# The socio-economic impact of importing LNG into the West Coast of the Western Cape

## Report prepared for the Western Cape Department of Economic Development and Tourism

**Final report**
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# List of abbreviations

| Acronym | Definition |
|---|---|
| **BCIPPPP** | Baseload Coal Independent Power Producer Procurement Programme |
| **CCGT** | Combined Cycle Gas Turbine |
| **CNG** | Compressed Natural Gas |
| **CSP** | Concentrated Solar Power |
| **DoE** | Department of Energy |
| **GIP** | Gas Infrastructure Development Plan |
| **IEP** | Integrated Energy Plan |
| **IPP** | Independent Power Producer |
| **IRP** | Integrated Resource Plan |
| **LCOE** | Levelised Cost of Electricity |
| **LNG** | Liquefied Natural Gas |
| **MW** | Mega Watt |
| **NDP** | National Development Plan |
| **NIP** | National Infrastructure Plan |
| **OCGT** | Open Cycle Gas Turbine |
| **REIPPPP** | Renewable Energy Independent Power Producers Procurement Programme |
| **PV** | Photovoltaic |
| **WCG** | Western Cape Government |

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# 1. Executive summary

## 1.1. Introduction

South Africa is in the midst of a serious power crisis with few immediate solutions at hand. Coal and nuclear power stations are 'lumpy investments' that have long construction lead times and renewable energy plant cannot contribute significantly to base load power generation due to its variable power generation profile. The additional coal-fire capacity that is to be commissioned gradually over the next few years may ease system pressure, but will not solve the electricity crisis – it will provide the 'space' to clear the maintenance backlog and decommission some inefficient plant.

In March 2014 Eskom, the national power utility, was forced to implement the first substantial power cuts since 2008 and load shedding began again in earnest in December 2014. Eskom has warned that the power system is severely constrained and load shedding is likely to continue for the next 18 months. In our view, the Southern African energy landscape will continue to be characterised by constrained supply for the next decade.

Inadequate power supply is posing a serious constraint to the economic growth in South Africa. The negative impact of outages on the economy is almost immediate - in 2008, Deloitte estimated that load shedding (which took place for several months) shaved 0.5 percentage points off GDP growth costing the economy R11.3bn[1]. The more insidious impact on GDP (and probably the largest) is the extent to which the general shortage of power is deterring new investment. The amount of investment that South Africa could lose to other destinations due to a lack of adequate reliable power is difficult to estimate.

In a bid to avoid power outages, Eskom has been operating its costly diesel-fired Open Cycle Gas Turbines (OCGT) at significantly higher than intended loads. Eskom ran these plants at a load factor of 19.3% in 2013/14 which is well above the 5% - 10% for which they were designed. The diesel fuel bill alone for the two OCGT plants in the Western Cape was R10.5bn in 2013/14. In December 2014, Eskom noted that it was operating its OCGTs at a load factor of close to 60% and was spending R2bn a month on diesel as a result[2]. This is not only contributing to Eskom's financial woes but also rising electricity costs, and is not a sustainable solution to the power crisis.

It is within this context that the Western Cape Government (WCG) is currently exploring the potential to import liquefied natural gas (LNG) into the province via the West Coast. The WCG believes that LNG imports can provide the province with an alternative source of energy and contribute to alleviating the prevailing power constraints in South Africa within the next 3 to 5 years. A bulk investment of this nature with power generation as the anchor tenant will result in the establishment of a natural gas industry, the potential economic impacts of which are explored in this document.

The introduction of natural gas to the West Coast is in keeping with the WCG's key strategic objective which is to enable economic growth that is 'green and smart' - to realise the double social dividend of

[1] Deloitte (2008) The Economic Impact of the National Recovery Plan Key issues and choices. Report commissioned by Eskom Holdings Ltd.

[2] Business Report, "Eskom in scramble to secure funding" http://www.iol.co.za/business/news/eskom-in-scramble-to-secure-funding-1.1791044#.VlbgJXgaKwk. 5 December 2014.

unlocking opportunities for economic growth and employment while enhancing the province's environmental performance.[3]

## 1.2. The LNG opportunity – power generation and beyond

In 2013, the WCG conducted a prefeasibility study to provide a preliminary assessment of the financial viability of importing natural gas into the Western Cape with a specific focus on the Saldanha Bay – Cape Town corridor along the West Coast. The study considered the potential market for imported natural gas for four categories of end-user – power generators, industrial consumers, transport and residential applications.

The study found that it would be financially feasible to establish a LNG import facility on the West Coast, if the existing diesel-fired Ankerlig OCGT plant was converted to a larger gas-fired Combined Cycle Gas Turbine (CCGT) plant and\or similar new CCGT plant was constructed and could act as the anchor off taker[4]. The study also noted that once an import terminal and anchor gas customer was in place, there would be potential to extend the gas distribution network to serve energy users in some of the key industrial nodes in the Cape Town and West Coast municipalities. The network could then potentially be extended further to provide gas as an alternative energy source to households and in transport applications, although further studies are required to understand the market potential for these customer segments.

The study also noted that South Africa was well placed to take advantage of new regional LNG supply opportunities, with additional natural gas liquefaction capacity set to come online in Angola, Nigeria and Mozambique, and potentially Tanzania.

## 1.3. Purpose of this report

The WCG subsequently commissioned Deloitte to undertake a study to assess the broader socio-economic impacts that could be associated with imports of LNG into the Western Cape if specific end-user scenarios, largely informed by the prefeasibility study, materialise.

*The main objectives of this report are:*

- To conduct a brief review of the provincial and national policy, plans and strategies that are key to the development of the gas and cleaner energy sector; and discuss how LNG imports into the Western Cape can support national government in achieving their policy objectives with respect to gas, economic development and the development of the cleaner energy sector.
- To provide an overview of key trends and developments in the local, regional and international Gas Market.
- To identify, research and discuss the main socio-economic impacts of introducing a new energy source to the Cape West Coast region in terms of the four distinct categories of end-user noted in the prefeasibility - power generation, industry, transport and households.

[3] Western Cape Government (2013) Green is Smart - Western Cape Green Economy Strategy Framework.4 July 2013.
[4] Visagie, H.J., (2013) Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor. Energy Business.

- To estimate and compare the economic impacts of the investment associated with LNG imports and distribution under the identified scenarios to illustrate the potential impact on:
  - Employment
  - Gross Domestic Product (GDP)
  - Investment levels
  - Tax revenues, and
  - Balance of payments

### 1.4. Structure of the report

*This report is structured around six sections:*

1. **Executive summary** - provides an introduction to the project, outlines the main objectives of the study, structure of the report, the study approach and summarises the key findings for each of the subsequent sections.
2. **Review of policies and plans** - provides a brief review of provincial and national policy, plans and strategies that are central to the development of the gas and cleaner energy sector and summarises key themes that emerge.
3. **Overview of the natural gas market and implications for LNG prices** - provides an overview of key trends and developments in the local, regional and international gas market and implications for future LNG prices and pricing methodologies.
4. **The LNG value-chain and its potential end-uses** - provides a simple illustration of the LNG value-chain from exploration to distribution.
5. **The socio-economic impact of LNG in the Western Cape for various end-user scenarios** - provides a detailed description of the four end-user scenarios and considers the factors that would determine whether these end-users would switch to gas from their current fuel and energy sources; and provides a qualitative assessment of the socio-economic benefits and costs associated with fuel switching under stated assumptions.
6. Macroeconomic impacts associated with LNG import infrastructure - provides estimates of the economic impact of infrastructure spend that would be associated with importing, distributing and consuming natural gas under the scenarios already defined. The economic impact is assessed in terms of the contribution of increased spending to GDP, employment and government revenue and the impact on the trade balance.

### 1.5. Approach and appraisal methods used

The starting point in this study was to understand the potential market for imported natural gas and to define four distinct end-user scenarios based on the recommendations of the prefeasibility report and in the case of households and transport on some additional market research.

*The four end-user categories considered were:*

- **Gas-to-power** - imported natural gas as an alternative fuel for electricity generation.
- **Gas-to-industries** - imported natural gas as an alternative energy source for large industrial consumers.
- **Gas-to-transport** - imported natural gas as an alternative fuel in transport.
- **Gas-to-households** - imported natural gas as an alternative energy source for households.

For each of the potential users of imported natural gas, we defined the likely market uptake based on specific applications – be it the construction of a gas-fired power plant or the conversion of a government vehicle fleet to run on natural gas. We then estimated the associated infrastructure costs relying largely on estimates presented in the prefeasibility report.

*Our appraisal of the socio-economic impacts associated with each of these end-user scenarios was then based on two main types of economic analysis:*

- A qualitative assessment of the socio-economic impacts that would be associated **with the use of imported natural gas** by each type of end-user. The results of this analysis are presented in section 5 and include potential environmental impacts like a reduction in CO2 emissions, financial impacts such as fuel cost savings realised in switching to gas and technical benefits like project risk and ease of financing. Where possible we quantified the benefits and costs associated with the potential impacts identified, and where this was not possible we referred to appropriate case studies.

- A quantitative assessment of **the macro-economic impacts associated with infrastructure investment** required to import, distribute and consume imported natural gas to our four end-users in aggregate. To estimate the macroeconomic impact of infrastructure and operations expenditure associated with the import and distribution of LNG we used a modified 42-sector Western Cape social accounting matrix (SAM) developed and published by Quantec Research. A SAM is a static economic model that simulates the interaction between all the different sectors and factors of production in an economy. It allows one to estimate the impact of an exogenous spending shock like an increase in the demand for a particular sector's output on macroeconomic parameters like GDP, employment, government revenue and the trade balance. It provides an indication of the upstream and downstream industries that will benefit from spending associated with LNG imports and how much of the expenditure would be retained in the local economy. Our overview of the natural gas market and implications for LNG prices is based on a desktop review and analysis of recent LNG market data and research with some input from Deloitte Global Oil and Gas expertise housed in our US based research group Marketpoint. A desktop review of national policy, plans and strategies that inform the development of the gas and cleaner energy sector was also performed.

### 1.5.1. Key Information sources and assumptions

Key information sources for the assessment are summarised in Table 1.

**Table 1: Key information sources**

| Source | Description of information |
|---|---|
| **Western Cape Government (2013) Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor, J. H. Visagie** | • Market size and specific application for each end-user scenario<br>• Infrastructure and operating cost estimates for each scenario |
| **Personal communication with Johan Visagie of Energy Business and Jim Petrie and Fernal Abrahams of WCG** | • Updated information on market size and specific applications<br>• Input on additional infrastructure and operating costs<br>• Input on fuel costs and cost of power generation |
| **EasyGIS, GIS Specialists** | • Spatially referenced data and analysis for the gas-to-transport scenario |
| **Representatives of NGV Gas, the WCG and the City of Cape Town (CoCT)** | • Input on infrastructure costs and fleet sizes for the gas-to-transport scenario |

| | |
|---|---|
| **Interviews with four large industrial users based in the Saldanha Bay Area** | • Information on factors affecting fuel-switching for industrial users and the likely downstream impact of imported natural gas on industry. |

The data assumptions maintained throughout the report are summarised in Table 2.

**Table 2: Key assumptions**

| Description | Assumption |
|---|---|
| **R/$ exchange rate** | R10.50/$ rounded down from average August 2014 exchange rate of R10.66/$ |
| **Landed price of LNG** | Assume a landed LNG price of $10/MMBtu as a lower bound and $15/MMbtu as the upperbound |
| **Fuel prices** | All fuel prices used for fuel cost comparisons were based on prevailing rates in August 2014 |

## 1.6. Key Findings

In this section we have summarised the findings of this report. All data and assumptions and supporting research and calculations can be found in the body of this report.

### 1.6.1. There is a strong economic case for the use of imported natural gas in power generation on the West Coast

In the context of the power situation highlighted above, imports of LNG to the West Coast of South Africa could make a contribution to alleviating power shortages (utilising plant capable of operating at higher loads than the current OCGTs) and reducing the cost of power generation in South Africa and particularly the Western Cape within 3 to 5 years (a period in which there are few alternatives).

The scenario considered for the use of imported gas in power generation was that Ankerlig, a 1350MW diesel-fired OCGT peaking plant would be converted to a gas-fired 2070MW CCGT plant and would run in mid-merit capacity (47% load factor) and an additional 800MW CCGT gas-fired power plant would be built in Saldanha or Cape Town.

The capital cost associated with this power generation infrastructure is estimated at R14.2bn while the LNG import terminal and associated transmission pipelines would cost an additional R2.8bn to R5.2bn depending on the choice of terminal.

An analysis of levelised cost of energy[5] (LCOE) for different types of power generation suggests that the levelised cost of producing electricity using an imported-gas-fired CCGT[6] (at R1.10/kWh) is 35% of the cost of producing electricity with diesel at Ankerlig[7] (R3.13/kWh). While the LCOE for imported-gas-fired CCGT's on the West Coast (at R1.10/kWh) may be higher than the LCOE for coal-fired plant in South Africa (which according to EPRI estimates ranges from R0.58/kWh to R1.30/kWh) [8] it is comparable to the LCOE of Eskom's new coal-plant - Medupi is expected to produce electricity at a LCOE of R1.05/kWh[9]. The cost of electricity from imported gas-fired CCGT plants also compares

[5] The LCOE includes all the major costs associated with a power plant, including the initial investment, operations and maintenance, cost of fuel and the cost of capital.

[6] Assuming LNG landed at $10/MMBtu and 2070MW CCGT running at 45% load factor.

[7] Diesel prices as at August 2014 and 1350MW Ankerlig running at a load factor of 20%.

[8] Based on estimates from Electric Power Research Institute (2012) *Power Generation Technology Data for Integrated Resource Plan of South Africa.* [Online] Available at: http://www.doe-irp.co.za/content/EpriEskom_2012July24_Rev5.pdf. [Accessed 14 October].

[9] Gosling, M. (2013) *More wind in power industry sails.* Business Report. 1 November 2013. [Online] *Available at:* http://www.iol.co.za/business/companies/more-wind-in-power-industry-sails-1.1600609#.VEOcI3gaIX4 [Accessed 12 October 2014]

favourably with the cost of producing electricity from renewable sources such as wind, CSP and solar PV[10]. The estimated LCOE for nuclear plant at R0.90/kWh is similar to imported gas-fired CCGT but the LCOE does not reflect the substantially higher construction, financial or operational risks associated with nuclear nor the significantly higher environmental costs. Our analysis suggests that imported-gas fired CCGT plants are a cost-competitive alternative to many alternative forms of power generation including diesel-fired OCGT, renewable energy plant and potentially even coal, lending further support to the GTP scenario informed by the prefeasibility study.

Furthermore our review of the broader economic impact of the GTP scenario proposed, suggests that the infrastructure cost while substantial, would be outweighed by the following economic benefits:

- **Cost savings in electricity generation** - we have estimated that Eskom could realise a substantial R5bn per annum in electricity generation cost savings if it converts Ankerlig from a diesel-fired OCGT to an imported gas-fired CCGT[11].

- **LNG imports can enable private sector investment in power generation, reducing pressure on the fiscus** - gas-fired CCGTs have some key technical advantages over other forms of generation. Gas-fired CCGT plants are relatively small modular plants that typically take between 24 and 36 months to deploy. Large lumpy power investments like nuclear power plants and mega-coal plants by contrast can take more than 10 years to build and are associated with significantly higher financial, operational and construction risk. Nuclear plants and megacoal projects by are seldom financed without some government support - be it direct support in the form of debt or equity, or indirectly through the provision of financial guarantees. Imports of LNG could therefore contribute to increasing private sector participation and investment in electricity generation in South Africa thereby reducing the burden on the fiscus.

- **LNG imports could help to alleviate electricity supply constraints and unlock potential economic growth** - The availability of imported LNG on the West Coast could make a contribution to alleviating South Africa's power shortage within the next 3 to 5 years – a period in which there are few alternatives. Ghana[12] and India[13] are example of countries that have used LNG imports to address short-to-medium term energy shortages and unlock economic potential. Imports of LNG into the West Coast of South Africa would under our GTP scenario increase South Africa's total national power output by approximately 5%, which would contribute to alleviating the power constraints that we believe will persist for the next decade.

- **Reduction in Greenhouse Gas (GHG) emissions** - the conversion of Ankerlig to a CCGT and construction of a new 800MW CCGT under the GTP scenario would provide an additional 9500GWh of electricity output annually in the Western Cape[14]. Assuming that the additional 9500GWh of gas-fired electricity output would reduce the requirement to import coal-fired electricity from Mpumalanga by the same amount each year, approximately 3.8 million tons of $CO_2$ emissions would be saved annually. This would reduce total provincial GHG emissions by approximately 9%.

[10] Based on estimates from Electric Power Research Institute (2012) Power Generation Technology Data for Integrated Resource Plan of South Africa. [Online] Available at: http://www.doe-irp.co.za/content/EpriEskom_2012July24_Rev5.pdf. [Accessed 14 October].

[11] We have estimated that if Eskom continued to run Ankerlig at a load factor of 20% (which is conservative relative to the 60% LF reported recently), costs to generate the same power output (roughly 2400GWh) by switching from diesel to imported natural gas

[12] "Quantum, Golar sign deal for Ghana LNG Terminal", Africa Reuters, www.af.reuters.com, Accessed 14 October 2014. "Ghana: Works on gas plant almost done. Jubilee gas to flow in 3Q," Offshore Energy Today, www.offshoreenergytoday.com, [Accessed 14 October 2014]

[13] International Energy Agency (2014) *Energy Supply Security in India* [Online] Available at: http://www.iea.org/media/freepublications/security/EnergySupplySecurity2014_India.pdf. Accessed [16 October]

[14] In addition to the 2400GWh produced by Ankerlig OCGT in 2013/14

- **Reduction in water usage** - of all the forms of power generation, natural gas-fired CCGT has some of the lowest consumption of water per unit of electricity generated, in part because of their relatively high thermal efficiency[15]

- **Supports the expansion of renewable energy - gas enables renewables to make a larger contribution to the power generation mix** - the combined renewable energy capacity in Eskom's 'Western Region' when projects from the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) bid windows 1 to 3 are commissioned, will be a substantial 2492MW. The availability of fast-ramping gas-fired CCGT plants in the Western Cape region could greatly enhance the grid stability in Eskom's Western Region (Western and Northern Cape).

- **Improve security of electricity supply in the Western Cape and reduce transmission losses** - together with 2492MW of planned renewable energy capacity an additional 2870MW of gas-fired CCGT plant would significantly reduce the current requirement to import around 2050MW of capacity from Mpumalanga at peak times. Estimated transmission losses of around 200MW could also be saved, potentially releasing over 2200MW of coal-fired power capacity for use inland.

*In our view the benefits associated with the gas-to-power scenario outweigh the associated costs. In addition to the capital cost associated with new power generation infrastructure, economic costs associated with the GTP scenario include the negative impact of fuel imports on the trade balance and increased reliance on imported fuel:*

- **Impact of LNG imports on the trade balance** - we estimated that the total fuel imports associated with the two CCGT plants in our GTP scenario would amount to approximately R9.2bn annually. However, assuming that Eskom would have continued to operate Ankerlig at 20% load factor if it was not converted to a larger gas-fired CCGT under the GTP scenario, LNG imports of R9.2bn replace R6.3bn of diesel imports[16] so that the net impact on the trade deficit is an increase of R2.9bn. An additional R2.9bn of fuel imports would increase South Africa's annual trade deficit, which stood at R73bn in 2013 by roughly 4%.

- **Security of supply -** importing LNG as a fuel source for power generation increases South Africa's reliance on imported fuel for electricity generation (an additional 5% of total output would be generated using imported fuels).

### 1.6.2. Once anchor gas-to-power customers are in place – infrastructure can be extended to serve industries

The prefeasibility study[17] suggests that since the infrastructure costs associated with a LNG import terminal and associated transmission infrastructure could be covered by a gas-fired CCGT plant, it would be financially feasible to extend the gas distribution network to some of the key industrial nodes once this 'anchor customer' is in place. According to prefeasibility estimates, approximately13km of gas distribution pipeline would be required to reach customers in Saldanha and 105km to reach customers in the City of Cape Town. We have assumed that all major industrial nodes in these two district municipalities would be connected at an estimated cost of R0.9bn.

[15] Harvard Kennedy School, 2010, "Water Consumption of Energy Resource Extraction, Processing, and Conversion."

[16] This is an approximate estimate and might overstate impact of diesel used at Ankerlig on the trade balance. We note that not all diesel used at Ankerlig is directly imported but source domestically from local refineries where domestic value-add is created in the refining of imported crude oil to diesel.

[17] Western Cape Government (2013) Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor, J. H. Visagie

An analysis of the relative cost of fuels[18] used in industrial processes suggests that LNG is likely to be a lower-cost alternative to diesel, LPG and heavy fuel oil (HFO). Landed at $10/MMBtu LNG is roughly 50% of the basic cost of LPG and diesel (per gigajoule) and 70% of the cost of HFO.

It will however be difficult to persuade coal users to make the switch on the basis of relative cost alone as coal at approximately R60/GJ is the lowest cost industrial fuel available in the Western Cape and is likely to be 60% of the anticipated cost of LNG. Relative cost however is not the only consideration in fuel-switching. The applications where industrial and commercial users could be persuaded to switch from coal to gas include where air quality and reliability of supply are key considerations or where the use of gas enables significant process efficiencies.

On average combustion of natural gas releases approximately 50% less carbon dioxide ($CO_2$) than coal and 33% less $CO_2$ than oil for every unit of useful energy.[19] It is also practically free from sulphur dioxide and carbon monoxide emissions in combustion.[20] As a result gas provides an attractive alternative to coal for industrial consumers in areas where stricter air quality controls are in place. Gas could also provide an attractive alternative to coal, LPG and electricity where reliability of supply is a key consideration as coal and LPG deliveries are vulnerable to supply and logistics bottlenecks and electricity supply has become increasingly constrained. The quick burning nature of natural gas and relatively low emissions mean that it is also preferred to coal, diesel and other fossil fuels in certain industrial applications.

As the LNG market in the Western Cape matures and gas volumes increase, economies of scale in the use of import, transmission and distribution of imported gas can also be realised which lower the cost and improve the likelihood of fuel switching.

*The potential economic benefits that are likely to be associated with the supply of imported natural gas if the 'gas-to-industries' scenario outlined materialises are threefold:*

- **Fuel cost savings** - assuming that all 3 million GJ of 'technically substitutable' HFO, diesel and LPG currently used by industrial consumers in the Western Cape is replaced with LNG, landed at $10/MMbtu, large industrial users could save R465 million annually on their current fuel bill. Reinvestment of this saving in the manufacturing industry would create an estimated 2074 additional jobs, 1631 of which would be located in the Western Cape, and lead to a R532 million increase in GDP.

- **Availability of a viable alternative fuel source can serve as a draw card for industrial investment given the current electricity supply constraints** - in Malaysia, it was estimated that a shortage of gas had deterred 270 mmscfd[21] of 'latent demand for premium gas' and that unlocking this demand by importing LNG would have an estimated impact on Gross National Income (GNI) of RM10.6bn (approximately R34bn) and would create 27,000 new jobs by 2020. The availability of 'premium natural gas' in the South African context could have a similar impact, unlocking the 'latent demand' for industrial investment.

- **Reduced industrial GHG emissions** - because GHG emissions from natural gas are significantly lower than alternative fossils fuels, if the 3 million GJ of HFO, Diesel and LPG consumed by firms

[18] Based on basic prices rather than delivered cost

[19] Centre for Climate and Energy Solutions. (2013)*Leveraging natural gas to reduce greenhouse gas emissions, June 2013 [online].* Available from http://www.c2es.org/publications/leveraging-natural-gas-reduce-greenhouse-gas-emissions. [Accessed: 9 October 2014]

[20] Sarkar, S.C. (2005) LNG as an energy efficient eco-friendly cryogenic fuel. Journal of Energy in Southern Africa [Online]. Vol 16 No 4 (November 2005). Available from http://www.erc.uct.ac.za/jesa/volume16/16-4jesa-sarkar.pdf. [Accessed: 9 October 2014].

[21] Million standard cubic feet per day

in the West Coast district and CoCT annually was replaced with imported natural gas, roughly 139 000 tons of $CO_2$ equivalent emissions could be saved annually.

Overall our analysis suggests that if the anticipated demand for imported natural gas materialises at expected prices, the economic benefits of extended gas infrastructure to industrial nodes in the West Coast and Cape Town district municipalities should exceed the associated costs.

### 1.6.3. The broader opportunity - gas-to-transport and households

The cost of distributing imported natural gas to residential users and transport users is high relative to the lower average volumes that these users consume. However, once the basic gas import, transmission and distribution infrastructure is in place (and largely paid for) for power and industrial users it may be financially feasible to incrementally connect users in areas that are close to existing pipelines. The gas-to-transport opportunity mentioned in the prefeasibility study was limited to the conversion of a public bus fleet with assumed annual gas consumption of 900 000GJ while for households it was assumed there would be a potential market for at least ~300 000GJ per annum.

Since the prefeasibility study was published, interest in the use of natural gas in transport in South Africa has increased and broader opportunities for the household sector are also emerging. As a result we considered the socio-economic impacts that would be associated with somewhat expanded gas-to-transport and gas-to-household scenarios. It is important to note that the financial viability of the gas-to-transport and households scenarios we have outlined has not yet been tested, but this does not preclude high-level analysis of the potential economic costs and benefits.

The scenario we considered for households was that infrastructure for industrial users could be leveraged to provide natural gas to relatively dense middle-income housing developments in the Blaauwberg- Atlantis corridor and Kraaifontein-Klipheuwel corridor in the CoCT. According to city planners, these are identified ‘future urban growth corridors’ that could accommodate 430 000 new housing opportunities over the next 30 years (roughly half the anticipated need). Both these corridors are adjacent to key industrial nodes and for the purposes of considering the potential economic impact we considered a scenario where an additional 200km of distribution pipelines, at the total cost of R1.5bn would be installed to connect some of the new housing developments in these corridors[22].

Factors that affect household choice of energy source include availability, cost of energy and cost of energy devices. In the Western Cape, where 90% of households have access to electricity and electricity meets 87% of household energy needs, availability of gas and its price relative to electricity are likely to be key considerations.

Since comparable domestic estimates of the cost of distributing LNG to households were not readily available we assumed that the costs associated with the transmission and distribution of imported LNG to households would be roughly equal to the landed price[23]. At double its anticipated landed price ($10 to $15/MMBtu) which is between R199 and R299 per GJ, imported natural gas represents a very cost-effective alternative to the dominant sources of energy in households – electricity and LPG. Households could expect to save up to 50% of their energy bill in switching to LNG.

[22] Note that further market analysis on the household market, which was beyond the scope of this report, would be required to establish whether it would indeed be a financially feasible to install this quantity of pipeline.

[23] This assumption is based on the fact that the cost of electricity distributed to residential consumers by the City of Cape Town at between R1.54/kWh and R1.87/kWh is just more than double the wholesale price of electricity at R0.68/kWh (Eskom average tariff in 2014). The US energy information administration also noted that transmission and distribution costs represented about half of a typical residential natural gas customer’s monthly gas utility bill, while the cost of the physical natural gas commodity represented the other half.

On this basis the key socio-economic benefits associated with the use of imported natural gas in our gas-to-household scenario would be a reduction in household energy costs, total household energy consumption and the GHG emissions associated with household fuels.

Of the energy available at source, 92% will reach the consumer in the case of domestic extraction of gas and only 32% of the original fuel source energy will reach the household in the case of electricity. If one considers the full-fuel cycle as described above a household that uses gas directly in appliances for things like heating, cooling, water heating and cooking will use 28% less energy than a similar home with all electric appliances and will produce 37% lower GHG emissions.

For gas-to-transport we considered a scenario where a large proportion of the public bus fleet in the CoCT would be converted to run on imported natural gas in addition to conventional fuel (including the MyCiTi bus fleet, 50% of the Golden Arrow and Sibanya buses). The scenario also included the conversion of vehicles in the government-owned CoCT fleet and 50% of the vehicles in the Western Cape Government (WCG) to bi-fuel engines that use Compressed Natural Gas (CNG) in conjunction with conventional fuel. We estimated that the infrastructure required to support this scenario would cost R1.7bn including the costs of converting engines, bus depots, fuel stations and building roughly 230 kilometres of gas distribution pipeline.

Relative price and availability are like to be the most important factors to consider in making a switch to CNG from traditional fuels - petrol and diesel. Vehicles currently using CNG in Gauteng realise fuel cost savings – the price of CNG at the pump at Langlaagte in Gauteng is R8.73/l which in September 2014 was roughly R5/l (55%) cheaper than petrol and R4/l (45%) cheaper than diesel[24] . Furthermore a study by the Industrial Development Corporation of South Africa and Cape Advanced Engineering (Pty) Ltd[25] based on a real world vehicle fleet trial in 2012/2013 in Gauteng, suggested that mini-buses and commuter taxis converted to bi-fuel and dual-fuel engines were able to realise fuel cost savings of around 20% when using CNG in combination with regular fuels as compared to normal petrol or diesel only operation[26]. The study concluded it would be financially feasible to convert vehicles to duel/bi-fuel operation provided CNG could be obtained at a discount of at least 15% of the existing retail price of diesel on an energy equivalent basis.

In the absence of a feasibility study it was not possible to estimate the cost of supplying CNG to the CoCT or the potential fuel cost savings. The cost of supplying CNG to the transport sector in the Western Cape however, is likely to be higher than in Gauteng (given that Sasol sources piped gas from Mozambique for Gauteng at low cost relative to anticipated LNG prices) so we would not expect savings to be as significant.

Aside from potential fuel-cost savings the other economic benefits that are associated with the gas-to-transport scenario include greater diversity in the transport fuel mix and a reduction in air and noise pollution. A 25% reduction in $CO_2$ equivalent emissions can be expected on a wheel-to-wheel basis when replacing petrol and diesel with CNG in light duty vehicles, and a reduction in noise pollution can be significant for heavy duty vehicles run on CNG[27]. With the transport sector estimated to account for just over 50% of total energy consumption in the province, replacing diesel with CNG in the 9350 government vehicles, which is approximately 10% of the total passenger vehicle fleet in the province,

[24] based on September 2014 prices.

[25] Industrial Development Corporation and Cape Advanced Engineering (2013) Investigation into the use of clean burning methane in the form of compressed natural gas (CNG) and compressed bio-gas (CBG) in public transport in South Africa, implemented a real world vehicle fleet trial in 2012/2013, to assess the feasibility of using CNG and compressed biogas (CBG) in minibus taxis and commuters buses

[26] assuming CNG at a cost of approximately R8/l diesel equivalent

[27] International Energy Agency (2010) *The contribution of natural gas vehicles to sustainable transport*. [Online] Available at: http://www.iea.org/publications

would make a significant contribution to diversifying the fuel mix and reducing GHG emissions associated with transport.

### 1.6.4. Overall cost and macroeconomic benefits

#### 1.6.4.1. Construction phase

- The total cost of rolling out infrastructure to support all the end-user scenarios described above is R21.7bn. This includes the conversion of the Ankerlig power station to a CCGT and the construction of a new 800MW CCGT plant which together are estimated to cost R14.2bn[28].
- About 80% of total infrastructure spend will be spent in the South African economy (R18.2bn) while the remainder leak out of the economy as direct imports.
- With most of the spending assumed to take place in the Western Cape, the provincial economy will grow at an additional 0.7% per year over the 5 year construction period. As a result the Western Cape's gross geographic product (GGP) will increase by R15.6 bn.
- The increase in local spending on LNG infrastructure will add 0.1 percentage points to national GDP growth, every year for 5 years and GDP is expected to increase by a total of R21.5bn.
- 84 000 jobs (Full Time Equivalent for 12 months) will be created during the construction phase and roughly 80% will be retained in the Western Cape (67 400).
- An estimated R4.1bn of additional tax revenue will be generated representing an increase in total government revenue of 0.41%.
- Total imports during the construction phase are estimated to be R10.5bn (over the 5 year period) which constitutes an increase in South Africa's estimated cumulative trade deficit of 2.2% (2013).

#### 1.6.4.2. Operations and Maintenance Phase

- During the operating and maintenance phase, depending on the scenario, an estimated additional R0.74bn in GDP will be created for the economy each year. This will add an additional 0.11% to Western Cape GGP every year.
- An additional 2300 jobs will be created and sustained during operations, 1600 of these will be in the Western Cape.
- A total of R9.2bn of LNG would be imported annually in the gas-to-power scenario but this would be partly offset by the estimated R6.3bn reduction in diesel imports currently used in power generation so that the annual trade deficit, which stood at R73bn in 2013 would increase by roughly 4 %).
- Government revenue from taxes is expected to increase by roughly R100 million.

### 1.6.5. It's the right time for a LNG investment in the Western Cape

If the Western Cape can begin importing LNG within the next 2 to 5 years it will be well positioned to take advantage of global gas market dynamics that are becoming increasingly favourable for LNG importers. It is also an opportune time from the perspective that imported-gas fired CCGT plants are one of the few power generation options that could make a significant contribution to alleviating the severe power shortages South Africa faces within the next 3 to 5 years. While arguments to support the latter point have already been discussed we provide an overview of recent global gas market dynamics below.

Between 2005 and 2010, the global market for LNG grew by more than 50 % and in 2013 LNG accounted for 10% of global gas supply and 31.5% of global trade[29].

[28] This assumes that the option of an offshore LNG import terminal is selected.

LNG spot prices for delivery into North Asia have fallen sharply from the high levels in the first two months of 2014 when prices hit a record of over $20/MMBtu, to $9.50/MMBtu in November 2014 due to weak demand from Japan and other major Asian consumers[30]. According to the Economic Intelligence Unit (EIU), the average price of LNG imported into Japan (which includes contracted long-term and spot prices) was $16.1/MMBtu in 2014 and this is expected to slide to $14.50/MMBtu by end-2016 as plentiful new supplies come into the market from Australia and Papua New Guinea and as Angola resumes exports. The EIU notes that because a number of contracts are still indexed to oil, the significantly lower oil price environment will also keep downward pressure on LNG prices.

According to the International Gas Union (IGU)[31], "the emergence of new areas with tremendous [LNG] supply potential has been one of the most striking changes in the LNG industry in the last 3 years." Exports from these areas which include the US Gulf Coast, Western Canada and East Africa and are expected to change LNG markets in a material way by offering new, globally distributed sources of supply and alternatives to traditional oil-linked contracts. According to the EIU these new sources of supply, are likely to add further downward momentum to LNG prices, from 2016 but particularly post 2019. The EIU expects the average price of LNG imported into Japan (the premium gas buyer) to fall to $12.50/MMBtu by 2019. The most notable risk to this outlook is a potential surge in demand from China. China has been taking an increasing share of total Asian LNG demand as Japan's imports have begun to wane with the gradual return of nuclear power. A surge in demand from China would halt the forecast decline in prices.

Overall the market outlook is positive for prospective LNG importers like South Africa, with demand and supply fundamentals pointing on balance to continued downward momentum in LNG prices, particularly beyond 2019. The discovery of prolific deepwater gas basins off the coast of Mozambique and Tanzania will also provide South Africa with new regional LNG supply opportunities (in addition to Angola and Nigeria). If a glut of global LNG supply does indeed materialise, South Africa will be in a strong position to negotiate LNG contracts with prices indexed to gas hub prices (such as Henry Hub or UK NBP) rather than oil - which in our view is an opportunity to take advantage of any continued divergence in natural gas and oil prices.

## 1.7. Concluding remarks

In this report we have assessed the broader socio-economic impacts that could be associated with imports of LNG into the Western Cape if specific end-user scenarios outlined materialise. In conclusion, we believe there is a strong economic case for investing in LNG import facilities in the Western Cape, founded primarily on the Gas-to-Power opportunity where the benefits are both tangible and sizeable. Whilst further feasibility studies may be required, we believe that should the anticipated demand for imported natural gas for industrial users materialise at expected prices, the economic benefits of the extended gas infrastructure to industrial nodes in the West Coast and Cape Town district municipalities should be sufficient to justify the costs. It is also important to note that in reality an incremental approach to connecting industrial, household and transportation nodes would be taken, and the industry will mature over time.

[29] IGU World LNG Report – 2014 and BP statistical review of world energy 2014

[30] EIU Global Forecasting Unit, LNG market update, November 2014

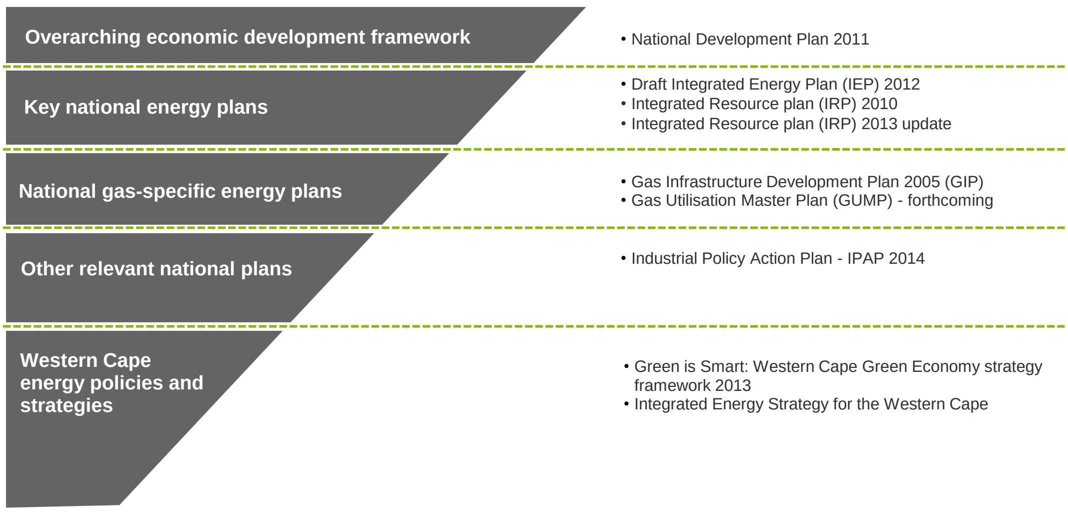
[31] IGU World LNG Report – 2014

# 2. Review of policies and plans to support the development of the gas sector in South Africa

## 2.1. Introduction

The development of a cleaner and more diverse energy sector in South Africa is currently high on the policy agenda of both national and provincial government. In this chapter, we provide a brief overview of policies, plans and strategies that support the development of cleaner energy, and natural gas in particular. The government policies and plans identified are summarised in Figure 1.

**Figure 1: Policies, plans and strategies for the development of gas and a cleaner energy sector**




*Source: Deloitte analysis*

At the most general level, The National Development Plan 2011 (NDP), adopted by government as the overarching long-term economic development framework, highlights several policy and planning priorities for the energy sector. The NDP considers the potential of gas as an alternative energy source to coal and nuclear and also outlines the potential role for imported liquefied natural gas (LNG).

The key long-term planning documents for the energy sector in South Africa are the Department of Energy's Integrated Energy Plan (IEP) and the Integrated Resource Plan for Electricity (IRP). Both explore the potential for gas under various energy and electricity planning scenarios. These plans are also informed by the national gas-specific energy plans – the Gas Infrastructure Development Plan (GIP), which was published in 2005 and the forthcoming Gas Utilisation Master Plan (GUMP), which is likely to be released before the end of 2014.

The Department of Trade and Industry's (dti's) most recent Industrial Policy Action Plan (IPAP 2014) also makes mention of the further exploration and development of potential domestic and regional gas resources. DTI is concerned primarily with the issue of developing local industry around these opportunities and building forward and backward linkages from the gas industry opportunities.

The Western Cape Green Economy Strategy Framework 2013 and the Integrated Energy Strategy for the Western Cape consider the potential of gas as an alternative fuel and energy source in the province.

Refer to Appendix A for a more detailed extraction of relevant information from each of these plans and policies.

## 2.2. Potential sources of natural gas considered

A number of potential sources of gas have been considered across the various government plans and policies. These include:

- Offshore domestic natural gas – the iBhubesi gas field off the West Coast
- Offshore Namibian gas fields – the Kudu gas field to be imported as electricity or pipeline
- Regional natural gas, imported through pipelines or as electricity – includes extensive proven natural gas reserves off the coast of northern Mozambique
- Coal-bed methane gas – potential being explored
- Shale gas in the Karoo basin – potential being explored
- Imports of liquefied natural gas (LNG)

In the last few years, the discovery of substantial new regional gas resources off Northern Mozambique and the emergence of unconventional gas in the form of shale gas has accelerated the consideration of introducing gas to South Africa's energy mix. As summarised in Figure 2, earlier plans such as the IRP 2010 and GIP 2005 only considered opportunities around the relatively small gas fields off the West Coast of South Africa and Namibia and imports of LNG, and touched on the possibility of coal-bed methane gas.

More recent documents (including the NDP, IRP 2010 update and IEP draft 2012) consider the opportunities around all six potential sources of gas identified. It is expected that GUMP, when released, will provide further insight into how these potential sources might be best prioritised and exploited. The Western Cape strategies focus on the short-to-medium term options for the province, which include LNG imports and the iBhubesi gas field.

**Figure 2: Potential sources of gas considered in plans and policies**

| | NDP | IEP draft 2012 | IRP 2010 | IRP 2013 update | GIP 2005 | IPAP 2014 | Green is Smarts | WCIES |
|---|---|---|---|---|---|---|---|---|
| **Offshore domestic natural gas** | ✓ | ✓ | | ✓ | ✓ | ✓ | ✓ | ✓ |
| **Offshore Namibian-import as electricity or piped gas** | ✓ | ✓ | ✓ | ✓ | ✓ | | | |
| **Regional gas more broadly (Mozambique and others)** | ✓ | ✓ | | ✓ | | | | |
| **Coal-bed methane gas** | ✓ | ✓ | ✓ | ✓ | ✓ | | | |
| **Shale gas in the Karoo basin** | ✓ | ✓ | | ✓ | | ✓ | | |
| **Imports of LNG** | ✓ | ✓ | ✓ | ✓ | ✓ | | ✓ | ✓ |

*Source: Deloitte analysis*

## 2.3. Key rationale for the development and introduction of natural gas

*The NDP highlights six policy and planning priorities for the energy sector. Four of the six relate to the increasing use of natural gas in the energy mix, suggesting that the development and use of natural gas is a strategic priority. The NDP notes that:*

- **Gas should be explored as an alternative to coal** for energy production.
- **There needs to be a greater mix of energy sources** and a greater diversity of independent power producers (IPPs) in the energy industry.
- Electricity pricing and access needs to accommodate the needs of the poor.
- The timing and/or desirability of nuclear power and a new petrol refinery need to be considered – **gas as alternative to base load nuclear.**

The key observations on each of these points and the potential socio-economic benefits the NDP identifies are summarised in Figure 3.

**Figure 3: NDP on gas a strategic priority and its potential socio-economic benefits**

| *Policy and planning priorities relevant to gas* | Key observations | Potential socio-economic benefits |
|---|---|---|
| **Gas should be explored as an alternative to coal for energy production** | • Shale gas, as a transitional fuel, has the potential to contribute a very large proportion of South Africa's electricity needs<br>• LNG imports could provide economically and environmentally positive options for power production, gas-to-liquids production at Moss gas and other industrial uses | • Substituting gas for coal will help to cut South Africa's carbon intensity and greenhouse gas emissions<br>• A global market for LNG has developed, increased supply of LNG has seen prices of LNG come under pressure and they are increasingly delinked from the oil price which provides an opportunity for South Africa to diversify its energy mix while lowering average energy costs |
| **Diversify power sources and ownership in the electricity sector** | • Gas-fired CCGT plants are cleaner and less capital-intensive than coal-fired power stations and because they are flexible sources of power generation they can be used to grid stability by picking-up any shortfall in supply from more intermittent renewable energy sources<br>• Reforms to South Africa's electricity market structure are required to enable greater private sector participation and investment in electricity generation. Reforms would include the establishment of an independent system and market operator to act as a single buyer of electricity, and preferably to also manage transmission assets | • **Complement renewables and improve electricity grid stability** – gas-fired generation capacity is flexible (can rapidly dispatch capacity) and can offset the intermittency of supply from renewable energy sources<br>• **Attract private-sector investment in power generation** – gas fired OCGT and CCGT plants are relatively small, modular low-risk power generation assets so it is relatively easy to attract private sector investment for these plants |
| **Electricity pricing and carbon tax** | • Government is also considering the introduction of an economy-wide carbon tax, with some conditional exemptions, to discourage investment in carbon-intensive power generation and incentivise the use of energy-efficient technologies | • Gas is price-competitive alternative in a carbon-pricing environment. Gas while more carbon-intensive than renewable energy sources is often referred to as the bridge to a low-carbon future. Gas will be increasingly price-competitive as compared to other fossil fuels under either carbon-tax and/or IRP policy-driven energy mix scenario |
| **Gas should be explored as an alternative to baseload nuclear** | • NDP notes that gas should be explored as an alternative to baseload nuclear. While nuclear provides a low-carbon baseload alternative and its operational costs are low, nuclear plants are large and often risky investments and may prove too expensive | • Gas plants are less 'lumpy' investments and can be commissioned at lower risk than nuclear – Gas may prove to be an attractive alternative as OCGT and CCGT plans are modular – that they can be built on a smaller scale to incrementally meet demand are therefore also easier to finance |

*Source: Deloitte analysis*

*Several common themes emerged across the various policy documents. In Figure 4 we have summarised the socio-economic rationale provided in government's policy and plans for the import of LNG and development of other natural gas resources in general. The rationale for introducing gas includes:*

- **Substituting diesel or coal for gas lowers carbon emissions** – the rationale for the development of natural gas as a fuel-source, which was common to almost all the documents, is that gas, when used as a substitute for diesel or coal, lowers carbon emissions.

- **Diversification of the energy mix** – the NDP, IRP 2013, Green is Smart note that the emergence of regional gas resources and a global market for LNG provides South Africa with an opportunity to diversify its energy mix away from coal. The extent to which South Africa can use gas in the energy mix, however, depends on its landed price. Analysis in the IRP 2010 update suggests that if LNG is landed at prices below $10/MMBtu, gas could contribute to lowering average energy costs.

- **Improve electricity grid stability and support renewables** – recent documents including the NDP, IRP 2013, Green is Smart also recognise that because gas power generation capacity is relatively flexible (it can be ramped up at short notice) it could be used to complement and support renewable energy plant generation which is known to be intermittent, thereby improving overall grid stability.

- **Attract IPPs in power generation –** the NDP and Green is Smart also note that the modular low-risk nature of gas-fired power plants means they are attractive investments for the private sector and thus provide an opportunity to introduce independent power producers (IPPs).

- **Gas is a price-competitive alternative in a carbon-pricing environment** – gas, and particularly LNG, is still expensive relative to coal in South Africa, but energy planning scenarios in the IRP 2010 update and IEP draft 2012 suggest that when a carbon price or emissions constraints are introduced, it becomes more competitive.

- **Gas-fired power plants can be built in shorter periods, at lower risk** – the IRP 2010 update notes that gas power plants are small modular investments relative to nuclear and mega-coal plants; and, as such, they carry a lower construction and financial risk.

- **Gas can facilitate the development of local upstream and downstream industries** – the IPAP 2014, Green is Smart and IES for the Western Cape note that gas, particularly domestic sources, can support the development of local downstream and upstream industries.

**Figure 4: Key rationale for the promotion of natural gas as an energy source**

| Key rationale or economic benefit | Description | NDP | IEP draft 2012 | IRP 2013 update | GIP 2005 | IPAP 2014 | Green is Smarts |
|---|---|---|---|---|---|---|---|
| **1. Lower emissions** | Substituting diesel or coal for gas lowers carbon emissions | ✓ | ✓ | ✓ | | ✓ | ✓ |
| **2. Diversity in energy mix to improve security of supply** | Gas available at lower prices (below $10 per MMBtu) could help SA to diversify its energy mix | ✓ | | ✓ | ✓ | | ✓ |
| **3. Improves electricity grid stability** | Gas power generation capacity is flexible supports renewables and improves electricity grid stability | ✓ | | ✓ | | | ✓ |
| **4. Attract private sector investment in power generation** | The modular low-risk nature of gas-fired power plants means they are suitable private sector investments | ✓ | | | | | ✓ |
| **5. Gas is price-competitive alternative in a carbon-pricing or emissions constrained environment** | Gas and particularly LNG is still expensive relative to coal but when a carbon price or emissions constraints are introduced its more competitive | ✓ | ✓ | ✓ | | | ✓ |
| **6. Gas-fired power plants can be built in shorter time frames, at lower risk** | Gas power plants are small modular investments relative to nuclear and mega coal and there is less construction and financial risk | | | ✓ | | | |
| **7. Facilitate the development of local upstream and downstream industries** | Gas can supports the development of specific downstream and upstream industries locally | | | | ✓ | ✓ | ✓ |

*Source: Deloitte analysis*

## 2.4. Potential end-uses for gas that have been considered

Gas has many potential end-uses in consumption, and a number of end-user categories have been considered across government policies and plans for the energy sector – these include gas for power generation, gas-to-liquids at the existing Mossgas plant, gas for industrial consumers and gas as alternative fuel in transports. For the most part the plans and policies put a strong emphasis on the use of gas in electricity generation and as an alternative fuel for large commercial and particularly industrial energy consumers. The IEP draft 2012 and Western Cape Green Economy Strategy also consider the use of gas in selected transport applications. The option of using LNG to extend the life of the current gas-to-liquid plant at Mossel Bay was also considered in the NDP and GIP. The use of natural gas by residential consumers was not mentioned in any of the documents.

**Figure 5: Potential end-uses for natural gas mentioned in government policies and plans**

| Potential end-use | Description | NDP | IEP draft 2012 | IRP 2010 | IRP 2013 update | GIP 2005 | IPAP 2014 | Green is Smarts | WC IES |
|---|---|---|---|---|---|---|---|---|---|
| **Gas-to-power** | Gas fired electricity generation plants | ● | ● | ◐ | ● | ◐ | ● | ● | ● |
| **Gas-to-liquids** | Options to extend life of current gas-to-liquids plant at Moss gas | ◐ | | | | ◐ | | | |
| **Gas-to-industry** | The opportunities to use natural gas in the commercial and industrial sectors | ◐ | ◐ | | | ● | ● | ● | ● |
| **Gas-to-transport** | Alternative fuel to petroleum products | | ◔ | | | | | ◐ | |
| **Gas-to-consumers** | The opportunity for gas for cooking and heating in households | | | | | | | | |

● *Strong emphasis* ◐ *Moderate emphasis* ◔ *Considered*

*Source: Deloitte Analysis*

## 2.5. Key considerations for the import of LNG as highlighted in energy plans

The key energy plans – the IEP and IRP also make some specific observations on the potential for LNG imports.

The IEP draft 2012 notes that imported natural gas plays an increasing role in all scenarios or "test cases" throughout the planning period, but it is not prominent in comparison to other primary energy sources. The IEP draft 2012 notes that, given a limited gas network in South Africa, the construction of an LNG facility in all likelihood would need to be underpinned by a gas-fired power plant as a key off-taker.

*"Power generation remains the main driver behind gas demand growth globally and remains a key potential for South Africa. South Africa has a limited gas network but with a well-developed electricity transmission grid, the construction of an LNG facility would need to be underpinned by a gas-fired power plant as a key off-taker as the most feasible solution in the short-to-medium term."* (IEP Draft 2012, 2013:66).

In the IRP 2010 update planning scenarios, LNG is considered available, uncapped at a price of R92/GJ, based on an assumed LNG price of $10/MMBTU. The IRP 2010 update concludes that at this price it would be feasible for OCGT peaking capacity to operate on gas rather than the current practice of utilising diesel. The IRP 2010 update notes that LNG has limited benefit as a major fuel source relative to alternatives available in South Africa, unless the costs for LNG decrease to below the expectation of R92/GJ (around $10/MMBtu). It is only in the case of higher nuclear capital costs and coal fuel costs that the LNG option becomes viable and is pursued, but since that capacity is only required after 2030, there is also time to assess developments before committing to the new capacity.

### 2.6. Summary

While most government plans and policies identify the power generation industry as the most promising “anchor gas off-taker” for an LNG import facility, the potential to provide LNG as an alternative fuel for large commercial and particularly industrial energy consumers has also been considered in a number of key national energy plans, including NDP, draft IEP 2012, IPAP 2014 and GIP 2005, as well as key Western Cape energy strategies. The basic premise is that imports of LNG into the Western Cape, if landed at a competitive price relative to existing alternatives, could enhance the competitiveness of existing industries and stimulate the expansion of industrial activity in the province.

The introduction of natural gas to the South African energy mix features strongly in both the overarching economic development plan and in key energy strategies and plans.

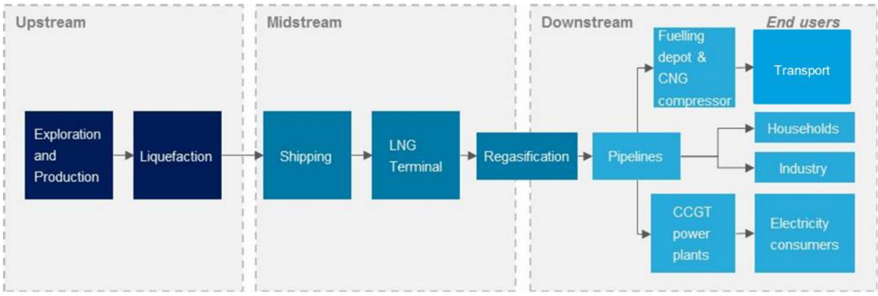
Imports of LNG into the Western Cape could assist government in achieving many of its stated energy policy objectives and planning priorities, including the reduction of GHG emissions, the diversification of the energy mix, improvements in electricity grid stability, increasing private-sector involvement in electricity generation and the facilitation of upstream and downstream industries.

Depending on its landed price, LNG could provide South Africa and the Western Cape with a cost-effective and lower carbon alternative to traditional fossil fuels, including petroleum products and in a carbon pricing environment, potentially even coal.

# 3. The LNG value-chain and its potential end-uses

The process and activities associated with importing liquefied natural gas (LNG) from its source to potential end-users in the Western Cape is illustrated in Figure 6. The LNG value chain consists of upstream, midstream and downstream activities.

**Figure 6: The LNG value chain**




*Source: Deloitte analysis adapted from “The economic impact of small scale LNG”, PWC, May 2013*

The upstream activities include the exploration and production of gas and the liquefaction of natural gas, which takes place at source. As discussed in Section 2, the market for LNG is becoming increasingly global, with extensive new liquefaction capacity expected to come online in Australia and in future in Mozambique, the US and Canada. Because shipping costs are a significant contributor to the overall LNG price, the most obvious suppliers for South Africa, are neighbouring Mozambique and Angola, Nigeria and Tanzania, while Qatar in the Middle East (although more distant than African exporters) is also an option as they are currently the dominant global supplier of LNG.

The midstream activities include the shipping of LNG and subsequent import at an onshore or offshore LNG terminal at the import destination. The prefeasibility study for the import of LNG into the Western Cape along the Saldanha Bay–Cape Town corridor[32] discusses the merits and drawbacks of an onshore versus offshore terminal. Once landed, LNG is typically regasified for distribution.

LNG is most commonly distributed in gaseous form to end-users via a network of pipelines. Based on the infrastructure scenarios outlined in the prefeasibility study for import of LNG into the Western Cape[33], we have assumed that LNG imported via the West Coast would be distributed via pipeline directly to power generators, residential and industrial consumers. For transport end-user scenario we have assumed that imported LNG would be regasified and transported via pipeline to CNG facilities at various bus depots and fuelling stations. The gas-to-transport scenario is described in detail in Appendix D.

Over the past decade, the “small-scale” distribution of LNG has emerged as an alternative and could be considered as an option for the Western Cape in future. Small-scale distribution involves distribution in liquid form in small tanks (typically tens of $m^3$) mounted on specialised LNG trucks or rail cars to LNG or compressed natural gas fuelling stations or small-scale storage facilities. LNG can also be distributed in liquid form as a fuel for small sea-going vessels.

[32] Western Cape Government (2013) Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor, J. H. Visagie

[33]

# 4. Overview of the natural gas market and implications for LNG prices

## 4.1. Introduction

The price of LNG (absolute and relative to alternative fuels) is a critical factor in determining uptake of LNG and the associated economic costs and benefits. In this chapter, we provide a brief overview of key developments in the global market for natural gas and the likely impact of changing demand–supply dynamics on the current and future price of LNG. We end the chapter with an analysis of the potential landed cost of supplying LNG to the West Coast from regional sources.

## 4.2. From regional natural gas markets to globally traded LNG

Natural gas, unlike oil, is low in density and has traditionally been difficult to transport; and, as such, its price have largely been set in regional markets rather than in a global market. Until recently, the high costs associated with transporting gas via long-distance pipelines or in LNG tankers represented a significant barrier to the establishment of a global gas market.

While most of the world's natural gas is still transported regionally by pipeline, the global trade in gas has grown substantially in the last decade, facilitated by an increase in LNG export, shipping and import capacity. Between 2005 and 2010, the global market for LNG grew by more than 50%; and in 2013, LNG accounted for 10% of global gas supply and 31.5% of international trade[34].

### 4.2.1. Global trade in LNG

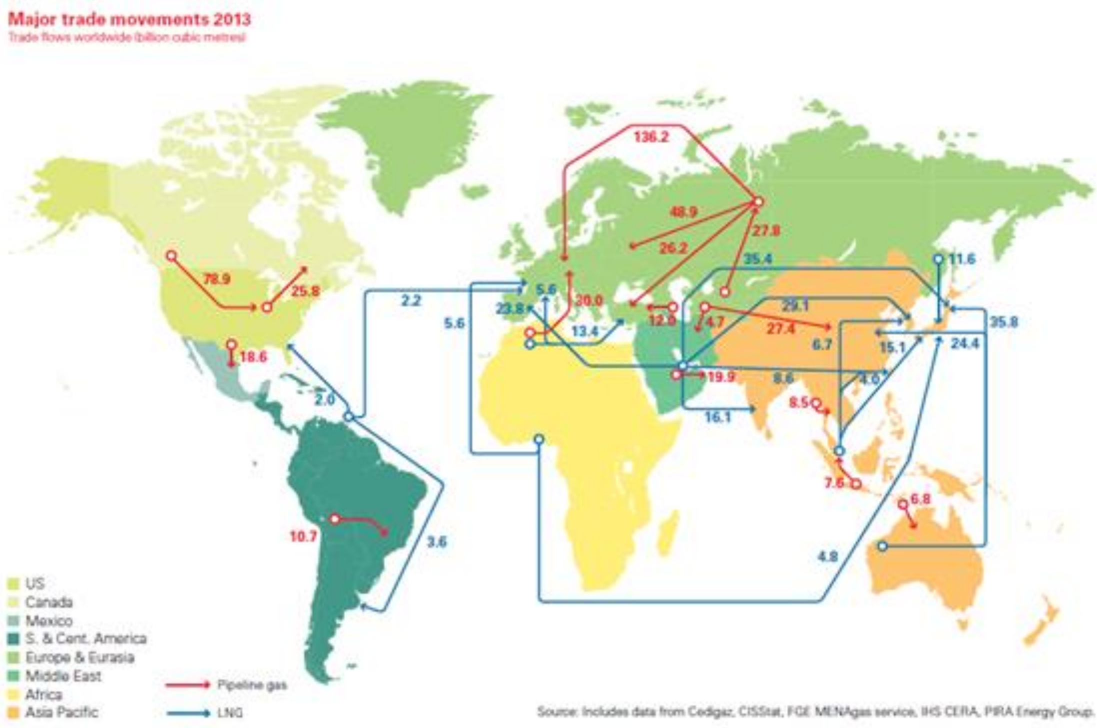
The world's gas supply (including unconventional resources) is geographically concentrated in three regions that are responsible for 70% of global supply – Russia, the Middle East (primarily Qatar and Iran) and North America.

Qatar dominates the LNG export market and was responsible for 33% of global supply in 2013. The Middle East *including Qatar* supplied 42% of the total LNG exports, while Asia-Pacific (Brunei, Indonesia, Malaysia and Australia) supplied a further 30%.

According to the IGU, 29 countries imported LNG in 2013. The Asia Pacific region is by far the leading market for LNG, accounting for 61% of total imports in 2013. Japan is the largest market in that region, followed by South Korea and Taiwan. Europe is the second-most-important destination for LNG, taking 14% of total volumes in 2013, with Spain and the UK being the region's main importers. Europe is closely followed by rapidly growing markets in Asia, where China and India now represent 13% of global imports. Combined, these three regions cover 88% of total LNG imports.

[34] IGU World LNG Report – 2014 and BP statistical review of world energy 2014

**Figure 7: Major global trade flows in LNG and pipeline gas 2014**




*Source: BP statistical review of world energy 2014*

## 4.2.2. Natural gas prices – regional differences, current prices and historical trends

### 4.2.2.1. Pricing mechanisms

Since the price of natural gas is set in regional markets rather than traded on global commodity exchanges and pricing mechanisms also vary from region to region. The most common pricing mechanisms for natural gas are oil-linked, regulated and competitive market pricing.

Under oil-linked contracts the price of natural gas is expressed in terms of crude oil prices or oil product prices. Natural gas will typically trade at a discount to oil and contracts are usually long-term (of duration 5 years or greater[35]). In markets regulated by governments the price of gas is usually determined as a function of the cost of production. Regulated prices however are not necessarily cost-reflective and can include an explicit or implicit subsidy.

Under competitive market pricing, trading points or hubs are established in market areas, and competition among various suppliers and consumers of natural gas determines the regional market price. In the United States, the deregulation of natural gas prices in the 1990s saw the emergence of several market-based gas trading hubs, the most well-known being Henry Hub in Louisiana.

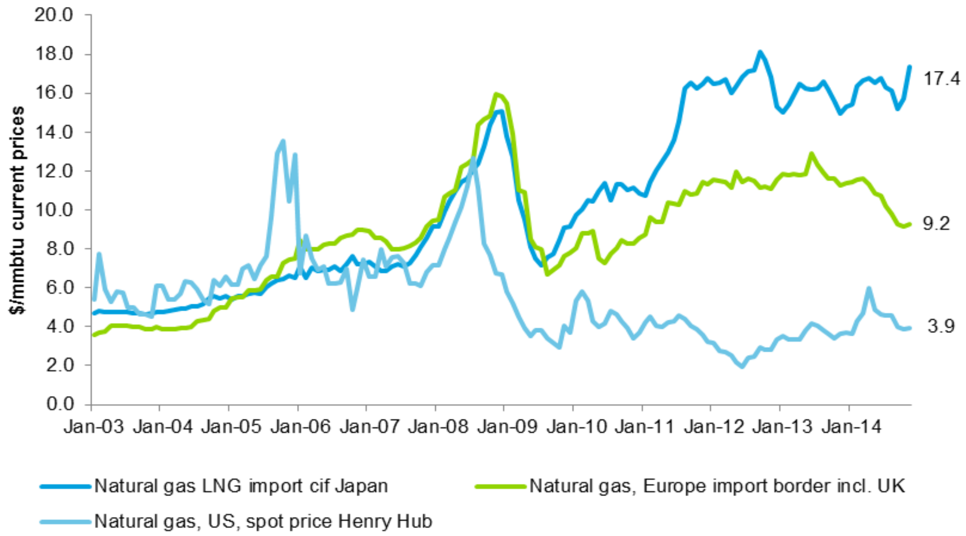
### 4.2.2.2. Regional differences in historical and current gas prices

In Japan where there no domestic gas supply options, long-term contracts for LNG linked to crude oil prices are still the norm, and LNG prices c.i.f. (cost in freight) were trading at about $17.4/MMBtu in December 2014 (Figure 8). By contrast, the price of gas traded at Henry Hub in the US was $3.9/MMBtu in November 2014 and natural gas prices in Europe averaged $9.2/MMBtu. Since 2005,

[35] This is the definition of short-term contracts used by the International Group of Liquefied Natural Gas Importers - see International Group of Liquefied Natural Gas Importers (2013) *The LNG Industry, 2013*

US gas prices have traded at a significant discount to oil prices per unit of energy. The shale gas revolution in the US saw gas prices falling from a peak of around $12/MMBtu in 2008 to around $4MMBtu in 2014 (Figure 8).

**Figure 8: Historical trend in average regional gas market prices – US, Europe and Japan, Jan 2003 to** Nov **2014**

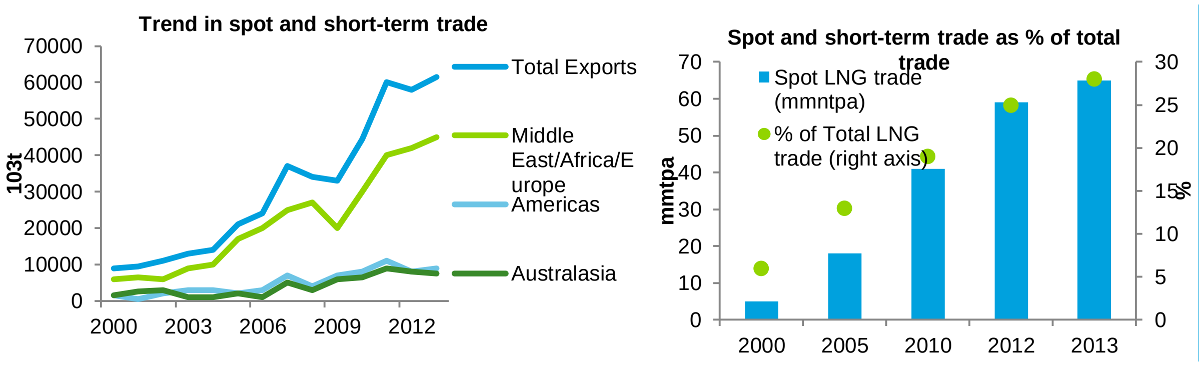



*Source: Deloitte analysis based on World Bank commodity price data, the pink sheet, December 2014*

### Wide price spreads and new supply options promote more flexible market based pricing

The significant spread (~$13.5/MMBtu in Nov 2014) between US and Japanese import prices has been sustained since 2011and as such the indexation of gas-to-oil is increasingly being challenged by Asian buyers. Asian buyers are also gaining access to a wider and more flexible range of LNG supply options, and the volume of LNG bought and sold on the spot market and under short-term contracts (trades under contract, with duration of four years or less)[36] has increased (Figure 9).

**Figure 9: Spot and Short-term LNG trade since 2000**




Source: *International Group of Liquefied Natural Gas Importers (2013)* The LNG Industry, 2013

A transition to more flexible (trades based on shorter duration commitments) and market-based pricing is still in progress in Europe, where the spread between US HH and European gas prices was about $5/MMBtu in November 2014 (Figure 8). While oil-indexation is still dominant, a number of European buyers have renegotiated the pricing formula in their long-term contracts and have introduced a higher share of hub indexation. According to data from the International Group of

[36] This is the definition of short-term contracts used by the International Group of Liquefied Natural Gas Importers - see International Group of Liquefied Natural Gas Importers (2013) *The LNG Industry, 2013.*

Liquefied Natural Gas Importers, most of the LNG bought on the spot and short-term LNG market since 2000 has been sold in the “Europe/Middle East/Africa” region, and just over 25% of total LNG traded was sold on this basis in 2013 (Figure 9).

While the pressure to move away from oil-indexation is mounting, a report by the IEA in 2013 noted that much of the additional tradable natural gas supply from 2015 to 2018 will come from new LNG liquefaction capacity in Australia, and most of this supply has already been secured by Asian buyers in the form of long-term oil-indexed contracts. This suggests that oil-link gas contracts will remain dominant in Asia and Asia-Pacific in the next three to four years. From 2019 however, it is possible that substantial new liquefaction capacity in the US will come online, and it is likely that the US LNG Export projects will sign long-term contracts pegged on HH prices. There is also increasing interest among Asian countries in developing an Asian natural gas trading hub.

### 4.2.3. Recent LNG price trends and the market outlook

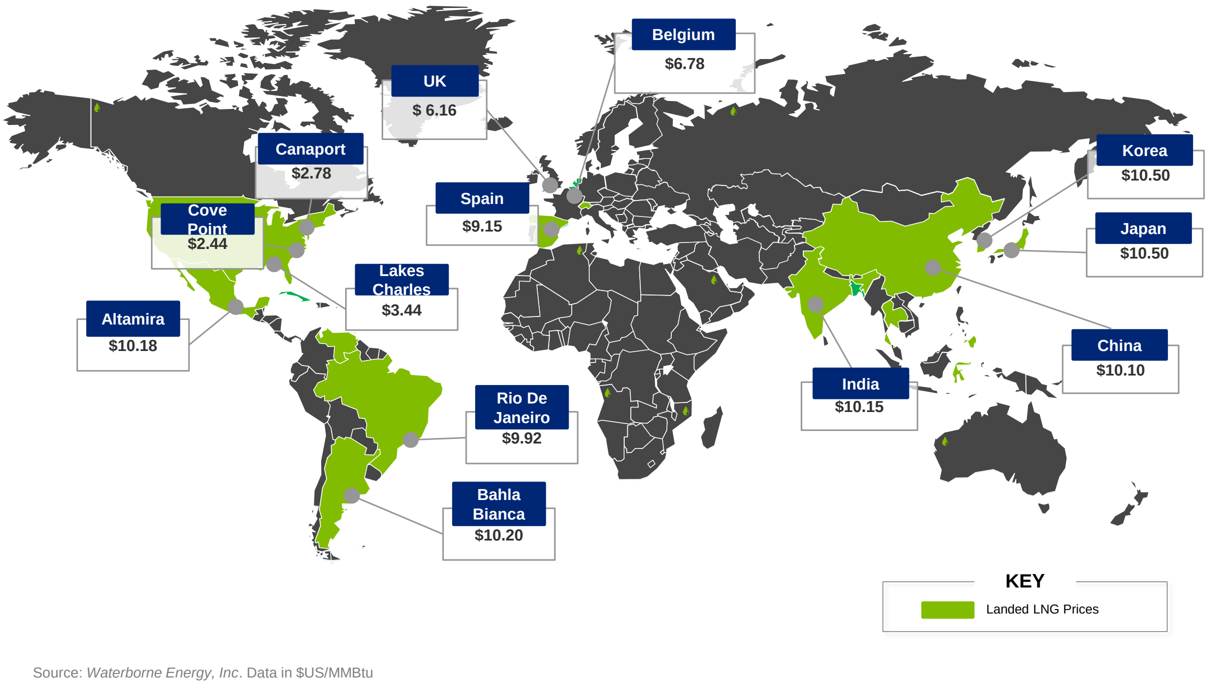
Because the majority of LNG cargoes delivered to Asia are still under long-term oil indexed contracts, the average LNG import prices (e.g. c.i.f Japan) move slowly and lag fundamental shifts in supply and demand. The LNG spot market, while volatile, reflects the demand and supply for flexible cargoes and as such is likely to provide a better indication of future LNG price trends.

A recent analysis by the Economic Intelligence Unit (EIU) suggests that LNG spot prices for delivery into North Asia fell by more than 50% during 2014 from a high of $20/MMBtu in February to $9.50/MMBtu by November. The sharp drop in spot prices was attributed due to weak demand from Japan and other major Asian consumers[37].

Data published by the Federal Energy Regulatory Commission in August 2014(which we believe is based on new contracts), provides further evidence the landed price of LNG is under pressure. According to FERC, landed LNG prices in Europe are currently between $6.16 and $9.15, while Asian countries are importing LNG at prices between $10.10 and $10.50 – significantly below the average Japanese import price of $17.4/MMbtu (Figure 10). LNG in the US is landed for as little as $2.44, while South and Central America face prices of around $10/MMBtu.

[37] EIU Global Forecasting Unit, LNG market update, November 2014

**Figure 10: Landed LNG prices, August 2014**

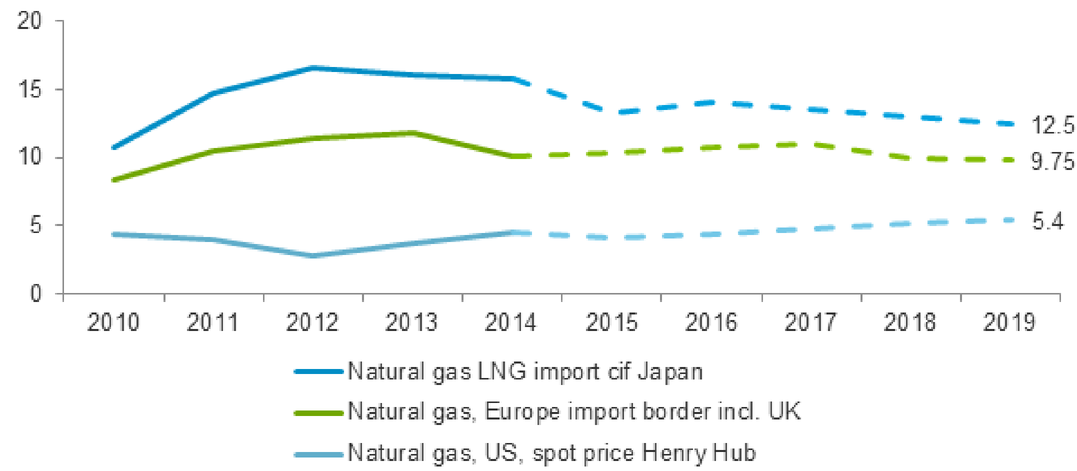



*Source: Federal Energy Regulatory Commission, based on Waterborne Energy*

## LNG price dynamics and forecasts for 2015 to 2019

According to the EIU the average price of LNG imported into Japan (which includes contracted long-term and spot prices) was $15.8/MMBtu in 2014 and this is expected to slide to $14/MMBtu by end-2016 as plentiful new supplies come into the market from Australia and Papua New Guinea and as Angola resumes exports (Figure 11). There are seven Australian LNG liquefaction projects currently under construction, with a total nameplate capacity of 61.8 million tons per annum, which would increase current global export capacity by over 20%[38]. The first US LNG export terminal is also set to come online in 2015. The EIU notes that because a number of contracts are still indexed to oil, the significantly lower oil price environment will also keep downward pressure on LNG prices.

**Figure 11: LNG medium-term price forecasts, 2015 to 2019**




*Source: EIU global forecasting unit, 20 August 2014*

[38] IGU World Gas Market Report, 2014

On the demand side, the restart of some of Japan's nuclear reactors (since the shutdown of all 50 plants following the Fukushima disaster in 2011) should see a softening in demand from the world's largest LNG consumer. The EIU expects the average price of LNG imported into Japan (the premium gas buyer) to fall to $12.50/MMBtu by 2019.

**LNG price expectations and forecasts 2020 and beyond**

*According to the International Gas Union (IGU)*[39]*, "the emergence of new areas with tremendous [LNG] supply potential has been one of the most striking changes in the LNG industry in the last 3 years." These areas include:*

- The US Gulf Coast and Western Canada (due to shale gas production)
- East Africa (due to prolific deepwater basins)
- Floating LNG globally (because of stranded gas)
- Asia Pacific brownfield projects
- Russian projects (following LNG export liberalisation)
- East Mediterranean projects (Cyprus, Israel)

Exports from these areas are expected to change LNG markets in a material way by offering new, globally distributed sources of supply and alternatives to traditional oil-linked contracts. According to the EIU these new sources of supply, are also likely to add further downward momentum to LNG prices, particularly post 2019. The sustained liquids-rich unconventional (shale) gas production and weak Henry Hub prices have led to a flurry of liquefaction proposals in the United States, and over 28 projects at close to 280 million tpa of capacity had been proposed as of the first quarter of 2014. While only one is currently under construction, several may come online post-2020.

In East Africa, prolific discoveries of offshore natural gas may translate to higher liquefaction potential than the 35+ million tpa that is currently proposed. In Mozambique US-based Anadarko Petroleum and its partners are planning to build two 5 million tpa liquefaction trains which would start export in 2021 and they suggest there is an opportunity for significant expansion in the future[40]. According to media reports, Anadarko has secured some preliminary deals with Asian Buyers to sell two-thirds of the terminal output but the deals have not yet be finalised and will be required to secure financing for the project[41.]

Plans for a potential LNG export project in Tanzania are also underway but are less advanced than in Mozambique. According to information provided on the company's website, in April 2014, Britain's BG Group and its partners signed a Heads of Agreement (HoA) setting out the terms for collaboration on a joint LNG project and a contract for a pre-front-end engineering and design was awarded in August 2014

The most notable risk to this outlook is a potential surge in demand from China. China has been taking an increasing share of total Asian LNG demand as Japan's imports have begun to wane with the gradual return of nuclear power. A surge in demand from China would halt the forecast decline in prices.

[39] IGU World LNG Report – 2014

[40] LNG Industry (2014) *East Africa: the newest LNG frontier.* 10 March 2014. [Online]. Available at: http://www.lngindustry.com/liquefaction/10032014/East_Africa_as_the_newest_LNG_exporting_frontier

[41] Reuters (2014) EXCLUSIVE-Asian buyers line up for Mozambican LNG with new deals. 30 October 2014. Available at: http://www.reuters.com/article/2014/12/11/asia-lng-idUSL3N0TV2JZ20141211

**Potential future LNG suppliers to the West Coast of the Western Cape**

The pre-feasibility study for the importation of LNG into the Western Cape[42] identified Angola and Nigeria in West Africa and Mozambique and Tanzania in East Africa as the most likely suppliers of LNG to the West Coast of the Western Cape. Oman and Qatar in the Middle East were also considered, given their relative proximity and ample export capacity.

#### 4.2.3.1. Estimating the landed cost of Mozambique LNG at Saldanha

The proximity of Mozambique to South Africa and its prolific deepwater gas reserves, and the relatively advanced stage of the planning for an LNG export terminal relative to Tanzania make it one of the high potential sources of LNG imports via the West Coast of the Western Cape.

A 2013 report on the potential of exports of gas from East Africa by David Ledesma from the Oxford Institute for Energy Studies[43] suggests that the landed cost of LNG in Asia from the East Africa, Australian and US gulf expansions post 2019 will be comparable so that East Africa while cost-competitive will face tough competition from other global suppliers. This may force East African producers to offer LNG on more favourable contracts and prices.

It appears that in preliminary agreements signed with Asian buyers for output from it planned liquefaction plant in Mozambique, Anadarko offered 20-year contracts where 70% of the LNG price will be linked to the oil-price and 30% will be linked to U.S. henry hub gas prices plus a premium of $5-$7MMB. While preliminary contracts are therefore still oil-dominated, it does appear that Anadarko is willing to consider some exposure to traded gas prices in a bid to attract buyers.

While LNG contract prices are typically determined by market forces they are also influenced by the cost of production. One way to assess the potential future landed price of LNG on the West Coast of South Africa is to estimate its wholesale delivered cost.

**Table 3: Estimating of the delivered cost of LNG from Mozambique to Saldanha and Japan**

| Cost components | Estimated landed LNG price | | |
|---|---|---|---|
| | Mozambique – Saldanha Low | Mozambique – Saldanha High | Mozambique – Japan* |
| Production costs | $3.0 | $3.0 | $3.0 |
| Liquefaction costs | $3.3 | $4.0 | $4.0 |
| Shipping costs | $0.4 | $0.4 | $2.2 |
| Additional infrastructure costs/risk premium | | $1.5 | $1.5 |
| **Total** | **$6.7** | **$8.9** | **$10.7** |

** As estimated in Ledesma 2013, Oxford Institute of Energy Studies*

In his 2013 study, Ledesma employs a high-level cost-based approach to estimating the price of LNG exported from Mozambique and landed in Japan, which is summarised in the third column of Table 3.The study assumes a gas production cost of $3/MMBtu and a $1.5/MMBtu cost for additional infrastructure that may be required to support exports in this undeveloped region. Liquefaction costs are estimated at $4/MMBtu. A shipping cost of $2.2/MMBtu, based on charter of a 170 000m$^3$ vessel

[42] Energy Business, 2013, “Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay–Cape Town corridor”

[43] Ledesma 2013, Oxford Institute of Energy Studies

at $85 000 per day, includes allowances for shipping detours to avoid piracy. This will result in a wholesale landed cost of Mozambique LNG delivered to Japan of $10.7/MMBtu.

To estimate the equivalent landed price of Mozambique LNG delivered on the West Coast of the Cape, we assume the same production, liquefaction and additional infrastructure costs but scale the shipping costs for the shorter distance between Northern Mozambique and Saldanha on the West Coast. The distance between Mozambique and Saldanha is roughly 2 500km, while the distance between Mozambique and Japan is roughly 12 500km. A simple back-of-the envelope calculation suggests that if the distance between Mozambique and Saldanha is 20% of the distance between Mozambique and Tokyo, the shipping costs should be in the order of $0.40/MMBtu. This compares favourably with estimates of the shipping cost provided in the prefeasibility study which was $1.34/MMBtu for the same route, but this estimate can be viewed as a an upper-bound estimate, as it was based on the cost of chartering a new vessel.

Based on these cost estimates, the landed cost of LNG from Mozambique in Saldanha would be in the region of $8.9/MMBtu. If the assumption that additional infrastructure costs of $1.5/MMBtu is dropped and a more optimistic $3.3/MMBtu liquefaction cost is assumed (as per IFC international's 2012 estimates)[44], Mozambique LNG landed in Saldanha is $6.7/MMBtu. A report by market research firm Wood Mackenzie in 2012 suggested the break-even price of LNG from Mozambique to Japan could be as little as $7/MMBtu, as the country is considered a cost-competitive producer[45].

### 4.3. Conclusion

Overall the market outlook is positive for prospective LNG importers like South Africa, with demand and supply fundamentals pointing on balance to continued downward momentum in LNG prices, particularly beyond 2019. The discovery of prolific deepwater gas basins off the coast of Mozambique and Tanzania will also provide South Africa with new regional LNG supply opportunities (in addition to Angola and Nigeria).

If a glut of global LNG supply does indeed materialise, South Africa will be in a strong position to negotiate LNG contracts with prices indexed to gas hub prices (such as Henry Hub or UK NBP) rather than oil - which in our view is an opportunity to take advantage of any continued divergence in natural gas an oil prices and reduce exposure to oil prices.

Estimates of the break-even price of Mozambique LNG landed in Saldanha are between $6.7/MMBtu and $8.9/MMBtu. We have based our analysis of the price of LNG relative to alternative fuels in the remainder of this report on a more conservative range of between $10/MMBtu and $15/MMBtu, which is also consistent with prices assumed in the prefeasibility study conducted by the WCG.

[44] Sustainable Engineering Lab, *"Potential for Regional Use of East Africa's Natural Gas* Colombia University", 2014

[45] Ernest and Young, "Natural gas in Africa The frontiers of the Golden Age", 2013

# 5. The socio-economic impact of LNG in the Western Cape for various end-user scenarios

## 5.1. Introduction

In 2013, the WCG conducted a prefeasibility study to provide a preliminary assessment of the financial viability of importing natural gas into the Western Cape with a specific focus on the Saldanha Bay – Cape Town corridor along the West Coast. The study considered the potential market for imported natural gas for four categories of end-user – power generators, industrial consumers, transport and residential applications.

The study found that it would be financially feasible to establish a LNG import facility on the West Coast, if the existing diesel-fired Ankerlig OCGT plant was converted to a larger gas-fired CCGT plant and\or similar new CCGT plant was constructed and could act as the anchor off taker[46]. The study also noted that once an import terminal and anchor gas customer was in place, there would be potential to extend the gas distribution network to serve energy users in some of the key industrial nodes in the Cape Town and West Coast municipalities. The network could then potentially be extended further to provide gas as an alternative energy source to households and in transport applications.

The purpose of this chapter of the report is to assess the broader socio-economic impacts that could be associated with the ***use of imported LNG*** in the Western Cape if specific end-user scenarios, largely informed by the prefeasibility study, materialise.

The gas-to-power and gas-to-industry scenarios were based largely on the recommendations of the prefeasibility study and the specific applications are summarised in Table 4. While the prefeasibility study also considers the use of imported natural gas in transports and households, the opportunities discussed were limited to the conversion of a public bus fleet with assumed annual gas consumption of 900 000GJ and annual gas consumption of ~300 000 GJ for households.

Given the increasing interest in the use of natural gas in transport in South Africa (including the completion of a CNG vehicle fleet trial in Gauteng in 2013[47]), the WCG requested that Deloitte consider an expanded "gas-to-transport" scenario. Details of our approach to estimating the infrastructure required to support an expanded gas-to-transport scenario[48] are provided in Appendix D. We have also considered an expanded household scenario, as the prefeasibility study limited the market opportunity to ~300 000 GJ per annum and did not provide estimates of the cost of infrastructure required. Our

[46] Western Cape Government (2013) Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor, J. H. Visagie

[47] Industrial Development Corporation and Cape Advanced Engineering (2013) *Investigation into the use of clean burning methane in the form of compressed natural gas (CNG) and compressed bio-gas (CBG) in public transport in South Africa*

[48] Our estimates provide an initial indication of the cost of converting the public vehicle fleet in part of the Western Cape to run on CNG. We note that a more detailed assessment of the business case for the use of CNG in the public transport fleet will need to be undertaken in order to determine whether the scenario proposed is indeed feasible.

approach to identifying a potential household market and our estimates of the associated infrastructure costs are also described in Appendix D.

*The specific applications assumed for all end-user scenarios are summarised in Table 4 below.*

**Table 4: End-user scenarios for imported LNG in the Western Cape based on prefeasibility study**

| End-user | Description of the end-user scenario considered | Alternative energy source to: |
|---|---|---|
| **Gas-to-power** | • Conversion of the existing diesel-fuelled 1 350MW Ankerlig open cycle gas turbine (OCGT) power plant to a 2 070MW CCGT power plant<br>• Construction of an additional 800MW CCGT gas-fired power plant<br>• Assuming the power stations are the "anchor tenants" for the LNG import terminal, this scenario also includes the cost of either an offshore or onshore LNG import terminal and associated transmission pipelines. | Potential alternative to diesel and a complement to and/or enabler of renewable energy generation |
| **Gas-to-industries** | • An additional 118km of gas distribution pipeline is installed to deliver imported natural gas to large industrial users in the CoCT and West Coast district municipalities. | Potential alternative fuel to LPG and diesel, HFO and a to a more limited extent coal |
| **Gas-to-transport** | • Roughly 850 public buses (MyCiTi, Golden Arrow and Sibanye) and 8 500 vehicles in the CoCT and WCG fleet are converted to operate on a combination of compressed natural gas and conventional fuels.<br>• Eleven depots and 42 service stations in the West Coast district municipality and CoCT are converted to supply CNG to these vehicles.<br>• An additional 230km of gas distribution pipeline is installed to deliver imported natural gas CNG refuelling stations and depots. | Potential alternative to diesel and petroleum |
| **Gas-to-households** | • An additional 200km of gas distribution pipeline is installed to deliver imported natural gas to new middle-to-high income housing developments in the Blaauwberg- Atlantis corridor for use in heating and cooking. | Potential alternative to LPG and electricity |

For each of the potential LNG end-users identified, we describe the scenario assumed and consider whether the end-users would be likely to switch to gas from current alternative energy sources based on key factors such as the price of LNG relative to alternatives. We then identify and quantify where possible the socio-economic benefits and costs that would be associated with switching under stated assumptions.

## 5.2. Gas-to-Power

### 5.2.1. Introduction

The Integrated Energy Plan (IEP draft 2012) notes that power generation is the main driver of the growth in gas demand globally and is likely to be the most feasible end-use of LNG in South Africa in the short-to-medium term. The IEP draft 2012 suggested that because there is limited existing gas pipeline infrastructure in South Africa, the construction of an LNG facility would in all likelihood need to be underpinned by a gas-fired power plant as a key off-taker.

In this section, we explore the potential socio-economic costs and benefits that are associated with imports of LNG into the Western Cape for power generation. We begin with an explanation of the gas-to-power scenario we have considered, followed by background and context for the energy sector in South Africa and the Western Cape. We then provide an outline of some of the key gas-to-power user considerations for switching to LNG. In the remainder of the section, we expand on the potential socio-economic benefits and costs that would be associated with the introduction of LNG under our gas-to-power end-user scenario.

### 5.2.2. Background and context

#### 5.2.2.1. South Africa's current electricity crisis

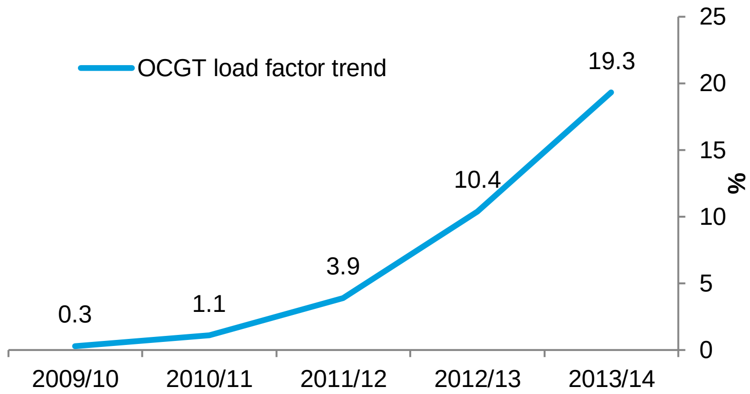
As demonstrated by recent load shedding, South Africa is in the midst of a serious power crisis with few immediate solutions at hand. Coal and nuclear power stations are not short term solutions and are 'lumpy investments' that have long construction lead times, while renewable energy plant cannot contribute significantly to base load power generation due to its variable power generation profile. The additional coal-fire capacity from Medupi and Kusile that is to be commissioned gradually over the next few years may ease system pressure, but will not solve the electricity crisis. Rather, it will provide the 'space' for carrying out neglected maintenance that will restore existing plant efficiency, and in certain cases allow for decommissioning of some inefficient plant.

In March 2014 Eskom, the national power utility, was forced to implement the first substantial power cuts since 2008 and load shedding began again in earnest in December 2014. Eskom has warned that the power system is severely constrained and load shedding is likely to continue for the next 18 months. In our view, the Southern African energy landscape will continue to be characterised by constrained supply for the next decade, largely because of an aging generation fleet.

In a bid to avoid power outages, Eskom has been operating its costly diesel-fired Open Cycle Gas Turbines (OCGT) at significantly higher than intended loads. Eskom spent an estimated R10.5bn on diesel to run the two large OCGT facilities in the Western Cape (Ankerlig and Gourikwa) for Eskom's financial year 2013/14, ending in March 2014, with these plants running at an average load factor of 19.3%, well above the 5%-10% for which they were designed[49].

[49] Mining Weekly, Eskom weighs gas options as diesel costs double to R10.5bn, 11 July 2014, Eskom Integrated Report 2014

**Figure 12: Trend in Eskom OCGT plant load factor, 2009 to 2013**




*Source: Eskom Integrated Report 2014*

In December 2014, Eskom noted that it was operating its OCGTs at a load factor of close to 60% and was spending R2bn a month on diesel as a result[50]. This is not only contributing to Eskom's financial woes but also rising electricity costs, and is not a sustainable solution to the power crisis.

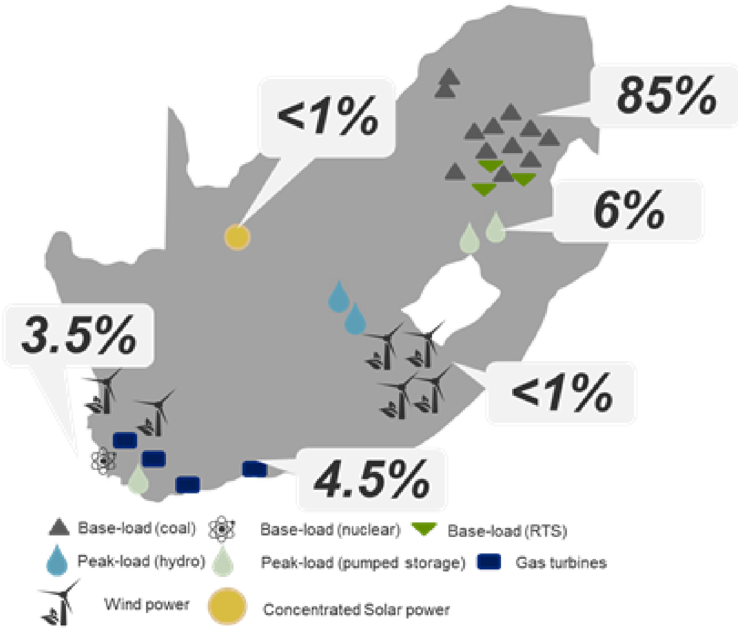
#### 5.2.2.2. South Africa's plan to diversify away from coal towards cleaner energy to encourage greater private-sector investment in power

The South African economy is heavily reliant on coal as an energy source. Coal accounts for more than 70% of primary energy consumption in South Africa and is used to generate about 85% of all electricity[51]. Because of its heavy reliance on coal, South Africa contributes disproportionately to global greenhouse gas emissions – data from the World Resources Institute's CAIT database suggested that South Africa was the 17th-largest contributor to total global GHG emissions in 2011 but is only the 33rd-largest economy in US dollar terms[52]. Electricity generation alone contributes to roughly 60% of South Africa's total GHG emissions[53].

Eskom generates 96% of the country's electricity, owns and controls the national high-voltage transmission grid and distributes approximately 60% of electricity directly to customers. The national electricity generation capacity is characterised by several large coal-fired power stations that are concentrated in the interior of the country near the coalmines in Mpumalanga.

[50] Business Report, "Eskom in scramble to secure funding" http://www.iol.co.za/business/news/eskom-in-scramble-to-secure-funding-1.1791044#.VIbgJXgaKwk. 5 December 2014.
[51] BP statistical energy review 2014
[52] World Bank GDP ranking 2013 available at: http://data.worldbank.org/data-catalog/GDP-ranking-table
[53] Department of Energy (2013) *Draft national greenhouse gas inventory for the Republic of South Africa*. August 2013

**Figure 13: Eskom Power Stations, 2014, by type of generation asset**




*Source: Deloitte analysis based on Eskom Generation Map, 2013*

As discussed in Section 2, plans to encourage the diversification of South Africa's electricity generation mix away from coal towards cleaner energy sources and to encourage greater private-sector participation in electricity generation are high on government's policy agenda. According to the IRP 2010 update, coal is expected to contribute only 33% to the generation mix by 2050 as compared to 85% today. In 2003, Cabinet approved a target of 30% for electricity generation capacity that should be provided by independent power producers (IPPs).

In a move towards the realisation of the IRP's non-coal capacity targets and to encourage increasing private-sector investment, the Department of Energy introduced the renewable energy independent power producer procurement (REIPPP) programme in 2011. The REIPPP programme invites prospective IPPs to submit renewable energy projects under a number of bidding windows within the programme. According to Eskom a total of 1000MW of renewable energy projects have been connected to the grid and a further 4280MW have been contracted[54]. The total allocation announced by the Department of Energy (DOE) in December 2012 was 6 925MW. Evaluation of bids for the fourth window, which closed on 18 August 2014, is underway.

In addition to the ongoing REIPPP programme, the Department of Energy (DOE) has recently launched a programme to procure baseload and mid-merit power capacity from IPPs. Under the baseload determination, 2 500MW was allocated for coal-fired IPP projects, 2 652MW for baseload or mid-merit natural gas capacity and 2 609 MW for domestic and imported hydro-electricity[55].

The DOE invited potential coal independent power producers (IPPs) to register their prospective projects by 25 July 2014, following which they issued a formal request for proposal under a Baseload Coal Independent Power Producer Procurement Programme[56] (BCIPPPP) in December 2014.
It appears, based on this announcement, the BCIPPPP will proceed ahead of the plan to procure gas and hydropower from IPPs.

54

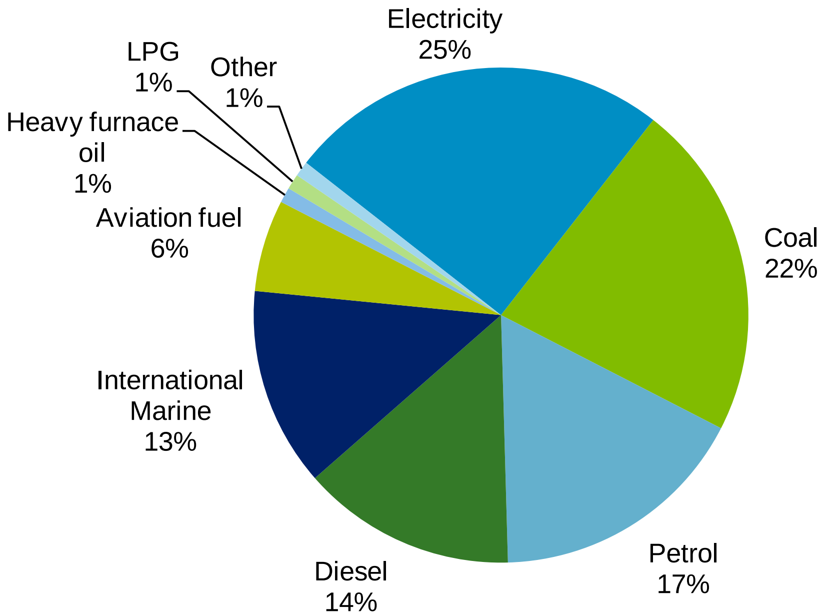
55 Engineering News, "Martins promises baseload, cogen IPP procurement programmes by March", 11 February 2014

56 Engineering News, "DoE gears up for baseload-coal IPP procurement", 4 July 2014

#### 5.2.2.3. The Western Cape energy mix and peak power deficit

The Western Cape economy is heavily reliant on electricity (25%), coal (22%) and petroleum products (31%) for energy (Figure 14). Eskom supplies the Western Cape with all its wholesale electricity, and the province has a peak daily electricity requirement of approximately 4 637MW[57].

**Figure 14: Contribution of various energy sources to total energy consumption in the Western Cape**




*Source: Deloitte analysis based on Western Cape Energy and $CO_2$ emissions Database 2013*

While current peak demand in the Western Cape at 4 637MW is slightly less than the province's installed electricity generation capacity of 4 698MW, the Koeberg nuclear plant (with a capacity of 1940MW) is the only source of baseload power generation (see Appendix B for a breakdown of installed capacity in the Western Cape). As a result, the Western Cape still has to import an average of 2 050MW[58] of power daily from coal-fired plants that are located over 1 500km away, in Mpumalanga.

Because of the dominance of coal in Eskom's electricity generation mix and in the primary energy mix of the province overall, the Western Cape is a significant contributor to total national greenhouse gas emissions. The Western Cape contributes about 11% of total national GHG emissions and has slightly higher energy consumption and GHG emissions per capita than the national average (eight metric tonnes of $CO_2$-equivalent ($tCO_2e$)/capita in the Western Cape versus 7.7 $tCO_2e$/capita nationally)[59].

[57] Eskom transmission development plan 2013

[58] Energy Business, 2013, "Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay–Cape Town corridor".

[59] Western Cape Provincial Government, 2013, Western Cape Energy and CO2 emissions Database 2013

### 5.2.3. Gas-to-power scenario considered

*The gas-to-power scenario that we have considered for this study is based on insights and recommendations from the prefeasibility study[60] and includes:*

- The conversion of the existing 1 350MW diesel-fired Ankerlig OCGT plant to a larger and more efficient 2070MW CCGT power plant with imported LNG as the feedstock
- The construction of a new 800MW gas-fired CCGT plant somewhere within the West Coast region of the Western Cape (between Saldanha and Cape Town)
- This scenario also includes the cost of either an offshore or onshore LNG import terminal and associated transmission pipelines.

The Ankerlig power plant is a 1350MW diesel-fired OCGT plant with nine units, located in Atlantis north of Cape Town. The rationale for the conversion of Ankerlig from a diesel-fired OCGT to a gas-fired CCGT was that CCGT plants are significantly more efficient than OCGT plants. They can be run at a much lower cost per kWh of electricity generated, are used at higher load factors and therefore generate more power annually for every unit of capacity. According to Eskom [61] both Ankerlig and Gourikwa gas turbines were designed in such a way that they could be converted to CCGTs, should natural gas become available. CCGT plants also generate lower $CO_2$ emissions than OCGT for every unit of fuel consumed. It is envisaged that a 2 070MW CCGT at Ankerlig would become the anchor consumer or off-taker for LNG imports to the Western Cape.

The rationale for a second CCGT plant on the West Coast is that it would assist the Western Cape in meeting a larger portion of its electricity demand deficit, it could unlock suppressed industrial demand for power and contribute to reducing the overall supply constraint on the South African grid.

### 5.2.4. Would power generators switch to LNG?

#### 5.2.4.1. Which fuels would LNG replace in power generation?

In the case of the Ankerlig plant conversion, imported LNG would directly replace diesel as the feedstock for power generation. The conversion of the plant from a 1 350MW plant to a 2 050MW plant would also add an additional 700MW of capacity to the national electricity grid.

In the case of the second new-build CCGT plant, LNG would add to overall electricity generation capacity which will have an indirect fuel replacement consequence. Given that CCGT plants are typically run in a mid-merit capacity (around 50% of the time), the new 800MW gas-fired plant would likely be used to reduce the need for the Western Cape to import 2 050MW of power at peak times from the rest of the country. This would notionally release 800MW of inland power generation capacity (in all likelihood coal) and the associated 80MW of transmission losses (estimated at 10%), so that a total of 880MW of inland coal-fired capacity would become available.

[60] Energy Business, 2013, "Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay–Cape Town corridor"

[61] Eskom (2014) *Fact Sheet: Ankerlig and Gourikwa gas turbine power station.* [Online]. Revision 9. January 2014. Available from ww.eskom.co.za/AboutElectricity/FactsFigures/Documents/GS0002AnkerligGourikwaGasTurbinePstnsRev9.pdf [Accessed: 14 October 2014]

#### 5.2.4.2. Cost of LNG in power generation relative to alternatives

Arguably, the most important factor in persuading power generators to consider imported LNG as an alternative fuel in power generation is its relative cost to existing and available future alternatives. The preferred measure for comparing the cost of electricity from different fuel and generation sources is the levelised cost of energy (LCOE). The LCOE includes all the major costs associated with a power plant, including the initial investment, operations and maintenance, cost of fuel and the cost of capital.

> "Our analysis… suggests that the levelised cost of producing electricity using an imported-gas-fired CCGT (at R1.10/kWh) is 35% of the cost of producing electricity with diesel at Ankerlig (R3.13/kWh). Estimates from the IRP 2010 suggest that if even if Ankerlig was kept in its current OCGT configuration, electricity could be produced at roughly 50% of its current cost simply by replacing the diesel feedstock with imported natural gas"

Our analysis of the levelised cost of energy[62] (LCOE) for different types of power generation suggests that the cost of producing electricity using an imported-gas-fired CCGT[63] (at R1.10/kWh) is 35% of the cost of producing electricity with diesel at Ankerlig[64] (R3.13/kWh) (Figure 15). This calculation was based on the assumption that Ankerlig would continue to run at its 2013/14 load factor of 20% with diesel at R8.40/litre (see Appendix B). and the CCGT would run at a 47% load factor with LNG landed at $10/MMBtu. If LNG is landed at $15/MMBtu instead of $10/MMbtu, electricity could still be produced with a gas-fired CCGT at roughly 50% of the cost of using diesel-fired Ankerlig (Figure 15).The calculations and assumptions supporting these estimates can be found in Appendix B.

Furthermore, LCOE estimates from the IRP 2010 suggest that if even if Ankerlig was kept in its current OCGT configuration, electricity could be produced at roughly 50% of its current cost simply by replacing the diesel feedstock with imported natural gas [65](Figure 15).

Overall, these estimates suggest that a clear case for the conversion of Ankerlig from a diesel-fired plant to a imported gas-fired plant can be made on the basis that electricity generated using imported natural gas is likely to be significantly less expensive than that generated with diesel.

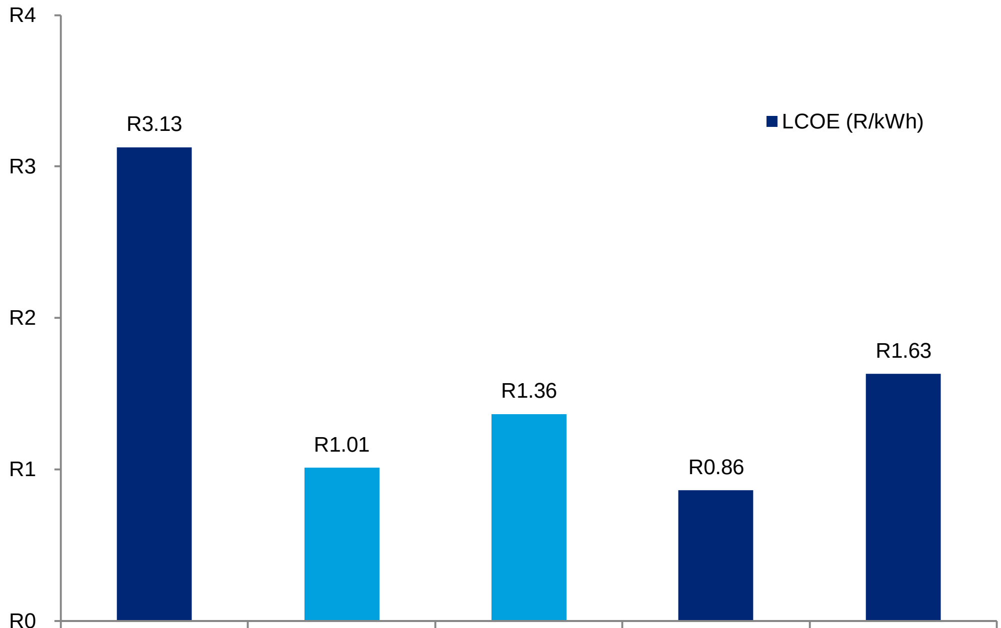
[62] The LCOE includes all the major costs associated with a power plant, including the initial investment, operations and maintenance, cost of fuel and the cost of capital.

[63] Assuming LNG landed at $10/MMBtu and 2070MW CCGT running at 45% load factor.

[64] Diesel prices as at August 2014 and 1350MW Ankerlig running at a load factor of 20%.

[65] The IRP 2010 update assumed a landed LNG price of R92/GJ, which at an exchange rate of R10.50/$ translates into a lower-end LNG price estimate of $8.7/MMBtu.

**Figure 15: Comparison of LCOE estimates for gas turbines fuelled with LNG and diesel**




| | Ankerlig OCGT 1350MW, Diesel R8.40/l | Ankerlig CCGT 2070MW, LNG $10/MMBtu | Ankerlig CCGT 2070MW, LNG $15/MMBtu | IRP 2010 Update CCGT 711MW, LNG $8.7/MMBtu | IRP 2010 Update OCGT 115MW, LNG $8.7/MMBtu |
|---|---|---|---|---|---|
| LCOE (R/kWh) | R3.13 | R1.01 | R1.36 | R0.86 | R1.63 |
| Load factor | 20% | 47% | 47% | 50% | 10% |

*Source: Deloitte analysis*

The business case for a second gas-fired CCGT plant in the Western Cape rests on the relative costs and merits of natural gas-fired CCGT versus a number of alternative power generation technologies. The LCOE for various power generation technologies is compared in Figure 16. All LCOE estimates were obtained from Electric Power Research Institute Report (EPRI) 2012[66], with the exception of diesel-fired OCGT and LNG-fired CCGT, which are based on our calculations[67].

While the LCOE for an imported-gas-fired CCGT on the West Coast (at R1.10/kWh) may be higher than the LCOE for coal-fired plant in South Africa (which according to EPRI estimates ranges from R0.58/kWh to R1.30/kWh) [68] it is comparable to the LCOE of Eskom's new coal-plant - Medupi is expected to produce electricity at a LCOE of R1.05/kWh[69].

[66] Electric Power Research Institute (2012) *Power Generation Technology Data for Integrated Resource Plan of South Africa.* [Online] Available at: http://www.doe-irp.co.za/content/EpriEskom_2012July24_Rev5.pdf. [Accessed 14 October].

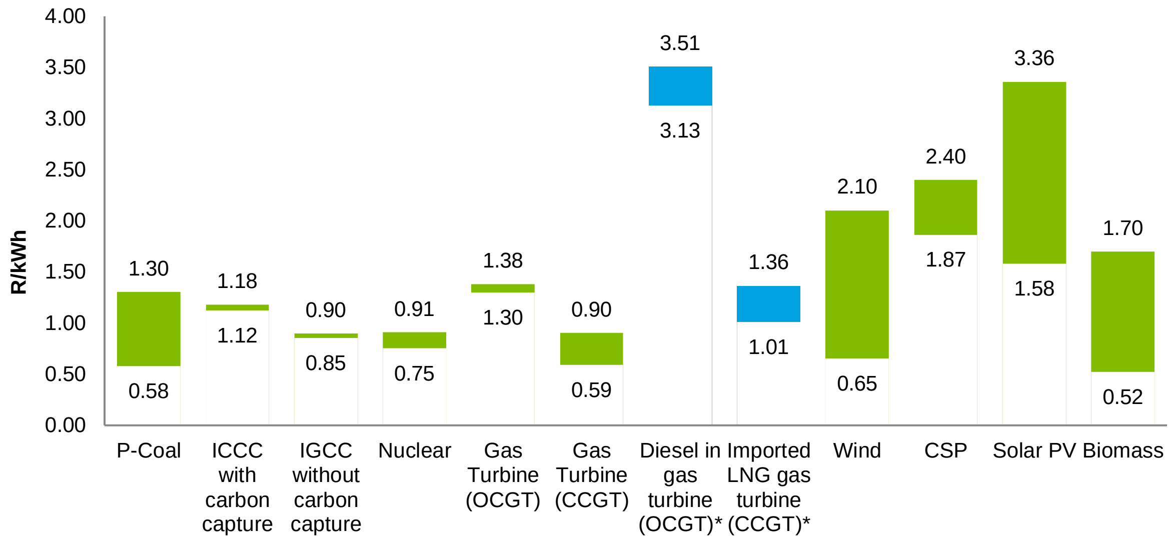
[67] EPRI estimates of the LCOE for gas-fired OCGT and CCGT plants are significantly lower than the Deloitte estimates, as they were based on the assumption that cheaper domestic gas would be available and they assumed a R8.00/$ exchange rate as compared to our R10.50/$.

[68] Based on estimates from Electric Power Research Institute (2012) *Power Generation Technology Data for Integrated Resource Plan of South Africa.* [Online] Available at: http://www.doe-irp.co.za/content/EpriEskom_2012July24_Rev5.pdf. [Accessed 14 October].

[69] Gosling, M. (2013) *More wind in power industry sails.* Business Report. 1 November 2013. [Online] *Available at:* http://www.iol.co.za/business/companies/more-wind-in-power-industry-sails-1.1600609#.VEOcI3gaIX4 [Accessed 12 October 2014]

The cost of electricity from imported gas-fired CCGT plants also compares favourably with the cost of producing electricity from renewable sources such as wind, CSP and solar PV (Figure 16)[70]. The estimated LCOE for nuclear plant at R0.90/kWh is similar to imported gas-fired CCGT but the LCOE does not reflect the substantially higher construction, financial or operational risks associated with nuclear nor the significantly higher environmental costs.

**Figure 16: Comparison of LCOE for various power generation technologies**




*Source: Deloitte analysis based largely on EPRI 2012 estimates, *data points in blue based on Deloitte estimates (see Appendix B)*

### 5.2.4.3. Other considerations in switching to LNG in power generation

*While the choice of power generation options largely depends on relative cost, other factors that could also influence the decision to switch are:*

1. Reliability and flexibility in generation (i.e. reliability of power supply and flexibility (load following capability) to increase or reduce output)
2. Availability of the input fuel source
3. Environmental impact (including GHG emissions, water-use, land-use, waste disposal and visual impacts)
4. Operational and financial risk
5. Ease of implementation (modularity) and time to deploy
6. Economic impact (e.g. percentage of total spending retained in SA and direct and indirect job and GDP impacts associated with construction and operation)
7. Reliance on government funding

[70] Based on estimates from Electric Power Research Institute (2012) Power Generation Technology Data for Integrated Resource Plan of South Africa. [Online] Available at: http://www.doe-irp.co.za/content/EpriEskom_2012July24_Rev5.pdf. [Accessed 14 October].

The natural gas-fired CCGT plants included in the gas-to-power scenario have several technical advantages over other fossil-fuel-based and renewable technologies. These technical advantages give rise to many of the potential socio-economic benefits that are associated with imports of LNG and, as such, are discussed in the following section.

#### 5.2.4.4. Conclusions on fuel-switching

In conclusion, our analysis suggests that power generators in South Africa will find imported-gas fired CCGT plants an attractive solution on the basis that they are a cost-competitive alternative to many alternative forms of power generation including diesel-fired OCGT, renewable energy plant and potentially even coal, and are beneficial in terms of capital cost, time to completion, ability to attract private sector investment and offer technical flexibility.

### 5.2.5. The socio-economic costs

#### 5.2.5.1. Capital cost of infrastructure

The capital cost associated with the power generation assets in the gas-to-power scenario is estimated at R14.2bn while the LNG import terminal and associated transmission pipelines would cost an additional R2.8bn to R5.2bn depending on the choice of terminal.

Estimates of the cost of this infrastructure, as provided in the prefeasibility study[71], are summarised in **Table 5.** The conversion of the Ankerlig OCGT plant to a larger 2 070MW CCGT facility is estimated tocost R7bn while a new 800MW CCGT plan would cost in the region of R7.2 bn. The total capital costs of infrastructure associated with the gas-to-power scenario are R17nm if an offshore terminal is selected and R19.5bn for the onshore terminal option.

The conversion of the Ankerlig OCGT plant to a larger 2 070MW CCGT facility is estimated to cost R7bn, while a new 800MW CCGT plant would cost in the region of R7.2 bn. The total capital costs of infrastructure associated with the gas-to-power scenario are R17bn if an offshore terminal is selected and R19.5bn for the onshore terminal option.

[71] Western Cape Government (2013) Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor, J. H. Visagie.

**Table 5: Estimate of infrastructure costs associated with "gas-to-power"**

| Description | | Onshore terminal | Offshore terminal | Data source/assumptions |
|---|---|---|---|---|
| Terminal costs (US$ million) | | 380 | 135 | As assumed in prefeasibility study |
| Transmission pipelines (US$ million) | Phase 1 | 122 | 61.7 | As assumed in prefeasibility study |
| | Phase 2 | | 71.0 | |
| Terminal costs (R bn) | | 4.0 | 1.4 | Converted to rands assuming R10.50/$ |
| Transmission pipelines (R bn) | Phase 1 | 1.3 | 0.6 | Converted to rands assuming R10.50/$ |
| | Phase 2 | | 0.7 | |
| Sub-total for LNG import infrastructure costs (R bn) | | 5.3 | 2.8 | |
| Conversion of Ankerlig to a 2070MW CCGT plant (R bn) | | 7.0 | 7.0 | As assumed in prefeasibility study |
| New 800MW CCGT plant | | 7.2 | 7.2 | As assumed in prefeasibility study |
| (located in Milnerton or Saldanha) | | | | |
| Sub-total CCGT plant costs (R bn) | | 14.2 | 14.2 | |
| **Total for all "gas-to-power" infrastructure costs (R bn)** | | **19.5** | **17.0** | |

*Source: Deloitte analysis*

### 5.2.5.2. Negative impact of LNG imports on South Africa's trade balance

One of the potential drawbacks of using imported LNG as an input into power generation is the negative impact that an increase in fuel imports will have on South Africa's trade balance. This has been evident in Japan where, after the Fukushima nuclear incident in 2011, Japan shut down its domestic nuclear electricity generation capacity, which accounted for 30% of total electricity output and replaced it with gas-fired CCGT plant fuelled with imported LNG. According to the Japanese Ministry of Finance, substantial imports of LNG have seen the trade deficit almost doubling from $70bn in FY12 to $134bn in FY13[72]. This, in turn, has put downward pressure on the Japanese Yen and could put government credit ratings at risk of downgrade increasing the country's cost of borrowing.

Under the gas-to-power scenario, the converted Ankerlig CCGT plant of 2 070MW and new-build 800MW CCGT plant would together produce roughly 11 800GWh gas-fired electricity (Table 6). Ankerlig is currently producing about 2 400GWh of electricity a year, so an additional ~9 500GWh of electricity would be provided to the grid annually.

[72] World Nuclear Association, August 2014, "Nuclear Power in Japan"

**Table 6: Additional electricity output generated under "gas-to-power" scenario**

| | Plant capacity (MW) | Load factor | Hours utilisation | MWh | GWh |
|---|---|---|---|---|---|
| **Current electricity output** | | | | | |
| Ankerlig | 1 350 | 20% | 1 752 | 2 365 200 | 2 365 |
| **Electricity output under "Gas-to-power" scenario** | | | | | |
| Ankerlig | 2 070 | 47% | 4 117 | 8 522 604 | 8 523 |
| New 800MW plant | 800 | 47% | 4 117 | 3 293 760 | 3 294 |
| Total | | | | | 11 816 |
| **Additional electricity output (difference in GWh)** | | | | | **9 451** |

*Source: Deloitte Analysis*

At the current exchange rate of R10.50/$ and assuming an LNG price of $10/MMBtu, total LNG fuel import associated with the two CCGT plants will amount to approximately R9.2 bn annually (Table 7). We estimate that imports of LNG at R9.2bn (holding all else constant) would increase South Africa's annual trade deficit, which stood at R73bn in 2013 by approximately 13%.

**Table 7: Estimates of annual fuel imports required under various power generation scenarios**

| | Load factor assumed | Hours utilisation per year | GWh per year | Fuel cost Rm/GWh | Total estimated annual fuel cost (Rbn) |
|---|---|---|---|---|---|
| **Diesel-fired turbines** | | | | **Diesel R8.40/l** | |
| Ankerlig 1 350MW OCGT | 20% | 1 752 | 2 365 | 2.7 | 6.3 |
| Ankerlig 1 350MW OCGT | 10% | 876 | 1 183 | 2.7 | 3.2 |
| **Gas-fired turbines** | | | | **LNG $10/MMBtu** | |
| 2 070MW CCGT | 47% | 4117 | 8523 | 0.8 | 6.6 |
| New 800MW CCGT | 47% | 4117 | 3294 | R 0.8 | R 2.6 |
| **Total gas-fired** | | | **11 816** | | **R9.2** |

*Source: Deloitte analysis*

However, because we have assumed that Ankerlig will be converted to a gas-fired CCGT, imports of LNG will replace Ankerlig's existing imports of diesel, which will reduce the net impact on the trade balance. Operating at the current high load factor of 20%, we estimate that Ankerlig consumes R6.3bn of imported diesel annually[73] (see Appendix B for calculations). Assuming that Eskom would have to continue to operate Ankerlig at 20% load factor if it were not converted to a larger gas-fired CCGT, LNG imports of R9.2bn replace R6.3bn of diesel imports so that the net impact on the trade deficit is an increase of R2.9bn. An additional R2.9bn of fuel imports would increase South Africa's annual trade deficit, which stood at R73bn in 2013 by roughly 4%.

[73] We assumed that 90% of Ankerlig R10.5bn operating costs in 2013 were related to imported diesel.

Alternatively, if Eskom were able to operate Ankerlig at a more typical load factor of 10%, assuming that total power supply becomes less constrained, the total costs of annual diesel imports would be in the region of R3.2 bn. In this case, the net impact on the trade balance is an increase of R6bn fuel imports annually, which would see South Africa's annual trade deficit widening by 8% from R73bn to R79bn (assuming all else constant).

"An additional R2.9bn of fuel imports would increase South Africa's annual trade deficit, which stood at R73bn in 2013 by roughly 4%."

#### 5.2.5.3. Security of supply – increased reliance on imported fuel for electricity generation

Importing LNG as a fuel source for power generation will increase both the Western Cape and South Africa's reliance on imported fuel for electricity generation thereby, reducing security of supply.

Countries that import most of their energy requirements are exposed to a high degree of geopolitical risk, especially if they are reliant on, or tied to, one source of supply – as is often the case with piped gas. In the case of freely and widely traded commodities such as crude oil, the risk is substantially lower. The geopolitical risks associated with imports of LNG are therefore considered to be less than piped gas but greater than oil. Although LNG is increasingly globally traded, there are still only a few dominant global suppliers and most supply is secured in long-term contracts – just over 25% of total LNG traded was sold in short-term contracts or spot basis in 2013[74].

Currently, only a small proportion of the fuel used in electricity generation in South Africa is imported and includes enriched uranium for the Koeberg nuclear plant and diesel for the OCGT plants.
In addition to the capacity that relies on imported fuel, Eskom currently imports about 3.3%[75] of its total electricity output almost exclusively from the Cahora Bassa hydro plant in Mozambique.

In our gas-to-power scenario, the additional 9500GWh of electricity output from the new CCGT capacity represents 5% of total electricity output (all else assumed constant), which in our view is not a significant or risky proportion.

### 5.2.6. The socio-economic benefits

*While the costs associated with the gas-to-power scenario are substantial, in our view they are outweighed by the following benefits:*

#### 5.2.6.1. Cost-savings in electricity generation

"If Eskom has to continue to run Ankerlig at its current high load factor of 20%, the utility would be able to save as much as R5bn a year in costs to generate the same power output (roughly 2 400GWh) by switching from diesel to imported natural gas and converting the plant to a CCGT."

[74] International Group of Liquefied Natural Gas Importers (2013) The LNG Industry, 2013. [Online] Available at: http://www.giignl.org [Accessed 12 October 2014].
[75] based on FY 2012/13 figures

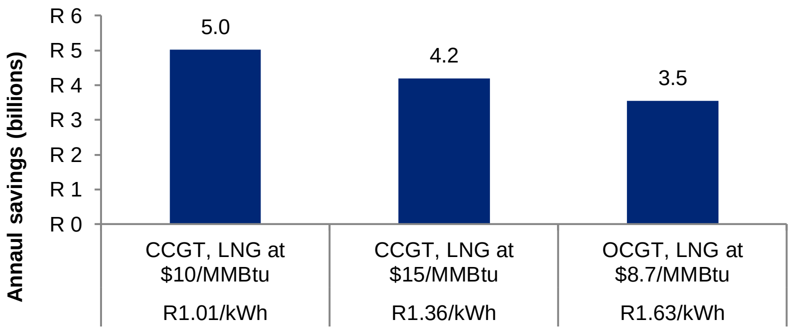
As discussed in Section 1.1.1.1, electricity could be produced at significantly lower cost if the diesel currently used in the Ankerlig OCGT plant at Atlantis was substituted with LNG. Cost-savings would however be greatest if the existing OCGT plant at Ankerlig was converted to a more efficient CCGT facility.

To estimate the total annual cost-savings that Eskom could realise if Ankerlig was converted to a natural gas-fired CCGT, we considered two reference cases. In the first reference case, Eskom continues to run diesel-fired Ankerlig at the current load factor of 20%, consuming an estimated R7.4bn of diesel annually. In the second reference case, Eskom operates Ankerlig at a load factor of 10%, which is more typical for an OCGT plant, consuming R3.7bn of diesel annually.

In the first reference case, Eskom would be able to save as much as R5bn a year in costs to generate the same power output (roughly 2 400GWh) by switching from diesel to imported natural gas and converting the plant to a CCGT[76] (

Figure 17).

**Figure 17: Reference Case 1: Potential cost-savings if Ankerlig runs at a load factor of 20%**



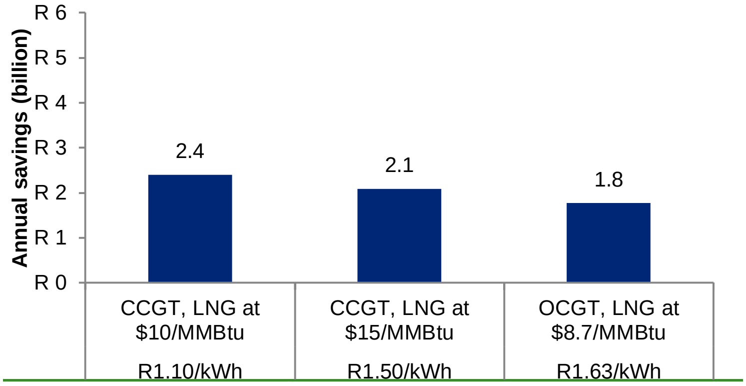

*Source: Deloitte Analysis based on own calculations and IRP 2010 update OCGT LCOE estimates*

If Eskom could operate Ankerlig at a more typical OCGT load factor of 10% in future, the utility would still be able to save as much as R2.4bn a year to generate roughly 1 200GWh of power by switching from diesel to imported natural gas and converting the plant to a CCGT (Figure 18).

Even if Ankerlig was not converted to a larger and more efficient CCGT plant, as we have assumed in our “gas-to-power” scenario, estimates based on the LCOE for an OCGT fuelled with imported natural gas from the IRP 2010 update suggest that around R1.8bn could be saved by simply substituting diesel with gas. The calculation and assumptions behind these estimates can be found in Appendix B. Overall, these estimates suggest that Eskom could realise significant cost-savings from its Ankerlig operations by switching from diesel to imported natural gas.

[76] Which is a more efficient technology and is designed to run at a higher load factor of 47%

**Figure 18: Reference Case 2: Potential annual cost-savings if Ankerlig runs at a load factor of 10%**




*Source: Deloitte Analysis based on own calculations and IRP 2010 update OCGT LCOE estimates*

### Lower average electricity tariffs

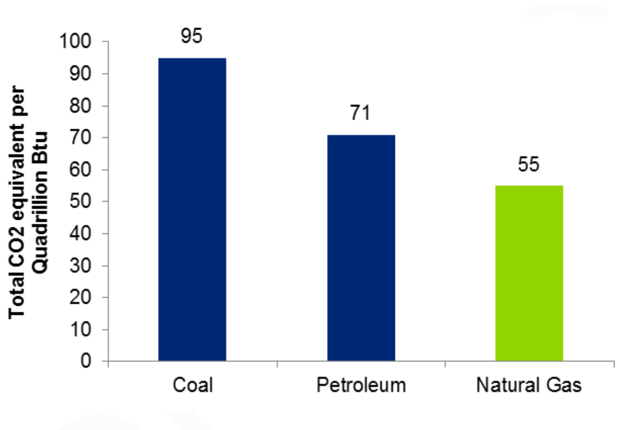
Ankerlig currently contributes about 1% of the Eskom's total annual power production[77], so if Ankerlig is able to produce power at 33% of current cost by switching to natural gas, it would result in a 0.66% reduction in Eskom's average tariffs (all other things being equal).

## 5.2.6.2. Environmental benefits – reduce GHG emissions and water use

*Reduction in greenhouse gas emissions*

Natural gas releases approximately 50% less carbon dioxide ($CO_2$) than coal and 33% less $CO_2$ than oil for every unit of useful energy[78]. Unlike petroleum, it is also practically free from sulphur dioxide and carbon monoxide emissions in combustion[79] (Figure 19).

**Figure 19: CO2 emissions from fossil fuel combustion**




*Source: Environmental Protection Agency in Centre for Climate Solutions, 2013*

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[77] Eskom produced 22750822 7508 GWh of electricity in 2013/14 according to the Eskom's 2014 integrated report while Ankerlig produced roughly 23652 365 GWh of electricity in 2013/14 (own estimates).

[78] Centre for Climate and Energy Solutions. (2013)*Leveraging natural gas to reduce greenhouse gas emissions, June 2013 [online].* Available from http://www.c2es.org/publications/leveraging-natural-gas-reduce-greenhouse-gas-emissions. [Accessed: 9 October 2014]

[79]Sarkar, SC, (2005) LNG as an energy efficient eco-friendly cryogenic fuel. Journal of Energy in Southern Africa [Online]. Vol. 16 No. 4 (November 2005). Available from http://www.erc.uct.ac.za/jesa/volume16/16-4jesa-sarkar.pdf. [Accessed: 9 October 2014].

As a result, natural gas-fired CCGT power plants emit approximately 50% less $CO_2$ and up to nine times less $NO_x$ per MWh than modern coal-fired power plants (Table 8). OCGT plants such as Ankerlig are less efficient than CCGT technology and therefore emit around 40% more $CO_2$ than CCGT plants using the same fuel.

**Table 8: Summary of environmental benefits of natural gas vs coal power generation**

| Environmental impact | Gas-fired OCGT | Gas-fired CCGT | Coal-fired power plant |
|---|---|---|---|
| **$CO_2$ and other GHG emissions, kg/MWh** | 480–575 | 340–400 | 730–850 |
| **NOx, g/MWh** | 50 | 30 | 180–800 |

*Source: IEA ESTAP technology brief E01 (Coal Power) and E02 (Gas) – April 2010*

The conversion of Ankerlig to a CCGT and construction of a new 800MW CCGT under the GTP scenario would provide an additional 9500GWh of electricity output annually in the Western Cape (see Table 6 on page 50 for calculations). Assuming that the additional 9500GWh of gas-fired electricity output would reduce the requirement to import coal-fired electricity from Mpumalanga by the same amount each year, approximately 3.8 million tons of CO2 emissions would be saved annually. This would reduce total provincial GHG emissions by approximately 9%. The $CO_2$ emissions that are associated with 9500GWh of electricity produced with a conventional coal-fired power station and a gas-fired CCGT are compared in Table 9.[80].

"Assuming that the additional 9500GWh of gas-fired electricity output would reduce the requirement to import coal-fired electricity from Mpumalanga by the same amount each year, approximately 3.8 million tons of $CO_2$ emissions would be saved annually. This would reduce total provincial GHG emissions by approximately 9%"

**Table 9: Difference in tonnes of $CO_2$ produced annually – coal vs gas**

| | Gas CCGT | Coal-fired plant | Difference |
|---|---|---|---|
| **GWh produced annually** | 9 500 | 9 500 | |
| **Tonnes $CO_2$/GWh** | 340 | 740 | |
| **Tonnes of $CO_2$ produced annually** | 3 230 000 | 7 030 000 | **3 800 000** |

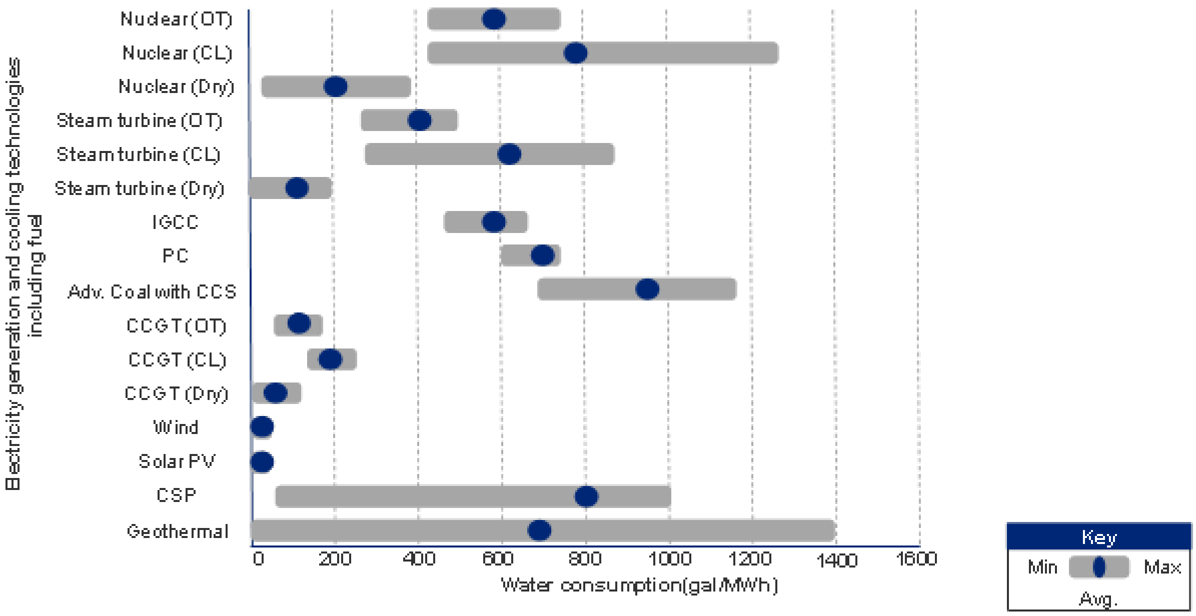
*Source: Deloitte analysis based on IEA estimates*

### *5.2.6.2.1. Reduction in water usage*

The Western Cape and West Coast in particular are water-scarce areas and the minimisation of water usage should be a factor in choosing power station technology in the province. Atlantis (the area where Ankerlig is currently situated) is located over an underground aquifer from which the community's water supplies are sourced, and this presents additional considerations for choosing the appropriate technology for a power plant.

[80] based on the lower bound emissions estimates for both fuels

**Figure 20: Water consumption in electricity generation using different cooling technologies***




** including water consumed during fuel extraction and processing*

*Source: Water Consumption of Energy Resource Extraction, Processing and Conversion, Harvard Kennedy School, 2010*

Of all the forms of power generation, natural gas-fired combined cycle power plants (CCGT) have some of the lowest consumption of water per unit of electricity generated, in part because of their relatively high thermal efficiency[81].

In Figure 20, water consumption for various types of power generation plants is compared for once-through (OT), closed loop (CL) and dry cooling technologies. Natural gas-fired CCGT plants have significantly lower water consumption rates per MWh of electricity generated than nuclear, steam turbines (coal) and concentrated solar power.

The conversion of Ankerlig to a natural-gas-fired CCGT plant and new-build CCGT plant in the Western Cape would assist in reducing the average water consumption associated with each GWh of electricity generated in both the Western Cape and South Africa.

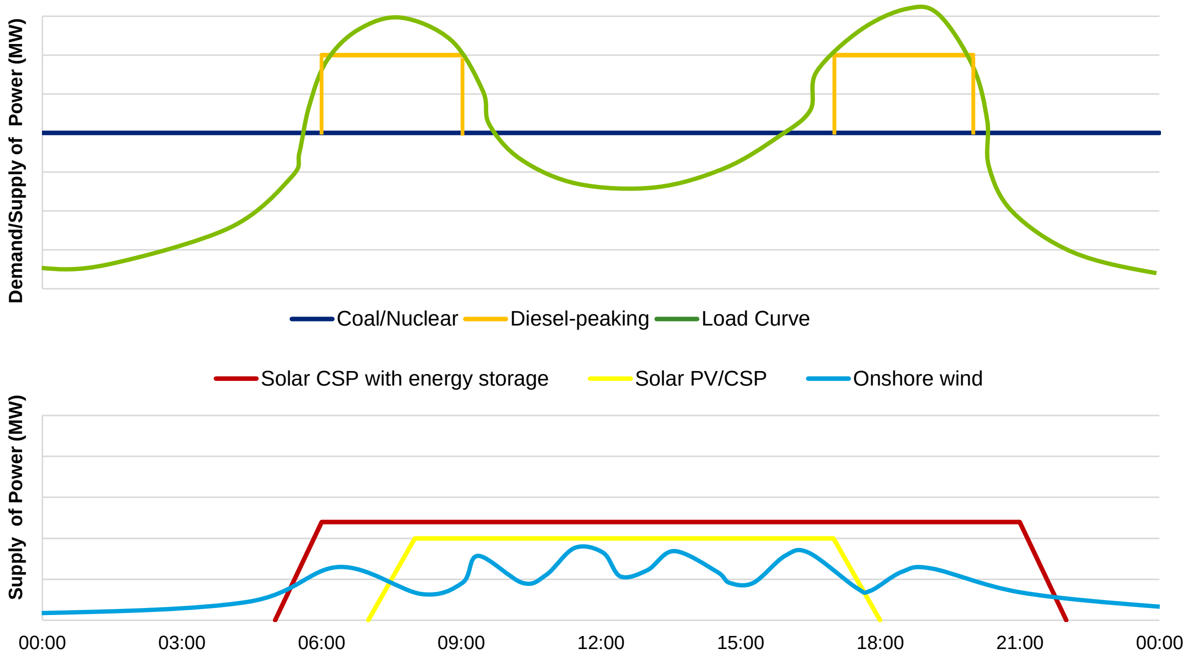
[81] Harvard Kennedy School, 2010, “Water Consumption of Energy Resource Extraction, Processing, and Conversion”

#### 5.2.6.3. Support the expansion of renewable energy build and avoid unnecessary baseload and peaking capacity

A drawback of generating power from renewable energy sources such as wind and solar is that the volume of power generated is intermittent and unpredictable. As noted in EPRI (2012:221), bringing wind and solar PV generation onto the grid usually means that additional flexibility is required in other sources of power generation to accommodate the variability of renewable generation[82].

A schematic representation of South Africa's load curve (demand profile) against power capacity supplied by various sources including wind, solar PV/CSP, coal/nuclear and diesel-peaking plants is provided in Figure 21.While coal and nuclear capacity provide predictable baseload capacity in South Africa, peak demand exceeds baseload supply. Solar PV and CSP provide somewhat predicable supply during daylight hours while power supply from wind generation capacity is variable (there are days and weeks where wind capacity may provide no power). For grid operators like Eskom, who need to match variable power demand with supply, the variable nature of renewable energy power supply creates challenges. As Eskom notes "natural gas is the only power generation technology that can follow the South African load curve – the morning and evening peaks and be ramped down overnight."[83]

**Figure 21: Wind power generation vs thermal (coal) generation, BPA January 2014***




*Source: Deloitte based on Eskom 2012, Gas Sourcing Strategy Presentation*

**Not to scale*

[82] Electric Power Research Institute (2012) *Power Generation Technology Data for Integrated Resource Plan of South Africa.* [Online] Available at: http://www.doe-irp.co.za/content/EpriEskom_2012July24_Rev5.pdf. [Accessed 14 October].

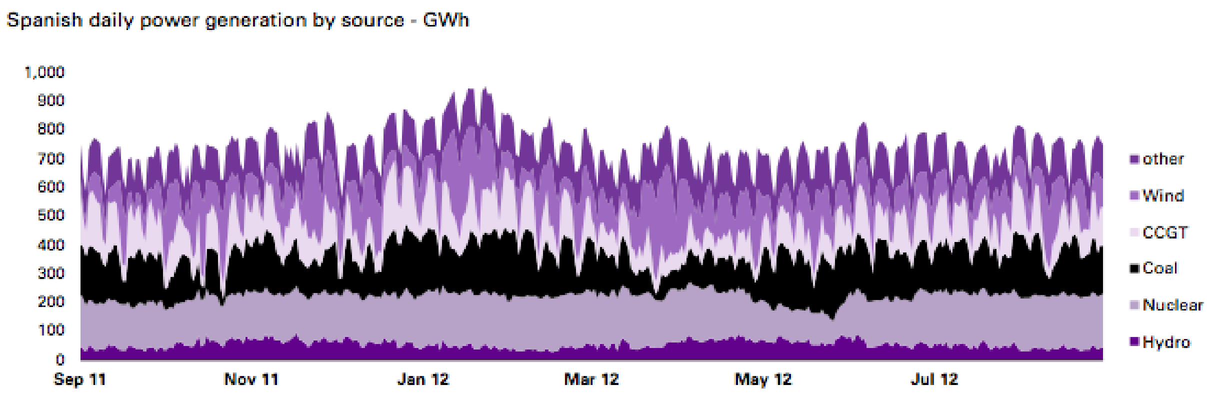
[83] Eskom (2012) *Presentation on the Gas sourcing strategy. Marokane, D.*

According to a report by the Scott Institute for Energy Innovation[84], fast ramping generation sources, which include gas turbines and gas engines with modern design and batteries, are best suited for balancing higher frequency variability from renewable generation. In the United States, the practice is to provide gas turbines as a back-up in system reserve to account for intermittency of renewable energy power generation[85]. Regulatory agencies typically assign a value of about 10% to 15% of the total installed capacity of wind farms to the reserve margin, and any shortfall in reserve margin is made up with gas turbines and gas engines.

The IRP 2010[86] noted that: as renewable energy generation capacity as a proportion of total installed capacity increases towards the “Policy-Adjusted IRP scenario” targets of 10% by 2020 and 20% by 2030, the benefits of increased flexible dispatch generation (such as gas turbines and pumped storage) would need to be considered to ameliorate the impact of fluctuating renewable energy capacity on the system. Eskom noted in late 2014 that 1000MW of renewable energy capacity had been connected to the grid[87] but it appears that the impact of increased penetration of fluctuating renewable capacity on the system is not yet known and that more research will be required in terms of identifying required support from flexible dispatch generation.

An example of how CCGT plants are used to offset the intermittency of renewable energy generation in Spain (and particularly wind), sourced from a report by Goldman Sachs, is provided in Figure 22. According to the Goldman Sachs report[88], the “Spanish grid operator has been able to manage successfully the intermittency of solar and wind power, partly by leveraging the spare capacity of gas and coal-fired plants… In order to balance the grid, daily generation from gas and coal-fired plants was negatively correlated with wind power output.”

**Figure 22: Spanish Power grid – example of using CCGT and coal to complement renewables**




*Source: Goldman Sachs analysis of the thermal coal industry, 2013 based on Red Eléctrica de España*

[84] Carnegie Mellon University, Scott Institute for Energy Innovation (2013) *Managing Variable Energy Resources to Increase Renewable Electricity's Contribution to the Grid*

[85] Electric Power Research Institute (2012) *Power Generation Technology Data for Integrated Resource Plan of South Africa*. [Online] Available at: http://www.doe-irp.co.za/content/EpriEskom_2012July24_Rev5.pdf. [Accessed 14 October].

[86] Department of Energy (2011) *Integrated Resource Plan for Electricity 2010-2030 Update Report*. [Online]. Available at: http://www.energy.gov.za/IRP/irp%20files/IRP2010_2030_Final_Report_20110325.pdf Accessed [14 October 2014]

[87] Business Report (2014) Eskom's profit drops by 24%.[Online] Available at: http://www.iol.co.za/business/news/eskom-s-profit-drops-by-24-1.1786305#.VLv8k0eUdq0

[88] Goldman Sachs, 24 July 2013, “The window for thermal coal investment is closing”

“The combined renewable energy capacity in Eskom’s ‘Western Region’ when projects from REIPPPP bid windows 1 to 3 come online, will be a substantial 2 492MW. The availability of fast-ramping gas-fired CCGT plants in the Western Cape region could, in our view, greatly enhance the grid stability in Eskom’s Western Region (Western and Northern Cape).”

In the Western Cape, new gas-fired CCGT capacity could play a crucial role in managing the intermittency of solar and wind power generation in the region. The combined renewable energy capacity in Eskom’s Western Region (Western and Northern Cape) when projects from bid windows 1 to 3 come online will be a substantial 2 492MW. The availability of fast-ramping gas-fired CCGT plants in the Western Cape region could, in our view, greatly enhance the grid stability in Eskom’s Western Region. Gas-fired CCGT plants have a role to play in ensuring that the integration of wind and solar power onto the South African grid is economically viable and that its contribution can continue to grow. The provision of flexible gas-fired capacity could also reduce the requirement for additional baseload and/or diesel-fired peaking capacity which when used to meet peak-demand are less cost-effective than gas.

#### 5.2.6.4. LNG imports will facilitate further diversification of the electricity generation mix and will enable private-sector investment, reducing pressure on the fiscus

The NDP lists the need for a greater mix of energy sources and a greater diversity of independent power producers (IPPs) in the energy industry among its energy sector planning priorities. The gas-to-power scenario supports both of these objectives.

Under our gas-to-power scenario, the conversion of Ankerlig to a CCGT plant would be undertaken by Eskom, but the new-build of an 800MW CCGT power plant somewhere on the West Coast presents an opportunity to attract private-sector investment in electricity generation capacity in the Western Cape.

CCGT plants are attractive to private-sector investors because they are relatively small modular plants that typically take between 24 and 36 months to deploy. Large lumpy power investments like nuclear power plants and mega-coal plants, by contrast, can take more than 10 years to build and are associated with significantly higher financial, operational and construction risk. Nuclear plants and mega-coal projects are seldom financed without some government support – be it direct support in the form of debt or equity, or indirect support through the provision of financial guarantees.

Imports of LNG will facilitate the development of gas-fired CCGT generation capacity in the Western Cape and contribute to increasing private-sector participation and investment in electricity generation in South Africa as a whole, reducing the burden on the fiscus.

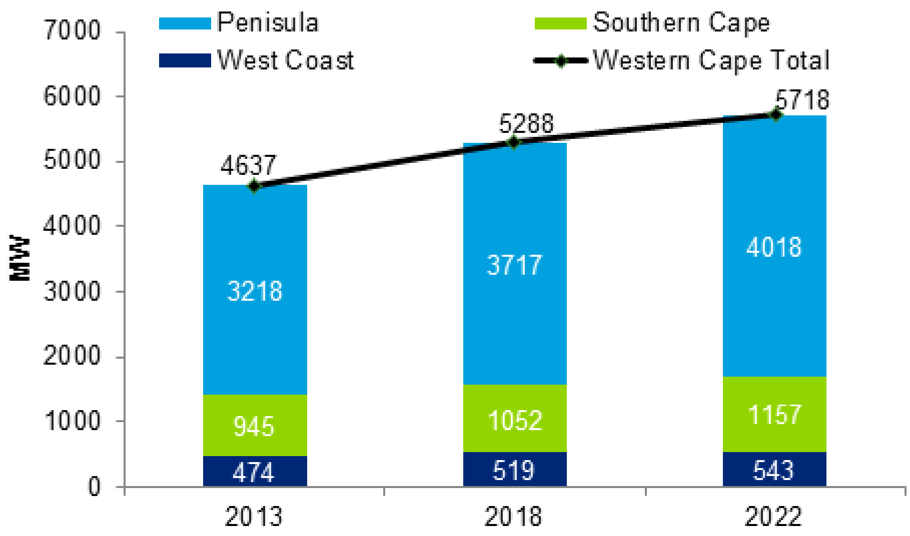
#### 5.2.6.5. Improve security of electricity supply in the Western Cape and reduce transmission losses

In 2005 and 2006, the Western and Northern Cape experienced rolling electricity blackouts due to damage caused to a unit at the Koeberg nuclear plant by a bolt that was accidently left in one of the plant's reactors. The energy crisis prompted the Western Cape to consider a plan to reduce the province's exposure to future electricity supply disruptions and to improve the security of supply within the province. The Western Cape Provincial Government's Sustainable Energy Strategy aims to ensure that the Western Cape is able to maintain a secure supply of quality, reliable and clean energy.

The Western Cape is responsible for approximately 10% of national electricity consumption[89], but it has less than 5% of the country's electricity generation capacity. As discussed in Section 5.2.2.3, the Western Cape has a peak power supply deficit and has to import an average of 2 050MW[90] daily from coal-fired plants that are located over 1 500km away, in Mpumalanga.

With peak demand in the Western Cape expected to increase to 5 288MW by 2018 and to 5 718MW by 2022 (Figure 23), the need to import power from coal-fired baseload power stations is likely to increase, unless demand can be met with local renewable and gas generation capacity. While the Northern and Western Cape have together been awarded over 2 492MW of renewable energy projects to date, these more intermittent sources of power will need to be complemented with conventional gas-fired CCGT capacity to ensure the consistent availability of power at peak times in the Western Region.

**Figure 23: Western Cape current and forecast peak demand**




*Source: Eskom (2013) Transmission Ten-Year Development Plan 2013–2022*

[89] Western Cape consumed approximately 22485GWh22 485GWh of electricity in 2009 based on the 2013 WCG report on energy consumption, national consumption in 2009 according to the 2012 Eskom annual report was 214850214 850 GWh. Based on these figures, the Western Cape consumes 10.5% of total GWh sold.

[90] Visagie, HJ.,(, (2013*) Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay–Cape Town corridor*. Energy Business.

LNG imports for use in gas-fired CCGT plants would assist the Western Cape in achieving greater security of supply. The 2 870MW of gas-fired CCGT plant would significantly reduce the current requirement to import around 2 050MW of capacity from Mpumalanga at peak times. Estimated transmission losses of around 200MW[91] could also be saved, potentially releasing over 2 200MW of coal-fired power capacity for inland use.

With peak demand in the Western Cape set to increase, the CCGT capacity outlined in our gas-to-power scenario will not be sufficient to meet the medium-term regional power requirements. According to information provided in Eskom's latest Transmission Development Plan (2015-2024)[92] (TDP), the Western Cape Region is likely to continue to experience a peak power deficit of 2350MW until 2024 across all three generation scenarios modelled (which include 'IRP base', 'green base' - increased gas and renewables to replace nuclear and 'increased imports' to replace coal and nuclear). As a result Eskom is currently investing in a new high voltage 765kv transmission interconnector between Mpumalanga and the Cape to facilitate transmission of inland power from large inland coal generation plants to the Northern and Western Cape. However the TDP (2015 to 2024) suggests that within 25 years the Western Cape region will move into a peak power surplus under both the 'base IRP' and 'increased import' scenarios. The Western Cape remains in deficit under the 'green base' scenario but neighbouring Northern Cape moves into a surplus position.

### 5.2.6.6. LNG imports could help to alleviate electricity supply constraints and unlock potential economic growth

The much-anticipated mega-coal generation projects, Medupi and Kusile, will be commissioned gradually over the next few years (beginning in June 2015) and will add 9 600MW of power to the grid. However, the additional coal-fire capacity will not increase total generation capacity by a full 9600MW as some inefficient plant is also due for decommissioning. The availability of imported LNG on the West Coast could make a contribution to alleviating South Africa's power shortage within the next 3 to 5 years – a period in which there are few alternatives.

Inadequate power supply is posing a serious constraint to the economic growth in South Africa. The negative impact of outages on the economy is almost immediate - in 2008, Deloitte estimated that load shedding (which took place for several months) shaved 0.5 percentage points off GDP growth costing the economy R11.3bn[93]. The more insidious impact on GDP (and probably the largest) is the extent to which the general shortage of power is deterring new investment. Figures for the second quarter of 2014 suggest that the South African economy is currently expanding at a rate of 0.6% q/q (seasonally adjusted and annualised), which is well below recent estimates of our long-term potential GDP annual growth rate of 3.5%[94]. Electricity supply constraints are but one of many factors that could explain South Africa's lacklustre economic growth so its impact while in all likelihood significant, is difficult to distinguish and quantify.

[91] Visagie, HJ.,(, (2013*) Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay–Cape Town corridor*. Energy Business.

[92] Eskom (2014) Presentation on the Transmission Development Plan (2015 to 2024) and Transmission Strategic Grid Study 2040. October 2014. [Online]. Available at: http://www.eskom.co.za/Whatweredoing/TransmissionDevelopmentPlan/Documents/2015-2024TDP_SGP_Presentation20141010.pdf

[93] Deloitte (2008) The Economic Impact of the National Recovery Plan Key issues and choices. Report commissioned by Eskom Holdings Ltd.

[94] Ehlers, N, Mboji, L and Smal, MM. (2013) *The pace of potential output growth in the South African economy. South African Reserve Bank.* [Online]. Available at: https://www.resbank.co.za/Lists/News%20and%20Publications/Attachments/5600/WP1301.pdf

Ghana[95] and India[96] are example of countries that have used LNG imports to address short-to-medium term energy shortages and unlock economic potential and details on these case studies are provided in Box 1. As is the case in India LNG-fired plants are unlikely to replace coal in baseload power generation in South Africa, but they could assist in meeting peak demand in a cost-effective manner. Because they are scalable and take a short time to construct relative to coal, hydro or nuclear-plant, gas turbines are an attractive option to alleviate South Africa's short-to-medium-term electricity supply constraints and to raise potential economic growth.

Imports of LNG into the West Coast of South Africa would under our GTP scenario increase South Africa's total national power output by approximately 5%, and as in the case in Ghana could contribute to alleviating the power constraints that we believe will persist for the next decade.

[95] "Quantum, Golar sign deal for Ghana LNG Terminal", Africa Reuters, www.af.reuters.com, Accessed 14 October 2014. "Ghana: Works on gas plant almost done. Jubilee gas to flow in 3Q," Offshore Energy Today, www.offshoreenergytoday.com, [Accessed 14 October 2014]

[96] International Energy Agency (2014) *Energy Supply Security in India* [Online] Available at: http://www.iea.org/media/freepublications/security/EnergySupplySecurity2014_India.pdf. Accessed [16 October]

**Box 1: The role of LNG can play in addressing energy shortages, the cases of India and Ghana**

Ghana's economic growth has been constrained for well over a decade by insufficient supply of energy. To address these shortages, plans have been approved for the construction of 250 million cubic feet per day offshore LNG import terminal. The import terminal is planned to provide gas to the Volta River Authority (VRA) for power generation projects beginning in 2016.

It is envisaged that LNG will replace more expensive light crude oil in current power generation facilities and will fuel an additional 500MW gas-fired power plant. In a country where total electricity generation capacity was approximately 2 000 MW in 2010, this represents a potentially significant step-change in the energy sector being able to meet the needs of the economy. In addition to the LNG import terminal, a gas plant with capacity to process 150 standard cubic feet of natural gas per day is due for commissioning in December 2014, which will help ease constraints and save the government an estimated USD500 million annually through reduced oil imports.

In India, the economy has expanded at an annual average rate of 7% to 8% over the past decade, leading to a sharp increase in energy consumption. While GDP growth slowed to 5% in 2013, the IMF forecasts growth of above 6% from 2016. Over the next few years, there will be a substantial increase in natural gas demand from power, fertiliser and industrial sectors. While India has domestic sources of natural gas, production from its maturing gas fields is stagnating and production from the newer KG-D6 field has disappointed.

India began importing LNG in 2004 into the gas-dominated West of the country at the two operating terminals at Dahej and Hazira in the State of Gujarat. Imports accounted for 28% of total Indian gas supply in FY 2011/12, but the share of imported LNG in total gas supply is expected to increase to almost 70% by 2017 in light of falling domestic supply. LNG imports are assisting in meeting the energy deficit in this gas-dominated Western region of India.

India has a two-market structure for pricing of natural gas: the first tier is a regulated market for domestically produced gas which feeds power generation, fertiliser production, city gas distribution and the liquid petroleum gas (LPG) and steel industries; the second tier is an unregulated market based on imported LNG, sold at free pricing on a cost basis . The two largest consumers of domestic natural gas are the power sector and fertiliser industry, which account for almost 80% of total consumption. The fertiliser industry is, however, very price-sensitive and cannot afford LNG at current landed prices. LNG is mostly consumed by captive and price-robust industrial consumers.

Currently, coal meets more than 50% of energy demand in India, and with the fifth-largest coal reserves in the world, average power prices of coal-fired power are half that produced from LNG. Base load demand will therefore continue to be met primarily through the thermal coal-based plants, whereas gas and hydro plants can assist in meeting peak demand. India is forecast to experience peaking power shortfalls of more than 70GW by 2020 from its deficit in 2013 of around 30GW. Gas is the energy source to bridge the peaking power gap, other than solar and hydro-power, given scalability, availability and time to construct. So far, gas-based peaking power capacity addition has been constrained by domestic gas shortage and absence of peaking power tariff regulations.

## 5.3. Gas-to-Industry

### 5.3.1. Introduction

The prefeasibility study[97] suggests that since the infrastructure costs associated with a LNG import terminal and associated transmission infrastructure could be covered by a gas-fired CCGT plant, it would be financially feasible to extend the gas distribution network to some of the key industrial nodes once this ‘anchor customer’ is in place.

In this section, we explore some of the socio-economic costs and benefits that could be associated with increased use of imported natural gas by industry in the Western Cape. We begin with some background to energy use by the industrial energy sector in the Western Cape and then explain the gas-to-industry scenario we have assumed. We then consider whether industrial users would switch to gas. In the remainder of the chapter, we expand on the potential socio-economic costs and benefits that could be associated with the introduction of natural gas as an alternative fuel for industries.

### 5.3.2. Background and context

#### 5.3.2.1. Industrial sector energy use and mix in the Western Cape

The industrial sector in the Western Cape is responsible for approximately 34% of all energy consumed (112 879 GJ of a total of 339 195 GJ in 2009) [98]. Because of its heavy reliance on coal, the industrial sector contributes a disproportionate 38% of total GHG emissions in the province.

While comprehensive data on the energy mix for the industrial sector in the province was not readily available, a 2013 report on energy consumption in the Western Cape[99] notes that electricity is the largest contributor to total industrial energy use, followed by coal. Other energy sources for industrial users in the province include heavy fuel oil, diesel, paraffin and liquid petroleum gas.

The WCG report also notes that heavy industries in the West Coast District Municipality (which include the iron and steel industry, cement, lime, and mineral beneficiation) contribute substantially to the provincial energy and emissions picture. Industrial users consume 87% of all energy used in the district, and 78% of this energy comes from direct consumption of coal.

There is no existing natural gas market or infrastructure in the Saldanha–Cape Town corridor.
All infrastructure relating to the offloading, storage and re-gasification, transportation and distribution of natural gas to any potential markets in the region would need to be provided to facilitate the distribution of gas to potential end-consumers.

[97] Western Cape Government (2013) Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor, J. H. Visagie
[98] WCG (2013) Energy consumption and $CO_2$e emissions database for the Western Cape

99 WCG (2013) Energy consumption and $CO_2$e emissions database for the Western Cape

### 5.3.3. Gas-to-industry scenario considered

The scenario we have assumed for gas-to-industries is based on market analysis conducted as part of the 2013 WCG LNG prefeasibility study[100]. The findings of the prefeasibility study were based in part on a market survey of industrial customers and their energy use conducted by Gigajoule Africa.
The prefeasibility study notes that industrial customers would need to be linked to the LNG receiving terminal by means of series of gas distribution pipelines and could include any of the key industrial nodes in the corridor between Saldanha Bay and Cape Town on the West Coast.

The high potential industrial market for LNG in the Western Cape therefore includes the key industrial nodes in the Cape Town Metropolitan Area, the West Coast District Municipality and Cape Winelands Municipality as listed in Table 10.

**Table 10: Potential industrial market for LNG in the Western Cape – list of key industrial nodes**

| Cape Town Metropolitan Area | West Coast District Municipality | Cape Winelands District Municipality |
|---|---|---|
| • Atlantis Industria<br>• Cape Town Urban Centre<br>• Airport Industria<br>• Beaconvale<br>• Bellville South Industria<br>• Blackheath Industria<br>• Epping Industria<br>• Killarney Gardens<br>• Montague Gardens<br>• Kuilsrivier<br>• Lansdowne<br>• Maitland Industria<br>• Ndabeni Industria<br>• Newlands<br>• Parow Industria<br>• Phesantekrall<br>• Phillipi<br>• Sacks Circle<br>• Salt River Industria | • Saldanha Bay industrial node | • Paarl Industria<br>• Wellington Industrial Area<br>• Klapmuts<br>• |

*Source: Energy Business (2013) Prefeasibility study for imports of LNG into the Western Cape*

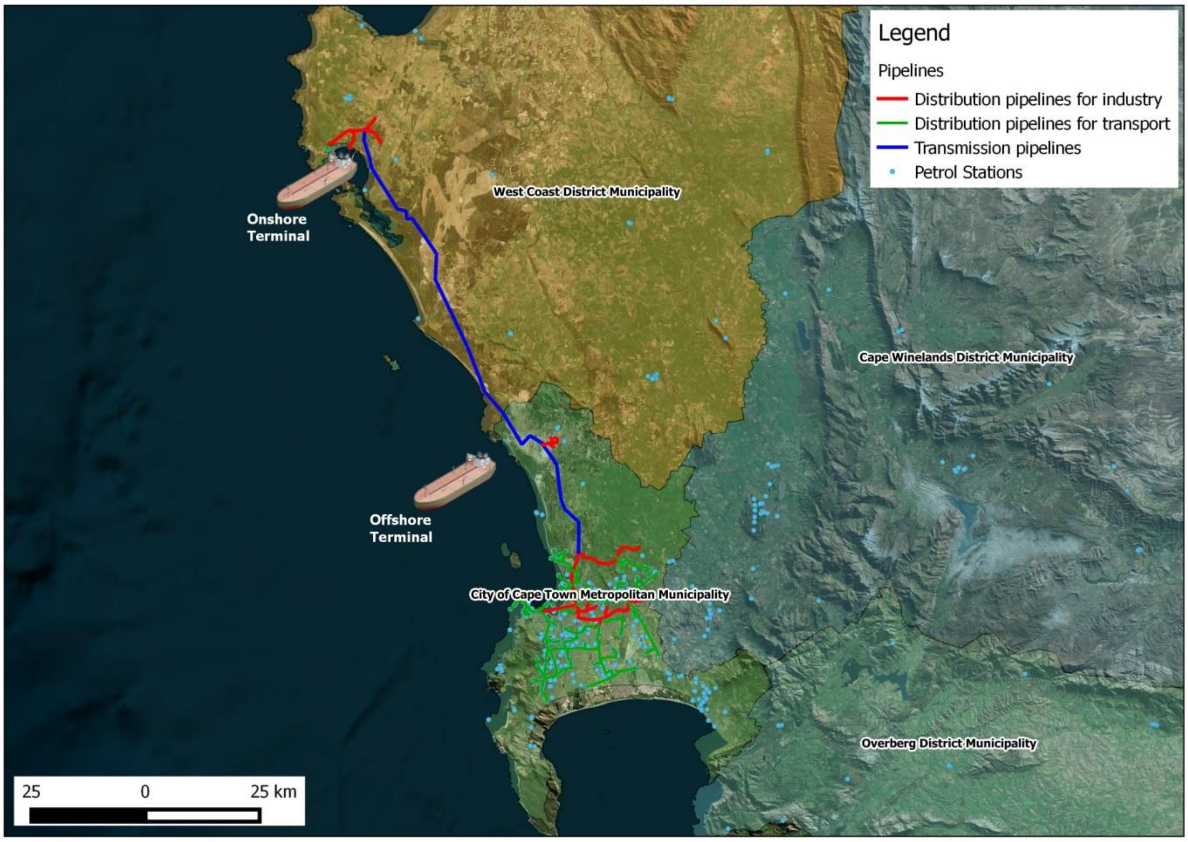
[100] Energy Business, 2013, "Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay–Cape Town corridor"

*The costs and feasibility of connecting these potential customers to the imported natural gas supply will depend on a number of factors including:*

1. Where the import receiving terminal is located
2. The landed and distributed cost of LNG relative to alternative energy sources
3. Other technical considerations in switching to LNG from existing fuel sources

For the purposes of this report, we have assumed that it would only be feasible to connect industrial nodes in the City of Cape Town and West Coast district municipalities. It was estimated in the prefeasibility study[101] that 13km of gas distribution pipeline would be required to reach customers in Saldanha and 105km of pipeline would be required to reach customers in the City of Cape Town. At least another 100km of pipeline would be required to connect industrial nodes in the Winelands District municipality at the cost of R735 million – and given the relatively small demand in these nodes we have assumed it would not be feasible to connect them although a more detailed business case could prove otherwise.

**Figure 24: Map illustrating the extent of distribution pipelines for industrial customers**




*Source: EasyGIS based on Deloitte analysis and various GPS point data sources*

[101] Western Cape Government (2013) Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor, J. H. Visagie.

### 5.3.4. Would industrial energy users switch to gas?

#### 5.3.4.1. Which fuels could LNG replace in industrial processes?

A recent study by Gigajoule Africa, the results of which are presented in the 2013 WCG LNG prefeasibility study, provides detailed information on fuel currently used by industrial firms in the West Coast, Cape Town and Cape Winelands district of the Western Cape. The study, based on a market survey of over 150 of the large industrial firms in the region provides an assessment of the industrial energy feedstock that could technically be substituted for natural gas. The results, summarised in Figure 25, suggest that across the 150 potential customers, roughly 21 million GJ of energy feedstock is consumed per annum that could, from a technical perspective, be replaced with natural gas.

According to the study there are about 20 large industrial firms in Atlantis (an area roughly 45km north of Cape Town on the West Coast), which consume roughly 1 million GJ of energy feedstock annually in processes that could technically be run on natural gas. About 70% of this is coal, 16% LPG; and the remainder is split between paraffin (6%), heavy fuel oil (6%) and diesel (0.5%). This fuel is used primarily for steam-raising, baking, drying and heating.

The 150 large industrial firms that were identified in the Cape Town Metropolitan Area and Cape Winelands district consume roughly 20 million GJ of energy feedstock annually in processes that could use natural gas. The largest fuel input in processes that could be run using natural gas is coal. Coal constitutes approximately 60% of current “technically substitutable” energy input for the large industrial concerns in these districts, followed by heavy fuel oil, waxy oil, diesel and LPG. This energy is used for processes like steam-raising, baking, drying, heating and smelting.

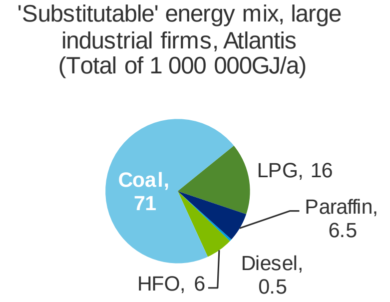
In Saldanha Bay, the main energy users are ArcelorMittal, Duferco and Tronox. As noted above, these energy-intensive firms rely chiefly on coal for steel manufacturing in the case of ArcelorMittal and for smelting in Tronox’s mineral sands beneficiation processes. Imported natural gas, however, would not be a viable substitute for the vast quantities of coal used in these energy-intensive processes. The “substitutable” energy consumption for industry in Saldanha is therefore limited to 1 300 000 GJ dominated by LPG used for heating and preheating in ArcelorMittal and Duferco’s steel processing activities. The remaining energy feedstock that could be replaced with gas is the coal and heavy fuel oil used by smaller industrial consumers in the area for steam-raising, baking, drying and heating.

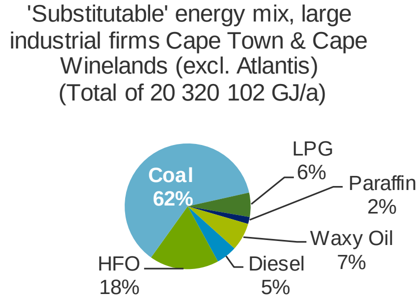
**Figure 25: "Technically substitutable" portion of the energy feedstock of large industrial firms**

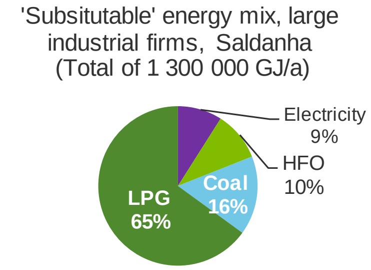
| Cape Town Metropolitan | |
|---|---|
| **Industrial node** | **GJ/annum** |
| **Atlantis** | **1 000 000** |
| | |
| Airport Industria | 20 500 |
| Atlantis Industria | 1 014 778 |
| Beaconvale | 58 946 |
| Bellville South | 875 913 |
| Blackhealth Industria | 144 185 |
| Brackenfell | 51 710 |
| Bottelary | 1 496 562 |
| Contermanskloof | 343 390 |
| Eersterivier | 45 800 |
| Elsies Rivier | 61 992 |
| Epping Industria | 920 247 |
| Killarney Gardens | 78 590 |
| Kuilsrivier | 289 741 |
| Lansdowne | 516 663 |
| Maitland | 363 887 |
| Montague Gardens | 5 829 442 |
| Ndabeni Industria | 510 000 |
| Newlands | 634 717 |
| Parow Industria | 946 816 |
| Phesantekrall | 625 000 |
| Phillipi | 227 692 |
| Sacks Circle | 1 896 301 |
| Salt River Industria | 212 438 |
| **Sub-total** | **18 165 310** |

| Cape Winelands District | |
|---|---|
| **Industrial node** | **GJ/annum** |
| Wellington | 229 072 |
| Paarl industria | 1 884 948 |
| Klapmuts | 41 386 |
| **Sub-total** | **2 155 406** |

| West Coast District | |
|---|---|
| **Industrial node** | **GJ/annum** |
| **Saldanha Bay** | **1 300 000** |
| | |
| **Total annual energy consumption** | **21 620 716** |




*Source: Gigajoule Africa in Visagie, HJ (2013)*

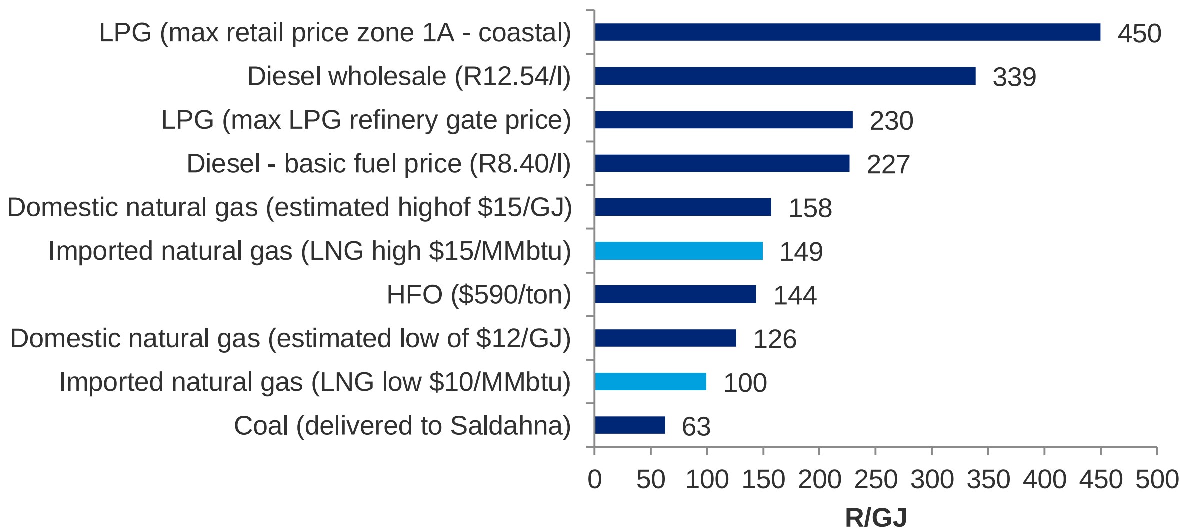
#### 5.3.4.2. The cost of imported natural gas relative to alternatives in industry

Whilst there are other considerations (as listed in 5.3.4.3), the extent to which the potential industrial market for LNG, as identified in the previous section, materialises will depend largely on the cost of LNG relative to its alternatives. Insight into alternative fuel costs and switching decisions were obtained from a series of interviews with key industrial energy users in the Saldanha Bay area.

"At $10/MMBtu, LNG is roughly 50% of the basic cost of LPG and diesel, and it is an attractive substitute for these fuels in industrial processes."

In Figure 26, we have provided a comparison of the cost of alternative fuels used in industry[102]. Details on the data sources and conversion calculations are provided in Appendix B. Of the fuels used in industrial processes, LNG is likely to be a lower-cost alternative to diesel, LPG and heavy fuel oil (HFO). If LNG is landed at $10/MMBtu it will be roughly 50% of the basic cost of LPG and diesel (per gigajoule) and 70% of the cost of HFO[103].

**Figure 26: Comparison of the cost of fuels used by industry**




*Source: Deloitte Analysis, Interviews with industrial users in the Western Cape*

It will however be difficult to persuade coal users to make the switch on the basis of relative cost alone as coal at R63/GJ is the lowest cost industrial fuel available in the Western Cape and is likely to be 60% of the anticipated cost of LNG. Heavy energy users such as ArcelorMittal confirmed that the price of coal is significantly lower than other alternatives. Transport costs account for nearly 50% of the coal price (coal is railed in from Mpumalanga), but even so it remains very competitively priced at roughly $6/GJ.

As the LNG market in the Western Cape matures and gas volumes increase, economies of scale in the use of import, transmission and distribution of imported gas can also be realised which may lower the cost and improve the likelihood of fuel switching.

#### 5.3.4.3. Other considerations for industrial firms in switching to LNG

[102] Based on price data from August 2014 and assuming an exchange rate of R10.50/$.

[103] Note: we have compared prices at the refinery gate/import terminal or similar as reliable data on the delivered cost of alternative fuels used in industrial processes was not available.

Relative cost however is not the only consideration in fuel-switching. According to feedback from interviews held with four of the large industrial firms in the Cape Town and West Coast districts, the applications where industrial and commercial users could be persuaded to switch from coal to gas include where air quality and reliability of supply are key considerations or where the use of gas enables significant process efficiencies. Feedback from the interviews is summarised in Table 11 and further notes are provided in Appendix C.

LNG produces fewer GHG emissions in combustion than most fossil fuel alternatives, as a result gas provides an attractive alternative to coal for industrial consumers in areas where stricter air quality controls are in place.

The quick burning nature of natural gas and relatively low emissions mean that it is also preferred to coal, diesel and other fossil fuels in certain industrial applications including processes in the ceramics, food processing, beverage and tiling industries where access to quick-burning clean energy sources like natural gas is preferred to limit spoiling of the product.

Gas could also provide an attractive alternative to coal, LPG and electricity where reliability of supply is a key consideration as coal and LPG deliveries are vulnerable to supply and logistics bottlenecks and electricity supply has become increasingly constrained.

Coal is also a bulky commodity that is difficult to store, so there are industrial users who would switch to natural gas based on limited storage space for coal.

For Continental China who relies primarily on LPG in its current processes, LNG at roughly 50% of the cost of LPG would represent a significant opportunity to reduce its overall fuel costs. Continental China also noted that the cost and reliability of LPG supplies together with other market factors was creating a challenging business environment and that they were considering downsizing. They suggested that stable supply of LNG at a lower cost would make their products more competitive with cheaper imports and could preserve 5 000 jobs. For ArcelorMittal, LPG is a small proportion of their feedstock but could be replaced with LNG. The most significant opportunity related to LNG is that a stable supply would allow them to expand production in certain areas of the plant. Namakwa Sands (Tronox) noted that there were no opportunities for switching to LNG in their processes, as it was too expensive to replace coal, and capital costs incurred in refitting the plant to use natural gas as an input would be too great.

**Table 11: Switching opportunities and benefits for selected large industrial firms**

| Industry player interviewed | LPG usage | LPG GJ used | Opportunity for switching to LNG | Potential socio-economic benefits |
|---|---|---|---|---|
| **ArcelorMittal** | 10 000 – 12 000 litres | ~250 GJ | • Availability of LNG would allow them to double production of hot-coiled steel in the Midrex process.<br>• LNG could be a low-cost alternative to LPG.<br>• Coal is their main energy input, but they use significant quantities at low prices so no opportunity for switching. | Expanded production and reducing some specific energy input costs. |
| **Continental China** | 4 million litres | ~100 000 GJ | • One of the largest users of LPG in the West Coast and uses an estimated 4 million litres of LPG per year in their ceramics business<br>• LPG is almost double the cost | Improve competitiveness and prevent retrenchment of 5 000 workers, which is a risk |

| Industry player interviewed | LPG usage | LPG GJ used | Opportunity for switching to LNG | Potential socio-economic benefits |
|---|---|---|---|---|
| | | | of LNG and its supply has been unreliable.<br>• Would definitely consider switching if LNG becomes available. | |
| **Atlantis Foundries** | 700–800 tonnes | ~3430 GJ | • Uses LPG in furnaces for drying<br>• Would substitute to lower cost LNG, enabling them to reduce on inland LPG supply | Cost-savings which can be passed on to consumers, while improving competitiveness in global markets |
| **Namakwa Sands (Tronox)** | Limited usage | n/a | • Limited opportunity to replace coal in their current processes – while LPG usage is also low. Limited switching opportunities; utilising natural gas as a feedstock would require significant changes to their current plant. | N/A |

*Source: Deloitte interviews with industry representatives*

### 5.3.5. The socio-economic costs

#### 5.3.5.1. Capital cost of infrastructure required for LNG imports and CCGT power generation

Regardless of whether LNG is imported through an onshore or offshore terminal, the infrastructure that would be required to distribute gas to all the industrial nodes identified in the Cape Town–Saldanha corridor would include a total of 118km of gas distribution pipeline at a total estimated cost of R0.9 billion.

**Table 12: Cost of infrastructure for "gas-to-industries" scenario**

| Description | | Onshore terminal | Offshore terminal | Data source/assumptions |
|---|---|---|---|---|
| Distribution pipelines (US$ millions) | Phase 1 | 88.6 | 80.2 | As assumed in prefeasibility study |
| | Phase 2 | | 8.5 | |
| Distribution pipelines (R billions) | Phase 1 | 0.9 | 0.8 | Converted to Rands assuming R10.50/$ |
| | Phase 2 | | 0.1 | |
| **Total for all "gas-to-industries" infrastructure costs (Rbn)** | | **0.9** | **0.9** | |

This would be in addition to the infrastructure already provided under the gas-to-power scenario, which included the cost of building the terminal and transmission pipelines to both Cape Town and Saldanha. The cost of providing this infrastructure needs to be weighed against the socio-economic benefits outlined below.

### 5.3.6. The socio-economic benefits

*The* potential economic benefits that are likely to be associated with the supply of imported natural gas if the 'gas-to-industries' scenario outlined materialises are threefold:

#### 5.3.6.1. Fuel cost savings

As noted in Section 5.3.4.2, LNG at $10/MMBtu would be an attractive substitute for diesel, HFO and LPG currently used in industrial processes by firms in the CoCT and West Coast district municipalities. In a survey of over 140 of the largest manufacturing firms in the West Coast and CoCT, Gigajoule Africa estimated that approximately 3 million GJ of HFO, diesel and LPG is consumed by firms in the West Coast district and CoCT annually (Table 13). If we assume that all 3 million GJ of "technically substitutable" HFO, diesel and LPG is replaced with LNG at $10/MMBtu, large industrial users could save R465 million annually on their current fuel bill (Table 14)[104].

"If we assume that all 3 million GJ of 'technically substitutable' HFO, diesel and LPG is replaced with LNG at $10/MMBtu, large industrial users could save R465 million annually on their current fuel bill."

**Table 13: LPG, Diesel and HFO consumed by 140 large manufacturers in the West Coast and CoCT**

| | Atlantis | Cape Town (excl. Atlantis) | Saldanha | Total |
|---|---|---|---|---|
| **LPG GJ/annum** | 160 000 | 1 089 919 | 845 000 | 2 094 919 |
| **Diesel GJ/annum** | 5 000 | 908 266 | | 913 266 |
| **HFO GJ/annum** | 60 000 | 3 269 756 | 13 000 | 3 342 756 |
| | | | | **3 008 184** |

*Source: Deloitte analysis*

**Table 14: Potential industrial fuel cost-savings if HFO, diesel and LPG are replaced with LNG at $10/MMBtu**

| | GJ/annum | Price (R/GJ) | Cost (Rm) | Cost if LNG at $10/MMBtu | Annual fuel cost-savings (Rm) |
|---|---|---|---|---|---|
| LPG (max refinery gate) | 2 094 919 | 230 | 481 | 233 | 249 |
| Diesel (basic fuel price) | 913 266 | 227 | 207 | 101 | 106 |
| HFO | 3 342 756 | 144 | 481 | 371 | 110 |
| **Total savings** | | | | | **465** |

*Source: Deloitte analysis*

While HFO, diesel and LPG together represent only 15% of the "technically substitutable" energy feedstock that is consumed by industries, the potential annual cost-saving of R465 million a year (if LNG can be landed at a price of $10/MMBtu) is still substantial.

Furthermore, we can assume that that the R465 million in annual fuel cost-savings is reinvested in the manufacturing industry. Using the GDP and employment multipliers from our static economic model of the Western Cape (and National economy), we have estimated that a R465 million increase in the demand for manufacturing output will lead to the creation of 2 074 additional jobs, 1 631 of which would be located in the Western Cape. The R465 million of additional investment in the manufacturing sector would also lead to a R532 million increase in GDP.

[104] We note that this calculation excludes distribution cost for all fuel types

#### 5.3.6.2. Availability of a viable alternative fuel source can serve as a draw card for industrial investment given the current electricity supply constraints

The health and maturity of a country's manufacturing sector is central to its ability to grow its economy, to innovate and to build intellectual capital. Over the past decade, South Africa's manufacturing sector has underperformed relative to many of its emerging market peers, with production growing at an annual average rate of around 1.6%[105]. In a survey conducted by Deloitte in 2013, manufacturing CEOs identified energy costs and policies as one of the most serious impediments to manufacturing competitiveness in South Africa (ranked third after the size and attractiveness of the domestic market and the cost and availability of labour).

As discussed in section 5.2.2.1, South Africa is currently in the midst of an electricity supply crisis, and the shortage of energy may have deterred investment in the manufacturing industry. Availability of natural gas may unlock suppressed demand for industrial investment. **A study on the potential impact of LNG imports into the Malaysian peninsular,** estimated that a shortage of gas had deterred 270 mmscfd[106] of 'latent demand for premium gas' and that unlocking this demand by importing LNG would have an estimated impact on Gross National Income (GNI) of RM10.6bn (approximately R34bn) and would create 27,000 new jobs by 2020 (see Box 2). While it is difficult to estimate the extent to which electricity shortages have deterred manufacturing investment in South Africa (distinguishing it from a range of other influences), it is possible that the availability of 'premium natural gas' in the South African context could unlock suppressed demand for industrial investment.

[105] Deloitte, 2013, "Enhancing Manufacturing competitiveness in South Africa."

[106] Million standard cubic feet per day

**Box 2: Case study - unlocking premium gas demand in Peninsular Malaysia with LNG imports**

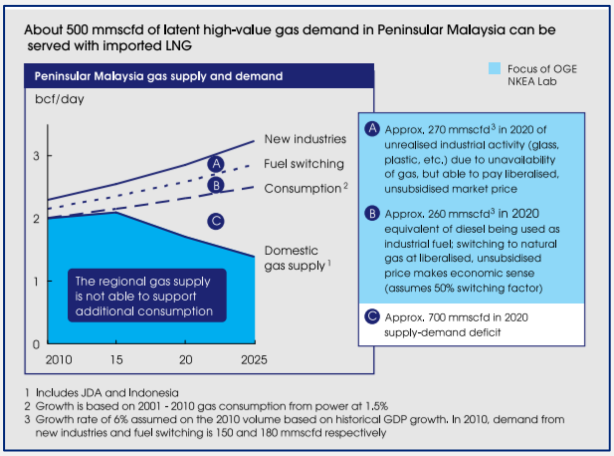
In the Malaysian peninsular, declining domestic gas production resulted in a gas supply shortage, and it was recognised that this had not only prevented existing diesel and LPG users from switching to more competitively priced natural gas, but it had also limited any additional investment from new industries, e.g. glass and plastics manufacturers and semiconductor wafer manufacturers[107].

Noting that imported LNG would be far more expensive than domestic gas and that it would only be possible to sell it at an unsubsidised, market-driven price, it was estimated that increasing the total availability of gas through LNG imports, Malaysia could attract an additional 270 mmscfd[108] of "latent demand for premium gas" from investors that had previously been deterred by the energy shortage. It was also estimated that 260 mmscfd of imported LNG could be sold to existing industrial users that were currently using higher-priced diesel but could switch to more competitively priced natural gas if it were made available to them (Figure 27).

It was further estimated that unlocking this gas demand will have an estimated impact of RM10.6 billion (Malaysian ringgits) on Gross National Income (GNI) and would create 27 000 new jobs by 2020, largely in other sectors beyond oil, gas and energy. An investment of RM3.9 billion will be required to fund the construction of the fixed and floating elements of the LNG regasification terminal. The expected increase in GNI is summarised as follows:

- Providing gas to companies that previously did not invest in Malaysia due to lack of gas supply would provide an RM8 billion GNI increase and will create 27 000 new jobs.
- Switching from diesel to natural gas will yield approximately RM1.9 billion in annual savings for Malaysian companies.
- Operating the terminal and transmission pipelines will generate an additional RM0.6 billion in GNI to Malaysia.

**Figure 27: Estimating of latent demand for LNG imports in Malaysia and demand for fuel-switching**




*Source: Economic Transformation Programme Handbook (2010) A Roadmap for Malaysia. Chapter 6.*

[107] Economic Transformation Programme (2010) ETP Handbook: A Roadmap For Malaysia. Chapter 6. [Online] Available at: http://etp.pemandu.gov.my/upload/etp_handbook_chapter_6_oil_gas_and_energy.pdf.

[108] Million standard cubic feet per day

#### 5.3.6.3. Reduce GHG emissions from industry

As noted previously, GHG emissions from natural gas are significantly lower than alternative fossil fuels; and, as such, natural gas is often referred to as the “bridge to a low carbon future”.

If we assume, as outlined in the previous section, that imported natural gas will replace the 3 million GJ of HFO, diesel and LPG that is consumed by firms in the West Coast district and CoCT annually, roughly 139 000 tonnes of carbon dioxide equivalent emissions would be saved annually.

**Figure 28: Potential GHG emissions savings if LNG replaces diesel, HFO and LPG**

| | Million GJ/annum | tCo2e/GJ | tCo2e ('000s) | tCo2e if substituted with LNG ('000s) | Savings of tCo2e ('000s) |
|---|---|---|---|---|---|
| **LPG** | 2.1 | 0.056 | 117 | 96 | 21 |
| **Diesel** | 0.9 | 0.072 | 66 | 42 | 24 |
| **HFO** | 3.3 | 0.074 | 248 | 154 | 94 |
| **Natural Gas** | | 0.046 | | | |
| **Total tonnes of $CO_2e$ that would be saved if fuels replaced with LNG** | | | | | **139** |

*Source: Deloitte Analysis based on DEFRA emissions conversion factors and Gigajoule Africa survey of industry consumption*

## 5.4. Gas-to-households

### 5.4.1. Introduction

The cost of distributing imported natural gas to residential users and transport users is high relative to the lower average volumes that these users consume. However, once the basic gas import, transmission and distribution infrastructure is in place (and largely paid for) for by power and industrial users it may be financially feasible to incrementally connect users in areas that are close to existing pipelines. The gas-to-households opportunity mentioned in the prefeasibility study was limited to ~300 000GJ per annum.

Since the prefeasibility study was published, interest in the use of natural gas in transport in South Africa has increased and broader opportunities for the household sector are also emerging. As a result we considered the socio-economic impacts that would be associated with a somewhat expanded gas-to-household scenario. It is important to note that the financial feasibility of serving households has not yet been tested, but this does not preclude high-level analysis of the potential economic costs and benefits.

In this section, we explore some of the socio-economic costs and benefits that could be associated with the use of imported natural gas in the residential sector in the Western Cape. We begin with a background to residential energy use in South Africa and the Western Cape and then provide an explanation of the gas-to-households scenario that we have considered. We then outline some of the key end-user considerations for switching to LNG in a residential context. In the remainder of the section, we expand on the potential socio-economic benefits and costs that could be associated with the introduction of natural gas as an alternative fuel for households.

### 5.4.2. Background and context

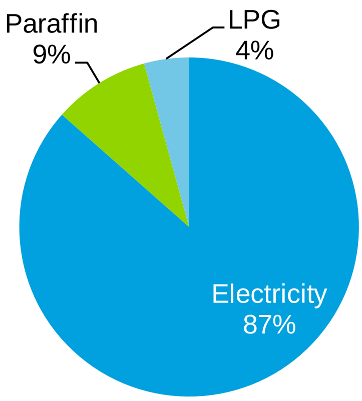
#### 5.4.2.1. Residential sector energy use and mix in South Africa and the Western Cape

According to the IEP[109], households are responsible for roughly 20% of South Africa's energy consumption and that electricity is the predominant form of energy used by households, accounting for ~73% of total consumption.

The IEP notes that in households, energy is mainly used for cooking (~38%), followed by space heating (~28%), water heating (~20%) and lighting (~5%), with the remainder used in other electrical appliances and equipment.

Households are responsible for only 8% of total energy consumed in the Western Cape; but, like the rest of South Africa, they rely predominantly on electricity to meet their energy needs. According to data for 2009, electricity accounted for 87% of household energy consumption in the Western Cape, followed by paraffin and LPG.

**Figure 29: Share of major fuel types in household energy in the Western Cape**



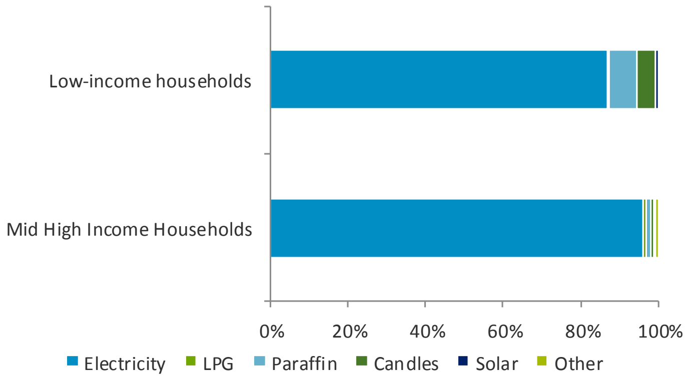

*Source: WCG energy consumption and emission data 2009*

The residential sector contributes substantially to daily peak electricity demand in the province, so a shift away from electricity towards other sources could make a significant contribution to reducing imports of electricity from inland and overall electricity generation capacity required. In light of this, the Western Cape Government has considered various initiatives to promote greater diversity in the household energy mix, including the introduction of LPG as a fuel to low-income households.

The vast majority (just under 90%) of low-income households in the Western Cape use electricity for lighting, while 7% are reliant on paraffin and 4% on candles (Figure 30). Just over 80% of low-income households use electricity in cooking, while around 10% use paraffin and the remainder use LPG or wood (Figure 31). Two-thirds of low-income households use electricity for heating, while paraffin (~24%) and wood (~7%) are also commonly used.

[109] Department of Energy, 2013, Integrated Energy Plan, Draft 2012

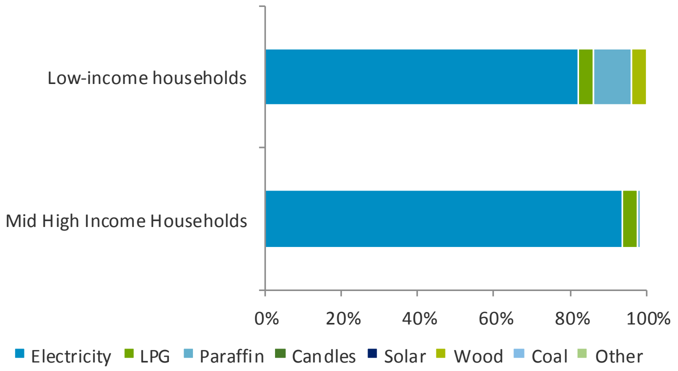
**Figure 30: Main fuel source used for lighting in the Western Cape, 2009**




*Source: WCG energy consumption and emission data 2009*

Almost all middle-to-high income households use electricity for lighting. There is more diversity in fuels for cooking and heating. Around 93% of middle-to-high income households use electricity for cooking, while about 5% use LPG and 2% use paraffin and other fuels. Around 85% of middle-to-high income households use electricity for heating, while the remaining 15% use paraffin, LPG and wood.

**Figure 31: Main fuel source used for cooking in the Western Cape, 2009**




*Source: WCG energy consumption and emission data 2009*

### 5.4.3. Gas-to-households scenario considered

The prefeasibility study[110] assumed that the potential household or residential market for imported gas in the Cape Town–Atlantis corridor would be limited to ~300 000 GJ per annum, and no estimates of the cost of infrastructure required to service this market were provided.

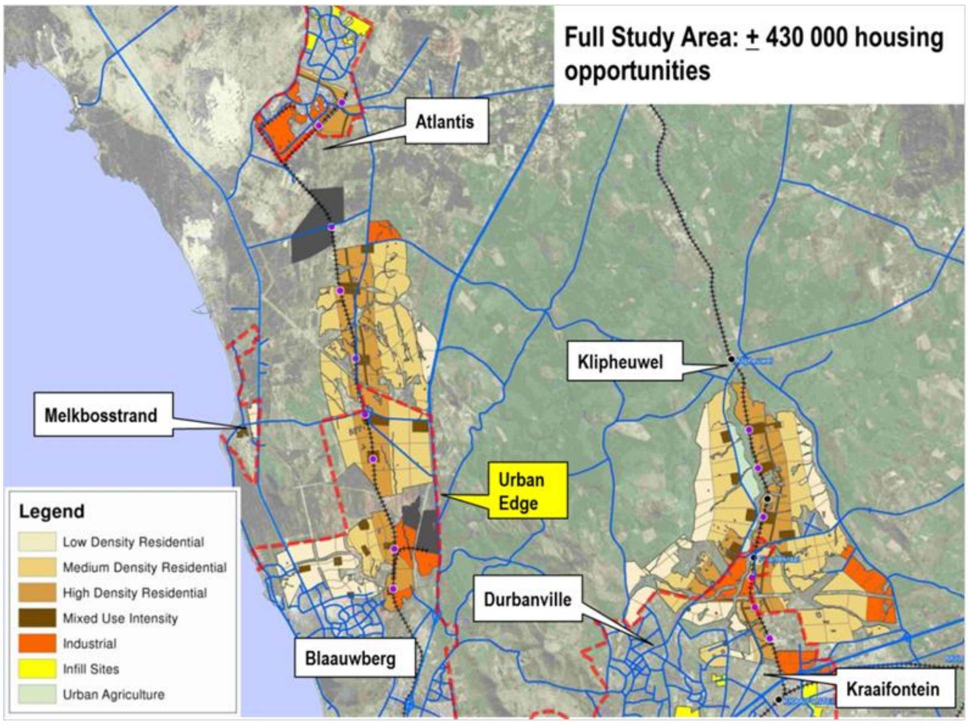
The Western Cape Provincial Government is, however, investigating the possibility that distribution infrastructure created for industrial users could be leveraged to provide natural gas to residential users in selected new dense residential housing developments. While a detailed business case on the viability of using imported natural gas in households has not been performed, we have assumed that it would not make commercial sense to retrofit existing residential houses with infrastructure for the distribution of piped gas. We have also assumed that it would not be viable to distribute LNG in the form of compressed natural gas (CNG) to households, because it has a much lower energy density than LPG and other fuels in this format, which makes it uneconomical to distribute CNG to households.

[110] Energy Business, 2013, "Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay–Cape Town corridor"

Rapid growth in the urban population of the City of Cape Town, however, may present some opportunities to extend the LNG distribution infrastructure to new housing developments. The population of Cape Town is expected to double in the next 30 years, and the City of Cape Town has identified the area between Blaauwberg and Atlantis as one of the potential future urban growth corridors. According to City of Cape Town planners, this corridor together with the north-eastern corridor between Kraaifontein and Klipheuwel could accommodate 430 000 new housing opportunities, which is roughly half of the anticipated 30-year need (Figure 32).

The opportunity that we have considered for the gas-to-households scenario is to extend the distribution pipeline that would serve key industrial customers to serve households in relatively dense middle-income housing developments in the Blaauwberg–Atlantis corridor and Kraaifontein–Klipheuwel corridor. Both these corridors are adjacent to some of the province's key industrial nodes.

**Figure 32: Identified future urban growth corridors for the City of Cape Town**




*Source: Deloitte, Prefeasibility study of the Atlantis Special Economic Zone, 2014*

While a more detailed market analysis would be required to understand the viability of this proposal, we have for the purposes of this scenario estimated the costs associated with 200km of pipeline for the distribution of residential gas.

### 5.4.4. Would households switch to natural gas?

Factors that affect household choice of energy source include availability, cost of energy and cost of energy devices. In countries with abundant and cheap domestic supplies of natural gas, such as the US, the use of natural gas in cooking and heating and a variety of household appliances is widespread. Over 65 million homes in the US use natural gas as an energy source[111].

In the Western Cape, where over 90% of households have access to electricity, the lack of distribution infrastructure to make natural gas available is likely to be the major barrier to uptake.

[111] Safe Gas Indiana

#### 5.4.4.1. The cost of imported natural gas relative to alternatives in households

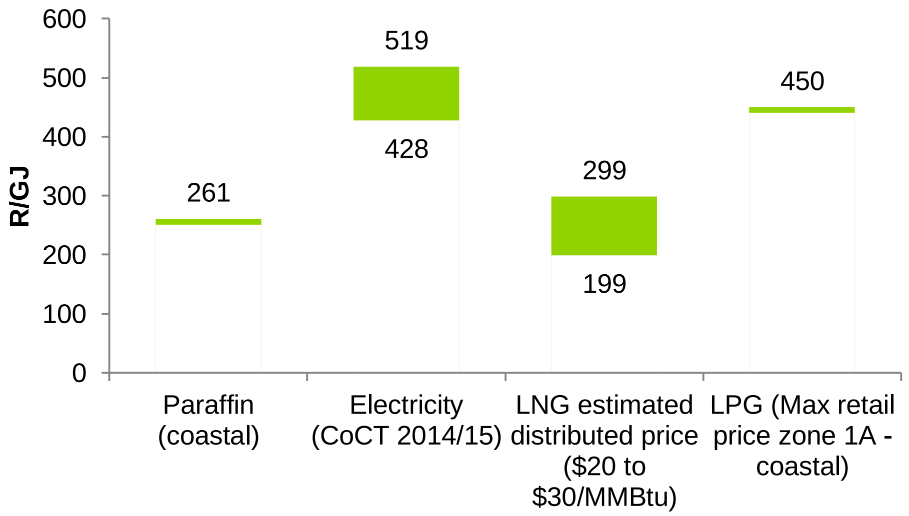
Since comparable domestic estimates of the cost of distributing LNG to households is not readily available, we have assumed that the costs associated with the transmission and distribution of imported LNG to household would be 100% of the landed price. This assumption is based on the fact that the cost of electricity distributed to residential consumers by the City of Cape Town at between R1.54/kWh and R1.87/kWh is just more than double the wholesale price of electricity at R0.68/kWh (Eskom average tariff in 2014). The US energy information administration also noted that transmission and distribution costs represented about half of a typical residential natural gas customer's monthly gas utility bill, while the cost of the physical natural gas commodity represented the other half. Based on this assumption, the distributed cost of LNG to households would be between \$20 and \$30 per MMBtu for current landed prices of between \$10 and \$15 per MMBtu.

"At a price of between R199 and R299 per GJ, imported natural gas would represent a very cost-effective alternative to the dominant sources of energy in households – electricity and LPG – households could expect to save 50% of their energy bill in switching to LNG."

A comparison of the cost of alternative energy sources used in households is provided in R/GJ in Figure 33, and detailed assumptions are provided in Appendix D. LNG estimated at \$20 per MMBtu translates into roughly R199 per GJ. LNG at a distributed price of \$20/MMBtu would be 50% of the cost of both LPG and electricity and is even slightly cheaper than Paraffin.

At a price of between R199 and R299 per GJ, imported natural gas would represent a very cost-effective alternative to the dominant sources of energy in households – electricity and LPG –households could expect to save 50% of their energy bill in switching to LNG.

**Figure 33: Comparison of cost of energy sources used in households, 2014**




*Source: Deloitte analysis based on various sources*

#### 5.4.4.2. Other considerations for switching

The common use of natural gas in households is for heating and cooking. Natural gas can also be used in specialised air-conditioning units and geysers and in appliances such as clothes dryers, pool heaters, fireplaces, barbecues, garage heaters and outdoor lights[112]. Natural gas is not a perfect substitute for electricity, as it cannot be used to power most household appliances and electronics. Cooking with a natural gas range or oven can provide many benefits over electrical equivalents, including instant heat and easy temperature control and greater efficiency in energy use. Given the current electricity supply constraint, and the favourable LNG price comparison, LNG for also becomes highly attractive in terms of fuel security, and can reduce the impact of load shedding on the residential sector.

#### 5.4.4.3. Conclusions on the potential for fuel-switching

If imported natural gas can be distributed at double its anticipated landed price ($10 to $15/MMBtu) which is between R199 and R299 per GJ, imported natural gas will represent a very cost-effective alternative to the dominant sources of energy in households – electricity and LPG. While the assumed distribution costs will need to be tested in a more rigorous business case for the household market, it appears that there is potential to connect new housing developments in areas of the CoCT that will be close to transmission and distribution pipelines of imported natural gas.

### 5.4.5. The socio-economic costs

#### 5.4.5.1. Capital costs

For the gas-to-households scenario, we only considered infrastructure costs associated with building a 200km pipeline to new housing developments in the Blaauwberg–Atlantis corridor. Based on an assumed installation cost of $700 000/km, we estimated that distribution pipelines to serve households with imported natural gas would cost in the order of R1.5 bn.

**Table 15: Infrastructure costs associated with the gas-to-households scenario**

| Description | No. of units | Cost per unit (R '000s) | Total cost (Rm) | Data source/assumptions |
|---|---|---|---|---|
| Distribution Pipeline (km) | 200 | 7 350 | 1 470 | Unit costs as per prefeasibility study assuming R10.50/$ exchange rate, kilometres estimated by Deloitte and HJ Visagie |
| **Total for all "gas-to-household" infrastructure costs** | | | **1 470** | |

### 5.4.6. The socio-economic benefits

#### 5.4.6.1. Reduce household energy costs – imported natural gas is likely to be a cost-effective alternative energy source

As discussed in Section 0, imported natural gas could provide households with a cost-effective alternative to electricity and LPG. The extent to which imported natural gas would replace traditional fuels, including electricity and LPG, would depend chiefly on the number of households that could be connected via the new distribution infrastructure.

[112] www.naturalgas.org, residential uses

At half the cost of electricity and LPG, one can assume that, of those households that can feasibly be connected to the distribution network, a significant proportion of the LPG and electricity currently used in heating and cooking and potentially water heating would be substituted with imported natural gas.

#### 5.4.6.2. Direct use of natural gas in household appliances reduces total household energy consumption and lowers GHG emissions

The American Gas Association (AGA) notes that the direct use of natural gas in households is both a cleaner and more efficient energy choice than using electricity. This is because far less energy is wasted in the extraction, transmission and distribution of gas than is used in the generation, transmission and distribution of electricity (Figure 34). In fact, of the energy available at source, 92% will reach the consumer in the case of domestic extraction of gas, and only 32% of the original fuel source energy will reach the household in the case of electricity. In other words, in the distribution of gas, while far more energy is consumed onsite in domestic appliances, far less energy is consumed in the process of getting energy from source to its end-use.

According to the AGA, if one considers the full fuel cycle as described above, a household that uses gas directly in appliances for things like heating, cooling, water heating and cooking will use 28% less energy than a similar home with all electric appliances and will produce 37% lower GHG emissions.

**Figure 34: The full lifecycle of natural gas compared to electricity**


*Source: American Gas Associate Playbook, http://playbook.aga.org*

## 5.5. Gas-to-Transport

### 5.5.1. Introduction

There is increasing interest internationally in the role that natural gas can play as alternative fuel to diesel and petrol in the transportation sector. The use of CNG in vehicles, however, is not a novel idea, as CNG has been used in vehicles since World War II. Countries with the largest fleet of natural-gas-fuelled vehicles include Iran, Pakistan and Argentina.

The potential to use gas in selected transport applications in South Africa was mentioned in both the national IEP draft 2012 and the Western Cape Green Economy Strategy. The Western Cape Green Economy Strategy Framework makes reference to “investigating the adoption of cleaner energies such as biofuels, hydrogen cells and liquefied natural gas in public transportation vehicles”. The results of a 10-month CNG vehicle fleet trial conducted in Gauteng by the Industrial Development Corporation (IDC) and Cape Advanced Engineering (CAE) in 2013[113] have suggested that the use of CNG in bi-fuel and dual-fuel vehicles[114] used for public transport is financially feasible.

In this section, we explore the potential socio-economic costs and benefits that are associated with using natural gas in public transportation in the Western Cape. We begin with background and context for the use of natural gas in vehicles in the Western Cape and an explanation of the gas-to-transport scenario assumed. We also provide some key considerations for the use of natural gas in transport, including experience from case studies and conclude with a possible future state for gas-to-transport and its key enablers.

### 5.5.2. Background and context

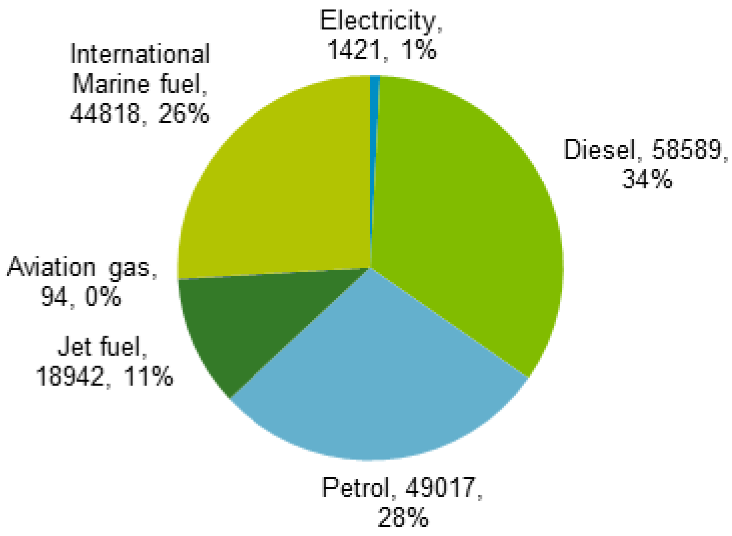
#### 5.5.2.1. The Western Cape transportation sector

The majority of energy consumption in the province is consumed within the transportation sector, with an estimated 58 million gigajoules of petrol and 49 million gigajoules of diesel being consumed in 2009, together with aviation gas, jet fuel and international marine fuel (Figure 35)[115]. The transport sector consumes approximately 52% of all energy used in the province, followed by industrial (34%), residential (9%) and commercial (4%).

The transport sector also contributes a large but proportionally smaller amount of GHG emissions in the province – roughly 31% of total provincial $tCO_2e$. The massive contribution of transport to total energy consumption suggests that the sector must be a focus in attempts to diversify the energy mix.

[113] Industrial Development Corporation and Cape Advanced Engineering (2013) *Investigation into the use of clean burning methane in the form of compressed natural gas (CNG) and compressed bio-gas (CBG) in public transport in South Africa*.
[114] Buses were converted to dual-fuel engines and mini-bus taxis were converted to bi-fuel engines. Bi-fuel vehicles are able to run on diesel fuel or natural gas, while dual-fuel vehicles are able to run on diesel fuel and gas simultaneously.
[115] Energy consumption and $CO_2$ database for the Western Cape, 2009

**Figure 35: Energy consumption by fuel type in the Western Cape transport sector**




*Source: Deloitte analysis based on Western Cape Energy and $CO_2$ emissions Database 2013*

### 5.5.3. Gas-to-transport scenario considered

The gas-to-transport scenario outlined in the prefeasibility study[116] was limited to the conversion of a public bus fleet with assumed annual gas consumption of 900 000 GJ. However, since the prefeasibility study was published, interest in the use of natural gas in transport in South Africa has increased. As a result, the WCG requested that Deloitte consider and estimate the infrastructure required to support an expanded gas-to-transport scenario. Our approach to defining the gas-to-transport scenario and estimating the associated infrastructure costs is provided in Appendix D. The gas-to-transport scenario assumes the:

1. Conversion of the MyCiTi Buses (a total fleet of 267)
2. 50% conversion of Golden Arrow and Sibanye buses (576 of the total fleet of 1 152)
3. Conversion of the CoCT (~6 000 vehicles) and WCG vehicle fleet (50% of ~5 000 vehicles)
4. Conversion of 11 Golden Arrow and MyCiTi fuel depots
5. Conversion of 42 commercial fuel service stations to service the CoCT and WCG fleet with CNG
6. 230km of distribution pipeline installed to supply the fuel depots and service stations with CNG

Our analysis suggests that roughly 230km of distribution pipeline (in addition to that required to connect industries) would be required to ensure that fuel service stations distributed throughout the most densely populated areas (judged to be those areas where there are existing fuel stations) of the West Coast and Cape Town District Municipalities could be connected to the gas pipeline. At an assumed cost of R7.35 million/km, the 230km of pipeline would cost roughly R1.69 bn.

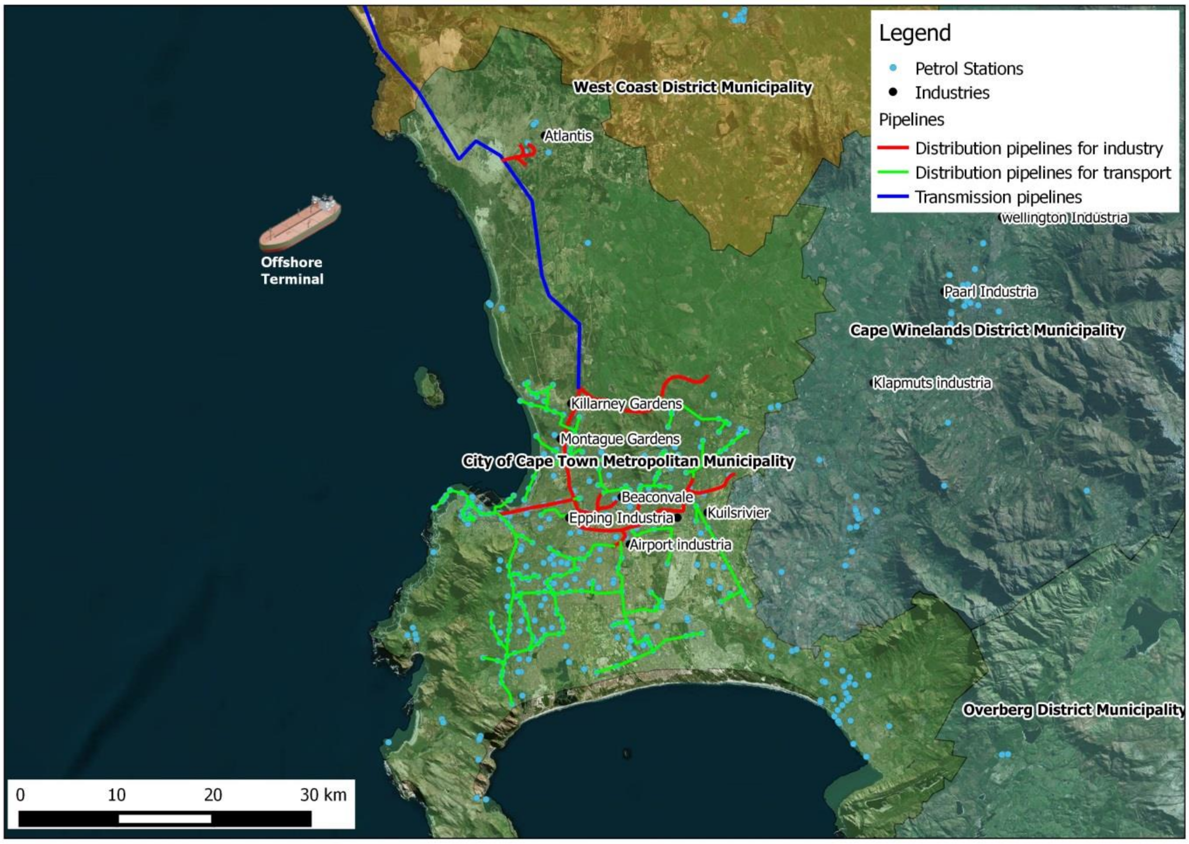
For the purpose of this study, we have assumed that for the first phase, the incremental cost to extend the pipeline to service stations located in the main urban centres of the Winelands District municipality would be too great, as at least 100km of additional pipeline would be required to connect the urban

[116] Western Cape Government (2013) Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor, J. H. Visagie.

centres in this district (which include but are not limited to Paarl, Wellington and Stellenbosch) to the gas distribution network. We have also assumed that the incremental costs of connecting fuel stations in the rest of the district municipalities in the Western Cape Province (which include Overberg, Eden and the Central Karoo) would be too large relative to the size of the market.

Figure 36 provides an illustration of the network distribution pipeline required to connect 42 geographically distributed service stations covering most of the CoCT.

**Figure 36: Service stations in the City of Cape Town and distribution pipelines required**




*Source: EasyGIS based on Deloitte analysis and various GPS point data sources*

If the public programme is successful, the gas-to-transport roll-out could be extended to private-sector vehicles in the CoCT. The total potential market for conversion to CNG is summarised in Table 16.

**Table 16: Potential CNG vehicle market in the Western Cape**

| Transportation services | Fleet size (No.) |
|---|---|
| **MyCiTi** | 267 |
| **Golden Arrows Bus Service** | 1 073 |
| **Sibanye** | 78 |
| **CoCT fleet** | 6 000 |
| **WCG fleet** | 5 000 |
| **Logistics & Distribution Fleets** | 260 |

| | |
|---|---|
| **Petrol Passenger Cars** | 82 500 |
| **Total** | **95 178** |

*Source: Deloitte analysis based on prefeasibility estimates and other sources*

### 5.5.4. Would transport users switch to natural gas

#### 5.5.4.1. Costs of CNG in comparison to transport fuel alternatives

Relative price and availability are likely to be the most important factors considered in deciding whether to switch to CNG from traditional fuels (petrol and diesel).

South Africa's first CNG refuelling station was opened in Langlaagte, Johannesburg in March 2014. The station owned by CNG holdings is supplied with gas from distributor Egoli Gas. Egoli Gas, in turn, is supplied with natural gas from fields in the southern part of Mozambique, via the 865km Sasol Gas Pipeline. The gas is piped via Temane to Secunda. A high-pressure natural gas -distribution grid in the greater Johannesburg area (Gauteng Province) connects Pretoria, Johannesburg and Sasolburg with the Mozambique pipeline.

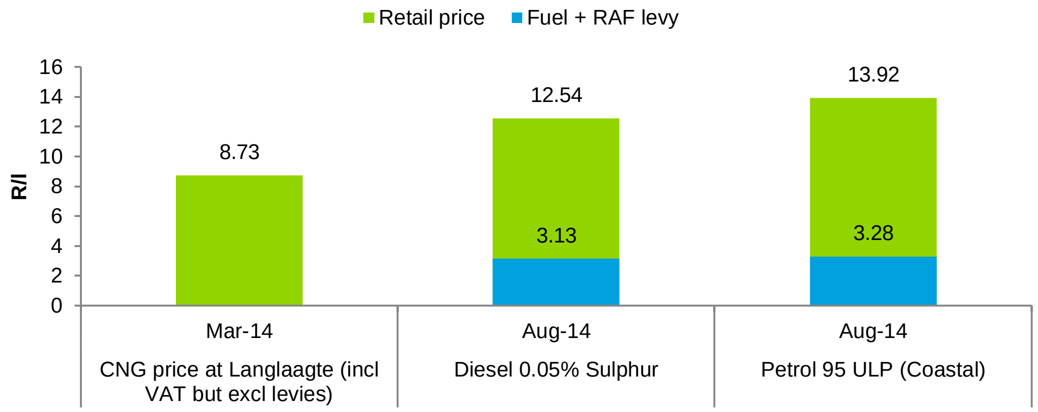
The price of CNG at the pump in Langlaagte is R9.99/l[117]. This price, which is for a litre of diesel-or-petrol-equivalent of CNG includes VAT as well as R1.26/l for the recovery of the conversion kits installed in the taxis. The fuel price excluding conversion costs would be R8.73/l. A pilot study undertaken by the Industrial Development Corporation (IDC) and Cape Advanced Engineering (CAE) to assess the feasibility of using CNG and compressed biogas (CBG) in minibus taxis based their research on CNG prices of R8.16 per diesel-equivalent litre and R7.74 per petrol-equivalent litre[118].

At R8.73/l, CNG is roughly R5/l (55%) cheaper than petrol and R4/l (45%) cheaper than diesel. CNG however, is not currently subject to fuel or road accident fund levies, which explains about R3/l of the difference between CNG and traditional fuel prices (Figure 37). In the absence of a business case for transport users it was not possible to estimate the cost of supplying CNG to the CoCT or the potential fuel cost savings. The cost of supplying CNG to the transport sector in the Western Cape however, is likely to be higher than in Gauteng (given that Sasol sources piped gas from Mozambique for Gauteng at low cost relative to anticipated LNG prices) so we would not expect savings to be as significant.

[117] Confirmed in telephonic communications with CNG holdings, November 2014.

[118] Industrial Development Corporation and Cape Advanced Engineering (2013) Investigation into the use of clean burning methane in the form of compressed natural gas (CNG) and compressed bio-gas (CBG) in public transport in South Africa.

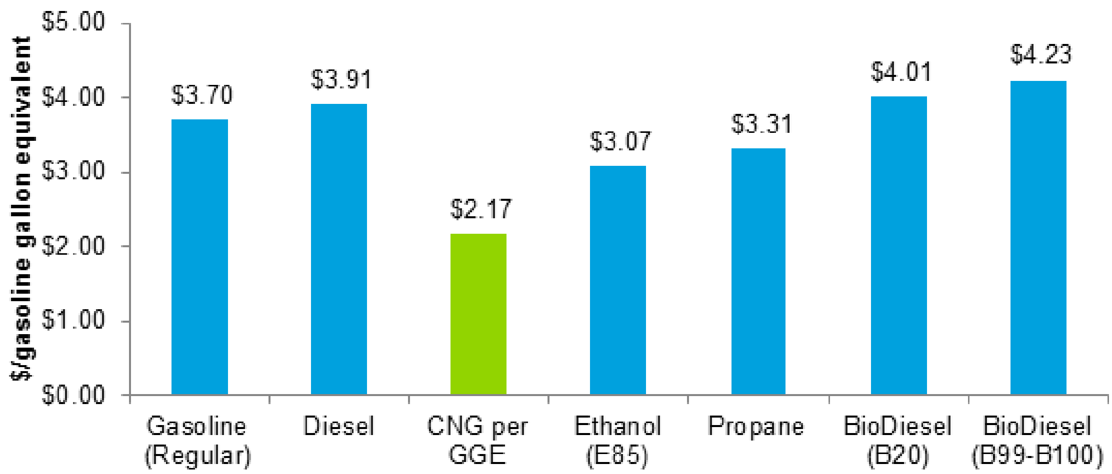
**Figure 37: Price of CNG at the pump relative to diesel and petrol in Gauteng, 2014**




*Source: Deloitte analysis, Shell petrol price breakdown*

In the United States, which has access to cheap and abundant supplies of domestic gas, CNG is just over half the cost of conventional petrol or diesel[119] (Figure 38). The spot price of gas at the US Henry Hub exchange, however, is only $4.6/MMBtu.. This suggests that CNG in the Western Cape, based on imports of LNG at $10/MMBtu may be almost as expensive on an energy-equivalent basis as diesel, unless the fuel tax regime on CNG is waived to promote transition to this cleaner fuel source.

**Figure 38: Comparison of fuel prices in the US on an energy-equivalent basis, July 2014**




*Source*: US DOE, Clean Cities Alternative Price Report, July 2014

### 5.5.4.2. Conclusions on the potential for fuel-switching

Relative price and availability will influence the switch to Compressed Natural Gas (CNG) from traditional fuels. CNG at the pump at Langlaagte in Gauteng was roughly R5/l (55%) cheaper than petrol and R4/l (45%) cheaper than diesel. But the cost of supplying CNG to the transport market via LNG in the Western Cape will be higher than the piped-gas supply to Gauteng so savings and potential for switching may not be as great.

[119] US DOE, Clean Cities Alternative Price Report, July 2014

### 5.5.5. The socio-economic costs

A summary of the infrastructure costs associated with the gas-to-transport scenario is provided in Table 17. The largest costs associated with importing natural gas for use in public transportation relates to construction of a 230km gas distribution network to connect service stations throughout the CoCT, which will cost an estimated R1.7bn.

The conversion of the ~9 350 vehicles to take CNG as a fuel will cost in the region of R271 million, while the conversion of existing depots and service stations will cost an estimated R318 million.

Overall, the infrastructure associated with the gas-to-transport scenario is expected to cost in the region of R2.3 billion. Further detail on the assumptions underlying these estimates is provided in Appendix D.

**Table 17: Estimated capital and operating costs for gas-to-transport scenario**

| Description | No. of units | Cost per unit (R '000s) | Total cost (Rm) |
|---|---|---|---|
| MyCiti Bus Conversion | 267 | 120 | 32 |
| Golden Arrow & Sibanye buses (50% of total fleet of 1152) | 576 | 120 | 69 |
| CoCT fleet (100% of 6 000 vehicles) | 6000 | 20 | 120 |
| WCG (50% of ~5 000 vehicles) | 2500 | 20 | 50 |
| **Total fleet conversion costs** | | | **271** |
| Conversion of depots | 11 | 6 000 | 66 |
| Conversion of fuel service stations | 42 | 6 000 | 252 |
| **Sub-total for depot and service station conversion** | | | **318** |
| Distribution Pipeline (km) | 230 | 7 350 | 1 690 |
| **Total for all "gas-to-transport" infrastructure costs** | | | **2 279** |

### 5.5.6. The socio-economic benefits

Other benefits associated with the gas-to-transport scenario include potential savings in fuel operating costs, greater diversity in the transport fuel mix and a reduction in air and noise pollution

#### 5.5.6.1. Potential -savings in average fuel operating costs

As mentioned, the Industrial Development Corporation of South Africa and Cape Advanced Engineering (Pty) Ltd implemented a real-world vehicle fleet trial in 2012/2013 to assess the feasibility of using CNG and compressed biogas (CBG) in minibus taxis and commuters buses[120].

The study was based on a sample of eight minibus taxis converted to bi-fuel engines and one bus that was converted to a dual-fuel engine. The study notes that for bi-fuel engines the *actual savings in fuel operating costs depend not only on the relative fuel price per petrol-equivalent-litre* but on the level of petrol displacement with CNG, the route operating conditions and the efficiency of the bi-fuel operation. The fleet of mini-bus taxis obtained a 22% saving in fuel operating cost when using gas or petrol (bi-

[120] Industrial Development Corporation and Cape Advanced Engineering (2013) *Investigation into the use of clean burning methane in the form of compressed natural gas (CNG) and compressed bio-gas (CBG) in public transport in South Africa.*

fuel) compared to standard petrol vehicle operation. Similarly the diesel dual fuel commuter bus realised a cost-saving of 76c/km (19.2%) compared to a standard diesel commuter bus of similar configuration when 71% of diesel was substituted for CNG.

"If using a conversion cost of R20 000 and a CNG pump price 25% lower than that of petrol, bi-fuel-converted minibus taxis that travelled less than 225km a day could pay back the cost of converting to a dual-fuel system in less than a year. If the daily travelled distance increases to 300km and the conversion cost reduced to R16 000, the payback period narrows to just six months," said CAE representative, Lovell Emslie in an Engineering News interview[121].

For buses, the operation of dual-powered vehicles was found to be financially feasible[122] if the vehicles operate over a distance of more than 220km per day, and if the conversion cost is limited to R150 000, and if the CNG fuel can be purchased at a discount of at least 15% relative to the existing retail price of diesel on an energy-equivalent basis.[123]

"The fleet of mini-bus taxis obtained a 22% saving in fuel operating cost when using gas or petrol (bi-fuel) compared to standard petrol vehicle operation…the diesel dual fuel commuter bus realised a cost-saving of 76c/km (19.2%)"

*The extent to which fuel cost-savings could be realised in our gas-to-transport scenario would therefore depend on:*

1. "Pay-back" period for conversion costs of approximately R150 000 per bus and R20 000 per taxi
2. Cost of CNG at the pump
3. Cost of Diesel at the pump
4. Proportion of diesel used relative to CNG
5. Fuel efficiency of the engine using the respective fuels
6. Kilometres travelled by the public transport and government-owned vehicle fleet

Without estimates for all these factors (particularly the technical fuel efficiency and cost of CNG at the pump), we were not able to accurately simulate the likely cost-savings associated with our gas-to-transport scenario however it appears from the IDC/CAE study that provided CNG at the pump can be purchased at a discount of at least 15% relative to the existing retail price of diesel or petrol (on an energy-equivalent basis), it would be financially feasible to convert public transport vehicles that travel in excess of 220km a day to bi-fuel or dual-fuel engine.

#### 5.5.6.2. Diversity in the transport fuel mix

The transport sector accounts for just over 50% of total energy consumption in the province and should be an important focus in efforts to create diversity in the province's energy mix. The use of gas in transport will provide the Western Cape with an opportunity to diversify away from diesel and petrol,

[121] Engineering News, July 2014, "Dual-powered public transport economically viable, 'favourable' – study"

[122] Meaning that the costs of conversion could be recovered in fuel operating cost savings in less than 2.5 years

[123] Industrial Development Corporation and Cape Advanced Engineering (2013) *Investigation into the use of clean burning methane in the form of compressed natural gas (CNG) and compressed bio-gas (CBG) in public transport in South Africa.*

which together account for two-thirds of transport fuel consumed in the province. According to the WCG, the 267 buses in the MyCiTi bus fleet alone consume roughly 4 million litres of diesel per year, which equates to roughly 148 000 GJ of energy or 0.1% of total energy consumed in the province. A total of ~9 350 vehicles would be converted to run off CNG in our gas-to-transport scenario, which is approximately 10% of the total passenger vehicle fleet in the province. The impact of this conversion on the transport fuel mix would be significant and would provide the foundations in terms of gas infrastructure for the conversion of privately owned vehicles in future.

#### 5.5.6.3. Reduction in air and noise pollution

The use of natural gas as a fuel for transportation is associated with several potential environmental benefits, including a reduction in air and noise pollution. According to the IEA (2010:23), "[o]n average, a 25% reduction in $CO_2$-eq emissions can be expected on a wheel-to-wheel (WTW) basis when replacing gasoline by light-duty vehicles running on CNG." Noise reduction is a less-often-cited benefit of natural gas vehicles, partly because light vehicles fuelled on CNG may actually be noisier than petrol equivalents, but reduction in noise pollution can be significant for heavy-duty vehicles run on CNG, like refuse trucks[124].

Two case studies on the use of CNG as an alternative to diesel and petrol in public transport are discussed in Box 3. It appears that in both cases the use of CNG resulted in a measurable reduction in toxic atmospheric pollutants such as $SO_2$, $NO_X$ and CO that are associated with the combustion of petrol and diesel.

[124] International Energy Agency (2010) *The contribution of natural gas vehicles to sustainable transport*. [Online] Available at: http://www.iea.org/publications

**Box 3: The use of CNG in public transport as a means to reduce pollution– case studies on Madrid and Delhi**

**Madrid**

The Municipal Transport Company of Madrid is a corporation owned by Madrid City Council, responsible for the provision of bus transportation within the city. The company is committed to reducing the amount of GHGs emitted by its vehicles and aims to achieve this by including electric vehicles and vehicles that run on alternative fuels such as CNG and biodiesel.

The EMT currently has a fleet of almost 2 000 buses and operates a total of 217 lines. In 2010, EMT identified the need to procure 165 low environmental impact buses in order to reach its GHG emissions reductions goal. After a successful tender process, EMT established a contract with five bus manufacturing companies to deliver 165 buses between 2012 and 2013. EMT is now one of the public transportation companies with the most CNG-fuelled vehicles in Europe.

They noted that the CNG-buses were slightly more expensive and the hybrid buses were 20% more expensive than conventional buses. The study noted that in terms of wheel-to-wheel $CO_2$ emissions, the use of CNG only provides a small benefit compared to traditional diesel engines. Total $CO_2$ emissions depend on the gas extraction process, quality of the gas, efficiency of the engine and distance from source to refuelling station.

A major advantage of using CNG over traditional (pre Euro VI) diesel buses, however, is the reduction of harmful tailpipe emissions, including particulates (which are negligible) and $NO_x$ emissions (which are substantially lower). The new CNG buses acquired by EMT under this contract produce between just 30% and 50% $NO_x$ emissions, compared to equivalent buses run on diesel fuel.[125]

Delhi

In the city of Delhi (India), the conversion of the public transport fleet to CNG was one of several initiatives aimed at reducing extremely high levels of pollutants present in the ambient air of the urban city. One of the initiatives was to move public transport to CNG. In 1998, the Supreme Court of Appeal issued a directive to convert all diesel buses in the City of Delhi to CNG in order to mitigate the substantial air pollution emitted by public vehicles. By 2006, an estimated 10 300 CNG buses, 55 000 CNG three-wheeler taxis, 5 000 CNG minibuses and 10 000 CNG cars had been converted[126] According to Goyal (2003), CNG is one of the most environmentally friendly transport fuels, as CNG-powered vehicles emit 85% less $NO_X$, 70% less reactive HCs and 74% less CO than similar gasoline-powered vehicles. An assessment of particulates, CO, NOX and $SO_2$ levels in the ambient air of Delhi in 2001, compared to 2000, showed that levels of SPM, SO2, NOX and CO had fallen by 14%, 22%, 6% and 10% respectively.

[125] European Commission (2013) *CNG and hybrid buses: Alternative vehicles for a cleaner city. GPP in Practice*: Issue 39 | February 2014. Available at: http://ec.europa.eu/environment/gpp/pdf/news_alert/Issue39_Case_Study83_Madrid_alternative_vehicles.pdf

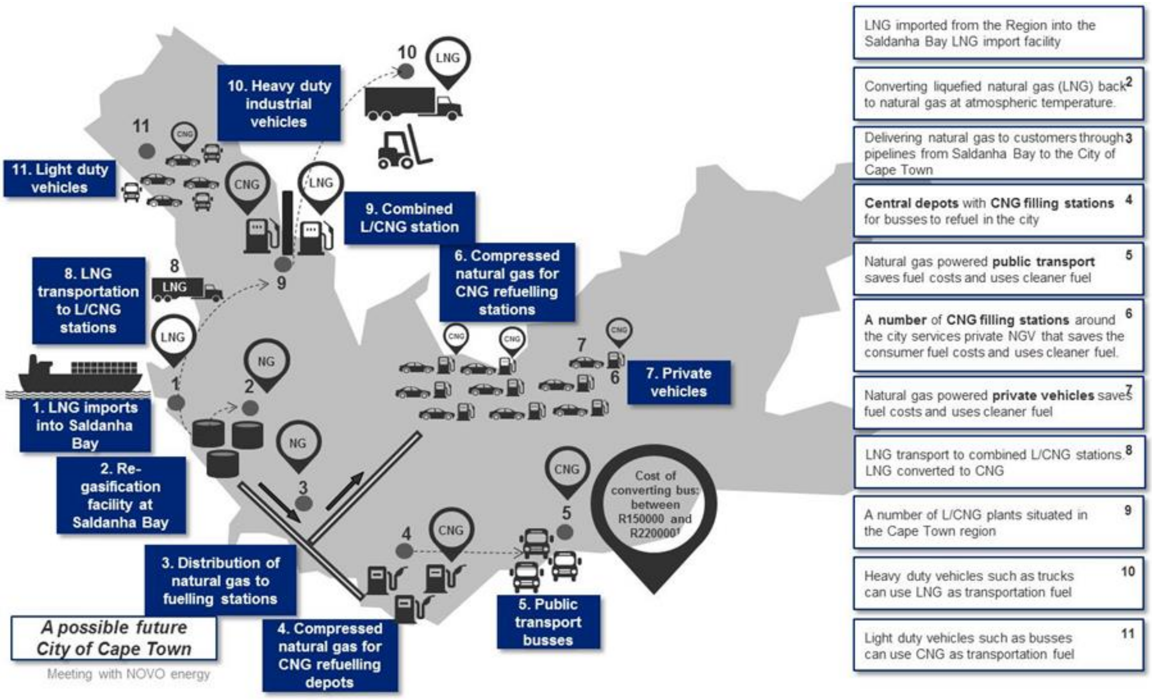
[126] Hohne, N, Burck, J, Eisbrenner, K, Vieweg, M and Grieβhaber, L, "Scorecards on best and worst policies for green new deal", WWF and E3G, Nov 2009.

### 5.5.7. Possible future states for gas-to-transport

Figure 39 provides a conceptual overview of the potential future state of gas-to-transport in the Western Cape as a result of importing natural gas to the region. The future state is contingent on: CNG at the pump being available at a sufficiently competitive price; the presence of key off-takers for imported LNG such as Ankerlig power station; the availability of funding to support the role-out of infrastructure required to support distribution of CNG; policy and regulation to encourage the use of natural gas in transport; and an appropriate fuel tax regime. The IDC/CAE study[127] suggests that CNG at the pump would need to be available at a competitive price (the at least 15% lower than the current cost of a diesel or petrol equivalent litre) to support the financially feasible conversion of public transport vehicles that travel greater than 220km per day. By inference, CNG would need to be available at an even greater discount to petrol/diesel equivalents to support the roll-out to private and government fleet that travel fewer kilometres per day.

The potential socio-economic benefits of using CNG in transport include diversity in the transportation fuel mix, potential fuel cost-savings and lower GHG emissions, particularly in urban areas.

**Figure 39: Possible future transportation end states for the Western Cape**




[127] Industrial Development Corporation and Cape Advanced Engineering (2013) Investigation into the use of clean burning methane in the form of compressed natural gas (CNG) and compressed bio-gas (CBG) in public transport in South Africa.

# 6. Macroeconomic impacts associated LNG import infrastructure spend

## 6.1. Introduction

In this section we provide a quantitative assessment of the **macro-economic impacts associated with the capital infrastructure and ongoing operating expenditure that is** required to import, distribute and consume imported natural gas to our four end-users in aggregate.

As outlined in section 5, the infrastructure and operating expenditure that is associated with LNG imports is a socio-economic cost that is incurred in order to realise the socio-economic benefits that are associated with the *use of imported natural gas*. However, the spending on infrastructure and operations in turn is associated with a range of *macroeconomic* impacts. The macroeconomic impact of expenditure on LNG-related infrastructure and operations on the Western Cape economy is assessed in terms of the following variables:

- Gross domestic product (GDP);
- Employment;
- Government revenue;
- Benefiting industries; and
- The trade balance

## 6.2. Approach and methodology

To estimate the macroeconomic impact of infrastructure and operations spending associated with the import and distribution of LNG, we used a modified 42-sector Western Cape social accounting matrix (SAM) published by Quantec Research. A SAM is a static representation of an economy that simulates the interaction between all the different sectors and factors of production in an economy. "More specifically it is an accounting framework that assigns numbers to the incomes and expenditures in the circular flow of spending within an economy"[128]. SAMs are widely used in economic impact assessments and policy analysis because they allow for analysis of the structural interdependences at the macro and meso level and inter-sectoral linkages within an economic system[129] A SAM is laid out as a square matrix in which each row and column is called an "account". For an illustration and further explanation of the circular flow concept and SAM matrix please see Appendix H.

In order to conduct an economic impact analysis using SAM, it is necessary to derive SAM-based multipliers. To this end, it is necessary to distinguish between endogenous accounts (those which are mutually interrelated and are subject to receiving the influence of external shocks and policy

[128] IFPRI (2010) Social Accounting Matrices and Multiplier Analysis. [Online]. Available at: http://www.ifpri.org/sites/default/files/publications/sp5.pdf

[129] FAO (2009) Quantitative Socio Economic Policy Impact Analysis - A Methodological Introduction. [Online]. Available at: http://www.fao.org/docs/up/easypol/774/quant_socio-economic_pia_068en.pdf

measures) and exogenous (those from which external shocks are generated)[130]. In the Western Cape SAM the production (activities and commodities), factor (labour, land, capital) household and business enterprise accounts are endogenous, while government, exports and capital formation are exogenous.

After reorganising the SAM into endogenous and exogenous accounts, it is possible to compute SAM-based multipliers, e.g. coefficients which show the average impact of an exogenous injection of additional income on one or more endogenous accounts[131]. These coefficients are used to assess the impact of income injections generated by specific policy measures. For example, they can be used to assess the economy-wide impact of a R1million increase in the final demand for construction commodities on GDP, intermediate imports, employment, household income etc.

The fact that some accounts in a SAM are by necessity exogenous, means that there is a limit to the endogenous responses that are captured in the multiplier model. For example in the Western Cape SAM, the government account is exogenous so that although government receives tax revenue it is not re-spent in the economy. To this extent, the multiplier effects associated with the initial injection will be under-estimated but this is one of the inherent limitations of a multiplier model.

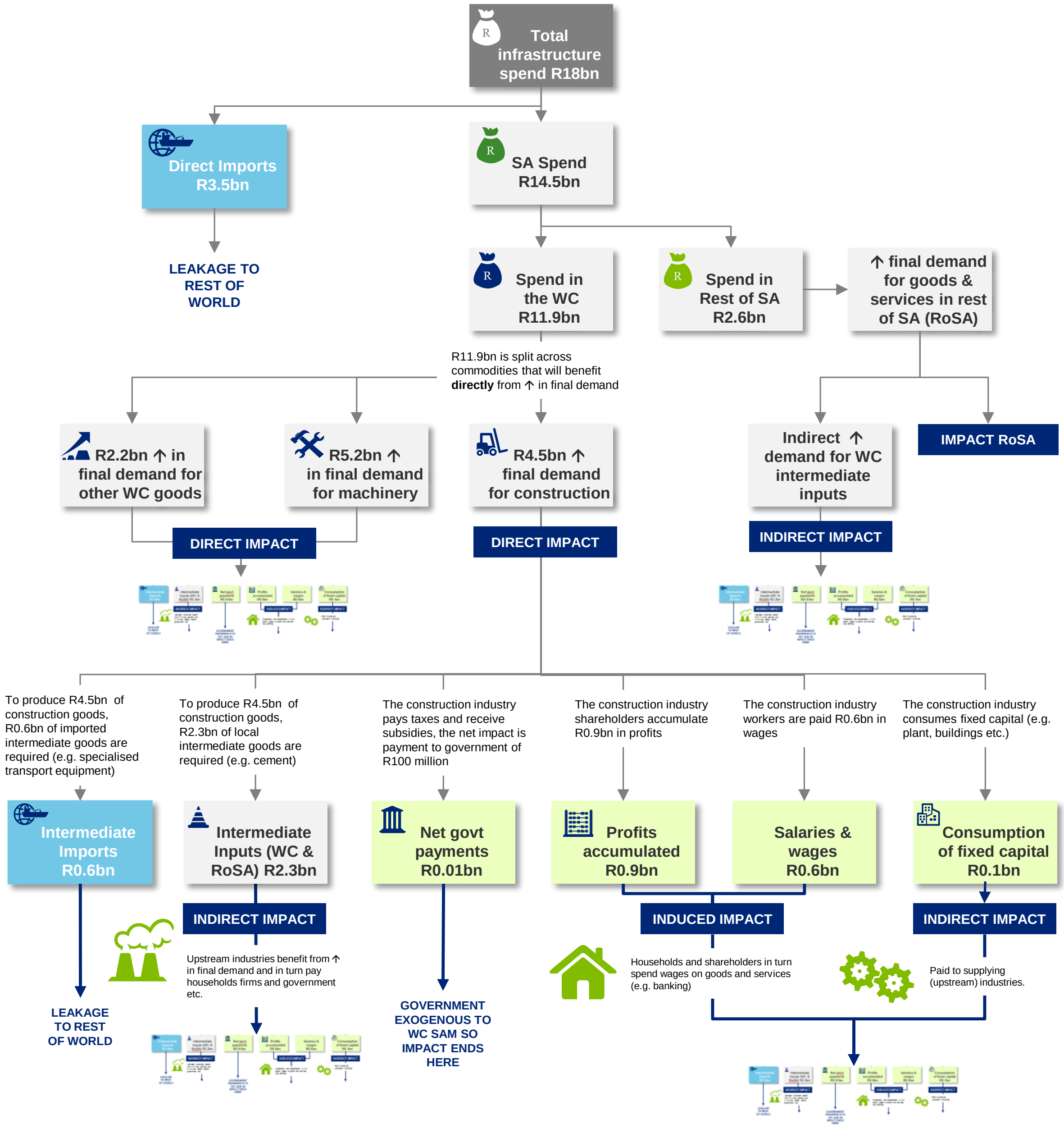
In Figure 40 we have illustrated how the R18bn initial investment in LNG and power infrastructure associated with scenario 1 flows through the economy (as captured in a SAM) to create an increase in GDP of R16.4bn.

The Western Cape SAM we have used is integrated with the rest of South Africa so that we are also able to estimate the impact of spending in the Western Cape on the rest of the South African economy (it is not just reflected as a leakage). The Western Cape SAM also contains information on the proportion of local spend that has historically be retained in the Western Cape economy when there is an increase in the final demand for each commodity (e.g. of every R1 spent on food products and services R0.92 is retained in the Western Cape). An example of this data and an explanation of how it impacts the multiplier analysis is provided in Appendix G.

Multiplier analysis, based on Social Accounting Matrices, can be used not only to quantify the impact of an exogenous shock but also to decompose the macroeconomic impact into its direct, indirect and induced components. A practical example of how multipliers are applied to calculate and decompose the impact of an exogenous demand shock on GDP is provided in Box 4.

[130] FAO (2009) Quantitative Socio Economic Policy Impact Analysis - A Methodological Introduction. [Online]. Available at: http://www.fao.org/docs/up/easypol/774/quant_socio-economic_pia_068en.pdf
[131] One or more of the accounts must be designated as being exogenous otherwise the matrix is not invertible and it's not possible to calculate multipliers.

**Figure 40 Example of how expenditure associated with scenario 1 impacts the economy**




## Example of circular flow of income and estimating the impact on GDP

- While the total initial investment in infrastructure is R18billion, R3.5billion is spent directly on imported goods and services so that only R14.5bn enters the SA economy. According to information gathered, of the R14.5bn, R11.9bn is likely to be spent on goods and services in the Western Cape while R2.6bn will be spent on goods and services in the rest of South Africa.
- The R11.9bn spent in the Western Cape results in an increase in the final demand for a number of different commodities including construction, machinery etc. As a result of the R4.5bn increase in the final demand for construction, the construction industry in turn requires a number of intermediate goods and services some of which are sourced locally while others are imported (another leakage). The construction industry then pays taxes to government and wages and profits to household and shareholders. The construction industry also pays owns of fixed capital it consumes.
- Upstream industries supplying construction, benefit from an increase in final demand and in turn pay households, firms and government and demand upstream inputs. Households in turn spend wages on goods and services (e.g. banking).
- To estimate the impact of the initial R18bn spend on GDP (or) all the “green boxes” representing the sum of all accumulated income (profit, salaries and wages and consumption of fixed capital) are added throughout all rounds of spending(direct, indirect and induced) to determine the total impact.
- Using the SAM we calculate that GDP of R16.4bn arose from the initial R14.5bn increase in final demand for SA goods and services. The GDP multiplier is therefore equal to 1.31 (16.4/14.5). In other words for every R1 increase in exogenous final demand for goods and services in SA, an additional R1.31 in GDP is created.

**Box 4: Understanding multiplier analysis – quantifying and decomposing the impact of an exogenous demand-shock on GDP**

Multiplier analysis, based on Social Accounting Matrices, can be used to quantify and decompose the macroeconomic impact of an “exogenous demand-side shock” such as an increase the final demand for a particular commodity output. The impacts of these shocks have both direct and indirect effects on economic variables such as household income, GDP and employment.

To illustrate how multipliers are applied and how the impact of a shock is decomposed we have provided a worked example in the Table 18 and have illustrated the outputs in. In our example we assume that an exogenous investment shock leads to a R1million increase in the final demand for construction output in the Western Cape (WC) and use GDP multiplier to decompose the impact on WC GDP.

**Table 18 Applying GDP multipliers - the example of a R1million construction demand shock**

| | A<br>Increase in demand for construction output | B<br>GDP Multipliers - Construction | AxB<br>Impact on GDP |
|---|---|---|---|
| Initial Impact | R 1 000 000 | 0.36 | R 356 678 |
| First Round | R 1 000 000 | 0.16 | R 162 254 |
| **Direct Impact** | **R 1 000 000** | **0.52** | **R 518 932** |
| Indirect Effect | R 1 000 000 | 0.13 | R 127 086 |
| **Direct and Indirect Impact** | **R 1 000 000** | **0.65** | **R 646 017** |
| Induced Impact | R 1 000 000 | 0.18 | R 180 129 |
| **Economy-wide Impact** | **R 1 000 000** | **0.83** | **R 826 146** |
| | | | |
| Average GDP Multiplier for construction in WC (R826146/R1000000) | | | 0.83 |

*Source: Deloitte Analysis*

The initial impact of R356K represents the “value-added” that is created within the economy as a result of an R1million increase in demand for construction goods and services and is simply calculated as the product of R1million and the initial impact GDP multiplier of 0.36. The initial impact on GDP, however, is far less than the R1 million spent on construction output because R644K of intermediate inputs and costs were required to produce the R1million of construction goods and these are subtracted from GDP to avoid double counting.

The R356K of value-added (or GDP) includes all salaries and wages, profits, consumption of fixed capital and net government payments disbursed in the creation of R1million of construction output..

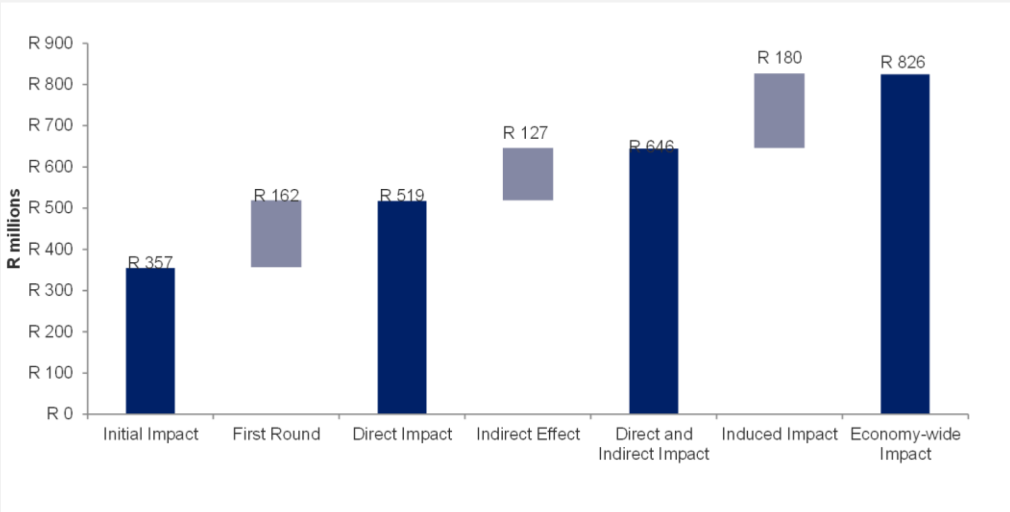
In order to produce R1million of construction output the industry buys intermediate inputs such as cement. The cement industry and other upstream suppliers to construction in turn generates value-add and this sums to R162K – equivalent to the first round impact on GDP. The total value of initial impacts and first-round impacts represents the direct GDP impact as a result of a R1 million increase in demand for construction-related goods and services within the Western Cape.

The cement industry then increases its demand for intermediate inputs such as electricity which in turn generate increased value-add to the tune of R127K. The indirect effect impact represents all the value-added generated by the suppliers of suppliers.

As value-add is generated, households receive salaries, wages and dividends. Households then spend a portion of their increased income on a range of other goods and services including banking, education and housing etc. The Induced Impact (R180K) represents the increase in value-added generated by an increase in household demand for a range of goods and services. This results in an increase GDP in industries like education that are not necessarily suppliers to the construction industry, or its suppliers.

The total economy-wide impact of a R1million increase final demand for construction services in the Western Cape is the sum of the direct, indirect and induced GDP impacts and in this example is R826K. The GDP multiplier for construction services in the Western Cape is therefore 0.83 (R826K/R1m)

**Figure 41 Impact of a R1m increase in final demand for construction on Western Cape GDP**

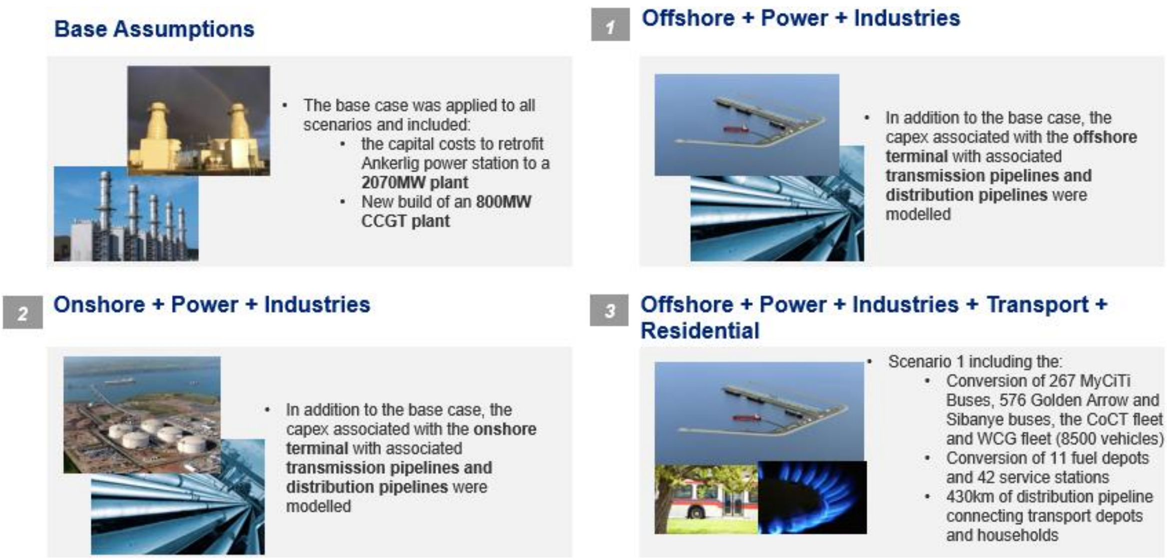



*Source: Deloitte analysis*

## 6.3. Overview of infrastructure spending scenarios modelled

To evaluate the macroeconomic impacts associated with the infrastructure that would be required to import LNG into the Western Cape; we considered the three scenarios outlined in Figure 42. The two power generation projects (retrofitting of the Ankerlig power station and the construction of a new CCGT[132] plant) are considered to be the "anchor off-takers" for imported LNG and, as such, were included in all three scenarios.

**Figure 42: Description of infrastructure spending scenarios modelled**




- **Scenario 1: Offshore Terminal + Power + Industries** – an offshore receiving terminal, including the associated re-gasification plant and the associated transmission and distribution pipelines to Ankerlig and key industrial areas;
- **Scenario 2: Onshore Terminal + Power + Industries (Scenario 2)** – an onshore terminal, including a re-gasification plant and the associated transmission and distribution pipelines to Ankerlig and key industrial areas;
- **Scenario 3: Offshore Terminal + Industries + Power + Transport + Residential** – an offshore receiving terminal (including the associated re-gasification plant), the transmission and distribution pipelines to Ankerlig and key industrial areas, the gas-to-transport scenario and the gas-to-household scenario.

We distinguish between the economic impacts associated with spending that takes place during the construction and operations phases of the project and report these separately. Construction spending is assumed to take place over a five-year period for all scenarios. The results for the construction phase are expressed in terms of summed totals for the five-year period and as average annual figures.

The operating expenditure impacts relate to the benefits derived from operating and maintenance activities associated with the completed infrastructure. These impacts are generally reported for a typical year and are assumed to last for the duration that the infrastructure or asset is in operation.

[132] Combined Closed-Cycle Gas Turbine

## 6.4. Key findings

Our key findings on the macroeconomic impact of spending related to the import and distribution of LNG via the West Coast are presented below. We distinguish between impacts that take place during the temporary 5 year construction phase and ongoing operations phases of the project.

### 6.4.1. Construction phase

*A summary of the macroeconomic impacts that are associated with the construction phase of the project is provided, for all three scenarios, in Table 19 we explain the following:*

- The total cost of rolling out infrastructure to support end-users in the scenarios described above is between R17.9bn (scenario 1) and.R21.7bn (scenario 3). All scenarios include the conversion of the Ankerlig power station to a CCGT and the construction of a new 800MW CCGT plant which together are estimated to cost R14.2bn133.

- About 80% of total infrastructure spend will be spent in the South African economy (R14.5n in scenario 1 and R18.2bn in scenario 3) while the remainder leak out of the economy as direct imports.

- With most of the spending assumed to take place in the Western Cape, the provincial economy will grow at an additional 0.5% per year (scenario 1) and 0.7% per year (scenario 3) over the 5 year construction period. As a result the Western Cape's gross geographic product (GGP) will increase by between R12bn (scenario 1) and R15.6bn (scenario 3).

- The increase in local spending on LNG infrastructure will add 0.1 percentage points to national GDP growth, every year for 5 years and GDP is expected to increase by a total of between R16.5 and R21.5bn.

- In scenario 3, 84 000 jobs (Full Time Equivalent for 12 months) will be created during the construction phase and roughly 80% will be retained in the Western Cape (67 400). In scenario 1, 64 000 jobs (Full Time Equivalent for 12 months) will be created during the construction phase and roughly 80% will be retained in the Western Cape (51 600).

- Between R3.1bn and R4.1bn (scenarios 1 and 3 respectively) of additional tax revenue will be generated representing an increase in total government revenue of between 0.32% and 0.41%.

- Total imports during the construction phase are estimated to be between R6.2bn and R10.5bn (over the five-year period)), which would constitute an increase in South Africa's 2013 trade deficit of between 1.9% and 2.2% (2013).

[133] This assumes that the option of an offshore LNG import terminal is selected.

•

**Table 19: Summary of the macroeconomic impacts of spending during construction phase**

| | Scenario 1 | | Scenario 2 | | Scenario 3 | |
|---|---|---|---|---|---|---|
| | Western Cape | National | Western Cape | National | Western Cape | National |
| **Total spend** | | 17.9 | | 20.4 | | 21.7 |
| **Total local spend (Rbn)** | 12.1 | 14.5 | 13.8 | 16.6 | 15.8 | 18.2 |
| **GDP – first round impact (Rbn)** | 5.6 | 6.6 | 6.3 | 7.5 | 7.3 | 8.6 |
| **Total GDP increase (Rbn)** | 12.0 | 16.5 | 13.7 | 18.7 | 15.6 | 21.5 |
| **Average increase in GDP per year** | 0.5% | 0.1% | 0.6% | 0.1% | 0.7% | 0.1% |
| **Total employment impact** | 51 600 | 64 300 | 58 600 | 73 200 | 67 400 | 84 200 |
| **Average increase in employment per year** | 0.5% | 0.1% | 0.6% | 0.1% | 0.7% | 0.1% |
| **Govt. tax revenue, five-year period (Rbn)** | | 3.2 | | 3.6 | | 4.1 |
| **Average increase in total govt revenue per year** | | 0.06% | | 0.07% | | 0.08% |
| **Total indirect imports, five-year period (Rbn)** | | 3.2 | | 3.7 | | 4.2 |
| **Total indirect and direct imports, five-year period (Rbn)** | | 6.7 | | 7.5 | | 7.7 |
| **Annual average imports over five-year period, (Rbn)** | | 1.3 | | 1.5 | | 1.5 |
| **% of 2013 trade deficit per year (five-year period)** | | 1.9% | | 2.1% | | 2.2% |
| **GDP multipliers** | | 1.16 | | 1.15 | | 1.15 |

*Source: Deloitte analysis*

### 6.4.1.1. Operations and Maintenance Phase

*A summary of the macroeconomic impacts that are associated with the operations and maintenance phase of the project in all three scenarios considered is provided in Table 20. We explain the key findings as follows:*

- During the operating and maintenance phase, an estimated additional R0.53bn (scenario1) and R0.74bn (scenario 3) in GDP will be created for the economy each year. This will add an increase GGP growth in the Western Cape by 0.1 percentage points every year.

- An additional 2300 jobs will be created and sustained during operations in scenario 3 and 1600 of these will be in the Western Cape. Scenario 2 which includes an onshore terminal has a larger employment impact – 3000 additional jobs would be created and sustained during operations and 2100 of these would be in the Western Cape.-

[134] Based on 2013 GDP

[135] Over five years, including informal sector employment impacts

- A total of R9.2bn of LNG would be imported annually for gas-to-power ( which is included in all 3 scenarios) but this would be partly offset by the estimated R6.3bn reduction in diesel imports currently used in power generation so that the annual trade deficit, which stood at R73bn in 2013 would increase by roughly 4%

- Government revenue from taxes is expected to increase by roughly R94 million in scenario 1 and R100million in scenario 3.

**Table 20: Economic impact of LNG infrastructure operations and maintenance per year**

| | Scenario 1 | | Scenario 2 | | Scenario 3 | |
|---|---|---|---|---|---|---|
| | Western Cape | National | Western Cape | National | Western Cape | National |
| **Local spending (Rm)** | 380 | 470 | 540 | 650 | 400 | 480 |
| **GDP – first round impact (Rm)** | 160 | 210 | 220 | 290 | 170 | 220 |
| **Total GDP increase (Rm)** | 350 | 530 | 480 | 740 | 360 | 550 |
| **Average increase in GDP**[136] | 0.08% | 0.01% | 0.11% | 0.02% | 0.08% | 0.01% |
| **Total employment impact**[137] | 1 500 | 2 100 | 2 100 | 3 000 | 1 500 | 2 200 |
| **Govt. tax revenue (Rm)** | | 94 | | 130 | | 100 |
| **Average increase in total govt revenue** | | 0.01% | | 0.01% | | 0.01% |
| **Total indirect imports (Rm)** | | 100 | | 150 | | 110 |
| **Total indirect and direct imports (Rbn)** | | 9.8 | | 9.4 | | 9.8 |
| **% of 2013 trade deficit per year (five-year period)** | | 14% | | 13% | | 14% |
| **GDP multipliers** | | 1.14 | | 1.14 | | 1.14 |

*Source: Deloitte analysis, see Appendix F for further breakdown*

[136] Based on 2013 GDP

[137] Including informal sector employment

## 6.5. Construction phase – detailed inputs and results

### 6.5.1. Scenario 1: Offshore Terminal + Power + Industries

#### 6.5.1.1. Expenditure inputs

The high-level breakdown of the infrastructure expenditure associated with Scenario 1 is provided in **Error! Reference source not found.**, which outlines the main components of infrastructure and the split between local spend and imports. Further information on how we have assumed that the local expenditure components are divided between specific commodities (e.g. construction goods and services) and on the sources of this data, is provided in Appendix E.

**Table 21: Composition of construction spending for Scenario 1**

| Infrastructure for Terminal | Local (Rm) | Imports (Rm) | Total (Rm) | Total Cost ($USm) |
|---|---|---|---|---|
| Offshore Terminal Costs | R 861 | R 557 | R 1 418 | $135 |
| Offshore Terminal Lines | R 969 | R 425 | R 1 393 | $133 |
| Offshore Distribution Lines | R 931 | R - | R 931 | $89 |
| **Gas-to-Power** | | | | |
| Ankerlig | R 6 748 | R 252 | R 7 000 | NA |
| CCGT Power Plant (800MW) | R 4 950 | R 2 250 | R 7 200 | NA |
| **Total Capex Costs (Scenario 1)** | **R 14 459** | **R 3 483** | **R 17 942** | |

#### 6.5.1.2. Results

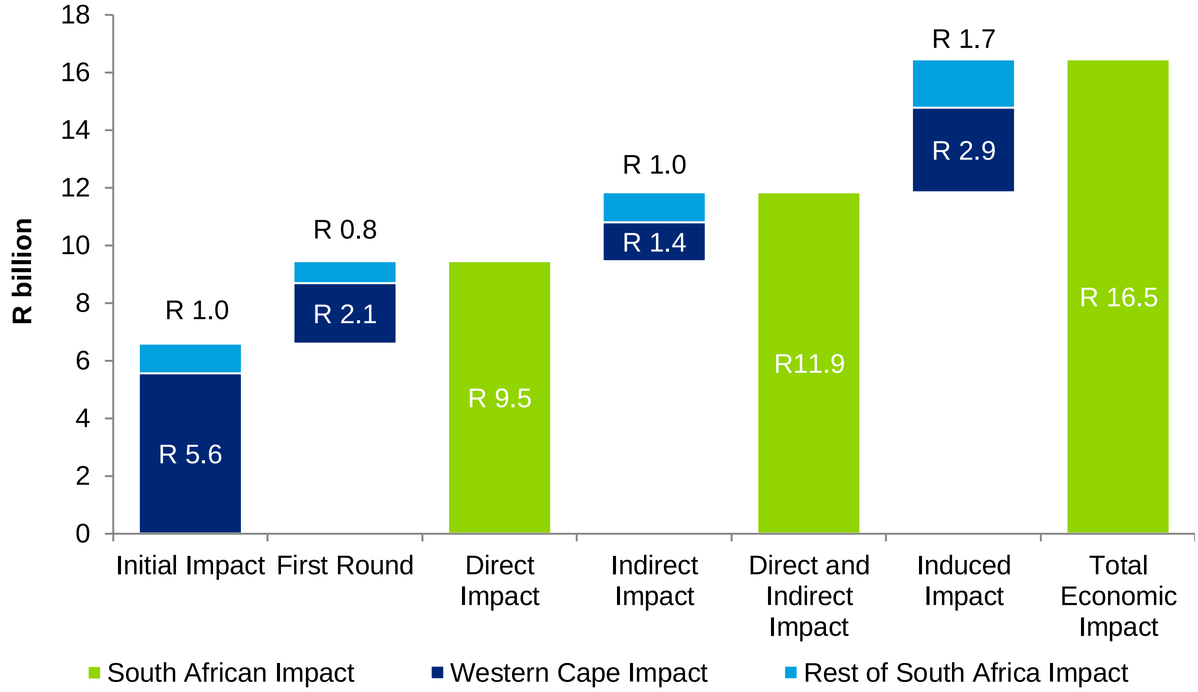
**GDP impact**

In Scenario 1 there is a R14.5bn increase in local infrastructure expenditure, of which R12.1bn is spent within the Western Cape economy. This initial increase in the final demand for goods and services (including metal products, electrical machinery, building and construction and business services) generates a R6.6bn increase GDP, of which R5.6bn remains within the Western Cape (Figure 43).

Increased demand for output for the upstream (first round) suppliers to these industries generates additional R2.9bn in GDP. If we include indirect and induced GDP impacts, then the total economy-wide GDP impact due to the construction of an offshore gas terminal and associated transmission and distribution pipelines, is R16.5bn, of which R12bn remains within the Western Cape economy. This is the equivalent of a 0.1% annual increase in national GDP over the five-year period. The Western Cape economy is expected to be the largest beneficiary of this increase in GDP, as its GGP[138] will increase by R12bn or by 0.5% per year over the five-year period.

[138] Gross Geographic Product – the GGP of the Western Cape is estimated at R438.7 billion (StatsSA)

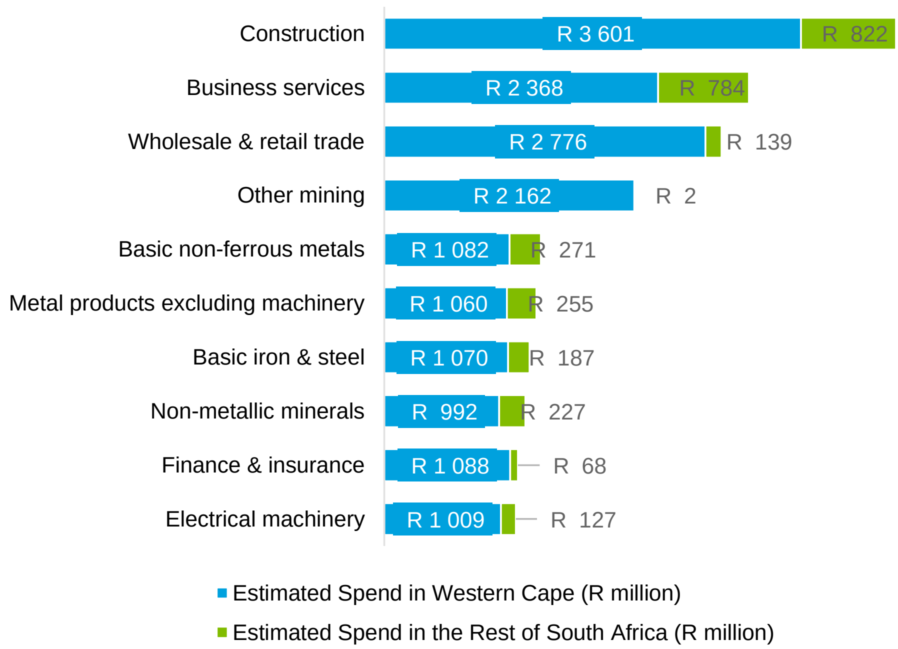
**Figure 43: Economy-wide GDP impact of construction spending associated with Scenario 1**




## Benefitting Industries

A summary of the top ten industries to benefit from directly (initial impact and first round suppliers) from infrastructure spending in scenario 1, is provided in Figure 44. The largest beneficiaries are the construction, business services and wholesale and retail trade.

**Figure 44: Top 10 benefiting industries as a result of spending on Scenario 1, R million**



### Imports

*An estimated R3.5bn of direct imports will be required for Scenario 1*[139] *, these consist of:*

- R557 million for the offshore terminal
- R425 million for the offshore transmission lines
- R252 million for the Ankerlig conversion
- R2.25 billion for the construction of a new-build 800MWe power plant

The SAM computes that another R 3.2bn of goods are imported indirectly in subsequent rounds of spending (by upstream suppliers and households) over the five-year period. A total of R6.7 billion of goods are imported over the 5-year period representing an average annual increase in the trade deficit of R1.3 billion or 1.8% of the 2013 trade deficit.[140].

### Government revenue

Government revenue is expected to increase by R3.15 billion over the 5-year period as a result of the increased economic activity associated with Scenario 1 infrastructure expenditure.

### Employment

Employment multipliers for highly skilled, skilled, unskilled and informal employment are applied to spending that takes place in Scenario 1 in order to estimates the associate increase in employment The total employment impact for scenario 1 is 64 300 jobs, of which the majority (51 600) will be associated with jobs created within the Western Cape. This equates to an average of 13 000 jobs created per year over the five-year construction period.

Employment will mainly be created for skilled and unskilled workers, with an equal proportion being created for the informal and highly skilled workers.

**Table 22: Employment impact in the Western Cape, Scenario 1**

| | | Total employment | Highly skilled | Skilled | Unskilled | Informal |
|---|---|---|---|---|---|---|
| Economy-wide | Western Cape | 51 600 | 7 300 | 20 500 | 17 500 | 6 500 |
| | National | 64 300 | 8 900 | 24 900 | 21 600 | 9 300 |

## 6.5.2. Scenario 2: Onshore Terminal + Power + Industries

### 6.5.2.1. Expenditure inputs

The high-level breakdown of the infrastructure expenditure associated with Scenario 2 is provided in Table 23 which outlines the main components of infrastructure and the split between local spend and imports. Further information how the local expenditure components are divided between specific commodities (e.g. construction goods and services), and on the sources of this data, is provided in Appendix E.

**Table 23 Composition of construction spending for Scenario 2**

[139] For more information on the calculations on which these estimates were based, please refer to Appendix F.
[140] SARB, 2013

| | Local (Rm) | Imports (Rm) | Total (Rm) | Total Cost ($USm) |
|---|---|---|---|---|
| Onshore Terminal | R 2 685 | R 1 305 | R 3 990 | $380 |
| Transmission Lines | R 1 281 | R - | R 1 281 | $122 |
| Distribution Lines | R 930 | R - | R 930 | $89 |
| **Gas-to-Power** | | | | |
| Ankerlig | R 6 748 | R 252 | R 7 000 | NA |
| CCGT Power Plant (800MW) | R 4 950 | R 2 250 | R 7 200 | NA |
| **Total Capex Costs (Scenario 2)** | **R 16 594** | **R 3 807** | **R 20 401** | |

### 6.5.2.2. Results

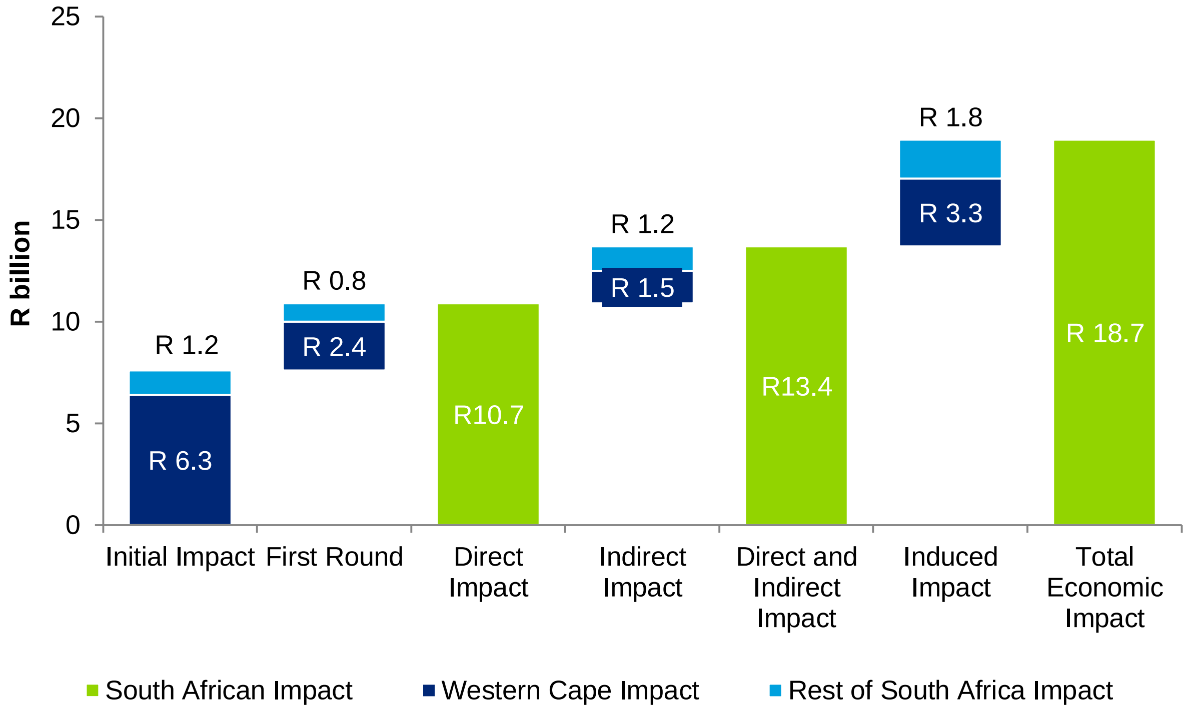
#### GDP impact

Scenario 2 results in a R20.4bn increase in local infrastructure expenditure, of which R13.8bn is spent within the Western Cape economy. This initial increase in the final demand for goods and services (including metal products, electrical machinery, building and construction and business services) generates a R7.5bn increase GDP, of which R6.3bn remains within the Western Cape (Figure 45). Scenario 2 includes similar sectors such as Scenario 1; however, a greater share of the costs is associated with construction services.

Increased demand for output for the upstream (first round) suppliers to these industries generates an additional R3.3bn in GDP. The total economy-wide impact (including indirect and induced impacts) of scenario 2 spending on GDP is R18.7bn, of which R13.5bn remains within the Western Cape economy. This is the equivalent of a 0.1% annual increase in national GDP over the five-year period. The Western Cape economy is expected to be the largest beneficiary of this increase in GDP, as its GGP[141] could increase by R13.5bn or by 0.6% per year over the five-year period.

[141] Gross Geographic Product – the GGP of the Western Cape is estimated at R438.7 billion (StatsSA)

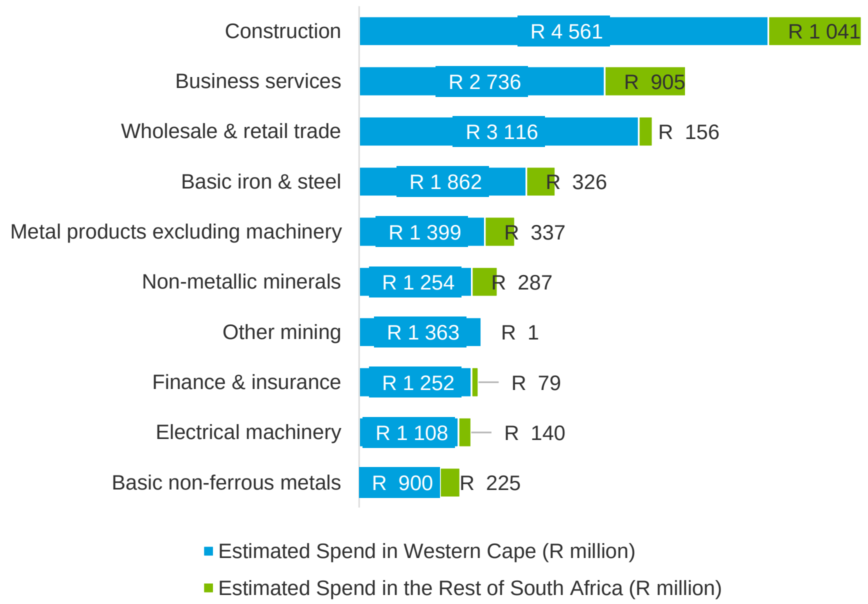
**Figure 45: Economy-wide GDP impact of construction associated with Scenario 2**




### Benefitting Industries

A summary of the top ten industries to benefit from directly (initial impact and first round suppliers) from infrastructure spending in Scenario 2, is provided in Figure 46. The largest beneficiaries are the construction, business services and wholesale and retail trade.

**Figure 46: Top 10 benefiting industries as a result of spending on Scenario 2, R million**




### Imports

An estimated R3.5bn of direct imports will be required for Scenario 2[142] , these consist of:

- R1.3bn for the construction of the onshore terminal
- R252mn for the Ankerlig conversion
- R2.25bn for the construction of a new-build 800MWe power plant

Using the multipliers for intermediate import from the SAM we estimate that another R 3.7bn of goods are imported indirectly in subsequent rounds of spending (by upstream suppliers and households) over the five-year period. A total of R7.5 billion of goods are imported over the 5-year period representing an average annual increase in the trade deficit of R1.5 billion or 2.1% of the 2013 trade deficit.[143].

**Government revenue**

Government can expect to collect and additional R3.6bn in revenue over the 5-year period as a result of the increased economic activity associated with Scenario 2 expenditure.

**Employment**

Employment multipliers for highly skilled, skilled, unskilled and informal employment are applied to spending that takes place in Scenario 2 in order to estimates the associate increase in employment The total employment impact for Scenario 2 is 73 200 jobs, of which the majority (58 600) will be associated with jobs created within the Western Cape. This equates to an average of 14 500 jobs created per year over the five-year construction period. (Table 24).

**Table 24: Scenario 2: Employment Impact on the Western Cape**

| | | Total employment | Highly skilled | Skilled | Unskilled | Informal |
|---|---|---|---|---|---|---|
| Economy-wide | Western Cape | 58 600 | 8 200 | 23 200 | 19 900 | 7 400 |
| | National | 73 200 | 10 000 | 28 200 | 24 600 | 10 600 |

### 6.5.3. Scenario 3: Offshore Terminal + Industries + Power + Transport + Residential

#### 6.5.3.1. Expenditure inputs

The high-level breakdown of the infrastructure expenditure associated with Scenario 3 is provided in Table 25. Scenario 3 includes all infrastructure associated with gas-to-transport and gas-to-household end-user scenarios in addition to the infrastructure provided Scenario 1. Further information, on how we have assumed that the local expenditure components are disaggregated into specific commodities (e.g. construction goods and services), and on the sources of this data, is provided in Appendix E.

**Table 25 Composition of construction spending for Scenario 3**

| | Local (Rm) | Imports (Rm) | Total (Rm) |
|---|---|---|---|
| Scenario 1 total expenditure | R 14 459 | R 3 483 | R 17 942 |

[142] For more information on the calculations on which these estimates were based, please refer to Appendix F.
[143] SARB, 2013

| | | | |
|---|---|---|---|
| Gas to Transport | R 2 280 | R - | R 2 280 |
| Gas to Households | R 1 470 | R - | R 1 470 |
| **Total** | **R 18 209** | **R 3 483** | **R 21 692** |

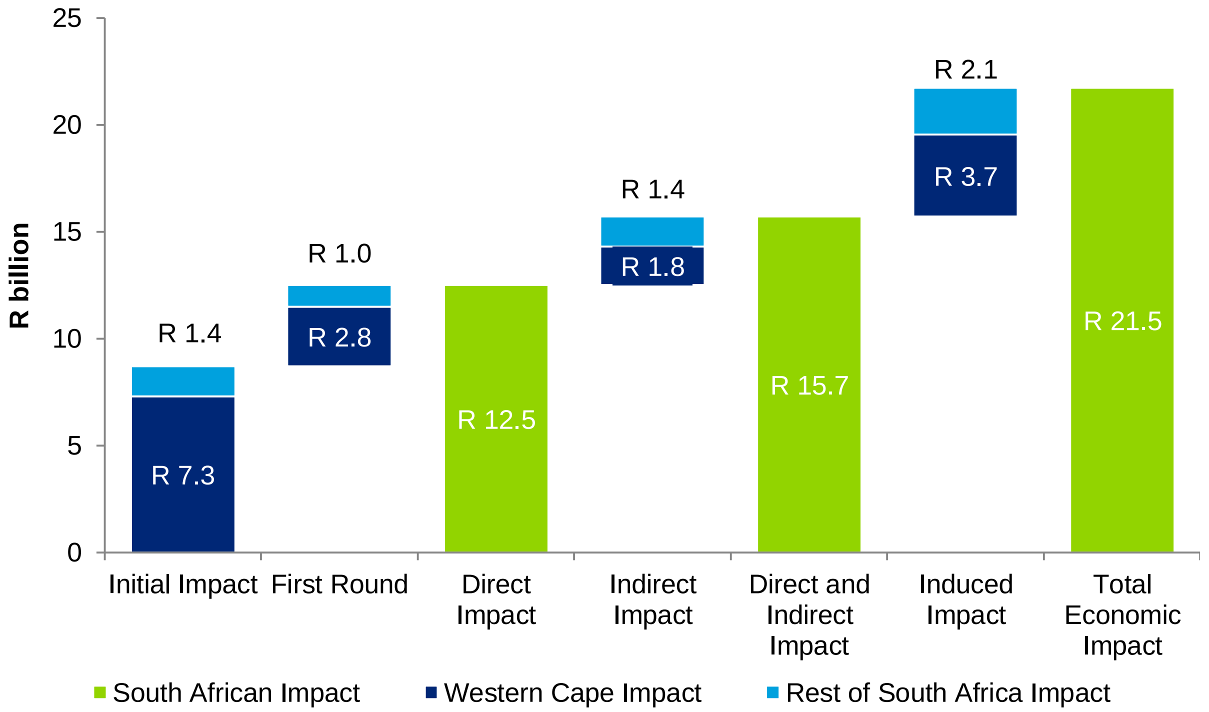
### 6.5.3.2. Results

**GDP impact**

Scenario 3 results in a R21.7bn increase in local infrastructure expenditure, of which R15.8bn is spent within the Western Cape economy. This initial increase in the final demand for goods and services (including metal products, electrical machinery, building and construction and business services) generates an R8.6bn increase GDP, of which R7.3bn remains within the Western Cape (Figure 47).

Increased demand for output for the upstream (first round) suppliers to these industries generates an additional R3.8bn in GDP. The total economy-wide impact (including indirect and induced impacts) of scenario 3 spending on GDP is R21.5bn, of which R15.7bn remains within the Western Cape economy. This is the equivalent of a 0.1% annual increase in national GDP over the five-year period. The Western Cape economy is expected to be the largest beneficiary of this increase in GDP, as its GGP[144] will increase by R15.7bn or by 0.7% per year over the five-year period.

**Figure 47: Economy-wide GDP impact of construction associated with Scenario 3**




**Benefitting Industries**

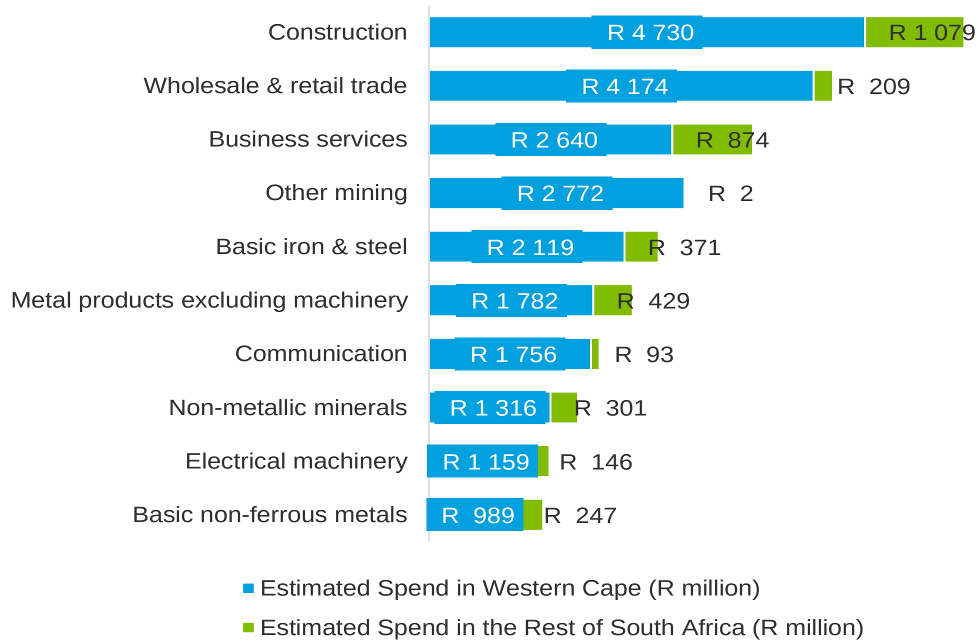
A summary of the top ten industries to benefit from directly (initial impact and first round suppliers) from infrastructure spending in scenario 3, is provided in Figure 48. The largest beneficiaries are again construction, business services and wholesale and retail trade.

[144] Gross Geographic Product – the GGP of the Western Cape is estimated at R438.7 billion (StatsSA)

**Figure 48: Top 10 benefiting industries from spending on Scenario 3, R million**

### Imports

The value of direct imports in Scenario 3 is the same as in Scenario 1 because we assume that all




additional spending on capital infrastructure in Scenario 3 is on local goods and services. It was also assumed that all transportation components for converting existing buses and vehicles and the laying of additional pipelines to households and service stations would be sourced locally sourced[145]. As such, direct imports required to construct all Scenario 3 infrastructure amount to R3.5bn and indirect imports as calculated using the SAM multipliers amount to R4.2bn. Total direct and indirect imports therefore amount to R7.7bn over the entire five-year construction period or an average of R1.5bn per year. This results in an estimated annual increase of 2.2% in the national trade balance deficit.

### Government Revenue

Government revenue is expected to increase by R4.1bn as a result of the increased economic activity associated with Scenario-3-related infrastructure expenditure.

### Employment

Employment gains are the largest for this scenario in comparison to Scenario 1 and Scenario 2 due to the larger spend on providing gas to the Western Cape transport market and residential sector.

The results of the modelling indicate that, should this scenario be considered, an additional 19 900 jobs would be created over the construction period above that of Scenario 1. This brings the total employment impact to 84 200 jobs over the five years. This equates to an average of 19 000 jobs created or sustained nationally per year.

As was the case in Scenario 1 and Scenario 2, the majority of employment impacts occur for skilled and unskilled workers, while informal and highly skilled individuals would still be in equal demand.

[145] This assumption may be subject to further change; however, for the purposes of this study, it was estimated that local components were 100% of costs.

**Table 26: Scenario 3: employment impact on the Western Cape**

| | | Total employment | Highly Skilled | Skilled | Unskilled | Informal |
|---|---|---|---|---|---|---|
| Economy-wide | Western Cape | 67 400 | 9 500 | 26 700 | 22 900 | 6 500 |
| | National | 84 300 | 11 600 | 32 500 | 28 300 | 9 300 |

## 6.6. Operations phase – detailed inputs and results

In addition to estimating the impacts associated with capital expenditure, we estimate the impacts that are derived from operation and maintenance (O&M) activities and costs. These impacts are reported as annual values and therefore do not require any further adjustments as is required when reporting Capex impacts. An overview of the O&M impacts per scenario is provided in Table 27 below:

**Table 27: Summary of operating expenditures and assumptions per scenario per year (Rbn)**

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| **Total operational expenditure** | 10.2 | 9.9 | 10.2 |
| **Direct import amount** | 9.7 | 9.2 | 9.7 |
| **Total national expenditure** | 0.5 | 0.7 | 0.5 |

*Source: Deloitte analysis*

### 6.6.1. Scenario 1: Offshore Terminal + Power + Industries

#### 6.6.1.1. Expenditure inputs

The high-level breakdown of the operations expenditure associated with Scenario 1 is provided in Table 28. Roughly R0.5bn will be spent locally while R9.7bn will be spent on imports, the bulk of which is spent on imports of LNG. Further detail on operating costs and on the sources of this data, is provided in Appendix F.

**Table 28: Scenario 1: Operating Costs (R million)**

| Description | Local cost (Rm) | Imported cost (Rm) | Total operating costs (Rm) |
|---|---|---|---|
| Offshore Terminal FSRU Cost | - | 537 | 537 |
| Port Authority Charges | 38 | - | 38 |
| Pipeline Operation Costs[146] | 6 | | 6 |
| **Base Case** | | | |
| Operating of Power Stations | 424 | 9 200 | 9 624 |
| **Total** | **466** | **9 737** | **10 203** |

*Source: HJ Visagie, Energy Business*

[146] All pipeline running and maintenance costs were estimated at 0.25% of the total capital costs based on information provided in the WCG prefeasibility study.

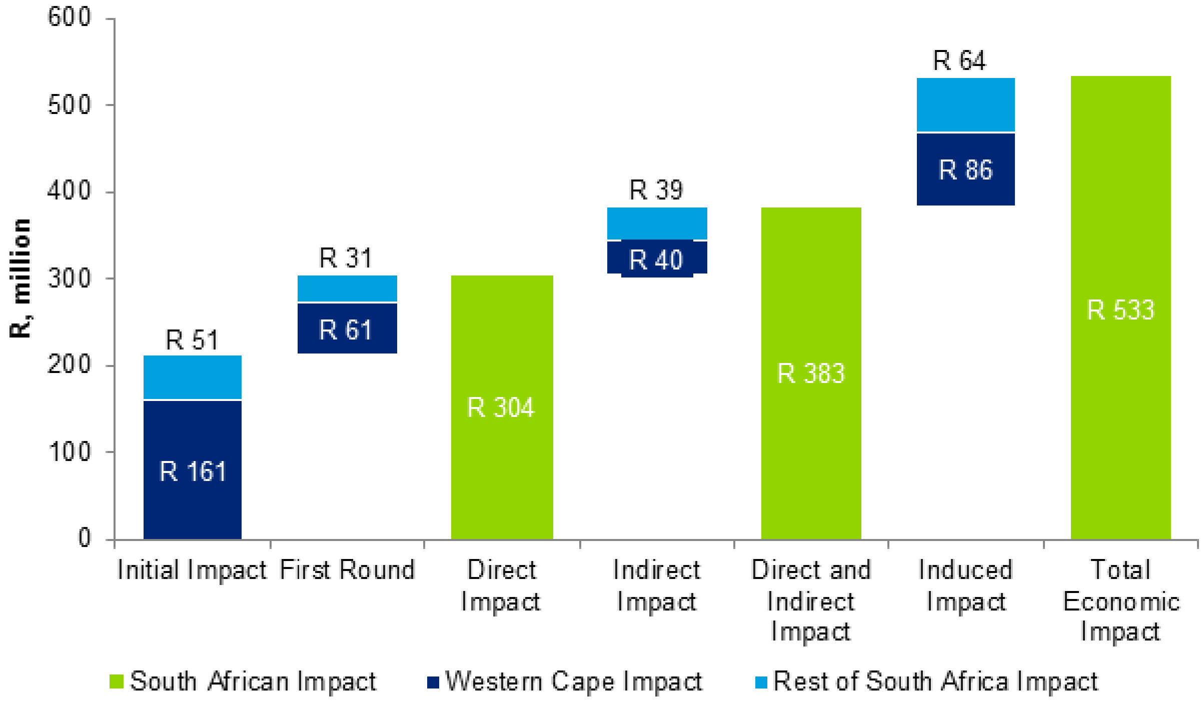
#### 6.6.1.2. Results

**GDP impact**

The local activities required to operate and maintain (O&M) the infrastructure associated with Scenario 1 are estimated to cost R470m per year. This comprises the operating expenditure associated with the converted Ankerlig power station, the 800MW CCGT new-build power station and the distribution and transmission pipelines that service the power stations and industries. The initial GDP impact on the national economy of this annual spending is R210m.

Once all subsequent impacts are included, the estimated annual GDP impact on the national economy due to operational expenditures associated with Scenario 1 is R533m. This annual GDP impact equates to a 0.08% increase in the annual GGP of the Western Cape economy or a 0.01% increase in national GDP. The GDP impacts associated with Scenario 1 O&M activities are illustrated in Figure 49. The GDP multiplier for Scenario 1 is 1.14.

**Figure 49: GDP impacts of operating expenditure associated with Scenario 1**



### Imports

Imports under the operating expenditure scenarios comprise the imports to physically maintain the infrastructure as well as the costs of importing LNG to meet the power stations' requirements.

Imported LNG for fuel comprises the largest component of spending and is estimated to be R2.6bn per year for the 800MW fuel station and R6.6bn for Ankerlig. Total fuel costs are therefore estimated to be R9.2bn per year, regardless of the scenario investigated. This cost represents the total expenditure required to power the converted 2 070MW Ankerlig power station and the 800MW new-build power plant.

Specifically for Scenario 1, the additional cost of operating the offshore terminal was also included and comprised expenditures on imports to maintain the FSRU (estimated at $140 000 a day) or $51.1m a year. At an exchange rate of R10.50 to the dollar, it is estimated that this would cost a foreign-owned company R536m a year to operate.

The cumulative trade balance for 2013 was an estimated R70bn[147]. If we increase the trade balance by the annual import values calculated for Scenario 1, we can expect a 15% increase in the cumulative trade deficit relative to 2013. Full calculations for these estimations can be found in Appendix F.

### Government revenue

The operating expenditure is estimated to increase government revenue to R94m.

### Employment

Employment impact results indicate that, should Scenario 1 be considered, an additional 2 200 jobs would be created per year, assuming no job substitution from other sectors. Most employment occurs for skilled and unskilled workers. Unlike the jobs created or sustained in the construction period, the employment impacts estimated with respect to O&M activities are more permanent in nature and depend on how long the infrastructure is in use. The expected impact of Scenario 1 operations and maintenance on employment is provided below in Table 29. The majority of these employment opportunities are anticipated to occur within the Western Cape.

**Table 29: Employment impact as a result of operating expenditure associated with Scenario 1**

| | | Total employment | Highly skilled | Skilled | Unskilled | Informal |
|---|---|---|---|---|---|---|
| Economy-wide | Western Cape | 1 500 | 300 | 600 | 600 | 200 |
| | National | 2 200 | 400 | 900 | 800 | 400 |

[147] South African Revenue Services, Bilateral Trade Statistics, 2014

### 6.6.2. Scenario 2: Onshore Terminal + Power + Industries

#### 6.6.2.1. Expenditure inputs

The high-level breakdown of the operations expenditure associated with Scenario 2 is provided in Table 30 Roughly R0.6bn will be spent locally while R9.2bn will be spent on imports, the bulk of which is spent on imports of LNG. Further detail on operating costs and on the sources of this data, is provided in Appendix F.

**Table 30: Scenario 2 operating: costs (R million)**

| Scenario 2 | Local cost (Rm) | Imported cost (Rm) | Total operating costs (Rm) |
|---|---|---|---|
| Operation of terminal | 218 | 24 | 242 |
| Pipeline operation costs | 6 | - | 6 |
| **Base case** | | | |
| Operating of power stations | 424 | 9 200 | 9 624 |
| **Total** | **648** | **9 224** | **9 872** |

*Source: HJ Visagie, Energy Business*

#### 6.6.2.2. Results

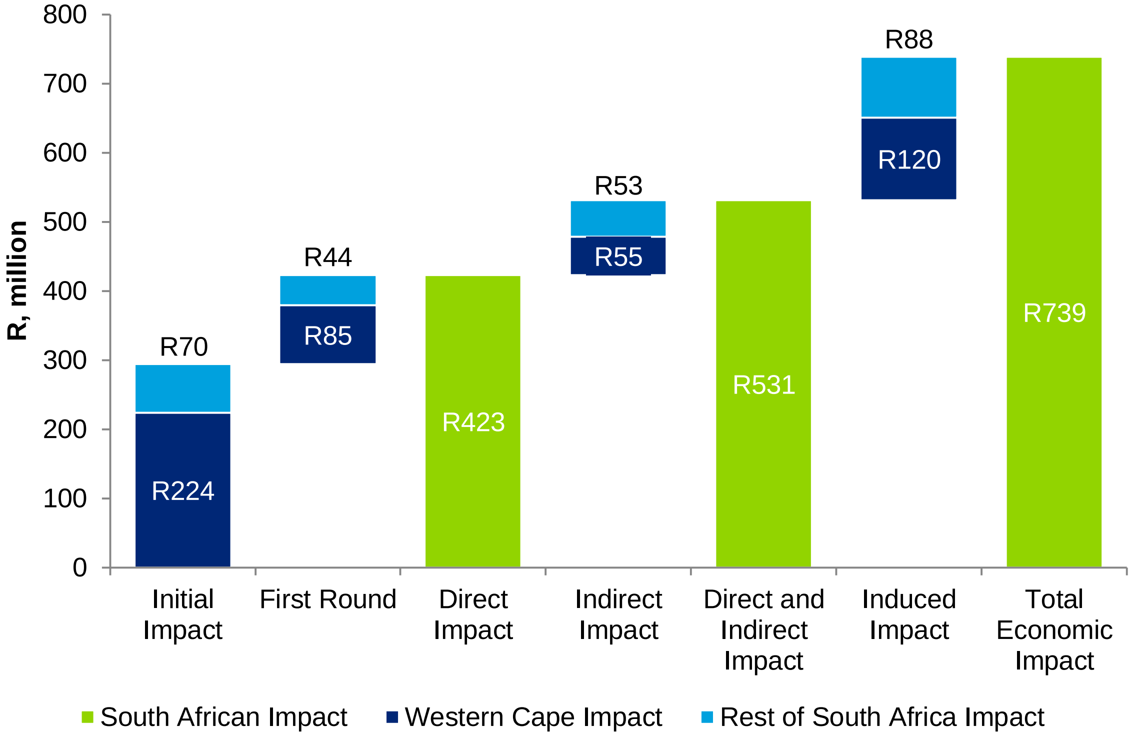
**GDP impact**

The various economic impacts related to operational activities within Scenario 2 are not anticipated to be considerably different from those estimated in Scenario 1. Scenario 2's operating expenditure is concentrated on providing the operations and maintenance of the onshore terminal and resulting pipeline. In addition to the onshore terminal, our calculations also capture the operating expenditure associated with Ankerlig and the new-build 800MW power plant.

The activities required to operate and maintain (O&M) the infrastructure associated with Scenario 2 are estimated to generate an additional demand for local goods and services equal to R648m per year. The initial GDP impact on the national economy of this annual spending is R423m.

Once all subsequent impacts are included, the estimated annual GDP impact on the national economy due to operational expenditures associated with Scenario 2 is R739m. This annual GDP impact equates to a 0.11% increase in the annual GGP of the Western Cape economy or a 0.02% increase in national GDP. The GDP impacts associated with Scenario 2 O&M activities are illustrated in Figure 50. The GDP multiplier for Scenario 2 is 1.14.

**Figure 50: Economic impact of operating expenditure associated with Scenario 2**




### Imports

*Scenario 2's direct imports are predominantly made up of imports similar to Scenario 1. These direct imports consist of:*

- Ten percent (10%) of the operating costs for the operation of the import terminal totalling R24.2m (total operating costs are estimated at R242m per year)
- R6.6bn in imported LNG fuel costs to power the Ankerlig power station
- R2.6bn in imported fuel costs to power the 800MW CCGT power plan

The data supporting these calculations can be found in Appendix F

## Operating expenditure inputs to the Modelling

### Base case

*In calculating operating costs for the gas-to-power infrastructure the following assumptions were made:*

- These plants would be utilised for 4 117 hours of the day at 51% load factor as noted in the prefeasibility report.
- Once Ankerlig was converted, the total GJ required would be 66.5 million GJ as noted in the prefeasibility report .
- $10/MMBtu and R10.50/$ was assumed for LNG fuel costs.
- Fixed operating and maintenance (O&M) costs were assumed to be R138/kW/annum based on a R/$ of R10.50/$ and $13.17/KW-year (O&M) costs from the EIA estimates

**Table 42: Ankerlig conversion annual running costs (R million)**

| Description | Local cost (Rm) | Imported cost (Rm) | Total operating costs (Rm) |
|---|---|---|---|
| Fixed O&M @ R138/kW/a | 306 | - | 306 |
| Fuel Costs @($10/MMBtu) | - | 6 600 | 6 620 |
| **Total** | **306** | **6 600** | **6 906** |

**Table 43: 800MW new-build annual running costs (R million)**

| Description | Local cost (Rm) | Imported cost (Rm) | Total operating costs (Rm) |
|---|---|---|---|
| Fixed O&M @ R138/kW/a | 118 | - | 118 |
| Fuel Costs @($10/MMBtu) | - | 2 600 | 2 600 |
| **Total** | **118** | **2 056** | **2 174** |

### Scenario 1

*In addition to the base scenario, operating costs for scenario 1 consisted of the following:*

**Table 44: Scenario 1: Operating Costs (R million)**

| Description | Local cost (Rm) | Imported cost (Rm) | Total operating costs (Rm) |
|---|---|---|---|
| Offshore Terminal FSRU Cost | - | 537 | 537 |
| Port Authority Charges | 38 | - | 38 |
| Pipeline Operation Costs | 6 | | 6 |
| **Base Case** | | | |
| Operating of Power Stations | 424 | 9 200 | 9 624 |
| **Total** | **466** | **9 737** | **10 203** |

*Source: HJ Visagie, Energy Business*

### Scenario 2

*In addition to the base scenario, operating costs for scenario 2 consisted of the following:*

**Table 45: Scenario 2 operating: costs (R million)**

| Scenario 2 | Local cost (Rm) | Imported cost (Rm) | Total operating costs (Rm) |
|---|---|---|---|
| Operation of terminal | 218 | 24 | 242 |
| Pipeline operation costs | 6 | - | 6 |
| Base case | | | |
| Operating of power stations | 424 | 9 200 | 9 624 |
| **Total** | **648** | **9 224** | **9 872** |

*Source: HJ Visagie, Energy Business*

### Scenario 3

*In addition to the base scenario, operating costs for scenario 3 consisted of the following:*

**Table 46: Scenario 3 operating: costs (R million)**

| Scenario 3 | Local cost (Rm) | Imported cost (Rm) | Total operating costs (Rm) |
|---|---|---|---|
| Offshore Terminal FSRU Cost | - | 537 | 537 |
| Port authority charges | 38 | - | 38 |
| Pipeline operation costs | 14 | | 14 |
| Base case | | | |
| Operating of power stations | 424 | 9 200 | 7 800 |
| **Total** | **476** | **9 737** | **10 213** |

*Source: HJ Visagie, Energy Business*

The estimated annual value of total imports required to operate and maintain the infrastructure associated with Scenario 2 is R9.8bn, which leads to an approximate increase of 14% in the cumulative trade balance based on 2013 figures.

#### Government revenue

The operating expenditure is estimated to increase government revenue by R130m.

#### Employment

The results of the modelling indicate that, should Scenario 2 be considered, an additional 3 000 jobs would be created per year, assuming no job substitution from other sectors. Most employment occurs for skilled and unskilled workers. Unlike the jobs created or sustained in the construction period, the employment impacts estimated with respect to O&M activities are more permanent in nature and depend on how long the infrastructure is in use. The expected impact of Scenario 2 operations and maintenance on employment is provided in Table 31. The majority of these employment opportunities are anticipated to occur within the Western Cape.

**Table 31: Employment impact as a result of operating expenditure associated with Scenario 2**

| | | Total employment | Highly skilled | Skilled | Unskilled | Informal |
|---|---|---|---|---|---|---|
| Economy-wide | Western Cape | 2 100 | 300 | 900 | 800 | 300 |
| | National | 3 000 | 500 | 1 200 | 1 100 | 500 |

### 6.6.3. Scenario 3: Offshore Terminal + Industries + Power + Transport + Residential

#### 6.6.3.1. Expenditure inputs

The high-level breakdown of the operations expenditure associated with Scenario 3 is provided in Table 28. Roughly R0.5bn will be spent locally while R9.7bn will be spent on imports, the bulk of which is spent on imports of LNG. Further detail on operating costs and on the sources of this data, is provided in Appendix F.

**Table 32: Scenario 3 operating: costs (R million)**

| Scenario 3 | Local cost (Rm) | Imported cost (Rm) | Total operating costs (Rm) |
|---|---|---|---|
| Offshore Terminal FSRU Cost | - | 537 | 537 |
| Port authority charges | 38 | - | 38 |
| Pipeline operation costs148 | 14 | | 14 |
| **Base case** | | | |
| Operating of power stations | 424 | 9 200 | 7 800 |
| **Total** | **476** | **9 737** | **10 213** |

*Source: HJ Visagie, Energy Business*

#### 6.6.3.2. Results

**GDP impact**

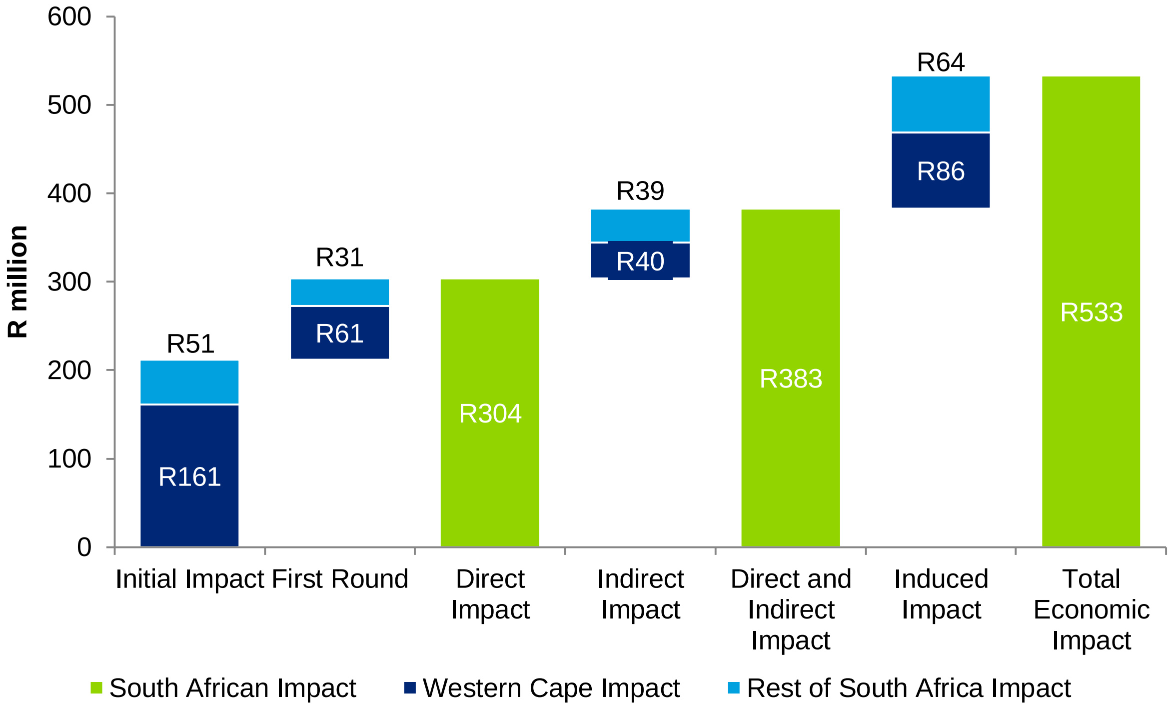
The operating expenditure associated with scenario 3 is very similar to scenario 1 as such they the results are also very similar. The additional operating expenditure within Scenario 3 relates to the operations associated with the extended pipeline that services service stations, bus depots and households. In addition to the onshore terminal, our calculations also capture the operating expenditure associated with Ankerlig and the new-build 800MW power plant.

The operating costs associated with the transportation market are assumed to remain constant regardless of the fuel type used, i.e. the costs to service and maintain a petrol service station, commuter bus or road vehicle that utilises CNG as opposed to petrol/diesel were assumed to remain the same, as no additional operating costs would be needed.

The activities required to operate and maintain (O&M) the infrastructure associated with Scenario 3 are estimated to cost R480m per year. The initial GDP impact on the national economy of this annual spending is R212m. Once all subsequent impacts are included, the estimated annual GDP impact on the national economy due to operational expenditures associated with Scenario 3 is roughly R533m. This annual GDP impact equates to a 0.08% increase in the annual GGP of the Western Cape economy or a 0.01% increase in national GDP. The GDP impacts associated with Scenario 3 O&M activities are illustrated in Figure 51. The GDP multiplier for Scenario 3 is 1.14.

[148] In addition to the existing transmission and distribution pipeline, an additional pipeline of 230km for connecting the transportation market and 200km to connect the residential market was costed at $700 000/km and operating costs of 0.25% of capital costs. In addition, there was assumed to be no additional operating costs for the conversion of myCiti buses, Golden Arrow fleet, Sibanye fleet, the WCG fleet and the CoCT fleet as these operations costs would be absorbed into the current running costs associated with operating these vehicles.

**Figure 51: Economic impact of operating expenditure associated with Scenario 3**




**Imports**

Imports under the operating expenditure scenarios consist of imports of goods and services to physically maintain the infrastructure as well as the costs of importing LNG to meet the power stations' requirements.

Imported LNG for fuel comprises the largest component of spending and is estimated to be R2.6bn per year for the 800MW fuel station and R6.6bn for Ankerlig. Total fuel costs are therefore estimated to be R14bn per year, regardless of the scenario investigated. This cost represents the total expenditure required to power the converted 2 070MW Ankerlig power station and the 800MW new-build power plant.

Specifically for Scenario 3, the additional cost of operating the offshore terminal was included, which comprised expenditures on imports to maintain the FSRU (estimated at $140 000 a day) or $51.1m a year. At an exchange rate of R10.50 to the dollar, it is estimated that this would cost the foreign-owned company R536m a year to operate.

The cumulative trade balance for 2013 was an estimated R70bn[149]. If we increase the trade balance by the annual import values calculated for Scenario 3, we can expect 20% increase in the cumulative trade deficit relative to 2013. Full calculations for these estimations can be found in Appendix F.

[149] South African Revenue Services, Bilateral Trade Statistics, 2014

### Government revenue

The operating expenditure is estimated to increase government revenue by R100m.

### Employment

The results of the modelling indicate that should Scenario 3 be considered, an additional 2 300 jobs would be created per year, assuming no job substitution from other sectors. Most employment occurs for skilled and unskilled workers. Unlike the jobs created or sustained in the construction period, the employment impacts estimated with respect to O&M activities are more permanent in nature and depend on how long the infrastructure is in use. The expected impact of Scenario 3 operations and maintenance on employment is provided below in Table 33. The majority (1 600) of these employment opportunities are anticipated to occur within the Western Cape.

**Table 33: Employment impact as a result of operating expenditure associated with Scenario 3**

| | | Total employment | Highly skilled | Skilled | Unskilled | Informal |
|---|---|---|---|---|---|---|
| Economy-wide | Western Cape | 1 600 | 300 | 700 | 600 | 300 |
| | National | 2 300 | 400 | 1 000 | 900 | 400 |

# Appendix A - policies and plans

## Summary of key policies and plans in relation to natural gas

The purpose of this appendix is to provide a summary of key policy and plans in relation to the development of the natural gas industry and stance on imported liquefied natural gas.

### A. The National Development Plan

The National Development Plan (NDP)[150]was produced by the National Planning Commission in the Department of the Presidency in 2011. It was adopted by cabinet in 2012, as the overarching policy framework to promote economic development in South Africa, eliminate poverty and reduce inequality over a long-term (20-year) planning horizon.

*For the energy sector, the NDP (2011:165) highlighted the following policy and planning priorities; those particularly relevant to business case for LNG imports into the Western Cape are highlighted in bold and expanded on below:*

- Growth in coal exports needs to be balanced against the need for domestic coal-supply security.
- **Gas should be explored as an alternative to coal** for energy production.
- **There needs to be a greater mix of energy sources and a greater diversity of independent power producers (IPPs) in the energy industry**.
- Municipal electricity-distribution services need to be improved.
- **Electricity pricing and access** need to accommodate the needs of the poor.
- **The timing and/or desirability of nuclear power and a new petrol refinery need to be considered**

#### Gas should be explored as an alternative to coal

Given the fixed investment in coal-related infrastructure and low direct coal costs, the NDP(2011:165) recognises that "coal will continue to be the dominant fuel in South Africa over the next 20 years". It is the country's' largest economically recoverable energy resource and among its three top mineral export earners.

The NDP suggests that one of the major arguments for substituting gas for coal is therefore that it will help cut South Africa's' carbon intensity and greenhouse gas emissions.

The possibilities for gas explored in the NDP include offshore natural gas, coalbed- methane, shale gas resources in the Karoo basin and imports of liquefied natural gas, which could be used for power production, gas-to-liquids and other industries.

According to the NDP (2011:167) "New natural gas resources – enough to power at least a medium-sized power station – have been discovered off the West Coast. Further drilling may indicate that the resource is larger" The NDP notes that the opportunity for shale gas extraction in South Africa could be significant as technically recoverable shale gas resources in South Africa are among the largest in the world (eighth-largest according to the United States Energy Information Administration from 2013).

[150] National Planning Commission (2011) *The National Development Plan 2030.* Department of the Presidency

The NDP (2011:167) maintains that, "Even if economically recoverable resources are much lower than currently estimated, shale gas as a transitional fuel has the potential to contribute a very large proportion of South Africa's electricity needs. For example, exploitation of a 24-trillion-cubic-feet resource will power about 20 gigawatts (GW) of combined cycle gas turbines, generating about 130 000GW-hours (GWh) of electricity per year over a 20-year period. This is more than half of current electricity production"

The environmental costs and benefits will, however, also need to be weighed against the alternatives of nuclear and coal. The potential for mining coal-bed methane gas is currently being assessed, although according to the NDP (2011:167) the overall potential of this resource for producing electricity in South Africa "is probably less than previously thought".

**Liquified natural gas**

With respect to liquefied natural gas, the NDP (2011:168) notes that "a global market has developed for liquefied natural gas imports, the prices of which are increasingly delinked from oil prices. With South Africa needing to diversify its energy mix, liquefied natural gas imports and the associated infrastructure could provide economic and environmentally positive options for power production, gas-to-liquids production (at Mossgas) and other industrial energy."

In general the NDP recommends that South Africa incorporate more gas in the energy mix, both through LNG Imports and if reserves prove commercially viable, using shale gas. Power generation was recognised as an opportunity for LNG imports in the short to medium term. The NDP(2011:168) proclaims that, "Investment should begin in liquefied natural gas infrastructure."

**Diversify power sources and ownership in the electricity sector**

"Increasing diversity in South Africa's energy production mix is important to mitigate climate change while enhancing supply security" (NDP 2011:169). Combined cycle gas turbines, for example, are cleaner and less capital-intensive than coal-fired power stations; and because they are flexible sources of power generation (power can be ramped up when required), they can also be used to improve supply security by picking up any shortfall in supply from more intermittent renewable energy sources.

The NDP recognises that South Africa's' electricity plan needs to balance increased use of new and renewable energy technologies with established, cheaper energy sources that offer proven security of supply. The Department of Energy's' Integrated Resource Plan 2010–2030 (and the subsequent update discussed in section C of this appendix) provide options for electricity generation that seek trade-offs between least-cost investment, technology risks, water-use implications, localisation and regional imports. This recognises that South Africa needs to remain competitive throughout the transition to a low-carbon future.

In terms of ownership, the NDP recognises that reforms to South Africa's electricity market structure are required to enable greater private-sector participation and investment in electricity generation. Reforms recommended include the establishment of an "independent system and market operator" to act as a single buyer of electricity, and preferably to also manage transmission assets. Regulatory uncertainties, including the question of IPPs selling to customers other than Eskom, access to Eskom's' grid and rights to trade electricity need to be resolved.

**Electricity pricing and access**

The NDP notes that electricity prices will have to increase to cost-reflective levels if Eskom is to be able to service its debt and fund effective operations, refurbishment and system expansion. Costs will increasingly need to be covered by tariffs, as government is close to its limits in terms of what it can offer Eskom in fiscal support and guarantees. The NDP, however, notes that measures to implement more gradual price increases will need to be explored to limit the impact on consumers and particularly low-income households.

Government is also considering the introduction of an economy-wide carbon tax, with some conditional exemptions, to discourage investment in carbon-intensive power generation and incentivise the use of energy-efficient technologies.

**The timing and/or desirability of nuclear power should be debated**

While recognising the nuclear provides a low-carbon alternative to coal, the NDP urges that in depth investigation into the financial viability of nuclear energy and the associated socio-economic costs and benefits be undertaken. The NDP also suggests that gas be explored as an alternative to base-load nuclear in South Africa's energy mix. Gas in their view, can provide reliable base-load and mid-merit power generation through CCGTs. Gas turbines also have several technical advantages over nuclear: capacity can be expanded incrementally to match demand, their unit capital costs are lower, they are easier to finance and it's also relatively easy to adjust their output. The NDP notes that their operational costs are however arguably higher than those of nuclear stations

### B. The draft 2012 Integrated Energy Planning Report

The Department of Energy (DoE) released the draft 2012 integrated energy planning report[151] in June 2013 for public consultation. It was envisaged that the Integrated Energy Plan (IEP) would be the output of an integrated energy planning process that would seek to determine the best way to meet current and future energy service needs in the most efficient and socially beneficial manner: while maintaining control over economic costs; serving national imperatives such as job creation and poverty alleviation; and minimising the adverse impacts of the energy sector on the environment.

The IEP seeks to provide the overall policy framework and guidelines for more detailed sector plans (e.g. the Integrated Resource Plan [IRP] for electricity and liquid fuels strategy) that look at how specific energy needs will be met. The IEP endeavours to be a long-term vision of how energy can be optimally used as a mechanism for South Africa to remain competitive.

*The IEP draft report 2012 considers a number of different energy-supply planning scenarios and "test cases", where test cases are scenarios where specific high-impact policy imperatives are considered guided by the NDP, IRP and National Climate Change Response White Paper. The scenarios considered include:*

- **Base Case** – assumes that only prevailing energy policies are pursued to shape the future energy pathway

- **"Peak-Plateau-Decline" Emission Limit Test Case** – an emissions limit is applied to electricity and liquid fuel supply sectors in order to meet policy target identified in the National Climate White Paper (i.e. a reduction on the "business as usual" emission level of 34% by 2020 and of 42% by 2025).

[151] Department of Energy (2013) Draft 2012 Integrated Energy Planning Report. Executive Summary. [Online] Available at: http://www.energy.gov.za/files/policies/energyPlanning/Draft-2012-Integrated-Energy-Planning-Report-an-Executive-Summary.pdf

- **Emission Limit – No Nuclear Build Programme Case** – This Test Case assumes that the emission limit of the "Peak Plateau Decline" must be met as described above, but that the 9 600MW Nuclear Build Programme is explicitly excluded as a supply option.

- **Renewable Energy Target Case** – No emission limit constraints are set, but renewable energy options are gradually introduced into the energy mix from 2010 to 2030, such that by 2030, 10% of total energy output (electricity generation and liquid fuel production) will be from renewable energy sources.

- **Emission Limit – Natural Gas Case** – This assumes that the emission limit of the "Peak Plateau Decline" trajectory must be met and that the Nuclear Build Programme be excluded as a supply option, as in the Test Case above. However, the nuclear option is replaced by natural gas options as a policy intervention. This Test Case seeks to analyse the efficacy of including natural gas in the energy supply mix as a transitional fuel towards a low carbon economy and the implications of choosing this as a supply option over nuclear. In this context, natural gas includes conventional gas, coal-bed methane and shale gas.

- **Carbon Tax Cases** – In these two test cases, no emission limit constraints are set, but the carbon tax is implemented as a test case with an upper bound of R120 per tonne of $CO_2$-eq and a second case is implemented with a R48 per tonne to simulate the 60% tax-free threshold.

*With respect to gas, the conclusions from the energy-supply modelling included:*

- Imported natural gas plays an increasing role in all Test Cases throughout the planning period, but it is not prominent in comparison to other primary energy sources.

- New natural gas options do not feature prominently in the Base Case or any of the Test Cases other than the "Emission Limit – Natural Gas Case" where Natural Gas options were explicitly enforced.

**It is important to note, however, that the draft IEP 2012 used the IRP 2010 as an input (rather than the IRP 2010 update) and, as such, did not consider expanded options for gas in the electricity generation mix.** The draft IEP did, however, note that there is significant potential for natural gas in both power generation and thermal heating in South Africa. But, claimed that because of the limited existing gas transmission and distribution infrastructure in South Africa, gas in power-generation was probably the most feasible option. Because of its lower carbon content than coal, the IEP noted that gas could also find broader applications in thermal uses and in transport in the longer term.

"Power generation remains the main driver behind gas demand growth globally and remains a key potential for South Africa. South Africa has a limited gas network but with a well-developed electricity transmission grid, the construction of an LNG facility would need to be underpinned by a gas-fired power plant as a key off-taker as the most feasible solution in the short- to medium-term." (IEP, 2013:66).

In terms of the way forward, the IEP(2013:37), "environmental pressures, increases in the global crude oil prices, potential increases in coal prices together with new potential discoveries of shale gas in the Karoo and natural gas in Mozambique are all potential game-changers which require a sharpened focus on the use of alternative energy sources as well as the efficient use of traditional energy."

*The IEP identified that further work in the following areas would be required:*

- Understanding of the constraints that natural gas infrastructure may have in meeting projected demand for natural gas, particularly in the industrial and commercial sectors
- Exploring options for natural gas imports and the potential impact on projected natural gas import prices including imports from Mozambique and other countries within the region
- Consider scenarios around the potential exploitation of shale gas in the Karoo

## C. The Integrated Resource Plan 2010

The Integrated Resource Plan 2010–30 (IRP 2010) was promulgated in March 2011 and is the official government plan for new electricity generation capacity and the outcome of an integrated planning process. The IRP 2010 identified the preferred generation technology (and assumed energy efficiency demand side management) required to meet expected demand growth up to 2030.

While gas and imported LNG do not featured prominently in the generation mix proposed in most of the IRP 2010 scenarios, most cater for some CCGT capacity fuelled with LNG. LNG prices were assumed in the IRP 2010 at R80/GJ.

*The IRP considers several variations on the following core scenarios:*

- **Base Case -** The Base Case (with Kusile and Medupi as per the original committed schedule) provides for imported hydro as the first base-load capacity in 2020 (after the committed programmes**), followed by CCGT fuelled by liquefied natural gas, or LNG**, then imported coal and fluidised bed combustion (FBC) coal, before pulverised coal which forms the basis of all further base-load capacity. Additional peaking capacity is exclusively provided by open-cycle gas turbines (OCGT), fuelled by diesel.

- **Emission Limit 1 -** Imposing a limit on emissions (at 275 million tons of $CO_2$ throughout the period) shifts the base-load alternatives away from coal (in particular pulverised coal) to nuclear and gas. Wind capacity is also favoured to meet the energy requirements over the period, especially as the emission constraint starts to bite in 2018. As the nuclear programme is restricted in terms of its build rate (one unit every 18 months starting in 2022) wind is required to reduce emissions in the interim. **CCGT provides a strong mid-merit alternative until nuclear is commissioned, especially providing higher load factors than wind, with some dispatchability.**

- **Emission Limit 2 -** The emission limit is retained at 275 million tons but is only imposed from 2025. Under these conditions the nuclear and wind build is delayed (nuclear by one year, wind by five years).

- **Emission Limit 3 -** The tighter emission limit of 220 million tons is imposed from 2020. This requires a significant amount of wind capacity (17600 MW starting in 2015) and solar capacity (11250 MW commissioned between 2017 and 2021) to meet the constraint. In total 17,6 GW of wind, 11,3 GW of solar and 9,6 GW of nuclear are built, with no coal capacity included. **CCGT is constructed as a lower emission mid-merit capacity** along with 6,5 GW of OCGT peakers.

- **Carbon Tax** - The carbon tax scenario includes a carbon tax at the level of that discussed in the Long Term Mitigation Strategy (LTMS) document, starting at R165/MWh in 2010 rands, escalating to R332/MWh in 2020 until the end of the period (2030) before escalating again to R995/MWh in 2040. This level of carbon tax causes a switch in generation technology to low carbon emitting technologies, in particular the nuclear fleet (starting in 2022) and wind capacity of 17,6 GW starting in 2020. The remainder is provided by imported hydro (1959 MW), OCGT (4255 MW) **and CCGT (4266 MW)** with some FBC coal after 2028 (1750 MW).

- **Regional Development** - While the Base Case only includes some import options (limited import hydro (Mozambique) and import coal (Botswana)), the regional development scenario considers all listed projects from the Imports parameter input sheet. The import coal and hydro options are preferred to local options, but **imported gas is not preferred to local gas options.**

- Enhanced DSM - A test case scenario was run to see what the impact of additional DSM would be on the IRP. For this scenario an additional 6 TWh of DSM energy was forced by 2015. The resulting reduction in cost was R12, 8bn.

- Balanced Scenarios- Two balanced scenarios were created considering divergent stakeholder expectations and key constraints and risks. The balanced scenarios represent the best trade-off between least-investment cost, climate change mitigation, diversity of supply, localisation and regional development. The $CO_2$ emission targets are similar to those in the Emissions 2 scenario. In the revised balanced scenarios **CCGT capacity, fuelled with imported LNG, totalling 1896 MW from 2019 to 2021 was included**

### D. The Integrated Resource Plan 2010 update

An IRP update report was released in late 2013 to provide critical insight into changes in the local energy landscape. These include the potential for shale gas and the extent of other gas developments in the region, the global agenda to combat climate change and uncertainty regarding cost of nuclear capacity and competing fuel prices (coal and gas).

The IRP 2010 update also suggests that a more flexible and responsive approach to energy-supply investment decisions will be preferable to the “fixed capacity plan” presented in the IRP 2010. The more flexible plan would favour gas because of the modular nature of gas plants.

*The gas generation options presented in the IRP 2010 update all consist of three components:*

- Imported gas (imported from Namibia and Mozambique as electricity)
- Combined-cycle gas turbine (CCGT) units
- Open-cycle gas turbine (OCGT) units

All the CCGT and OCGT units are assumed to be installed at the five main port areas of Saldanha, Mossel Bay, Port Elizabeth (Coega), Durban and Richards Bay. This is to either import the gas as LNG initially or as a result of massive shale gas resources to collect the gas in the port areas for generation or export as LNG.

The IRP 2010 update considers a base case scenario and then 14 different variations on the base case scenario based on differing demand and supply-side assumptions. The majority of scenarios provide for a limited exposure to new gas-fired CCGT capacity – about 3 480MW by 2020 and 9 330MW in 2050). The Big Gas scenario which calls for 62 480MW of CCGT capacity by 2050, based on large-scale shale exploitation and relatively high nuclear and coal costs is the exception.

In the base case, both domestic (west coast) and regional (Namibian) gas options were considered at a fuel price of R70/GJ (2012 prices). As was the case in the IRP 2010, LNG is considered available, uncapped at a price of R92/GJ, based on an assumed LNG price of $10/MMBTU. The IRP update 2013 concludes that at this price, it would be feasible for OCGT peaking capacity to operate on gas rather than the current practice of utilising diesel. The OCGT is assumed to be able to utilise the domestic and regional gas as a first priority and then only LNG if the capacity is reached.

The IRP 2010 update notes that the development of additional conventional offshore gas fields in Mozambique, specifically in Sofala province, would increase the volume available at the R70/GJ price from 2020 (by an additional 986 PJ). The large gas fields in the far north of Mozambique (Rovuma basin) and Tanzania are not considered in this pool, as the IRP 2010 update argued the distance would lead to higher costs, closer to the LNG price. There may even be an argument that suggests South Africa would be better served to allow this gas to be liquefied and then import it as LNG rather than increase energy dependency on one source of gas.

The potential for shale gas in South Africa, specifically the Karoo, after 2025 is also explored in the Big Gas scenario. For the purposes of the scenario, the price of shale is assumed at the R92/GJ mark in 2025 but decreases annually to a low of R50/GJ in 2035. The possible decrease in the gas price resulting from an expected large-scale exploitation of shale gas results in a switch in electricity generation from coal and nuclear towards a gas-dominated regime along with a more limited renewable fleet.

The IRP 2010 update maintains that LNG has limited benefit as a major fuel source relative to alternatives available in South Africa, unless the costs for LNG reduce below the expectation of R92/GJ (around $10/MMBtu). It is only in the case of higher nuclear capital costs and coal fuel costs that the LNG option becomes viable and is pursued; but since that capacity is only required after 2030, there is also time to assess developments before committing to the new capacity.

Gas generation for three of the fifteen scenarios in the IRP 2010 update are presented in Table 34.

**Table 34: Gas generation capacity in three of IRP 2010 update scenarios**

| | GAS generation (MW) | | | | Demand assumptions |
|---|---|---|---|---|---|
| | 2020 | 2030 | 2040 | 2050 | GDP growth rate (annual average) |
| **Moderate decline scenario** | 3 480 | 10 510 | 15 350 | 18 140 | 5.4% |
| **Weathering the storm scenario** | 3 480 | 7 660 | 12 380 | 13 520 | 2.9% |
| **Big gas scenario** | 3480 | 20880 | 45690 | 67770 | 5.4% |

*Source: IRP 2010 update*

## E. Industrial Policy Action Plan – IPAP 2014

Another national government plans that makes reference to the exploitation of domestic and regional gas opportunities is the Department of Trade and Industry's most recent Industrial Policy Action Plan – IPAP 2014.

The DTI's focus in IPAP 2014 is in the further exploration and development of potential domestic gas resources, including onshore shale gas resources identified in the Karoo and exploration of the identified and potential offshore oil and gas resources off the East and West Coast of South Africa. DTI is concerned primarily with the issue of developing local industry around these opportunities and building forward and backward linkages from the gas industry opportunities. IPAP 2014 also recognises and supports the further development of the Saldanha oil and gas special economic zone, which will focus on the development of an industry to provide services including repair and maintenance, fabrication, logistics and other services to the oil and gas exploration and production industry.

## F. Western Cape Green Economy Strategy and Integrated Energy Strategy

The Western Cape Green Economy Strategy 2013 and Integrated Energy Strategy suggest that the introduction of natural gas as an alternative fuel should receive high priority in order to enable the Western Cape to maximise its contribution to national economic development. The Western Cape plans view gas as an opportunity to lower the carbon footprint of the province and to attract private-sector investment in local energy infrastructure to support job creation and economic growth.

Specific mention is made of opportunity for gas to support power generation and diversification of the energy mix and to provide an alternative fuel source to industries. The key opportunities for natural gas, as described in provincial plans and the policy objectives associated with them, are summarised in Figure 52.

**Figure 52: Summary of opportunity for gas outlined in Western Cape energy strategies**

| | How does gas feature? | What policy objectives can gas support? |
|---|---|---|
| **Green is Smart: Western Cape green economic strategy framework** | • Natural gas is considered a high-level priority for the Western Cape to diversify its energy mix away from coal<br>• WCIF promotes the use of natural gas a transitional fuel in the use for transport<br>• Supports the use of Gas-fired power plants to complement renewables and provide a cleaner energy alternative to coal<br>• Private sector should drive investment in the green economy and consequently also gas<br>• Offshore natural gas resources off the West Coast should be explored | • Significantly lower the carbon footprint of the Western<br>• Support expanded roll-out of renewable energy options<br>• Greenfield gas infrastructure to stimulate and attract investment into the province<br>• Diversification of energy mix for the Western Cape and its energy import requirement<br>• Availability of natural gas could facilitate development of the provinces industrial base |
| **Integrated Energy Strategy (IES)** | • Switch coal for gas in the industrial sector, particularly in thermal use to reduce emissions<br>• Importing gas is an option if domestic sources prove economically unviable<br>• Gas can provide base-load energy and is therefore an alternative to nuclear. It's less risky or controversial than nuclear as a clean energy source | • Switching coal for natural gas in thermal use in industry is a way to reduce the carbon footprint of the province<br>• Greenfield gas infrastructure would support local job creation |

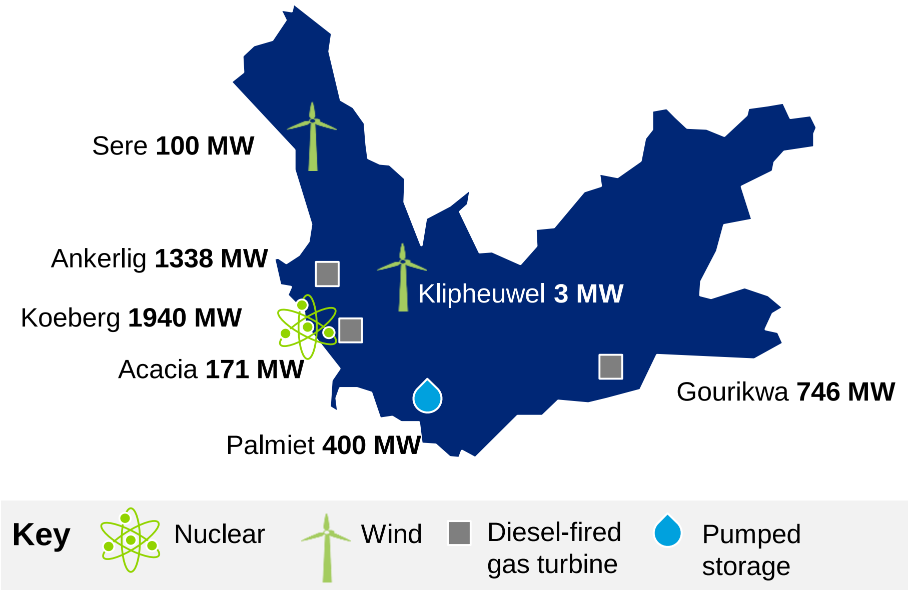
# Appendix B – calculations for gas-to-power

## Key gas-to-power and gas-to industry scenario calculations

### A. Eskom's current power generation capacity in the Western Cape

Eskom's current power generation capacity in the Western Cape includes the Koeberg nuclear power station, Ankerlig, Acacia and Gourikwa diesel-fired OCGT power stations, the Klipheuwel wind farm and the Palmiet pumped-storage facility. Nine of the renewable energy IPP projects that were successfully awarded under REIPPP programme windows 1 to 3 will be located in the Western Cape. These nine projects will have a total installed capacity of 453MW (Table 35).

**Figure 53: Eskom's power stations in the Western Cape, 2014**




*Source: Deloitte analysis based on Eskom Generation Map, 2013*

**Table 35: Renewable energy IPP projects awarded in the Western Cape**

| | Technology | Closest town | Capacity (MW) | REIPPP Programme Window |
|---|---|---|---|---|
| **Dassiesklip Wind Energy Facility** | Onshore Wind | Caledon | 26.2 | 1 |
| **Hopefield Wind Farm** | Onshore Wind | Hopefield | 65.4 | 1 |
| **SlimSun Swartland Solar Park** | Solar Photovoltaic (PV) | Swartland | 5 | 1 |
| **Touwsrivier Project** | Concentrated Solar Photovoltaic (CPV) | Touwsrivier | 36 | 1 |
| **Aurora** | Solar Photovoltaic (PV) | Aurora | 10.35 | 2 |
| **Gouda Wind Facility** | Onshore Wind | Gouda | 135.2 | 2 |
| **Vredendal** | Solar Photovoltaic (PV) | Vredendal | 8.8 | 2 |
| **West Coast 1** | Onshore Wind | Vredenburg | 90.8 | 2 |
| **Paleisheuwel Solar Park** | Solar Photovoltaic (PV) | Clanwilliam | 75 | 3 |
| **Total capacity** | | | **453** | |

*Source: Deloitte analysis based on the Energy blog projects database (www.energy.org.za/knowledge-tools/project-database)*

## B. Calculations and assumptions supporting fuel costs in power generation

| | R/litre | $/MMBtu | $/GJ | R/$ | R/GJ | Data sources |
|---|---|---|---|---|---|---|
| **Pulverised coal** | | | | | 17.5 | As per the IRP 2010 update |
| **LNG ($10/MMBtu)** | | 10 | 9 | 10.5 | 100 | $10/GJ and R10.50/$ assumed by Deloitte |
| **LNG ($15/MMBtu)** | | 15 | 14 | 10.5 | 149 | $15/GJ and R10.50/$ assumed by Deloitte |
| **Diesel** | R12.54 | | | | 339 | Coastal Diesel price 0.05% Sulphur August 2014 available at: http://www.engen.co.za/home/apps/content/products_services/fuel_price/default.aspx |
| **Diesel – Basic fuel price (R8.40/l)** | R8.40 | | | | 227 | DOE http://www.energy.gov.za/files/media/fuelprice/2014/Fuel-Adjustment-August2014.pdf |
| **Energy conversion factors** | | | | | | |
| **Natural gas** | | MMBtu/GJ | 0.948213 | | | http://www.energy.gov.ab.ca/about_us/1132.asp |
| **Diesel** | | GJ/litre | 0.037 | | | WCG (2013) Energy consumption and CO2e emissions database for the Western Cape |

## C. Estimate of the LCOE for 1 350MW OCGT diesel-fired plant (Ankerlig)

**Estimating the Levelised Cost of Electricity for a 1 350MW diesel-fired OCGT plant**

**Key assumptions:**

*R10.50/$*

*load factor 20%*

| **Levelised Cost of Electricity for a 1 350MW OCGT plant** | | | ***Notes*** |
|---|---|---|---|
| | **Load factor 20%** | **Load factor 10%** | |
| Capex for 1 350MW OCGT plant in 2014 rands | R8 500 000 000 | R8 500 000 000 | *Estimated by Deloitte based on EIA (2013)** |
| Total Capex | R8 500 000 000 | R8 500 000 000 | |
| | | | |
| Total Plant Capacity (MW) | 1 350 | 1 350 | |
| Loan Interest Rate | 10% | 10% | |
| Payback term | 30 | 30 | *As assumed in the IRP 2010 update* |
| **Annual Capex cost** | **R901 673 610** | **R901 673 610** | |
| Utilisation per year (hours) at Load factor of 20% or 10% | 1 752 | 876 | *Load factor in 2013/14* |
| **kWh per year** | **2 365 200 000** | **1 182 600 000** | |
| Total cost of diesel consumed per hour by 150MW unit | R399 824 | R399 824 | *See fuel cost calculation below* |
| Total costs of diesel consumed per hour by nine 150 MW units | R3 598 414 | R3 598 414 | |
| Total costs of diesel consumed by 1 350MW plant per year | R6 304 421 829 | R3 152 210 914 | |
| Cost of fuel (R/kWh) (R10.50/$) | R2.67 | R2.67 | |
| Fixed annual O&M cost (R/kWh)(R10.50/$) | R0.08 | R0.08 | *$13.17/KW-year based on EIA estimates** |
| Cost of capital (R/kWh) | R0.38 | R0.76 | |
| **LCOE (R10.50/$)** | **R3.13** | **R3.51** | |

**EIA (201“) “Report on Updated Capital Cost Estimates for Electricity Generation Plants – Nov. 2010/May 2011”*

| **Fuel costs calculation for 150MW OCGT unit for one hour** | | |
|---|---|---|
| **Tonnes diesel consumed per hour** | 40 | 40 |
| **R/litre** | R8.40 | R8.40 |
| **Litres diesel per tonne** | 1 190 | 1 190 |
| **R/tonne** | R9 996 | R9 996 |
| **Total cost of diesel consumed per hour by 150MW unit** | **R399 824** | **R399 824** |

## D. Estimate of the LCOE for 2 070MW CCGT imported gas-fired plant

**Estimating the Levelised Cost of Electricity for a 2 070MW LNG-fired CCGT plant (assuming conversion of Ankerlig)**

**Key assumptions:**

Ankerlig requires 66.5 million GJ/annum, should it be converted to a 2 070MW CCGT plant based on a load factor of 47%. Currently, Ankerlig is a 1 350MW plant.

| Levelised Cost of Electricity for a 2 070MW LNG-fired CCGT plant (assuming conversion of Ankerlig) | | | Notes |
|---|---|---|---|
| | LNG landed price (US$10/MMBtu) | LNG landed price US$15/MMBTU | |
| Original Capex for 1 338MW OCGT plant in 2014 rands | R8 500 000 000 | R8 500 000 000 | Estimated by Deloitte based on EIA report* |
| Capex for conversion to a 2 070MW CCGT plant | R7 000 000 000 | R7 000 000 000 | Cost of converting Ankerlig to a 2070MW CCGT plant + original cost of Ankerli131roductrox R3bn). |
| Total Capex | R15 500 000 000 | R15 500 000 000 | |
| Total Plant Capacity (MW) | 2 070 | 2 070 | |
| Loan Interest Rate | 10% | 10% | |
| Payback term | 30 | 30 | As assumed in the IRP 2010 update |
| **Annual Capex cost (R)** | **R1 644 228 348** | **R1 644 228 348** | |
| Load factor of 47% (hours utilisation/year) | 4 117 | 4 117 | Noted in the prefeasibility report** |
| Efficiency | 51% | 51% | Noted in the prefeasibility report |
| **kWh per year** | **8 522 190 000** | **8 522 190 000** | |
| Cost of fuel ($ per MMBtu) | $10 | $15 | |
| Transmission cost per MMBtu (assuming offshore terminal) | $0.08 | $0.08 | Noted in the prefeasibility report |
| Total cost of fuel ($ per MMBtu) | $10 | $15 | |
| Gas required (MMBtu/annum) | 63 056 186 | 63 056 186 | Converted from 66.5 million GJ in prefeasibility report |
| Total cost of fuel ($/annum) | $635 606 359 | $950 887 291 | Annual cost of importing LNG in USD |
| Total cost of fuel (R/annum) | R6 673 866 767 | R9 984 316 552 | Assuming an exchange rate of R10.50/$ |
| Cost of fuel (R/kWh) | 0.78 | 1.17 | |
| Fixed annual O&M cost (R/kWh) | 0.03 | 0.03 | $13.17/KW-year based on EIA estimates |
| Cost of capital (R/kWh) | 0.19 | 0.19 | |
| **LCOE (R10.50/$)** | **R1.01** | **R1.36** | |

*EIA (2013) Report on Updated Capital Cost Estimates for Electricity Generation Plants – Nov. 2010/May 2011

** Western Cape Government (2013) Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor, J. H. Visagie

## E. Reference Case 1: Potential annual cost-savings if Ankerlig continued to run at a load factor of 20%

| Reference Case 1: Potential annual cost-savings if Ankerlig continued to run at a load factor of 20% | | |
|---|---|---|
| | **Plant type and fuel price** | |
| Ankerlig MW Capacity | | 1 350 |
| Total MWh available per year | | 11 826 000 |
| MWh generated per year at 20% load factor | | 2 365 200 |
| kWh generated per year at 20% load factor | | 2 365 200 000 |
| Running cost at R3.13/kWh | OCGT, diesel at R8.40/l | R7 403 076 000 |
| **Levelised cost of energy (LCOE)** | | |
| R1.01/kWh | CCGT, LNG at $10/MMBtu | R2 388 852 000 |
| R1.36/kWh | CCGT, LNG at $15/MMBtu | R3 216 672 000 |
| R1.63/kWh | OCGT, LNG at $8.7/MMBtu | R3 855 276 000 |
| R1.01/kWh | CCGT, LNG at $10/MMBtu | R5 014 224 000 |
| R1.36/kWh | CCGT, LNG at $15/MMBtu | R4 186 404 000 |
| R1.63/kWh | OCGT, LNG at $8.7/MMBtu | R3 547 800 000 |

## F. Reference Case 2: Potential annual cost-savings if Ankerlig runs at a load factor of 10%

| Reference Case 2: Potential annual cost-savings if Ankerlig runs at typical OCGT load factor of 10% | | |
|---|---|---|
| **MW Capacity** | | 1 350 |
| **Total MWh available per year** | | 11 826 000 |
| **MWh generated per year at 10% load factor** | | 1 182 600 |
| **kWh generated per year at 10% load factor** | | 1 182 600 000 |
| **Running cost at R3.13/kWh** | OCGT, diesel at R8.40/l | R3 701 538 000 |
| | | |
| **Levelised cost of energy (LCOE)** | | |
| **R1.01/kWh** | CCGT | R1 300 860 000 |
| **R1.36/kWh** | CCGT | R1 608 336 000 |
| **R1.63/kWh** | OCGT | R1 927 638 000 |
| | | |
| **R1.10/kWh** | CCGT, LNG at $10/MMBtu | R2 400 678 000 |
| **R1.50/kWh** | CCGT, LNG at $15/MMBtu | R2 093 202 000 |
| **R1.63/kWh** | OCGT, LNG at $8.7/MMBtu | R1 773 900 000 |

## G. Calculations supporting Figure 26 – Comparison of fuel costs used by industry

| | R/l | R/kg | $/tonne | $/MMBtu | $/GJ | R/GJ | Source |
|---|---|---|---|---|---|---|---|
| **Coal** | | | | | 6 | 63 | Provided by ArcelorMittal – based cost of coal delivered to ArcelorMittal operations in Saldanha |
| **LPG (Max LPG refinery gate price)** | 6 | | | | | 230 | Department of Energy (2014) Breakdown of petrol, diesel and paraffin prices as on 01 October 2014. [Online] Available at: http://www.energy.gov.za/files/esources/petroleum/October2014/Breakdown-of-Prices.pdf |
| **LPG (Max retail price zone 1A – coastal)** | 12 | 24 | | | | 450 | Department of Energy (2014) LPG Regulations, August 2014. Available at: http://www.energy.gov.za/files/esources/petroleum/August2014/LPG-Regulations.pdf |
| **Diesel – Basic fuel price (R8.40/l)** | 8 | | | | | 227 | Coastal Diesel price 0.05% Sulphur August 2014 available at: ://www.engen.co.za/home/apps/co134roductoducts_services/fuel_price/default.aspx |
| **Diesel** | 13 | | | | | 339 | Department of Energy (2014) http://www.energy.gov.za/files/media/fuelprice/2014/Fuel-Adjustment-August2014.pdf |
| **Heavy Fuel Oil (HFO)** | | | 590 | | 14 | 144 | National Institute for Statistics and Economic Studies Rotterdam HFO FOB August 2014 sahttp://www.insee.fr/en/bases-de-donnees/bsweb/serie.asp?idbank=001642883 |
| **Domestic natural gas (estimated low)** | | | | | 12 | 126 | Sunbird estimates for the iBhubesi gas field |
| **Domestic natural gas (estimated high)** | | | | | 15 | 158 | Sunbird estimates for the iBhubesi gas field |
| **Imported natural gas (LNG low)** | | | | 10 | 9 | 100 | Deloitte assumption |
| **Imported natural gas (LNG high)** | | | | 15 | 14 | 149 | Deloitte assumption |

| Conversion factors | | |
|---|---|---|
| **LPG GJ/litre** | 0.0268 | WCG (2013) Energy Consumption and CO2e emissions database for the Western Cape. January 2013 |
| **LPG litre/kg** | 0.51 | WCG (2013) Energy Consumption and CO2e emissions database for the Western Cape. January 2013 |
| **Diesel GJ/litre** | 0.037 | WCG (2013) Energy Consumption and CO2e emissions database for the Western Cape. January 2013 |
| **HFO GJ/tonne** | 43 | NERSA (2012) Energy Indicator Prices, Conversion Factors and Weights |
| **R/$** | 10.5 | Deloitte assumption based on R10.66/$ in August 2014 |
| **MMBtu/GJ** | 0.94821 | WCG (2013) Energy Consumption and CO2e emissions database for the Western Cape. January 2013 |

# Appendix C – notes from industry interviews

## A. Notes from interviews with selected large industrial firms

### ArcelorMittal

ArcelorMittal is situated on the West Coast, roughly 10 kilometres away from Saldanha Bay. The steel plant is designed to produce 1.2 million tonnes per annum (Mtpa) of hot-rolled carbon steel coil per year[152]. It competes on an international scale and is considered a key driver of economic growth in the region.

The current operations are based on a Corex process, where coal is used as an energy feedstock to reduce iron ore, made up of 80% iron ore and 20% pellets, to a hot pig iron liquid. This product is further heat-processed via an Electric Arc Furnace (EAF) to form liquid steel. The liquid steel is processed through a Caster and Rolling Mill into hot-rolled carbon steel coils.

The introduction of LNG to the Midrex process has the ability to increase the production of hot-rolled steel coil by double[153], provided the price is right. Coal is the predominant form of energy for use in the Midrex process; however, it is significantly cheaper than that of alternative energy inputs. Estimates are that coal can be sourced for US$6 a GJ, while estimates on LNG are between $12/GJ and $15/GJ.

Although the likelihood of replacing coal with LNG in the Midrex process may be unlikely in the near future, replacing LPG with LNG may be a more feasible option. Currently, ArcelorMittal utilises 10 000 to 12 000 litres of LPG in various processes in its business.

### Continental China

Located in Black Heath, Continental China is an established ceramics company specialising in the production of table-top ceramics. It is one of the largest users of LPG in the West Coast and uses an estimated 4 million litres of LPG per year[154]. An estimated 9 000 litres are shipped to Continental China each day for use in its kilns to heat for its ceramics business.

### Atlantis Foundries

The Atlantis Foundries produces automotive casting for both passenger and commercial vehicle industries and is a wholly owned subsidiary of Mercedes-Benz. It currently has two large reservoirs of LPG, which it uses in its furnaces for drying. The company estimates that it consumes roughly 700 to 800 tonnes of LPG, which it receives from inland sources (mainly Sasol).

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[152] Western Cape Government (2013) Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor, J. H. Visagie.

[153] Telephonic interviews with ArcelorMittal

[154] Interview with Herman Breytenbach

**Namakwa Sands (Tronox)**

The Namakwa Sands operation of Tronox (formerly under Exxaro) is to mine and beneficiate heavy minerals. The operation is located on the west coast of South Africa and operates facilities in three separate sites. LPG is used in their facilities for use in their pilot burners as well as for various operational activities occurring onsite. The largest energy source they currently use is coal in their reduction furnaces, and illuminating paraffin (IP) is also required for this process. It was indicated that utilising natural gas as a feedstock would require significant changes to their current capital costs and is highly unlikely to be used as a main feedstock[155].

[155] Interview with Peter Haley Tronox Representative

# Appendix D – gas-to-transport appendices

### A. Defining the gas-to-transport scenario and estimating infrastructure costs

The gas-to-transport scenario outlined in the prefeasibility study[156] was limited to the conversion of a public bus fleet with assumed annual gas consumption of 900 000 GJ. However, since the prefeasibility study was published, interest in the use of natural gas in transport in South Africa has increased. The results of a 10-month CNG vehicle fleet trial conducted in Gauteng by the Industrial Development Corporation (CAE) and Cape Advanced Engineering in 2013[157] has suggested that the use of CNG in bi-fuel and dual-fuel vehicles[158] used for public transport is financially feasible.

*As a result, the WCG requested that Deloitte consider and estimate the infrastructure required to support an expanded gas-to-transport scenario[159], which would include:*

1. Conversion of the MyCiTi Buses (a total fleet of 267)
2. Fifty percent (50%) conversion of Golden Arrow and Sibanye buses (576 of the total fleet of 1 152)
3. Conversion of the CoCT (~6 000 vehicles)and WCG vehicle fleet (50% of ~5 000 vehicles)
4. Conversion of Golden Arrow and MyCiTi fuel depots
5. Conversion of a sufficient commercial fuel service stations to adequately service the CoCT and WCG fleet
6. Distribution pipeline required to supply the fuel depots and service stations with CNG

The key cost assumptions used in this scenario are summarised in Table 36. It was assumed that buses would be converted to dual-fuel engines, and public vehicles to bi-fuel engines; and unit conversion costs assumed were based on those presented in the IDC and CAE pilot study. In reality, existing fleet may simply be replaced rather than converted to CNG engines, in which case the incremental cost (additional cost of buying a natural gas rather than diesel engine) would be of interest. The cost of converting existing fuel service stations to provide CNG at R6 million per station was based on estimates provided by NGV Gas, and the cost of installing distribution pipeline at R7 million per kilometre was obtained from the prefeasibility report.

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[156] Western Cape Government (2013) Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor, J. H. Visagie.

[157] Industrial Development Corporation and Cape Advanced Engineering (2013) Investigation into the use of clean burning methane in the form of compressed natural gas (CNG) and compressed bio-gas (CBG) in public transport in South Africa.

[158] Buses were converted to dual-fuel engines and mini-bus taxis were converted to bi-fuel engines. Bi-fuel vehicles are able to run on diesel fuel or natural gas, while dual-fuel vehicles are able to run on diesel fuel and gas simultaneously

[159] Our estimates provide an initial indication of the cost of converting the public vehicle fleet in part of the Western Cape to run on CNG. We note that a more detailed assessment of the business case for the use of CNG in the public transport fleet will need to be undertaken in order to determine whether the scenario proposed is indeed feasible.

**Table 36: Cost assumptions for the gas-to-transport scenario**

| Cost assumptions | Data source |
|---|---|
| • R120 000 per bus to convert to a dual fuel CNG/diesel<br>• R20 000 per minibus taxi to convert to bi-fuel CNG/petrol | IDC & CAE (2013) "CNG and CBG in Public Transport in South Africa" |
| • R6 million to convert an existing petrol station to CNG | Information sourced in an interview with NGV Gas, August 2014 |

**Table 37: Data sources for the vehicle numbers**

| Description | No. of units | Data source/assumptions |
|---|---|---|
| **MyCiti Bus Conversion** | 267 | Provided by WCG |
| **Golden Arrow & Sibanye buses (50% of total fleet of 1152)** | 576 | Provided by Golden Arrow in an telephonic interview |
| **CoCT fleet (100% of 6 000 vehicles)** | 6 000 | City of Cape Town (2011) Cape Town's Action Plan for Energy and Climate Change |
| **WCG (50% of ~5 000 vehicles)** | 2 500 | Deloitte estimates based on fleet size in Western Cape Government (2014) Government Motor Transport Annual Performance Plan 2014/15 |
| **Conversion of depots** | 11 | Provided by Golden Arrow in an telephonic interview |
| **Conversion of fuel service stations** | 42 | Deloitte estimates |
| **Distribution Pipeline (km)** | 230 | Deloitte estimates |

### Estimating cost of infrastructure for the expanded "gas-to-transport" scenario

*Public vehicle fleet that could potentially be converted to run on CNG*

Our estimates of the size of the public vehicle fleet that could potentially be converted to CNG were based on discussions with the WCG. Assuming that "anchor tenants" for imported natural gas are already in place (including power stations outlined in the "gas-to-power" and industrial consumers in "gas-to-industries"), we have proposed that it may be feasible to extend the gas network to service a fleet of public transport and government-owned vehicles in the City of Cape Town and West Coast District Municipalities. It should be noted that a more detailed business case would have to be conducted to determine the financial viability of this proposal. The rationale for the size of the public vehicle fleet that could be converted to run on CNG is as follows:

1. If CNG becomes available in the CoCT, we have assumed that it would be feasible to convert the entire MyCiTi bus fleet (a total of 267 commuter buses).
2. Assuming the MyCiTi conversion or replacement is successful, there would be an opportunity to convert or replace at least 50% of the Golden Arrows and Sibanye fleet – totalling 1 151 commuter buses with CNG or dual-fuel engines.
3. Assuming that gas distribution pipeline network can be extended to cover most of the densely populated parts of the CoCT and West Coast District municipalities, we have also assumed that 100% of the 6 000[160] vehicles in the CoCT public fleet could be converted to take CNG as a fuel. We have assumed that only 50% of the 5 000[161] vehicles in the WCG fleet could be converted, as the

[160] Number of vehicles quoted in the City of Cape Town 2011, *Cape Town's Action Plan for Energy and Climate Change*
[161] Western Cape Government 2014/15 , *Government Motor Transport Annual Performance Plan 2014/15*

incremental cost to extend the pipeline to fuel service stations located in the main urban centres of the Winelands, Overberg, Eden and Central Karoo districts would be too great for the size of the market; and, as such, the WCG fleet in these areas could not be feasibly converted.

**The total cost of converting these vehicles is estimated to be in the region of R270 million (Table 38).**

**Table 38: Estimate of fleet conversion costs**

| Description | No. of units | Cost per unit (R '000s) | Total cost (Rm) |
|---|---|---|---|
| **MyCiTi Bus Conversion** | 267 | 120 | 32 |
| **Golden Arrow & Sibanye buses (50% of total fleet of 1152)** | 576 | 120 | 69 |
| **CoCT fleet (100% of 6000 vehicles)** | 6 000 | 20 | 120 |
| **WCG (50% of ~5000 vehicles)** | 2 500 | 20 | 50 |
| **Total fleet conversion costs** | | | **271** |

### Depots and service stations

To supply the public bus fleet and government-owned vehicle fleet with CNG, a number of depots and service stations in the CoCT and West Coast District Municipalities would need to be converted to supply CNG.

### Depots – estimating number and conversion costs

For public transport, we assume that all existing fuel depots serving the MyCiTi, Golden Arrow and Sibanye would be converted to CNG. There are eight depots for Golden Arrow (which service Sibanye as well) and three depots for MyCiTi buses. A total of 11 depots will need to be converted to serve the public transport fleet. At a cost of R6 million per depot, total deport conversion costs are estimated at R66 million.

### Service Stations – estimating number and conversion costs

Most of the CoCT and WCG vehicle fleet is refuelled at conventional commercial fuel service stations rather than depots. We therefore need to estimate the number of existing commercial petrol stations that would need to be converted to service this fleet (these petrol stations could also service privately owned vehicles and taxis in future).

According to spatially referenced data obtained from EasyGIS, there are roughly 650 fuel stations in the Western Cape, 400 in Cape Town and 50 in the West Coast District[162]. There are an estimated 88 500 passenger vehicles in the Western Cape (excluding public buses/vehicles) and the CoCT and WCG combined fleet, which would be converted (8 500 vehicles) in addition to this estimate, constitutes roughly 9.3% of this combined total[163]. On this basis, we assumed that roughly 9.3% of the 450 service stations in the West Coast and City of Cape Town districts would need to be converted to supply CNG in order to make gas widely available for use in transport – a total of 42 stations. The cost of converting an existing fuel service station to provide CNG will cost R6 million, based on information provided by

[162] Point Data for petrol stations provided by EasyGis
[163] Data provided from the Western Cape government

NGV Gas. The estimated cost of converting 42 service stations is R252 million (Table 39). The total cost for converting existing depots and service stations is estimated at R318 million (Table 39).

**Table 39: Estimate of depot and service station conversion costs**

| Description | No. of units | Cost per unit (R '000s) | Total cost (Rm) |
|---|---|---|---|
| **Conversion of depots** | 11 | 6 000 | 66 |
| **Conversion of fuel service stations** | 42 | 6 000 | 252 |
| **Sub-total for depot and service station conversion** | | | **318** |

### Distribution pipeline

Lastly, in order to service these depots and service stations, additional pipeline would have to be laid. To estimate the cost of the pipeline, we estimated the number of kilometres of distribution pipeline that would be required to provide gas to most of the areas in the West Coast and the City of Cape Town district municipalities currently serviced by fuel service stations. This analysis assumed that the transmission pipelines and distribution pipelines for industry as described in the gas-to-power and gas-to-industries scenarios would already be in place.

Geographically referenced point data on the location of petrol stations in the Western Cape suggest there are roughly 650 petrol stations in the Western Cape, the majority of which are in the City of Cape Town (402).

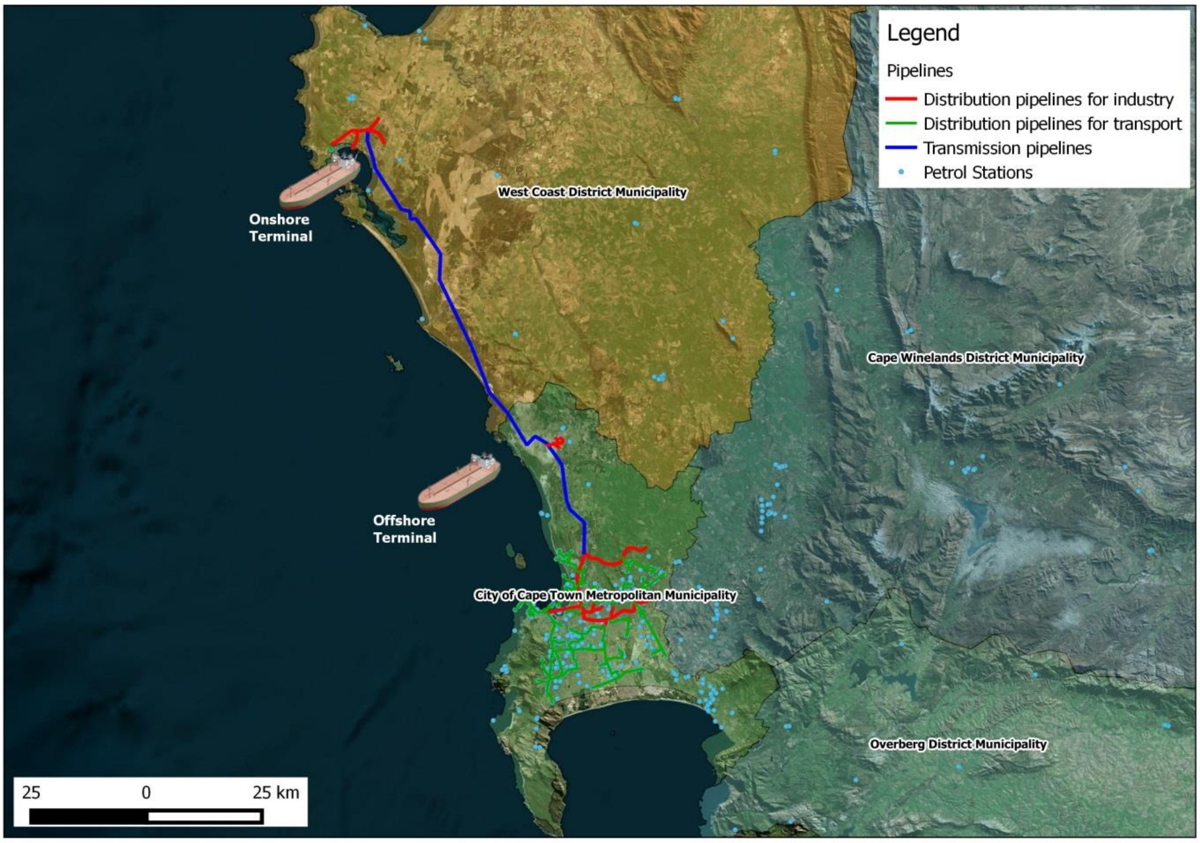
**Table 40: Number of petrol stations in the Western Cape**

| Western Cape | 654 |
|---|---|
| **Cape Winelands** | 78 |
| **Central Karoo** | 11 |
| **City of Cape Town** | 402 |
| **Eden** | 73 |
| **Overberg** | 37 |
| **West Coast** | 53 |

*Source: EasyGIS based on various GPS point data sources*

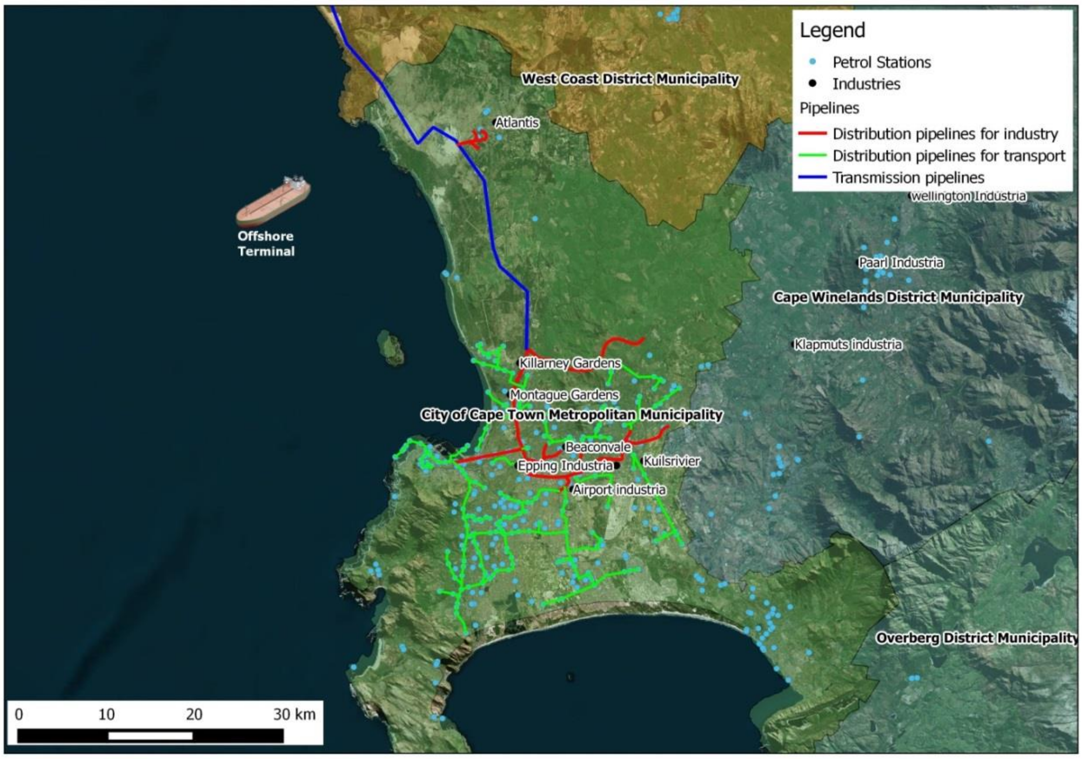
The analysis suggests that roughly 230km of distribution pipeline (in addition to that required to connect industries) would be required to ensure that fuel service stations distributed throughout the most densely populated areas (judged to be those areas where there are existing fuel stations) of the West Coast and Cape Town District Municipalities could be connected to the gas pipeline. At an assumed cost of R7.35 million/km, the 230km of pipeline would cost roughly R1.69 billion. For the purpose of this study, we have assumed that the incremental cost to extend the pipeline to service stations located in the main urban centres of the Winelands District would be too great, as at least 100km of additional pipeline would be required to connect the urban centres in this district (which include but are not limited to Paarl, Wellington and Stellenbosch) to the gas distribution network. A more detailed feasibility assessment would, however, need to be done to thoroughly investigate the business case for extending the gas distribution network to these areas. We have assumed that the incremental costs of connecting fuel stations in the rest of the district municipalities in the Western Cape Province (which include Overberg, Eden and the Central Karoo) would also be too great for the size of the market.

**Figure 54: Overview of envisaged gas distribution network**




*Source: EasyGIS based on Deloitte analysis and various GPS point data sources*

**Figure 55: Service stations in the City of Cape Town and distribution pipelines required**




*Source: EasyGIS based on Deloitte analysis and various GPS point data sources*

## Summary

The total capital expenditure required for the gas-to-transport scenario is summarised in Table 41.

**Table 41: Total capital expenditure required to support distribution of gas under "Gas-to-Transport" scenario**

| Description | No. of units | Cost per unit (R '000s) | Total cost (Rm) |
|---|---|---|---|
| MyCiTi Bus Conversion | 267 | 120 | 32 |
| Golden Arrow & Sibanye buses (50% of total fleet of 1 152) | 576 | 120 | 69 |
| CoCT fleet (100% of 6 000 vehicles) | 6 000 | 20 | 120 |
| WCG (50% of ~5 000 vehicles) | 2 500 | 20 | 50 |
| **Total fleet conversion costs** | | | **271** |
| Conversion of depots | 11 | 6 000 | 66 |
| Conversion of fuel service stations | 42 | 6 000 | 252 |
| Sub-total for depot and service station conversion | | | 318 |
| Distribution Pipeline (km) | 230 | 7 350 | 1 690 |
| **Total for all "gas-to-transport" infrastructure costs** | | | **2 279** |

*Source: Deloitte analysis*

## B. Raw data for the estimate of cost of alternative household fuels

| | R/l | R/kWh | R/kg | $/MMBtu | $/GJ | R/GJ | Sources |
|---|---|---|---|---|---|---|---|
| **Paraffin (coastal)** | 9.40 | | | | | 261 | Department of Energy (2014) Breakdown of petrol, diesel and paraffin prices as on 6 August 2014 |
| **Electricity** | | 1.54 | | | | 428 | City of Cape Town domestic electricity tariff for residential users 2014/15 |
| | | 1.87 | | | | 519 | |
| **LNG estimated distributed price ($10/MMBtu landed)** | | | | 20 | 19 | 199 | Deloitte estimates based on current landed price of LNG |
| **LNG estimated distributed price ($15/MMBtu landed)** | | | | 30 | 28 | 299 | Deloitte estimates based on current landed price of LNG |
| **LPG (Max retail price zone 1A – coastal)** | 12.06 | | 23.65 | | | 450 | Department of Energy (2014) LPG Regulations, August 2014. Available at: http://www.energy.gov.za |

| **Conversion factors** | | |
|---|---|---|
| **LPG GJ/litre** | 0.0268 | WCG (2013) *Energy Consumption and $CO_2$e emissions database for the Western Cape*. January 2013 |
| **LPG litre/kg** | 0.51 | WCG (2013) *Energy Consumption and $CO_2$e emissions database for the Western Cape*. January 2013 |
| **Electricity GJ/kWh** | 0.0036 | WCG (2013) *Energy Consumption and $CO_2$e emissions database for the Western Cape*. January 2013 |
| **Paraffin GJ/Litre** | 0.036 | WCG (2013) *Energy Consumption and $CO_2$e emissions database for the Western Cape*. January 2013 |
| **R/$** | 10.5 | Deloitte assumption based on R10.66/$ in August 2014 |
| **MMBtu/GJ** | 0.9482 | WCG (2013) *Energy Consumption and $CO_2$e emissions database for the Western Cape*. January 2013 |

# Appendix E – capital expenditure inputs

## A. Detailed breakdown of capital expenditure costs for LNG end-user scenarios

This appendix provides a breakdown of the expenditure estimates used to model the macroeconomic impact of LNG infrastructure spending on the WC and SA economy. Base case

| | | |
|---|---|---|
| **Assumptions** | Landed LNG Price | $10/ MMBtu |
| | ZAR / USD Exchange rate | R10.50/$ |
| | All ZARs and USD costs are in millions | |

### Gas to Power Scenario

***Estimated Costs of Converting Ankerlig Power Station***

| All costs in ZAR Million | Local (Rm) | Imports (Rm) | Total (Rm) |
|---|---|---|---|
| **Civil and structural costs** | R 378 | R 252 | R 630 |
| **Mechanical equipment supply and installation** | R 3 500 | R - | R 3 500 |
| **Electrical instrumentation** | R 560 | R - | R 560 |
| **Project Indirect Costs** | R 1 400 | R - | R 1 400 |
| **Owners Costs** | R 910 | R - | R 910 |
| **Total** | **R 6 748** | **R 252** | **R 7 000** |

*Source: Expenditure breakdown provided by Johan Visagie, total from the WCG prefeasibility study*

***Estimated Costs of Building a New CCGT Power Plant (800MW)***

| | Local (Rm) | Imports (Rm) | Total (Rm) |
|---|---|---|---|
| **Civil and structural costs** | 648 | - | 648 |
| **Mechanical equipment supply and installation** | 1 350 | 2 250 | 3 600 |
| **Electrical instrumentation** | 576 | - | 576 |
| **Project Indirect Costs** | 1 440 | - | 1 440 |
| **Owners Costs** | 936 | - | 936 |
| **Total** | **4 950** | **2 250** | **7 200** |

*Source: Expenditure breakdown provided by Johan Visagie, totals from the WCG prefeasibility study*

### Offshore terminal & transmission lines

***Offshore Terminal Costs***

| | Local (Rm) | Imports (Rm) | Total (Rm) | Total Cost ($USm) |
|---|---|---|---|---|
| **Single Buoy** | 557 | 557 | 1 113 | $106 |
| **Owners Costs** | 305 | 0 | 305 | $29 |
| **Total (Rm)** | **861** | **557** | **1 418** | **$135** |

*Source: Expenditure breakdown provided by Johan Visagie, total from the WCG prefeasibility study*

***Offshore transmission Lines***

| | Local (Rm) | Imports (Rm) | Total (Rm) | Total Cost ($USm) |
|---|---|---|---|---|
| Subsea Piping | - | 102 | 102 | $10 |
| Transmission Coast to Atlantis | 302 | 101 | 402 | $38 |
| Transmission Atlantis to CT | 108 | 36 | 144 | $14 |
| **Total Phase 1 (Terminal, Atlantis, Milnerton)** | | | **648** | **R 61.7** |
| **Phase 2 (Atlantis, Saldanha Bay)** | **559** | **186** | **746** | **R 71.0** |
| **Total (Phase 1 and Phase 2)** | **969** | **425** | **1 393** | **R 133** |

*Source: Expenditure breakdown provided by Johan Visagie, total from the WCG prefeasibility study*

***Offshore Distribution Lines***

| | Local (Rm) | Imports (Rm) | Total (Rm) | Total Cost ($USm) |
|---|---|---|---|---|
| Phase 1 (Atlantis, Cape Town, Paarl, Wellington) | 842 | - | 842 | $80 |
| Phase 2 (Saldanha Bay) | 89 | - | 89 | $9 |
| **Total Distribution Lines** | **931** | **-** | **931** | **$89** |

*Source: WCG prefeasibility study*

***Total Offshore Terminal Lines and Distribution Lines***

| | Local (Rm) | Imports (Rm) | Total (Rm) | Total Cost ($USm) |
|---|---|---|---|---|
| Total | 1 900 | 425 | 2 325 | $221 |

## Onshore terminal & transmission lines

***Onshore Receiving Terminal***

| | Local (Rm) | Imports (Rm) | Total (Rm) | Total Cost ($USm) |
|---|---|---|---|---|
| Major Equipment | 280 | 45 | 325 | $31 |
| Bulk Materials | 559 | 836 | 1 395 | $133 |
| Sub Contracts | 1 245 | 62 | 1 306 | $124 |
| Labour | 147 | 37 | 184 | $18 |
| Other Costs | 190 | 62 | 252 | $24 |
| EPC Contractor Costs | 264 | 264 | 527 | $50 |
| **Total capital costs** | **2 685** | **1 305** | **3 990** | **$380** |

*Source: Expenditure breakdown provided by Johan Visagie, total from the WCG prefeasibility study*

***Onshore Transmission Pipeline***

| | Local (Rm) | Imports (Rm) | Total (Rm) | Total Cost ($USm) |
|---|---|---|---|---|
| 116km Transmission Pipeline | 1 281 | - | 1 281 | $122 |
| **Total Capex Costs** | **1 281** | **-** | **1 281** | **$122** |

***Onshore Distribution Pipeline***

| | Local (Rm) | Imports (Rm) | Total (Rm) | Total Cost ($USm) |
|---|---|---|---|---|
| Distribution Saldanha | 89 | - | 89 | $8 |
| Distribution Atlantis | 58 | - | 58 | $6 |
| Distribution Cape, Paarl and Wellington | 784 | - | 784 | $75 |
| **Total Capex Costs** | **930** | **-** | **930** | **$88.6** |

*Source: WCG prefeasibility study*

### Gas to Transport

| Sources | | Number of units | Unit cost | Total (Rm) |
|---|---|---|---|---|
| **1** | **Distribution Pipeline (km)** | 230 | R 7.35 | R 1 691 |
| **2** | **Conversion of buses** | 843 | R 0.120 | R 101 |
| **3** | **Conversion of CoCT and WCPG fleet** | 8500 | R 0.02 | R 170 |
| **4** | **Conversion of depots** | 11 | R 6.0 | R 66 |
| **5** | **Conversion of fuel service stations** | 42 | R 6.0 | R 252 |
| | **Total** | | | **R 2 280** |

Sources:

1. *Deloitte estimates for 230km of pipeline, prefeasibility study estimate of $700,000 per km of distribution pipeline*
2. *No. of buses provided by WCG and Golden Arrow in an telephonic interview, unit conversion cost from IDC & CAE (2013) "CNG and CBG in Public Transport in South Africa"*
3. *Deloitte estimates based on fleet size in Western Cape Government (2014) Government Motor Transport Annual Performance Plan 2014/15, unit conversion cost from IDC & CAE (2013) "CNG and CBG in Public Transport in South Africa"*
4. *No of depots provided by Golden Arrow in an telephonic interview, conversion cost sourced in an interview with NGV Gas, August 2014*
5. *Deloitte estimates for no. of fuel station, conversion cost sourced in an interview with NGV Gas, August 2014*

### Gas to Households

| | Number of units | Unit cost | Total (Rm) |
|---|---|---|---|
| **Distribution Pipeline (km)** | 200 | R 7.35 | R 1 470 |
| | **Local (Rm)** | **Imports (Rm)** | **Total (Rm)** |
| **Construction costs** | 387 | - | 387 |
| **Material costs** | 647 | - | 647 |
| **Cathodic protection** | 28 | - | 28 |
| **Engineering services** | 163 | - | 163 |
| **Contingencies** | 245 | - | 245 |
| **Total** | **1 470** | **-** | **1 470** |

*Source: Expenditure breakdown and total kilometres of pipeline (200km) provided by Johan Visagie, prefeasibility study estimate of $700,000 per km of distribution pipeline*

# Appendix F – operating expenditure inputs

## A. Operating expenditure inputs to the Modelling

### Base case

*In calculating operating costs for the gas-to-power infrastructure the following assumptions were made:*

- These plants would be utilised for 4 117 hours of the day at 51% load factor as noted in the prefeasibility report[164].
- Once Ankerlig was converted, the total GJ required would be 66.5 million GJ as noted in the prefeasibility report[165].
- $10/MMBtu and R10.50/$ was assumed for LNG fuel costs[166].
- Fixed operating and maintenance (O&M) costs were assumed to be R138/kW/annum based on a R/$ of R10.50/$ and $13.17/KW-year (O&M) costs from the EIA estimates[167]

**Table 42: Ankerlig conversion annual running costs (R million)**

| Description | Local cost (Rm) | Imported cost (Rm) | Total operating costs (Rm) |
|---|---|---|---|
| **Fixed O&M @ R138/kW/a** | 306 | - | 306 |
| **Fuel Costs @($10/MMBtu)** | - | 6 600 | 6 620 |
| **Total** | **306** | **6 600** | **6 906** |

**Table 43: 800MW new-build annual running costs (R million)**

| Description | Local cost (Rm) | Imported cost (Rm) | Total operating costs (Rm) |
|---|---|---|---|
| **Fixed O&M @ R138/kW/a** | **118** | **-** | **118** |
| **Fuel Costs @($10/MMBtu)** | **-** | **2 600** | **2 600** |
| **Total** | **118** | **2 056** | **2 174** |

164 Western Cape Government (2013) Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor, J. H. Visagie.

165 Western Cape Government (2013) Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor, J. H. Visagie.

166 Obtained from estimates presented in the IRP 2010–2030

167 EIA (2013) Report on Updated Capital Cost Estimates for Electricity Generation Plants – Nov. 2010/May 2011

### Scenario 1

*In addition to the base scenario, operating costs for scenario 1 consisted of the following:*

**Table 44: Scenario 1: Operating Costs (R million)**

| Description | Local cost (Rm) | Imported cost (Rm) | Total operating costs (Rm) |
|---|---|---|---|
| Offshore Terminal FSRU Cost | - | 537 | 537 |
| Port Authority Charges | 38 | - | 38 |
| Pipeline Operation Costs[168] | 6 | | 6 |
| **Base Case** | | | |
| Operating of Power Stations | 424 | 9 200 | 9 624 |
| **Total** | **466** | **9 737** | **10 203** |

*Source: HJ Visagie, Energy Business*

### Scenario 2

*In addition to the base scenario, operating costs for scenario 2 consisted of the following:*

**Table 45: Scenario 2 operating: costs (R million)**

| Scenario 2 | Local cost (Rm) | Imported cost (Rm) | Total operating costs (Rm) |
|---|---|---|---|
| Operation of terminal | 218 | 24 | 242 |
| Pipeline operation costs | 6 | - | 6 |
| **Base case** | | | |
| Operating of power stations | 424 | 9 200 | 9 624 |
| **Total** | **648** | **9 224** | **9 872** |

*Source: HJ Visagie, Energy Business*

[168] All pipeline running and maintenance costs were estimated at 0.25% of the total capital costs based on information provided in the WCG prefeasibility study.

### Scenario 3

*In addition to the base scenario, operating costs for scenario 3 consisted of the following:*

**Table 46: Scenario 3 operating: costs (R million)**

| Scenario 3 | Local cost (Rm) | Imported cost (Rm) | Total operating costs (Rm) |
|---|---|---|---|
| Offshore Terminal FSRU Cost | - | 537 | 537 |
| Port authority charges | 38 | - | 38 |
| Pipeline operation costs[169] | 14 | | 14 |
| **Base case** | | | |
| Operating of power stations | 424 | 9 200 | 7 800 |
| **Total** | **476** | **9 737** | **10 213** |

*Source: HJ Visagie, Energy Business*

[169] In addition to the existing transmission and distribution pipeline, an additional pipeline of 230km for connecting the transportation market and 200km to connect the residential market was costed at $700 000/km and operating costs of 0.25% of capital costs based on information provided in the prefeasibility report. No additional operating costs for the conversion of myCiti buses, Golden Arrow fleet, Sibanye fleet, the WCG fleet and the CoCT fleet were assumed as these operations costs would replace the current running costs associated with operating these vehicles.

# Appendix G – WC vs SA spend

### B. Understanding how the proportion of spending that is retained in the WC is determined

The Western Cape SAM provides information on the estimated spending that would remain in the Western Cape as a result of an exogenous demand shock. The SAM suggest that on average for every R1 increase in the final demand for a commodities output in the Western Cape, R0.78 remains in the Western Cape and R0.28 is ‘imported’ from the rest of South Africa. Table 47 provides some examples of the proportion of spending that is retained in the Western Cape for every R1 increase in demand for a commodity’s output.

**Table 47: Proportion of spending retained in the Western Cape for R1 increase in demand for output of certain commodities**

| Sector | For every R1, % retained in Western Cape | For every R1, % "imported" from rest of South Africa |
|---|---|---|
| **Agriculture, forestry & fishing** | 53% | 47% |
| **Coal mining** | 0% | 100% |
| **Gold & uranium ore mining** | 0% | 100% |
| **Other mining** | 100% | 0% |
| **Food** | 92% | 8% |
| **Beverages & Tobacco** | 39% | 61% |
| **Textiles** | 74% | 26% |

For example, coal, gold and uranium mining do not have a presence in the Western Cape and as such for every R1 spent by companies in the Western Cape which required these commodities, 100% of this had to be “imported” from the rest of South Africa. As a result, there would be no direct impact on the economy of the Western Cape should demand for these commodities increase in the Western Cape since all of the associated economic activity would occur elsewhere in the country. By contrast, for every R1 spent by companies on food, R0.92 of this economic activity would retain in the Western Cape.

# Appendix H – multiplier methodology

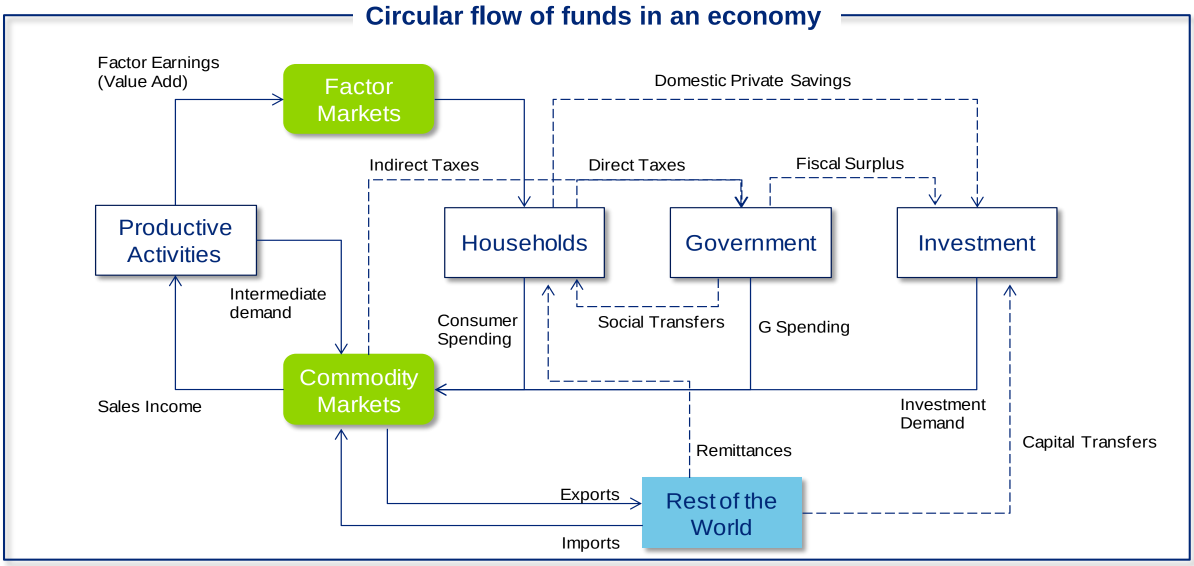
## C. Social Accounting Matrix Methodology

### a. The circular flow of economic activity

A popular starting point in explaining social accounting matrices and the associated methodology for conducting economic impact assessments is the circular flow diagram. A circular flow diagram, as shown below in Figure 56, is one way of depicting an economy. The diagram captures all transfers and real transactions between the various sectors, agents and institutions within an economy. Productive activities purchase land, labour and capital inputs from the factor markets, and intermediate inputs from commodity markets, and use these to produce goods and services. These are supplemented by imports (M) and then sold through commodity markets to households (C), the government (G), investors (I) and foreigners (E – Exports). Based on the simple macroeconomic identity, national income or GDP (Y) is therefore equal to C+I+G+E-M.

Much in the same way that a regular economy functions, the circular flow shows that households use their earnings from the factors of production to consume, pay taxes or save. Government uses its revenue to purchase goods and services, make social transfers or save/borrow through its fiscal balance. Investment in the economy is determined by the funds saved or dis-saved by households and the government and the funds made available by foreigners through capital transfers. To reiterate, the flow depicts all financial flows that occur between sectors, agents and institutions in an economy.

**Figure 56: Circular flow diagram**



## b. Social Accounting Matrix Structure

A social accounting matrix is simply the quantification of the "circular flow '" of an economy in a given period (typically a year). Seen in the figure below, it is a representation of an economy or region in matrix form. Built from data taken from the national accounts and various statistical surveys, expenditure equals income in the economy (all expenditure is received as income by some entity within the economy). Columns represent this expenditure while the rows represent the income received. For instance, households (Column 4) pay taxes, which are received by the government (Row 5) and government in its spending (Column 5) uses a portion of these funds to make social transfers to households (Row 4). In the same way, each expenditure or income depicted in the circular flow diagram can be seen in the SAM below.

**Figure 57: Structure of a typical SAM**

**Expenditure columns**

**Income Rows**

| | Activities C1 | Commodities C2 | Factors C3 | Households C4 | Government C5 | Savings and Investment C6 | Rest of the World C7 | Total |
|---|---|---|---|---|---|---|---|---|
| Activities R1 | | Domestic Supply | | | | | | Activity income |
| Commodities R2 | Intermediate demand | | | Consumption spending (C) | Recurrent spending (G) | Investment Demand (I) | Export earnings (E) | Total demand |
| Factors R3 | Value-added | | | | | | | Total factor income |
| Households R4 | | | Factor payments to households | | Social transfers | | Foreign remittances | Total household |
| Government R5 | | Sales taxes and import tariffs | | Direct taxes | | | Foreign grants and loans | Government income |
| Savings and Investment R6 | | | | Private savings | Fiscal surplus | | Current account balance | Total savings |
| Rest of the World R7 | | Import payments (M) | | | | | | Foreign exchange outflow |
| Total | Gross output | Total Supply | Total factor spending | Total household spending | Government expenditure | Total investment spending | Foreign exchange inflow | |

*(Source: IFPRI, Social Accounting Matrices and Multiplier Analysis, 2010)*

SAMs differ widely in their complexity, ranging from simple representations of the national accounts to detailed decompositions of economic activity and the associated financial flows.

## c. SAM Economic Multipliers

Not explicitly discussed above, when social accounting matrices are sufficiently detailed, they capture the economic linkages between different sectors and industries within an economy. These linkages can be either upstream or downstream. For example, the transport industry requires vehicles, fuel and tyres as inputs to the services provided. These inputs, in turn, require steel, chemicals and rubber, respectively. The production of these commodities would require their own inputs, and so forth. If the transport industry were to experience growth in demand, the upstream industries would too experience an increase in demand and would have to increase its supply to take advantage of the improved economic/trading environment. In a similar way, an industry downstream may benefit from an increase in supply from one of the upstream industries either through costs being lowered or it being able to expand output more seamlessly.

Crucially, the linkages contained in an SAM allow for the calculation of economic multipliers associated with spending in the different industries. The term multiplier stems from the well-known economic effect of an amount of spending, for argument's sake R10, having a greater-than-R10 impact on economic activity. The size of an industry's multiplier depends on the proportion of the inputs sourced domestically versus the rest of the world, the amount of tax paid in the production process. It also depends on what proportion of their income households will consume. These multipliers (and the amounts spent in a given project) result in the total economic impacts generally measured in terms of GDP, employment, government revenue, imports and exports.

### d. Basic SAM assumptions and limitations

*In addition to the above considerations, SAMs are based on several other assumptions, which are explained below:*

#### Demand equals supply

Unconstrained SAMs assume that all increases in demand can be matched by supply. In a constrained SAM, selected sectors' supply can be limited and demand increases met with import increases. The SAM model employed in this study is unconstrained.

#### Fixed prices

SAMs are fixed-price models – there are no changes in prices, only output.

#### Fixed proportions

Imports, exports, commodities, capital and labour inputs are used in fixed proportions to an industry's output based on the data used to build the SAM. Discussed briefly above, this restrictive assumption results in an X% increase in each of these components if an industry's output increases by X%. This is arguably the most unrealistic assumptions governing SAMs.

#### Constant returns to scale

No economies of scale exist in SAMs. This is related to the fixed proportions assumption in that a doubling of output requires the doubling of inputs.

#### No time dimension

SAMs are static models. As a result, the evolution of economic impacts is generally not reported over time, especially when induced impacts are included. However, it is beneficial to report employment impacts by year, but this is a calculation left open to the modeller.

#### Employment impacts in SAM modelling

While the impacts on macroeconomic variables such as GDP, government revenue and the external accounts are relatively simple to calculate via SAM modelling, the employment impact of a given expenditure shock requires additional assumptions. SAMs are based on fixed proportions assumptions; and from the employment perspective, each industry therefore has a fixed output to employment ratio. When an industry experiences growth in its demand and has to increase its supply, employment is increased by the same proportion as the increase in output. Furthermore, employment impact results from an SAM are typically in terms of FTEs and have no time dimension to them when induced impacts are included (as was discussed above). It is generally left open to the modeller to determine the impact per year. This study calculates the average annual employment increase by dividing the total FTE impact by the number of years of the project in question.