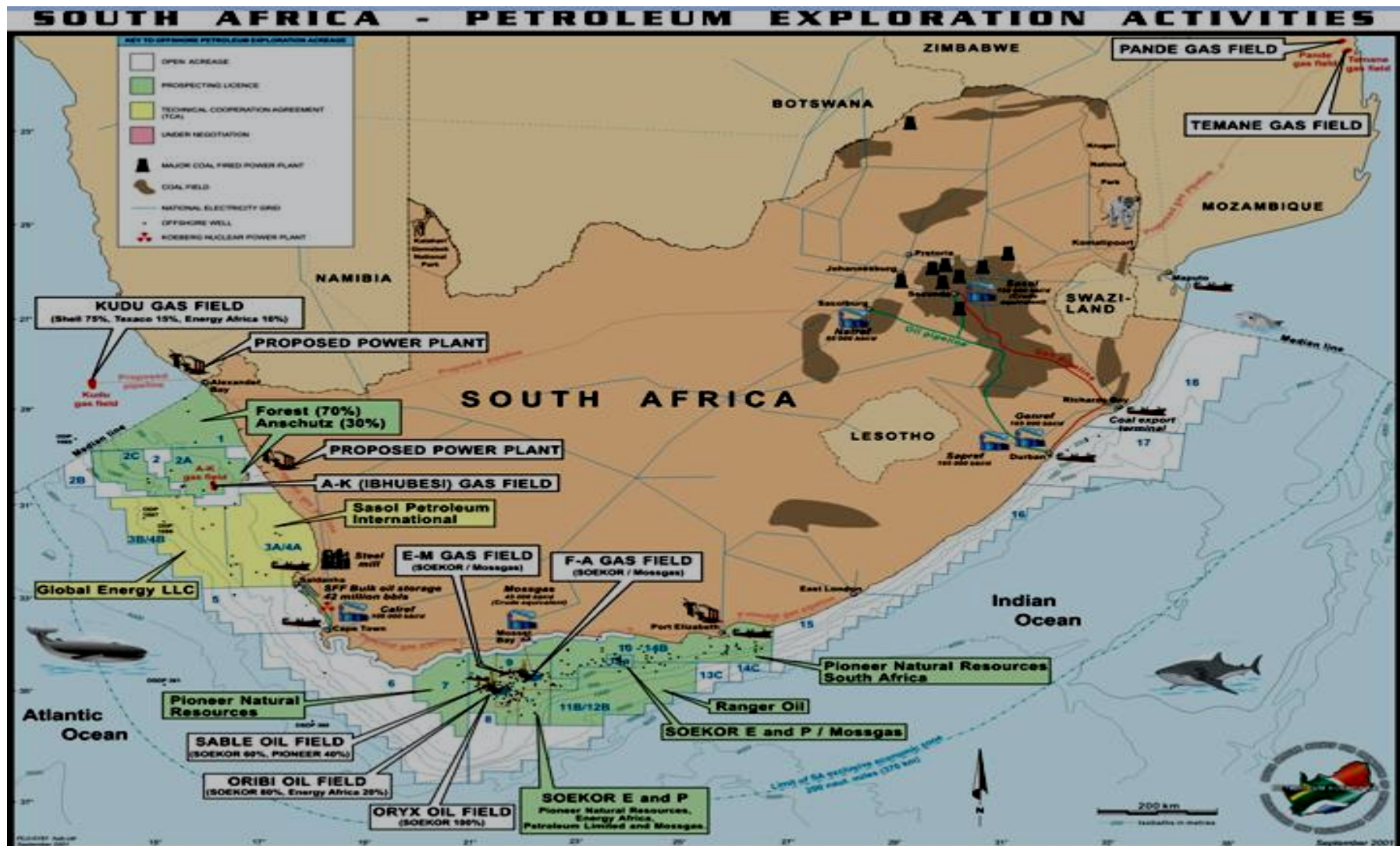


Figure 6 - Upstream E&P activity map

8.5 Mozambique Natural Gas Reserves

The onshore Pande field is located 600 – 650 kilometres north of Maputo and the Temane field is located approximately 40 kilometres south of Pande. Together these fields have proven gas reserves of more than 2 tcf. Production has started in 2004 in Temane and is scheduled to start in 2006 in Pande. Production commenced at 80 million Gigajoules (GJ) per annum and is expected to increase to 120 million GJ per annum.

8.6 Namibia Natural Gas Reserves

The **Kudu** gas field is located 130 kilometres offshore Namibia and 170 kilometres from Oranjemund. It has a license size of 4070 km² and it is situated in water depth of 170 metres. Proven gas reserves amount to 1.3 tcf.

8.7 Angola Natural Gas Reserves

Angola has major resources, both associated and dry gas, but limited market only for small-scale use power generation in Cabinda and most of it is flared on the daily basis. Gas utilisation studies have been conducted for South Congo Basin on exploring Liquefied Natural Gas (LNG) GTL and large-scale power generation.

Cabinda gas field is located 20 to 50 kilometres offshore and situated in depths of <200 metres. Cabinda field is considered a rich offshore province with extensive amount of associated and free natural gas. Gas exploration is still underdeveloped. Natural gas is also required for reservoir pressure maintenance (reinjection).

Block 17 is situated at depths of between 200 and 1500 metres. It is a major oil block with estimated production of more than 200 000 barrels per day. Major reserves of associated and non-associated gas exist in the block.

8.8 Tanzania Natural Gas Reserves

The **Songo Songo** gas field is located about 25 kilometres off the Tanzania coast and about 200 kilometres south of Dar es Salaam. The field is partly located on Songo Songo Island and offshore of the island. It has proven gas reserves of 1.0 tcf based on recent independent reserve audit. Songo Songo field is being developed as part of the Songas gas to power project.

Mnazi Bay is located offshore close to the coast and close to the Mozambique/Tanzania border. The reserves are estimated at 0.5 tcf. It is envisaged that the field will be dedicated to a local gas-to-power project, targeting power demand in the southeastern part of Tanzania. Cinergy Global Power of the US is promoting the project development.

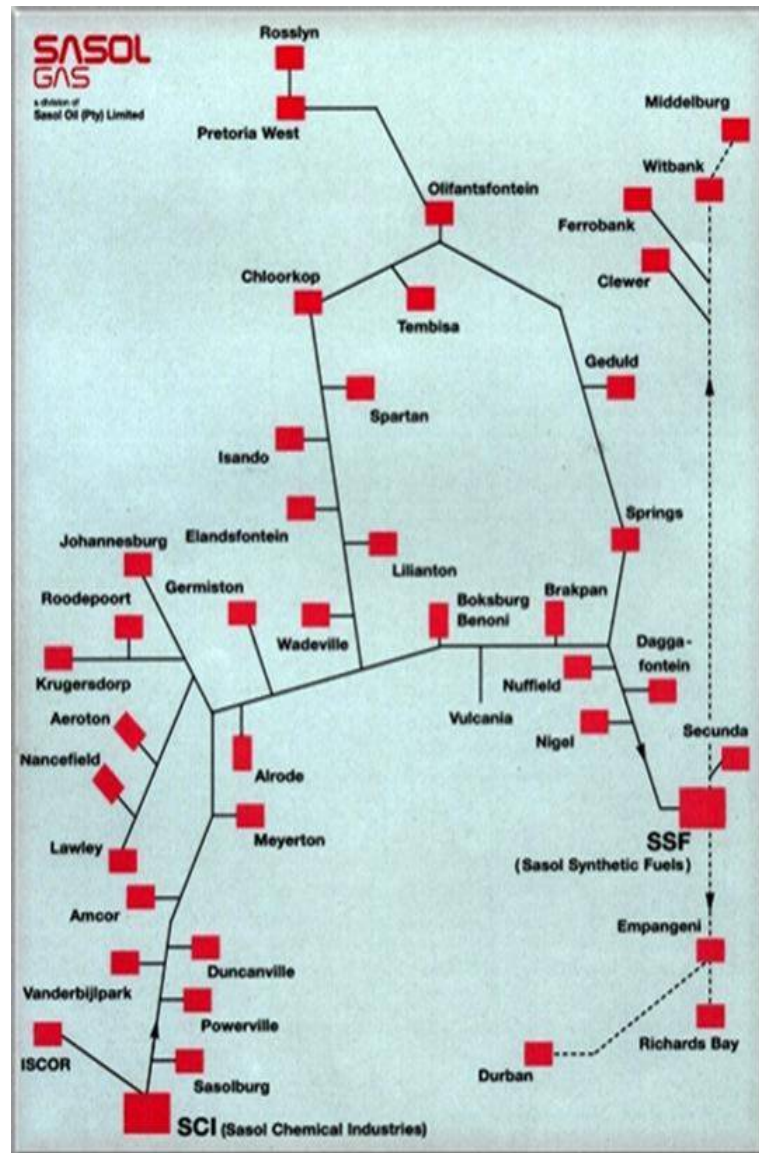
Realisation of these gas projects is closely linked to the power sector reform.

9 SOUTH AFRICAN GAS INFRASTRUCTURE

9.1. Sasol Gas

Sasol Gas, a wholly owned subsidiary of Sasol, supplies piped gas to consumers in the Gauteng area. Sasol Gas owns about 1500 km of gas distribution and transmission pipeline, serving about 600 mainly industrial customers. Sasol supplies Egoli Gas, a reticulator supplying piped gas in the Greater Johannesburg metropolitan area, which serves a mix of industrial, commercial, and domestic customers.

Figure 7 - Sasol Gas Distribution Network In 2001 27.3 million GJ (66 percent) of the gas supplies came from the Sasol 1 plant at Sasolburg (hydrogen rich gas) and 14.3 million GJ (34



percent) come from Sasol 2 and 3 plants at Secunda (methane rich gas). The hydrogen rich gas has a calorific value of 18.9 MJ/cm and the methane rich gas 33.9 MJ/cm compared with 37 to 40 MJ/cm of natural gas. Hydrogen rich gas is supplied to Gauteng and the methane rich gas to Witbank and Middleburg in Mpumalanga and via the Petronet Lilly pipeline to Kwazulu Natal (Newcastle, Richard's Bay and Durban).

9.2 Petronet

Petronet, a division Transnet Limited, a commercialised SA public enterprise, owns and operates over 3 000 km high-pressure pipelines. The pipeline system transports crude oil and petroleum products. It has diversified into natural gas transportation. The Petronet gas pipeline, known as the Lilly Line, is approximately 600 km long and transports methane rich gas from Sasol's Secunda plant as far as the Durban area. The Lilly line has a capacity of 23 MGJ p.a at 59 bar and it is currently running at 50% capacity. Its capacity could be increased to 40MGJ p.a.

Any market growth in excess of 40MGJ p.a would require the construction of a new transmission line

9.3 Egoli Gas

Egoli's origins are as a town gas producer distributing through its own pipes in the Johannesburg area. It no longer produces its own gas but buys about 2 MGJ p.a of Sasol hydrogen rich gas, of which it sells 87 percent to 3 000 industrial and commercial customers and the remainder to 12 000 domestic sector customers. The company has a 1 300 km distribution pipeline operating at <1-bar gauge pressure.

Egoli allows for swings in demand by means of storage and interruptible customers. Some 25 large customers are on interruptible contracts of one year at a modest discount to firm prices.

9.4 Port Elizabeth Gas

The only other gas distribution system in South Africa is a privately owned company in Port Elizabeth supplying an LPG/air mixture to a limited number of industrial customers.

9.5 PetroSA's GTL facility

The only natural gas production in South Africa is from the 20 bcm F-A field in the Bredasdorp basin in 105 metres of water depth some 93 km offshore of Mossel Bay. Gas is dried and refrigerated at the platform and transported to the PetroSA synfuel facility through an 18-inch pipeline. Condensate is transported through an 8-inch pipeline after separation offshore. A small LNG and storage tank have been constructed offshore to ensure reliability of supply. The whole output of this operation is dedicated to the government-owned PetroSA GTL plant.

9.6 iGas

iGas acts as the official agent of the state for the development of the hydrocarbon gas industry in South Africa. iGas is a 100% subsidiary of CEF (Pty) Ltd. The mandate of this company is to:

- Enter into joint ventures for gas transmission pipelines and related projects, using sound business principles;
- Advance the energy goals as set out in the SA government's White Paper on Energy (December 1998); and
- Focus on investments in SADC and African countries.

iGas projects will be undertaken on a commercial basis.

9.7 PetroSA

PetroSA has secured gas supplies to 2008 and also has a 26% equity in Ibhubezi gas field. PetroSA is investigating the introduction of natural gas into the Cape area, and currently believes that such a venture is dependent on the construction of a gas fired electricity generation station. The company is also looking at further offshore gas deposits in the Mossel Area as well as the import of LNG.

10 POTENTIAL FUTURE MARKETS FOR NATURAL GAS IN SOUTH AFRICA

10.1 Potential Major Gas Markets

Gas-to-liquids - liquid fuels or petrochemical production

- Sasol 1 petrochemical plant being converted 100% to natural gas feedstock
- The conversion from low grade coal will have positive environmental impacts
- PetroSA GTL facility requires alternative gas supplies as current supply is being exhausted
- PetroSA is the first GTL plant to operate at a profit
- 'Clean' liquid fuels could increase demand from the facility
- Domestic production of liquid fuels nets to a saving on oil imports

Direct reduced iron

- Iscor and IDC interested in the project
- Viable option for Saldanha Bay, Western Cape.
- Abundance of raw material (iron ore)
- Existence of steel markets
- Capital and operating costs benefits
- Clean products at affordable gas prices.

Mineral Beneficiation

- Alumina production for Alusaf smelter - Phalaborwa
- Lower investment, operating costs
- Clean products

Power Generation

- Potentially attractive, particularly in the Cape and KwaZulu Natal.
- More flexible than coal-fired generation – peaking purposes and network balancing.
- Requires shorter lead-time for planning and construction of a Gas Turbine Combined Cycle, (GTCC) plant.
- Flexible expansion path
- Reduce transmission losses

- Improve quality/reliability
- Environmental benefits

Note: The White Paper requires that the National Energy Regulator, (NER), approve "tariffs for the purchase of co-generated and independently generated electricity on the basis of full avoided costs". This has not yet been done so potential power station investors cannot determine the price of the product. "Full avoided costs" is an American concept where it is defined as *"a utility company's production or transmission cost avoided by conservation or purchasing from another source rather than building a new generation facility"* ("Natural Gas Electric Power" by Ann Chambers). The key points of the concept are:

- The avoided costs refer to new or incremental costs (i.e. additional costs) not present costs;
- By definition, full-avoided cost is the least cost option for providing future supplies of electricity.

Ammonia

- Used in the manufacture of mining explosives
- Utilisation of Richards Bay export terminal

10.2 Western Cape Gas Market Potential

Power Generation

The power generation sector is considered a potential anchor market for natural gas in the Western Cape. An analysis of the power demand for electricity in South Africa, and in particular the Western Cape, indicated a requirement for approximately 1 000 MW to 1 500 MW additional power generating capacity by 2005/6. It has been assumed that the 1 000 MW plant will commence operations in 2008 as a base-load generator with a load factor of starting at 60 per cent and gradually increasing to 80 per cent by 2010. An additional 500 MW plant will commence operations in 2011 with a 60 per cent load factor increasing to 80 per cent by 2015. The high case scenario represents an assessment of the market requirements by CAMALA.

Industrial Sector

Cape Town Region

Coal and fuel oil users dominate the industrial markets in the Western Cape. Of the identified markets, natural gas could immediately replace approximately 35 per cent of both the coal and fuel oil markets. On this basis, the use of natural gas in the Western Cape's industrial sector for relatively small types of industry (e.g. textiles/clothing, food, cement manufacturing, etc.) could increase from an initial 7 million GJ per annum in year 2008 to approximately 15 million GJ per annum by 2027 (base case scenario). For a high case scenario, it has been assumed that the market requirement could grow to 25 million GJ by 2027.

It should however be recognised that the construction of a gas transmission line to Cape Town will serve as catalyst to the establishment of new large industries in the region.

Saldanha Bay Region

The Saldanha Steel expansion project should also be considered for inclusion in the gas demand profile. Phase two of this project could be based on the HYD III gas based steel reduction process. Some gas could also be made be available to Phase I (Midrex) for reductive purposes to enhance its current performance. The Duferco steel galvanising project is a current downstream project associated with Saldanha Strategic Development Initiative (SDI) with a constant energy requirement. Saldanha Steel provided information on energy required for their metallurgical reduction process using natural gas and power consumption. A direct gas requirement for a base case and high case scenario is as indicated in attached table.

MINTEK

MINTEK has indicated a requirement for natural gas for a hot briquette iron (HBI) plant, a nickel and magnetite beneficiation plant, and a pelletising facility in Saldanha Bay. This has been identified as an anchor market for Forest Oil. For a high case scenario, it has been assumed that 80 MMScfd will be required for processing purposes from 2013 onwards. Consumption for the base case scenario has been assumed at 40 MMScfd from 2013 onwards.

Mineral Beneficiation

Saldanha Bay Region

The Anglo American Corporation (AAC) Namaqua Sands heavy minerals beneficiation project has previously indicated a power co-generation requirement of approximately 70 MW (high case scenario). For the base case scenario, it has been assumed that electricity will be purchased from Cape Town.

Non-Energy Sector

Mossel Bay

At present the only non-energy use of natural gas involves gas-to-liquids conversion process at PetroSA facility in Mossel Bay and at Sasol.

The PetroSA high case can be described as the expansion of the gas loop with an additional reformer, in order to provide sufficient syngas to meet the capacity requirements of the proposed Sasol Advanced Synthol (SAS) reactors. The capacity of each SAS reactor is more than that of each of the current PetroSA Synthol reactors, and the proposal is to replace the three Synthol reactors with SAS reactors. The SAS reactors will improve efficiency of the conversion of gas to syncrude and reduce the conversion and operating costs. The refinery capacity will not necessarily change. This will increase GTL facility's requirement for natural gas to 270 MMScfd. At these consumption rates, the GTL facility will require additional gas reserves from 2008, thus making it a potential anchor customer for any of the Western Cape gas projects. The critical issue will be the landed cost of gas to the facility, as it is sensitive to the dollar price of oil when calculating the threshold gas price it can absorb in relation to the competition in the liquid fuels market.

Residential Sector

At present, the residential sector for energy consumption in the Western Cape does not provide sufficient residential consumer density to justify the required capital cost requirement for an extensive gas distribution infrastructure. This is however seen as a large future growth potential for the industry. Spatial heating is not seen as a growth opportunity, whilst heat exchange cooling may be.

10.3 Eastern Cape Gas Market Potential

Power Generation

Port Elizabeth

Since the closure of the Swartkops Power Station outside Port Elizabeth, the region has become totally dependent on the importation of its electricity requirements. The potential therefore exists for gas-fired power generation, which could service Port Elizabeth's current electricity requirements of approximately 500 MW. It has been assumed that an initial 400 MW plant will commence operations in 2008 as a base load generator with a load factor starting at 60 per cent and gradually increasing to 80 per cent by 2014. For a high base scenario, a third train of 250 MW will be added in 2015 with a 60 per cent load factor increasing to 80 per cent by 2017. This would equate to approximately 10 - 20 MGJ p.a.

Industrial Sector

The Port Elizabeth/Uitenhage Metropolitan is one of the major manufacturing sectors in the RSA and is a key industrial sector contributing to the Gross Geographic Product (GGP) of the Eastern Cape. The area is the location of two major motor manufacturers with substantial automotive component industries in support. The Coega industrial development zone is an industrial development initiative with projects such as a deep-water harbour, a stainless steel plant, a mini-mill, and galvanised steel mill muted as potential industries to establish itself in the region. The remaining industries are relatively small and consist of the manufacturing of fibre optic cables, batteries, food, medicines, leather products, cement manufacturing, and brick works. An important conclusion is that the industrial sector of Port Elizabeth/Uitenhage is focussed in a relatively small number of densely populated industrial areas that would obviate the need for a large distribution system.

In estimating potential natural gas demand, it has been assumed that the steel mill together with the combined cycle gas turbine (CCGT) facility would provide the anchor demand to justify the capital and operational cost requirements of a gas transmission system. It has been assumed that an initial energy requirement of 10 million GJ per annum will be needed in year 2008 which will increase to approximately 20 million GJ per annum by 2027 (base case scenario). For a high case scenario it has been assumed that the market requirement could grow to 40 million GJ by 2027.

Residential Sector

As in the Western Cape, the residential sector for energy consumption in the Eastern Cape does not provide sufficient residential consumer density to justify the required capital cost requirements for an extensive gas distribution infrastructure.

10.4 Northern Cape Gas Market Potential

Mineral Beneficiation

Springbok – Namaqualand Corridor

The only gas region in the Northern Cape close to the proposed Western Cape Gas Pipeline with any sizeable industry is the area surrounding the town of Springbok. Goldfields own a series of copper mines in the region, which are very energy intensive. The Northern Cape government has also earmarked the Namaqua Corridor for development and is providing incentives to establish new enterprises. A Zinc mine outside Aggenys, using recent technological advances by MINTEK, is also being planned. An energy requirement of approximately 6 million GJ per annum for a co-generation facility has been assumed from 2008 onwards for the base case and 10 million for the high case scenario.

10.5 Eastern South Africa Market Potential

(Gauteng, Mpumalanga, Free State, And Kwazulu Natal)

The markets potential of the provinces of Gauteng, Kwazulu-Natal, parts of Mpumalanga and Free State are examined together and these provinces fall within the ambit of the SASOL Gas system, which shall be bringing natural gas from Mozambique.

Power Generation

Due to the proximity of this area to the Mpumalanga coal area, gas would not be able to compete with either existing or new coal-fired electricity generation facility unless environmental factors are considered. However, gas would be able to compete with electricity generated by coal in co-generation systems taking advantage of the high efficiency rate of co-generation technology.

Industrial Sector

Among the reasons for the development of Mozambican gas by Sasol is its own fuel requirement. With the Sigma Colliery at Sasolburg nearing the end of its economic life, there was a need to seek a new source of feedstock for the Sasol Chemical Industries (SCI) plant at Sasolburg. In addition, Sasol Synthetic Fuel (SSF) in Secunda shall also be using natural gas as a supplementary feedstock. The demand by SCI and SSF is expected to be at 38.8 million GJ and 15 million GJ per annum respectively. In addition to SSF and SCI, Sasol will also convert its oil refinery Natref in Sasolburg to natural gas. The demand by Natref is expected to be at 6 million GJ per annum.

The potential Kwazulu-Natal industrial market could grow to 20MGJ p.a over the next year as the minerals beneficiation and refining industries increase their gas usage. There are also co-generation opportunities in the Durban South petrochemical estates depending on the access of IPP's to the transmission network of Eskom in the context of the ESI restructuring.

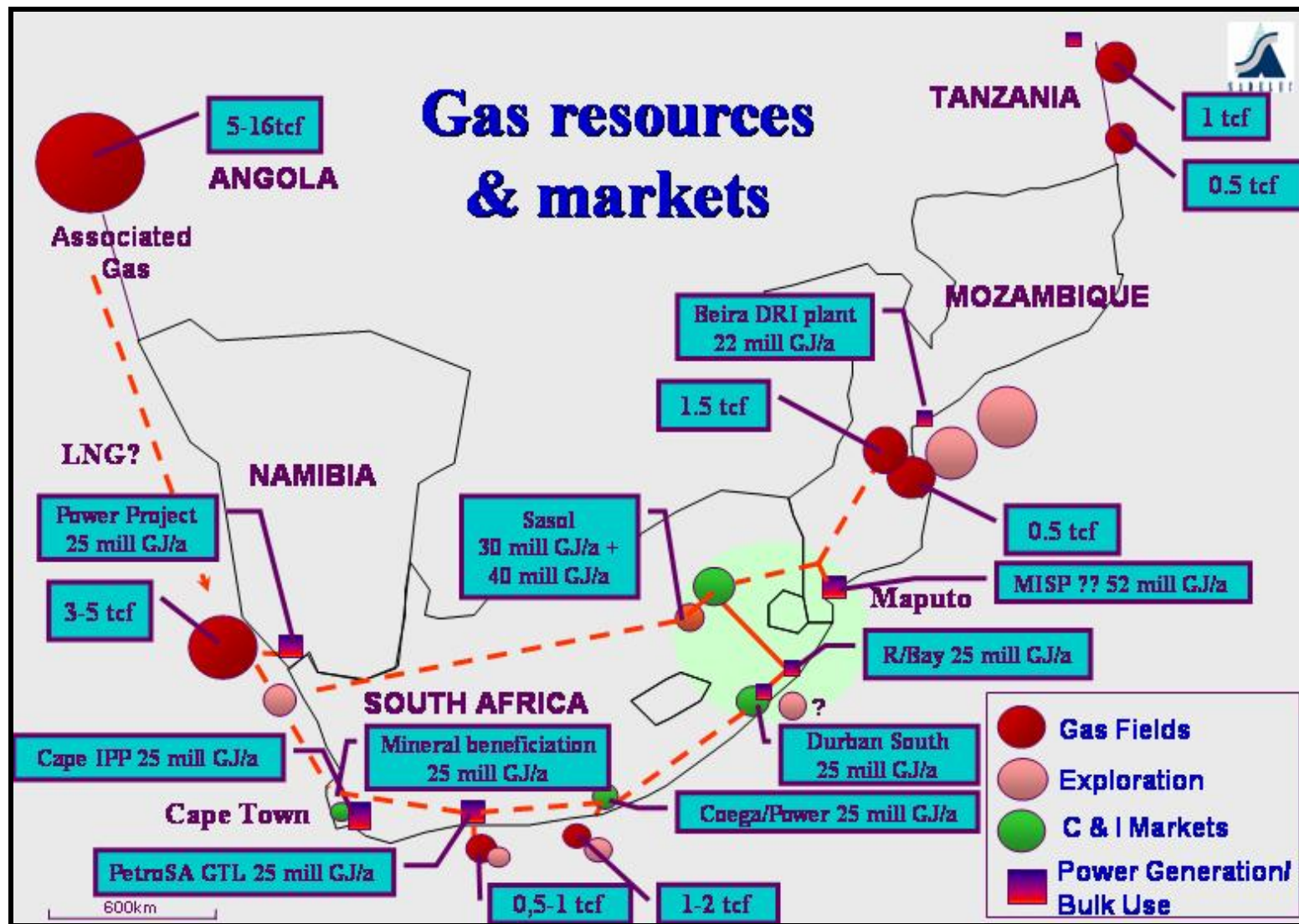


Figure 8 – Overview of the potential gas market and the associated resources

11 GAS INFRASTRUCTURE DEVELOPMENT PLANS

There are a number of pipelines to be built in terms of the anticipated market developments. Essentially the developments represent 4 main phases, although within each phase, there may be a number of sub-phases:

- Phase 1 = the Mozambique/South Africa Transmission Pipeline project.
- Phase 2 = the Western Cape Transmission Pipeline
- Phase 3 = the Northern Cape to Gauteng transmission Pipeline
- Phase 4 = the coastal transmission pipeline

These phases may or may not take place and may or may not be in the above order. Such decision will be made on a commercial basis and matching reserves with markets.

Once these phases are complete, there will be a fully integrated network linking the major economic centres with upstream supplies of gas enabling one to transport gas from any inlet flange in the system to any outlet flange where there is a market.

The current infrastructure is indicated in black on the map – Figure 9. All the coloured pipelines are either under construction or proposed as per the detailed infrastructure plan outline after the map. The assumption has been made that the proposed Lilly 2 (proposed, pink, 1 to 8) pipeline would follow the same course as the Lilly 1 (black, existing 1 to 8) pipeline. This assumption is open to debate depending on what the state strategy is in response to the discussion in 'Additional Infrastructure scenarios'.

The planned future gas infrastructure map is as follows where reference in square brackets in the following detailed outline refer the map below:

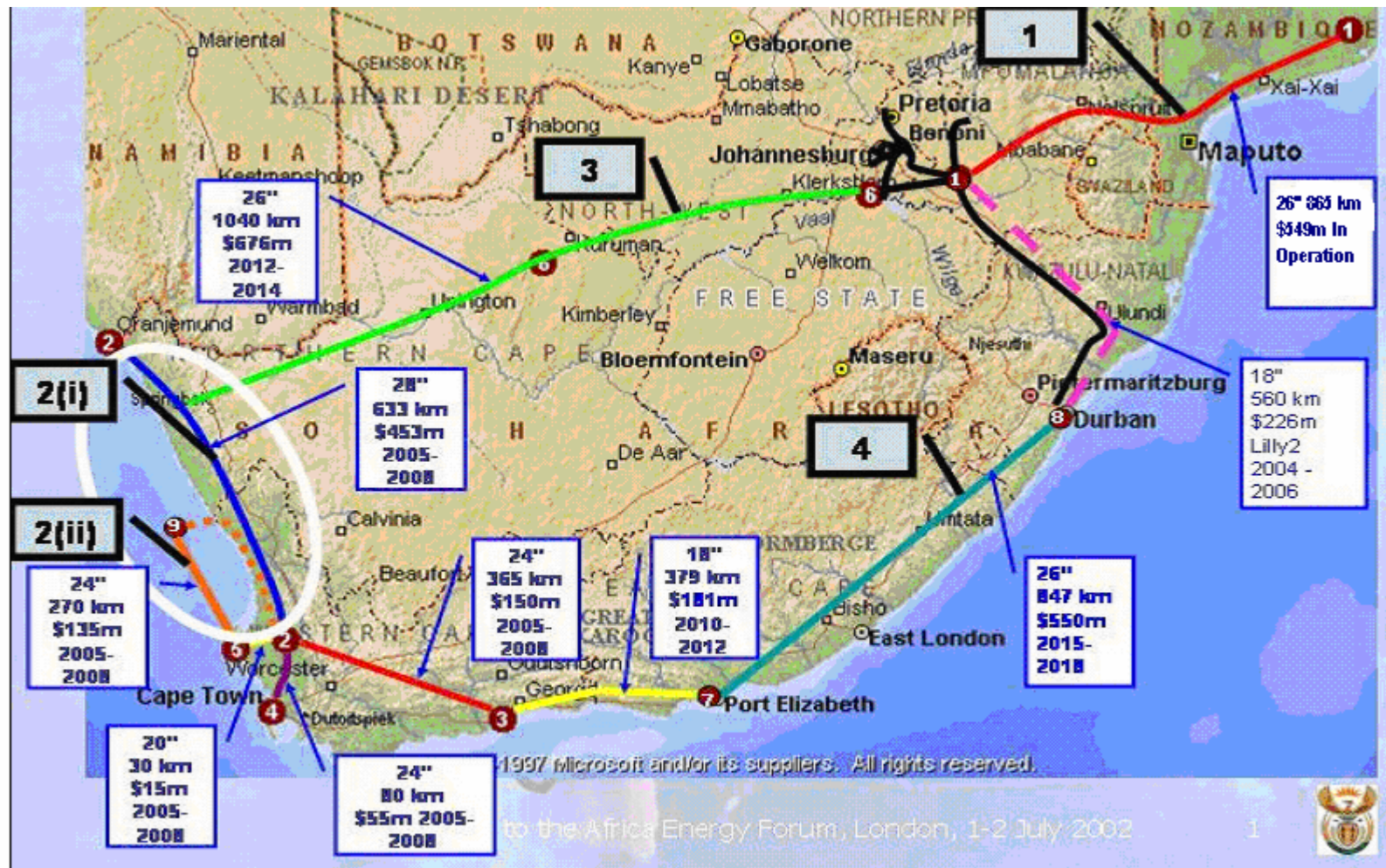


Figure 9: Infrastructure development map

11.1 Phase 1 (the east coast)

The Mozambique to South Africa Gas Project

This involves the following development infrastructure:

Mozambique to South Africa Gas Pipeline = [1 to 1 in Fig 9]	
Project Sponsor	Sasol
Reserves	2tcf
Anchor customers	Sasol plants – specifically SCI in Sasolburg
Market Demand	Assumed demand of eastern South African market is constant at 120mGJ/a
Pipeline Costs	\$549 million
Distance	865 km
Construction	2002 to 2004 – now complete and operational

Petronet

At present, the existing Lilly 1 liquid fuels pipeline from Secunda to Durban is used as a gas pipeline. Lilly 1 is limited to 23 mGJ/a. The present utilisation of Lily 1 is 12mGJ/a, and there is sufficient capacity to cope with the 'ramp up' from the Mozambique gas project. If the capacity is to be increased to 40mGJ/a, the cost would be approximately US\$40 million. To meet the anticipated demand with the introduction of Mozambique gas to 70mGJ/a, a new dedicated line will need to be built, probably in 2008-2009 at a cost of about US\$200million

Petronet has in early 2004, given Sasol 7 years notice of its intention to convert the existing Lilly gas pipeline back to a petroleum pipeline.

11.2 Phase 2 - (the west coast) = 2(i) and 2(ii) on map

The Western Cape Gas Project

The Western Cape imports majority of its energy requirements such as fossil fuels and electricity and as a result, it serves as an ideal region for the introduction of an alternative and cheaper energy carrier. Offshore Western Cape is considered as a gas

province and the introduction of natural gas into the region will facilitate the establishment of different industries, which is in line with the government's policy objectives of achieving energy security by diversifying the supply of energy carriers. Gas is environmentally less damaging than coal but the most viable resources are far from the markets and expensive to transport. This involves the following development infrastructure:

Option 1 [2(i)]- Kudu Gas (Namibia)-Saldanha Pipeline = [2 to 2 in Fig 9]	
Project Sponsor	Texaco and Energy Africa remain after Shell withdrew.
Reserves	1.3tcf
Anchor customers	proposed 400MW Oranjemund Power Station (OPP) and proposed 1600MW Cape PowerStation (CPP)
Market Demand	OPP is 25 mGJ/annum CPP is 100 mGJ/annum
Pipeline Costs	\$453 million
Distance	633 km
Construction	2005 to 2008

The development of the Kudu gas field and hence the introduction of gas into the Western Cape hinges on a power station in Oranjemund and a power station in Cape Town as anchor customers. Based on the above assumptions, the Kudu gas field can supply the two anchor customers for 13 years.

The alternative development is the Ibhubesi field and the corresponding market. Forest's plan involves installing an undersea transmission pipeline to Saldanha, and then supplying the smaller fuel replacement market in the short term (2005), and then anchor customers such as PetroSA or a gas-to-power project in the long term ((2009). This can be summarised as follows:

Option 2 [2(ii)] – Ibhubesi Gas - Saldanha Pipeline = [8 to 5 in Fig 9]	
Project Sponsor	Forest Exploration International
Reserves 2tcf	0.216tcf
Anchor customers	Forest is looking at all the market opportunities, and regards PetroSA's GTL facility as a possible anchor in the future, but wants to sell into the switchables market in the first instance so as to monetise their current upstream investment in order to prove up replacement reserves.
Market Demand	Switchables = 5 – 15 MGJ p.a GTL = 73 mGJ p.a
Pipeline Costs	\$200 million
Distance	273 km
Construction	2004 to 2006

Once the main transmission line is installed to Saldanha, a number of other pipelines will need to be built to supply the markets in and around Cape Town. Although these pipelines have been ring fenced for strategic planning purposes, they would be segments of the network rather than phases in construction.

In early 2004, there was insufficient proven gas reserves in Kudu and Ibhubesi for a bankable project. Other options such as the importation of liquefied natural gas (Saldanha/Coega) are being investigated.

Map references refer to Figure 9 above	Saldanha to Cape Town = [2-4 on Figure 9]	Cape Town to Mossel Bay Pipeline = [2-3 on Figure 9]	Mossel Bay to Port Elizabeth Pipeline = [3-7 on Figure 9]
Pipeline Costs	\$55 million	\$150 million	\$181 million
Distance	80 km	365 km	375 km
Construction	2005 to 2008	2005 to 2008	2010 to 2012
Target market	switchable (fuel replacement) customers IPP's LPG market	PetroSA GTL facility = anchor and baseload IPP - cogeneration	Coega industrial development zone (IDZ) IPP – baseload or cogeneration

Assuming no further gas is found in the Bredasdorp Basin offshore Mossel Bay then a pipeline can be planned to feed Port Elizabeth and Coega

11.3 Phase 3 (Proposed furthest horizon for development)

Pipeline from West Coast to Gauteng via Sishen

West Coast to Gauteng Pipeline = [6 to 6 in Figure 9]	
Pipeline Costs	\$676 million
Distance	1040 km
Construction	2012 to 2014
Target markets	Sishen mineral beneficiation projects Gauteng fuel replacement market

Considering the upside claimed to have for the Kudu gas field, a pipeline supplying gas to Gauteng in the future may have the potential to cause gas on gas competition once the Sasol dispensation expires. Poor results from Shells recent appraisal campaign (2 dry wells) may change this picture. The alignment of this supply chain will be difficult as the mineral beneficiation projects in Sishen will be extremely gas price sensitive as there

is no lucrative fuel replacement market en route except at the end of the pipeline in Gauteng.

11.4 Phase 4 (no plans put forward – theoretical end state)

Pipeline from Port Elizabeth to Durban via East London

East Coast to Durban Pipeline = 7 to 8 in Fig 9	
Pipeline Costs	\$550 million
Distance	847 km
Construction	2015 – 2018
Target markets	potential replacement fuel market potential petrochemical hub

11.5 West Cape Infrastructure Scenarios

Scenario 1 (best option – depending on availability of gas) – All available gas (Kudu, Ibhubesi, FA and EM etc) transmitted via integrated pipeline system to western (Saldanha and Cape Town), southern (Mossel Bay) and eastern (Coega and Port Elizabeth) Cape provinces. GTL, CCGT and mineral beneficiation projects developed.

Scenario 2 – Kudu gas transmitted to Namibia and SA for gas-to-power projects. Forest Oil supplies additional gas to the anchor customers. Both target switchables as well.Scenario 3 – Importation of liquid natural gas – currently under investigation.

11.6 The Lilly Pipeline

Petronet's petroleum pipelines were under-utilised in the nineties and were re-configured to form the Lilly gas pipeline. However, there will come a time when the capacity in the remaining petroleum pipelines will be exhausted and to ensure security of supply to the industrial heartland, the Lilly pipeline may have to be reconfigured for liquid fuels. According to Petronet's current capacity planning, this should be around 2006 to 2008.

Thus it can be seen in Figure 10, that although a new Lilly line is not considered as a significant phase of development, it is actually a deferred sub-phase of Phase 1 and therefore needs to be developed earlier rather than later.

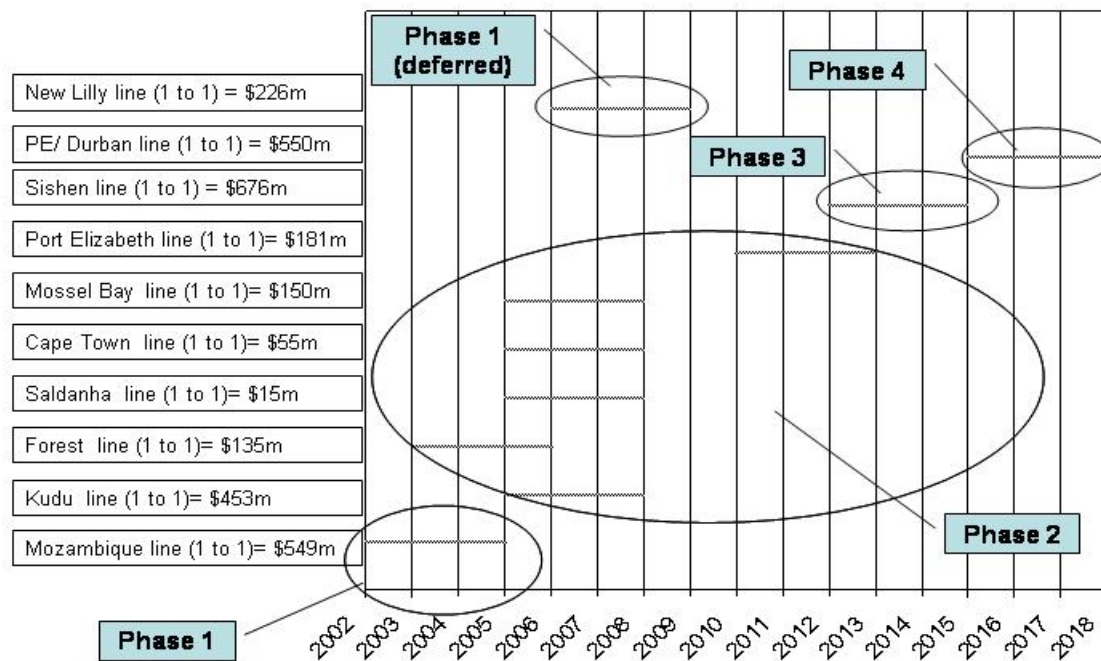


Figure 10 - Pipeline infrastructure investment timing

Petronet has early in 2004 given Sasol 7 years notice of its intention to convert the existing Lilly gas pipeline back to a petroleum pipeline. A new gas pipeline would then have to be built from Gauteng to Durban. This will result in higher gas transport tariffs, as the current tariffs are based on the conversion capex and not the full capex of the Lilly line.

11.7 Liquefied Natural Gas (LNG)

In addition to pipeline gas, LNG should not be ignored as an alternative form of natural gas transmission to South African gas markets.

A LNG delivery chain comprise of the following elements:

- transport of the gas from the wellhead to the liquefaction plant

- purification and liquefaction by cooling the gas to -160°C .
- storage at production site.
- Ocean transport of the LNG.
- unloading and storage at the reception terminal
- reception, storage and regasification. The International Energy Agency (IEA), states "the regasification plant warms the LNG by heat exchange, usually with vast quantities of sea water. In some cases the "cold" can be sold to nearby industries such as air separation or chemical plants".

LNG as potential source of gas for Cape market should be considered in addition to Kudu gas via pipeline transmission. One of the main advantages of LNG is that it does not restrict South Africa to any one source of LNG as the distance has minimal impact on the final gas price. LNG can also ensure more reliable supply than pipeline transmission from Kudu as any disruption in supply by the supplier can be met by temporary LNG supply from the world's spot LNG market.

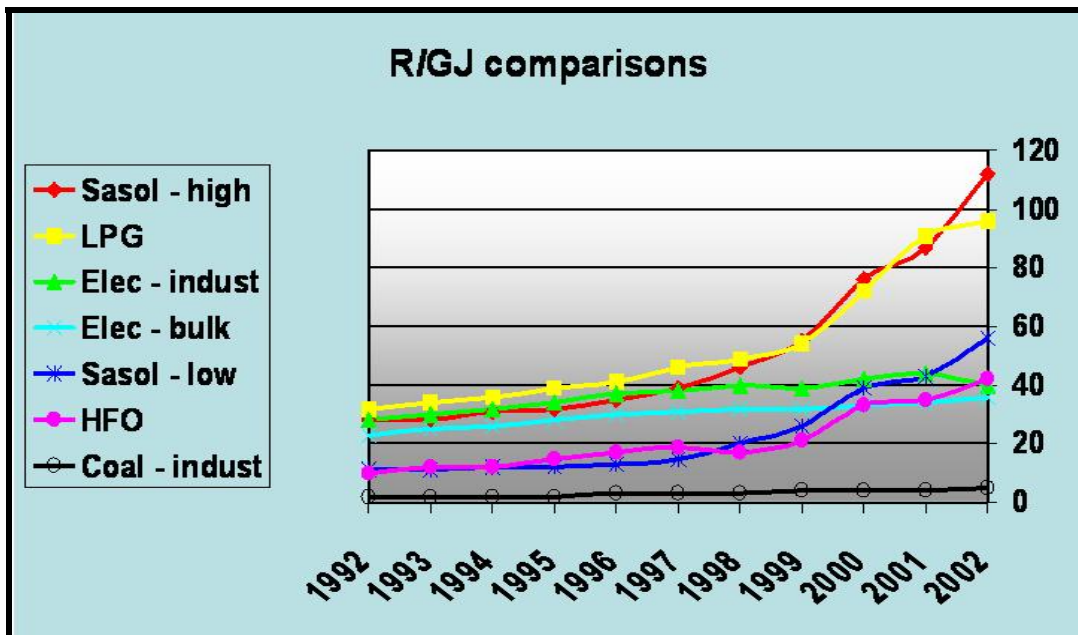


Figure 11 - R/GJ energy carrier comparison for South Africa during 1992-2002

The average cost of LNG delivered to Cape Town is expected to be in the region of US\$3.16/GJ. This cost includes gas production costs, LNG liquefaction and storage costs as well as transportation costs to Cape Town. The additional cost to this would be regasification cost. LNG is more expensive in the short term, resulting in a higher gas price to the market making the price of LNG in the Western Cape as high as US\$5/GJ – double what the present bulk market could withstand.

Figure 11, indicates that competition for LNG will centre around two alternatives, namely HFO and LPG. This graph uses Sasol syngas as the comparison, as this is the only gas sold commercially in South Africa at present. By comparison with other energy carriers, natural gas will be competitive anywhere between US\$2 to US\$10/GJ depending on:

- what is the intended use for the gas,
- what is its logical alternative, and
- what is the volume of the demand.

Intended use	Projected volume	proportion of total potential demand	Logical alternative fuel	Price threshold (US\$/GJ)
Power generation/GTL - baseload demand	> 60 MGJ p.a	40%	Coal (indirect)	1 – 2
power generation – load balancing	20 – 30MGJ p.a	13 – 20%	Diesel	1.5 – 2.5
Industrial	½ - 10MGJ p.a	5 - 15%	HFO Coal	4 – 6 3 - 5
Commercial	< ½ MGJ p.a	1 – 5%	coal (anthracite) LPG	6 - 8 8 - 10

Table 3 - Relative demand profile for Western Cape based on a minimum demand of 150MGJ p.a

Table 3 assumes the current LPG prices. The introduction of natural gas should drive LPG prices down by 20 – 30%.

The capital costs of a regasification facility is shown in Table 4 and was developed based on the following assumptions:

- modifications to the Cape Town harbour facilities to accommodate 60000 tonnes LNG tankers.
- LNG receiving terminal with 130000 m³ transfer capabilities. This will include loading arms, LNG transfer lines and return gas lines.
- two 65 000 m³ LNG storage tanks.
- secondary 75 bar LNG compression system.
- 70 MMscfd regasification plant.
- 75 bar, 18" pipeline connecting the LNG plant to the main transmission line at City Gate 2.

Plant Capital Costs	US\$m
Modifications to Cape Town harbour	5.8
LNG receiving terminal	72.6
LNG storage tanks	112
Regasification plant	52
Gas pipeline	2.5
Total	244.9

Table 4 - Investment for Regasification terminal

Total annual terminal and pipeline operational expenditure will amount to US\$9.06 million.

12 SOCIAL DEVELOPMENT PLANS TO BENEFIT COMMUNITIES

Government policy is that pipeline companies must produce implementable social economic development plans to leverage micro-economic benefits for communities in proximity to transmission pipelines.

The anticipated routes of the majority of the transmission infrastructure will traverse outlying rural areas that are sparsely populated. The towns that are along the routes, especially in the Northern and Eastern Cape Provinces are small underdeveloped and staggering under the burden of the highest unemployment levels in South Africa.

In the light of outlying infrastructure being vulnerable to vandalism and theft, the policy of implementing social benefits programmes based on such infrastructure was introduced. The purpose is to give the communities along the routes a vested interest in preserving the infrastructure, whilst promoting sustainable economic development in the long term.

The 'east coast' will for the short to medium term be dominated by the Mozambican gas project with a transmission pipeline being built to South Africa's industrial heartland. The South African Government and Sasol have signed agreements relating to the pipeline and an associated regulatory dispensation. These agreements contain 'gas pricing' (Clauses 9 and 13) an 'obligation to supply' requirement (clauses 6 and 13). These provisions include requirements that Sasol will:

- Supply gas to reticulators at a maximum wholesale gas price depending on the volume involved, and
- Negotiate special prices for government backed projects.

The viability of projects that may need off-takes from the transmission line is being investigated by CEF and the Public Private Infrastructure Advisory Facility (PPIAF). CEF (iGas) and PPIAF have commissioned a Danish group, COWI, to identify and assess development projects in the vicinity of the pipeline route through South Africa.

The projects were assessed in the context of their benefit to low income areas by either supplying affordable alternative energy carriers or providing employment during the construction in the short term and operation and maintenance associated with the projects in the long term.

The findings thus far are not substantive, and constitute a pre-scoping study, and at a stakeholder meeting in April 2002, the following findings were discussed:

- A project to supply gas to individual householders through a distribution network in Witbank may be viable.
- A project to supply gas to individual householders through a distribution network in Middelburg may be viable.
- Gas-to-Power generation in Nelspruit and gas reticulation in the greater Nelspruit were assessed, but were considered unviable due to the saturation of the electricity.
- Fuel for power generation has been met with limited response as South African wholesale electricity consumers have not yet begin to think in terms of own generation and on-selling of excess into the grid (ie. mini-IPP's).
- The potential for using CDM (CO₂) credits to leverage marginal projects is currently being assessed.

From a broader energy perspective, the inclusion of smaller IPP's feeding excess capacity into the national grid would have a positive load balancing effect on the ESI, and this was looked at as an option. The disappointing finding of the study was that co-generation opportunities, which represent up to 90% efficiencies in terms of gas-to-power generation, were not attractive as the potential co-generators were wary of the current state of the ESI restructuring and how they could be incorporated as suppliers in a liberalised transmission grid and power exchange.

Similar opportunities are being assessed by the gas project promoters in the Western Cape, where a community development plan will be a precondition to the government backing for the preferred development option.

Mechanisms to leverage local economic development plans could take two forms. The first option involves management of the regulatory environment and would, simply put, make a local economic development plan a condition for issuing of a gas distribution or transmission licence.

The second option would involve government conceding strategic regulatory dispensations in conjunction with government's commercial entities strategically negotiating commercial concessions. These negotiations could then be used to leverage provision for development projects at a later date. In the Cape, for example, government's commercial entities will have a critical impact from an aggregated demand perspective and this could be used to leverage development projects in that region.

The two options are not mutually exclusive as any company that has to develop a local economic benefit plan will likely look to government for an equity share as part of its risk mitigation and for government to 'put its money where its mouth is' in terms of socio-economic development.

Whilst government would like to maximise the local economic impact of the introduction of gas and the associated infrastructure, the complex trade-offs and policy objectives, referred to earlier, may undermine the project economics. The negotiation around the relationship between the state and the private sector on these investments will necessitate a 'give-and-take' attitude by all stakeholders to get the optimal outcomes. A sophisticated and proactive strategy by Government will help to show when stand by principle and when to compromise in the interest of the project as a whole.

13 Enabling market development with regulatory dispensations

In most instances, gas suppliers and transporters will look to the Regulator and/or Government for some form of dispensation to secure a return on their initial investment. This may take the form of exclusive access to a potential market, improving the bottom line with commercial incentives such as tax concessions. Whatever the outcome of these dispensations, they do at some stage have to be removed to allow market dynamics to play a role in determining prices and tariffs.

Modern regulation tends towards light-handed economic incentives to improve efficiencies within the company.

These can take the form of price caps as seen in the UK, or based on historical average or using a competitive yardstick method. The goal in all cases is to get the gas market to operate towards a profit incentive, but to make profiteering unprofitable. With the Sasol dispensation, the price cap system was settled on as this gives Sasol the comfort that it can maximise the efficiencies from its investments and cash flow in the short term and the consumer will be protected in the long term. The price cap will be weighted according to European gas prices and over recovery will result in repayments to consumers.

In the UK, the price cap is driven by the inflation and efficiency gains from the operator. The incentive is to be more efficient, and reduce the overheads. The danger is that there is always a temptation to take the inside curve and reduce overheads in the easiest, but most costly area of operation, namely maintenance.

The yardstick price cap is essentially where the dominant/monopoly player has their costs compared to those of other players. Thus when the market price is pegged to the market costs, then the pressures on the monopoly player to reduce its costs in line with the market costs, thus reducing the market price of gas. This is similar to the In-Bond Landed Costs (IBLC) method previously used to determine the market related 'price of crude oil landed in South Africa' if the price cap is exceeded then penalties are incurred for the over recovery, usually in the form of repayments to consumers or a reduced market price. For this mechanism, the regulator needs to have a sophisticated

understanding of the supply side costs to be sure that the price cap is indeed beneficial for all parties.

Regulated cost related pricing is often used until effective gas on gas competition has developed.

Ideally, gas-on-gas competition should determine the market price for gas. The Gas regulator needs to develop strategies to promote competition once dispensation(s) lapse and other players are offered the opportunity to enter the market.

In most other countries, the critical aspect of liberalisation has been to ensure third party access to at least uncommitted capacity. The Gas Act has this provision along with measures to curb cross subsidisation and discriminatory pricing practices and it will be the regulators responsibility to ensure that the regulations are applied appropriately

14 REVIEW OF THE GAS INFRASTRUCTURE PLAN

The critical aspect of the gas infrastructure plan is the timing of various investments and the trade offs made to align the gas value chain. It is therefore recommended that the Masterplan be reviewed in 2008, when the investment pace will likely be peaking as Phase 2 comes on stream and the reviewer will be able to assess the correctness of the development plans envisaged at this time. The Regulator will be able to avert unnecessary expenditure with the expensive CAPEX in the next two phases or redirect investments to more cost effective developments such as LNG etc.