2019
STRATEGIC ENVIRONMENTAL ASSESSMENT FOR THE IDENTIFICATION OF ENERGY CORRIDORS AS WELL AS ASSESSMENT AND MANAGEMENT MEASURES FOR THE DEVELOPMENT OF A PHASED GAS PIPELINE NETWORK IN SOUTH AFRICA

PART 1

Background to the Phased Gas Pipeline Network Strategic Environmental Assessment

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PART 1. BACKGROUND TO THE PHASED GAS PIPELINE NETWORK STRATEGIC ENVIRONMENTAL ASSESSMENT

1.1 Introduction and Background

Operation Phakisa was launched by the South African National Government in July 2014, with the aim of implementing priority economic and social programmes and projects better, faster and more effectively. It includes the 1) Oceans Economy Lab; 2) Health Lab and 3) Education Lab. The Oceans Economy Lab aims to unlock the potential of the South African coast and considers the following four critical areas:

- Marine Transport and Manufacturing;
- Offshore Oil and Gas Exploration;
- Aquaculture; and
- Marine Protection Services and Ocean Governance.

This Strategic Environmental Assessment (SEA) Process is related to the critical area of Offshore Oil and Gas Exploration. Eleven initiatives were identified as part of the Offshore Oil and Gas Exploration critical area and the development of a Phased Gas Pipeline Network was identified as initiative A1 of the Offshore Oil and Gas Exploration Lab. Operation Phakisa recognises that to enable successful offshore oil and gas exploration, adequate infrastructure such as (but not limited to) pipeline networks need to be developed (Transnet, 2016[1]).

The Integrated Resource Plan (IRP) 2010-30 was promulgated in March 2011, and at the time of promulgation it was considered a "living plan" to be updated frequently by the Department of Energy (DoE). Since the promulgation of the IRP 2010-30, there have been a number of developments in the energy sector in South and Southern Africa, and the electricity demand outlook changed from that projected in 2010. As an update to the 2010-30 IRP, the DoE published Assumptions and Base Case documents for public comment in 2016. According to these documents, there is a significance placed on pursuing a diversified energy mix in South Africa, which "reduces reliance on a single or a few primary energy sources" (DoE, 2016[2]). In August 2018, the DoE published an updated Draft IRP for public comment. The updated report was focused on ensuring security of supply, as well as reduction in the cost of electricity, negative environmental impact (emissions) and water usage (DoE, 2018[3]). One of the main implications of the Draft IRP 2018 and updated process is that the progression and level of new capacity developments needed up to 2030 should be reduced compared to that noted in the 2010-30 IRP (DoE, 2018). It was also concluded that additional detailed studies be undertaken to inform the update of the IRP, and this includes, but is not limited to, undertaking a detailed analysis of the options for gas supply to identify the technical and financial risks and mitigation measures needed for an energy mix that is dominated by Renewable Energy and Gas post 2030 (DoE, 2018). The DoE further states that natural gas presents the most significant potential in the energy mix. Refer to Table 1 and Figure 1 below, which indicates that Gas / Diesel have a 3 830 MW installed capacity as at 2018, with an additional capacity of 8 100 MW by 2030 (equating to 11 930 MW capacity by 2030). It is important to note that the entire 11 930 MW capacity could be produced using natural gas only instead of both gas and diesel. This statement is only effective if Eskom and Independent Power Producers (IPPs) with Open Cycle Gas Turbine (OCGT) power stations convert these stations currently running on diesel to gas within the remaining 12 years. As indicated in Figure 1 and Table 1, in terms of the future total installed capacity mix (as a percentage), coal represents the highest percentage, followed in descending order by Gas/Diesel, Wind, Solar PV, Hydro, Pumped Storage, Nuclear, CSP and Other. Based on the 2018 Draft IRP, the **current installed capacity** (i.e. as at 2018) of gas, wind and solar PV respectively represent approximately 5.06 %, 2.61 % and 1.95 % of the **future energy mix (i.e. future installed capacity)**.

Table 1: Draft IRP 2018: Proposed Updated Plan for the Period Ending 2030 (DoE, 2018)

	Coal	Nuclear	Hydro	Storage (Pumped Storage)	PV	Wind	CSP	Gas / Diesel	Other (CoGen, Biomass, Landfill)	Embedded Generation
2018	39 126	1 860	2 196	2 912	1 474	1 980	300	3 830	499	Unknown
2019	2 155					244	300			200
2020	1 433				114	300				200
2021	1 433				300	818				200
2022	711				400					200
2023	500									200
2024	500									200
2025					670	200				200
2026					1 000	1 500		2 250		200
2027					1 000	1 600		1 200		200
2028					1 000	1 600		1 800		200
2029					1 000	1 600		2 850		200
2030			2 500		1 000	1 600				200
TOTAL INSTALLED	33 847	1 860	4 696	2 912	7 958	11 442	600	11 930	499	2600
Installed Capacity Mix (%)	44.6	2.5	6.2	3.8	10.5	15.1	0.9	15.7	0.7	

Installed Capacity
Committed / Already Contracted Capacity
New Additional Capacity (IRP Update)
Embedded Generation Capacity (Generation for own use allocation)

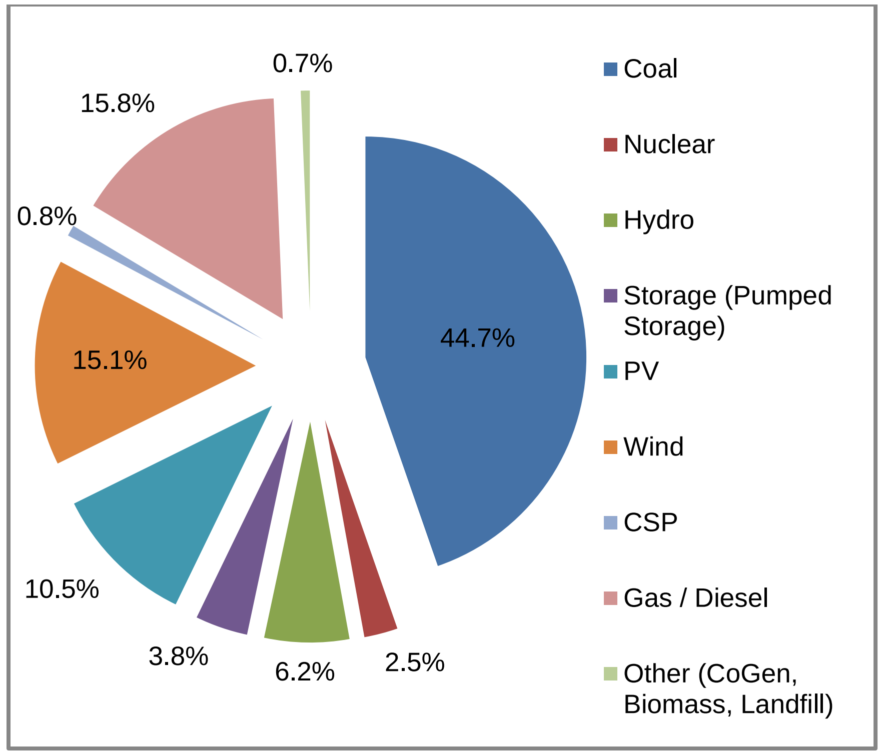

Figure 1: Graph indicating percentages of the future installed capacity mix (taking into consideration Installed Capacity as at 2018; Committed/Already Contracted Capacity; and New Additional Capacity (IRP Update)) based on the Draft IRP (DoE, 2018).

Operation Phakisa and the Department of Trade and Industry (dti) argue that the development of gas could support South Africa's industrialisation as a result of competitively priced energy and stable energy supply (Figure 2).

[1] Transnet SOC Limited (2016). Long–Term Planning Framework: Chapter 6: Natural Gas Infrastructure Planning.

[2] Department of Energy (November 2016). Integrated Resource Plan Update Assumptions, Base Case Results and Observations Revision 1. Pretoria.

[3] Department of Energy (August 2018). Integrated Resource Plan 2018 (Draft). Pretoria.

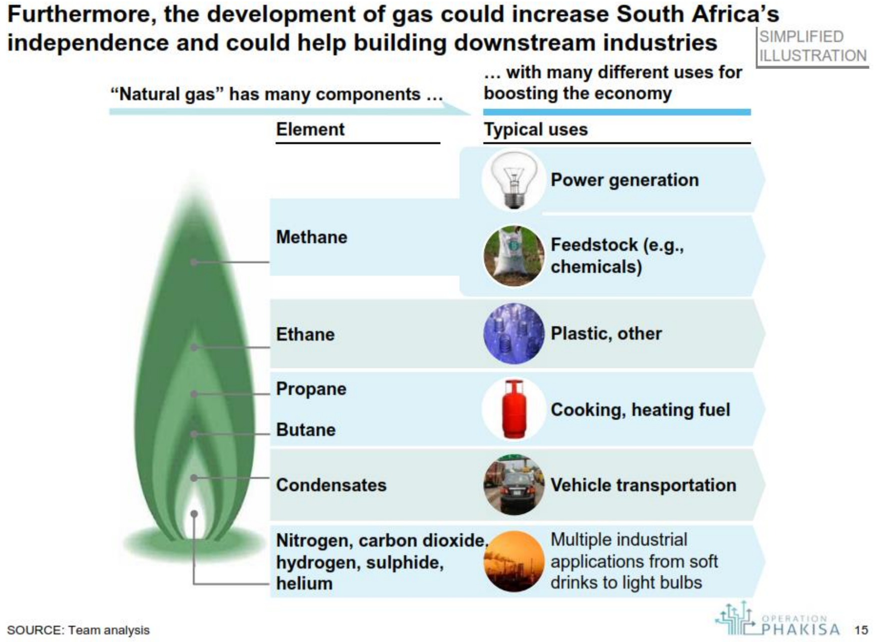

Figure 2. Opportunities to downstream users in using gas (Source: Republic of South Africa Operation Phakisa Offshore Oil and Gas Exploration, 2014).

To support the objectives of the Operation Phakisa Oceans Economy Oil and Gas Lab, to accelerate the planning for gas to power as part of the IRP and as part of the Gas Utilisation Master Plan (GUMP), and to ensure that when required, environmental authorisations are not a cause for delay, the Department of Environmental Affairs (DEA), DoE, and the Department of Public Enterprises (DPE), as well as iGas, Eskom and Transnet, have commissioned the Council for Scientific and Industrial Research (CSIR) to undertake a SEA to identify and pre-assess suitable corridors for a Phased Gas Pipeline Network and for the expansion of the Electricity Grid Infrastructure (EGI) corridors that were assessed as part of a previous SEA Process (which was in response to the Strategic Integrated Project SIP 10: Electricity transmission and distribution for all), which concluded in 2016. The CSIR is undertaking the SEA in collaboration with the South African National Biodiversity Institute (SANBI). Refer to Figure 3 for a breakdown of the SEA Project Team.

This SEA Report deals specifically with the Phased Gas Pipeline Network. The EGI Expansion corridors are subjected to a separate assessment and compiled as part of a separate SEA Report.

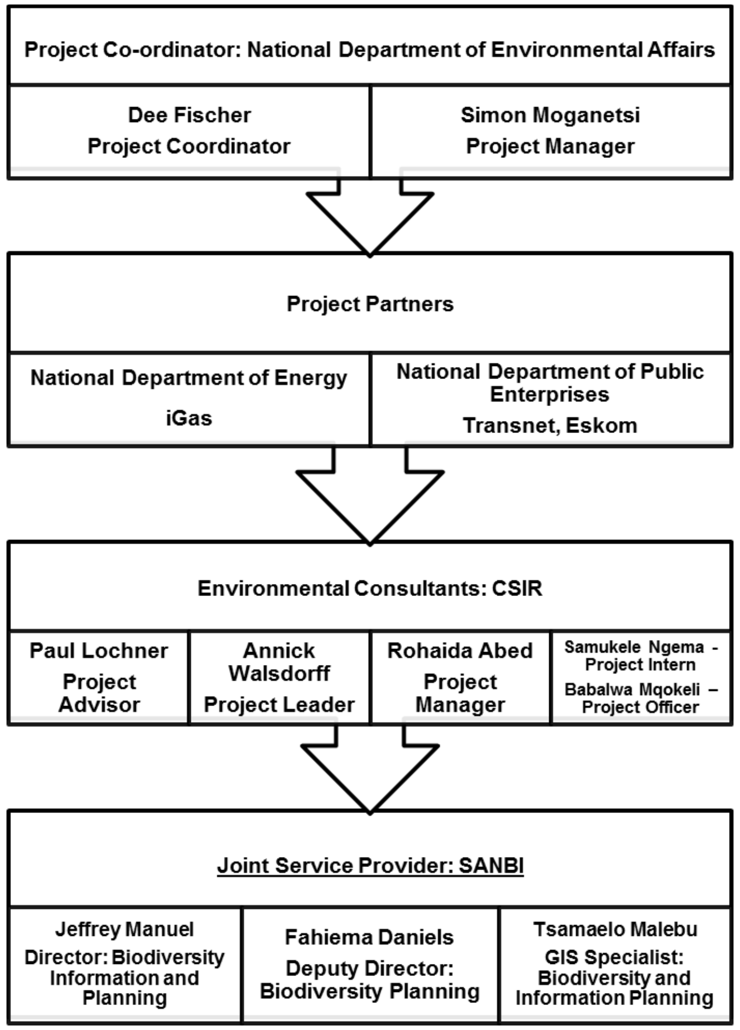

Figure 3. SEA Project Team

1.1.1 The History of Exploration and Production in South Africa

The information included in this section has been provided courtesy of the Petroleum Agency of South Africa (PASA). Table 2 provides a summary of the history of exploration and production in South Africa.

Table 2: History of Exploration and Production in South Africa

Year	Description
1940's	The first organised search for hydrocarbons in SA was undertaken by the Geological Survey of South Africa
1965	Soekor (Pty) Ltd was formed by the government. It began its search in the onshore areas of the Karoo, Algoa and Zululand Basins
1967	A new Mining Rights Act was passed and offshore concessions were granted to a number of international companies including Total, Gulf Oil, Esso, Shell, ARCO, CFP and Superior.
1969	First offshore well drilled and the discovery by Superior of gas and condensate in the Ga-A1 well situated in the Pletmos Basin.
1970	Soekor (together with Rand Mines) extended its efforts to the offshore but, despite further encouraging discoveries, international companies gradually withdrew.
Mid 1970's to the late 1980's	Soekor was the sole explorer operating the entire offshore area of South Africa.
1994	The offshore areas were once again opened to international investors via a Licensing Round.
1999	Petroleum Agency SA was established.
2001	A new State oil company, PetroSA, was formed by the merger of Soekor and Mossgas.
2002	The Mineral and Petroleum Resources Development Act was passed.
1 May 2004	The Mineral and Petroleum Resources Development Act became operational.

In the entire offshore area there are now over 300 exploration wells including appraisal and production wells. In addition, 233 000 km of 2D seismic data and 10 200 km of 3D seismic data have been acquired since exploration began offshore. Exploration drilling was most active from 1981 to 1991 during which period some 181 exploration wells were drilled. The Bredasdorp Basin has been the focus of most of the seismic and drilling activity since 1980.

The results of this exploration are the discovery of several small oil and gas fields, and the commercial production of oil and gas from the Bredasdorp Basin of the southern coast of South Africa. In the Pletmos Basin off the west coast of South Africa, there are two undeveloped gas fields and a further six gas discoveries. One oil and several gas discoveries have been made in the South African part of the Orange Basin. One of these discoveries is currently being appraised and developed as the Ibhubesi gas field by Sunbird Energy/Umbono.

Producing Fields

The F-A/E-M and satellite gas fields, situated 90 km offshore the Mossel Bay area, are owned and operated by PetroSA. Production began in 1992 and gas and condensate are piped ashore to the PetroSA Gas-to-Liquid (GTL) Refinery at Mossel Bay where they are converted to petrol, diesel, paraffin and petrochemicals. During 2006, average daily production from these fields was approximately 160 MMscfg/d (million standard cubic feet of gas per day) and 3900 BOPD (barrels of oil per day).

South Africa's first oil production began in 1997 when the Oribi oil field began flowing at an initial rate of 25 000 bbl/d. A floating production facility (the Orca) is used to fill a shuttle tanker, which supplies crude oil to the Chevron refinery in Cape Town. In May 2000 the adjacent Oryx oil field was also brought on stream utilising the same facilities. A third field, Sable, commenced production in August 2003. During 2006 average daily production from Sable was 9700 BOPD. The Oribi/Oryx fields are now almost depleted with only minor production. The Sable field is now producing gas to supplement the feedstock to the Mossel Bay GTL Refinery. Production from these gas fields is also in decline, making exploration for further domestic reserves imperative.

Database

A substantial database has been accumulated during 40 years of offshore exploration. This comprises well, seismic, gravity, magnetic, geochemical, geological, biostratigraphic and other data together with a large volume of interpretation reports and related studies. Most of this data is held by Petroleum Agency SA on behalf of the State and is well organised and accessible. The quality of this database varies considerably from area to area. Seismic data coverage for example, varies greatly in quantity and vintage from one basin to another. Drilling activity shows a similar pattern with a heavy concentration in the Bredasdorp Basin.

1.1.2 Vision for Gas Exploration, Usage & Planning in South Africa

Given this history, and although offshore exploration began as far back as 1967, South Africa's oil and gas sector is arguably in the early development phase but nevertheless has the potential to create large value for the country in the long run. However, it must be understood that developing South Africa's current oil and gas industry to a level comparable with West African countries like Nigeria, Ghana and Angola will take decades.

In order to get a view of actual prospectivity, exploration activity must increase. In 2014 the Offshore Oil and Gas Lab set an aspiration of drilling 30 exploration wells in 10 years (i.e. by 2024).

South Africa has possible resources of ~9 billion barrels oil and 11 billion barrels oil equivalent of gas. However, there is great uncertainty in developing these possible resources into reserves. Oil and Gas exploration requires significant investments, particularly in the South African deepwater offshore environment, where a single exploration well can cost over $150 million. To achieve 30 exploration wells by 2024 will require investments in the range of $3 - $5 billion. Given that exploration success rates are below 15%, investors see these opportunities as risky.

The dti (dti, 2017[4]) sees the gas economy developing in three broad phases over the next 15 years and beyond. The first phase (over the next 3-5 years) is focused on imported LNG and is followed by the importation of regional gas from offshore gas reserves in Phase 2 in the next 7-15 years. Phase 3 (in about 15 years' time) sees the addition of onshore domestic gas reserves to the energy mix. South Africa has a number of large offshore gas fields which are in an advanced stage of exploration. Blocks 11B/12B, currently being explored by Total is an example of such an area in its advanced stage of exploration.

1.1.3 Pathway to Achieving the Vision

Although infrastructure is currently not a constraint to exploration, particularly for gas, further coordination with other stakeholders may be helpful to incorporate the potential implications of offshore production into infrastructure plans. Infrastructure development is therefore seen as an enabler to offshore exploration. This infrastructure includes port facilities, pipeline networks and multi-purpose research vessels. The Phased Gas Pipeline Network therefore forms part of the infrastructure envisaged as an enabler for the offshore oil and gas development to transport gas from the landing points to domestic markets.

Other drivers of the Phased Gas Pipeline Network include imported LNG (via the LNG to Power Program), Shale Gas developments in the Karoo Region and Imported Pipeline Gas from Mozambique.

1.1.4 Current State of Gas Exploration in South Africa

According to PASA, P50 Gas Resources (which means that there is only a 50% probability that the quantities actually recovered will equal or exceed the estimated quantities) in South African Waters are 28 TCF off the West Coast; 26 TCF off the South Coast; and 9 TCF off the East Coast. These are quantities of gas that the geology indicates could be there. However, exploration will still have to be undertaken to confirm that actual extractable gas at a P90 (proven) reserve level (Figures 4 and 5 below).

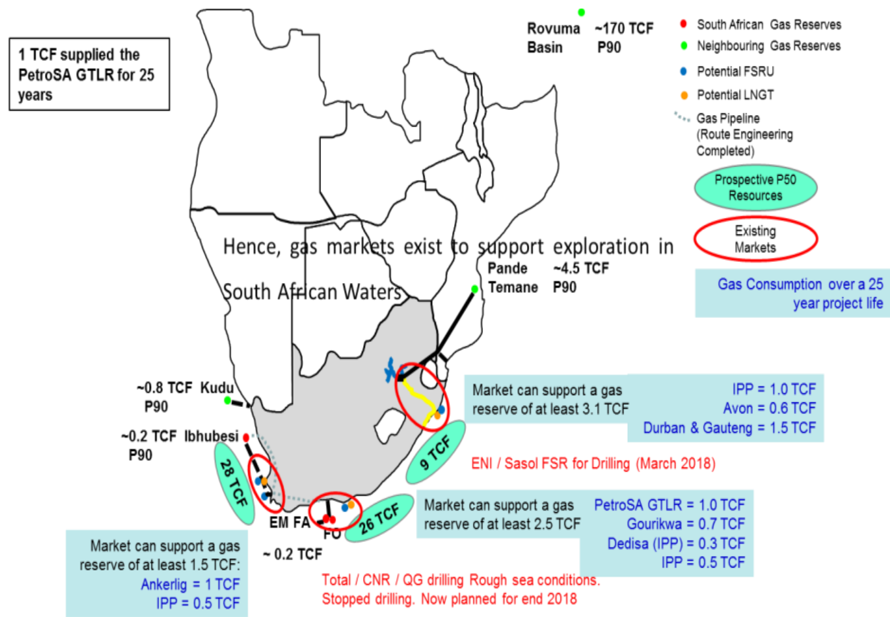

Figure 4: Potential Gas Markets and Planned Pipeline Infrastructure in South Africa

In terms of South African offshore gas finds, these are limited to:

- PetroSA's FA and EM fields off the Mossel Bay coast (largely depleted, but with a tail that can still be utilised, provided other gas sources can be used to supplement the tail). PetroSA has also produced from the FO field, which had a P90 reserve estimate of 0.2 TCF although the recoverable gas turned out to be 10% to 20% of this.
- Sunbird Energy/Umbono is developing a business case for the Ibhubesi Gas field (0.21 TCF P90) to bring the gas to market in the Western Cape, i.e., Eskom's Ankerlig Power Station. iGas has completed the Route Engineering for an onshore pipeline from the original landing point (Abraham Villiersbaai) to Saldanha and Ankerlig. However, Sunbird Energy opted for a development plan that will transport the gas via a subsea pipeline with options for landing points closer to market. Sunbird Energy received Environmental Authorisation for this development on 3 August 2017.
- Figure 5 presents the petroleum exploration and production activities in South Africa. Total started drilling an exploration well off the southern coast of the country in 2014/15 in Block 11B/12B. However, Total stopped the activity due to rougher than

[4] Department of Trade and Industry (dti) (2017). Industrialising the KZN- Gauteng corridor through natural gas. Pretoria.

expected sea conditions and subsequent mechanical problems with the drilling rig. In February 2018, Qatar Petroleum joined the partnership with Total for exploration in the block and a revised drilling program was devised resulting in the re-instatement of drilling activities (Total, 2018[5]). In February 2019, Total made a large gas condensate discovery on the Brulpadda well located within the block approximately 175 km off the southern coast of South Africa (Total, 2019[6]). The well intersected with a 57 m deep reservoir interval in the Albian section of the southern Outeniqua Basin (PASA, 2019[7]), and was deepened to a depth of about 3633 m (Total, 2019).

- On 8 March 2018, ENI as operator of Block ER 236 off the east coast of South Africa submitted their Final Scoping Report to drill up to six (6) exploration wells. A final Environmental Impact Assessment (EIA) Report was compiled by ERM in December 2018 and submitted to PASA for decision-making. The prospecting area extends from Port Shepstone in the south up to St Lucia in the north; while the planned exploratory drilling is expected to take place within two areas of interest i.e. off the coast of Richard Bay and Scottburgh in the north and south of KwaZulu-Natal, respectively (ERM, 2018[8]). Drilling is expected to start in 2019, pending mandatory permit and authorisation approvals.
- The Kudu gas field in Namibia (0.80 TCF P90) remains unexploited. Past projects that have been contemplated include an 800MW Power Station in Namibia; or transmitting the gas to Cape Town. Thus far none have developed past conceptual studies. In August 2018, there were reports of the Namibian Government noting that the Kudu Gas to Power Project has been delayed for over 20 years, with the viability of the project being discussed (Engineering News, 2018[9]).

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[5] Total (2018). *Qatar Petroleum joins Total as a partner in the Exploration Block 11B/12B in South Africa*. Press Release: 5 February 2018. Available on line: https://www.total.com/en/media/news/press-releases/qatar-petroleum-joins-total-partner-exploration-block-11b12b-south-africa [Accessed 27 February 2019].

[6] Total (2019). *Total Makes Significant Discovery And Opens A New Petroleum Province Offshore South Africa*. Press Release: 7 February 2019. Available on line: https://www.total.com/en/media/news/press-releases/total-makes-significant-discovery-and-opens-new-petroleum-province-offshore-south-africa [Accessed 27 February 2019].

[7] PASA (2019). *Total's Brulpadda discovery*. Available on line: https://www.petroleumagencysa.com/index.php/home [Accessed 27 February 2019].

[8] ERM (2018). Exploration Drilling within Block ER236, off the East Coast of South Africa. Final EIA Report compiled by ERM for ENI. Available on line: https://www.erm.com/contentassets/9b249338ddb744a2bfa31f57febf7566/final-eia-report-2018/1a.eni-sa-drilling-final-eia-report-chapters-1-5-small.pdf [Accessed 27 February 2019].

[9] Engineering News (2014). *Kudu gas project might not be viable for Namibia – Energy Minister*. Available on line http://www.engineeringnews.co.za/article/kudu-gas-project-might-not-be-viable-for-namibia-energy-minister-2018-08-14 [Accessed 27 February 2019].

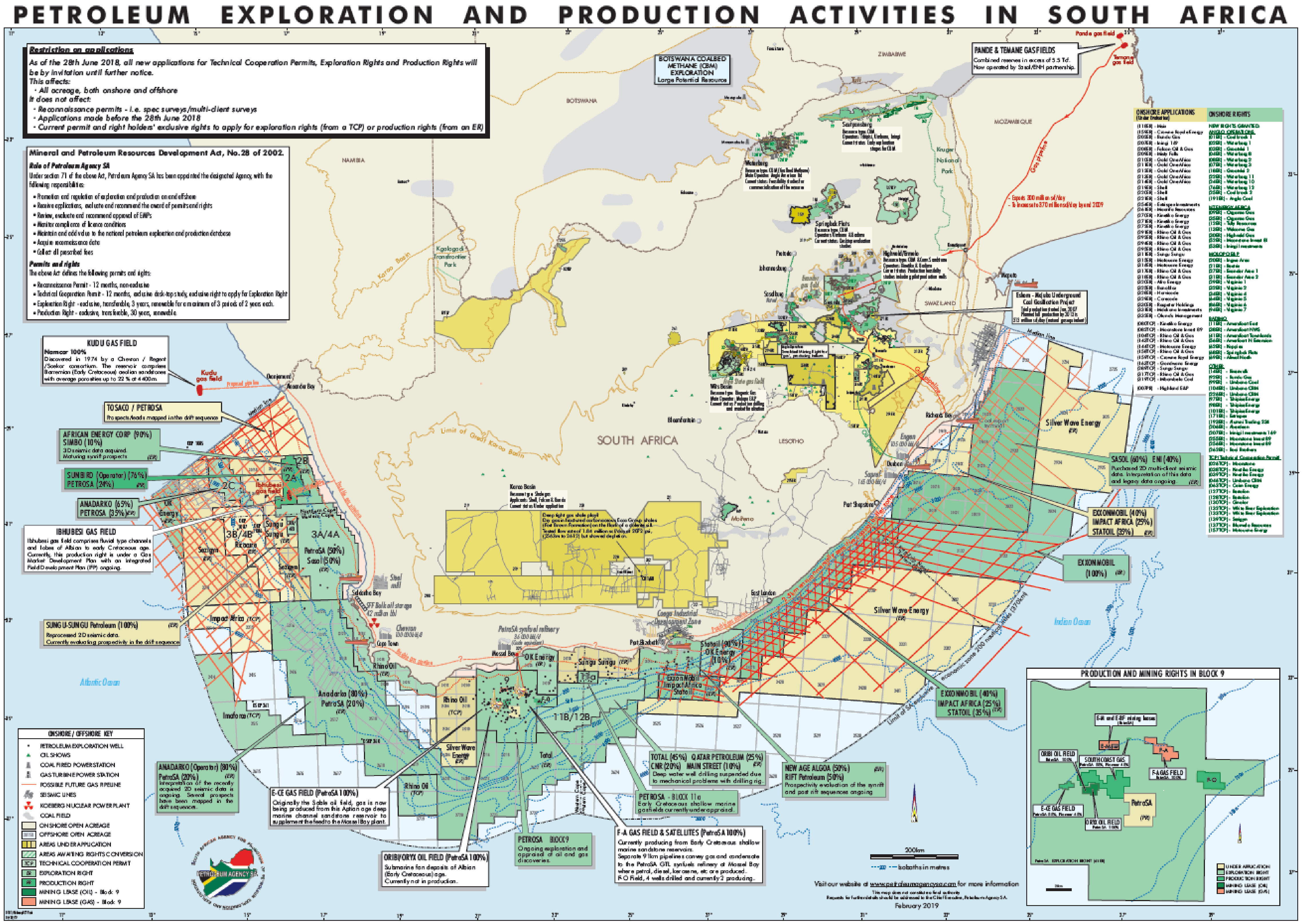


Figure 5: Petroleum Exploration and Production Activities in South Africa (Source: Petroleum Agency South Africa https://www.petroleumagencysa.com/images/pdfs/Hubmap0219.pdf)

1.1.5 Current Market in terms of Attracting Offshore Exploration to South Africa

This section is mainly based on the Gas opportunity analysis study undertaken by Rae Wolpe from Impact Economix (please refer to Part 1, Appendix 1 for the full report), as well as on information submitted by iGas.

Any natural gas found as associated gas with oil in deep waters will probably be re-injected to increase the extraction of oil. Natural gas found in quantities larger than the likely re-injection quantities can immediately supply the South African markets. A prerequisite is a focus on gas to power projects and pre-planning for a gas transmission system before the resource comes into production. Natural gas found in large quantities will, unlike Mozambique, need to be encouraged to first supply the industrialisation of coastal cities and the unsatisfied industrial demand from Gauteng before being exported as Liquefied Natural Gas (LNG) to international markets. This opportunity, if the gas reserves are found, has the potential to significantly grow the South African economy.

The principal determinants of energy demand growth are numerous and complex and include: energy policies, rates at which economic activity and population grow, relative energy source prices (and technological developments which impact on the relative costs of exploration, production and distribution) and technology innovations which can have a downward impact on energy prices - amongst other impacts. Demand for gas is highly price elastic.

The identification of potential bulk gas users in South Africa is a complex and ever-evolving challenge for a wide number of reasons. These include changing global energy prices, technological developments, energy switching costs, and the timing of future environmental policies and the magnitude of linked costs to reduce carbon emissions and Green House Gases (GHGs).

Sectoral opportunities fall within the following three main sectors:
1. Electricity generation
2. Industry and mining
3. Transportation

The potential also exists to expand residential demand for gas. It must, however, be noted that the scope of this SEA is limited to transmission pipelines and does not include gas distribution or reticulation networks.
A critical issue impacting on the nature of future demand for gas is the price of gas and how this differs between Liquefied Petroleum Gas (LPG) and Liquefied Natural Gas (LNG). The complexities of gas prices include the client-specific demand characteristics and requirements. In addition to exchange rate fluctuations and levels, there are a range of costs along the gas logistics chain which also need to be taken into account when determining final gas prices to the customer.

Gas for future **electricity generation** *may* be a major source of future gas demand in South Africa and will most likely *have* to be the anchor for large gas development and importation projects. Eskom's projections show that there will only be a need for new electricity generation capacity to meet peak demand around 2025/2026 (possibly sooner depending on the levels of economic growth). As indicated in Figure 1, the 2018 IRP identifies the need for an additional 8 100 MW of gas/diesel generated electricity by 2030 (DoE, 2018). As noted above, the 2018 Draft IRP states that detailed studies will be required to inform the desired energy mix post-2030.

Another factor that may impact on a growing need for gas-powered electricity generation in the longer term is the increased share of electricity from renewable sources (including solar powered electricity) in South Africa's energy mix. The country's 2018 Draft IRP calls for the generation capacity of a total of 19 400 MW from renewable energy sources (i.e. Solar PV and Wind only (excluding Hydropower, Storage Schemes and CSP)) by 2030. This value includes 1 474 MW and 1 980 MW of currently installed capacity for Solar PV and Wind, respectively. In February 2018, the Minister of Public Enterprises approved 27 utility-scale renewable energy projects consisting mainly of solar PV and wind (i.e. one from Bidding Window 3.5 and 26 from Bidding Window 4). The agreements were signed into effect under the Minister of Energy in April 2018[10] and the Power Purchase Agreements became effective between April 2018 and 31 July 2018. The Draft IRP 2018 notes that these "determinations for capacity beyond Bid Window 4 (i.e. 27 signed projects) issued under the IRP 2010–2030 must be reviewed and revised in line with the new projected system requirements for the period ending 2030" (DoE, 2018, page 12).

Gas represented approximately 3% of South Africa's total energy mix (DoE, 2013[11]) based on the 2012 DoE Integrated Energy Planning Report. Based on the 2018 Draft IRP, the current installed capacity for gas is 3 830 MW (although this is currently fueled by diesel), representing approximately 5 % of the future energy mix. Figure 6 illustrates Eskom's existing power stations, including four gas turbine plants i.e. Acacia, Port Rex, Ankerlig and Gourikwa (two of which are run by IPPs). As indicated in Figure 6, these 4 power stations represent an installed capacity of 2 426 MW. However, according to the Draft IRP 2018 (DoE, 2018, Page 59), the total nominal capacity of Ankerlig and Gourikwa decrease to 1327 MW and 740 MW respectively. The Draft IRP 2018 (DoE, 2018, Page 59) explains that the "difference between installed and nominal capacity reflects auxiliary power consumption and reduced capacity caused by the age of the plant". Additional OCGT power generating capacity comes from the IPP power stations Avon (670 MW) near Salt Rock on the KwaZulu-Natal north coast and Dedisa (335 MW) in the Coega Industrial Development Zone (IDZ). Other generators include Sasol Synfuel Gas (250MW) and Sasol Infrachem Gas (maximum of 175MW) (DoE, 2018, Page 59).

[10] Fin 24 (April 2018). Article on line: https://www.fin24.com/Economy/Eskom/jeff-radebe-signs-long-delayed-renewable-power-deals-20180404

[11] Department of Energy (January 2013). Draft 2012 integrated energy planning report executive summary (For Public Consultation). Pretoria. Available online: http://www.energy.gov.za/files/IEP/IEP_Publications/Draft-2012-Integrated-Energy-Plan.pdf

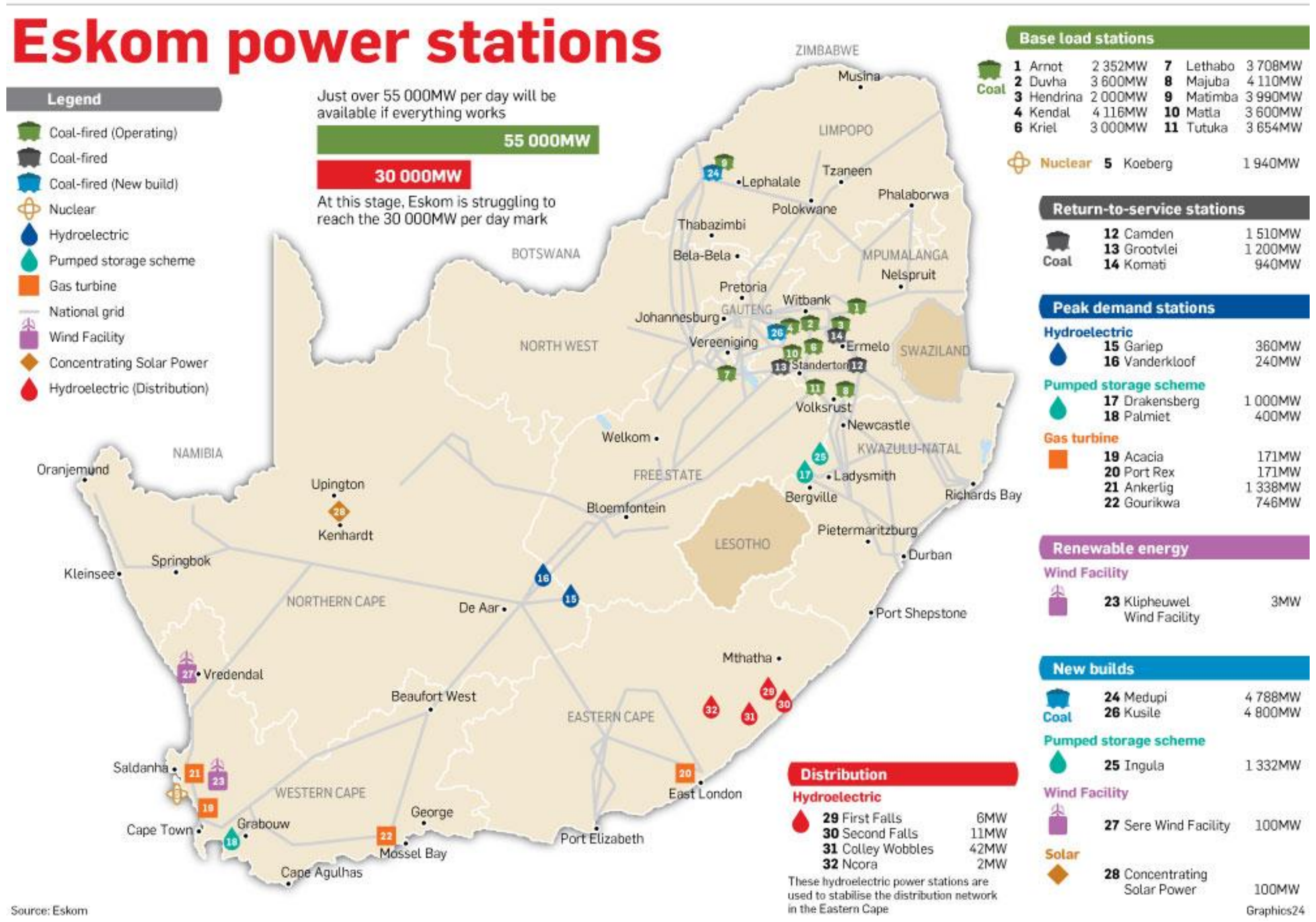


Figure 6. Eskom's current power stations: 2017 (Source: Eskom, October 2017)

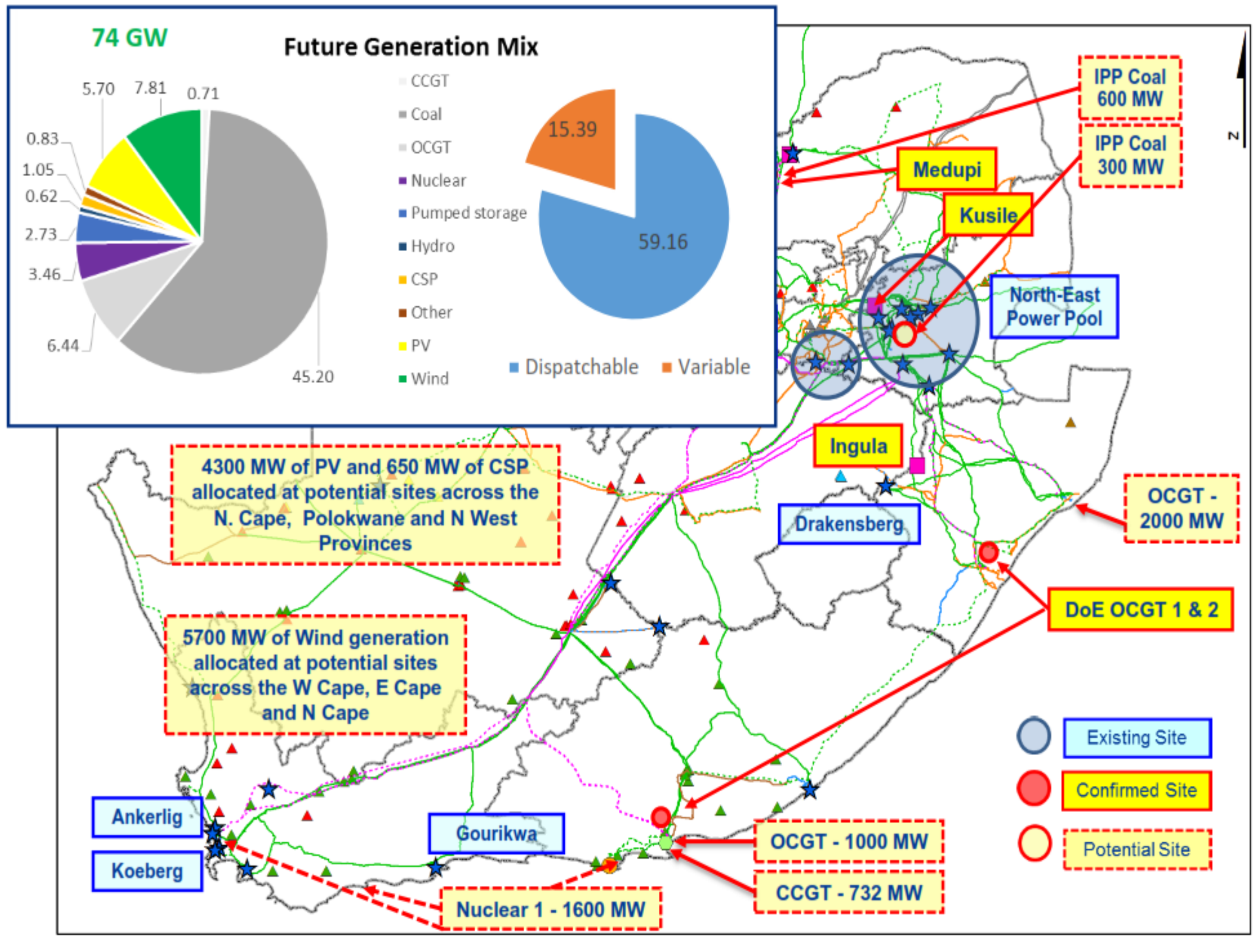


Figure 7. Eskom's 2017 view on potential future power stations (Source: Eskom, October 2017).

The feasibility of Eskom being able to upgrade existing gas turbine power stations to utilise gas has been called into question given the large investment amounts required for these upgrades (According to Eskom, an additional R1.5 billion is required to fully upgrade the Gourikwa and Ankerlig power stations after investing R160 million to convert the burners to dual fuel). As a result, it appears that there may be more scope for the future use of gas to generate electricity by IPPs, which is described further below.

- Eskom's Ankerlig OCGT power station in Atlantis is currently fueled by diesel. However, in the 2015 State of the Nation Address (SONA), Eskom was "directed" to convert all their diesel fired OCGT's to gas. Eskom subsequently embarked on a program to implement this and completed the conversion of both Ankerlig and the Gourikwa Power Station in Mossel Bay to duel fuel burners, i.e., these power stations can now use both diesel and natural gas as fuel. Depending on the operation of Ankerlig and a possible conversion of 5 of the units to Combined Cycle Gas Turbines (CCGTs), Ankerlig will have a demand of up to 1 TCF of gas over a 25-year period.
- Potential IPP in the Saldanha IDZ (0.5 TCF or greater, depending on eventual size and operation).
- Eskom's Gourikwa OCGT in Mossel Bay has been converted to use both diesel and gas fuel, and with the possible conversion of two units to CCGT the plant will have a demand of 0.7 TCF. A Total gas find off the south coast will definitely be of significance for Gourikwa.
- The DoE IPP Office Project Information Memorandum (PIM) specifies 3000 MW of IPP Gas to Power with 1000 MW at Coega (equivalent to a demand in the region of 0.5 TCF) and the balance at Richards Bay. A Mid Merit IPP at Richards Bay will therefore create a minimum demand of 1 TCF with the potential for more, depending on how big the power plant at Coega will be. It is understood that the EIAs commissioned for such Gas to Power developments within the Ports of Ngqura and Richards Bay are currently on hold.
- The Dedisa IPP OCGT peaking power plant in the Coega IDZ is currently fueled by diesel and has the capability to use natural gas as fuel. As a result of its peak operating mode it will only have a demand of 0.3 TCF over a 25-year period.
- The Avon IPP OCGT peaking power plant near Salt Rock in northern KwaZulu-Natal is currently fueled by diesel but has the capability to use gas as fuel, creating a demand of 0.6 TCF over a 25-year period.

Eskom's 2017 view of future power stations is illustrated in Figure 7 above.

In terms of **industrial use of gas**, industries are attracted to switching to gas because of the possible price advantages and supply security (which is a major potential attraction since it allows the company to go off the grid). However, the conversion costs for industrial users serve as a potential constraint to switching energy sources. As a result, it is difficult to identify at what gas cost switching is an attractive option for industrial users as the conversion costs first need to be identified and built into a feasibility assessment. A number of industries located in Gauteng, Mpumalanga, Durban, and the Western Cape are already making use of Methane Rich Gas (MRG) from Sasol. As a possibility, existing Durban, Richards Bay and Gauteng markets could be supplied with gas via reverse flow up the Lilly Pipeline or a new gas transmission pipeline to Gauteng (which has an estimated demand of 1.5 TCF over a 25-year period). The dti has conducted a gas market demand assessment for KwaZulu-Natal and found large-scale potential for this demand to grow. The Western Cape Government is currently updating a 2013 Western Cape gas market demand assessment to quantify the demand for gas in the Western Cape and the results are expected by the end of March 2019. A gas find off the Southern Coast of the country will definitely be of significance for the PetroSA's Mossel Bay GTL refinery and encourage fast-tracked developments for the Coega IDZ. As an indication of the volume of gas, note that the PetroSA GTLR in Mossel Bay operated on 1 TCF of gas for 25 years, consuming an average of 210 million standard cubic feet of gas per day (scfd).

There is growing use of gas in many segments of the **transport sector**, including: bus, taxi, road freight, and shipping. Globally, many countries are now setting sales targets for the sale of electric-powered motor vehicles and the phasing out of petrol and diesel powered vehicles (Gray, 26 September 2017[12]). The growth in natural gas powered vehicles appears to be negatively correlated with increases in the oil price. Current opportunities already being explored in South Africa include inner city public transport bus systems, mini-bus taxis, and road transport logistics haulers.

Hence, gas markets **as listed in Table 3** exist to support exploration in South African Waters.

Table 3: Potential gas markets

West Coast	1.5 TCF
South Coast	2.5 TCF
East Coast	Minimum of 3.1 TCF

Based on the above, existing Gas Markets and planned pipeline infrastructure are not the limiting factors for offshore exploration. Baseload IPP CCGT's are currently being planned; will require maturity; and, once offtake agreements are signed will take about 26 months to construct.

The current gas pipeline infrastructure in South Africa includes:

- The 865km Rompco pipeline from Sasol's Pande and Temane gas fields in Mozambique to Secunda. At the start of production in 2004, these fields had a total P90 reserve estimate of 4.5 trillion cubic feet (TCF). From Secunda, Sasol transmits the gas to Sasolburg and to other industrial users in Gauteng.
- The Lilly Pipeline, in which Transnet transmits Methane Rich Gas (MRG) from Sasol to Richards Bay and Durban.

In terms of future gas transmission pipeline planning:

- iGas has completed the onshore route engineering for a West Coast gas transmission pipeline from Abraham Villiersbaai to Saldanha and Atlantis to take West Coast Gas to the closest markets;
- PetroSA has completed the Pre-Feasibility Study for a gas transmission pipeline from Saldanha to Mossel Bay and on to Coega to take West Coast gas to the South Coast markets. Alternatively, the flow can be reversed to take South Coast gas to the West Coast markets; and
- In terms of Transnet's Long-Term Framework Planning, potential gas transmission pipelines include the following:
  - Line from Secunda to Botswana;
  - Gas from northern Mozambique to link with the proposed Petroline to Secunda;
  - Line from the Northern Cape to Gauteng;
  - Line from Gauteng to the Port of Ngqura;
  - Line from Northern Cape to Saldanha;
  - Line from Saldanha to Mossel Bay and to Port Elizabeth.

1.1.6 Challenges in terms of the Construction of Gas Pipelines

The market exists and there are unexploited gas reserves on the West Coast, however, the following challenges still exist in terms of constructing gas pipelines:

- Ownership of the gas: Namibia and South Africa have been in discussions for years about developing the Kudu gas field. However, negotiations stalled with South Africa's desire to transport the gas to Ankerlig for power generation and Namibia's desire to build a power station in Namibia and export excess power to South Africa.
- Ibhubesi is too small to support a conventional power station: The P90 reserve of 0.21 TCF is too small to support a large power station like Ankerlig beyond about 5 years.
- Currency and commodity price risk for fuel: Eskom currently buys coal in ZARs and sells electricity in ZARs. Gas prices are typically indexed against oil and priced in USD, introducing both currency and commodity price risks for the fuel. This will require Eskom to buy fuel priced in USD and fluctuating with the price of oil but will only be able to sell electricity in ZAR and priced in accordance with the Multi-Year Price Determination (MYPD).
- Spatial planning: Securing servitudes is a significant task for pipeline development, requiring individual negotiations with multiple landowners. Strategic servitude planning needs to be undertaken well in advance of the final planning of a gas transmission pipeline system.
- The development of a Bankable Feasibility Study and completing the relevant business case can only be led by the relevant gas reserve finds with commercial opportunities, i.e., a source of gas and a guaranteed offtaker, prior to the pipeline being constructed.

1.2 SEA Rationale

The development and related operation of infrastructure for the bulk transportation of dangerous goods (including gas using a pipeline exceeding 1000 m in length) is identified as Activity 7 of Listing Notice 2 (Government Notice R325) of the 2014 EIA Regulations (as amended). These activities require environmental authorisation in terms of the 2014 EIA Regulations (as amended) via a full Scoping and Environmental Impact Report (EIR) Process, which requires the submission of a Scoping Report and EIA Report to the Competent Authority. The National DEA is the regulated Competent Authority for all Applications for Environmental Authorisation that are submitted by statutory bodies.

Based on observations and previous cases, it has been realised that the authorisation process currently being applied to linear infrastructure including gas transmission pipelines may be too rigid to be an effective assessment mechanism for these types of structures. The current process locks the routing options to an approved route, determined well in advance of any construction process, which results in the following challenges:

- Higher costs of land to be used as servitudes: The EIA Process is important in the initial planning and route selection of new gas pipelines. For this reason, it is common practice for the servitude

[12] Gray, Alex (27 September 2017). Countries are announcing plans to phase out petrol and diesel cars. Is yours on the list? Available online at: https://www.weforum.org/agenda/2017/09/countries-are-announcing-plans-to-phase-out-petrol-and-diesel-cars-is-yours-on-the-list/

negotiation process to begin after the EIA has been completed. At that stage there is greater confidence in the route to be adopted. The problem with this sequence of events however, is that the Environmental Authorisation locks the developer into a predefined route. Therefore, should a gas pipeline developer encounter an unwilling landowner during the servitude negotiation process, there is little to no flexibility to adapt the course of the route. In these instances, the developer is forced pay above market rate to the landowner for access to the servitude, undergo an expropriation process or reroute the line, the latter requiring an amendment to the Environmental Authorisation and all options resulting in increased costs and delays to the project.

- The EIA Process is initiated too late to provide strategic input into the alignment of gas transmission pipelines and other key linear infrastructure, as it is usually initiated when the project has been approved by the relevant approval board and by that time the strategic decisions regarding route planning would have been taken and the alternatives in the EIA Process would be limited;
- The inflexibility of the approved routes limits the possibility of adding more users identified after the environmental authorisation process;
- There is a high probability of amendments being sought to the route at construction due to maturing of information, including the identification of additional users, changes in the supply and demand scenarios etc.
- As the pipeline network is constructed in phases, authorisations are submitted and processed in phases. This makes it impossible to assess the entire planned gas transmission needs strategically or to give consideration to the cumulative effects of the entire network construction; and
- Complication is introduced by the fact that any changes or opposition during the EIA Process resets the project making the delivery of gas to the economy and society either redundant or late.

Furthermore, for a major gas transmission route, it takes on average between one to two years for an EIA Process to be completed in terms of the National Environmental Management Act (NEMA) (Act Number 107 of 1998, as amended). For long gas pipelines crossing many different land parcels, the risk of an appeal is high, which often results in significant delays in receiving the authorisation. Major routes often trigger additional environmental permitting requirements, such as a Water Use Licence Authorisation, Mining Permit, and Permit for the Removal of Protected Trees, each managed by a different Competent Authority under an independent authorization process. Only upon EIA authorisation do many of these additional authorising processes commence. This lack of integration between the different licensing processes means that it can take up to seven years for all the necessary environmental approvals to be awarded, before construction can start.

In addition, as noted above strategic planning for servitudes needs to be undertaken well in advance of the final planning of a gas transmission pipeline system. It would therefore be beneficial for the applicant of the major gas pipeline to submit a pre-negotiated route, where the upfront approval of landowners has been obtained. The current EIA Process does not allow for the submission of applications on a pre-determined route.

From the perspective of the National DEA, every effort needs to be made to ensure that the requirements for environmental authorisation are streamlined, they follow an efficient and effective assessment and review process and achieve the objectives of sustainable development. Therefore, in order to overcome the constraints listed above, and to support the Operation Phakisa, this SEA Process has been commissioned to identify and pre-assess suitable gas routing corridors to facilitate a streamlined environmental authorisation process for the development of energy infrastructure related to gas.

1.2.1 Problem Analysis

Linked to the above, the construction of the Phased Gas Pipeline Network to support offshore exploration as well as to bring gas to strategic industrial centres, via third party distributors, to all of the citizens of the country is seen a strategic intervention. As an Operation Phakisa project, all government departments that have a mandate with respect to the facilitation and implementation of Operation Phakisa must ensure the efficient and effective administration of this mandate.

As many of the Operation Phakisa initiatives and associated projects will trigger a number of listed activities for which environmental authorisation will be required, the DEA will need to prioritise the review and decision making process associated with Phakisa related projects. It has been identified that significant improvements can be made to the assessment and decision making process related to linear activities. This includes gas pipeline infrastructure and the assessment and decision-making process will ensure the highest level of environmental protection while reducing the number of applications required to be submitted. Through the inclusion of a pre-assessment process, which identifies the environmental constraints/sensitivities of proposed linear infrastructure routes, it will be possible to identify gas transmission pipeline corridors and management measures which avoid environmentally sensitive areas, while following the most socially acceptable and economically viable routing options and applying the most effective and environmentally sound management measures.

PROBLEM STATEMENT

Limited consideration by developers of environmental constraints in the early planning stages is proving costly (both environmentally and economically) and affecting the ability to make strategic investment decisions

1.3 Study Objectives

In partnership with the DEA, DoE, DPE, iGas, Eskom and Transnet, and in consultation with relevant stakeholders; identify routing corridors, environmental management measures including norms or standards and a streamlined environmental authorisation for the construction of the linear infrastructure associated with energy provision including a gas pipeline network as well as interventions required to secure long term energy planning corridors and zones identified.

It is intended that the routing corridors identified through the SEA Process, be submitted to Cabinet for approval to ensure buy-in from all Departments and that the corridors can be integrated into Strategic Development Frameworks at local, provincial and national level, to ensure that long term energy planning is secured.

The SEA has been undertaken at a level of detail that will allow the Minister of Environmental Affairs to consider a streamlined environmental authorisation process for the development of gas transmission pipeline infrastructure within the gazetted energy corridors and/or exclude these from environmental authorization on the basis that a standard will be applied.

The vision of the SEA is that strategic development of a gas pipeline network is undertaken in an environmentally responsible and efficient manner that responds effectively to the economic and social development needs of the country. With this vision in mind, the following objectives were developed to guide the study:

- **Sustainable Development**

Sustainable development is a process for meeting societal development needs whilst maintaining the ability of natural systems to continue to provide the natural resources and ecosystem services upon which the economy and society depends. *This SEA aims to facilitate sustainable development through the identification of a set of strategic corridors, which fundamentally serve the purpose of connecting demand areas, but are positioned in such a way to maximise opportunities for economic and social development whilst minimising constraints to the environment.* Development inside of the Gas Corridors will be encouraged to proceed in areas of low and medium environmental sensitivity.

- **Participation**

The identification of strategic corridors that meet the long term requirements of industry and society whilst also considering factors such as environmental constraints/sensitivities and financial cost requires inputs from a diverse group of stakeholders. Furthermore, the successful implementation of strategic planning initiatives requires the buy-in and commitment from a range of role players. Early consultation and formal agreement amongst stakeholders is thus central to the success of the SEA. From the onset of the SEA Process, extensive consultation was undertaken with all three levels of government, the private sector, non-governmental agencies and the general public.

- Coordination

Legal recognition of the Gas Corridors is required to facilitate effective implementation. This process should start with the formal adoption of the Gas Pipeline Corridors through a publication in the Government Gazette and end with the recognition of these areas within relevant national, provincial and local plans and policies. The alignment of the corridors across the relevant plans and policies of all three levels of governments will signify the high level agreement needed to facilitate effective implementation of the Gas Pipeline Corridors.

- Streamlining

In the context of this study, 'streamlining' means better coordination of environmental assessment procedures with the aim of reducing unnecessary administrative burdens, creating synergies and speeding up the environmental assessment process. **'Streamlining' does not imply a weakening of environmental protection requirements under the NEMA.** Instead, the outputs of the SEA are designed to improve the quality of the environmental assessment process and decision making; and better facilitate strategic gas pipeline development in the Gas Pipeline Corridors.

The environmental pre-assessment of the corridors undertaken as part of the SEA is comparable to a scoping phase and hence will assist with focusing additional assessment requirements required in further environmental assessment processes. Agreement on and official adoption of the Gas Pipeline Corridors in relevant plans and policies should serve to create an advantageous environment for the development of gas pipeline infrastructure. As an output of the SEA, all future gas pipeline development inside of the Gas Corridors normally triggering an EIA Process in terms of NEMA will either be exempted from obtaining an Environmental Authorisation provided that Norms/Standards/Protocols are enforced or be subject to a streamlined environmental assessment process (e.g. Minimum Information Requirements). Additional information on the outcome and tools of the SEA are described in Section 1.6 of this chapter (i.e. Part 1: Background to the Phased Gas Pipeline Network SEA).

- Integration

The SEA seeks to achieve integration between the different competent authorities responsible for environmental authorisation and licensing. This will be facilitated through the creation and adoption of a commonly agreed upon 'Development Protocols'. The scope of the project level environmental assessment process in the Gas Pipeline Corridors will be informed by requirements specified in the development protocol, and undertaken in accordance with the relevant existing regulations. This will ensure that, where separate environmental legislation requires separate assessments, those assessments and associated decision making processes should, as best as possible, be aligned with the respective project specific environmental assessment procedure. Where possible, assessment and decision making procedures will also be integrated to maximise efficiencies. Integration will assist with streamlining processes.

- Facilitation of Strategic Investment

The integrated approach followed to identify Gas Pipeline Corridors, official agreement to these areas, and the alignment of policies and plans together with the pre-assessment work undertaken as part of the SEA, should help to create an enabling environment for gas pipeline development within the Gas Pipeline Corridors.

Streamlined and coordinated processes will ensure that development can take place more quickly. However, the provision of environmental information at the earliest opportunity to inform route planning will also assist with identifying environmentally acceptable routes which should enable developers of gas pipeline infrastructure to make upfront strategic investment in these areas in advance of formal environmental approval. Also official adoption of the Gas Pipeline Corridors should assist developers with motivating for the necessary funding to enable gas pipeline expansion in the Gas Pipeline Corridors as well as serve as a commitment to industry that investment in pipeline development will be undertaken in these areas.

1.4 Legal Framework

The key pieces of legislation that enable the identification and implementation of Gas Pipeline Corridors are summarised below. Key legislation is also described in the Specialist Studies in Part 3 of this SEA Report.

1.4.1 National Environmental Management Act (NEMA) (Act Number 107 of 1998, as amended)

NEMA provides for co-operative environmental governance by establishing principles for decision-making on matters affecting the environment, institutions that will promote cooperative governance, and procedures for coordinating environmental functions exercised by organs of state.

The SEA is undertaken under in terms of Section 24(2) of NEMA which allows for the identification of geographical areas (e.g. Gas Pipeline Corridors) based on environmental attributes, and specified in a spatial development tool adopted in the prescribed manner by the Competent Authority, in which specified activities may not commence without environmental authorisation from the Competent Authority. Specifically, Section 24(2)(d) of the NEMA allows the Minister to exclude an activity from the requirements to obtain and environmental authorisation from the Competent Authority, but that must comply with prescribed norms or standards. Section 24 (10)(a)(i)(aa) – (ee) of the NEMA allows the Minister to develop or adopt norms or standards for a listed or specified activity, any part of a listed or specified activity, any sector, any geographical area or any combination of activity, sector, geographical area, listed activity or specified activity. One of the outcomes of the SEA Process is to develop Norms or Standards to ensure that gas pipeline infrastructure constructed within the corridors are managed through this norm or standard and excluded from the requirement to obtain an environmental authorisation.

In addition, sensitivity maps prepared as part of the SEA Process give effect to Section 24(3) of NEMA that allows for the compilation of information and maps that specify the attributes of the environment that need to be taken into consideration by all Competent Authorities. The assessment requirements in the form of Development Protocols prepared through the SEA process further give effect to Section 24(5) of NEMA which allows for the laying down of procedures to be followed in respect of application for environmental authorisation and decision making as well as any matter necessary for dealing with and evaluating applications for environmental authorisation.

1.4.2 Infrastructure Development Act (Act Number 23 of 2014)

This act provides for the facilitation and co-ordination of public infrastructure development which is of significant economic or social importance to the country. It ensures that infrastructure development in the country is given priority in planning, approval and implementation. It furthermore ensures that the development goals of the state are promoted through infrastructure development and improves the management of such infrastructure during all life-cycle phases.

1.4.3 Spatial Planning and Land Use Management Act (SPLUMA), (Act Number 16 of 2013)

SPLUMA as a framework act for all spatial planning and land use management legislation in South Africa seeks to promote consistency and uniformity in procedures and decision-making in this field. The other objectives of the act include addressing historical spatial imbalances and the integration of the principles of sustainable development into land use planning, regulatory tools and legislative instruments. Chapter 8 of the 2014 draft SPLUMA regulations prescribes the institutional, spatial planning, and land use management requirements for municipalities in whose jurisdiction a SIP has been designated.

1.4.4 Gas Act (Act Number 48 of 2001)

The inclusion of Natural Gas into South Africa's energy supply is considered important in terms of fulfilling one of the objectives of the White Paper of Energy Policy. The DoE formulated the Gas Act (Act Number 48 of 2001), which aims to promote the orderly development of the piped gas industry; to establish a national regulatory framework; to establish a National Gas Regulator as the custodian and enforcer of the national regulatory framework; and to provide for matters connected therewith. Section 36 of the Gas Act deals with and specifies the provisions of the Mozambique Gas Pipeline Agreement.

In line with the above, the National Energy Regulator (NERSA) is a regulatory authority established as a juristic person in terms of Section 3 of the National Energy Regulator Act, 2004 (Act Number 40 of 2004). NERSA's mandate is to regulate the electricity, piped-gas and petroleum pipelines industries in terms of the Electricity Regulation Act, 2006 (Act No. 4 of 2006), Gas Act, 2001 (Act No. 48 of 2001) and Petroleum Pipelines Act, 2003 (Act No. 60 of 2003).

Subsequent to the establishment of NERSA, the Piped Gas Regulations were promulgated in Government Notice 321 on 20 April 2007 in order to promote the orderly development of the piped gas industry.

Pipeline Operators of the Phased Gas Pipeline Network will need to comply with the requirements of NERSA and the DoE in terms of the Gas Act.

1.4.5 Gas Regulator Levies Act (Act 75 of 2002)

The Gas Regulator Levies Act was formulated with the overall objective to provide for the imposition of levies by the National Gas Regulator; and to provide for matters connected therewith.

1.5 Process Overview

The process followed to identify and assess the Gas Pipeline Corridors is briefly summarised below and discussed in detail in Part 2 of this SEA Report. Figure 9 illustrates the SEA Process and Figure 10 illustrates the process of the SEA since inception until the project specific Environmental Authorisation process.

1.5.1 Context

The SEA Process aims to add spatial context to national level policies, plans and programmes. The SEA will allow for proactive investment as well as faster and more coordinated permitting procedures. This will ensure that priority gas transmission pipeline projects are implemented more effectively, *whilst maintaining the highest level of environmental assessment and protection*. *It should be noted that the SEA Process is undertaken at a strategic level and cannot replace the requirements for project level environmental assessment.* The high level environmental, social and economic data utilised to identify the 100 km wide corridors and undertake environmental pre-assessment of the corridors, is not sufficient for project-level decision making. The SEA should therefore be considered as a scoping level exercise used to identify key potential impacts. Additional assessment will be necessary at a project level, together with effective public participation, to determine the significance of impacts and inform environmental authorisation. These requirements will be stipulated in the Decision-Making Tools.

As illustrated in Figure 9, the SEA Process consists of the following three phases:

- Phase 1: Inception;
- Phase 2: Assessment of the Corridors; and
- Phase 3: Gazetting and Decision- Making Framework.

1.5.2 Phase 1: Inception

The SEA Process began in April 2017 and a project specific website (https://gasnetwork.csir.co.za) and email address (gasnetwork@csir.co.za) were created to ensure that stakeholders are able to access project specific information and download reports available for comments. An Expert Reference Group (ERG) and Project Steering Committee (PSC) were also convened during the Inception Phase, with assistance from the DEA.

The PSC comprises authorities with a legislated decision-making mandate for gas pipeline development in South Africa. The ERG consists of, but is not limited to, all PSC members, as well as representatives from environmental and conservation bodies, Non-Government Organizations, research institutions and industry. The ERG provides assistance and technical knowledge, as well as insights with respect to the issues relevant to specific sectors.

1.5.3 Phase 2: Assessment of the Corridors

Phase 2 consists of the following four tasks:

- Task 1: Confirmation of Preliminary Corridors;
- Task 2: Negative Mapping (Sensitivities and Constraints);
- Task 3: Corridor Refinement; and
- Task 4: Environmental Assessment.

1.5.3.1 Task 1: Confirmation of Preliminary Corridors

A set of 100 km wide preliminary corridors was identified based on the Phased Gas Pipeline Network proposed in initiative A1 of the Offshore Oil and Gas Exploration component of Operation Phakisa's Ocean Lab (held from July to August 2014). This was the starting point of the SEA. Shortly after the initiation of the A1 Workgroup, iGas, Transnet and Eskom were requested to ensure strategic alignment of the Phased Gas Pipeline Network, and prioritisation of the phases. This resulted in a strategic alignment and re-numbering of the phases. This alignment takes into consideration the current opportunities to supply indigenous gas to existing power plants (Ankerlig and Gourikwa Power Stations), the prospects for greenfield power plants in Saldanha, Richards Bay and Coega, as well as other developments outside of Operation Phakisa, i.e. the 2015 Electricity War Room; imported Liquefied Natural Gas (LNG); Karoo Shale Gas; and Eskom's targets for the Gasnosu (Mozambique North-South) pipeline in Mozambique. An inland corridor was also required to assess the possibility of routing the pipeline away from intensive land use areas between Saldanha and Coega. The corridors are illustrated in Figure 8 and are titled as follows:

- Phase 1: Saldanha to Ankerlig and Mossel Bay;
- Phase 2: Mossel Bay to Coega;
- Phase 3: Richards Bay to Secunda;
- Phase 4: Mozambique Southern Border to Richards Bay;
- Phase 5: Abraham Villiersbaai to Saldanha and Ankerlig;
- Phase 6: Abraham Villiersbaai to Oranjemund;
- Phase 7: Coega to Richards Bay;
- Shale Gas Corridor;
- Rompco Corridor; and
- Inland Corridor from Saldanha to Coega with a link to Mossel Bay.

It must be noted that the phase numbering indicated above does not necessarily indicate the sequence in which the phases will be constructed. Instead, each phase will be developed based on its own viable business case.

A series of focus group and sector specific meetings and workshops with key authorities and stakeholders were held during Phase 2 in order to gather information from major gas users, and important business and government stakeholders, to confirm the location of the Preliminary Corridors. In this regard, the first Authority and Public outreach was undertaken in November 2017 at strategic locations across the country, i.e. Cape Town, George, East London, Durban, Johannesburg and Springbok. A second Authority Public Outreach was undertaken towards the end of Phase 2, in October 2018, to present the findings of the specialist studies and draft refined corridors. The same locations visited during Round 1 of the outreach were visited during Round 2, with Upington and Port Elizabeth added as additional locations.

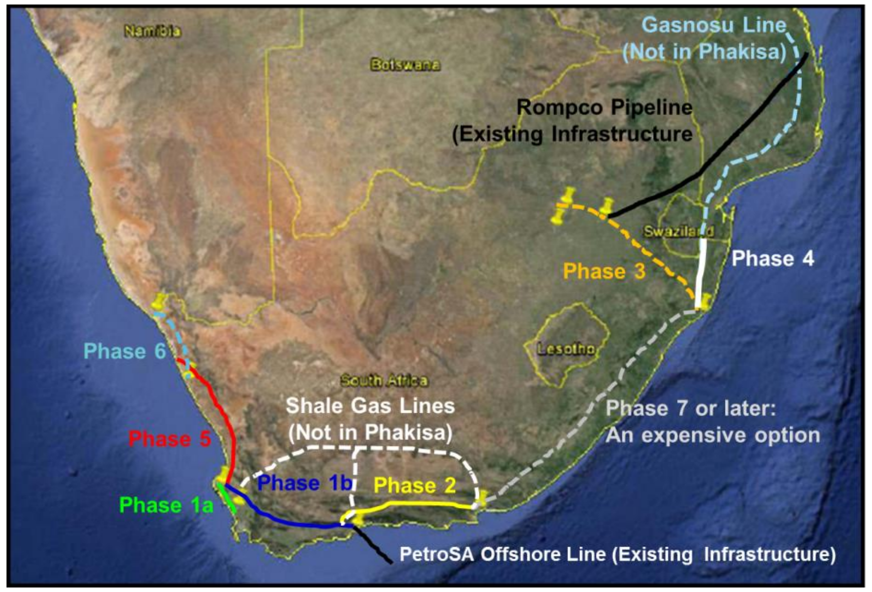


Figure 8: Proposed Phased Gas Pipeline Network for South Africa (Operation Phakisa Offshore Oil and Gas Lab, 2014)

1.5.3.2 Task 2: Negative Mapping (Sensitivities and Constraints)

Task 2 involved identifying key environmental sensitivities and engineering constraints in terms of gas pipeline infrastructure development. Environmental sensitivities in the context of this process were regarded as environmentally sensitive features which may be negatively impacted by gas pipeline development, such as Protected Areas, known bird habitats or wetlands. Engineering constraints are environmental features which are likely to impact upon the development of gas pipeline infrastructure. These are features which developers preferably avoid when planning a gas pipeline development due to the increased cost of constructing and or maintaining the infrastructure in these areas, such as, but not limited to, steep slopes, geology, and commercial forestry areas. Engineering constraints also include proximity to other linear infrastructure such as high voltage power lines and railway lines that present corrosion problems for the pipelines if they run parallel to this infrastructure for extended distances.

Dedicated national scale, wall to wall environmental sensitivity and engineering constraints maps were developed, highlighting areas of sensitivity and constraints across four tiers (Very High, High, Medium and Low).

1.5.3.3 Task 3: Corridor Refinement

Task 3 (i.e. Corridor Refinement) involved aggregating the spatial information captured in Tasks 1 and 2 to determine optimal placement of the corridors from both an 'opportunities' and 'constraints' perspective i.e. where opportunities are maximized whilst ensuring suitable transmission routing alternatives are available from a constraints and sensitivities (both environmental and engineering) perspective. The objective of this task was to determine whether any pinch points, significantly constrained areas, exist at any position within the corridors.

In the event of a complete or partial pinch point, the area outside and immediately adjacent to that point in the corridor was considered from an environmental sensitivity and engineering constraints perspective. Where relief (less sensitive area) was shown to be present, and without compromising the intersection of the corridors with the key anchor points, the corridor boundary was shifted in the direction of relief. Where no obvious relief was shown to be present, the position of the corridor remained unchanged. The output from this process was a set of refined corridor positions i.e. Draft Refined Corridors, which represents areas of highest anticipated demand for gas pipeline infrastructure without compromising on the environment.

The national, wall to wall, environmental sensitivities and engineering constraints maps from Task 2 were then reduced to the extent of the Draft Refined Corridors to produce a draft environmental and engineering constraints map. This map was carried through to Task 4.

1.5.3.4 Task 4: Environmental Assessment

Task 4 of Phase 2 included Specialist Studies, which involved scoping level pre-assessments and sensitivity mapping. Specialists were required to review, validate and enhance the draft environmental constraints/sensitivities map for a range of environmental aspects (as specified below). The spatial sensitivity of further aspects including defence, agricultural capability and the Square Kilometer Array (SKA) were determined in consultation with the relevant authorities. Sensitivity maps were produced for all the specialist studies.

The following specialist studies have been commissioned as part of the SEA:

- Biodiversity and Ecology (Terrestrial and Aquatic Ecosystems, and Species, including Bats and Avifauna);
- Impacts of seismicity; and
- Settlement Planning, Disaster Management and related Social Impacts.

Feedback is also provided on the impact of the gas pipeline on Agriculture, Defence, Civil Aviation and Heritage.

The Specialist Assessment Studies are currently being released to stakeholders for a 30-day comment period via the project website. Following this review period, based on the inputs from specialists and stakeholder, the draft refined corridors will be adjusted and finalised for consideration by Cabinet.

1.5.4 Phase 3: Gazetting and Decision- Making Framework

Phase 3 will translate the outputs from Phase 2 into environmental management measures and planning interventions for inclusion in the relevant legal environmental framework and local government planning tools, including Municipal Spatial Development Frameworks, to ensure that long term energy planning is considered within these plans.

The outputs of the SEA (i.e. final corridors, final corridor environmental constraints/sensitivities map, EMPr, Standards and/or Minimum Information Requirements and Development Protocols) will be released for public comment through publication in the Government Gazette. The gazetting process is envisaged to take place in the first quarter of 2020.

1.6 Procedure of Environmental Assessment within the Gas Pipeline Corridors: Objectives and Vision

One of the key points that the DEA has realised over time is that unless developers plan with the environment in mind, it is not really considered as a priority. *This SEA is ensuring that the environment is brought to the forefront as a priority in planning*. Once gas finds materialise, there will be a demand for such linear infrastructure being assessed as part of this SEA. One of the outcomes of this SEA is therefore to ensure that environmental approvals for such infrastructure within the corridors are not a cause for delay towards development, whilst still maintaining and ensuring the highest levels of environmental rigour.

To ensure that gas pipeline development within the corridors are not a cause for delay, the DEA is proposing that such development is either 1) exempt from the need to obtain Environmental Authorisation in terms of the NEMA; or 2) is subjected to a streamlined Environmental Authorisation process. These approaches are being discussed with various SEA Project Team members, Authorities and key Stakeholders, and only one of these approaches may be recommended and put forward at the end of this SEA Process. In the first option, complete exemption from the Environmental Authorisation process can only be achieved if there is compliance with prescribed Norms or Standards. These will, as a fundamental minimum, request for a level of site verification and site Environmental Assessment to be conducted. The second option of streamlining the Environmental Authorisation process could be achieved through the adherence to Minimum Information Requirements, which will revert to the 2014 EIA Regulations (as amended), with additional detail in terms of providing a clear and structured process for environmental monitoring, assessment and decision-making related to gas pipeline development.

It however remains critical to ensure that any environmental management instrument, Norm, Standard, Minimum Information Requirement or EMPr developed as part of this SEA process is comprehensive and environmentally rigorous, whilst still maintaining practicality and feasibility.

One of the objectives of this SEA process is also to enable the developers the flexibility to consider a range of route alternatives within the pre-assessed corridors to avoid land negotiation issues and to submit a pre-negotiated route to the department. This has currently been achieved for the development of EGI within any of the five Strategic Transmission Corridors gazetted in February 2018 (GN 113 in Government Gazette 41445), for which (a) a pre-negotiated route can be submitted to the department, and (b) a Basic Assessment procedure needs to be followed in compliance with the 2014 EIA Regulations (as amended) instead of a full Scoping and EIA Process previously triggered by such activities. This new streamlined environmental assessment process also includes a reduced decision-making timeframe for the Competent Authority (i.e. 57 days as opposed to 107 days). Several factors served as motivation for the abovementioned streamlining of the Environmental Assessment Process, including the fact that the development of linear EGI is a well-known type of development, and the DEA has previously considered and issued Environmental Authorisations for numerous applications in this regard. Therefore, the type of issues and impacts linked to a proposed EGI development is well understood and would apply across many EGI development applications.

Given the similarities between these two linear type developments (i.e. EGI and Gas Transmission pipelines); a similar streamlined Environmental Assessment approach is sought for the development of gas transmission pipeline within pre-assessed corridors.

Feedback on the above suggested approach for the development of gas transmission pipelines within the proposed energy corridors is sought from the stakeholders, and a final informed decision will be taken as to whether the exemption from Environmental Authorisation with compliance with the EMPr and Standards, or Minimum Information Requirements will be adopted.

1.7 SEA Report Structure

The Final SEA Report will comprise of six parts. Parts 1 to Part 4 describe the approach and outputs of the Phased Gas Pipeline SEA Process. Part 5 of the report describes the process for utilising the SEA outputs to plan strategically including the role of key stakeholders (developers, Environmental Assessment Practitioners, Competent Authorities, and Commenting Authorities) in the context of the proposed streamlined Environmental Authorisation Process or exemption thereof. Part 6 introduces a generic gas pipeline EMPr for standardising the management and mitigation of potential impacts as a result of gas pipeline construction. Figure 11 illustrates the structure of the SEA Report.

It is important to reiterate that the SEA Process has not been completed yet, Task 4 of Phase 2 (refer to Section 1.5.3.4) still needs to be finalised following the stakeholder review process.

As such, the following documents are currently available for stakeholder information and in support of the Specialist Assessment Reports:

- Part 1: Background to the Phased Gas Pipeline Network SEA (i.e. this chapter); and
- Part 2: Identification of the Gas Pipeline Corridors.

The following Specialist Studies released for stakeholder review are included in Part 3: Specialist Assessment and Additional Impacts:

- Integrated Biodiversity and Ecology (Terrestrial and Aquatic Ecosystems, and Species) Assessment Report (including annexures of individual chapters);
- Seismicity Assessment Report;
- Settlement Planning, Disaster Management and related Social Impacts Report;
- Additional Issues (Agriculture, Defence, Civil Aviation and Heritage);
- Appendix A: Specialist and Author Team Declarations of Interest; and
- Appendix B: Peer Review Sheets and Specialists Responses.

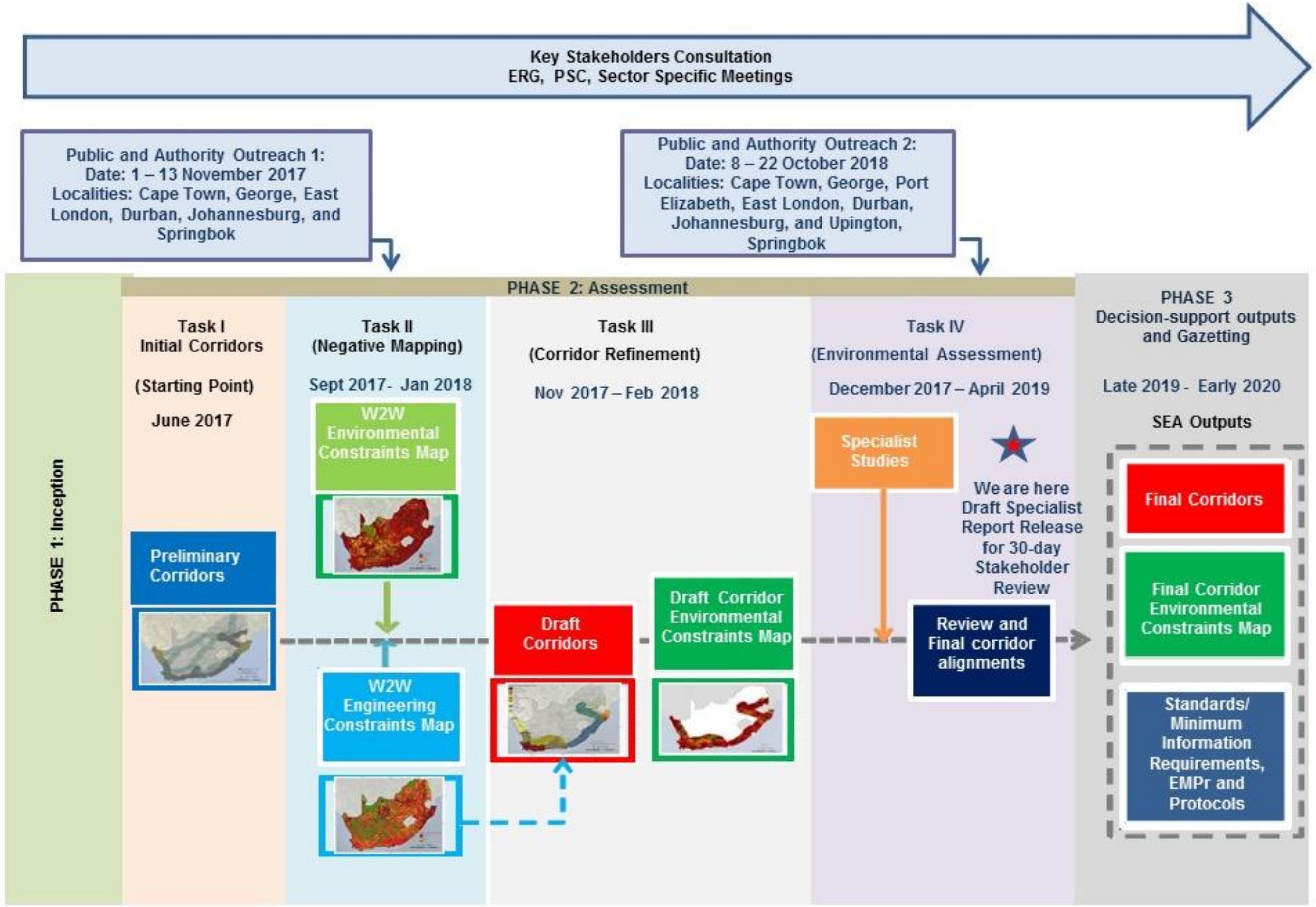


Figure 9: Phased Gas Pipeline SEA Process

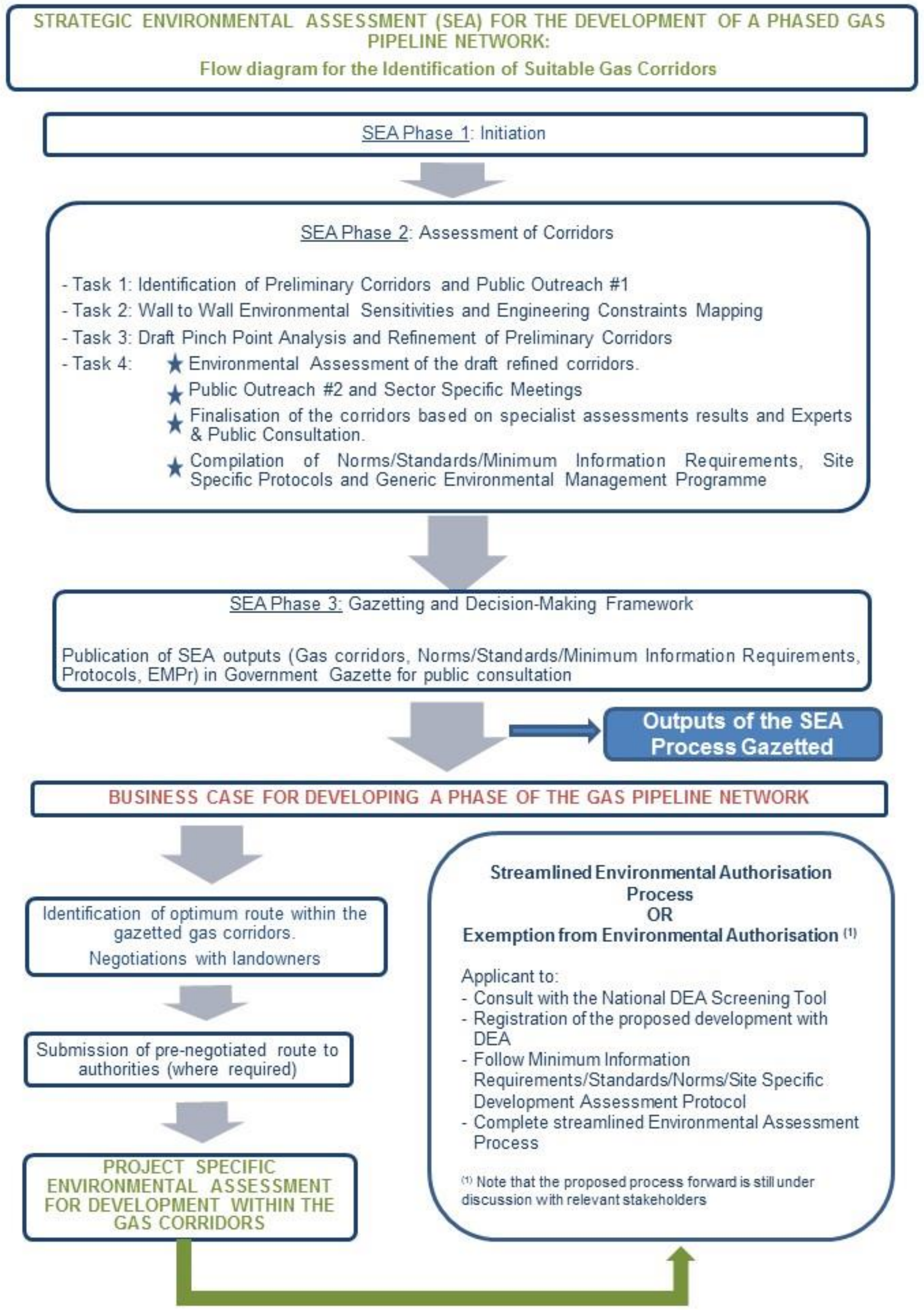


Figure 10: Phased Gas Pipeline SEA Process from Initiation to Project Specific Environmental Authorisation Process

STRATEGIC ENVIRONMENTAL ASSESSMENT (SEA) FOR THE PHASED GAS PIPELINE NETWORK

PART 1	PART 2	PART 3	PART 4 *(TO BE COMPLETED FOLLOWING STAKEHOLDER REVIEW)*	PART 5 *(TO BE COMPLETED FOLLOWING STAKEHOLDER REVIEW)*	PART 6 *(TO BE COMPLETED FOLLOWING STAKEHOLDER REVIEW)*
SEA DEVELOPMENT				**SEA IMPLEMENTATION**	
BACKGROUND	**IDENTIFICATION OF GAS PIPELINE CORRIDORS**	**SPECIALIST ASSESSMENTS AND ADDITIONAL ISSUES**	**GAS PIPELINE CORRIDORS**	**APPLICATION PROCESS INSIDE GAS PIPELINE CORRIDORS**	**ENVIRONMENTAL MANAGEMENT PROGRAMME FOR CONSTRUCTION**
- SEA Rationale - Objectives of the SEA - Legal Framework - Process Overview	- Operation Phakisa Draft Initial Phased Gas Pipeline Network and Corridors - Constraints and Sensitivity Mapping - Corridor Refinement - Gas Pipeline Corridors - Consultation Process	- Specialist Studies - Additional Issues (Agriculture, Defence, Civil Aviation and Heritage) - Sensitivity Maps	- Final Pinch Point Analysis - Final Gas Corridors - Publication of SEA Outputs (i.e. Final Corridors, EMPr, Standards/ Minimum Information Requirements)	- Screening - Specialist inputs - Streamlined Environmental Assessment Process (e.g. Minimum Information Requirements) - Post-Authorisation - Standards/ Protocols	- Specialist site walk through - Final line profile - Update construction EMPR - Implement

Figure 11: Phased Gas Pipeline SEA Report Structure

APPENDIX 1: GAS OPPORTUNITIES ANALYSIS

Contributing Authors	Rae Wolpe (Impact Economix)

Date: 24 September 2018

CONTENTS

List of acronyms, abbreviations and units

CHEVREF	Chevron South Africa (Pty) Ltd
dti	Department of Trade and Industry
CCGT	Combined Cycle Gas Turbines
CNG	Compressed Natural Gas
DoE	Department of Energy
ECA	Emission Control Area
EIA	Environmental Impact Assessment
ENREF	Engen Petroleum Ltd
FSRU	Floating storage regasification unit
GHG	Greenhouse Gas
GJ	Gigajoule
GTLR	Gas-to-liquids refinery
GUMP	Gas Utilisation Master Plan
IDZ	Industrial Development Zone
IMF	International Monetary Fund
IPP	Independent Power Producer
IRP	Integrated Resource Plan
KZN	KwaZulu-Natal
LNG	Liquefied Natural Gas
LPG	Liquid Petroleum Gas
MBTU	Million British thermal units
MRG	Methane Rich Gas
MW	Megawatts
MWe	Megawatt electric
MWh	Megawatt hour
MYPD	Multi-year price determination
NERSA	National Energy Regulator of South Africa
OCGT	Open Cycle Gas Turbine
PJ	Petajoule
PetroSA	The Petroleum Oil and Gas Corporation of South Africa (Pty) Ltd
PIM	Project Information Memorandum
PPA	Power Purchase Agreement
PV	Photovoltaic
REIPPPP	Renewable Energy Independent Power Producers Procurement Programme
ROMPCO	Republic of Mozambique Pipeline Company
SAPREF	South African Petroleum Refineries (Pty) Ltd
SEA	Strategic Environmental Assessment
Tcf	Trillion cubic feet
TNPA	Transnet National Ports Authority
USD	United States Dollars
ZAR	South African Rand

1 Introduction

The purpose of this Gas Corridor: Strategic Environmental Assessment (SEA): Economic assessment is to identify opportunities regarding potential bulk users of gas in South Africa and identify potential benefits that could be realised to South Africa as a result of selected bulk users making greater use of gas in the future. The information contained in this report is gleaned from publicly available reports as well as from a set of interviews conducted with selected role-players (see Annexure C).

This economic assessment is not an economic impact assessment. Instead, it identifies potential future opportunities and benefits based on a rapid review of the gas sector opportunities in South Africa and in selected corridor geographic case studies focusing on potential gas bulk users in South Africa. The scope of this assessment therefore also excludes any benefits which may accrue from offshore exploration activities (even though offshore exploration and production is required to service bulk users in South Africa).

This introductory background section comprises the following sub-sections which provide an important backdrop to identifying and analysing potential gas demand opportunities in the various gas corridors:

- 3.1: Selected international developments regarding the energy sector.
- 3.2: Selected aspects of South Africa's current energy context relevant to future energy demand and sources.
- 3.3: Overview of sectors where opportunities for growing gas demand exist in South Africa.
- 3.4: Discussion of potential benefits (and linked issues) and impacts of growing gas demand in South Africa.

The principal determinants of energy demand growth are energy policies, rates at which economic activity and population grow, relative energy source prices (and technological developments which impact on the relative costs of exploration, production and distribution) and technology innovations which can have a downward impact on energy prices- amongst other impacts.

The identification of potential bulk gas users in South Africa is a complex and ever-evolving challenge for a number of reasons. These reasons include, but are not limited to, the following:

- Technology changes are constantly impacting on the relative costs and attractiveness (for users switching between energy sources) of different energy sources in many ways. For example, the costs of solar power are projected to continue declining. Oil and gas offshore exploration companies are constantly improving efficiencies to reduce exploration costs. Energy storage costs are declining as battery technologies continue to improve (International Renewable Energy Agency, 2017).
- Global economic growth prospects and the demand for petroleum products (and the price of oil and diesel) are constantly evolving.
- There are difficulties in quantifying all relevant cost factors in determining future gas prices. These cost factors include: technology upgrades to facilitate switching by existing users; transportation costs; costs of distribution and other infrastructure (e.g. storage infrastructure). In addition, the economics (and therefore the gas cost and potential demand and feasibility) of servicing bulk users in a particular region are impacted on by economies of scale which can be achieved by sharing road tanker transport costs if multiple customers are serviced in a region (as opposed to only one large industrial bulk user for example).
- There are cultural or behavioural factors which impact on the likelihood of users switching energy sources (e.g. in the transport and residential sectors).
- The extent of future constraints on carbon emissions is not yet clear. These constraints will impact on future energy source choices.

Because of these and other factors, identifying potential bulk user demand for gas in South Africa has proved challenging. According to the Department of Trade and Industry (dti), even large energy sector multi-national companies such as Shell have found it challenging to model market demand for gas based on different price points (key informant interview). A dti official interviewed for this report and involved in efforts to support the South African oil and gas sector believes that only once gas supply can be made available, demand will begin to emerge and evolve. At the same time, dti studies on demand in Kwazulu-Natal (KZN) and Richards Bay have found that industries have expressed an interest in switching to gas at a price of $8/Million British thermal units (MBTU) but that 60% of this demand falls away at a price of $10/MBTU. Demand for gas is therefore highly price-elastic.

For the above reasons, energy and electricity demand forecasters cannot formulate accurate future demand predictions with a high degree of accuracy beyond the short term (1-5 years). Some commentators have stated that there needs to be a shift in focus to smaller and flexible generation plants, with well-known and declining deployment costs, that can be constructed faster – like solar Photovoltaic (PV) and wind power in combination with mid-merit Combined Cycle Gas Turbines (CCGT) (a highly efficient energy generation technology that combines a gas-fired turbine with a steam turbine) and Open Cycle Gas Turbine (OCGT) (a combustion turbine plant fired by gas or liquid fuel (diesel) to turn a generator rotor that produces electricity) plants, pumped storage and other emerging energy storage options for peaking capacity.

2 Scope of this Study

The Terms of Reference for this study include:

- Undertake research in order to identify where the current or most likely bulk users are located (such as (but not limited to) the major ports, Ankerlig and other gas turbine power stations, Coega Industrial Development Zone (IDZ) and other relevant IDZs, mines in Gauteng, potentially Eskom Power Stations that can be converted to gas), as this will inform the need for gas and potential connecting points for "smaller users" (currently not identified).
- Identify the potential benefits that could be achieved should gas be available to the selected bulk users.
- Undertake an opportunities analysis and determine the overall economic benefits (including direct and indirect benefits) of having gas in the energy mix, based on case studies.

<u>Limitations</u>

This economic assessment is a high level assessment, mainly focusing on the review of existing research and limited interviews with key stakeholders in the gas market in South Africa. In addition, numerous market demand research and feasibility reports are confidential in nature and could not be considered as part of the assessment. This study cannot therefore be regarded as a comprehensive assessment of economic opportunities.

This economic assessment is not an economic impact study. Such a study would require a detailed South African market demand analysis and this is beyond the scope of this SEA. This assessment also does not identify any benefits which may accrue from offshore exploration activities (even though offshore exploration and production is required to service bulk users in South Africa) (over and above providing high-level job creation figures which operation Phakisa has identified for the overall Ocean Economy in South Africa). Finally, this assessment does not examine opportunities and benefits in the residential sector as this requires detailed energy system modelling to identify knock-on effects on the entire energy system.

3 Current energy trends

3.1 Selected international energy market developments

Globally, the International Energy Agency's World Energy Outlook for 2017, notes that "…significant market imbalances that are likely to maintain downward pressure on prices for some time to come: this is the case not only for oil and gas, but also for some other parts of the energy sector such as solar PV panels. They also show an energy system that is changing at considerable speed, with the dramatic falls in the costs of key renewable technologies upending traditional assumptions on relative costs" (International Energy Agency, 2018).

Gas is abundantly available in world markets and trading at prices lower than $10/MBTU. In 2016 and 2017, coal traded at $ 2.11 and $ 2.08 MBTU and natural gas at $ 2.87 and $ 3.39 MBTU respectively[13], making it competitive with coal for electricity generation. Given the competitive pricing, gas has replaced coal as the biggest producer of electricity in the USA in April 2015. Natural gas is a source of carbon for fuel, petro-chemicals and agriculture, and produces electricity with 50-60% less CO_2 emissions than coal (Liang et. al. 2012; National Energy Technology Laboratory, 2010; Salovaaraa. 2011; U.S. Energy Information Administration accessed September 2018 at https://www.eia.gov/tools/faqs/faq.php?id=73&t=11).

Global scenarios for 2025 and 2040 for fossil fuel import prices have been developed by the International Energy Agency and show relatively modest increases in the prices of natural gas when compared to both crude oil and steam coal (Table 1).

Table 1. Global scenarios for fossil fuel import prices for years 2025, 2030, 2035 and 2040 (International Energy Agency, 2018)

				New Policies				Current Policies		Sustainable Development	
Real terms ($2016)	2000	2010	2016	2025	2030	2035	2040	2025	2040	2025	2040
IEA crude oil ($/barrel)	38	86	41	83	94	103	111	97	136	72	64
Natural gas ($/MBtu)											
United States	5.9	4.8	2.5	3.7	4.4	5.0	5.6	4.3	6.5	3.4	3.9
European Union	3.8	8.2	4.9	7.9	8.6	9.1	9.6	8.2	10.5	7.0	7.9
China	3.5	7.4	5.8	9.4	9.7	10.0	10.2	10.4	11.1	8.2	8.5
Japan	6.4	12.1	7.0	10.3	10.5	10.6	10.6	10.8	11.5	8.6	9.0
Steam coal ($/tonne)											
United States	37	63	49	61	61	62	62	62	67	56	55
European Union	46	101	63	77	80	81	82	81	95	67	64
Japan	44	118	72	82	85	86	87	86	101	71	68
Coastal China	34	127	80	87	89	90	91	90	101	78	77

Notes: MBtu = million British thermal units; LNG = liquefied natural gas. The IEA crude oil price is a weighted average import price among IEA member countries. Natural gas prices are weighted averages expressed on a gross calorific-value basis. The US gas price reflects the wholesale price prevailing on the domestic market. The EU and China gas prices reflect a balance of pipeline and LNG imports, while the Japan gas price is solely LNG imports; the LNG prices used are those at the customs border, prior to regasification. Steam coal prices are weighted averages adjusted to 6 000 kilocalories per kilogramme. The US steam coal price reflects mine-mouth prices (primarily in the Powder River Basin, Illinois Basin, Northern Appalachia and Central Appalachia markets) plus transport and handling cost. Coastal China steam coal price reflects a balance of imports and domestic sales, while the EU and Japanese steam coal price is solely for imports.

It is not clear what factors have been taken into account in the above scenarios. For example, if there is a major switch to electric vehicles in the USA and/or Europe, this may result in a major drop in demand for oil and it is unclear what impact this will have on future oil prices.

3.2 Selected aspects of South Africa's current energy context relevant to future energy demand and sources

3.2.1 Economic and population growth

The International Monetary Fund (IMF) and World Bank produced global and regional economic growth forecasts for 2016-2040 (World Bank. January 2018). These show South Africa's economy a projected growth between 2.1%- 2.9% compared to an overall global average economic growth of 3.4% over the same period (2016-2019) (see the Annexure A for detailed South African economic growth projections). In addition to the growth rate and nature of economic growth, population growth will also impact on future energy demand. South Africa's population is projected to grow from 55 million in 2016 to about 63-64 million in 2030 (a nett increase of 9 million people or 16%) (United Nations, 2017).

The senior Eskom representative interviewed for this study indicated that Eskom's projections show that there will only be a need for new generation capacity to meet peak demand around 2025/2026. However, if economic growth accelerates beyond the above projections, additional peak generation capacity may be required sooner.

3.2.2 Greenhouse Gas emissions targets

Another key factor which will impact on preferred energy sources will be global and national development regarding Greenhouse Gas (GHG) emissions targets and commitments and the scope and level of carbon pricing. This will have a major impact on the relative costs of using different fuels (International Energy Agency, 2018).

South Africa's per capita carbon emissions are relatively high (9.0 tonnes per capita p.a. in 2014 and similar to that of Germany) (World Bank, https://data.worldbank.org/indicator/EN.ATM.CO2E.PC) and there is pressure on the country to reduce this. The Paris Agreement on climate change officially comes into force in 2020. For the first time ever, almost every country has committed to cut its carbon emissions and to limit global warming to "well below" 2˚C above preindustrial levels in order to achieve a collective goal. South Africa (as part of its Nationally Determined Contribution) has pledged to follow a trajectory in which emissions will peak between 2020 and 2025, plateau for approximately a decade, and then decline (Department of Environment, 2015). The agreement sends a clear and unequivocal signal to the private sector – a global political intention to shift to a low carbon, and ultimately zero carbon, future.

National Treasury has indicated that it intends on introducing a carbon tax on 1 January 2019. Projections show this tax will add R13.7 billion to the fiscus in an effort to reduce GHG emissions. On the down side, it is possible that the increased costs to business due to this tax will be passed onto consumers.

3.2.3 Price regulation of energy sources

The relative demand for and supply of different energy sources (as well as the different market structures and ways in which various energy source prices are regulated) can impact on relative energy source prices. Unlike some other energy sources, the price of gas is not dictated by world gas prices as it is largely negotiated on a decentralised basis between suppliers and buyers. The national Energy Regulator of South Africa (NERSA) regulates the maximum price of piped gas in South Africa. The current cost of diesel and Liquid Petroleum Gas (LPG) in terms of cost per gigajoule (GJ) are approximately equal at the time of writing (January 2018).

Given that there are large sources of gas in various stages of development off of South Africa's shore, South Africa is in a good position to negotiate cost-competitive prices for gas supply. However, the 2014 Operation Phakisa report on the oil and gas sector states that a currency and commodity price risk exists for fuel in terms of Eskom's use of gas as "Eskom currently buys coal and sells electricity in ZARs. Gas prices are typically indexed against oil and priced in USD [United States Dollars]. This will require Eskom to buy fuel priced in USD and fluctuating with the price of oil but can only sell electricity in ZAR and priced in accordance with the MYPD [multi-year price determination]. This is currently too much of a risk for them" (Republic of South Africa Operation Phakisa Offshore Oil and Gas Exploration, 2014).

3.2.4 Renewable Energy

Another factor that may impact on a growing need for gas-powered electricity generation in the longer term, is the increased share of solar powered electricity in South Africa's energy mix.

The country's 2010 IRP calls for the generation capacity of 17 800 Megawatts (MW) from renewable energy sources by 2030. The Department of Energy (DoE), through the Renewable Energy Independent Power Producers Procurement Programme (REIPPPP), by the end of its Round 4 Expedited Window, will have awarded around 8000 MW of renewable energy generation capacity. In February 2018, the Minister of Public Enterprises approved 27 utility-scale renewable energy projects consisting mainly of solar PV and wind projects. The agreements were signed into effect under the Minister of Energy in

[13] Cost of coal and natural gas for electric generation in the U.S. from 1980 to 2017 (in U.S. dollars per million British thermal units) available at: https://www.statista.com/statistics/189180/natural-gas-vis-a-vis-coal-prices/

April 2018[14] and the Power Purchase Agreements became effective between April 2018 and 31 July 2018[15].

It is likely that there will be a need for new gas power stations in future due to the increased introduction of renewable energies (including solar energy) into the electricity grid and the Duck Curve (refer to Annexure B for further details on the Duck Curve). Essentially, gas powered stations may be required to meet peak demand at some time in the future (although it is difficult to predict when this need may exist in South Africa). However, other solutions to the Duck Curve include connecting multiple energy grids, battery storage power stations (the cost of which will decline as time goes on), and energy demand management interventions.

3.2.5 Allocation of gas powered generation in energy planning policies

The draft 2018 IRP (released in August 2018 by the Department of Energy for public comments) provides the following future energy mix detailed in Table 2 which includes an additional 8,100MW of energy from gas/ diesel by 2030. The 2018 IRP considered four scenarios and their impact on the future energy mix: Electricity demand scenario, a gas scenario, a renewables scenario and an emissions constrained scenario. The energy mix for 2030 sees the decommissioning of old coal power plants reaching the end of their life.

The least cost scenario shows the new capacity coming on stream from 2019 onwards as illustrated in Table 2.

The costs of new generation technologies have come down - and this has resulted in reduced costs on wind and PV (photovoltaic) projects. Government has recommended the least cost plan which favours wind, PV and gas. A total of 5,670 MW of energy will be derived from PV, 8,100 MW from wind and 8,100 MW from gas. By 2030, wind will account for 15% of installed capacity, gas 16% and PV 10%.

The Southern African Development Community (SADC) has an inter-State committee working on a gas master plan for the region to look at gas supply issues. Research indicates that the relevant Ministers signed a statement of intent regarding the gas master plan with an overall commitment to improve access to reliable and safe energy in the region, as well as to align the plan with the principles of the Energy Protocol, and the objectives of SADC Industrialization Strategy Framework[16]. From a national perspective, the Minister of Energy pointed out that it is important for South Africa's national energy plans to be reflected in the regional gas master plan[17].

The DoE's Liquefied Natural Gas (LNG) to Power Independent Power Producer (IPP) Programme aims to identify and select successful bidders and to enable them to develop, finance, construct and operate a gas-fired power generation plant at each of the two ports, Ngqura (up to 1000MW) and Richards Bay (the balance of 3000MW). The successful bidder/s will also be required to put in place the gas supply chain to fuel the plant with gas from imported LNG. The LNG to Power IPP Programme will provide the anchor gas demand on which LNG import and regasification facilities can be established at the Ports of Ngqura and Richards Bay. This will provide the basis for LNG import, storage and regasification facilities to be put in place that can be available for use by other parties for LNG import and gas utilisation development. Therefore, Third Party Access will be a fundamental aspect of the LNG to Power IPP Programme. This will enable the development of gas demand by third parties and the associated economic development (Department of Energy, Undated).

The scope of the projects for each port will include:

- LNG procurement and delivery;
- LNG storage and regasification facilities via a floating storage re-gasification unit (FSRU) or equivalent LNG regasification and storage technology (FSU plus offshore/land based regasification);
- Port infrastructure, including fixed maritime structures and modifications;
- Gas transmission pipelines to connect the FSRU (or equivalent LNG regasification and storage technology) with the new power generation facility;
- LNG and or gas distribution hub(s) for third party off take;
- Power plant, including the high voltage connection to the electrical grid; and
- Arrangements for independent delivery of LNG, and the sale of a modest percentage (5 %) of gas and LNG to external users.

Table 2 IRP 2018: Proposed Updated Plan for the Period Ending 2030 (Source: Department of Energy (2018). Draft Integrated Resource Plan 2018.)

	Coal	Nuclear	Hydro	Storage (Pumped Storage)	PV	Wind	CSP	Gas / Diesel	Other (CoGen, Biomass, Landfill)	Embedded Generation
2018	39 126	1 860	2 196	2 912	1 474	1 980	300	3 830	499	Unknown
2019	2 155					244	300			200
2020	1 433				114	300				200
2021	1 433				300	818				200
2022	711				400					200
2023	500									200
2024	500									200
2025					670	200				200
2026					1 000	1 500		2 250		200
2027					1 000	1 600		1 200		200
2028					1 000	1 600		1 800		200
2029					1 000	1 600		2 850		200
2030			2 500		1 000	1 600				200
TOTAL INSTALLED	33 847	1 860	4 696	2 912	7 958	11 442	600	11 930	499	2600
Installed Capacity Mix (%)	44.6	2.5	6.2	3.8	10.5	15.1	0.9	15.7	0.7	

Installed Capacity
Committed / Already Contracted Capacity
New Additional Capacity (IRP Update)
Embedded Generation Capacity (Generation for own use allocation)

3.2.6 Evolving technologies: gas turbines

Evolving gas turbine technologies may also impact on the potential role that gas can play in terms of power generation in South Africa. Wärtsilä, a Finnish supplier of gas engine technology has completed modelling of the South African domestic power system and has argued that flexibility should be prioritised over project-level cost optimisation, as flexible gas solutions improve system reliability and enable greater levels of renewable energy to be introduced to the grid (Creamer, 20 January 2017).

Using power system modelling software to re-create the domestic power system, the company found that gas serves two key functions: displacing expensive diesel generation; and optimising inflexible coal generation.

3.2.7 Gas supply and potential demand

Operation Phakisa provides a summary of offshore oil and gas exploration potential supply and potential demand for gas, including gas-fired power generation capacity, along South Africa's coastline illustrated in Figure 1.

[14] https://www.fin24.com/Economy/Eskom/jeff-radebe-signs-long-delayed-renewable-power-deals-20180404
[15] https://www.iol.co.za/business-report/energy/brown-gives-eskom-the-ipp-go-ahead-13104895
[16] https://www.sadc.int/news-events/news/joint-meeting-sadc-ministers-energy-and-water-held-27th-june/
[17] http://www.engineeringnews.co.za/article/south-africa-to-align-energy-plans-with-sadc-gas-master-plan-2018-06-26

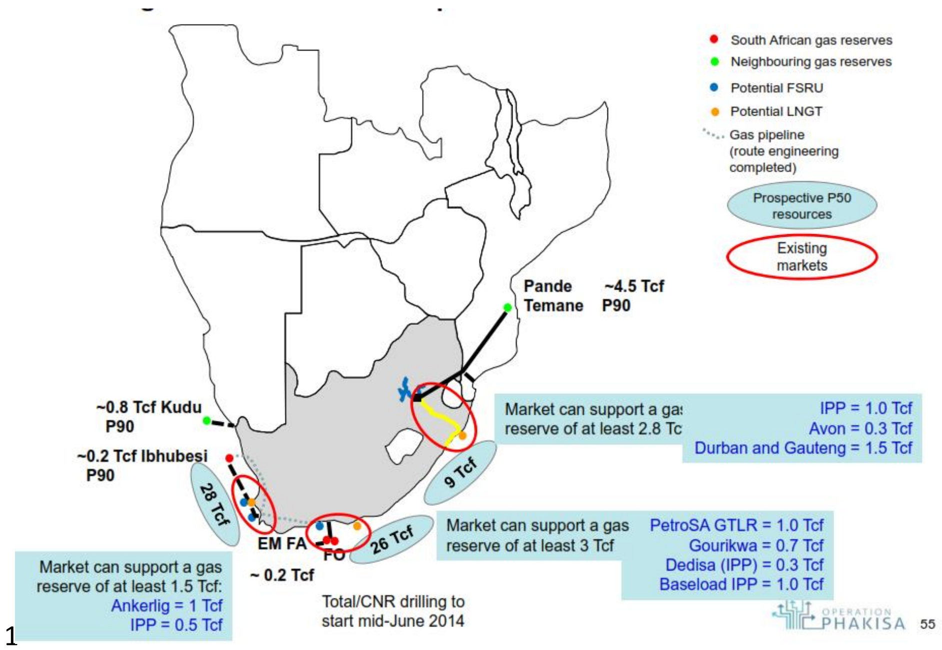


Figure 1. Offshore oil and gas exploration potential supply and potential demand for gas (including gas-fired power generation capacity) along South Africa's coastline (Operation Phakisa Offshore Oil and Gas Exploration, Republic of South Africa, 2014)

Current gas pipelines in South Africa include the 865 km Republic of Mozambique Pipeline Company (ROMPCO) Pipeline from the Pande/Temane gas fields in Mozambique to Secunda. At commissioning, these fields had a total P90 reserve (which means that there is a 90% probability that the quantities actually recovered will equal or exceed the estimated quantities) of 4.5 trillion cubic feet (Tcf). From Secunda, Sasol transmits the gas to Sasolburg and to industrial users in Gauteng. Transnet transmits methane-rich offshore gas from Sasol to Richards Bay and Durban via the Lilly Pipeline network.

South African offshore gas finds are limited to:

- PetroSA's FA and EM fields off the Mossel Bay coast (largely depleted, but with a tail that can still be utilised, provided other gas sources can be used to supplement the tail). PetroSA is also currently producing from the FO field, which has a P90 reserve estimate of 0.2 Tcf.
- Ibhubesi gas field: Sunbird Energy, the current developers plan to bring the gas to market in the Western Cape, i.e., via Eskom's Ankerlig Power Station. iGas has completed the route engineering for an onshore pipeline from the landing point (Abraham Villiersbaai) to Saldanha and Ankerlig. However, Sunbird is currently contemplating a subsea pipeline to these locations.
- The Kudu gas field in Namibia (0.80 Tcf P90), which remains unexploited. Past projects contemplated include an 800 MW power station in Namibia and a gas transmission pipeline to transmit the gas to market in the Western Cape, i.e., also via Eskom's Ankerlig Power Station.

Total is currently exploring off the Southern Coast of the country. Although the official press release from Total indicates a condensate find. A gas find in this region has significance for both the PetroSA Mossel Bay's gas-to-liquids refinery (GTLR), as well the Eskom Gourikwa OCGT; and for encouraging fast-tracked developments for the Coega Industrial Development Zone (IDZ).

According to Operation Phakisa, existing gas markets or markets that can be developed in the short term (within 5 years) include the following (Republic of South Africa, 2014):

West Coast (1.5 Tcf)

- Eskom's Ankerlig OCGT in Atlantis, fuelled by diesel, but with burners converted to use both diesel and gas and plans for the conversion of 5 units to CCGT (1 Tcf). This power station, located on the west coast of the Western Cape, is strategically placed should the opportunity to use natural gas arise in the future.
- Potential IPP in the Saldanha IDZ (0.5 Tcf).

South Coast (3.0 Tcf):

- PetroSA's GTLR in Mossel Bay (1 Tcf).
- Eskom's OCGT in Mossel Bay, currently also fuelled by diesel, but with burners converted to duel fuel (gas and diesel) and the conversion of 2 units to CCGT (0.7 Tcf).
- The Dedisa IPP OCGT peaking power plant in the Coega IDZ – currently fuelled by diesel, but that also use natural gas fuel (0.3 Tcf).
- An IPP mid-merit power station of ~2,400 MW at Coega (1 Tcf).

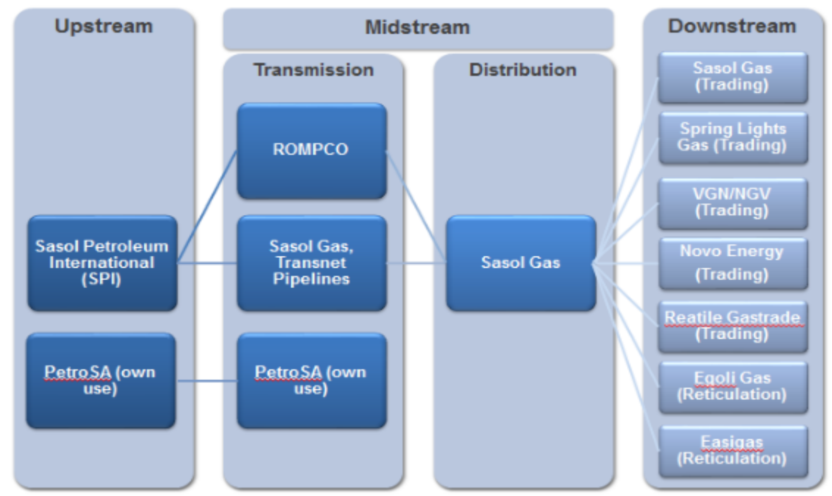
East Coast (minimum of 2.8 Tcf)

- Existing Durban, Richards Bay and Gauteng markets via reverse flow up the Lilly Pipeline or a new gas transmission pipeline to Gauteng (1.5 Tcf).
- The Avon IPP OCGT peaking power plant south of Richards Bay – currently fuelled by diesel, but which can also use gas and fuel (0.3 Tcf).
- A minimum 1,600 MW baseload IPP in Richards Bay (1 Tcf). As aging coal-fired power stations in Mpumalanga are retired, this can be increased depending on the gas availability.

P50 gas resources (which means that there is only a 50% probability that the quantities actually recovered will equal or exceed the estimated quantities) in South African waters are as follows:

- 28 Tcf off the West Coast.
- 26 Tcf off the South Coast.
- 9 Tcf off the East Coast.

Gas markets therefore exist to support exploration in South African waters. The current market structure for pipeline gas in South Africa is as follows (Figure 2):



Note: There are newly licenced operators in the market. These include Molopo which was granted operation and trading licences in the Virginia area of the Matjhabeng Local Municipality of the Free State Province; Spring Lights Gas – CNG which was granted a licence for construction and the operation of the storage facility in KwaZulu-Natal as well as a trading licence; and Columbus Stainless Steel granted a licence for the operation of the pipeline and trading licences in Mpumalanga. These licensees have not been included in the figure above as they have been licenced quite recently and have not commenced operations.

Figure 2. Current markets for pipeline gas in South Africa (Genesis Analytics, 2015)

4 Overview of sectors where opportunities for growing gas demand exist in South Africa.

The dti (2017) sees the gas economy developing in three broad phases over the next 15 years and beyond. The first phase (over the next 3-5 years) is focused on imported LNG (Figure 3). This is followed by the importation of regional gas from offshore gas reserves in Phase 2 in the next 7-15 years. Phase 3 (in about 15 years' time) sees the addition of onshore domestic gas reserves to the energy mix.

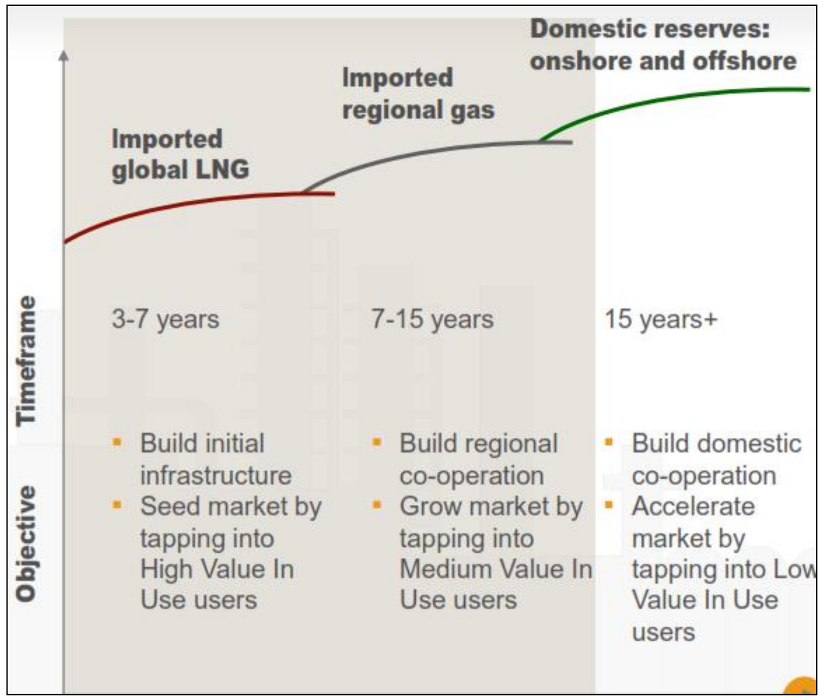


Figure 3. Gas economy developing in three broad phases over the next 15 years and beyond (dti, 2017)

This section discusses opportunities in the following sectors where potential to increase gas demand exists:

1. Electricity generation.
2. Industry and mining.
3. Transportation.

The residential sector is not discussed in any detail, however, it must be noted that potential exists to expand residential demand and that this may impact on reducing the demand for electricity as this takes place.

A critical issue impacting on the nature of future demand for gas is the price of gas and how this differs between LPG and LNG. The complexities of gas prices include the client-specific demand characteristics and requirements. While many view the price of gas as being slightly cheaper than coal (see Section 1.1), this view is not necessarily shared by all role-players in South Africa. There may therefore be value in clarifying the gas-coal price differential (based on certain scenarios and assumptions) so that transparent pricing information can be shared between energy decision-makers in South Africa. Given that the price of gas is seen as linked to the Rand/Dollar exchange rate, an exchange rate risk is also seen to exist in terms of the price of gas. Finally, there are a range of costs along the gas logistics chain (such as transportation as well as gas storage and distribution infrastructure located at the customer) which also need to be taken into account when determining final gas prices to the customer.

It would appear that there is a need for greater transparency and availability of information regarding gas prices in different demand scenarios so as to ensure that ongoing exploration of gas opportunities is informed by pricing information that is as transparent as possible.

4.1 Electricity generation

At the time of writing this report (i.e. Appendix 1 of Part 1 of the SEA Report, February 2018), the South African Department of Energy had not yet released its revised IRP. Both the National Development Plan (National Planning Commission, 2013) and the draft IRP (Department of Energy, November 2016) indicates the intention to diversify South Africa's energy production mix and introduce gas fired electricity generation into this mix. Currently, gas represents approximately 3% of South Africa's total energy mix (Department of Energy, January 2013). Figure 5 illustrates Eskom's existing power stations, including four gas turbine plants (two of which are run by IPPs).

Eskom is currently facing large-scale financial challenges, in part due to its large-scale investments in the Kusile and Medupe coal-fired power stations and in part due to lower than requested increases in electricity tariffs. Eskom's financial challenges may be exacerbated into the future given that it has signed Power Purchase Agreements (PPAs) at a cost of R2.50/kWh and it is now possible (according to one informant interviewed) to sign such PPAs at a cost of R0.44c/kWh. As the cost of solar power continues to fall, it is likely that larger numbers of businesses and residential users will switch to solar and that this will further undermine Eskom's future sales and revenue growth.

The feasibility of Eskom being able to upgrade existing gas turbine power stations to utilise gas has been called into question given the large investment amounts required for these upgrades (According to Eskom, R1.5bn is required to fully upgrade the Gourikwa and Ankerlig power stations). Eskom's recent expenditure on diesel is illustrated below with R340 million being spent in 2016/17; R638 million projected for 2017/18 and R691 million for 2018/19 (it is unclear if all or only a proportion of this expenditure is incurred for Ankerlig and Gourikwa Power Stations): Eskom has indicated that it needs gas supply agreements that are flexible and not based on bulk supply agreements.

Eskom's 2017 view of future power stations is illustrated in Figure 4.

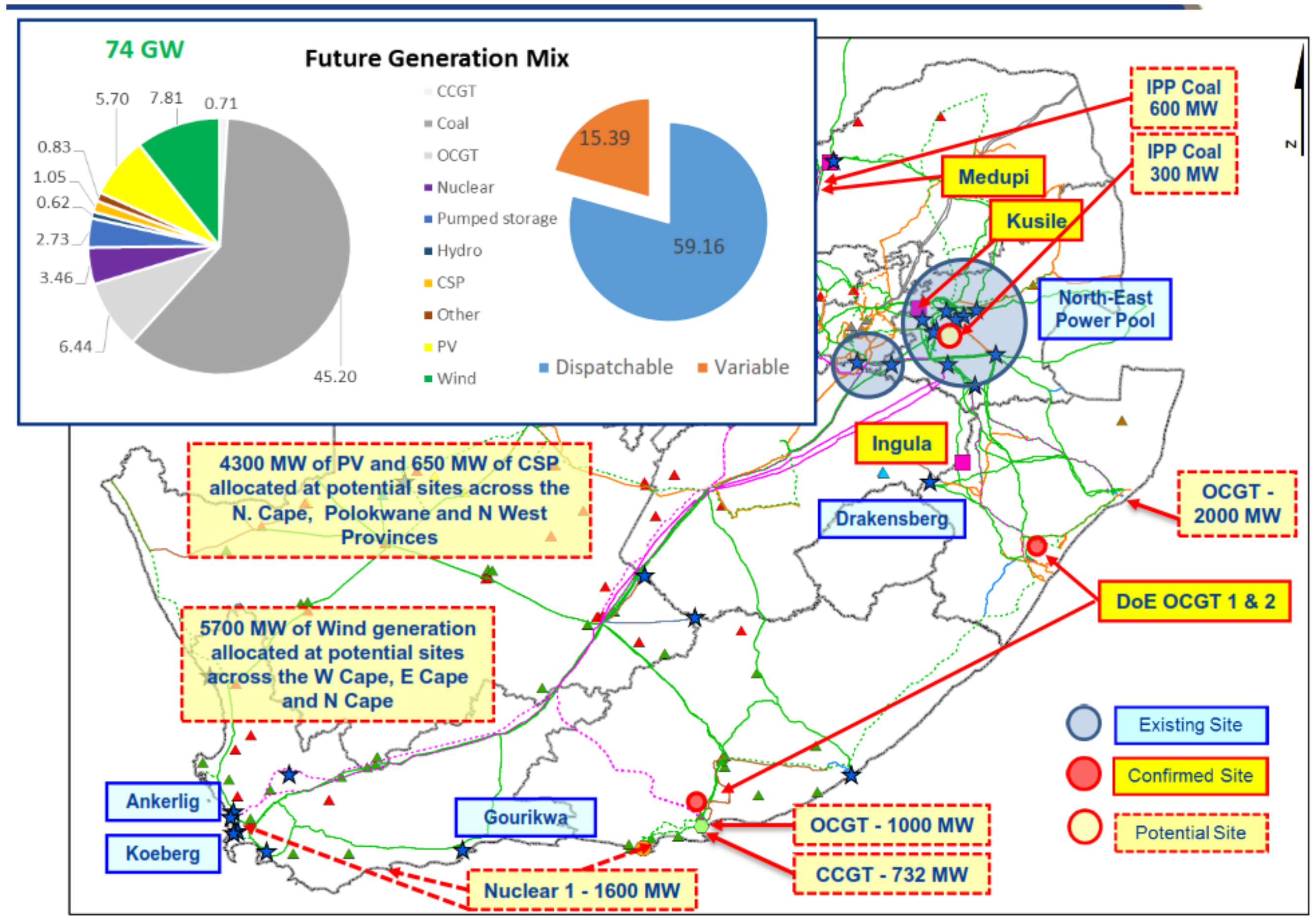


Figure 4. Eskom's 2017 view on potential future power stations. Source: Eskom (October 2017).

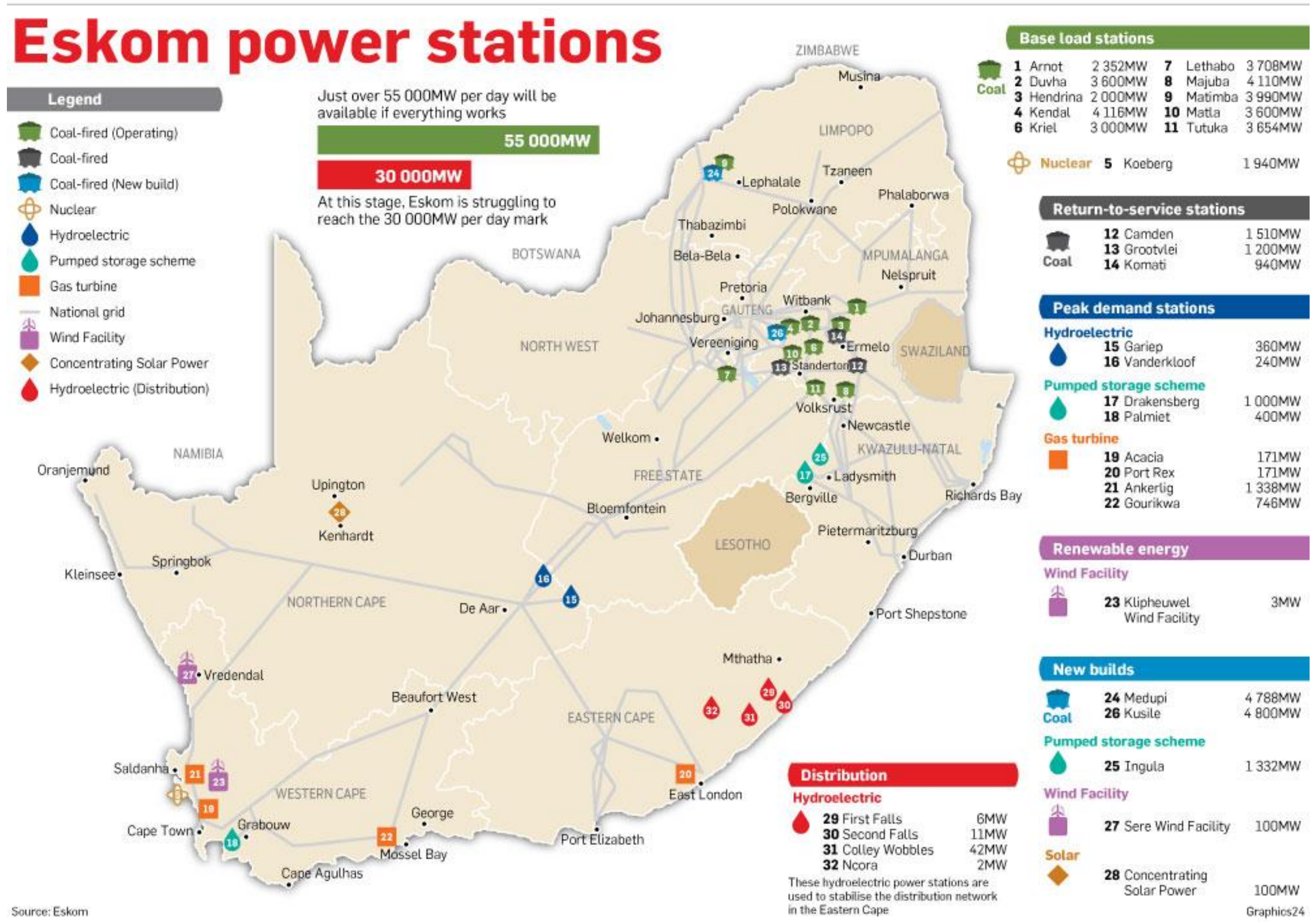


Figure 5. Eskom's current power stations: 2017. Source: Eskom (October 2017).

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Table 3. Eskom's detailed primary energy cost for 2016/17 and projected primary energy costs for 2017/18 –2018/19

	Actuals	Projections	Application
Primary energy costs R'million	2016/17	2017/18	2018/19
Coal usage	44 164	45 642	48 687
Coal obligations provisions	488		1 304
Water usage	1 751	2 185	2 310
Fuel & Water procurement service	163	211	223
Coal handling	1 758	1 874	1 974
Water treatment	423	465	490
Sorbent usage	-	36	63
Gas and oil (coal fired start-up)	2 216	2 268	2 405
Total coal	50 963	52 681	57 456
Nuclear	727	808	865
Coal and gas (Gas-fired)	10	8	9
OCGT fuel cost	340	638	691
Demand Market Participation	194	301	319
Total Eskom generation	52 234	54 436	59 340
Environmental levy	8 087	8 152	7 994
IPPs	21 720	24 450	34 209
International Purchases	2 681	3 127	3 216
Total primary energy	84 722	90 165	104 759

Source: Eskom (August 2017).

Given Eskom's financial challenges[18], it is likely that future gas powered stations may emerge from the IPP process and be driven by large energy intensive users. This will depend in part on the differences in gas and coal supply scenarios. Eskom has begun discussions with various entities to explore the possible supply of gas from Mozambique fields, but these have not yet provided an indication of possible gas supply prices.

Gas and electricity system modelling conducted by the Energy Research Centre at the University of Cape Town (Mervan et al., 2017) has shown that there is a drastic reduction in demand for gas use for power generation at a gas price point of USD$11/MBTU but that below this price point there could be a strong role for gas to play in the future power generation system).

The expansion of South Africa's gas pipeline is seen as a pre-condition for servicing and growing demand for gas in South Africa and Operation Phakisa has established a national task team to take this process forward as part of unlocking a range of opportunities in the Ocean Economy. A draft Gas Utilisation Master Plan (GUMP) was developed in 2014/15 and is reportedly in the process of being updated by the DoE (although this has not been officially confirmed at the time of writing this report in February 2018) and will provide South Africa with a long term gas plan.

This report has not assessed the scope for municipal electricity generation using gas. For example, it is known that the City of Cape Town has done studies on the feasibility of using gas for electricity generation (key informant interview). It is not clear what infrastructure investment will be required and what the City of Cape Town's future plans are in this regard. There may be opportunities for municipalities to grow their demand for gas for electricity generation, however, the scope for such demand will require further research.

4.2 Industry and Mining

Industries are attracted to switching to gas because of the possible price advantages and supply security (which is a major potential attraction since it allows the company to go off the grid). However, the conversion costs for industrial users serve as a potential constraint to switching energy sources. As a result, it is difficult to identify at what gas cost switching is an attractive option for industrial users as the conversion costs first need to be identified and built into a feasibility assessment.

A number of selected existing large industrial users are located in Gauteng, KwaZulu-Natal (KZN) and Mpumalanga (Table 4).

Table 4. Selected existing large industrial users are located in Gauteng, KZN and Mpumalanga

Company	Manufacturing Facility	Location	Province
Acerlor Mittal	ArcelorMittal South Africa Coke & Chemicals (Vanderbijlpark)	Delfos Boulevard Vanderbijlpark	Gauteng
Ceramic Industries	Gryphon Factory	Farm 2, Old Potchefstroom Road Vereeniging, 1939	Gauteng
Consol	Wadeville Factory	Consol House, Osborn Road, Pretoria, Gauteng	Gauteng
Ferro SA	Enamel Factory	12 Atomic Street, Vulcania, Brakpan	Gauteng
Nampak	Nampak Can	Du Plessis Road, Springs	Gauteng
PFG Building Glass	Head Office Springs	216 Industry Road, New Era Springs	Gauteng
SAB	SAB Chamdor	Alrode, Alberton	Gauteng
Illovo Sugar	Sezela Plant	Cnr Smuts & Mill Road, Scottburgh, Scottburgh/Umzinto North	KZN
Mondi	Mondi Merebank	Travancore Dr, Merebank East, Merebank	KZN
NCP Alcohols	Head Office Durban	121 Sea Cow Lake Rd Durban	KZN
Columbus Steel	Middelburg Mpumalanga Factory	Hendrina Rd, Middelburg, 1050	Mpumalanga

[18] According to one article, "Eskom's current debt is R350bn and it needs to raise perhaps another R150bn over the next three to four years. This is almost certainly impossible, even with a government guarantee." Source: https://www.businesslive.co.za/bd/opinion/2018-01-22-selling-assets-and-embracing-wind-and-solar-can-solve-eskom-woes/

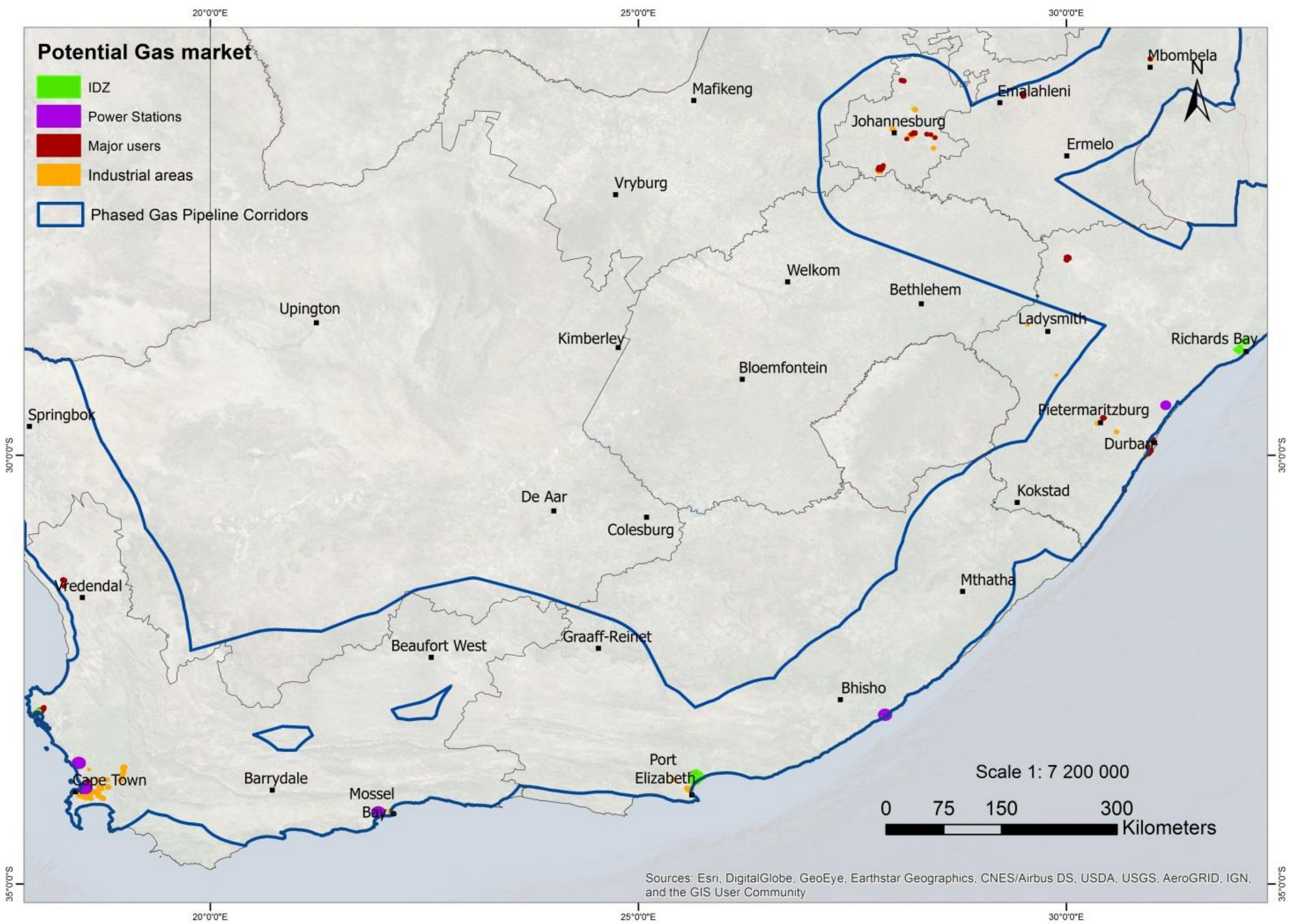


Figure 6. Existing large industrial energy users that could potentially convert to Gas (excludes Mining and Agriculture)

Potential industries also exist at the Saldanha IDZ, Coega IDZ, and Richards Bay IDZ. The 2013 Western Cape Demand assessment found that the industrial potential demand was in the order of 20 million GJ p.a. as follows: "The existing industrial markets which could potentially be converted to natural gas were found to be mostly concentrated in the Cape Town, Atlantis and Saldanha Bay regions. Cape Town, Paarl and Wellington have the largest concentration of "switchable" industries and accounted for about 23 percent, or 20 million GJ per annum".

PetroSA believes that a constraint to industrial users converting to LNG in Saldanha is the absence of a storage facility at the port and the need for such customers to finance and build storage infrastructure on site to provide for 10 days' supply. Building an LNG storage tank at the port as well as a pipeline will reduce the conversion cost for large industrial users and enhance the feasibility of switching to gas (key informant interview).

PetroSA has identified that a LNG opportunity exists in the Mossel Bay/Western Cape/ Eastern Cape sub-region and believes that there are approximately 15 potential large user clients for LNG within a 500 km radius of Mossel Bay. These include automotive companies such as Daimler Chrysler in East London who have expressed a desire to convert to LNG use. A major challenge to converting manufacturers is production down time. PetroSA is looking for clients that will use between 5-7 tonnes of LNG a day. The major challenge in creating this market are the tanker transport costs to service it as the transport costs in servicing one client with one tanker day are large, however, economies of scale can be achieved when smaller clients are also served at the same time. So the more clients serviced, the greater the economies of scale as transport costs are reduced.

The South African dti commissioned a detailed KZN market demand study in 2017. This anchor demand could catalyse latent demand from Industry and Transport in KZN. Gas demand from Industry and Transport is 24 Petajoules (PJ) in the short-term (3-7 years) and 47 PJ in the long-term each with their own dynamics.

There are also mining operations using smelters where there may be an opportunity to convert to gas use. However, detailed feasibilities on these will be required based on identifying all the conversion costs as well as operation disruption issues. No audit has been conducted of the mining conversion opportunities in South Africa.

Refer to Figure 6 for an indication of existing large industrial energy users that could potentially convert to gas (excluding mining and agriculture).

4.3. Transportation sector (road logistics, mini-bus taxis and bus public transport, and shipping)

There is growing use of gas in many segments of the transport sector, including: bus, taxi, road freight, and shipping. Globally, many countries are now setting sales targets for the sale of electric-powered motor vehicles and the phasing out of petrol and diesel powered vehicles (Gray, 26 September 2017). The growth in natural gas powered vehicles appears to be negatively correlated with increases in the oil price (see Figure 7 below) (dti, 2017).

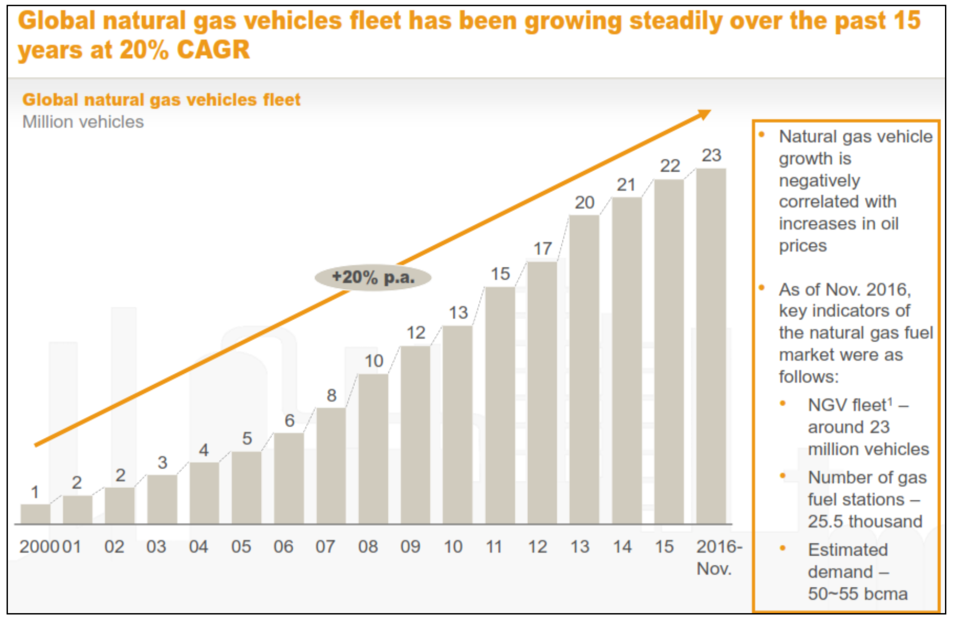


Figure 7. Growth of global natural vehicles fleet (2000-2016) (dti, 2017)

The dti's 2017 transportation sector gas demand assessment identified the main transport sector opportunities as represented in Figure 8 (dti, 2017).

In addition, the study identified barriers to switching to gas use as well as scenarios for the number of vehicles that may switch to gas in the different sub-sectors (Figure 9).

The dti transport demand assessment found that international experience showed that government support in four areas was required to support the successful adoption of gas in the transport sector:

1. Provide policy direction, especially in light of competing technologies (e.g. electric vehicles).
2. Guarantee gas supply at a specific price.
3. Minimise cost of switching (e.g. retrofitting subsidy).
4. Create a local market (e.g. infrastructure, part supply, servicing centres) to minimize vehicle downtime.

In South Africa, the application of the fuel levy by the Department of Transport reduces the price advantage of gas over diesel from 57% to 35% by adding R1.48 to the gas price (using the levy used for bio fuels) (this decreases transport demand by 10% according to the dti study). Transport operators estimate that <40% price differential erodes the adoption of gas.

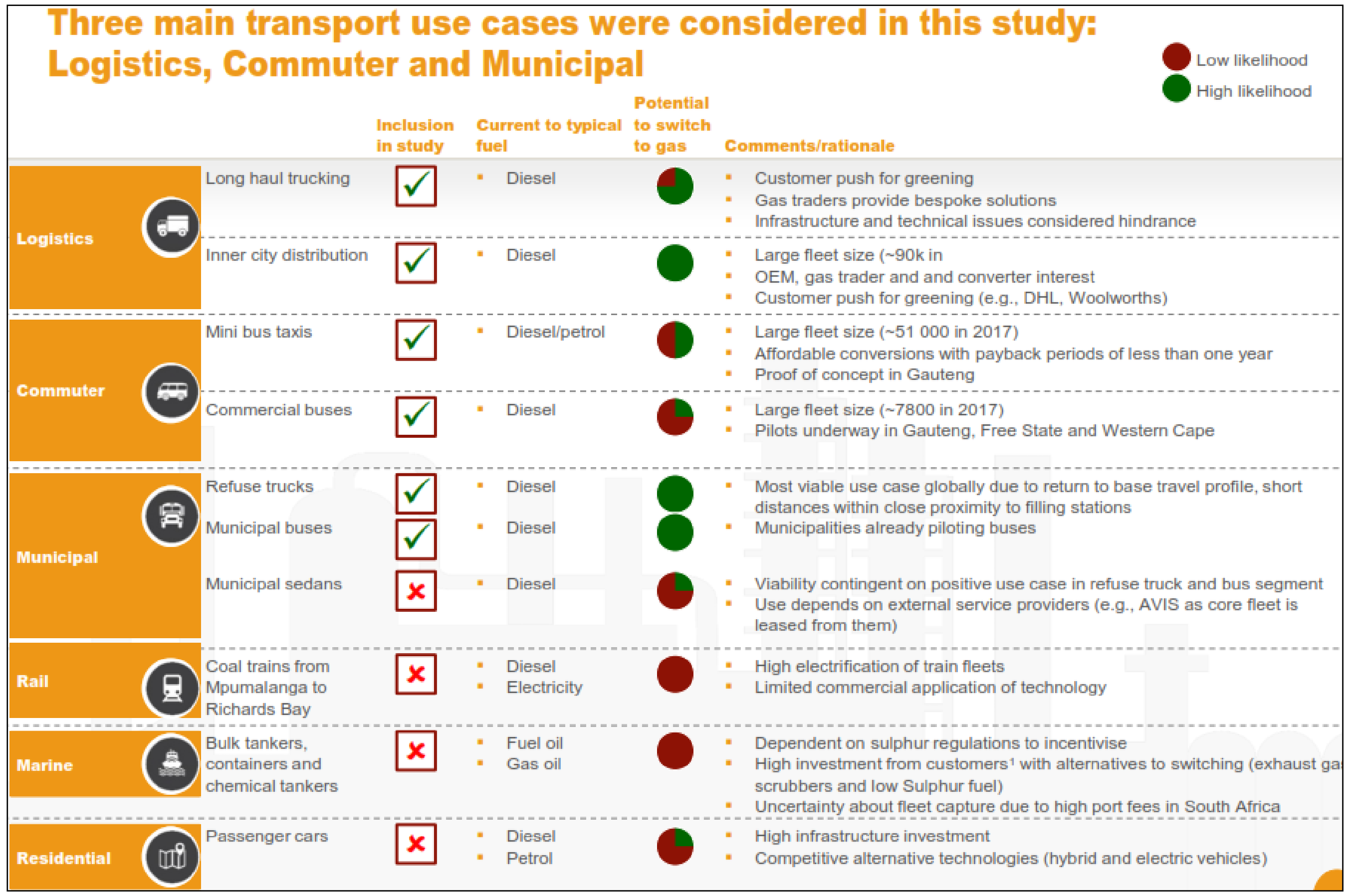


Figure 8. SA Transport sector gas demand opportunity assessment (dti, 2017)

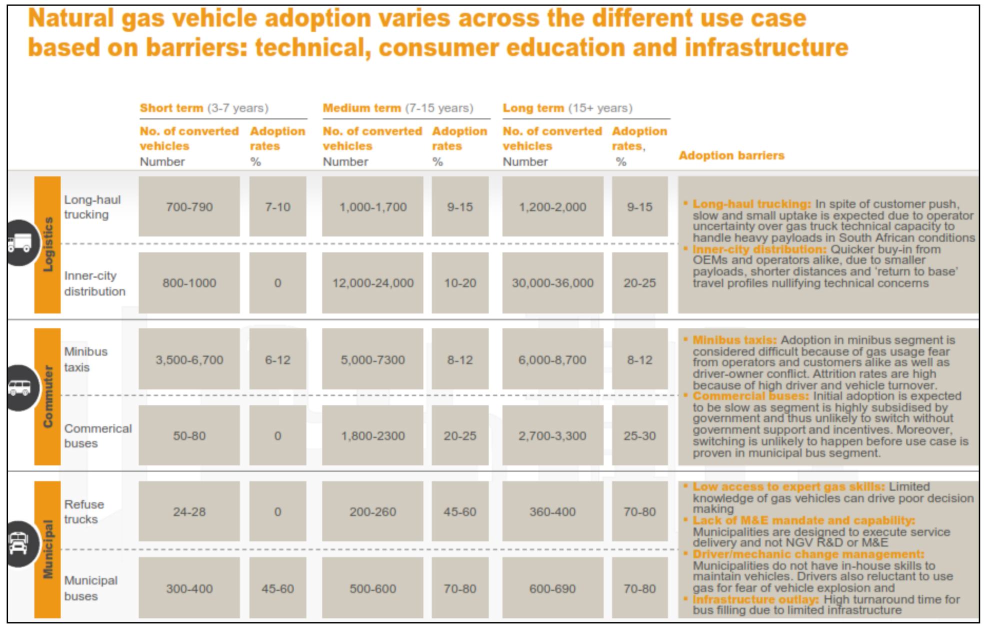


Figure 9. Barriers for the transport sector to switch to gas. Source: dti (2017)

A number of initiatives are underway in transportation/ road logistics, the taxi sector, and the bus/public transport sector in South Africa and which involve the use of LPG, LNG and Compressed Natural Gas (CNG). In a properly tuned engine, gas combustion delivers lower carbon and GHG emissions compared with the cleanest petrol engines. LPG is more cost effective than diesel or petrol due to lower costs per litre as well as great fuel-efficiency. Fuel consumption on smaller vehicles is around 4 litres/100 km.

A 2015 report[19] states that "…there are less than 10 filling stations in South Africa that offer CNG or LPG re-fuelling facilities to supply gas to motor vehicles. The current number of stations is greater than this, but is not known. The Automotive Industry Centre (AIDC), Sasol and Sabtaco have been driving an initiative to convert taxis in Gauteng. Gauteng has over 32,000 min-bus taxis and there are over 200,000 mini-bus taxis in South Africa.

The following example shows the initiative of one company that has been involved with upgrading taxis to use LPG in Gauteng- to incentivise the process, taxis receive a conversion kit worth about R15 000 at no cost:

> Versus Autogas Equipment, has already converted more than 100 minibus taxis from the Johannesburg Southern Suburbs Taxi Association - based in Eldorado Park - and the Randburg United Local and Long Distance Taxi Association. The company installs the required equipment, including an 80-litre LPG tank, in the taxis and turns them into hybrid vehicles that run on both LPG and petrol. One of the people who had his taxi converted is owner/driver Flyman Stanley, 37, who has been a taxi driver for the past 15 years, and bought his first minibus taxi in April 2016. Describing the savings he has accrued since converting his vehicle in November 2016, Stanley said he used to spend approximately R850 a day for a full tank of petrol, which is 50 litres, but now spends about R740 to fill up his 80-litre gas tank, which lasts him longer than the petrol. The price of the LPG is R9.50 a litre.

Gas is currently being used in the Johannesburg Metro bus network:

> The Company has in partnership with the University of Johannesburg undertaken a pilot project aimed at converting some of the current diesel run buses to Dual Diesel Fuel, a technology that allows for substitution of diesel with natural gas, which has lower carbon emissions. This project is a first in South Africa, and the company aims to be the leader by developing a Centre of Excellence on Natural Gas vehicle conversions. In the financial year 2014-2015, the company converted 30 buses, thereby contributing positively on the climate and giving the aged buses a new lease of life. As of December 2017[20], Metrobus reported that 150 buses had been retrofitted as dual fuel buses as part of its efforts to minimize the impact of carbon emissions into the environment[21].

This is also under consideration in Cape Town (key informant interview).

Road freight: According to one source interviewed, there will be 12 gas trucks operational in 2019 in Gauteng. There appears to be growing demand in the transport sector to switch from diesel to gas. The established road haulage companies in South Africa are evaluating whether they switch their fleets to electric or gas powered vehicles. The Western Cape Government has just initiated (as of February 2018) a study into the potential for gas demand in the Western Cape transportation sector (key informant interview).

Shipping: Gas carriers around the world have been using LNG as part of their fuel source for decades. Ships entering harbours will also require LNG to power them due to environmental issues at the ports of Saldanha, Cape Town, Durban and Coega. Driven by tougher international and environmental standards, LNG is being termed as the fuel of the future. According to experts, large scale shipping is believed to be sourced by LNG in the near future. LNG offers huge advantages, especially for ships in the light of ever-tightening emission regulations. LNG fueled ships are able to reduce sulphur oxide emissions by 90%-95%. This reduction level has also been mandated within the so-called Emission Control Areas (ECAs) by 2015[22]. A similar reduction will be enforced for worldwide shipping by 2020 (Man Diesel and Turbo, undated). Due to lesser carbon content in LNG, release of the harmful carbon dioxide gas is reduced by 20%-25%. While different technologies can be used to comply with air emission limits, LNG technology is a way to meet existing and upcoming requirements for the main types of emissions (SOx, NOx, PM, CO_2).

A few global examples of the use of LNG in shipping include the following:

> Wärtsilä, a major ship engine maker has developed and completed conversion from oil-run engines to LNG powered. Such duel fuel engines have now been implemented in several cargo ships. M/V Bit Viking is considered the largest of the vessels afloat and in service with approximately 25,000 dwt powered by LNG. Similarly, M/S Viking Grace is the largest passenger vessel to use LNG fuel. After almost a decade in development of LNG technology, presently, approximately 30 floating vessels are LNG fueled and servicing the European waters (Singh, 2016)

5 Discussion of potential benefits (and linked issue) and impacts of growing gas demand in South Africa.

5.1 Potential Benefits

The expanded use of gas in South Africa's energy mix has a number of potential national benefits. These include the following:

a) **Macro-economic and balance of payments** benefits as a result of reducing the need for imported oil and petroleum-based products to meet the country's growing petroleum demand (mainly transport demand). However, concern has also been expressed that increasing the importation of LNG could have negative balance of payments impacts. There is a need to conduct further macro-economic modelling of various future energy scenarios to better understand the possible macro-economic impacts of these scenarios.

b) **Electricity system benefits**:
Supplementing South Africa's energy mix with natural gas through gas powered electricity generation will have energy system benefits and positive implications for the energy price, energy supply, energy security, environmental emissions, and the overall economy, including:

- Achieving faster growth in energy generation targets than the current energy split;
- Lower energy costs due to the cost-competitive price of gas and which can have further knock-on benefits include reducing inflation pressure as well as enhancing the global competitiveness of export-oriented energy intensive industries in South Africa (e.g. metals) as well as domestic industries supplying the agriculture sector (e.g. fertilisers);
- Ensuring system balancing by supporting flexible, dispatch able generation. Gas supports a quick response energy system where power generation stations can be rapidly started to respond to increases in peak consumption;
- Supports the expansion of renewable energy - gas enables renewables to make a larger contribution to the power generation mix. The availability of fast-ramping gas-fired CCGT plants in the Western Cape region could greatly enhance the grid stability; and

[19] http://www.efm.co.za/Media/Documents/pdf/Case-Study-LPG/Auto-Gas-for-Mobility-March-2015.pdf
[20] https://www.mbus.co.za/images/quotations/Metrobus_mid-year_performannce_assessment_report.pdf
[21] https://www.mbus.co.za/index.php?option=com_content&view=article&id=86&Itemid=87
[22] The ECAs are as follows: The Baltic Sea, the North Sea and the North American Area (coastal areas of the United States (including the United States Caribbean Sea (specifically areas around Puerto Rico and the United States Virgin Islands) and Canada)).

- Improve security of electricity supply and reduce transmission losses. In the Western Cape alone it is estimated that gas-fired CCGT plant(s) 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 (Viljoen, 2013).

c) **Enable private sector investment in power generation and reduce pressure on the fiscus**: LNG imports can enable private sector investment in power generation, reducing pressure on the fiscus.

Gas-fired CCGT plants 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 mega-coal projects 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 (Deloitte, 2015).

d) **Environmental benefits through a reduction in CO_2 emissions**: LNG is likely to grow in importance as a fuel of the future due to its lower CO_2 emissions when compared to coal and petroleum liquids. As an example, calculation of potential CO_2 emission reductions: Assuming that the additional 9500GWh of gas-fired electricity output in the Western Cape 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 (Deloitte, 2015). In addition, substantial CO_2 reductions from the increased use of gas in the transport, mining, and industrial sectors would further contribute to lower CO_2 emissions.

e) **Environmental benefits through reduced water usage**: Of all the forms of power generation, natural gas-fired CCGT plants have some of the lowest consumption of water per unit of electricity generated, in part because of their relatively high thermal efficiency.

f) **Industrialisation and mining benefits:** These benefits include direct job creation impacts in oil and gas-related firms/ value chains, as well as indirect benefits experienced by large energy intensive industries and mines that are subject to international competition (and often involved in or linked to exports) potentially having access to competitively priced energy from gas and which supports their global competitiveness.

Operation Phakisa and the dti argue that the development of gas could support South Africa's industrialisation as a result of competitively priced energy and stable energy supply (Figure 10):

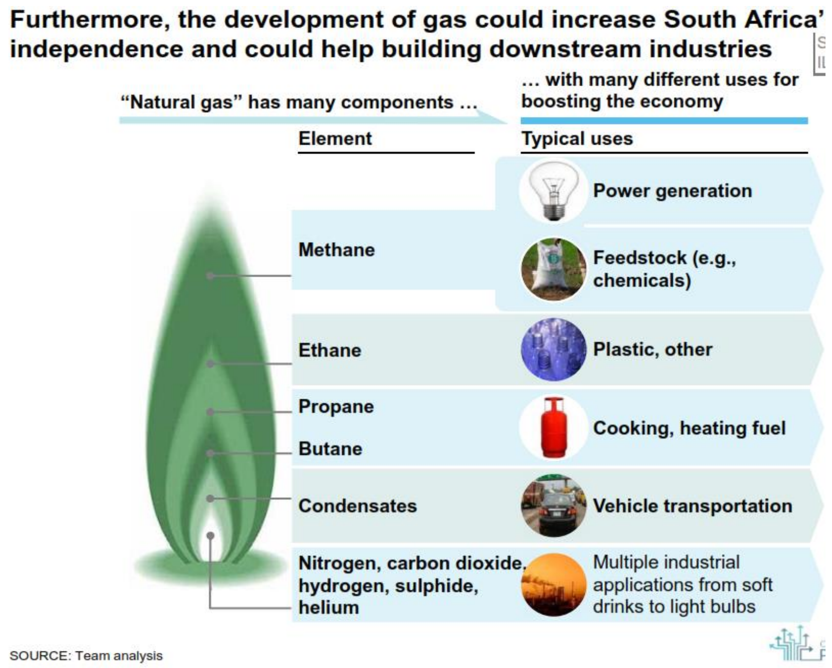


Figure 10. Simplified Illustration of the Opportunities to downstream users in using gas (Source: Operation Phakisa Offshore Oil and Gas Exploration, Republic of South Africa (2014))

5.2 Potential Impacts

Work conducted on the Oceans Economy in South Africa estimates that the oil and gas and aquaculture sectors (of which gas is a sub-sector) have the potential to create between 500,000-700,000 jobs by 2030[23]. Operation Phakisa has outlined the following possible scenario relevant to understanding selected possible benefits:

> The Offshore Oil and Gas Lab has set an aspiration of achieving 30 exploration wells in the next 10 years. Assuming that South Africa could achieve production levels of 370 thousand barrels of oil and gas per day (the likelihood of which is hard to assess at this stage), would mean up to 130,000 jobs are created with annual uplift to GDP of $2.2 billion. The dependence on expensive oil and gas imports would also be reduced (Operation Phakisa Offshore Oil and Gas Exploration, Republic of South Africa, 2014).

Operation Phakisa has identified the following range of potential direct and indirect upstream (exploration) and downstream (South African industries) benefits from developing South Africa's offshore oil and gas industry (Figure 11).

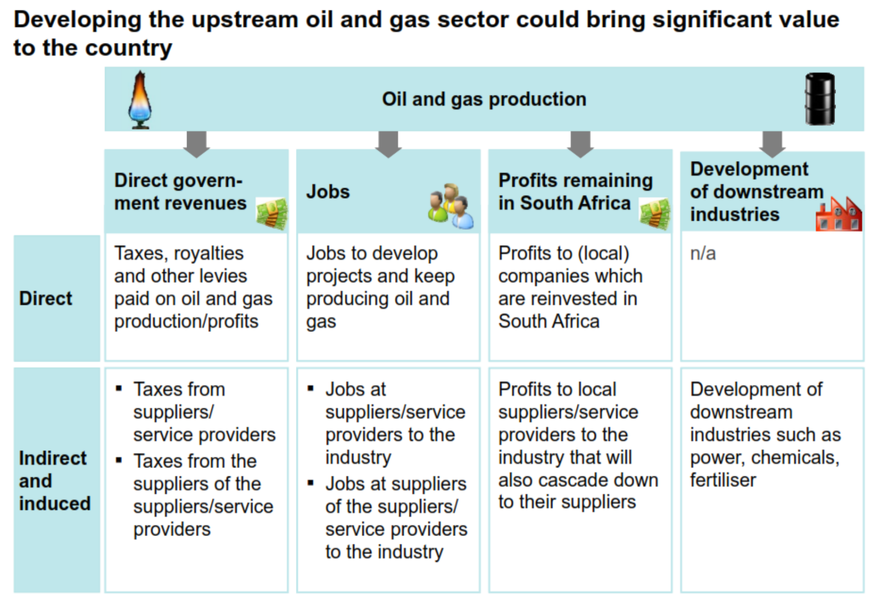


Figure 11. Upstream and downstream benefits of developing South Africa's oil and gas sector (Source: Operation Phakisa Offshore Oil and Gas Exploration, Republic of South Africa, 2014) (

Regarding the phased expansion of the gas pipeline in South Africa, a range of limited direct and temporary benefits can be expected from the construction phase. These include the jobs created to build the pipeline as well as jobs created or supported as a result of the materials and supplies required for the pipeline. In this regard, Operation Phakisa has identified the possibility of pipeline fabrication as an opportunity requiring further market research:

> If South Africa is to build a network in excess of 3500 km, the opportunity exists to develop the local mills and bring them up to international standards. There is also the opportunity for investment by international pipe fabricators in these mills or in new local mills. Any of these options will establish a South African capability for world class pipe manufacturing and coating and should be pursued as part of Operation Phakisa's objectives before resorting to international pipe mills. However, it must be

[23] Further information **on ocean economy opportunities** (which include marine transport and boatbuilding, oil and gas offshore exploration and ship repair, small harbour development, and aquaculture) can be found in the dti's ocean economy guide available **at** http://www.thedti.gov.za/DownloadFileAction?id=1120 : The Ocean Economy forms part of Operation Phakisa.

noted that, globally, there may be an excess capacity for pipeline manufacturing and coating. A thorough marketing exercise, considering global supply and demand must therefore be undertaken, before this opportunity is pursued (Republic of South Africa, 2017: 25).

Regarding the phased timing of realising opportunities and benefits, the first phases for expanding South Africa's gas pipeline network are expected to begin around 2025 (Republic of South Africa, 2014). In 2014, Operation Phakisa estimated that about R1.7 billion would be required to develop this pipeline network over the next 5 years (with the majority of this funding being from non-government sources) but it is unclear if this takes into account projected increases in the cost of construction and other variables subject to change. In addition, an estimated budget of R500 million was identified as being needed to secure servitudes for the gas pipeline (Republic of South Africa, 2014).

iGas has completed the onshore route engineering for a West Coast gas transmission pipeline from Abraham Villiers Bay to Saldanha and Atlantis to take West Coast gas to the Ankerlig power station. PetroSA has completed the pre-feasibility for a gas transmission pipelines from Saldanha to Mossel Bay and Coega to take West Coast gas to the South Coast markets. Alternatively, the flow can be reversed to take South Coast gas to the West Coast markets.

As the 2017 Operation Phakisa document states, "Natural gas found in large quantities will, unlike Mozambique, need to be encouraged to first supply the industrialisation of coastal cities before being exported as LNG to international markets. This opportunity, if the gas reserves are found, has the potential to significantly grow the South African economy." (Republic of South Africa, 2017: 6).

Gas IPPs are expected to provide for initial gas offtakes. In the short term, South Africa will require imported LNG. Baseload IPP CCGT plants currently being planned will require maturity and, once offtake agreements are signed, will take ~26 months to construct.

In addition to future energy price trends favouring gas, other drivers for the gas pipeline network in South Africa (as identified by iGas) include the following:

- LNG importation initially at Richards Bay, followed by Coega and thereafter Saldanha Bay;
- Development of Shale Gas in the Karoo Region; and
- Increased focus on the importation of Gas from Mozambique.

Regarding potential negative impacts of future gas corridors, the potential impact on existing mining rights (especially in Gauteng) has been identified as a potential issue to be mitigated through the optimum routing of any future gas transmission pipelines. It will also be important that the transmission pipelines are designed, constructed and operated in line with best practices and relevant local and international standards. Such transmission pipelines will also need to comply with relevant licences and permits, including the NERSA Licence.

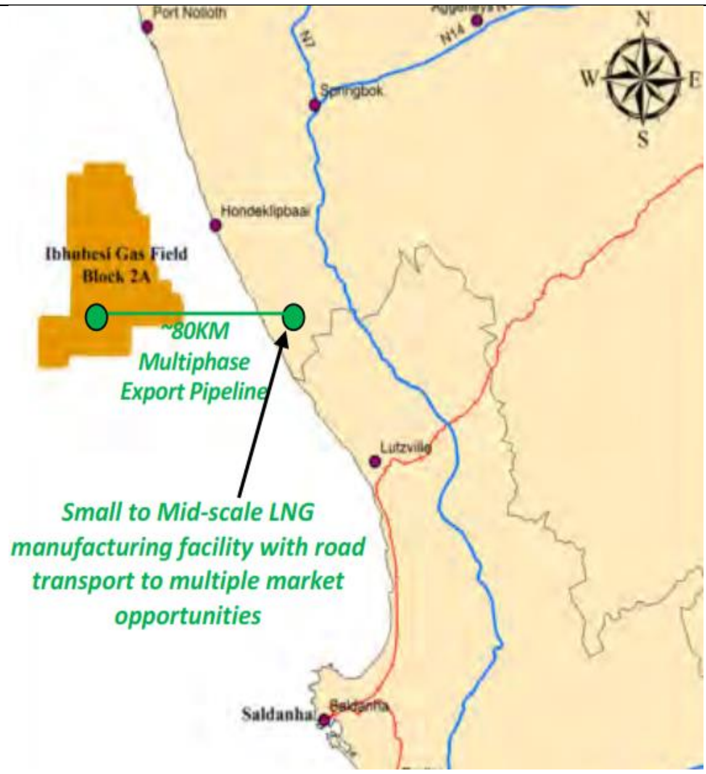
6 Key gas corridor economic attributes and opportunities

This section discusses potential gas opportunities for the various phases of the proposed gas pipeline corridors and has been informed by a limited number of stakeholders' interviews and review of available documents (Table 5).

Table 5. Opportunities identified within the corridors

Corridor phase and name	Summary profile and brief discussion regarding opportunities and related issues
Phase 1: From Saldanha Bay to Atlantis and to Mossel Bay on the south coast; and Phase 6 from Abraham Villiersbaai to Saldanha	Key potential opportunities include the current plans with the Ibhubesi gas fields and the Eskom plans with the Gourikwa power station. However, if Gourikwa will only be used as a peaking plant into the future then it is not clear if its full conversion to gas can be justified. The gas turbine burners chambers have been converted to use natural gas but the infrastructure to transport gas to site and supply it to the gas turbines have not been installed. Related opportunities include future industrial demand in Saldanha, Atlantis and Cape Town and potential transport and residential sector market demand in Cape Town. The Western Cape Government has conducted a 2013 market demand assessment based on detailed bottom up user demand data (see Viljoen, 2013) and has just initiated an updated Western Cape Market Demand Study that should be completed by end March 2019 which will also provide detailed bottom up market demand data. This study will also include the identification of preferred contractual options as well as infrastructure needs, requirements and options along the full value or distribution chain to service the identified demand. In addition, a risk analysis and socio-economic impact assessment will be conducted. Ibhubesi gas project has over half a Tcf of proven gas reserves at a P50 level (proved and probable, whereas a level P10 = proved, probable and possible) and situated 80km off of the Northern Cape coast. Current Ibhubesi gas reserves could potentially provide electricity to a city of 1 million people for about ten years. With added investment, up to 8 Tcf or 16 times the current proven reserves, could be added to the domestic energy mix (Sunbird Energy, 2018). An Environmental Impact Assessment (EIA) has been granted to Sunbird Energy in August 2017 to build an offshore pipeline of 300-400 km to deliver gas to Atlantis and the Ankerlig power station (see Annexure A for the Ibhubesi northern and southern pipeline alternatives). This means that there may no longer be a need for an onshore gas pipeline linking Saldanha and Atlantis to the Ibhubesi offshore gas supply. Eskom does not currently require sufficient volume of gas to use Ankerlig as a mid-merit power station and prefer to keep it in its current dispatch mode as a peaking power station. Eskom will also be required to invest approximately R1.56 billion in fully upgrading both the Ankerlig and Gourikwa fuel systems to supply the gas to the dual fuel burners (Eskom key informant citing Eskom feasibility studies). Doubts have been expressed by key informants interviewed as to whether: a) such a conversion will be required based on future Eskom peak power generation capacity relative to demand; and b) Eskom will be able to obtain gas for a price that will allow it to break even after incurring the large financial cost of this conversion to the fuel supply system. An older 2013 Western Cape market demand assessment found the following with respect to the Ankerlig Power Station: The opportunity was however identified, should natural gas become available, for Ankerlig to be converted to a gas-fired CCGT plant, which would not only increase its efficiency from approximately 32 percent to 52 percent, but its generating capacity from 1,350 MWe to 2,070 MWe. The Western Cape has a peak daily electricity requirement of approximately 3,864 MWe. With its local base load generating capacity by its Koeberg nuclear power plant and the Palmiet hydro-electric pump storage facility, and its electricity export commitments to Namibia, Eskom on average imports about 2 050 MWe of peak power on any given day to the region. The increase in generating capacity by the Ankerlig power station, should it be converted to a gas-fired CCGT facility, could therefore significantly contribute to the reduction of electricity imports to the Western Cape province and at the same time contribute to the reduction in transmission losses, estimated to be in the region of 200MW, during the transmission of electricity to the region. For the purposes of this study, it was included that the existing Ankerlig power station would be converted to a gas-fired mid-merit CCGT power plant. The total energy requirement for Ankerlig in this configuration equated to approximately 66.5 million GJ per annum, roughly about 75 percent of the total identified gas market potential in the Cape West Coast region (Viljoen, 2013: 7). The 2013 Western Cape Demand assessment conducted by Viljoen found that the potential industrial demand was in the order of 20 GJ p.a. as follows: "The existing industrial markets which could potentially be converted to natural gas were found to be mostly concentrated in the Cape Town, Atlantis and Saldanha Bay regions. Cape Town, Paarl and Wellington have the largest concentration of "switchable" industries and accounted for about 23 percent, or 20 million Gigajoule per annum" (Viljoen, 2013). Sunbird energy has signed a 2017 Gas Production and Sales Agreement with Afrox for offtake of LNG (17 November 2017) to purchase up to 365,000 tons p.a. (or up to 900 tons/ day). Planned production will be 600-1200 tons per day which leaves space to supply other customers (e.g. power generation for peak shaving). Sunbird Energy's current focus is on conducting a detailed costing exercise over the next 12-18 months to establish an onshore gas processing and LNG facility (Gas dehydration, condensate stripping and storage, LNG manufacture and storage). According to Sunbird Energy (key informant interview), the first gas deliveries are possible by 2022 with LNG being transported by road / truck to multiple sales and delivery points within 400-600 km radius; 200,000-400,000 tons of LNG could be produced p.a. LNG customer delivery point infrastructure required would include: LNG truck offloading bays, LNG buffer storage, regasification heat exchangers, gas conditioning, pressure regulation and metering. According to Sunbird Energy (2018), substantial new and fuel switching markets exist where LNG is price competitive, including: peaker power generation replacing diesel; industrial/ mining replacing diesel or LPG; and transportation (replacing diesel).

Corridor phase and name	Summary profile and brief discussion regarding opportunities and related issues



The high-level capital infrastructure investment estimates provided by Sunbird Energy in 2018 total about $800 million as follows (Sunbird Energy, 2018):

Upstream Production	Midstream Transmission	Downstream Manufacturing	Downstream Trading
Subsea infrastructure - Production wells - Wellheads - Flowlines - Manifold	**Export gas pipeline** - 80-100km offshore to onshore - Multiphase or dry	**Onshore gas processing and LNG manufacture** - Gas dehydration - Condensate stripping - Storage - LNG manufacture and storage	**Onshore LNG transport and sales** - 20-40 ton LNG truck and trailer or rail transport - LNG offloading bays and buffer storage - Regasification heat exchangers - Gas conditioning, pressure regulation and metering
~US$500 million	**~US$100 million**	**~US$150 million**	**~US$50 million**

Corridor phase and name	Summary profile and brief discussion regarding opportunities and related issues

Source: Sunbird Energy (February 2018).

According to the Western Cape Government (key informant interview), there are 25 industrial investment projects at various stages of the investment process and which are energy intensive.

Cape Town:
In terms of the Chevron/ Caltex refinery in Cape Town, it is not clear what implications the planned purchase of the Chevron oil refinery by Chinese company Sinotec will have. Government has approved the planned purchase recently. This will involve R6bn of upgrading at the facility (Killian and Lazenby, January 2018). In addition, Sinotec has agreed to a number of commitments, including that it will increase the level of LPG that is supplied to black-owned businesses.

In addition, the City of Cape Town has undertaken studies on the feasibility of using gas for electricity generation. It is not clear what infrastructure investment will be required and what the City of Cape Town's future plans are in this regard.

Corridor phase and name	Summary profile and brief discussion regarding opportunities and related issues
Phase 2: From Mossel Bay to Coega on the south coast.	As per the previous discussion, challenges and uncertainties related to Eskom's full conversion of Gourikwa power station exist in the short term. Past work on the feasibility of establishing an LNG import facility at Mossel Bay found that this was not feasible (in part due to the rough sea conditions).

<table>
<tr><th>Corridor phase and name</th><th>Summary profile and brief discussion regarding opportunities and related issues</th></tr>
<tr><td></td><td>The current PetroSA gas to liquids refinery facility in Mossel Bay currently manufacture's 4.5 million gigajoules p.a. PetroSA wants to enter the commercial gas market and take LNG to the market and are currently conducting market studies. Once a market has been created, PetroSA may want to import additional LNG. The price of LNG would need to be lower than the price of LPG if sufficient incentive exists for existing customers to use LNG (key informant interview).

Current gas supply to PetroSA will run out in about 2020 (key informant interview). PetroSA is a 25% owner of the Ibhubesi gas field off the West Coast.

Commissioned in 1992, the PetroSA plant is 27 years old and cannot compete with Sasol in Gauteng due to the low prices at which Sasol imports gas from Mozambique. The future focus of the PetroSA plant is likely to be on gas to chemicals (key informant interview).

The PetroSA plant will require major new investments in the refinery to make it possible to focus on LNG in future (the media has reported an investment requirement of R3bn[24], however, PetroSA is still in the process of costing the upgrades needed at the facility) and is in discussions with government regarding how to finance these investments and whether government will provide a guarantee. PetroSA sees the transport sector as a major market for LNG in future. Government is only expected to make a decision regarding the future focus of the PetroSA plant after the next national elections in 2019.

PetroSA uses 100 MW of power a day from Eskom. It is unlikely that PetroSA will be able to obtain electricity at a cheaper rate from other sources such as gas or solar. This limits the potential to switch energy sources at Gourikwa.

PetroSA believes that the Saldanha port is the best location for an LNG import/export plant. PetroSA will be the largest user of LNG in the Western Cape and will focus on using LNG for chemical production.

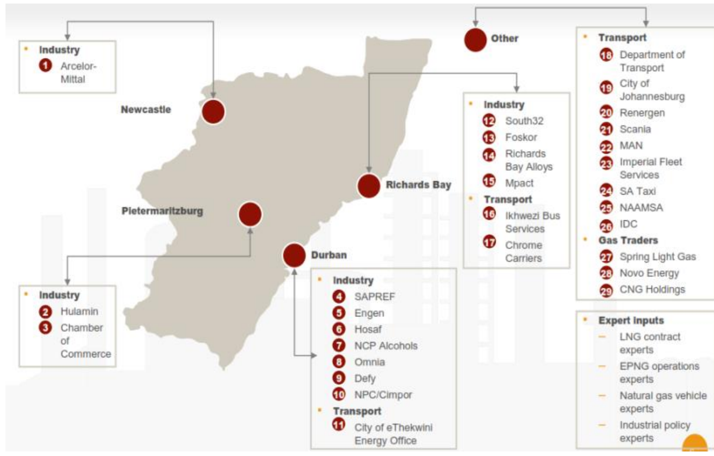
PetroSA has identified that an LNG opportunity exists in the region and believes that approximately 15 potential large user clients exist for LNG within a 500 km radius of Mossel Bay. These include automotive companies such as Daimler Chrysler in East London who have expressed a desire to convert to LNG use. A major challenge to converting manufacturers is production down time. PetroSA is looking for clients that will use between 5-7 tonnes of LNG a day. The major challenge in creating this market are the tanker transport costs to service it, as the transport costs in servicing one client with one tanker day are large, however, economies of scale can be achieved when smaller clients are also served at the same time. So the more clients serviced, the greater the economies of scale as transport costs are reduced.</td></tr>
<tr><td>Phase 7: From Coega to Durban on the east coast.</td><td>DoE plans for a 1000 MW CCGT IPP power station. It is not clear what industrial demand exists for gas at Coega. Apparently, there are plans for a smelter at Coega which would require gas by 2022 (key informant interview). The cost of gas pipelines to the West and East of Coega will be extensive and is will only be feasible once the Durban market has been saturated. The development of this pipeline therefore seen as a longer term opportunity. Coega could receive gas supplies via the pipe-line from Cape Town.

The Industrial Development Corporation is involved in financing a new R350 million gas bottling manufacturing facility in Coega. Construction of the plant is scheduled for completion in February 2018. These gas bottles will replace imported bottles and will be gas neutral and not linked to one of the major gas wholesale brands (although the bottles will be sold to these wholesalers). This will allow for gas to be sold to consumers at cheaper prices. The facility has a production target of 500 000 cylinders during its first phase and year of operation, after</td></tr>
</table>

<table>
<tr><th>Corridor phase and name</th><th>Summary profile and brief discussion regarding opportunities and related issues</th></tr>
<tr><td></td><td>which, at full capacity, the plant would produce 1.5 million units a year, or 3 200 cylinders a day (Gillham, April 2017) .</td></tr>
<tr><td>Phase 7 and 4: From Durban to Richards Bay and to the border of Mozambique to facilitate an import option.</td><td>The information in this section is derived from the dti's 2017 KZN market demand assessment (dti, 2017).

Richards Bay also in a good position as some of the Eskom Coal Burners will go offline and it is expected that the new LNG import facility will be completed as early as 2020 (although it is not clear if this timeframe is feasible) (key informant interview). The DoE plans for a new IPP CCGT plant to produce 2000 MW and to service growing industrial demand. Offshore seismic exploration is currently taking place near Richards Bay with drilling planned for some time in 2019.

The dti commissioned a detailed KZN market demand study in 2017 (dti, 2017). This included obtaining inputs from the following stakeholders (including industries):

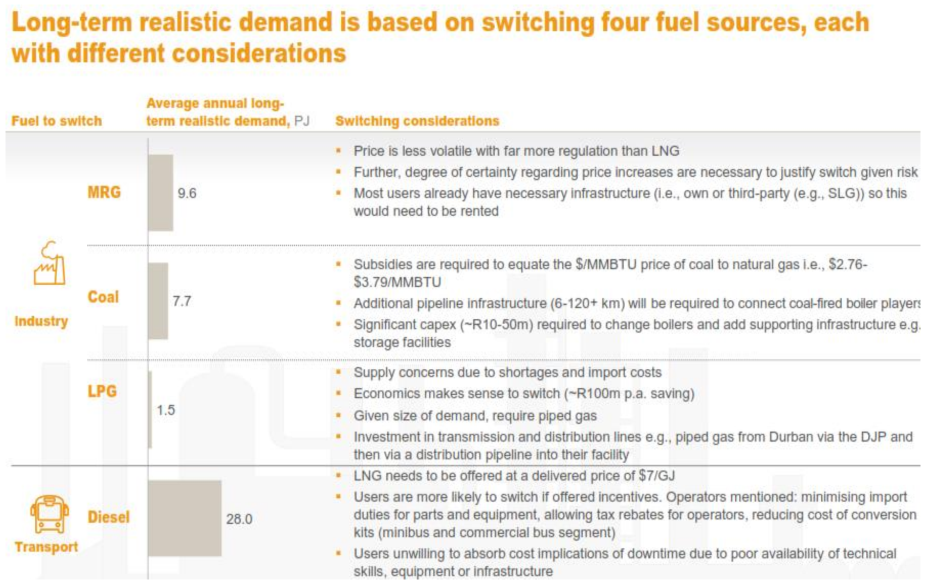


Source: dti (2017).

The key findings from this 2017 demand assessment are as follows:
Gas demand in KZN will be anchored by gas-powered electricity generation. This anchor demand could catalyse latent demand from Industry and Transport in KZN. Gas demand from Industry and Transport is 24 PJ in the short-term (3-7 years) and 47 PJ in the long-term each with their own dynamics.
This 47 PJ Industry and Transport demand can be broken down into four fuel groups:
Methane Rich Gas (MRG): Demand from Industrial users already using MRG amounts 9.6 PJ. Switching requires similar delivered prices to existing gas (expected to be between $ 6-8/MMBTU). Most users already have necessary infrastructure (i.e., own or third-party) but will require some modifications and capital input to switch from MRG to natural gas.
Coal: Demand from Industrial users, using coal for boilers or blast furnaces, amounts to 7.7 PJ in the long- term. Switching requires investment. To equate the $/MMBTU price of coal to natural gas, gas prices need to be < $4/MMBTU (assuming no CO2 taxes). Pipeline infrastructure (6-120+ km) will be required to connect coal-fired boiler players and capex (~R10-50m) is required to change boilers and add supporting infrastructure (e.g., storage facilities)
LPG: Demand from Industrial users already using LPG amounts 1.5 PJ. This is relatively easy to switch given large price differential between LPG and gas, it requires some investment in infrastructure
Diesel: Demand from Transport users in the Logistics, Commuter and Municipal segments amounts to 28 PJ. International case studies show that this demand is viable if economic</td></tr>
</table>

[24] See for example: https://www.businesslive.co.za/bd/companies/energy/2016-10-12-petrosa-to-spend-big-on-mossel-bay-refinery/

Corridor phase and name	Summary profile and brief discussion regarding opportunities and related issues
	payback for operators is clear and short (<3 years). In South Africa, interviews suggest a delivered gas price of $7/GJ and various incentives such as minimising import duties for parts and equipment, allowing tax rebates for operators, reducing cost of conversion kits (minibus and commercial bus segment) **Switching sensitivity**: Industrial and Transport demand is price sensitive. For industry 80% of demand is lost for a $4/MMBTU increase on delivered price (from $6/MMBTU to $10/MMBTU). For Transport, 75% of demand is lost for a $0.5/l (R7.84/l) price increase through the fuel levy, decreasing demand to 7 PJ in the long-term. **Economic impacts**: Industry: Impact is positive (~+R18m): micro effects are positive (~+R193m); macro effects are negative (~-R175m), these effects are almost solely driven by its impact on the trade balance. Transport: Impact is positive (~+R614m) owing to positive fuel switching economics. The assessment also identified key energy switching issues and gas price requirements for users currently using different energy sources as follows:



Corridor phase and name	Summary profile and brief discussion regarding opportunities and related issues
Phases 3-4: Replacement or duplication of the existing Lilly Pipeline from Sasolburg to Richards Bay and Durban by a second pipeline following a similar route.	The Lilly pipeline (Secunda to Durban) supplies various industrial users and the Rompco Mozambique to Secunda Pipeline (MSP) supplies natural gas feedstock to the Sasol plants in Secunda and Sasolburg and to industrial users in the Gauteng region. Currently more than 180 million GJ of natural gas or methane-rich gas is delivered, per annum, to customers in Gauteng, Free State, KwaZulu-Natal and Mpumalanga. Transnet currently leases the Lilly pipeline to Sasol and this lease comes to an end around 2022. It is not clear what Transnet's plans are for the pipeline once the Sasol lease comes to an end.
Phase 8: From Sasolburg to the border of Mozambique (including the ROMPCO pipeline)	The ROMPCO pipeline has been expanded 3 times over the past decade as demand has increased. Indications are that there may be sufficient new potential demand to double the pipeline capacity in future if sufficient supplies of new gas can be found (key informant interview) Sasol is currently searching for new gas supplies. The price at which Sasol brings gas to Secunda and Sasolburg is much lower than what LNG will cost (key informant interview). Sasol will prioritise their own usage before go into any other partnerships regarding the use of imported LNG.
Phase 6: From Saldanha Bay to Abraham Villiersbaai (landing point for the Ibhubesi field).	See phase 5 analysis above.
Phase 6: From Abraham Villiersbaai northwards to the Namibian border (Oranjemund), to link to potential Kudu gas extraction; and Phase 3: From the Shale Gas sweet spots to Mossel Bay and Coega.	Supply of shale gas is a long term opportunity. The feasibility of shale gas is also linked to the oil price and one commentator mentioned that an oil price of $85 is required before shale gas becomes price competitive (this figure has not been verified or subject to further scrutiny). If shale gas does become available in the quantities anticipated, gas powered stations will still not create sufficient demand to absorb this supply of domestic gas and therefore export terminals will be needed at key ports to allow for global exports.

The DoE's IPP LNG-to-Power procurement programme has a potential to unlock further possibilities for the growth of the gas industry in South Africa. The Project Information Memorandum (PIM) issued in October 2016 identifies Richards Bay and Coega as destinations for initial implementation while Saldanha will be introduced in a later phase (iGas, undated).

7 Gaps in Knowledge

The following gaps in knowledge, which could deepen the understanding and identification of opportunities to expand gas demand in South Africa, have been identified:

1. **Gas pricing transparency (including gas-coal relative price scenarios):** It would appear that there is a need for greater transparency and availability of information regarding gas prices in different demand scenarios so as to ensure that ongoing exploration of gas opportunities is informed by pricing information that is as transparent as possible. In addition, transparent scenarios illustrating the possible gas-coal price differentials are important to develop to inform ongoing stakeholder discussions in South Africa. The Department of Energy, in partnership with the dti may be best-positioned to coordinate such an initiative in partnership with other stakeholders such as NERSA and other relevant role-players.
2. **Eskom gas conversion of Ankerlig and Gourikwa power stations and the future Duck Curve**: It is not clear if Eskom can obtain gas at a price level which will allow it to break even after incurring the costs to fully upgrade the Ankerlig and/or Gourikwa power stations to gas. It is also unclear if such conversions will be required in future based on future Eskom power peak generation capacity relative to demand. There is a need to conduct energy system modelling which looks at the Duck Curve in relation to the future expansion of solar and wind energy in the electricity system to inform a more detailed assessment regarding the possible need for gas. Because of the importance of investigating possible large bulk anchor tenants to support future gas pipeline infrastructure investments, there may be value in commissioning further research into the desirability and feasibility of completing gas conversion of the Ankerlig and Gourikwa power stations.
3. **Demand from municipalities for gas for electricity generation:** This report has not assessed the scope for Municipal electricity generation using gas. For example, it is known that the City of Cape Town has done studies on the feasibility of using gas for electricity generation. It is not clear what infrastructure investment will be required and what the City of Cape Town's future plans are in this regard. There may be opportunities for Municipalities to grow their demand for gas for electricity generation; however, the scope for such demand will require further research.
4. **Market demand for gas in the transportation sector:** Further research may be required on the nature of potential gas demand in the transportation sector- although the dti study (dti, 2017) does provide good information at the level of KZN (with some national level constraints enabling issues identified). The Western Cape Provincial Government: Department of Economic Development has just commissioned (with a study beginning in March 2018) a Western Cape Study on this topic which could feed into a national market demand assessment study.
5. **Market demand for gas in the industrial and mining sectors:** Further research on the conversion costs for different types of industrial and mining sectors may be of value to inform the gas price at which such conversions are attractive and feasible for such users. It is difficult to identify at what gas cost switching is an attractive option for industrial users as the conversion costs first need to be identified and built into the feasibility assessment.
6. **Developing a strategy to enhance the direct economic impacts of building gas pipelines in South Africa** may be advisable in future. For example, Operation Phakisa has identified the possibility of pipeline fabrication as an opportunity requiring further market research.
7. **Macro-economic and balance of payments impacts of various future energy demand and supply scenarios need to be better understood:** There is a need to conduct further macro-economic modelling of various future energy scenarios to better understand the possible macro-economic impacts of these scenarios. National Treasury and the dti are apparently discussing an exercise to address this need. It is not clear what the scope of this exercise might be and how other role-players in the energy sector are involved, or could be involved, in this exercise.

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ANNEXURE A: DETAILED SUPPORTING INFORMATION

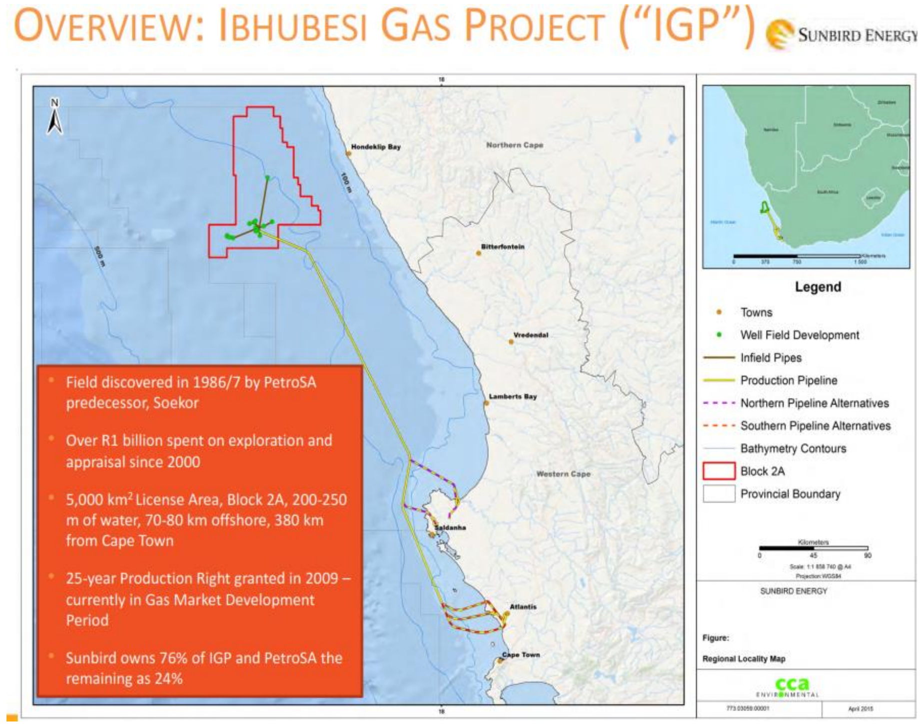
World Bank Future Economic Growth Projections (2017)

	Compound average annual growth rate			
	2000-16	2016-25	2025-40	2016-40
North America	1.8%	2.1%	2.1%	2.1%
United States	1.8%	2.0%	2.0%	2.0%
Central & South America	2.8%	2.3%	3.0%	2.8%
Brazil	2.4%	1.9%	3.0%	2.6%
Europe	1.7%	1.9%	1.6%	1.7%
European Union	1.4%	1.7%	1.4%	1.5%
Africa	4.4%	4.1%	4.4%	4.3%
South Africa	2.9%	2.1%	2.9%	2.6%
Middle East	4.4%	3.0%	3.5%	3.3%
Eurasia	4.1%	2.3%	2.7%	2.6%
Russia	3.4%	1.7%	2.4%	2.1%
Asia Pacific	6.0%	5.4%	4.0%	4.5%
China	9.2%	5.8%	3.7%	4.5%
India	7.2%	7.7%	5.7%	6.5%
Japan	0.8%	0.7%	0.7%	0.7%
Southeast Asia	5.2%	5.1%	4.0%	4.5%
World	3.6%	3.7%	3.3%	3.4%

Notes: Calculated based on GDP expressed in year-2016 dollars in purchasing power parity (PPP) terms. See Annex C for composition of regional groupings.

Sources: (IMF, 2017); World Bank databases; IEA databases and analysis.

Ibhubesi Northern and Southern Pipeline Alternatives



Source: Sunbird Energy (February 2018). Ibubesi Gas Project: Development Update.

ESKOM OPEN CYCLE GAS TURBINE POWER FIRE STATIONS OVERVIEW: GOURIKWA AND ANKERLIG

Power station	Overview (from Eskom)
Ankerlig (Atlantis)	First phase commenced in January 2006 and comprised of 4 x 148 MW units which was completed and handed over for commercial operation by June 2007. The second phase comprising of 5 x 147MW units was declared commercial during February 2009. Technical Details Type: Open Cycle Gas Turbines (OCGT) Number of Units: (Nine) 9 Output per unit: 148MW Installed Capacity: 1327 MW Role The OCGT units are powered by Fuel oil (Diesel). It is intended to supply electricity into the National Grid during peak hours and emergency situations. In addition to its generating capabilities the units are also used to regulate network voltage fluctuations (SCO – Synchronous Condenser Operation)
Gourikwa (Mossel Bay)	First phase commenced in January 2006 and comprised of 3 x 148 MW units which was completed and handed over for commercial operation by June 2007. The second phase comprising of 2 x 148MW units was declared commercial during November 2008. Technical Details: Type: Open Cycle Gas Turbines (OCGT) Number of Units: 5 Output per unit: 148MW Installed Capacity: 740 MW Role The OCGT are powered by Fuel oil (Diesel). It is intended to supply electricity into the National Grid during peak hours and emergency situations. In addition to its generating capabilities the units are also used to regulate network voltage fluctuations (SCO – Synchronous Condenser Operation)

ANNEXURE B: THE DUCK CURVE: WHAT IS IT AND WHAT DOES IT MEAN?

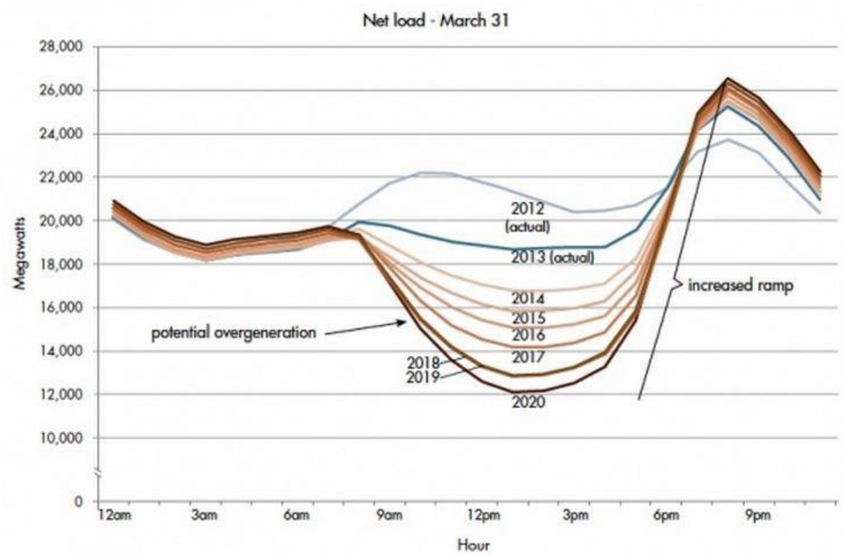
Source: https://alcse.org/the-duck-curve-what-is-it-and-what-does-it-mean/

MAY 29, 2017 BY DANIEL TAIT

So let's talk about the duck curve and what it means in the world of renewable energy. But what is the "duck curve?" Does it involve our adorable little animal friends who quack the day away? Well, kinda, but not really.

Put simply, the duck curve is the graphic representation of higher levels of wind and solar on the grid during the day resulting in a high peak load in mid to late evening. The difference in the Duck Curve and a regular load chart is that the duck curve shows two high points of demand and one very low point of demand, with the ramp up in between being extremely sharp. It looks like a duck! Since renewable energy has become more common over the years, the duck curve is appearing more often and is getting worse.

Let's look at an example of what the duck curve looks like:



The duck curve, explained.

As you can see, this chart shows the electric load of the California Independent System Operator (ISO), just think the California grid, on an average spring day. The lines show the net load—the demand for electricity minus the supply of renewable energy—with each line representing a different year, from 2012 to 2020. The chart also shows that energy demand reaches its peak in the morning (between 6 A.M. and 9 A.M.) and afternoon times (between 6 P.M. and 9 P.M). This demand shows that people need more energy as they get prepared for work or school in the morning and when they come home from work or school in the afternoon. Let's look at lines 2012 and 2017, for example. Comparatively, the 2012 line is much smoother than the 2017 line. This is because the feed of a renewable power supply has not yet been introduced. By slowly integrating solar energy, the demand for electricity from the electrical grid becomes smaller and smaller. However, the renewable energy source is not enough to meet the demand in its entirety, especially in those peaks hours that I referenced earlier. So the electric grid is left to pick up the slack, which can sometimes be problematic.

Why is a duck causing problems?

As you can see by the chart, solar energy works best during the bright hours of the day, which makes energy demand lower greatly. We'll call this the duck's belly: the lowest point of demand. The demand begins to rise rapidly as the sun sets and people get home at 6 P.M. There's no sun to power all of the appliances getting turned on by people returning home from work or school, and the grid is left to answer to that high demand. Therefore, the demand rises very rapidly (the duck's neck) to a peak in the afternoon hours (the duck's head).

For many decades, energy demand followed a fairly predictable pattern, with very little change in levels of demand. This allowed electrical workers to become experts with sustaining a stable output of energy. Well the duck curve kinda throws a wrench in that. In order to meet the baseline requirement, or "baseload", utilities run BIG power plants that run on either nuclear or coal, which run around the clock. The problem with coal and nuclear power plants is that they're expensive to completely start-up and shutdown, and are more effective in ramping up or down. Then there's the "peak load," which is satisfied by peaker plants that usually run on natural gas, and more frequently renewables.

In order to maintain top efficiency, regulators will often turn peaker power plants off and ramp down the baseline plants during times of very low demand, such as hours of the "duck's belly." However, the sudden and rapid increase in demand means that regulators have to quickly turn back on these power plants, which is not only expensive, but could lead to more pollution and high maintenance costs.

Another problem with the duck curve lies in the belly of the duck. In some places, demand becomes so low that grid operators are forced to turn off the peaker power plants and ramp down the baseline power plants. Then, just a few hours later, they all have to get ramped up again with little to no warning, which can cause problems for grid stability.

So problems with the duck curve lie in those sudden and steep changes in demand. Grid operators and regulators struggle to maintain stability and efficiency by turning power plants on and off, causing instability in the power supply, large expense to taxpayers, and pollution to the environment.

So what can we do about the Duck Curve?

One probable solution for the duck curve can be found in a method called **interconnection**. This strategy involves connecting multiple energy grids together to make a large energy grid. In theory, this would broaden and disperse the load and availability of solar and wind across a larger area, which in turn would flatten the duck curve.

This strategy could provide a long term solution to the problem. However, although the technology already exists, the politics of a large, interconnected grid is unlikely due to "not in my backyard" concerns and securing the rights of way.

The second method of smoothing out the duck curve is committing to the **storage of energy** generated by solar and wind, instead of immediately sending that energy directly to the grid. The energy can then be "dispatched" when it's needed, and would almost definitely flatten the curve. This method could prove very expensive to execute in near term however battery storage continues to fall in price and more utilities are actively seeking it as a viable solution.

ANNEXURE C: KEY INFORMANTS INTERVIEWED

Organisation	Person(s)
Department of Energy	Zita Harber: Demand Modeling Specialist (15th February 2018)
Department of Trade and Industry	Kishan Pillay: Director: Up- and Midstream Oil & Gas: Industrial Development Division (9th February 2018)
Eskom	Kobus Steyn: Group Executive (Acting): Group Capital Division (15th February 2018)
Sunbird Energy (Ibhubesi gas fields)	Kerwin Rana: CEO (9th February 2018)
Petro-SA	Dr. Faizel Mulla: Director: Strategy (5th February 2018) Peter Nelson: Gas Business Manager New Ventures Midstream (6th February 2018)
Price Waterhouse Coopers	Chris Bredenhan (9th February 2018)
South Africa Gas Development Corporation (SOC) Ltd	Neville Ephraim: Senior Project Manager (25th January 2018)
Western Cape Government: Department Economic Affairs and Tourism	Professor Jim Petrie (9th February 2018) (independent consultant) Ajay Trikam (9th February 2018): Director: Energy: Green Economy: Strategic Economic Accelerators and Development
Transnet (13 February 2018)	Adrian Cogills: Transnet Group Capital Imran Karim: Transnet Group Capital Marc Descoins: Transnet Group Capital

ANNEXURE D: ENERGY MARKET IN ATLANTIS, CAPE TOWN METROPOLIS AND SURROUNDS

Potential energy consumption in Atlantis (including Eskom's Ankerlig power station) and the Cape Town, Paarl and Wellington areas

Potential Energy Market – Atlantis, Cape Town Metropolis & Surrounds	
Fuel Type	**Consumption (GJ/a)**
Atlantis Industrial	1 000 000
Atlantis – Ankerlig Power Station	66 500 000
Cape Town Metropolis and surrounds	20 000 000
Total	***87 500 000***

List of currently available markets within the Atlantis and Cape Town corridor susceptible to conversion to natural gas as an energy source.

Potential Customer	Customer Type	Assessed Energy Usage (GJ/a)	Total Energy Usage (GJ/a)
Airport Industria:			
SA Metal	Heating	20,500	**20,500**
Atlantis Industria:			
Ankerlig Power Station	Power generation	66,500,000	
Ahlesa Blankets	Boiler	11,250	
Brits Textiles	Boiler	43,333	
Comar Chemicals	Thermal oil heating	5,000	
Promeal	JT boiler	15,166	
MSA	JT boiler	18,000	
Appolo Bricks	Heat firing	550,000	
Nu Era Packaging	JT boiler	17,250	
Atlantis Foundries	End user	68,400	
Bokomo Foods - Paraffin	Baking & drying	85,625	
Bokomo Weetbix	Drying	34,250	
Braitex Tenslon	JT boiler	18,750	
Craft Box Corugated	JT boiler	76,500	
Kulu Roof Tiles	drying & baking	3,233	
Rotex Fabrics	JT boiler	39,375	
SA Fine Worsteds	JT boiler	28,416	
Elvinco Plastics	Printing	230	**67 514 778**
Beaconvale:			
Cape Galvanising	Heating	14,266	
Golden Girl Hosiery	Heating	5,860	
Metlite	Heating	36,600	
Svenmill	End user	2,220	**58,946**
Bellville South Industria:			
African Products	Boiler	353,095	
Good Hope Bakery	Boiler & baking	25,277	
Grace (Darex)	Boiler	2,195	
Falke Textiles	Boiler	18,750	
Winelands Pork	Heating	43,950	
Latex Threads	Boiler	203,496	
Marley Tiles	Drying & baking	26,410	
Nampak Tissue Cape	Boiler	58,300	
Nestle	Heating & boiler	30,000	
Spekenham (Supreme Foods)	Heating	111,091	
Trade Wipers	End user	3,350	**875,913**
Blackheath Industria:			
Cape Town Iron & Steel	Heating & smelting	27,519	
Continental China	Firing & baking	116,666	**144,185**
Brackenfell:			
HBH Textiles	Boiler & drying	11,016	
Everite	Firing & drying	40,693	**51,710**
Bottelary:			
Crammix Bricks	Drying & baking	286,562	
Cabrico - Coal	Drying & baking	525,000	
Joosten Brick Claytile	Tile firing & drying	685,000	**1,496,562**
Contermanskloof/Philadelphia:			
Brick & Clay	Drying & baking	225,000	
Much Asphalt	Drying & heating	117,390	**342,390**
Eersterivier:			
Much Asphalt	Drying & heating	45,800	**45,800**
Elsies Rivier Industria:			
Continental Knitting	Boiler	9,375	
Mattex	End user	4,000	
Messaris - LO 10	Boiler	19,555	
Romatex	Boiler	29,062	**61,992**
Epping Industria:			
Allnet	Boiler	18,256	
Anchor Yeast	Boiler	31,050	
Bevcan & Bevcap	Boiler	98,100	
Bowman Ingredients	Boiler	1,221	
Bokomo Ltd	Drying	5,100	
Cape Coaters	Boiler	6,250	
Coca-Cola Canners	Boiler	3,000	
Colas Southern Africa		32,840	
CTC		37,000	
Dairybelle		40,500	
Disaki Cores &Tubes		320	
Distell	Boiler	67,620	
Donaldson Filtration	Boiler	6,400	
DPM Transformers	Heating	5,175	