# TABLE OF CONTENTS
**AFRICA TRANSPORT INFRASTRUCTURE PLANNING**

1. **INTRODUCTION**
   - 1.1 The Natural Gas Context
   - 1.2 What is Natural Gas?
   - 1.3 Natural Gas Potential Applications
     - 1.3.1 Transportation Fuel
     - 1.3.2 LNG as Marine Bunker Fuel
     - 1.3.3 Small-scale LNG Supply
   - 1.4 Natural Gas Supply Chain
   - 1.5 Global Piped Gas and LNG Trade
   - 1.6 Natural Gas Pricing Trends
   - 1.7 LNG Industry Overview
   - 1.8 Classification of Gas Reserves
   - 1.9 International Gas Resources
   - 1.10 Unconventional Gas - Shale Gas
   - 1.11 Environmental Considerations for Natural Gas

2. **Drivers for South African Natural Gas Developments**
   - 2.1 Gas Resources in Southern Africa
   - 2.2 South African Natural Gas Market and Industry Structure
   - 2.3 Commercial Considerations and Capital Investment
   - 2.4 Natural Gas Policy and Regulation
   - 2.5 Regulatory Considerations for Gas to Power Developments
   - 2.6 Current Government Initiatives
     - 2.6.1 Operation Phakisa
     - 2.6.2 DOE War Room
     - 2.6.3 Western Cape Government Plans to Develop an LNG Import Terminal in Saldanha Bay
     - 2.6.4 Gas Energy for Electricity Generation
     - 2.6.5 Gas for Industrial and Commercial Energy Applications
   - 2.7 Transnet’s Role in Gas Development

3. **Gas Infrastructure**
   - 3.1 Navigational and Safety Requirements for Importing LNG
     - 3.1.1 LNG Transportation
     - 3.1.2 LNG Carrier Vessels
     - 3.1.3 Membrane Type LNG Carriers
     - 3.1.3.1 LNG Safety Requirements
   - 3.2 LNG Infrastructure Options in Ports
     - 3.2.1 Conventional Land Based LNG Terminal
     - 3.2.2 Floating Storage and Regasification Unit (FSRU)
   - 3.3 Electricity Generation using Natural Gas
     - 3.3.1 Land Based Gas Power Station
     - 3.3.2 Power Barges
     - 3.3.3 Cost of Gas-generated Power

4. **Potential Gas Terminals and Pipeline Networks in South Africa**
   - 4.1 Development of Gas Infrastructure in the Western Cape
   - 4.2 Development of Gas Infrastructure in the Eastern Cape (Port of Ngqura)
   - 4.3 Development of Gas Infrastructure in KwaZulu-Natal (Port of Richards Bay)
   - 4.4 Potential Long Term Gas Infrastructure Development in South Africa

---

Please note this long-term framework planning is not a business or operational plan, and is unconstrained to capital planning and independent to other more detailed Transnet business and operating division (OD) plans. The LTPF is only a planning tool, to guide Transnet and all external and public stakeholders. The LTPF is published annually at [www.transnet.net](http://www.transnet.net).
# ACRONYMS AND ABBREVIATIONS

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>CBM</td>
<td>Coal Bed Methane</td>
</tr>
<tr>
<td>CCGT</td>
<td>Closed (or Combined) cycle gas turbine. CCGT electricity-generation turbines have higher efficiency than OCGT due to exhaust heat recovery and use.</td>
</tr>
<tr>
<td>CEF</td>
<td>Central Energy Fund</td>
</tr>
<tr>
<td>CNG</td>
<td>Compressed Natural Gas</td>
</tr>
<tr>
<td>DEA</td>
<td>Department of Environmental Affairs</td>
</tr>
<tr>
<td>DOE</td>
<td>Department of Energy</td>
</tr>
<tr>
<td>EIA</td>
<td>Energy Information Agency (or Environmental Impact Assessment)</td>
</tr>
<tr>
<td>FSRU</td>
<td>LNG Floating Storage and Regasification Unit</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse Gases</td>
</tr>
<tr>
<td>GIIGNL</td>
<td>French Acronym for International Group of LNG Importers</td>
</tr>
<tr>
<td>GTL</td>
<td>Gas to Liquids</td>
</tr>
<tr>
<td>GUMP</td>
<td>Gas Utilisation Master Plan. DOE initiative</td>
</tr>
<tr>
<td>HH</td>
<td>Henry Hub natural gas trading marker price for the United States of America</td>
</tr>
<tr>
<td>IDZ</td>
<td>Industrial Development Zone</td>
</tr>
<tr>
<td>IEP</td>
<td>Integrated Energy Plan</td>
</tr>
<tr>
<td>iGAS</td>
<td>Subsidiary of CEF responsible for gas infrastructure development</td>
</tr>
<tr>
<td>IPP</td>
<td>Independent Power Producer</td>
</tr>
<tr>
<td>IRP</td>
<td>Integrated Resource Plan</td>
</tr>
<tr>
<td>JKM</td>
<td>Japan Korea Marker - Natural Gas Trading Marker Price for Asia</td>
</tr>
<tr>
<td>LNG</td>
<td>Liquefied Natural Gas</td>
</tr>
<tr>
<td>MGj</td>
<td>Million Gigajoule</td>
</tr>
<tr>
<td>MJ</td>
<td>Megajoules</td>
</tr>
<tr>
<td>mmBtu</td>
<td>Million British Thermal Units – a unit of energy used internationally for pricing natural gas US$/mmBtu. Note 1mmBtu = 1,055GJ.</td>
</tr>
<tr>
<td>mtpa</td>
<td>Million tons per annum</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatt</td>
</tr>
<tr>
<td>NBP</td>
<td>Natural Balance Point – natural gas trading marker price for UK/Europe</td>
</tr>
<tr>
<td>NDP</td>
<td>National Development Plan</td>
</tr>
<tr>
<td>NERSA</td>
<td>National Energy Regulator of South Africa</td>
</tr>
<tr>
<td>NG</td>
<td>Natural Gas</td>
</tr>
<tr>
<td>OCGT</td>
<td>Open Cycle Gas Turbine</td>
</tr>
<tr>
<td>PIANC</td>
<td>Permanent International Association of Navigational Congresses. Also known as the “World Association for Waterborne Transportation Infrastructure”</td>
</tr>
<tr>
<td>PPA</td>
<td>Power Purchase Agreement</td>
</tr>
<tr>
<td>ROMCO</td>
<td>Republic of Mozambique Pipeline Investments Company</td>
</tr>
<tr>
<td>SBM</td>
<td>Single Buoy Mooring</td>
</tr>
<tr>
<td>SNG</td>
<td>Synthetic Natural Gas</td>
</tr>
<tr>
<td>tcf</td>
<td>Trillion cubic feet = 28,3bcm = 1,054MJ</td>
</tr>
<tr>
<td>tcm</td>
<td>Trillion cubic metres = 37,239MJ = 724,9 million ton LNG = 35,3tcf</td>
</tr>
<tr>
<td>TNPA</td>
<td>Transnet National Ports Authority</td>
</tr>
</tbody>
</table>
1. INTRODUCTION

1.1 THE NATURAL GAS CONTEXT

South Africa’s energy resources are dominated by coal, with more than 80% of electricity generated by Eskom from coal fired power stations. To align with the global objectives of lower greenhouse gas emissions, Government aims to diversify South Africa’s energy supply mix to improve security of energy supply and to reduce the overall carbon footprint of the country. Natural gas is an obvious significant alternative energy source for South Africa. Other sustainable energy sources include nuclear power and renewables such as solar, wind and hydro power.

The benefits of using natural gas as an energy source include higher electricity generating efficiencies and significantly lower emissions when compared to coal fired power stations. The potential development and use of natural gas, including Liquefied Natural Gas (LNG), within South Africa is inevitable. This would require significant new infrastructure and it is imperative that Transnet plan accordingly.

An updated view of developments around natural gas, both regionally and internationally, is therefore required to fully understand the potential impact it could have on the current and future business of Transnet.

While gas is currently supplied and distributed by Sasol to north eastern parts of the country, further development of a gas economy and infrastructure in South Africa will require significant planning and investment. The required infrastructure includes LNG import terminals, storage and regasification facilities, primary high-pressure gas transmission pipelines and secondary distribution pipeline networks.

1.2 WHAT IS NATURAL GAS?

Natural gas is composed mainly of the gas methane (95 to 99%), which is the simplest of the hydrocarbon molecules (chemical formula CH4). Depending on the location and characteristics of the production facility, natural gas also has small quantities of heavier hydrocarbons ethane, propane, butane and pentane and other gases such as hydrogen sulphide (H2S), nitrogen and water.

Natural gas is processed to remove non-hydrocarbons and heavier molecules to produce a consistent quality gas, usually controlled in terms of heating or calorific value. Production of natural gas is usually characterised as conventional or unconventional gas and these are described in Figure 1.

Natural gas is either transported via high pressure gas transmission pipelines, or it can be liquefied under cryogenic temperatures (-162°C) and transported by ship as liquefied natural gas (LNG). Alternatively smaller volumes can be pressurised in containers and transported as compressed natural gas (CNG).

**Conventional Gas**

- Trapped gas in reservoirs on-shore or off-shore which flows easily.
- May or may not be associated with an oil reservoir.
Unconventional Gas

- Not associated with a gas reservoir.
- Gas is interspersed with rock, tight sandstone formation or coal seams.

Unconventional gas includes:

Shale Gas

- Gas accumulation is locked in tiny bubble-like pockets within layered sedimentary rock such as shale.
- Production method consists of fracturing the shale rock to release the gas to the surface.

Tight Gas

- Gas is interspersed within low porosity silt or sand areas.
- Production method consists of fracturing the shale rock to release the gas to the surface.

Coal Bed Methane - CBM

- Methane gas is loosely bound (absorbed) by coal.
- Coal beds can retain six to seven times more gas than rock.
- Production methods consist of removing water (pumping) from coal seams which reduces pressure and releases gas to the surface.

Figure 1: Characterisation of Conventional and Unconventional Natural Gas
1.3 NATURAL GAS POTENTIAL APPLICATIONS

The primary use of natural gas globally is in the combustion of the gas for the generation of electricity and for the provision of direct energy and heating for industrial, commercial and domestic processes.

Compressed natural gas (CNG) and liquefied natural gas (LNG) is used as fuel in the transportation sector in vehicles such as cars, trucks, locomotives and as bunker fuel for ships. Natural gas is also used as feedstock for conversion processes for the production of petrochemicals and fuels (gas to liquids plants). The various uses of natural gas are illustrated in Figure 2.

1.3.1 TRANSPORTATION FUEL

The trucking industry uses LNG and CNG as fuel to meet environmental emission standards and to reduce fuel costs; examples being China and the United States of America (predominantly California).

The use of LNG or CNG as vehicle fuel requires investment in refuelling stations and storage facilities. Currently South Africa is piloting a CNG fuel network facility in Langlaagte, Johannesburg, which was commissioned in March 2014 and is run by CNG Holdings. The customer base is a taxi fleet and other commercial vehicles. CNG Holdings also operate a second site on the West Rand.

1.3.2 LNG AS MARINE BUNKER FUEL

LNG is used as bunker fuel for marine transport, mainly to meet strict environmental emission standards in Europe and US. Currently there are few vessels that are capable of using LNG as bunker fuel, but the market is expected to develop over the next 15 to 20 years. For the South African ports to provide this service, LNG importing and bunkering infrastructure will have to be developed.
1.3.3 SMALL-SCALE LNG SUPPLY

LNG can now also be stored and transported on a small scale in containers which can be transported by ship, rail or road. The ISO-containers hold approximately 27 tons of LNG. The LNG is kept in liquefied form through a process called ‘boil-off gas’ whereby small amounts of the LNG is vaporised to create the refrigeration effect to keep the temperature cryogenic (below -162°C). Figure 3 shows examples of small scale LNG supply.

Small scale LNG is suitable for small scale power generation of between 20 to 50 MW. This is typically used by the private sector to supply emergency backup power. Mid-merit or base load electricity generation typically requires LNG facilities with a capacity greater than 1mtpa for the required economies of scale.
Total global production of gas (2012/13) was 3.370 billion cubic metres (bcm) of which 83% constituted conventional gas and 17% unconventional gas (shale gas, tight gas and CBM). This is based on global natural gas supply and demand at the end of 2013. The unconventional gas production is based on 2012 data.

The total global gas trade (imports and exports) in 2014 was 1.036 bcm, of which 69% was piped gas and 31% LNG. The overall gas supply chain volumes are shown in Figure 4.

Note: all figures are given in Billion Cubic Metres (bcm) at standard temp and pressure. The difference between global production and consumption is due to storage stock variations and disparities in definition and measurement.

Figure 4: Global Natural Gas Supply Chain Volumes
1.5 GLOBAL PIPED GAS AND LNG TRADE

North America and Europe are the dominant piped gas markets, whereas the major suppliers such as the Middle East, Indonesia, Australia and Nigeria that connect with the key Asian markets are generally served by the LNG industry. This is illustrated in Figure 5.

![Figure 5: Piped Natural Gas and LNG Trade Volumes in Billion Cubic Metres (bcm)](image)

The proportion of piped natural gas trade remains more than double that of LNG trade, however, with the expected commissioning of new LNG liquefaction plants in Australia and with United States of America LNG exports possibly entering the market over the next five to 10 years, the LNG industry is expected to grow to a larger portion of the overall global natural gas trading market. Gas developments in southern Africa (Mozambique, Tanzania and Angola) will be primarily selling and transporting their gas resources, to international markets, in the form of LNG. When gas needs to be transported less than 3 000km then pipeline options become more viable and should be considered. Both LNG and pipeline gas should be considered when supplying South Africa with gas from Mozambique.
1.6 NATURAL GAS PRICING TRENDS

Historically the prices of natural gas varied significantly between regions due to distances between gas sources, fixed off-take points and gas markets. Due to the fact that gas supply and demand is relatively localised in regional geographic terms (as a result of significant costs associated with liquefaction and shipping), there are various markets and price trends to consider.

The key gas trading marker prices are:

- The Henry Hub (HH) for North America: This is a distribution hub on the natural gas pipeline system located in Louisiana that serves as the official delivery location for futures contracts on the New York Mercantile Exchange (NYMEX);
- The National Balancing Point (NBP) for the United Kingdom: This serves the UK-Europe gas market; and
- The Platts Japan Korea Marker (JKM): This serves the Asian market, Japan and South Korea, and are the largest importers of LNG in Asia.

The natural gas price has been on a steady decline since the end of 2014. Reasons for this include:

- Lower crude oil prices which influences crude indexed pricing of natural gas;
- Lower economic growth in China and the rest of Asia;
- Japan is closer to restarting their nuclear reactors;
- Lower coal pricing which prompts switching from gas to coal; and
- Expected over-supply of LNG production over the next five to 10 years.

Figure 6 shows how the Brent crude oil and gas prices have varied over the last few years with a significant downward trend over the last few months.

---

**Figure 6: Natural Gas Pricing Trends in the United States of America, Europe and Asia (Price Data from Platts)**
The anticipated new LNG liquefaction projects due to be commissioned are shown in Figure 7, where over 110 million tons per annum of liquefaction capacity is expected to come online over the next five years, more than half of which will come from Australia. Other countries adding to this capacity include Papua New Guinea, Malaysia, Indonesia, Russia and the United States of America. This additional capacity represents almost 50% more than the current LNG market of 237 million tons per annum.

![New LNG Liquefaction Capacity Due to Come Online](image)

Many LNG liquefaction projects are delaying final investment decision due to the lower prices. However, projects already well developed, especially in Australia, will tend to keep the supply greater than the demand, hence lower gas prices. The global market looks to be entering a new phase of lower and more convergent regional gas prices since buyers will be able to shop for the best prices in a competitive market. Buyers should be able to diversify their supply sources and negotiate supply contracts that provide better flexibility especially if their contracts involve large volumes, similar to what occurs in the crude oil supply market. According to Platts, spot trades generally represent around 20% of the LNG volumes traded yearly. While the LNG market continues to be dominated by traditional 20- to 30-year long-term contracts, there is a marked movement towards shorter term and spot deals. In the view of Platts, there is a strong call in the Asian markets to move away from oil-indexation, together with de-linking LNG prices from other commodities.

About 80% of the landed cost of LNG relates to upstream costs in the supply chain. Typical relative costs are shown in Figure 8: The shipping costs vary depending on the distance between source and destination market.
The Mozambique LNG developments are looking at the Asian and European markets (NBP and JKM) for monetisation of their gas resources and will likely need to be competitive in these markets. The location of South Africa relative to the gas trading markets suggests that the Asian and European markers will be the most relevant markers for future LNG pricing for South Africa. Potential gas suppliers to South Africa will need to evaluate South Africa’s alternative gas supply options and set prices accordingly.

1.7 LNG INDUSTRY OVERVIEW

The global LNG industry is growing with the development of new gas resources in East Africa, Australia and the Middle East. An overview of the industry is provided in Figure 9. Compared to the current global LNG trade, liquefaction capacity is 24% greater than the demand, which means that utilisation of some plants have to be reduced. If demand does not keep up with the new capacity coming online, there will be added pressure on plant throughputs.

Regasification capacity is almost three times greater than global trade. This is largely a result of the many LNG regasification facilities that were built in the United States of America in anticipation of large scale imports into the US, which subsequently was not required as local shale gas resources were rapidly developed.
1.8 CLASSIFICATION OF GAS RESERVES

Gas resources are described and recorded based on standardised conventions used throughout the global oil and gas industry. Clear terms and definitions that result in reliable and easily comparable reserves estimations are essential for investors, regulators, governments and consumers not only in assessing a petroleum company’s current and future value, but in determining the outlook for the world’s energy supply.

The Petroleum Resources Management System (PRMS) defines resources as volumes that will be commercially recovered in the future. Reserves are physically located in reservoirs deep underground and cannot be visually inspected or counted, but rather are estimates based on the evaluation of data that provides evidence of the amount of oil and gas present. All reserve estimates therefore involve some degree of uncertainty.

The certainty or probability of gas reserves are often measured by the ratio of the favourable cases to the whole number of cases possible. The convention is to quote cumulative probability of exceeding or equaling a quantity where P90 refers to a small estimate and P10 refers to a large estimate.

The PRMS uses a framework that categorises reserves in terms of uncertainty associated with the recoverable volumes along a horizontal axis and classifies it according to the potential for reaching commercial producing status along the vertical axis. An illustration of the reserves framework is shown in Figure 10 where the horizontal axis describes uncertainty as proved, probable and possible, while the vertical axis classifies potential commerciality of reserves as prospective, contingent and reserves.

(Source: SPE Petroleum Resources Management Systems - Guide to Non-Technical Users, SPE International)

Figure 10: Classification of Gas Reserves
The descriptions used in Figure 10 are described as follows:

- **Production**: quantity of oil and gas that has been recovered already;
- **Reserves**: commercially recoverable and justified for development;
- **Contingent**: potentially recoverable but not yet considered mature enough for commercial development;
- **Prospective**: less certain than contingent. Potentially recoverable based on indirect evidence but which have not yet been drilled;
- **Proved (P90)**: high degree of confidence that resources will be recovered;
- **Probable (P50)**: less likely to be recovered than proved reserves;
- **Possible (P10)**: less likely to be recovered than probable reserves; and
- **Unrecoverable**: may never be recovered due to physical or chemical constraints. May become recoverable with commercial or technology changes.

In order for volumes to move from one category to the next, the technical issues which cause it to be placed in less certain categories must be resolved. In the majority of cases, this requires additional data for greater certainty. This may include, among other things, drilling of additional wells, monitoring of current production or the implementation of a pilot to give greater confidence in the volumes of full-scale production.

### 1.9 International Gas Resources

According to the US Energy Information Agency (EIA) 2014 database, the total global proven (P90) natural gas reserves in 2014 was 198 trillion cubic metres (tcm) (6 973tcf).

Proven gas reserves comprise mainly conventional gas but also include unconventional gas reserves, such as the shale gas in the United States of America. These proven reserves represent approximately 60 years of supply based on current global demand. The world’s largest proven gas reserves are shown in Figure 11. The information is based on US (EIA) database.

![Figure 11: World’s Largest Proven Gas Reserves as at 2014](image)

Mozambique joins the world as a major gas player with proven reserves of 2,8tcm (100tcf) together with Nigeria at 5,1tcm (181tcf). Many southern African countries’ reserves fall in the range of 0,01 to 0,10tcm including Namibia with 0,062tcm (2,2tcf) and Tanzania with 0,006tcm (0,23tcf).
1.10 UNCONVENTIONAL GAS - SHALE GAS

Shale gas reserves are more widespread than conventional gas reserves. In the US today, shale gas reserves represent approximately 50% of the total US gas reserves (US EIA). Although not proven as yet due to lack of exploration drilling data, the US EIA estimate of South Africa’s technically recoverable shale gas in the Karoo is just under 11.3tcm (400tcf) and is one of the largest in the world as can be seen in Figure 12.

(Source: Unconventional Gas Market Appraisal, Scottish Development International, 29 May 2014)

Figure 12: Estimates of Technically Recoverable Shale Gas

The South African Government, however, has reduced this estimate to 0.8tcm (30tcf) based on a more realistic gas recovery scenario. The potential volume of shale gas, nevertheless, still represents a huge indigenous resource, which, if developed, could derive large economic benefits for South Africa as an energy source and catalyst for new industrial development.
A study comparing the life cycle emissions of natural gas and coal used for the generation of electricity in the United States of America revealed that, using existing power generation technology, natural gas is a cleaner energy source (Jamarillo, et al., 2007). This is illustrated in Figure 13, where the ranges of greenhouse gas (GHG) emissions for coal, natural gas and LNG are compared. GHG emissions resulting from the combustion of natural gas ranges from 750 to 1 300lbs CO2 equivalent. This is much lower than that of coal which ranges from 2 000 to 2 600lbs CO2 equivalent. This conclusion remains when the entire life cycle is taken into account. Furthermore, when the liquefaction, shipping and regasification processes involved with LNG are included, on average natural gas still remains cleaner than the coal alternative.
2. DRIVERS FOR SOUTH AFRICAN NATURAL GAS DEVELOPMENTS

2.1 GAS RESOURCES IN SOUTHERN AFRICA

The drive for alternative energy as envisaged by energy policies and IRP requires natural gas to supplement coal for electricity generation and achieve environmental benefits from gas as a lower emissions fuel source. South Africa is therefore looking at opportunities to develop indigenous resources, import gas either through pipeline from Mozambique or Namibia, or shipments of LNG from international suppliers. Figure 14 shows potential gas supply areas in Southern Africa.

**Angola Plans**
- Proven reserves of 275 bcm.
- Construction of 5.2 mtpa LNG liquefaction plant at Soyo completed.
- Will provide 3540 m³/day for local consumption.

**Namibia Plans**
- Proven reserves of 62 bcm, probable 108 bcm.
- Anchor project for Kudu gas field is 800 MW CCGT power plant.
- Second phase to consider gas export pipeline to SA and LNG export terminal.

**South Africa**
- Ishubesi Field 5.7 bcm P90
- Project Ilhweni 5.7 bcm.
- Karoo shale gas potential reserves 850 bcm.
- Waterberg CBM potential 283 bcm.

**Tanzania Plans**
- Proven reserves 6.5 bcm, probable 206 bcm.
- Gas production from Songo-Songo field with pipeline to Dar es Salaam for power plants and city gas distribution.
- New pipeline from Mnazi Bay gas field to Dar es Salaam.

**Mozambique Plans**
- Proven reserves 2832 bcm.
- Anchor project is 2 x 5 mtpa LNG liquefaction trains at Palma for LNG export.
- Once LNG established, development of gas power plants, gas distribution network and possible fertiliser/GTL plants.

**Botswana**
- Morupule CBM potential 190 bcm.

Figure 14: Southern Africa Natural Gas Developments
2.2 SOUTH AFRICAN NATURAL GAS MARKET AND INDUSTRY STRUCTURE

South Africa has a history of gas as an energy source dating back to 1892 when gas was first produced in Johannesburg. In 1966 the South African Gas Distribution Company (now Sasol Gas) was formed to market and distribute pipeline gas on a broader scale. Initially gas was sourced from industrial coal-to-gas processes. Around the same time (1969) the first offshore well was drilled by Superior Group. In the same period natural gas deposits were also discovered in the continental shelf complex off the southern Cape coast.

In January 1993 the PetroSA Gas to Liquid (GTL) plant in Mossel Bay went operational using natural gas resources from the southern offshore fields. These gas fields are now being depleted and additional finds are proving inadequate. Current gas supply to the GTL plant is limited and consequently the plant runs at below capacity. Additional gas resources are required to keep this GTL plant operational.

In 2004 the first natural gas from Mozambique (Pande/Temane gas fields) was delivered in Secunda through the ROMPCO over border pipeline. Sasol imports this gas to primarily supply their Sasolburg Secunda plants with feedstock. This resulted in the conversion of the Gauteng gas market from a hydrogen rich gas to natural gas. The KwaZulu-Natal and Mpumalanga markets are supplied from Secunda with methane rich gas.

The main gas pipelines currently in South Africa include:
- ROMPCO pipeline from Mozambique to Secunda;
- Transnet operated Lilly pipeline from Secunda to Richards Bay and Durban;
- Pipeline network from Secunda to Sasolburg and industries in Gauteng and Mpumalanga; and
- Subsea pipeline from the southern offshore gas fields to the PetroSA GTL plant in Mossel Bay. The existing gas pipeline network in the north east of the country is shown in Figure 15.

![Figure 15: Existing Gas Network in South Africa](image-url)
The ROMPCO pipeline has been expanded to a capacity of 183 million gigajoules (MGJ) per annum and most of this capacity has been accounted for. In 2014 Sasol gas sales amounted to 171MGJ. A high-level gas supply and demand for South Africa is provided in Figure 16. This excludes the PetroSA GTL plant feed gas.

![Figure 16: High-level Gas Supply and Demand for the ROMPCO Pipeline](image)

Figure 17 indicates the various players in the South African natural gas industry. Only Sasol Gas and PetroSA are in upstream and gas conversion activities of the supply chain. The majority of the players are in the sale of gas to the commercial, industrial and retail sectors.

![Figure 17: Players in the South African Natural Gas Industry](image)
2.3 COMMERCIAL CONSIDERATIONS AND CAPITAL INVESTMENT

To increase the gas economy in South Africa, gas infrastructure (pipelines, LNG terminals, etc.) will have to be significantly expanded beyond the current capacity in Gauteng, Mpumalanga and KZN. As gas infrastructure cuts across many sectors, it will be necessary to integrate planning of developments so that timing of capacity is aligned to meet South Africa's requirements. Gas infrastructure development will most likely be underpinned by gas to power infrastructure, as this will potentially be the largest anchor demand for gas that would justify the business case for investment for LNG imports and related gas pipeline developments. In establishing a gas to power value chain, the DOE is dependent on various regulatory bodies to integrate the entire value chain. The critical regulatory role players include:

- **Transnet National Ports Authority (TNPA)** - Port terminals licencing, Port rules for port control, Port planning alignment;
- **National Energy Regulatory of South Africa (NERSA)** - Gas facility construction and operations licencing and tariff cap regulation;
- **Department of Environment Affairs (DEA)** - Environmental permitting;
- **National Treasury** - to provide the guarantee for Eskom Power Purchase Agreement (PPA) and
- **The Department of Mineral Resources** - Minerals and Petroleum Resources Development Act (MPRDA) Amendment bill which provides for a number of contentious provisions governing the development of oil and gas resources. The bill has been returned to parliament with a view to assess the suitability to separate the oil and gas regulations from the mining industry.

Other key stakeholders are PetroSA, iGas and the Department of Trade and Industry, who are keen to see the investment in the industrial development Zones (IDZs) and Department of Public Enterprises. The private sector is also likely to play a major role in the investment and development of gas infrastructure. For this to be achieved, the policy and regulatory environment must align and provide certainty.

2.4 NATURAL GAS POLICY AND REGULATION


The Integrated Resource Plan (IRP) (2013) provides a national electricity plan until 2030 including preferred generation technologies and timelines. Gas is allocated 3 126MW of base load and/or mid-merit CCGT generation capacity between 2019 and 2025 and another 1 659MW CCGT capacity between 2028 and 2030.

The Department of Energy (DOE) is working to release a gas utilisation master plan (GUMP) which will set out how South Africa plans to utilise natural gas until 2050. GUMP aims to provide a framework for investment in gas infrastructure and outlines the role that gas could play in the electricity, transport, domestic, commercial and industrial sectors. It should advise the appropriate regulatory and licencing framework that provides an enabling environment for gas development. GUMP is also expected to consider various supply options, including the potential for domestic production of natural gas, shale gas, coal bed methane, importation of liquefied natural gas (LNG) and piped gas from Namibia and Mozambique.

The National Development Plan (NDP) (2012) recognises gas as an alternative form of energy to help move South Africa into a lower carbon economy. The regulatory framework is illustrated in Figure 18.
In terms of the Gas Act and the Piped Gas Regulations, NERSA issues licences for gas infrastructure construction and operation and gas trading and determines maximum gas prices per applicant and pipeline transmission tariffs for the pipeline owner/operator. In the absence of a transparent gas market price in South Africa, NERSA currently calculates the maximum price for gas based on a formula that uses weighted energy indicators for coal, diesel, electricity, heavy fuel oil (HFO) and LPG. A second approach available is to use the so-called pass-through method which requires a cost build-up, including the cost of the gas, transportation and regasification costs, transmission tariffs, distribution tariffs and trading margin (Methodology to Approve Maximum Prices of Piped Gas, NERSA Oct 2011).
In a scenario where LNG is imported and used to generate electricity in new combined cycle gas turbine (CCGT) plants, a number of regulatory conditions have to be fulfilled as specified by numerous acts and policies. LNG importation will need to meet South Africa’s ports and maritime safety regulations. NERSA would have to approve all licencing for gas infrastructure construction and operational activities. The independent power producer (IPP) facility will be subject to the Electricity Regulatory Act.

Preceding all the activities would be the requirement to meet environmental impact assessment (EIA) processes as set out by the National Environmental Management Act (NEMA), Act 107 of 1998. All these regulatory linkages for a gas to power development are illustrated in Figure 19.

**Figure 19: Regulatory Considerations for New Gas to Power Development**

- **Port Facilities**
  1. LNG import licence, Nersa price regulation.

- **LNG Storage and Regasification**
  1. Gas Act - Section 15(1)(a), licence is required for construction and operation of regasification facilities.
  2. Rights of way/land servitude agreements.
  3. Construction law related to permits and approvals.

- **IPP Construction and Operation**
  1. Electricity Regulation Act - Section (1)(a), licence required to operate any generation, transmission and distribution facility.
  2. Right of way/land servitude agreements.
  3. Construction law related to permits and approvals.

- **LNG and NG Pipelines**
  1. Gas Act - Section 15 (1)(a), licence is required for construction and operation of LNG/NG transmission facilities.
  2. Gas Act - Section 21(1)(p) Nersa approves the maximum gas prices where there is inadequate competition in terms of chapter 2-3 of Competition Act.
2.6 CURRENT GOVERNMENT INITIATIVES

Gas development is a subject that is integral to a number of Government development plans and initiatives which cover both short and long-term time frames. The inclusion of gas energy and its target utilisation has already been described in the IRP and NDP and the GUMP (still to be published) is expected to set out how South Africa plans to utilise natural gas until 2050. Transnet’s primary role would be to help facilitate the DOE– gas IPP (GIPP) programme via its role as Port Authority and through facilitating the development of South African ports so as to accommodate LNG importation.

Operation Phakisa, which has evolved out of Government’s long-term national infrastructure development plans, considers the need to explore offshore gas reserves. Government has formed the Electricity War Room and one of the projects focusses on imported gas to generate power. The project participants include state owned companies (SOCs): Transnet, Eskom, PetroSA, CEF and DOE.

2.6.1 OPERATION PHAKISA

The South African Government recognises that there are potential large undiscovered oil and gas resources located offshore along the South African coastline however, offshore exploration is extremely expensive. To create an enabling, supportive environment for oil and gas exploration, six key areas were identified as work streams to focus on evaluation of the current status and recommendations to support exploration and developments in the future. These key areas or work streams are:

A. Gas infrastructure;
B. Local skills development;
C. Environmental management;
D. Institutional governance; and
E. Supply chain – leveraging local content;
F. Legislative

From these key work streams, 11 initiatives were identified, of which the A1- Gas Pipeline Network is the most relevant to the future gas scenario for South Africa. Operation Phakisa recognises that to enable successful offshore oil and gas exploration, adequate infrastructure like port facilities, pipeline networks and multi-purpose research vessels need to be developed.

Initiative A1 seeks to develop a phased gas pipeline network to speed up the development of gas in South Africa, should gas be discovered. The pipelines are primarily located along the coastline. The potential pipelines and phases of development are shown in Figure 20.
Phase 1 envisages the development of a gas pipeline along the west coast joining the Ibhubeisi Field with Saldanha Bay and demand centres (mainly electricity generation such as Ankerlig) in the Cape Town region.

A prerequisite for imported gas or LNG is the focus on gas to power generation which serves as anchor demand for the business case for LNG importation.

2.6.2 DOE WAR ROOM

In response to the current shortage of electricity generation capacity, Government established the Electricity War Room to study the best ways to provide supplementary electricity generation capacity relatively quickly (18 to 36 months) and cost effectively. Gas power has been identified as a key opportunity through the use of imported LNG.

2.6.3 WESTERN CAPE GOVERNMENT PLANS TO DEVELOP AN LNG IMPORT TERMINAL IN SALDANHA BAY

The Provincial Government of the Western Cape is spearheading an initiative to develop an LNG import facility in Saldanha Bay. The studies have concluded that the potential industrial and commercial demand for the gas, including the anchor demand for a new IPP CCGT electricity generation, will support LNG imports of 1 to 2 million tons per annum.

2.6.4 GAS ENERGY FOR ELECTRICITY GENERATION

The majority of electricity generation in South Africa is coal based and Government policy aims to diversify the energy mix by growing other power sources i.e. renewables wind, solar and hydro power, together with nuclear and gas power. The implementation of the alternative sources of electricity is guided by the Integrated Resource Plan and executed through the DOE’s IPP procurement process.

Due to Eskom’s constrained generation capacity, significant volumes of diesel are being consumed by Eskom’s OCGT plants (Ankerlig and Gourikwa). By switching to cheaper gas fuel, this provides an opportunity to reduce the cost of these operations. A successful project similar in nature was completed by Sasol when they commissioned a 140 MW gas facility in Sasolburg in December 2012 at a cost of R1,5 billion.
Gas can play a much larger role in base load and mid-merit electricity generation, but more gas is required over and above what is currently available in South Africa. Additional gas will have to come from indigenous gas resources and/or imported LNG. The proposed new Gas IPPs are likely to become the anchor demand for future LNG imports.

The Ibhubezi Gas field off the West coast has an estimated P90 reserve of 5.66bcm (0.2tcf). A joint venture between Sunbird Energy (76%) and PetroSA (24%) has entered into a gas sales agreement (GSA) with Eskom for the supply of gas from the Ibhubezi Gas field to the Ankerlig OCGT power station, starting from 2018. This gas supply appears to be exclusively for Ankerlig, with limited surplus for other gas projects.

To provide some guidance for gas to power equivalence, 28.3 bcm (1tcf) of gas can sustain a 1 000 MW CCGT plant generating electricity continuously for about 20 years. Alternatively, the typical gas consumption for a base load 1 000 MW CCGT would be around 1 mtpa.

2.6.5 GAS FOR INDUSTRIAL AND COMMERCIAL ENERGY APPLICATIONS

The availability of gas and the development of gas infrastructure will stimulate further industrial and commercial demand for gas. Three scenarios can be considered for the South African natural gas demand. The first scenario is the current gas use which is in the order of 242MJ per annum. The second scenario is if LNG is imported into the country then industrial beneficiation projects like fertiliser, aluminium smelter, manganese ferro alloy, steel and cement plants can be initiated. In this scenario the estimated national gas demand is 760 MGJ per annum, including a supply to the PetroSA’s GTL plant in Mossel Bay.

The third scenario includes the supply of local gas (Karoo Shale, CBM) and additional supply of piped gas from northern Mozambique. This long-term potential, industrial, electrical and new GTL plant demand is estimated at approximately 1 800 MGJ per annum. The potential gas demand for various scenarios is shown in Figure 21.

![Figure 21: Potential National Gas Demand for Current, LNG Import and Long-Term Potential Scenarios](image-url)
2.7 TRANSNET’S ROLE IN GAS DEVELOPMENT

One of the 10 key performance areas for Transnet, as defined by the Shareholder (Department of Public Enterprises), is to “ensure the provision of critical logistics infrastructure and capacity over the short term that is aligned to a long-term national plan that is geared towards meeting the growing demands of the total national economy”.

Gas is becoming an important energy commodity in South African plans for electricity generation, with significant upside potential economic benefits should significant gas resources be discovered in South Africa (e.g. Karoo shale gas). Gas infrastructure is required to grow a gas economy. For the import of LNG, the gas supply chain will require LNG port facilities, storage, regasification facilities, gas transmission pipelines to move the gas to the regional demand centres and then secondary distribution pipeline networks to individual customers.

Transnet National Ports Authority (TNPA), as landlord of the ports, can play a pivotal role in providing the required LNG berths and terminal infrastructure to help realise the DOE IPP LNG to power value chain.

Gas transmission pipelines will have to be built to move the gas from the ports to demand centres and Transnet Pipelines can play a future role using their expertise in the operation and management of these regional pipelines.

3. GAS INFRASTRUCTURE

3.1 NAVIGATIONAL AND SAFETY REQUIREMENTS FOR IMPORTING LNG

3.1.1 LNG TRANSPORTATION

Natural gas can be transported to the market as gas, compressed gas (CNG) or liquefied gas (LNG). Natural gas is cooled to -162°C to create LNG, which is a very efficient state to transport as it is 1/600th of its volume in a gaseous state. The transportation of LNG is complex as it has to be carried at a temperature below -162°C. The transportation of LNG over long distances occurs primarily via LNG carriers. Due to the high cost and safety issues, cryogenic pipelines are less feasible for long distance transportation of LNG.

3.1.2 LNG CARRIER VESSELS

LNG carriers are primarily separated into classes based on their containment systems. These include the Moss-type and membrane-type vessels as shown in Figure 22 below.

Figure 22: Typical LNG Carriers
3.1.3 MEMBRANE TYPE LNG CARRIERS

The membrane-type LNG carriers allow for the tanks to be incorporated entirely into the hull of the vessel. The primary advantages of the membrane containment system are:

- Due to the optimal use of the vessel’s hull, membrane-type LNG carriers can be scaled up to larger capacities with relatively small changes to the vessel dimensions;
- Membrane containment systems have a faster cool-down time owing to the thin nature of the membrane barriers; and
- LNG tanks are incorporated into the vessel’s hull, thereby reducing air draft and windage area.

Due to the prismatic nature of the membrane tanks, sloshing of LNG is a serious concern especially when considering the thin containment membranes which are not self-supporting structures. Therefore, membrane-type LNG carriers are generally subject to filling restrictions, ensuring that tanks are either above the upper filling limit or below the lower filling limit as indicated in Figure 23.

As at November 2014 the global LNG shipping fleet totalled 386 vessels (Drewry Shipping Insight, Dec 2014). By the end of 2013 the number of membrane tankers accounted for 68% of the global fleet, while the Moss-type tankers only represented approximately 28% of the global fleet. Of the 45 orders for LNG vessels placed in 2013, 37 were of the membrane type, clearly indicating the increasing trend for membrane LNG carriers (GIIGNL, 2013).

![Figure 23: Filling Limits for Membrane-Type LNG Carriers (DNV, 2014)](image)

3.1.2.1 MOSS TYPE LNG CARRIERS

The Moss (or Moss-Rosenberg) containment system consists of a number of independent spherical tanks. Owing to their spherical geometry, the tanks are able to withstand high pressures and are self-supporting when fully loaded. LNGCs with Moss containment systems have been in operation for the longest period of time, rendering the technology well established.

The primary advantages of the Moss containment system are:

- The simplicity of the spherical tanks enables accurate stress and fatigue design, resulting in a high degree of safety against failure;
- Due to the absence of vertical walls, spherical tanks effectively deal with sloshing of the LNG in adverse wave conditions;
- Since sloshing is not a concern, Moss-type LNGCs can sail with partially full tanks; and
- The tanks are separated from the ship's hull and therefore do not contribute to or rely on the integrity of the ship's hull.
Although having the many advantages listed above, the spherical tanks protrude from the hull of the LNG carrier, resulting in high air draft and large windage area, which complicates manoeuvring during strong winds. Furthermore, due to the spherical nature of the tanks, the hull of the LNG carrier cannot be used optimally, requiring large increases in vessel dimensions to increase the capacity of the vessel.

Although membrane tankers with capacities up to 266 000 m³ have been built for Qatargas (Q-Max type vessel), the overwhelming majority (77%) of LNGCs servicing the industry fall within the 90 000 m³ to 170 000 m³ capacity range (GIIGNL, 2013).

For long-term planning purpose the larger Q-Max type LNG carriers have been considered. The following vessel and navigational and special requirements for an LNG port terminal are shown in the Table 1 below. Depth requirements are based on PIANC (2014) guidelines.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Dimensions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vessel capacity</td>
<td>266 000m³</td>
</tr>
<tr>
<td>Vessel length</td>
<td>345m</td>
</tr>
<tr>
<td>Vessel beam</td>
<td>54m</td>
</tr>
<tr>
<td>Design vessel laden draft</td>
<td>12m</td>
</tr>
<tr>
<td>Turning circle</td>
<td>620m</td>
</tr>
</tbody>
</table>

Table 1: Design Vessel and Port Navigational Requirements

### 3.1.3 LNG SAFETY REQUIREMENTS

Due to the cryogenic nature of LNG and the flammable nature of methane boil-off, LNG poses a number of hazards to the public and to property. The primary hazards from LNG spills are:

- Cryogenic burns to crew or nearby persons from contact with LNG;
- Brittle fracture of the vessel or storage tanks due to contact with the cryogenic LNG;
- Asphyxiation when a person is trapped within a LNG vapour cloud; and
- Fires and overpressures following ignition of the vapour cloud emanating from a LNG spill.

A series of studies on the safety of LNG spills over water have been conducted by the US Department of Energy. The first of these studies investigated impacts of LNG spills over water resulting from a range of accidental and intentional scenarios of a breach in the hull of a LNG vessel. Management approaches to reduce risks to the safety of the public and property from LNG spills were identified as:

- Operation and safety management;
- Improved modelling and analysis;
- Improved ship and security system inspections;
- Establishment and maintenance of safety zones; and
- Advances in LNG offloading technologies.

In an effort to minimise the risk to public safety and property, LNG vessels and terminals are usually surrounded by an exclusion zone. Exclusion zones can normally be defined as a safety zone or a security zone. Although the area defined by safety zones and security zones are often the same, the grounds for the establishment of the zone and its implications on access are usually different (Cobanli, 2005).

Irrespective of the grounds therefore, exclusion zones are usually applicable to LNG vessels in transit and to LNG terminals. The extent of these zones varies from port to port, based on local safety policies and should be determined through a quantitative risk assessment of the site under consideration.
NATURAL GAS INFRASTRUCTURE PLANNING

In alignment with the TNPA Position Paper for LNG (TNPA, 2014), the following exclusion zones have been adopted in conceptual development of potential South African LNG terminals:

<table>
<thead>
<tr>
<th>Area</th>
<th>Extent of Exclusion Zone</th>
</tr>
</thead>
<tbody>
<tr>
<td>LNG carrier</td>
<td>500m ahead, 250m abeam and astern while transiting along shipping channels</td>
</tr>
<tr>
<td>Load-out berth</td>
<td>250m radius safety zone while unoccupied by LNG carrier</td>
</tr>
<tr>
<td></td>
<td>250m radius commercial shipping safety zone during loading operations</td>
</tr>
<tr>
<td></td>
<td>1 000m public exclusion safety zone during loading operations</td>
</tr>
<tr>
<td>Cryogenic pipeline</td>
<td>50m each side of the pipeline</td>
</tr>
<tr>
<td>Storage facility</td>
<td>Site perimeter boundary to be located 500m from storage facility</td>
</tr>
<tr>
<td>LNG processing plant</td>
<td>250m clearance zone to other hazardous industry inventory</td>
</tr>
<tr>
<td></td>
<td>1 000m clearance to residential areas</td>
</tr>
</tbody>
</table>

Table 2: Exclusion Zones for LNG Terminals

3.2 LNG INFRASTRUCTURE OPTIONS IN PORTS

With the limited gas resources and infrastructure in South Africa, LNG will need to be imported to meet the aspirations to grow a gas economy and to develop gas based electricity generation capacity.

The most suitable ports that have been identified in South Africa to develop LNG import terminals are Saldanha Bay, Ngqura and Richards Bay. There are various LNG terminal layout options in each of these ports and the most suitable location, layout and technology will depend on the required capacity, funding mechanisms, schedule requirements, port geography, operational constraints and it is critical that LNG terminals fall within the long-term port framework (LTPF) plans.

Industry is generally geared towards the delivery of large parcel sizes suitable for relatively large scale LNG terminals (greater than 1mtpa). Typically a single berth terminal will have a capacity of between 3mtpa and 5mtpa. To give an idea of the expected vessel traffic a 170 000 m³ LNG carrier has a cargo of approximately 74 000 tons. If one such vessel calls at the terminal each week the annual throughput will be around 4mtpa.

The two main types of LNG port terminal options that need to be considered are:

- A conventional terminal with a LNG berth and a cryogenic pipeline to land based storage and regasification facilities; and
- A berth with a floating storage and regasification unit (FSRU). These terminal options are discussed below in more detail.

3.2.1 CONVENTIONAL LAND BASED LNG TERMINAL

Conventional terminals require suitably designed berths for LNG vessels, with associated cryogenic off-loading arms and pipelines to land-based LNG storage facilities. LNG is transported via cryogenic pipeline to a regasification facility where the LNG is vaporised and sent to the market via high pressure primary gas transmission pipelines. This infrastructure all requires appropriate safety exclusion zones.

This option allows flexibility for future capacity expansion but comes with a high capital cost for marine infrastructure and for the LNG regasification plant. Long lead times (six to eight years) are required for the engineering and construction of a LNG regasification facility. The typical size of a terminal is between 3mtpa and 5mtpa and a high level cost estimate is in the order of R11 billion.

An example of a conventional LNG terminal is shown in Figure 24.
3.2.2 FLOATING STORAGE AND REGASIFICATION UNIT (FSRU)

The storage and regasification facilities are typically located offshore on a custom-built or converted LNG carrier which is permanently moored at a sea island offshore jetty. The FRSU is replenished by LNG carriers that moor alongside and transfer LNG via a cryogenic pipeline to the FSRU storage tanks. The LNG is regasified on the FSRU and the gas is transported from the facility to the primary gas transmission pipelines and on to the market.

The main advantages of this option are the lower capital costs and the shorter time required to establish. This option does however incur high operational costs that are associated with the long-term lease costs for the FSRU vessel and it cannot be readily expanded and is usually used for lower gas demands compared to a conventional LNG terminal. An example of an FSRU import terminals are shown in Figure 25 and Figure 26.
3.3 ELECTRICITY GENERATION USING NATURAL GAS

3.3.1 LAND BASED GAS POWER STATION

Combined cycle gas turbine (CCGT) power plants use natural gas to generate electricity. These plants are proven technology and are more efficient (57 to 60%) than the latest generation coal fired stations (43%). Gas turbine sizes range up to 500 MW and can be combined to provide large scale base load electricity of between 1 000 MW and 3 000 MW.

A CCGT plant is normally located near the LNG import facility and high level capital costs based on Foster Wheeler estimates (2014) are R6 600/kW. Therefore a 1 000 MW CCGT power station will cost in the order of R 6,6 billion. The average design and construction duration will take approximately three years.

Natural gas, which is significantly cheaper than diesel, can be used in place of diesel in existing open cycle gas turbine (OCGT) power stations such as those operated by Eskom at Ankerlig in Atlantis and Gourikwa in Mossel Bay. Refer to Figure 27. There would be further fuel cost savings if these units were upgraded to CCGT generators as they are typically 15 to 20% more efficient than OCGT generators.
3.3.2 POWER BARGES

A power barge is a marine barge on which a power plant has been installed to generate power. A power ship is an existing ship that has been modified for power generation. The advantage of the power ship over the power barge is that it is self-propelled. Power barges are typically equipped with turbines or engines that run on natural gas, LPG, diesel or heavy fuel oil (HFO). Power barges can typically produce up to 200 MW of power, with some of the new power ships generating up to 500 MW. Globally there are just over 70 power barges.

The main advantage of power barges is that they can be rapidly mobilised to provide power to support the national grid. As an interim short term measure the DOE War Room, together with Transnet’s assistance, is currently considering the option of using power barges in selected ports to help provide additional power for the national grid. An example of a power barge and power ship are shown in Figure 28.
3.3.3 COST OF GAS-GENERATED POWER

The unit cost of power generated using gas varies significantly depending on the size of power plant and frequency of use (e.g. peaking power, mid-merit or base load). Various power generating options from smaller capacity and short delivery time options to larger base load, more cost effective options. Longer delivery times have been considered and are shown in Figure 29. It is only the larger long-lead projects that are closer to the current Eskom tariffs.

![Power Generation Options Diagram]

**Figure 29: Power Generation Options, with Electricity Costs and Typical Construction Durations**

Figure 30 illustrates how market-driven scenarios provide more commercially feasible outputs that would require co-ordination of multiple stakeholders and a likely National Treasury financial underpin of the entire value chain.

In the short term, the delivery of up to 350 MW of power could be in place within about 21 to 33 months. Due to the smaller scale of the scenario, economies of scale may not be realised, resulting in higher to mid-range LNG prices and associated power prices. Larger scale optimised technical designs to achieve best economies of scale could be procured with the delivery of up to 2 000 MW of power in the medium term. Substantial economies of scale using land based infrastructure may be realised resulting in lower LNG and power prices. The timing of bringing the technology online may however, take between four to six years to procure and build.
At over 1 750 MW of capacity, the present value of the price of power would match the assumed future value Eskom price in about 2021. This is based on the 2014 NERSA price determination, which is likely to be adjusted upwards in 2015.
4. POTENTIAL GAS TERMINALS AND PIPELINE NETWORKS IN SOUTH AFRICA

Various LNG terminals, offshore developments and pipelines that have been considered for supplying South Africa with natural gas are shown in Figure 31.

As shown in Figure 31, offshore FSRU terminals have been considered along the coastline; however, due to typically high wave energy along the coastline, utilisation rates would be low.

LNG terminals and related pipeline infrastructure have been considered in three main regions in South Africa; namely Western Cape, Eastern Cape and KwaZulu-Natal and potential developments are described further in the following section, together with potential gas demand and capital infrastructure costs.

4.1 DEVELOPMENT OF GAS INFRASTRUCTURE IN THE WESTERN CAPE

A gas network in the Western Cape region would be based on three potential sources of gas supply. These include proposed LNG imports into Saldanha Bay or St Helena Bay, offshore gas resources from the Ibhubesi and Kudu gas fields.

The potential gas markets include of the existing Ankerlig OCGT power station, proposed IPP CCGT power stations, and industrial, commercial and agricultural energy applications in the Cape Town region. In addition to the above, a gas pipeline could be built to Mossel Bay approximately 350km away to also supply the Gourikwa OCGT power station and the PetroSA GTL plant.
A potential primary gas transmission pipeline network joining the supply and demand areas is shown below in Figure 32. This network is aligned with the envisioned Operation Phakisa gas pipeline network.

Based on the above developments, the indicative future gas demand for the Western Cape is estimated to be approximately 5.2 mtpa. The makeup of this demand is shown in Figure 33.

**Western Cape Indicative Gas Demand (mtpa)**
**Total Gas Demand = 5.2 mtpa LNG = 270 MGJ/yr**

- Ankerlig OCGT nominal (1 338 MW)
- New IPP CCGT (1 000 MW)
- Western Cape Industry
- New cement and steel SB IDZ
- Gourikwa OCGT nominal (746 MW)
- PetroSA GTL
Figure 34: Potential LNG Terminals in the Port of Saldanha Bay

Figure 34 shows the potential layout of a conventional land-based terminal (1) and a FSRU LNG sea island (2) in the Port of Saldanha Bay.
Opportunities and challenges of the potential LNG terminals in Saldanha Bay include:

<table>
<thead>
<tr>
<th>Option 1: Conventional Terminal</th>
<th>Option 2: FSRU in Big Bay</th>
</tr>
</thead>
<tbody>
<tr>
<td>This is a conventional LNG terminal with land-based storage and regasification.</td>
<td>This option includes a sea island with a permanent FSRU and a subsea gas pipeline to the main land.</td>
</tr>
<tr>
<td><strong>Opportunities</strong></td>
<td></td>
</tr>
<tr>
<td>• This option can be phased with a FSRU and then develop into a conventional land based storage and regasification terminal;</td>
<td></td>
</tr>
<tr>
<td>• This terminal is remote from other port operations;</td>
<td></td>
</tr>
<tr>
<td>• There is a suitable lease area, in close proximity to the terminal, available for developing the land side infrastructure; and</td>
<td></td>
</tr>
<tr>
<td>• The berth is well protected from ocean swell.</td>
<td></td>
</tr>
<tr>
<td><strong>Opportunities</strong></td>
<td></td>
</tr>
<tr>
<td>• Lower capital cost; and</td>
<td></td>
</tr>
<tr>
<td>• Shorter implementation schedule.</td>
<td></td>
</tr>
<tr>
<td><strong>Challenges</strong></td>
<td></td>
</tr>
<tr>
<td>• Significant capital dredging is required; and</td>
<td></td>
</tr>
<tr>
<td>• High capital costs of marine infrastructure.</td>
<td></td>
</tr>
<tr>
<td><strong>Challenges</strong></td>
<td></td>
</tr>
<tr>
<td>• Potential downtime due to exposed berth location;</td>
<td></td>
</tr>
<tr>
<td>• High FSRU operating costs;</td>
<td></td>
</tr>
<tr>
<td>• Proximity to Port of Saldanha Bay anchorage area; and</td>
<td></td>
</tr>
<tr>
<td>• This cannot easily be upgraded to a conventional landside terminal.</td>
<td></td>
</tr>
</tbody>
</table>

![Figure 35: Potential LNG Terminal in the St Helena Bay](image-url)
**Figure 35** shows a potential LNG sea island for a FSRU option in the St Helena Bay, which is approximately 20km north of Saldanha Bay.

The potential St Helena Bay LNG terminal would be an exposed open sea island terminal located in the required water depths. It would have a FSRU permanently moored at a sea island with a subsea gas pipeline to the mainland. As the shoreline between Shelley Point and Slippers Bay has many residential developments, the pipeline landfall has been proposed were the current land use is agricultural.

Opportunities and challenges of this potential terminal include:

**OPPORTUNITIES**

- Reasonably protected bay;
- Low safety risk due isolation from other vessels;
- No disruption to other port operations;
- Relatively low marine infrastructure capital cost; and
- Relatively short implementation schedule.

**CHALLENGES**

- It does not have the same protection as a port and this could result in potential downtime;
- No supporting port facilities;
- Close to residential community;
- High FSRU operational costs;
- Limited opportunity to upgrade to a conventional land based

A high level capital cost estimate for a typical LNG Terminal in the Western Cape, with typical project engineering and construction durations is shown in Table 3. Additional costs for pipelines between Namibia and Saldanha Bay and from Cape Town to Mossel Bay are also shown. Costs exclude escalation.

<table>
<thead>
<tr>
<th>Western Cape Region</th>
<th>Typical Design and Construction Duration (Years)</th>
<th>Option 1 Conventional Terminal (R mil)</th>
<th>Option 2 FSRU Terminal (R mil)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Port Marine infrastructure for LNG Terminal</td>
<td>3-4</td>
<td>3 000</td>
<td>800</td>
</tr>
<tr>
<td>FSRU purchase and mobilisation</td>
<td>1-2</td>
<td>1 400</td>
<td></td>
</tr>
<tr>
<td>Landside storage and regas</td>
<td>2-7</td>
<td>5 000</td>
<td></td>
</tr>
<tr>
<td>Gas compressor</td>
<td>5</td>
<td>2 000</td>
<td>2 200</td>
</tr>
<tr>
<td>Pipeline to Saldanha Bay IDZ (16-inch)</td>
<td>1</td>
<td>0</td>
<td>40</td>
</tr>
<tr>
<td>Pipeline from Saldanha to Atlantis IDZ (24-inch)</td>
<td>4</td>
<td>1 400</td>
<td>1 400</td>
</tr>
<tr>
<td>Pipeline from Atlantis to Cape Town (16-inch)</td>
<td>4</td>
<td>500</td>
<td>500</td>
</tr>
<tr>
<td>Total</td>
<td>5-7</td>
<td>15 280</td>
<td>8 820</td>
</tr>
</tbody>
</table>

| Other Potential Pipelines                   |                                                |                                       |                                |
| Pipeline from Cape Town to Mossel Bay (16-inch) | 5                                              | 3 910                                 | 3 910                          |
| Pipeline from Ibhubesi to Saldanha (24-inch landside) | 5                                              | 3 840                                 | 3 840                          |
| Pipeline from Kudu Gas to Ibhubesi (24-inch)  | 6                                              | 6 010                                 | 6 010                          |

Table 3: Estimated CAPEX for a Western Cape Terminal and Primary Distribution Pipelines

**4.2 DEVELOPMENT OF GAS INFRASTRUCTURE IN THE EASTERN CAPE (PORT OF NGQURA)**

The source of gas supply into the Eastern Cape region is proposed via LNG imports through the Port of Ngqura. Potential markets for the gas in this region include the proposed new IPP CCGT power station, Dedisa OCGT power station (currently under construction), industrial and commercial customers in Coega IDZ and the proposed Mthombo Refinery.
A gas pipeline could be built to Mossel Bay to supply the Gourikwa OCGT power station and the PetroSA GTL plant. This pipeline would need to be approximately 350km long. An alternative could be a gas pipeline from Saldanha Bay which would be a similar length. A potential pipeline network and customers for the Eastern Cape region is shown in Figure 36.

Based on the above developments an indicative future gas demand for the Eastern Cape is estimated to be approximately 3,4 mtpa. The makeup of this demand is shown in Figure 37.

**Eastern Cape Indicative Gas Demand (mtpa)**
Total Gas Demand = 3.4 mtpa LNG = 178 MGJ/yr

![Figure 36: Eastern Cape Potential Pipeline Network](image)

![Figure 37: Potential Medium-term Gas Demand for the Eastern Cape](image)
Figure 38: Potential LNG Terminals in the Port of Ngqura

Figure 38 shows two potential LNG terminal layouts for the proposed importing of LNG through the Port of Ngqura. Both of these layouts are conventional LNG terminals with a berth and cryogenic pipeline extending to land based storage and regasification facilities. Due to special constraints and navigation requirements, a LNG terminal with a FSRU is not considered suitable.
Opportunities and challenges of the potential LNG terminals in the port of Ngqura include:

<table>
<thead>
<tr>
<th>Option 1: LNG Terminal on Existing Breakwater</th>
<th>Option 2: Breakwater Reconfiguration</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Opportunities</strong></td>
<td><strong>Opportunities</strong></td>
</tr>
<tr>
<td>• Lower marine infrastructure capital cost; and</td>
<td>• Dedicated LNG basin; and</td>
</tr>
<tr>
<td>• Shorter implementation schedule for marine infrastructure works.</td>
<td>• Terminal remote from other port operations.</td>
</tr>
<tr>
<td><strong>Challenges</strong></td>
<td><strong>Challenges</strong></td>
</tr>
<tr>
<td>• The terminal encroaches on the port’s turning area;</td>
<td>• Relocation of the breakwater results in high marine infrastructure capital cost; and</td>
</tr>
<tr>
<td>• Risk for vessel navigation in the port – will need to be verified; and</td>
<td>• Significant volumes of rock dredging may be required.</td>
</tr>
<tr>
<td>• Exclusion zone requires the relocation of the existing turning circle.</td>
<td></td>
</tr>
</tbody>
</table>

A high level capital cost estimate and typical project engineering and construction durations are shown in Table 4. Additional costs for pipelines between Coega and Mossel Bay are also shown. Costs exclude escalation.

<table>
<thead>
<tr>
<th>Eastern Cape Region</th>
<th>Typical Design and Construction Duration (Years)</th>
<th>Option 1 Conventional Terminal (R mil)</th>
<th>Option 2 FSRU Terminal (R mil)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Port Marine Infrastructure for LNG Terminal</td>
<td>2-3</td>
<td>890</td>
<td>3 900</td>
</tr>
<tr>
<td>Landside storage and regas</td>
<td>7</td>
<td>8 100</td>
<td>8 100</td>
</tr>
<tr>
<td>Gas compressor</td>
<td>5</td>
<td>2 200</td>
<td>2 200</td>
</tr>
<tr>
<td>Pipeline to Coega IDZ (16-inch)</td>
<td>1</td>
<td>70</td>
<td>70</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>5-7</td>
<td>11 260</td>
<td>14 270</td>
</tr>
<tr>
<td>Other Potential Pipelines</td>
<td></td>
<td>3 840</td>
<td>3 840</td>
</tr>
<tr>
<td>Pipeline from Coega to Mossel Bay (16-inch)</td>
<td>5</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 4: Estimated CAPEX for Eastern Cape Terminal and Primary Distribution Pipelines

4.3 DEVELOPMENT OF GAS INFRASTRUCTURE IN KWAZULU-NATAL (PORT OF RICHARDS BAY)

KwaZulu-Natal has an existing gas supply via Transnet’s Lilly pipeline. This pipeline transports methane-rich gas from Secunda in Mpumalanga via Richards Bay to Durban. An additional gas source is proposed via a LNG terminal in the Port of Richards Bay and this could also feed imported gas into the Lilly pipeline network. In addition there could be a new gas network supplying alternative gas markets.

Potential gas markets in KwaZulu-Natal include a proposed IPP CCGT power station, Avon OCGT power station (currently under construction), new customers in the Richards Bay IDZ and existing and new markets in KZN. Inland gas demand could potentially rise to the extent that the gas flow in the Lilly pipeline is reversed and gas is sent from the Richards Bay inland. A potential pipeline network and customers for the KwaZulu-Natal region is shown in Figure 39.
Figure 39: KwaZulu-Natal Potential Pipeline Network

Based on the above developments indicative future gas demand for the KwaZulu-Natal is estimated to be 2.8 mtpa. The makeup of this demand is shown in Figure 40.

KwaZulu Natal Indicative Gas Demand (mtpa)
Total Gas Demand = 2.8 mtpa LNG = 148 MGJ/yr

![Pie chart showing gas demand split]

- Avon OCGT (670 MW)
- Richards Bay IDZ new industry
- New CCGT (1 000 MW)
- Lilly Line (Current customers)

Figure 40: Potential Medium-term Gas Demand for the KwaZulu-Natal
Opportunity and challenges of the potential LNG terminals in Richards Bay include:

<table>
<thead>
<tr>
<th>Option 1: Dig-Out Basin</th>
<th>Option 2: FSRU in the Port</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Opportunities</strong></td>
<td><strong>Opportunities</strong></td>
</tr>
<tr>
<td>• Dedicated LNG basin;</td>
<td>• Dedicated LNG basin;</td>
</tr>
<tr>
<td>• Terminal remote from other port operations;</td>
<td>• Terminal remote from other port operations; and</td>
</tr>
<tr>
<td>• Sufficient suitable lease area available in close proximity; and</td>
<td>• Lower capital costs and quicker to build.</td>
</tr>
<tr>
<td>• A FSRU can be used in the first phase of development and then construction of a land based terminal can take place at a later stage.</td>
<td></td>
</tr>
<tr>
<td><strong>Challenges</strong></td>
<td><strong>Challenges</strong></td>
</tr>
<tr>
<td>• Potential for minor maintenance dredging; and</td>
<td>• Long subsea pipeline to shore.</td>
</tr>
<tr>
<td>• Obtaining environmental approvals for the dig-out of a wetland area.</td>
<td></td>
</tr>
</tbody>
</table>
A high level capital cost estimate and typical project engineering and construction durations are shown in Table 5. Costs exclude escalation.

<table>
<thead>
<tr>
<th>KwaZulu-Natal Region</th>
<th>Typical Design and Construction Duration (Years)</th>
<th>Option 1 Conventional Terminal (R mil)</th>
<th>Option 2 FSRU Terminal (R mil)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Port Marine infrastructure for LNG Terminal</td>
<td>3-4</td>
<td>1 500</td>
<td>1 500</td>
</tr>
<tr>
<td>FSRU purchase and mobilisation</td>
<td>1-2</td>
<td></td>
<td>3 800</td>
</tr>
<tr>
<td>Landside storage and regas</td>
<td>7</td>
<td>8 100</td>
<td></td>
</tr>
<tr>
<td>Gas compressor</td>
<td>5</td>
<td>2 200</td>
<td>2 200</td>
</tr>
<tr>
<td>Pipeline to Richards Bay (1.6-inch)</td>
<td>1</td>
<td>70</td>
<td>70</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>5-7</strong></td>
<td><strong>11 870</strong></td>
<td><strong>7 570</strong></td>
</tr>
</tbody>
</table>

Table 5: Estimated CAPEX for a KwaZulu-Natal Terminal and Primary Distribution Pipelines

**4.4 POTENTIAL LONG-TERM GAS INFRASTRUCTURE DEVELOPMENT IN SOUTH AFRICA**

If significant gas resources are discovered both onshore (Karoo shale gas and Coal Bed Methane) or offshore, a national pipeline network would be required to distribute the gas. This could also include piped gas from Mozambique’s potential Palma gas fields. This pipeline network would most likely also incorporate the import of LNG via the port system.

The availability of local gas will stimulate the growth of new industries with new logistics corridors developed. An indicative total gas demand in a potential long-term scenario is estimated to be in the order of 35mtpa or 1 800 MGJ per annum. The potential supply areas and gas infrastructure associated with this long-term scenario are illustrated in Figure 42.