CHAPTER 2

Effects on National Energy Planning and Energy Security

CHAPTER 2: EFFECTS ON NATIONAL ENERGY PLANNING AND ENERGY SECURITY

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South Africa's energy system is based on coal and oil; natural gas could be a missing link

The South African energy system is currently based on domestic coal and imported oil, with limited wind and solar photovoltaic (PV) renewable energy supply. Natural gas is currently only available in small quantities. The electrical power sector is the largest energy supply sector, predominantly based on the burning of domestic coal (~90%). The heating sector is generally small, and the transport sector is supplied by liquid fuels (crude or refined) which are either imported or domestically produced through coal-to-liquid (CTL) and gas-to-liquid (GTL) processes.

Domestic gas resources (from a number of offshore gas fields close to Mossel Bay) are nearing depletion, and imported piped gas from Mozambique is currently predominantly utilised by Sasol as feedstock into their CTL process. In this process, the natural gas is used for hydrogen production as a necessary feedstock for the production of carbon monoxide which together forms syngas (CO, H_2).

Natural gas could be a missing link in South Africa's energy system, as it exhibits certain qualities that existing energy carriers do not possess. Natural gas:

1. Cuts across a number of sectors in its possible end use (power generation, heat and transport);
2. Is easily transported via pipelines;
3. Is supported via a growing international market capacitated via increasing liquefied natural gas (LNG) trade volumes;
4. The complexities surrounding gas storage (gaseous/liquefied) are appreciable, but relative to coal, is typically considered to be a more homogeneous fuel and thus more flexible and easier to handle;
5. Is less CO_2 intensive when burnt per heat value than coal and in addition its heat value can be more efficiently utilised (combined-cycle gas turbines with up to 60% efficiency);
6. Is less of a general air pollutant than coal (Sulphur Oxide (SOx), Nitrogen Oxide (NOx), Mercury, particulates etc.);
7. Fires power stations (gas turbines and gas engines) that are technically highly flexible in their ramping and cold-start capabilities and can be operated at very low power output compared to their nameplate capacity without much deterioration in efficiency; and
8. Has an inherent end-use cost structure that is capital light and more fuel intensive, which makes it economically flexible.

Possible drawbacks of natural gas could include:

1. Price volatility if procuring gas on spot markets or linked to oil prices (albeit limited in comparison to overall system size);
2. If imported (not domestically sourced via conventional/unconventional sources), there is exchange rate risk (albeit limited in comparison to overall system size);
3. Natural gas leakage during production and transport when considering large scale usage is problematic, especially when considering the greenhouse gas (GHG) potential of natural gas. However, the electricity mix when including natural gas will likely include significant renewables and as a result system level emissions will be significantly lower. More detail on this can be found in Chapter 3 of this report (Winkler et al., 2016).
4. Hydraulic fracturing can cause environmental problems (water and air contamination as well as general biodiversity impacts). This is dealt with in various other Chapters of this report (Hobbs et al., 2016; Winkler et al., 2016; Holness et al., 2016).

Energy planning in South Africa done in different layers

Ideally, the Integrated Energy Plan (IEP) is the plan that links the different energy sectors and plans for the entire South African energy system in an integrated strategic planning framework. The Integrated Resource Plan (IRP) is the electricity plan for the country. The Gas Utilisation Master Plan (GUMP) is a strategic plan which provides a long term roadmap for the strategic development of natural gas demand and supply into South Africa’s diversified future energy mix. These plans are led by the South African Department of Energy (DoE) usually in consultation with other government entities and external stakeholders.

In terms of gas supply, South Africa has in principle three options:

1. To increase the volumes of piped gas imported from neighbouring countries;
2. To import LNG that is supplied from a global market; and/ or
3. To develop domestic sources (either conventional or unconventional).

Initial gas demand and the development of a gas market will likely be stimulated by LNG-based gas supply creating large anchor demand that would trigger investments into additional gas infrastructure. Following this, related investments into indigenous conventional (offshore) and unconventional (shale/Coal-Bed Methane (CBM)) gas exploration will occur supplemented with increasing volumes of imported piped gas. All these scenarios are similar in that the cost of natural gas would be above the pure heat-value-based fuel cost of coal or diesel/petrol (while remaining cognisant of the fact that it is still a fossil fuel but one that is less carbon intensive than coal).

If shale gas became a new supply option with potentially low cost, it would affect the fundamentals of the different energy plans' scenarios. It mostly affects the IRP, as the electricity sector consumes most of the primary energy sources (other than oil). The availability of an electrical power generation technology and fuel that is cost competitive to new coal fundamentally changes the planning assumptions and hence the planning outcomes.

Effect of significant shale gas on energy planning: Renewable energy enabler and less coal
Scenarios identified for shale gas development (SGD) in South Africa are summarised below.

Table i: Overview of scenarios as defined for the scientific assessment.

Scenario	Available shale gas	Annual shale gas production (40 years)[1]	Estimated cost range of shale gas[1]
Scenario 0 (Reference Case)	-	-	-
Scenario 1 (Exploration Only)	0 tcf	0 PJ/a	N/A
Scenario 2 (Small Gas)	5 tcf ≈ 5 300 PJ ≈ 1 500 TWh	130 PJ/a ≈ 40 TWh/a *(≈50% of current natural gas supply in South Africa)*	6-10 US$/MMBtu = 20-35 US$/MWh
Scenario 3 (Big Gas[2])	20 tcf ≈ 21 000 PJ ≈ 5 900 TWh	530 PJ/a = 150 TWh/a *(2.5-3 times current natural gas supply in South Africa)*	4 US$/MMBtu = 15 US$/MWh

[1] *Estimated based on generally accepted industry practice and national energy planning resources.*
[2] *The "Big Gas" scenario of this scientific assessment and the "Big Gas" scenarios of the IRP and GUMP are not the same scenarios and should be treated accordingly.*

Significant domestic shale gas resources would affect the planning for the South African energy sector. If the volumes are significant enough to justify energy plans for a couple of decades to be developed around them, a second question would then be at what price the domestic shale gas can be exploited.

<u>Nominally priced shale gas (≈6-10 US$/MMBTu)</u>
LNG-priced natural gas in a mix with cost effective variable renewables (VRE: solar PV and wind) is today already cheaper than alternative base-load-capable new-build options in the electricity sector, and would hence replace baseload and mid-merit coal in the electricity sector. This is regardless of whether the natural gas is imported (LNG or piped) or whether it is domestic. As such, shale gas finds do not affect the optimal planning scenario for the electricity sector. But if large volumes of shale gas at prices below imported LNG and below imported piped gas could be made available, the domestic shale gas would then essentially be a replacement for imported natural gas, hence improving the trade

balance and shielding the country from volatility in the pricing of a globally traded commodity like LNG.

Cheaply priced shale gas (<= 4 US$/MMBTu)

Displacement of coal fired power generation: Cheaply priced shale gas would enable the creation of a large, flexible gas-fired fleet of power generators that would be complementary to planned significant VRE capacities for South Africa (while coal is retiring). In the electricity sector, gas-fired power generation would now become cost competitive to new coal in its own right, even without blending with low cost VRE. In such a scenario of cheap gas, domestically accessed without risk of exchange rate fluctuations or global market volatility (local market volatility will still be present though), it would be a no-regret move to deploy large amounts of gas-fired power stations and subsequently complement them with a VRE fleet.

Fertiliser production: Potentially, South Africa could start producing its own fertiliser from very cheap domestic shale gas. Fertiliser production is not an energy-related topic, but would create a link between the energy and chemical sectors, which helps to balance fluctuations in energy demand (chemical sector being the anchor gas off-taker).

Gas-fired transportation: If cheaply priced, shale gas could be utilised for transportation (internal combustion engines run on compressed natural gas, electric vehicles running on gas fired power generation and/or natural gas derived hydrogen fuelled vehicles). It furthermore can be used as input feedstock into the GTL process to produce liquid transportation fuels. This would leverage the existing expertise in this sector, but it comes at the risk of increasing CO_2 emissions unnecessarily, as the natural gas could be burned with fewer emissions in internal combustion engines directly (especially in urban areas).

Heating: With sufficient network infrastructure, residential space heating and cooking demand could be supplied from natural gas. Similarly, industrial heat demand could switch from being supplied by biomass, coal and electricity to natural gas. However, this would necessitate large investments in domestic gas network infrastructure.

In general, the introduction of large quantities of cheap natural gas would increase the complexity while assisting in the integration of energy planning, because it introduces links between previously de-coupled energy sectors. It would however, for the very same reason, also make energy planning more resilient, because natural gas can also be seen as a “pressure valve” that is introduced between different energy sectors and that allows for adjustment to changing planning assumptions between sectors.

Risk of not finding sufficient or cheaply priced shale-gas resources

Not finding sufficient shale-gas resources

The role that shale gas would play in the energy mix, priced comparatively to imported piped gas (i.e. cheaper than LNG) would be an improved trade balance and the lowered risk exposure to globally determined commodity costs (in the case of LNG). These benefits of shale gas, even if not very cheaply priced, are certainly beneficial for the economy from a financial and energy security perspective.

From a purely technical energy planning perspective, the risk of not finding significant shale gas resources is therefore relatively small as gas demand could be supplied via imported gas (pipeline and/or LNG). Of course, energy security in some respect would be slightly reduced if gas supply remains dependent on imports, and exchange rate risk would be present. The IRP considers gas on the basis of its pricing and not primarily on the basis of where it originates from. Shale gas finds, even if not very cheaply priced, will therefore come as a macroeconomic added benefit under gas-dominated planning scenarios.

Not finding cheaply priced shale gas resources

Since the capital expenditure that leads to a gas-dominated energy sector (gas-fired power stations, gas-fired boilers, gas cooking/heating, etc.) are relatively small compared to the alternative new-build options (mainly coal), there are substantial "no-regret moves" associated with planning for a gas-dominated energy system. If the energy planning for the country anticipates very cheap shale gas and this is then not discovered, it would mean that the gas infrastructure built would have to be supplied with gas from more expensive sources. This would have a cost escalation effect. At the same time, even more VRE would be deployed to burn less of the more expensive gas. Because of the relatively light capital intensiveness of the gas infrastructure, the lower utilisation would not have a major effect on the overall costs of the energy system.

The main risk in energy planning related to the role of natural gas lies in the decisions that are taken in anticipation of no shale gas finds in South Africa, i.e. an energy future with relatively speaking smaller gas supply (although LNG, piped gas and domestic conventional sources can still make a significant energy contribution, even if shale gas does not materialise). This might lock the country into energy infrastructure that is not compatible with energy infrastructure flooded with inexpensive gas.

CHAPTER 2: EFFECTS ON NATIONAL ENERGY PLANNING AND ENERGY SECURITY

2.1 Introduction and scope

Natural gas has substantial benefits to offer the South African energy system, which at present is largely based on domestic coal resources. With natural gas, a diversification of energy supply is possible, sector coupling between different energy end-use sectors can be easily established, and gas-fired power stations bring economic and technical flexibility into the power system.

Three different natural gas supply sources can in principle be available to South Africa:

1. Piped natural gas from neighbouring countries;
2. Imported liquefied natural gas (LNG);
3. Domestic natural gas, either from conventional (onshore/offshore) or unconventional sources (shale gas/coal-bed methane (CBM)).

One of the unconventional domestic natural gas resources; shale gas, is the focus of this Chapter.

2.1.1 Scope

This Chapter elaborates on the effect that different South African SGD scenarios will have on investment decisions made, as based on energy planning and scenario development for the country. The Chapter considers the changes in planning outcomes for the long-term energy planning of the country in terms of supply sources and demand patterns for the different shale-gas scenarios. Although a specific study area is defined (geographically), historically energy planning in South Africa has tended to be performed at a national level.

The main links between this Chapter and the other Chapters of the scientific assessment are:

- Chapter 1: Scenarios and Activities (Burns et al., 2016)
- Chapter 3: Air Quality and Greenhouse Gases (Winkler et al., 2016)
- Chapter 4: Economics (Van Zyl et al., 2016)

The main assumptions (other than those outlined in the shale gas scenarios themselves) are based on principal plans developed for South Africa including the National Development Plan (NDP), Integrated Energy Plan (IEP), Integrated Resource Plan (IRP), and Gas Utilisation Master Plan (GUMP).

2.1.2 Special features of South Africa in relation to energy

Energy Balance

The present South African energy system is relatively self-sufficient; with less than 20% energy imports (Figure 2.1). Oil as a feedstock to refine liquid fuels and a small amount of gas is imported, but all other energy is supplied from domestic sources (mainly coal). Unique to South Africa is that large parts of the liquid fuel demand (approximately 33%) is supplied from coal-to-liquid (CTL) processes, based on domestic coal as feedstock (South African Department of Energy (DoE), n.d.). Additionally, gas-to-liquid (GTL) processes supply approximately 4-6% of the country's liquid fuel demand (South African Department of Energy, n.d.). The Mossgas plant close to Mossel Bay recently had to reduce its output due to depletion of the domestic natural gas fields that supply its feedstock. Hence, the South African energy system is not well diversified, and natural gas can be considered to be a possible missing link in the energy mix.

The total primary energy production and import in 2013 was 8 400 PJ (approximately 2 300 TWh_{th}) (International Energy Agency (IEA), 2013). The vast majority of this primary energy was supplied from coal at 6 100 PJ in 2013 (approximately 1 700 TWh_{th}). Natural gas only accounted for a small component of primary energy (~2%) with 170 PJ in 2013 (approximately 45-50 TWh_{th}). The total breakdown of primary energy production and imports in 2013 for South Africa is shown in Figure 2.1 and Figure 2.2.

The recent significant procurement of renewable electricity through Independent Power Producers (IPPs) in the electricity sector is not yet in this figure (as IPPs only started connecting to the electrical grid from 2014 onwards). By the end of 2015, all operational solar PV and wind power generation together stood for approximately 17 PJ of produced energy (4.65 TWh) (DoE, 2016b).

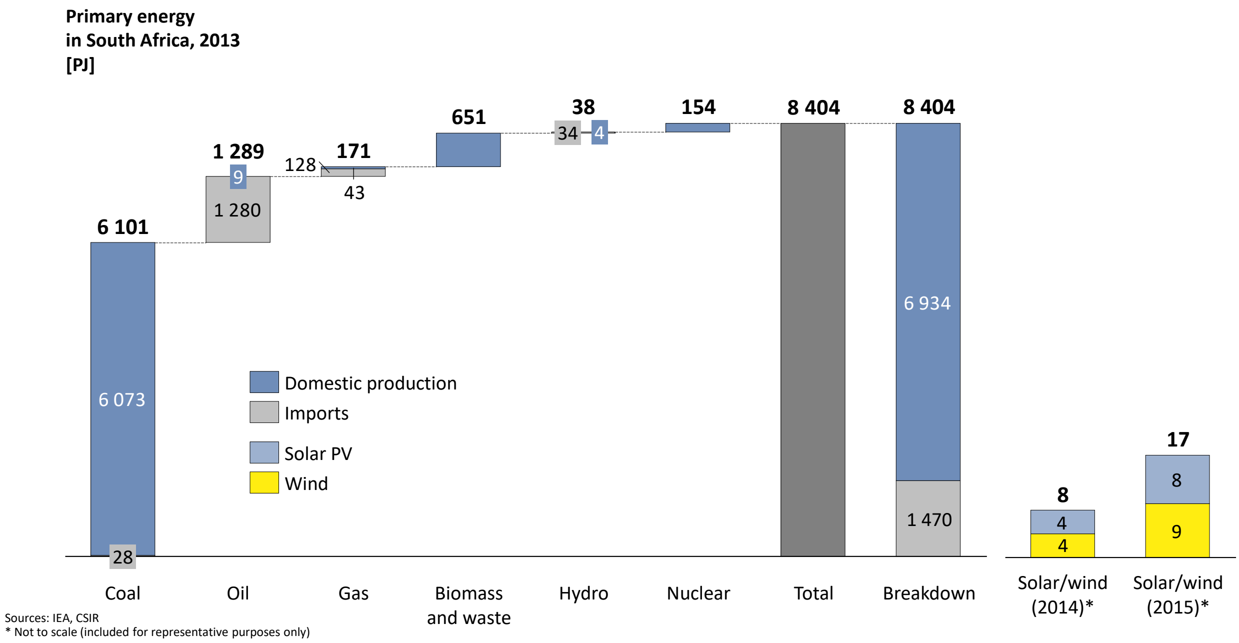

Figure 2.1: Primary energy production and imports for South Africa in 2013 showing the clear reliance on coal as a primary energy source and minimal local oil production (\IEA, 2013). Only in recent years (2014 onwards) has renewable energy made a significant contribution (mainly wind and solar PV, as shown) complemented by Concentrated Solar Power (CSP), mini-hydro, biomass, biogas and landfill gas produced domestically.

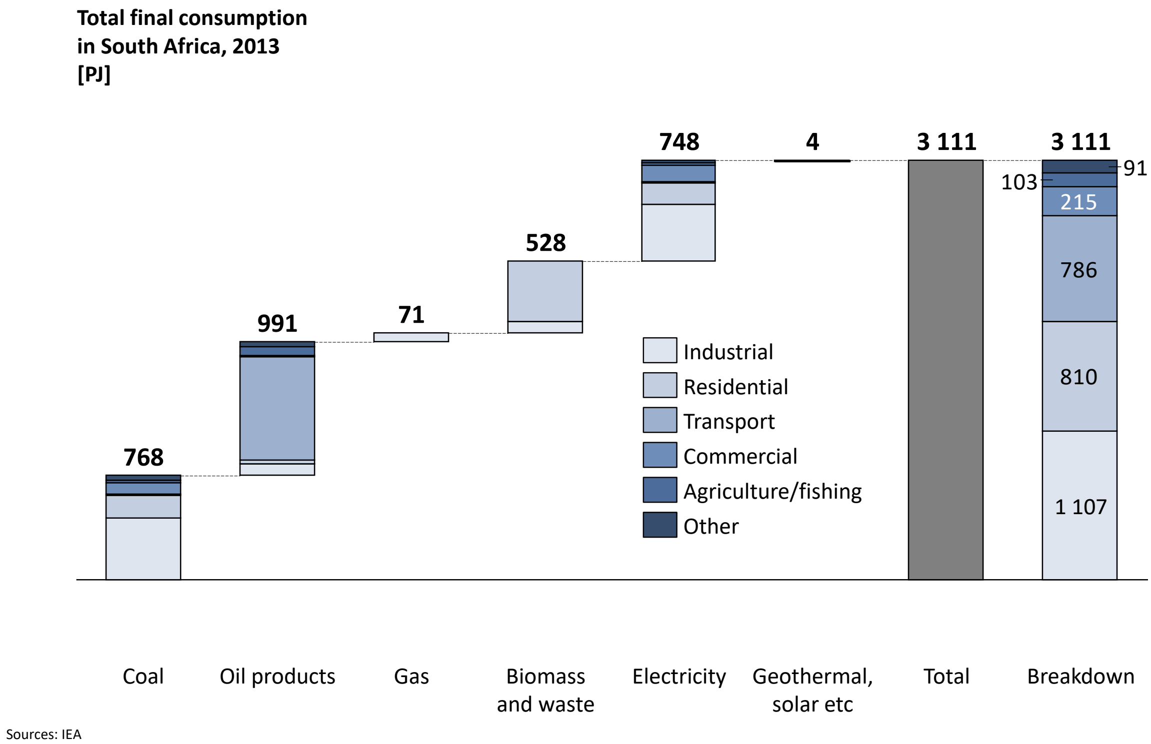

Figure 2.2: Total final energy consumption in South Africa in 2013 illustrating that most of South Africa's energy is industrial end-use with transportation and residential end-use being similar (IEA, 2013).

Coal

The South African energy system is highly dependent on its domestic coal resources. Coal was historically utilised when carbon dioxide (CO_2) emissions were not of concern and alternatives were prohibitively expensive. South African coal has been easy to mine and therefore has been a low cost position – even in a global market with current relatively low coal prices. However, in support of the clear direction given in the Energy Policy White Paper of 1998 (Department of Minerals and Energy, (DME), 1998) where security of supply through energy diversity is stated explicitly, there are a number of reasons why South Africa needs to diversify its energy mix away from a coal dominated energy system:

1. Heavy coal-reliance makes the country one of the largest emitters of CO_2 globally (ranked in the top twenty absolute CO_2 emitters in the world and top ten in terms of CO_2 emissions per GDP) (The World Bank, n.d.a; The World Bank n.d.b);
2. The single-failure risk of a one-fuel-reliant power system e.g. controlled load shedding after heavy rains due to wet coal in 2008;
3. Financial risk: South African coal prices are not reflective of globally traded prices for coal (high risk exposure to coal-price changes in the electricity sector);
4. The depletion of coal reserves in the Mpumalanga region and challenges associated with developing the relatively underutilised Waterberg coalfields (Hartnady, 2010) e.g. low grades, high ash content, complex geology, water scarcity and the requirement for new transport linkages including major electrical grid strengthening.

The South African government has recognised the problematic nature of a high dependency on one fuel source, and has expressed its desire to diversify the energy mix in a number of government plans. The Department of Energy's Integrated Resources Plan (DoE's IRP 2010 (DoE, 2011b)) describes a doubling of power capacity by 2030 (compared to 2010) and a significant diversification of the power mix, away from "coal only". This diversification of the energy mix includes a range of sources (solar PV, hydro wind, gas and nuclear).

Natural Gas

Natural gas could be a missing link in South Africa's energy system, as it exhibits certain qualities that existing energy carriers do not possess. Natural gas:

1. Cuts across a number of sectors in its possible end use (power generation, heat and transport);
2. Is easily transported via pipelines;
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Possible drawbacks of natural gas could include:

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4. Hydraulic fracturing can cause environmental problems such as water and air contamination (Hobbs et al., 2016; Winkler et al., 2016) as well as general ecosystem and biodiversity impacts (Holness et al., 2016).

At present, there is very little gas infrastructure in South Africa. Domestic resources are limited to offshore gas fields close to Mossel Bay (F-A field), where the gas is piped onshore and converted into petrochemical products (predominantly liquid fuels). According to the draft GUMP, the volume of gas supply from the Mossel Bay gas fields steadily declined from ~60 PJ/yr (17 TWh_{th}) in 2010 to approximately 35 PJ/yr in 2013 (10 TWh_{th}/yr) i.e. averaging ~40-50 PJ per year (8-14 TWh_{th}/yr). Based on the draft GUMP, these gas fields are in an advanced stage of decline and are only expected to last for a further 6-7 years. The F-0 offshore field (Project Ikhwezi) is envisioned to complement this supply in the short to medium term. Other offshore potential in the Ibhubesi field off the West Coast of South Africa has proven reserves of ~540 bcf (Sunbird Energy, 2016).

Neighbouring countries have substantial gas reserves (i.e. Mozambique and Namibia) as do regional African nations (i.e. Angola and Tanzania). Some gas quantities are already imported through the Republic of Mozambique Pipeline Company (ROMPCO) pipeline from Mozambique, which stands for the entire imported primary energy from natural gas (120-140 PJ per year, which is 33-39 TWh_{th}/yr). This gas is mostly used for chemical processes (hydrogen production as feedstock for syngas) in Sasol's CTL process. The Transnet-operated Lilly pipeline from Secunda to Richards Bay/Durban transports synthetic gas produced in Sasol's CTL plant in Secunda to Durban via Empangeni. The volume delivered through this pipeline is approximately 16 PJ per year (4.5 TWh_{th}/yr) (Transnet SOC Ltd, 2015).

In 2013, the total natural gas supply in South Africa (domestic production and import) was approximately 170 PJ (45-50 TWh_{th}), plus the synthetic gas from Sasol's Secunda plant of 16 PJ (4.5 TWh_{th}); a total of gas supply of approximately 190 PJ (53 TWh_{th}), which is ~2.5% of total primary energy supply. To put this into perspective, it is the equivalent throughput of one medium size LNG landing terminal. Spain, a country with a similar primary energy and electricity demand as South Africa, has an annual natural gas supply of 1 260 PJ (350 TWh_{th});~7-8 times the current South African volume.

Crude Oil and Synthetic Crude Oil

South Africa has almost no domestic crude oil resources, but very significant scale and expertise in CTL and GTL processes. It should be noted that the high carbon-intensity of fuels from these processes has significant impacts on South African climate change obligations. The country consumes approximately 24 billion litres of petrol and diesel per year (approximately 820 PJ/yr or 230 TWh_{th}/yr) (DoE, 2015). *"… about 36% of the demand is met by coal-to-liquids synthetic fuels as well as gas-to-liquid synthetic fuels plus a very small amount of domestic crude oil. South Africa has the second largest oil refining capacity in Africa. The current total refining capacity amounts to 703 000 barrels per day, of which 72% is allocated to crude oil refining, with the balance allocated to synthetic fuel refining*" (DoE, 2015).

In fact, South Africa is the only country globally that produces liquid fuels from coal to the scale that makes these fuels a very dominant contributor to the domestic liquid-fuels market. Only China produces liquids from coal in similar absolute scale, but in relative numbers it is significantly less than in South Africa.

Nuclear

South Africa hosts the only nuclear power plant on the African continent. Koeberg nuclear power station consists of two French-designed and -built reactors of a total of 1 800 MW net capacity with Unit 1 being completed in 1984 and Unit 2 in 1985. This power station produces approximately 5% of the South African domestic electricity supply.

Renewables

South Africa exhibits world-class solar resources with achievable annual energy yields from solar technologies that are amongst the best globally (SolarGIS, n.d.).

Less known, the country also has excellent wind resources with achievable load factors well above that of leading wind markets (Council for Scientific and Industrial Research (CSIR), 2016). More than 80% of the entire South African land mass has enough wind resource to achieve 30% annual load factor or more, whereas the actual average annual load factor of the entire wind fleets in Germany (46 GW installed capacity) and Spain (23 GW installed capacity) are 17-23% and 25-27% respectively (CSIR, 2016).

The highly successful Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) has grown utility scale wind and solar PV in South Africa from a zero base in 2013 to 2 040 MW by the end of 2015 (contributing 4.75 TWh to the electricity mix) (CSIR, 2015). The Small Projects IPP Procurement Programme also run by the DoE aims to procure renewable energy from smaller renewable power plants (<5 MW), while small-scale embedded generation is being considered by various industry stakeholders (likely via rooftop solar PV installations).

The hydro potential in South Africa is relatively limited, but countries in the South African Development Community (SADC) region (including Zimbabwe, Zambia, Democratic Republic of Congo and Mozambique) have vast potential for hydro power. In fact, ~5% of South Africa's electricity demand is currently supplied through hydro power imported from Cahora Bassa power station in Mozambique.

Transmission Grid

The South African transmission grid is characterised by the large geographical area that power is transmitted over (see Figure 2.3). Currently, the majority of the power generation (coal-fired) is located in the North East of the country, with a significant component of this power needing to be transmitted over significant distances e.g. ~1500 km. The 400 kV and 765 kV transmission systems transmits power from North to South. In future, it is anticipated that this power flow direction will reverse, predominantly as a result of a changing power generation mix. Strategic documents like the periodically published Eskom Transmission Development Plan (TDP) (Eskom Holdings SOC Limited, 2015b) and Generation Connection Capacity Assessment (Eskom Holdings SOC Limited, 2015a) as well as Strategic Grid Plan (SGP) (Eskom Holdings SOC Ltd, 2014) consider various scenarios to ensure that sufficient power transmission corridors and substations are planned for in advance to adequately integrate power generation expected in the future. The key planning document that feeds into these transmission plans is presently the IRP 2010.

Pipeline Infrastructure

The existing and potential South African national pipeline infrastructure is shown graphically in Figure 2.4 (Transnet SOC Ltd, 2015). There are currently only two major pipeline operators in South Africa; Sasol and Transnet. There is a minimal amount of existing gas pipeline infrastructure in South Africa. The main existing pipeline infrastructure is:

- The 865 km ROMPCO import pipeline (Pande/Temane-Secunda);
- The 85 km offshore PetroSA pipeline (FA platform-Mossel Bay);
- The 600 km Lilly pipeline (Secunda-Durban); and
- The 145 km Secunda-Sasolburg pipeline

As shown in Figure 2.4, there are long-term options for pipeline infrastructure in the study area (depending on SGD outcomes). These could link with existing ports in Cape Town, Saldannha Bay, Mossel Bay and Ngqura (Port Elizabeth). This gas network could then, in the future, link up to the existing gas networks at Sasolburg and Durban.

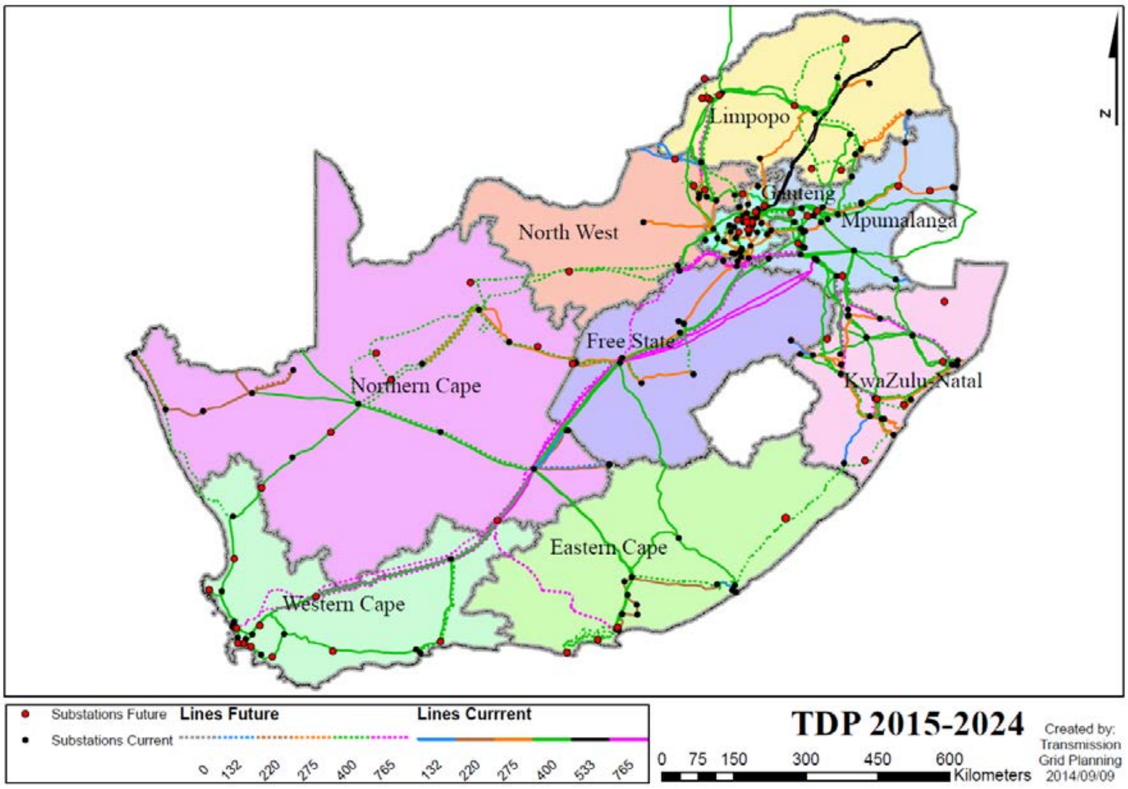

Figure 2.3: Existing and planned Eskom transmission grid infrastructure as per the Transmission Development Plan 2015-2024 (Eskom Transmission Group, 2014). There is existing transmission network infrastructure through the study area, with additional planned transmission infrastructure into the future.

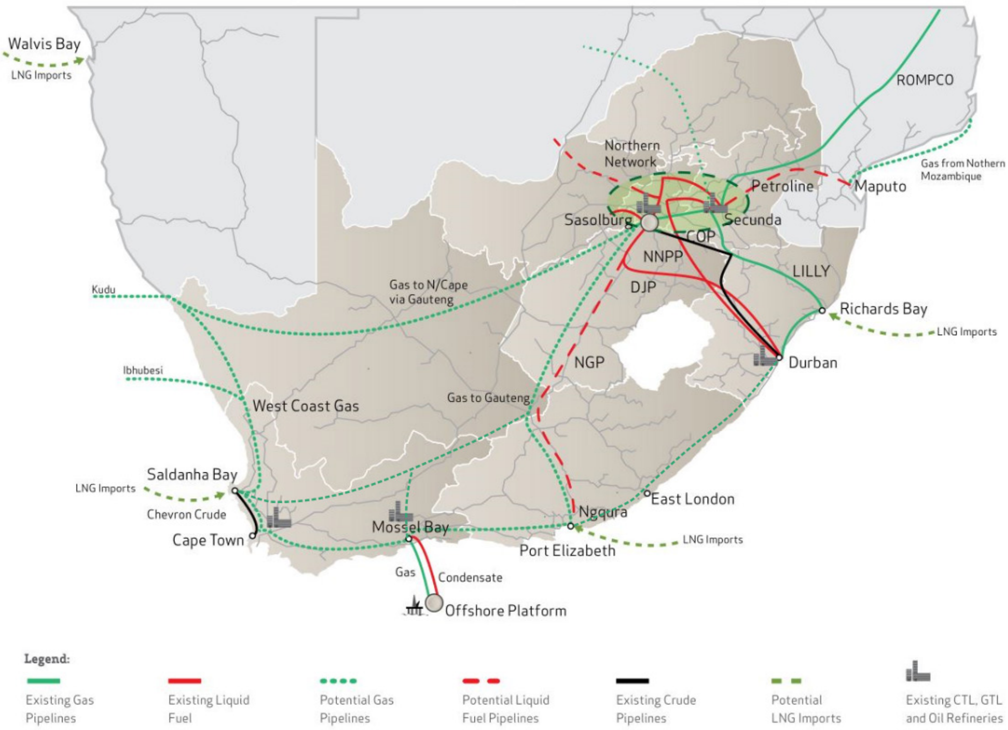

Figure 2.4: Existing and potential South African pipeline networks showing minimal existing gas pipeline infrastructure (adjusted from Transnet SOC Ltd (2015)). The long term potential for gas pipeline infrastructure through the study area is shown here.

2.1.3 Relevant legislation, regulation and practice

Energy Policy White Paper

The White Paper on the Energy Policy of the Republic of South Africa of 1998 laid the foundation for the approach to energy planning in the country (DME, 1998). Integrated energy planning, yet not optimal and dependent on availability of reliable data, was identified as the tool to be used by South African policy makers in the planning of the energy system (DME, 1998). Security of energy supply for South Africa through energy supply diversity was identified as one of the main goals. In addition, natural gas was already identified as a viable source of complementary primary energy supply to the existing mix.

National Energy Act and Electricity Regulation Act

The National Energy Act of 2008 prescribes that energy planning in South Africa must be conducted in an integrated manner and that the Energy Minister has the mandate and the obligation to conduct such planning (Parliament of the Republic of South Africa, 2008). Already, the Electricity Regulation Act of 2006 mentioned the term "Integrated Resources Plan", but was not explicit about the details of such a planning instrument (Parliament of the Republic of South Africa, 2006). The draft version of the Electricity Regulation Second Amendment Bill of 2011 is very explicit in that it prescribes an IRP to precede any implementation of new power generation capacity (DoE, 2011b).

National Development Plan (NDP) 2030

The NDP 2030 (National Planning Commission (NPC), 2012) is the overarching planning document for the development of South Africa and aims to eliminate poverty and reduce inequality in South Africa by:

- Enhancing the quality of life;
- Realising an expanded, more efficient, inclusive and fairer economy; and
- Enshrining leadership and promoting active citisenry.

The NDP 2030, as published in 2012, is composed of 15 Chapters. Two (2) introductory Chapters focus on policy-making and local demographic trends and the remaining 13 Chapters focus on specific sectors of South Africa each having their own defined specific objectives and actions. The NDP 2030 has 119 actions to implement. The NDP considers energy planning in a number of clear actions in Chapters 3, 4, 5 and 7. Specifically, related to natural gas in the energy system it states:

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16. *Enable exploratory drilling to identify economically recoverable coal seam and shale gas reserves, while environmental investigations will continue to ascertain whether sustainable* *exploitation of these resources is possible. If gas reserves are proven and environmental concerns alleviated, then development of these resources and gas-to-power (GTP) projects should be fast-tracked.*

17. *Incorporate a greater share of gas in the energy mix, both through importing LNG and if reserves prove commercial, using shale gas. Develop infrastructure for the import of LNG, mainly for power production, over the short to medium term.*

18. *Move to less carbon-intensive electricity production through procuring at least 20 000 MW of renewable energy, increased hydro-imports from the region and increased demand-side measures, including solar water heating.*

From a national planning perspective, it is therefore clearly supported to not only investigate shale gas opportunities, but to also exploit them, should they be economically viable.

Integrated Energy Plan (IEP) and Integrated Resources Plan (IRP)

From these high-level government policies flow the IEP for the entire energy sector, and the IRP for electricity. An overview of the integration between these plans (as well as others) is shown in Figure 2.5.

A draft of the IEP was circulated in 2013 for public comment (DoE, 2013a), but was not finalised. The most recent version of the IEP was being finalised, but was not publicly available for inclusion as a formal guiding policy document at the time of publication. However, it has been considered as a guide for the strategic direction of gas policy in South Africa. The DoE reported to Parliament in May 2016 on the IEP and IRP and indicated that they will be presented to the Parliamentary Portfolio Committee on Energy in the 3rd quarter of 2016/17 financial year, following which they would be submitted to Cabinet for approval. While these key planning documents are currently under revision and have not been updated for an extended period of time, it is very likely that natural gas as a primary energy fuel source will have a significant role to play in South Africa's energy future.

The DoE has adopted a central planning approach for the electricity sector. The latest promulgated version of the IRP is the IRP 2010 (DoE, 2011b). An update of the IRP 2010 was conducted in 2013, which was published for public comment but never promulgated (DoE, 2013b).

The approach (in-principle) to planning in the South African electricity sector is illustrated in Figure 2.6. At the core of the process is a mathematical least-cost optimisation model that, subject to certain boundary conditions and policy-adjustments, determines the least-cost expansion path for the South

African electricity system. The IRP 2010 has so far been implemented via the procurement of Independent Power Producers (IPPs).

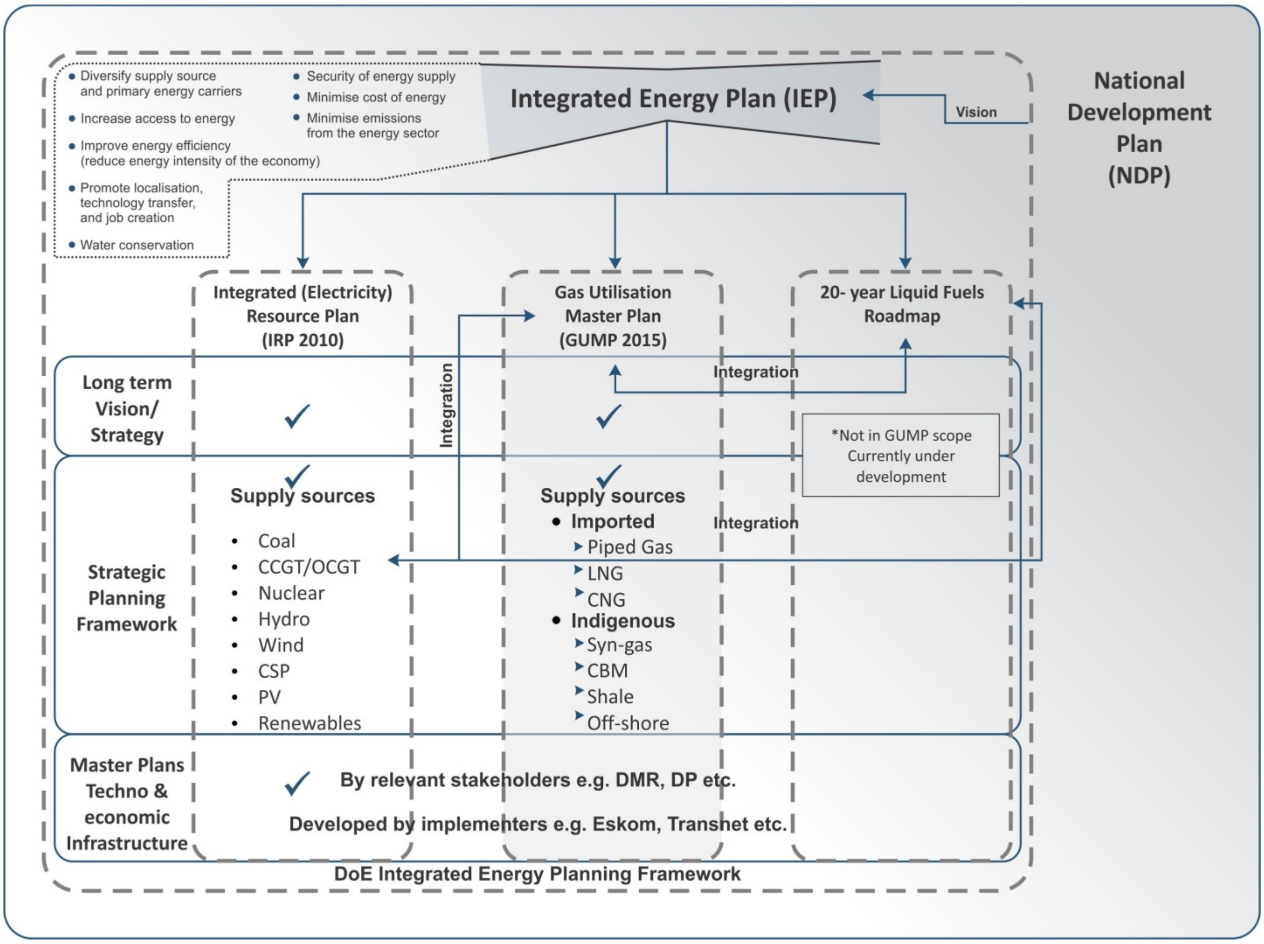

Figure 2.5: An extract from the draft IEP indicating the DoE Integrated Energy Planning Framework. The framework shows the envisioned integration between the principal energy plans of South Africa and the NDP 2030.

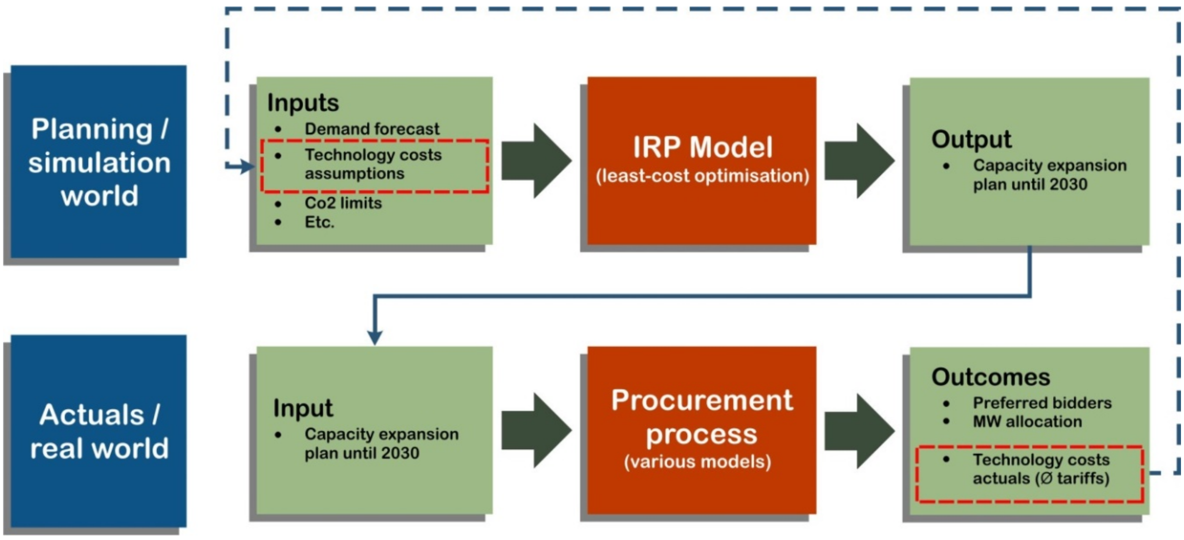

Figure 2.6: The principle approach to planning in the South African electricity sector, showing the expected feedback between the planning/simulation and the actual/real world domains.

Gas Act

As for natural gas specifically, the Gas Act of 2001 was promulgated with the objectives (amongst others) to promote the orderly development of the piped gas industry and to establish a national regulatory framework (Parliament of the Republic of South Africa, 2001). The Gas Amendment Bill (published draft for public comments in 2013), more broadly, has the objective to stimulate the natural gas industry and explicitly introduces a number of new gas technologies (e.g. gas liquefaction and regasification) (DoE, 2013c).

Gas Utilisation Master Plan (GUMP)

The DoE is at present finalising a Gas Utilisation Master Plan (GUMP) for South Africa, which will *"analyse potential and opportunity for the development of South Africa's gas economy and sets out a plan of how this could be achieved"* (DoE, 2016a). The GUMP will fit into South Africa's energy planning landscape with other principal energy planning processes as shown in Figure 2.6.

Natural gas plays a very small part of South Africa's current energy mix and the GUMP will form a critical part of diversifying the energy mix by outlining the possible future paths for natural gas market development. The DoE reported to Parliament in May 2016 on the GUMP and indicated that it will be presented to the Parliamentary Portfolio Committee on Energy in the 3rd quarter of 2016/17 financial year, following which they would be submitted to Cabinet for approval. At a high level, possible future gas market evolution paths taken from the draft of the GUMP are illustrated in Figure 2.7, where the three paths of "Niche", "Hub" and "Big Gas" are shown. The relationship between the scenarios developed in the GUMP and this scientific assessment are outlined in more detail in

Section 2.2. It should be noted that the "Big Gas" scenario of the GUMP and the "Big Gas" scenario of this scientific assessment are not the same and should be treated accordingly.

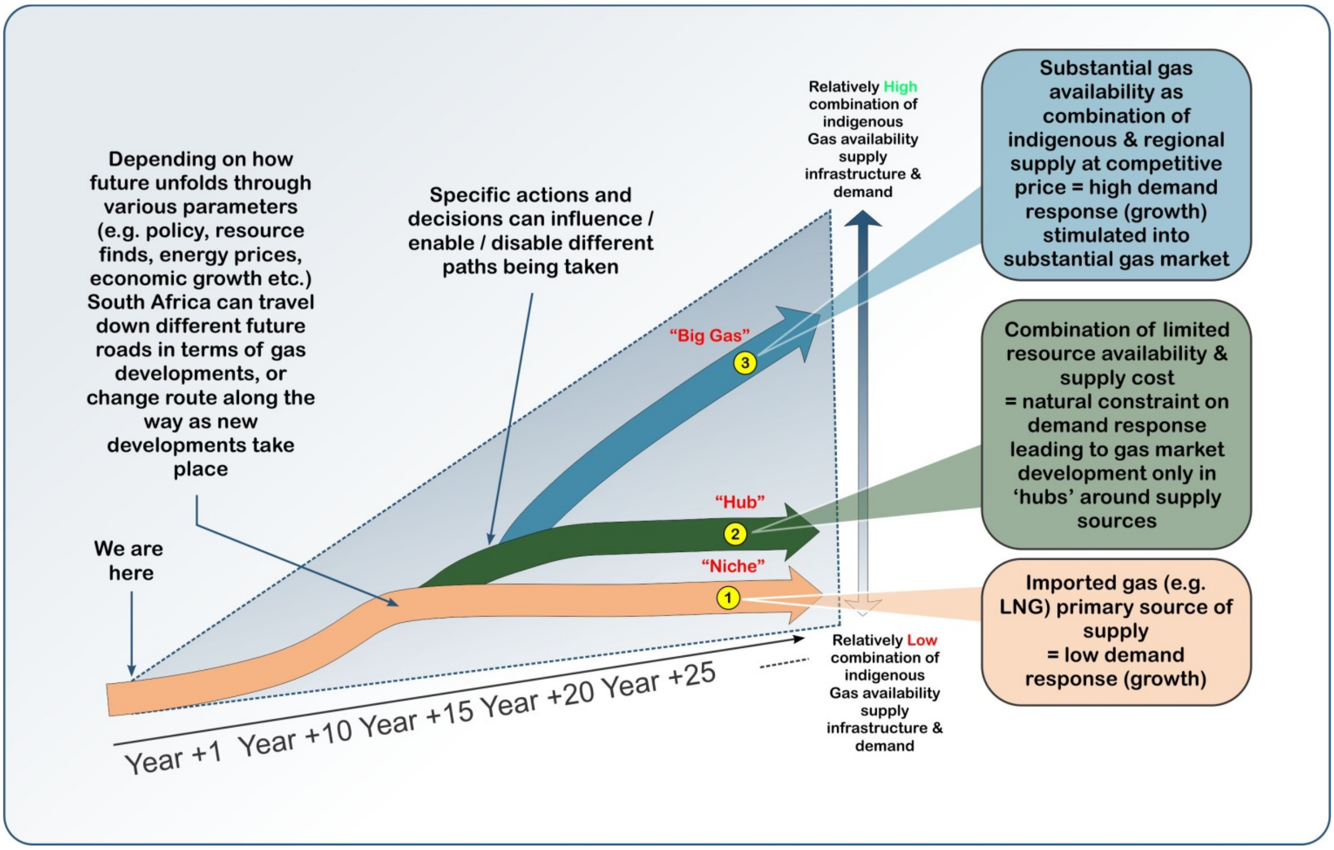

Figure 2.7: Gas Utilisation Master Plan (GUMP) illustration of possible future gas market evolution paths (Source: DoE, GUMP (Draft)).

Eskom Transmission Development Plan (TDP)

The TDP is an Eskom plan that outlines how the electric transmission system needs to be developed over the next 10 years. *"The Transmission Development Plan (TDP) represents the transmission network infrastructure investment requirements. The TDP covers a 10 year window and is updated annually. It indicates the financial commitments required by Eskom in the short to medium term."* (Eskom Holdings SOC Limited, 2015b). Specifically, this is inclusive of grid infrastructure required to integrate new gas-fired power plants.

Eskom Strategic Grid Plan (SGP)

The SGP is also an Eskom plan, which outlines strategically where new transmission grid developments need to be triggered (Eskom Holdings SOC Ltd, 2014). *"The Strategic Grid Plan formulates long term strategic transmission corridor requirements. The Plan is based on a range of generation scenarios and associated strategic network analysis. The time horizon is 20 years. The SGP is updated every 2-3 years"* (Eskom Holdings SOC Limited, 2015b).

Eskom Generation Capacity Connection Assessment (GCCA)

The GCCA (Eskom Holdings SOC Limited, 2015a) is periodically published by Eskom in response to a government call to connect IPPs planned for under the IRP 2010. It establishes existing connection capacity available at each Main Transmission Substation (MTS) as well as planned strategic transmission corridors and MTSs based on the latest version of the TDP (Eskom Holdings SOC Limited, 2015b). The GCCA has historically been updated every 2-4 years.

Transnet Long-term Strategic Framework (LTSF)

The LTSF, as developed by Transnet in 2015, provides a long term and broader view of transportation networks required, including expansions of existing transportation infrastructure (Transnet SOC Ltd, 2015). Specifically, natural gas infrastructure planning and pipeline developments include the possibility of SGD.

2.1.4 Overview of international experience

The United States of America (USA) has by far the largest experience in shale gas exploration and production. In 2014, shale gas to the amount of almost 14 000 PJ was produced in the United States (US), which contributed almost 20% to the entire domestic primary energy production of 82 500 PJ in the US (EIA, 2014; EIA, 2015a). This is a tenfold increase of shale gas contribution compared to 2007, when less than 1 400 PJ of shale gas where produced. Shale gas has therefore been a significant contributor to domestic energy sources and hence to security of supply and trade balance improvements for the US in recent years. The latest projections to 2040 by the EIA indicate that the majority of natural gas production in the US will come from shale gas (Figure 2.8) while Figure 2.9 shows that there will likely be a growing role for shale gas to play internationally (EIA, 2016a).

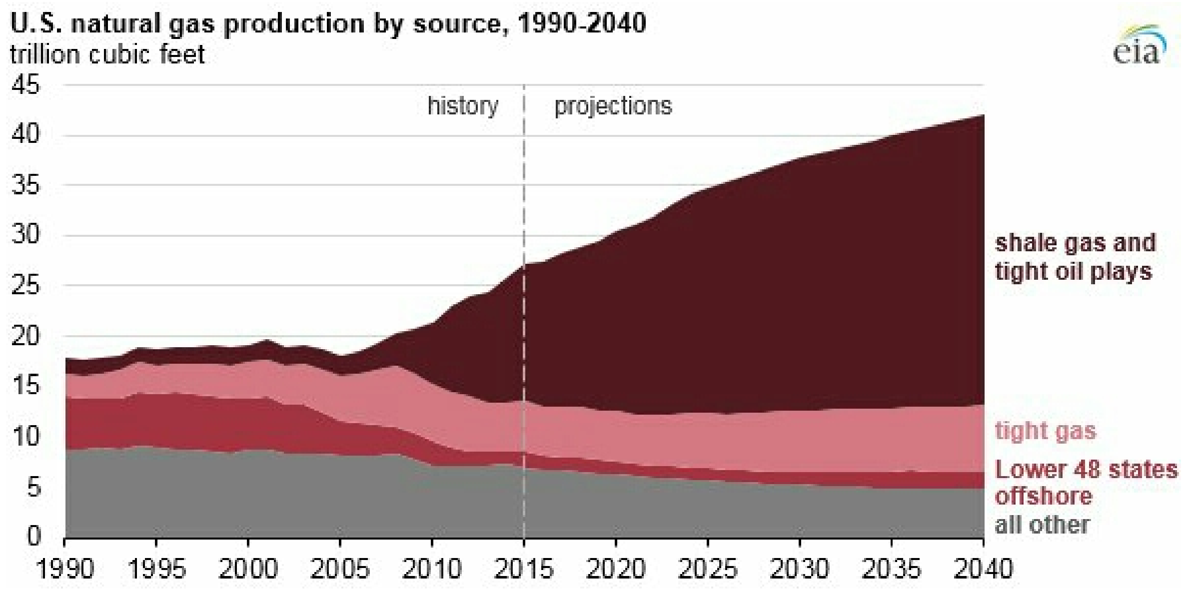

Figure 2.8: Historical and projected shale gas production in the US (EIA, 2016a), showing the significant and growing role that shale gas is likely to play in future for the US.

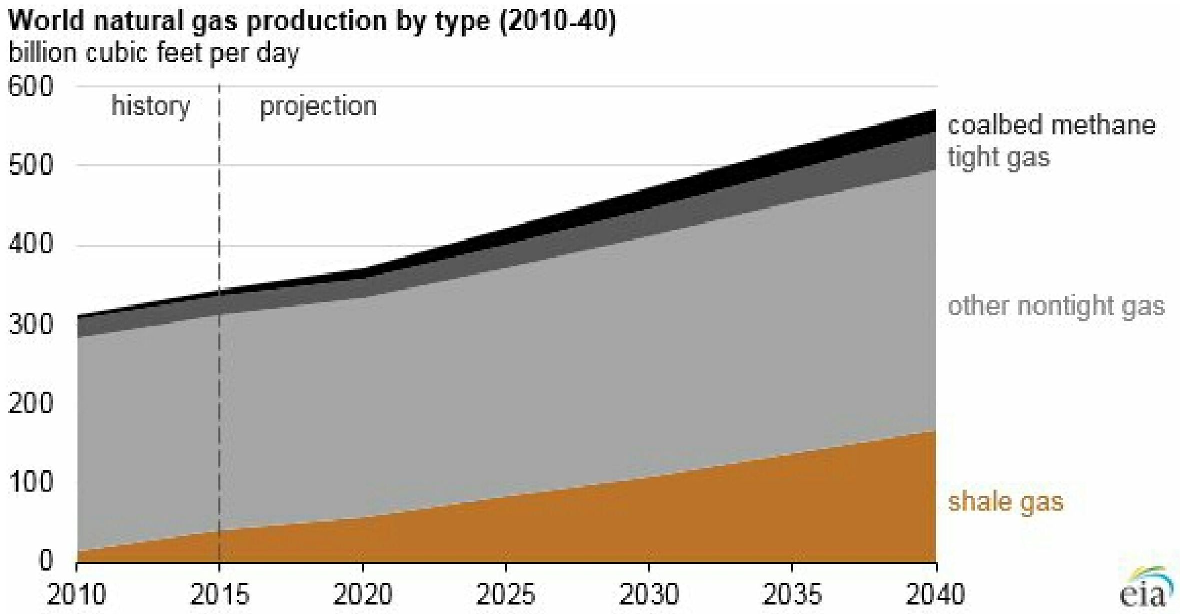

Figure 2.9: Historical and projected shale gas production internationally (EIA, 2016a), showing the growing role that shale gas is likely to play in future.

In the US, if a shale gas resource is discovered, the land owner is the owner of the resource. As a result, shale gas is predominantly privately owned but with regulatory oversight. This is notable considering the South African context of resource ownership in the context of the Mineral and Petroleum Resources Development Act (MPRDA) Amendment Bill released in 2012 (but referred back to Parliament by the President in January 2015). More recently, in the Minister of Energy Budget Speech Vote 2016/17, the relevant framework for the oil and gas supply chain is proposed to be separated from the MPRDA Amendment Bill into an "Upstream Gas Bill" and a separate "Gas Amendment Bill" for the midstream gas value chain (DoE, 2016c).

The developments in the US happened in a short timeframe of just the last decade. The high-level effects of the shale gas boom in the US are that:

- First, a portion of power production from coal was replaced by electricity from gas-fired power stations (Logan et al., 2015);
- Second, domestic shale gas replaced imported gas and put on hold or cancelled the envisaged importation of natural gas;
- Third, shale gas added sufficient supply to the US natural gas sector to cut natural gas spot prices by more than half in recent years (from 4-5 US$/MMBtu in 2009-2011 to below ~2.50 US$/MMBtu in 2015) (EIA, 2016b).

The first effect is the significantly reduced carbon emissions in the US power sector in the last 10 years (EIA, 2015b). As a first-order effect, cheap shale gas-fired power generation replaced coal-fired power generation. The deployment of new natural gas fired power generation has not been significantly high in the past decade but rather most of the shift away from coal-fired generation has been a result of a "re-dispatch" of existing plants. Utilities are operating existing fleets of coal plants less and increasing operations at existing gas-fired plants. This has all happened as a result of significant amounts of new renewable capacity being deployed (specifically solar PV). Because of the roughly 50% lower carbon emission factor of natural gas compared to coal, combined with the higher efficiency of gas-fired compared to coal-fired power stations, this led to a lower carbon-intensity of the electricity supply. From an energy planning perspective, this development reduced the immediate need for a very fast deployment of renewable energy sources in the energy and power sector in order to contain the US's CO_2 emissions.

In the African context (see Figure 2.10), based on EIA (2013), Algeria has by far the highest level of technically recoverable resources (707 tcf, ~750 000PJ) while South Africa (390 tcf, 410 000 PJ), Libya (122 tcf, 130 000 PJ) and Egypt (100 tcf, 110 000 PJ) have significant technically recoverable shale gas resources. Other African countries with smaller shale gas resources thus far include Chad (44 tcf, 47 000 PJ), Tunisia (23 tcf, 24 000 PJ), Morocco (12 tcf, 12 500 PJ) and Western Sahara (8.6 tcf, 9 100 PJ). The technically recoverable reserves in South Africa do have a high level of uncertainty associated with them but an independent study performed for the DoE as part of the GUMP has revealed up to 120 tcf of shale gas potential; of which 9 tcf is economically recoverable.

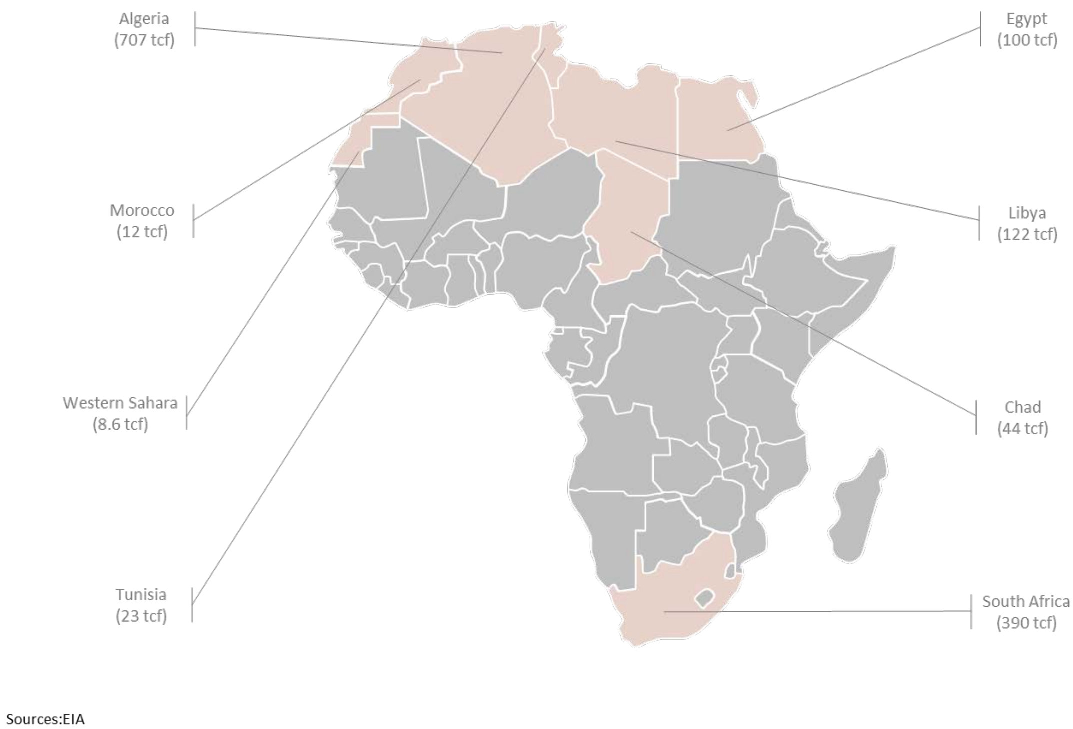

Figure 2.10: Technically recoverable shale gas resources in Africa (EIA, 2013). Most shale gas countries are in North Africa. Algeria has the largest shale gas resource with South Africa having the second largest.

2.2 Key potential impacts on energy planning and options

2.2.1 Natural gas in the South African energy planning landscape

In this Chapter the impacts of the different shale gas scenarios on energy planning and energy security are elaborated. This will lead to a risk assessment of the shale gas scenarios from an energy planning and energy security perspective.

The draft of the IEP includes four main scenarios (Base Case, Environmental Awareness, Resource Constrained and Green Shoots). A sensitivity of these scenarios was a scenario that explicitly assumed no shale gas in South Africa. The impact of this no shale gas scenario is that energy security will be slightly reduced following an increased requirement for imports of comparatively more expensive refined petroleum products (and resultant increased overall energy costs, specifically LNG). This scenario also aligns quite well with the “Niche” scenario in the draft of the GUMP being developed where gas is predominantly imported (via LNG terminals) with very small scale indigenous production and regional pipeline imports.

The IRP 2010 plans the capacity-expansion programme for the power sector in South Africa until 2030 (DoE, 2011b). The promulgated version of IRP 2010 calls for 3.9 GW of new peaking plants (gas-fired Open Cycle Gas Turbines (OCGTs), or similar) and 2.4 GW of new mid-merit gas-fired power plants (Combined Cycle Gas Turbine (CCGTs)) (DoE, 2011a). Examples of OCGTs and CCGTs are shown in Figure 2.11 and Figure 2.12 respectively. OCGTs are cheaper to build than CCGTs, they are more flexible, but also have a lower efficiency when compared to CCGTs. Figure 2.13 shows the planned capacities and electricity production as per the IRP 2010.

In the IRP 2010, the planned CCGT and OCGT capacities by 2030 have the operating regime outlined in Table 2.1. These numbers indicate that CCGTs in the IRP 2010 are planned as mid-merit plants which do load-following during the day and which usually do not operate during night. The reason for this is that gas-fired CCGTs have a lower levelised cost of energy than new-build coal-fired power stations at low load factors. Hence they supply the mid-merit-type of demand of load-following during the day. The OCGTs are planned as a pure “safety net” for the system with insignificant load factors and hence with insignificant gas demand/throughput for these plants. OCGTs are relatively cheap to build but expensive to operate, and are therefore pre-destined for this type of use case with very low annual load factor.

Although never promulgated, in the Base Case of the IRP Update 2013, the installed capacities for gas-fired power stations were adjusted upwards to 3.6 GW of CCGT and 4.7 GW of OCGT by 2030. The electricity production and associated load factors of these plants in the IRP Update 2013 are shown in Table 2.1 (the IRP update was not promulgated and hence the values are shown for indicative purposes). The load factor of the CCGTs in 2030 is considerably higher than in the original IRP 2010 (38%) but by 2050 drops back to 22%. The main reason for the increased capacities of gas-fired power generators moving from the IRP 2010 to the IRP Update 2013 is the more graduated phasing of planned nuclear capacity by 2030. The resulting energy gap in the IRP Update 2013 is filled with a mix of VRE and natural gas-fired power stations. The load factor for the OCGT fleet stands at 2-3% in 2030/2050 – again acting as the safety net for the power system.

Figure 2.11: Existing OCGTs at Atlantis, South Africa (9 x 148 MW, 1 327 MW Ankerlig power station) currently running on diesel (Eskom Holdings SOC Ltd, n.d.). Similar plants will be part of new OCGT capacity planned for in the IRP 2010 but will run on natural gas.

Figure 2.12: Existing CCGTs at Wilaya of Tipaza, Algeria (3x400 MW configuration, 1 227 MW Shariket Kahraba Hadjret En Nous power station) (Mubadala Development Company PJSC, 2016). Similar plants will be part of new CCGT capacity planned for in the IRP 2010.

The IRP 2010 assumed natural gas to be priced at LNG prices (planning assumption in the IRP 2010: 42 ZAR/GJ i.e. ~11 US$/MMBtu). The plan did not explicitly consider shale gas yet as a planning option. It assumed a certain gas supply at a certain cost without making reference to shale gas. From an energy planning perspective in the power sector, it should be noted that the only relevance that shale gas has is the availability of fuel (quantities) and the price of the fuel (US$/MMBtu). Whether a certain quantity and a certain fuel price can be achieved through imported piped gas, imported LNG or through domestic conventional or shale gas resources is irrelevant for the IRP-type power sector planning. These different supply streams will obviously lead to a very different gas industry structure depending on what combination is pursued. This is however something not considered in the IRP. This is considered in more detail in the GUMP, which will integrate with the IRP in future revisions. Similarly, these plans (IRP and GUMP) are guided by the overarching IEP (as is the Liquid Fuels Master Plan (LFMP) currently under development). The integration between the key energy planning processes in the South African energy sector is shown in Figure 2.13.

Table 2.1: Installed capacities and load factors of new CCGT/OCGT for South Africa as per IRP 2010 (DoE, 2011b) and Base Case of the IRP 2010 Update (2013) (DoE, 2013b).

IRP 2010 **Policy adjusted**	**CCGT**	**OCGT (new)**
Total electricity demand in 2030	435 TWh, 68 GW (peak load)	
Installed capacity in 2030	2.4 GW	3.9 GW
Electricity production in 2030	4.2 TWh *(shale gas equivalent: 25-35 PJ/a)* *(LNG equivalent: 0.8 mmtpa)*	0.1 TWh
Average load factor in 2030	20%	< 1%
IRP Update 2013 **Updated Base Case**	**CCGT**	**OCGT (new)**
Total electricity demand in 2030	410 TWh, 61 GW (peak load)	
Installed capacity in 2030	3.6 GW	4.7 GW
Electricity production in 2030	12 TWh *(shale gas equivalent: 70-80 PJ/a)* *(LNG equivalent: 2.5 mmtpa)*	0.9 TWh *(shale gas equivalent: 10-15 PJ/a)* *(LNG equivalent: 0.5 mmtpa)*
Average load factor in 2030	38%	2%
Total demand in 2050	525 TWh, 80 GW peak load	
Installed capacity in 2050	6.4 GW	12.2 GW
Electricity production in 2050	12 TWh *(shale gas equivalent: 70-80 PJ/a)* *(LNG equivalent: 2.5 mmtpa)*	3.3 TWh *(shale gas equivalent: 35-45 PJ/a)* *(LNG equivalent: 1 mmtpa)*
Average load factor in 2050	22%	3%

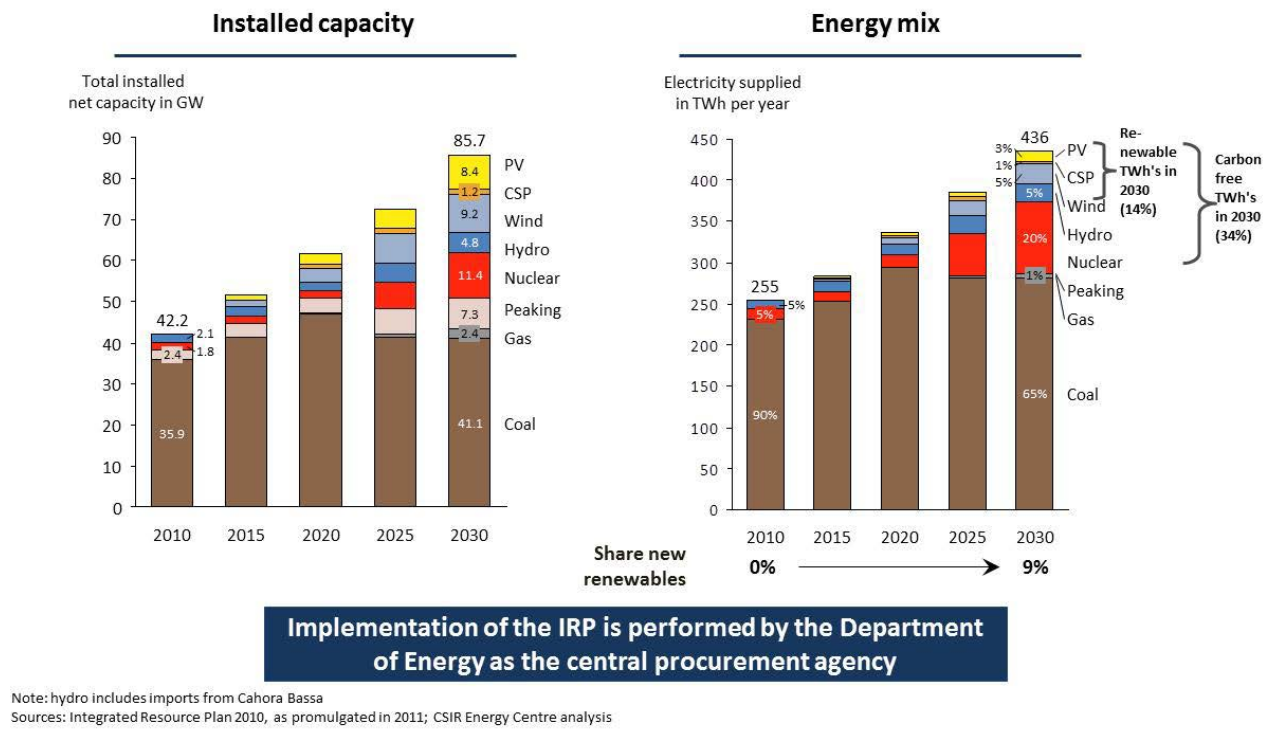

Figure 2.13: IRP 2010-2030 as promulgated in 2011

2.2.2 Impacts and mitigations

For reference, scenarios considered in this scientific assessment report are summarised in Table 2.2.

Table 2.2: Overview of scenarios as defined for the scientific assessment

Scenario	Available shale gas	Annual shale gas production (40 years)[1]	Estimated cost of shale gas[1]
Scenario 0 (Reference Case)	-	-	-
Scenario 1 (Exploration Only)	0 tcf	0 PJ/a	N/A
Scenario 2 (Small Gas)	5 tcf ≈ 5 300 PJ ≈ 1 500 TWh	130 PJ/a ≈ 40 TWh/a *(≈50% of current natural gas supply in South Africa)*	6-10 US$/MMBtu = 20-35 US$/MWh
Scenario 3 (Big Gas[2])	20 tcf ≈ 21 000 PJ ≈ 5 900 TWh	530 PJ/a = 150 TWh/a *(2.5-3.0 times current natural gas supply in South Africa)*	4 US$/MMBtu = 15 US$/MWh

[1] *Estimated based on generally accepted industry practice and national energy planning resources.*
[2] *The "Big Gas" scenario of this report and the "Big Gas" scenarios of the IRP and GUMP are not the same scenarios and should be treated accordingly.*

In principle, "expensive", "nominal" and "cheap" gas prices can be envisaged from an energy planning perspective for the scenarios presented. At this stage, whether natural gas is sourced from regional pipeline imports, LNG imports or shale gas is not considered yet nor is the source of gas critically significant from an energy planning perspective. The impacts on energy planning and energy security for each of the scenarios are outlined.

For all cases we assume that the available gas quantities are not a constraint and that only economic considerations determine gas utilisation[1].

1) Expensive gas (gas priced between 10-20 US$/MMBtu - ≈35-70 US$/MWh)
    a. It is economical to utilise gas-fired power stations as an enabler for renewables (solar PV and wind), where the relatively expensive gas provides the flexibility to allow large quantities of relatively cheap renewables based electricity to be deployed in the electricity sector. This is one of the many complementarities between natural gas and renewables like solar PV and wind (Lee et al., 2012). As mentioned in the draft of the GUMP, gas usage at these prices would also act as a "primer" for possible future expanded natural gas usage in the wider economy. Solar PV and wind act as fuel-savers for the existing thermal fleet (coal and gas). Depending on the cost of new build coal and nuclear capacity, the mix of solar PV, wind and natural gas can already be cheaper than these new-build options, even at these high gas prices (gas-based electricity will only make up a small portion of the total solar PV, wind and gas mix) (Bischof-Niemz, 2016).
    b. The electrical grid implications in this case will be minimal as significant transmission grid infrastructure already exists in the study area and it is likely that there will be a de-loading effect on the large North-South transmission corridor for the proposed power plant. Of course, sufficient proactive detailed grid planning will be required of which a significant portion of this is already being performed as part of various strategic planning documents (TDP, GCCA and SGP previously outlined).
    c. It is also economical to use gas as a substitute to electricity in the heating sector (especially residential space heating and cooking). Of course, localised heating demand in the study area will likely be very small. As a result, associated pipeline infrastructure will need to be developed if deemed economically feasible to transport gas to major urban settlements where end-use markets will be much larger.
    d. For a large compressed natural gas (CNG) uptake in the transport sector these gas prices are too high. However, even at high natural gas prices, the use of gas in transportation can prove beneficial in terms of emissions (especially in urban environments).

[1] Projections of actual shale gas prices would require an individual investigation in itself (or set of investigations); hence, the reason for assuming three cases of shale gas prices ("cheap", "nominal" and "expensive"). The draft of the GUMP does attempt to estimate shale gas prices but these are for illustrative purposes only.

e. For GTL production these prices are also too high (Sajjad et al., 2014; Al-Shalchi, 2006). Break-even crude oil prices at which GTL would be feasible at these natural gas prices would be in the range of ~100-180 US$/bbl i.e. only in very expensive crude oil scenarios.

f. The price of gas at these levels is aligned with the IRP Update 2013 (~11 US$/MMBtu). Thus, the gas volume by 2030 at these gas prices is anticipated to be as per the IRP Update 2013, approximately 80-90 PJ/yr (3 mmtpa of LNG equivalent), which is an additional ~50% of current gas demand in South Africa.

2) Nominal gas (gas priced between 6-10 US$/MMBtu – ≈20-35 US$/MWh)

a. Solar PV and wind are still fuel savers for a gas-fired power fleet, because the full lifetime cost of solar PV and wind per energy unit (today: 50-70 US$/MWh; by 2030: 40-60 US$/MWh) are still lower than the pure fuel-cost of gas-fired power generation. The mix of natural gas, solar PV and wind is now certainly cheaper than new-build coal and nuclear capacity.

b. More detailed grid planning (not only relating to the study area) may be necessary in this case as a result of significantly higher levels of gas-fired generation in a number of geographical locations. This will be in addition to the periodic strategic plans currently developed by Eskom (TDP, GCCA and SGP amongst others). Likely geographical locations could include locations within the study area, ports (Saldanha Bay, Mossel Bay, Richards Bay, Coega) and possibly areas surrounding Secunda and Sasolburg where pipeline gas is currently imported from Mozambique (Transnet SOC Ltd, 2015).

c. The utilisation of gas in the heating sector starts making sense not only in residential applications with relatively high cost of alternatives (high residential electricity tariffs), but also in industrial applications for process heat production (competitors: coal, biomass, cheaper-priced electricity). As previously mentioned, associated pipeline infrastructure will need to be developed if deemed economically feasible to transport gas to major urban settlements where end-use markets will be much larger.

d. Petrol and diesel cost approximately 40 US$/MWh to produce (at 50 US$/bbl crude oil price). At the assumed gas prices it therefore starts to become economical to convert the petrol-driven car fleet to CNG fuel. To put this into perspective, the petrol energy demand in Gauteng represents approximately 36 TWh/yr (South African Petroleum Industry Association (SAPIA), 2014). This is equivalent to ≈120 bcf/yr of natural gas or 20% of South Africa’s 2013 natural gas production and imports.

e. For GTL or other chemical processes, the envisaged gas prices are still too high (Sajjad et al., 2014; Al-Shalchi, 2006). Break-even crude oil prices at which GTL would be feasible at these natural gas prices would be in the range of ~70-100 US$/bbl.

f. The additional gas volume triggered at these gas prices is likely higher than in the IRP Update 2013 as a result of additional end-use opportunities for gas at these prices. A re-run of the IRP at these gas prices would likely also lead to solar PV/wind/gas contributing significantly more to the electricity mix than currently envisaged. Indicative additional gas demand is 200-300 PJ/yr (56-83 TWh/yr or 190-280 bcf/yr). This is made up of 200 PJ/yr in the electricity sector to balance VRE and 100 PJ/yr from additional gas demand outside the electricity sector.

3) Cheap gas (gas priced at 4 US$/MMBtu – ≈15 US$/MWh)

a. Baseload gas-fired power generation in the form of CCGTs are now the cheapest new-build options of all alternatives (selected existing coal plants could also be repowered to run on natural gas if deemed feasible). It is cheaper than new-build coal, but in addition the pure fuel cost of natural-gas-fired power stations are now cheaper than the envisaged full lifetime costs of solar PV and wind. Solar PV and wind do not play a cost-efficient fuel-saver role anymore. From a pure economic perspective, it would make most sense to supply the entire electricity demand from natural gas only (refer to Big Gas scenario in IRP Update 2013 and draft of the GUMP). But from an environmental perspective, significant amounts of renewables would have to be introduced into the electricity system to achieve the country's CO_2 reduction targets. A pure gas-based power system and a VRE/gas power system are cost-wise at a tipping point at such low gas prices. Therefore, it a minimal regret decision to deploy renewables anyways, even if the fuel-saver logic of scenarios with higher gas costs does not fully apply anymore.

b. Significant changes in detailed grid planning assumptions will be necessary as a result of notable changes in generation mix (as mentioned above). As previously mentioned, in addition to the strategic grid planning performed in periodic plans like the TDP and SGP it will be necessary to perform a significant amount of detailed grid planning in order to integrate the significant gas-fired fleet when gas prices are at these low levels.

c. Gas is fully cost competitive in all heating applications. Associated pipeline infrastructure will need to be developed to transport gas to major urban settlements for residential end-use. Local industrial demand may be significant in this scenario.

d. Gas is fully cost competitive in the transport sector as replacement fuel for petrol/diesel-driven vehicles.
e. GTL now also starts to become economical (Sajjad et al., 2014; Al-Shalchi, 2006) as break-even crude oil prices would be > 50 US$/bbl – however for the domestic market it is likely more reasonable to convert the transport fleet into CNG-driven vehicles. In addition, the high carbon-intensity of GTL fuels will have clear impacts on South African climate change obligations. For an export market, GTL-based fuel can make economic sense but it is likely in this scenario that global oil prices will also be low as a result of successful shale programs globally. However, because of the high carbon-intensity of such a fuel it is unlikely that the addressable market size globally will be large.
f. At such low gas prices the domestic production of fertilisers may start to make economic sense.
g. Exporting of natural gas through LNG export terminals may become an option.
h. The additional gas demand under this very-low gas price scenario would be as per the Big Gas scenario of the IRP Update 2013, i.e. between 2 600 – 3 300 PJ/yr (720 – 920 TWh/yr, 2 450-3 100 bcf/yr) with additional offtake from many sectors outside the electricity sector.

Reference Case and Exploration Only Scenario

The Reference Case and Exploration Only scenarios align quite well with the draft IEP scenario where no shale gas is assumed. The impact of this is that energy security will be slightly reduced following an increased requirement for imports of comparatively more expensive refined petroleum products and LNG and/or pipeline imports. This scenario also aligns quite well with the "Niche" scenario in the draft GUMP, where gas is predominantly imported (via LNG terminals) with very small scale indigenous production and regional pipeline imports (an estimate of 1 tcf of overall gas supply assumed for South Africa in this scenario).

In the electricity sector, the status quo in energy planning would be to consider shale gas as an "add on" to the already planned GTP generation based on the abovementioned LNG and/ or regional pipeline imports. No shale gas will mean that the IRP base case planning assumptions are implemented, and any cheaper gas than planned will improve the cost and flexibility position.

Small Gas

The draft version of the GUMP estimates shale gas prices in the range of 7-11 US$/MMBTu, and up to 10-14 US$/MMBTu if the state's free carry is implemented as part of the MPRDA Amendment

Bill and associated legislation being considered (depending on size of reserves and cost assumptions). In this scenario, it is likely to be on the higher end of the estimation at 11-14 US$/MMBTu.

This scenario aligns quite well with the “Hub” scenario of the GUMP where a combination of limited domestic shale gas (and CBM) is available, and localised hubs develop around gas sources i.e. surrounding the study area for shale gas. In the GUMP, there is an estimate of 1-10 tcf of gas supply assumed in this scenario (fitting quite well with the volumes assumed for this scenario, 5 tcf).

The quantity of shale gas available in this scenario is approximately 65% of the natural gas in the South African energy system. The gas volume in this scenario is therefore not suitable for a very large uptake of natural gas and subsequent large gas infrastructure investments. In this scenario the shale gas will likely be utilised for power production and possibly some domestic offtake with small volumes (some residential and industrial heating applications and possible conversion of a portion of the petrol/diesel-driven car fleet to CNG) in urban environments outside of the study area.

In this scenario, some additional detailed electrical grid planning (not only relating to the study area) may be necessary as a result of likely higher levels of gas-fired generation in a number of geographical locations.

It is unlikely that GTL will be deployed in this scenario, as the quantities of available natural gas are expected to be too small to justify such investment. In this scenario there could be a transition of anchor gas demand away from imported gas (pipeline and/or LNG) to domestic shale gas. As long as the shale gas is cheaper than these two alternative gas sources, a substitution effect will happen. No additional switching to gas due to low enough prices would materialise.

The main effect of this scenario on energy planning is a trade balance effect, where imported gas sources would be substituted with domestic shale gas. No significant implications are envisioned regarding gas transmission infrastructure planning requirements unless CNG for transportation in urban environments is opted for following which a pipeline network to these urban environments will be required.

Big Gas

As previously mentioned, the draft version of the GUMP estimates shale gas prices in the range of 7-11 US$/MMBTu and up to 10-14 US$/MMBTu if the state's free carry is implemented as part of the MPRDA Amendment Bill and associated legislation being considered (depending on size of reserves and cost assumptions). In this scenario, the price of shale gas is likely to be on the lower end of the estimation at 7-10 US$/MMBTu or less. However, there is a risk of escalating costs even with high shale gas quantities due to up-scaling challenges.

The quantities of shale gas in the Big Gas scenario align relatively well with the IRP 2013 Update Big Gas scenario and high levels of shale gas in the "Big Gas" scenario of the draft GUMP, in which the assumption of a significant shale gas-based boom occurs in South Africa (with gas at relatively low prices). There is assumed gas supply of 10-30 tcf of gas supply in South Africa in this scenario. The assumed gas price in this Big Gas scenario of the IRP Update 2013 is 4 US$/MMBtu. This Big Gas scenario of the IRP 2013 Update and draft of the GUMP is slightly higher when compared to the Big Gas scenario for this report in terms of assumed gas costs but is used as a proxy at this stage to represent a large shale gas scenario. To give an idea of the relative scale of this, in the Big Gas scenario of the IRP Update 2013 the total gas consumed in 2030 and 2050 absorbs the shale gas quantities of the Small Gas and Big Gas scenarios respectively in 6-8 years.

The results for a "Big Gas" scenario from the IRP Update are shown in Table 2.3. In this case of very cheap gas, the bulk of the South African electricity is supplied from gas-fired power stations. The entire fleet of CCGTs now runs at 70-80% average annual load factor, supplying mid-merit and baseload demand. In 2030, there is a ≈25% share of gas fired power generation in the energy mix while in 2050 this becomes ≈85% (this is a very imbalanced energy mix but is expected as a result of this being a "Big Gas" scenario).

The rollout of these levels of gas-fired power generation will likely necessitate significant changes in detailed transmission grid planning assumptions as a result of notable changes in generation mix (not only for gas fired generation). As previously mentioned, detailed grid planning performed in the periodic plans like the TDP and GCCA will need to be updated accordingly.

In this scenario, gas is fully cost competitive in heating (residential/commercial/industrial), transport, GTL (with the development of a new GTL facility), domestic fertiliser production and possibly LNG export applications.

Table 2.3: Installed capacities and load factors of new CCGT/OCGT in South Africa as per the Big Gas scenario of the IRP Update 2013 (DoE, 2013b)

IRP Update 2013 Updated Base Case	**CCGT**	**OCGT (new)**
Total electricity demand in 2030	410 TWh, 61 GW (peak load)	
Installed capacity in 2030	16.3 GW	1.4 GW
Electricity production in 2030	106 TWh *(shale gas equivalent: 600-800 PJ/a)*	0.3 TWh
Average load factor in 2030	74%	2%
Total demand in 2050	525 TWh, 80 GW peak load	
Installed capacity in 2050	62.5 GW	6.7 GW
Electricity production in 2050	440 TWh *(shale gas equivalent: 2 600-3 300 PJ/a)*	0.3 TWh
Average load factor in 2050	80%	< 1%

2.3 Risk assessment

2.3.1 Measuring risks and opportunities

The risk assessment approach considers risk to be the product of the probability of a specific event/trend occurring and the consequences of that specific event/trend with/without mitigation[2].

Table 2.4 summarises the impacts considered in the following risk assessment. Details of the impacts are:

1) Energy security: How does the development of shale gas affect the position with respect to energy security?
    a. Consequences of reduced energy security has the following range:
        i. *"Slight"* considered to be a minimal increase in energy imports of an additional ~5% from existing ~20% of total primary energy;
        ii. *"Extreme"* is considered to be a doubling of energy imports to more than 50% of total primary energy.
    b. The risk of reduced energy security with low levels of SGD is relatively low but measurable as increased imports of LNG will be necessary (as well as refined petroleum products). Even without shale gas though, the planning assumptions are such that energy security and energy independence are not jeopardised significantly (LNG infrastructure is already being considered as the "primer" for gas to play a bigger role in South Africa's energy future). Any domestic energy

[2] Please refer to the Preface of this scientific assessment for details on this approach (Scholes et al., 2016).

source in addition to the already highly endowed energy landscape (abundant coal, solar and wind resources) can only improve the already high security of supply level.

c. The high dependence of the country on imported crude oil for transport is an energy security consideration that if abundant and cheap shale gas results; GTL, CNG and electricity-driven transport systems could bolster energy security.

d. The primary actors likely best positioned to mitigate against energy security risk related to shale gas would be at a national level i.e. the DoE and Department of Mineral Resources (DMR). Other actors would include Nersa, state-owned enterprises (Eskom, PetroSA) and upstream/midstream operators and developers.

2) Energy cost: How does the development of shale gas affect the cost of energy in South Africa?

   a. Consequences of increased energy costs has the following range:

      i. *"Slight"* is considered to be annual energy cost increases aligned with consumer price index (CPI);

      ii. *"Extreme"* is considered to be annual energy cost increases at more than double CPI.

   b. The risk of high energy costs due to SGD is low if energy planning is initially based off LNG and imported piped gas as baseline planning assumptions.

   c. The risk is mainly linked to sub-optimal planning outcomes if energy planning is based on the assumption of the availability of low-cost shale gas which then does not materialise. Shale gas is low risk when planning off a zero shale gas baseline. The main risk arises if shale gas pricing/volumes are assumed, influencing investment decisions, but then don't materialise. At this stage, the key mitigation is that energy planning principal documents (IEP, IRP and GUMP) do not primarily assume cheap shale gas but rather assume the availability of shale gas as an option in specific scenarios.

   d. The primary actors who would likely be in the best position to mitigate against high energy costs would be at a national level and include Nersa, DoE and DMR. Other actors would include state-owned enterprises as well as private operators and developers active in the upstream/midstream South African gas market.

3) Energy accessibility to disadvantaged populations: How does the development of shale gas affect the delivery of modern energy to disadvantaged communities?

   a. Consequences of energy accessibility has the following range:

      i. *"Slight"* is considered to be 100% envisioned access to modern energy systems;

ii. *"Extreme"* is considered to be any decline in access to modern energy systems as a result of SGD.

b. Communities in the immediate study area of the SGD could benefit directly from the available gas either via cheap shale gas supply from electric power generation blended into the power generation mix (which when provided with electricity access will realise the benefits of cheap modern energy) or gas for direct use in residential heating/cooking, localised commercial/industrial end-use applications (creating job opportunities) and possibly transport end-use.

c. If shale gas does not materialise, electrification in the study area is already planned for where access is not yet available as defined in the NDP 2030 where universal access is envisioned.

d. There is an opportunity for energy price trajectories to be lower into the future relative to other options if significant cheap shale gas is found. In turn, this will result in cheaper energy access to disadvantaged populations.

e. Communities in the rest of South Africa do not feel the direct benefit of shale gas availability but could realise these benefits via reduced energy system costs and environmental impact as significant gas-fired power generation will likely displace coal-fired power generation. If shale gas does not materialise, the rollout of solar PV and wind power generation in South Africa will still allow for significantly reduced energy system costs and environmental impact.

f. The primary actors who would likely be in the best position to mitigate against reduced energy accessibility would be at a national level (the DoE). State owned enterprises like Eskom as well as municipalities implement electricity access specifically in areas that do not currently have access via the DoE subsidised Integrated National Electrification Programme (INEP). Direct access to gas for heating/cooking for residential use would be led by DoE, Nersa and downstream gas infrastructure developers as minimal existing infrastructure is currently in place.

4) Potentially obsolete energy infrastructure lock-in: Does the development of shale gas pose the risk of locking the country into potentially obsolete energy infrastructure?

a. Consequences of potentially obsolete energy infrastructure has the following range:

i. *"Slight"* is considered to be investment in two (2) or less major upstream/midstream infrastructure investments that become obsolete i.e. a gas-fired power station, pipeline, storage, LNG facility etc.;

ii. *"Extreme"* is considered to be investment in an integrated network of gas infrastructure that becomes obsolete from upstream to midstream to downstream investments e.g. LNG import facilities, storage facilities, gas-fired power stations, GTL facilities, gas transmission pipelines, distribution and reticulation infrastructure.

b. Planning for large shale gas uptake could lead to the development of large GTL infrastructure for transport end-use. This may become obsolete if envisaged shale gas quantities and costs do not materialise. In order to mitigate this, it would likely be better to continue importing liquid fuels into the medium term, and also as a result of the high overall CO_2 emissions associated with GTL technology anyway.

c. Planning for large shale gas uptake at very low prices and with significant volumes could lead to less development of renewable energy sources (at very low gas prices a high energy-share of gas-fired power stations can potentially be cheaper than a mix of solar PV, wind and relatively more costly natural gas fired generation). However, if the envisaged low shale-gas costs do not materialise, then the large solar PV and wind fleet that is needed as a gas fuel-saver is only built with a significant delay, and there is little risk in stranded gas-fired power generation.

d. Obsolete pipeline infrastructure to connect potential shale gas to demand areas could be a risk. In order to mitigate this, only when reasonable expectation and evidence of commercial scale shale gas resources are found should there be investment decisions made on pipeline infrastructure. Localised and limited power generation in the study area should be pursued initially with imported LNG and/or regional piped gas being sought while initial SGD is being undertaken. Only once significant shale gas volumes at proven low prices is feasible, should pipeline infrastructure be considered for transport of gas to demand areas.

e. Obsolete LNG import infrastructure, which is a natural outcome of a Big Gas scenario (a consequence of success), could materialise, but the associated storage facilities could potentially be converted to support liquefaction for LNG export and thus would not be stranded.

f. Gas reticulation infrastructure for residential/industrial/commercial end-use may become stranded if developed too quickly. Similar to large pipeline infrastructure from the study area to demand areas around the country, developments in this regard should be moderated initially until significant shale gas volumes at feasible prices are established.

g. There is a risk of gas end-users converting processes to gas and then having sub-optimal outcomes as a result of higher gas prices and needing to convert to other energy sources if gas prices increase. Again, the switch to gas as a primary energy source should only be sought once domestic gas volumes and prices are better defined (early adoption will prove risky).

h. As for power generation, the risk of stranded assets is relatively low, as a gas fleet built on the assumption of large and cheap shale gas supply can be utilised in a Big Gas scenario and in a solar PV/wind/LNG or solar PV/wind/piped gas scenario alike (with lower load factors – which does not affect the unit cost much for relatively cheap-to-build gas-fired power stations). The clear requirement for pipeline infrastructure to get shale gas to demand centres not located in the study area is a risk. However, planning for and implementation of significant pipeline infrastructure from the study area to demand centres will only take place once considerable verification of the shale gas resource has taken place and risk of stranded infrastructure is minimised.

i. Key actors to mitigate against obsolete infrastructure investment would include DoE at a national level as well as key state-owned enterprises (Transnet, PetroSA) as well as upstream/midstream developers. Key actors in mitigating against over-investment in gas distribution and reticulation infrastructure would likely include DoE, Nersa and downstream industry stakeholders.

5) Emissions:

a. For details on the consequences of a risk of a change in emissions please refer to Winkler et al. (2016).

b. Generally, an increase in carbon emissions relative to an alternative scenario that is based on VRE and (more costly, but less) natural gas. If shale gas is found at very cheap prices, it will play a larger role in the electricity mix, displacing coal but also replacing some VRE. The more gas-heavy VRE/gas mix will lead to higher overall carbon emissions from the electricity sector (but less carbon intensive than present day). A balanced policy approach will be necessary in this regard to ensure planned carbon emission trajectories are adhered to i.e. gas fleet expansion along with carbon free power generation (solar PV and wind).

c. More importantly, very cheap shale gas has the potential to increase the volume of GTL production in South Africa (which is a cost-efficient process if input gas cost is low) but a very carbon-intensive one. In order to mitigate this, crude and/or refined fuel imports may need to continue even with cheap natural gas that could enable economic GTL conversion. Winkler et al. (2016) considers this in more detail.

d. The prevention of gas leakage during production and transport is important to any potential carbon mitigation scheme if large scale natural gas use is considered for South Africa.

6) Network infrastructure:

a. Consequences of insufficient network infrastructure has the following range:

i. *"Slight"* is considered to be when there is largely sufficient network infrastructure available but constrained electrical networks result in a re-dispatch of the shale gas based power generation less than 5% of unconstrained levels and gas transmission pipelines are never utilised at more than 100% monthly average utilisation;

ii. *"Extreme"* is considered to be when there is constant curtailment of shale gas-fired power generation as a result of insufficient electrical transmission networks (>20% curtailment) and gas transmission pipelines are utilised at above 100% daily utilisation for one day in each month of the year.

b. The development of sufficient network infrastructure to evacuate gas-fired power generation as well as transport natural gas to demand centres from relevant geographical locations (not only in the study area) becomes more essential at high shale gas volumes. It will become increasingly critical to ensure that sufficient electrical and natural gas network planning is periodically performed and updated in order to ensure sufficient network capacity at appropriate timescales in various locations (including the study area).

c. Key actors to mitigate against insufficient transmission network infrastructure would include current state-owned enterprises like Eskom and Transnet while private industry midstream operators and developers would also play a key role. Key actors in ensuring sufficient gas distribution and reticulation infrastructure would likely include DoE, Nersa and downstream industry stakeholders.

2.3.2 Limits of acceptable change

The limits of acceptable change to SGD in South Africa as it relates to energy planning and energy security are assumed to be outlined in the following policy guiding principal planning documents:

- Integrated Energy Plan 2015 (IEP 2015) [DRAFT]
- Integrated Resource Plan (IRP) 2010-2030

- Integrated Resource Plan (IRP) Update 2013
- Gas Utilisation Master Plan 2015 (GUMP 2015) [DRAFT]

At a more strategic level, the NDP 2030 outlines the high level plan for the development of South Africa to 2030. The above guiding policy documents flow from the NDP 2030 and align with the envisioned future for South Africa as it relates to energy.

Of course, the relevant regulatory frameworks required and necessary legislation to enable the development of shale gas in South Africa will act as limits of acceptable change into the future. Details of the relevant legislation are included in Section 2.1.3 of this Chapter. The speed at which SGD could occur and resulting limits to change from the status quo will depend on the speed and flexibility of development of additional legislation and adjustments to existing legislation. More specifically, envisaged MPRDA amendments (as well as other associated legislation) in order to ensure a balance between investors and the state share in the value of projects.

Relatively small gas-fired power station capacities with low annual gas throughput are currently envisaged in the IRP 2010 but scenarios are included for “Big Gas” in the IRP Update 2013 and in the draft of the GUMP where significant natural gas finds are assumed (10-30 tcf). The other principal scenarios in the draft of the GUMP are “Niche” which assumes 1 tcf of gas supply in South Africa and “Hub” which assumes 1-10 tcf of gas supply.

Table 2.4: Risk Assessment Matrix for Energy Planning and Energy Security (See Section 2.3.1 for details)

			Without mitigation			*With mitigation*		
Impact	**Scenario**	**Location**	**Consequence**	**Likelihood**	**Risk**	**Consequence**	**Likelihood**	**Risk**
Energy security Negatively affected security-of-supply position	Reference Case	National	Substantial	Not likely	Low	None	Not likely	Very low
	Exploration Only		Substantial	Not likely	Low	None	Not likely	Very low
	Small Gas		Substantial	Very unlikely	Low	Moderate	Very unlikely	Low
	Big Gas		Substantial	Extremely unlikely	Low	Moderate	Extremely unlikely	Low
Energy cost Increasing electricity, heating and/or transport fuel cost	Reference Case	National	Moderate	Likely	Low	Slight	Likely	Very low
	Exploration Only		Moderate	Likely	Low	Slight	Likely	Very low
	Small Gas		Moderate	Not likely	Low	Moderate	Very unlikely	Low
	Big Gas		Slight	Not likely	Very low	Slight	Extremely unlikely	Very low
Energy accessibility to disadvantaged populations Inadequate supply of modern energy to communities in shale gas areas	Reference Case	Regional	Substantial	Likely	Moderate	Moderate	Not likely	Low
	Exploration Only		Substantial	Likely	Moderate	Moderate	Not likely	Low
	Small Gas		Moderate	Not likely	Low	Moderate	Very unlikely	Low
	Big Gas		Moderate	Very unlikely	Low	Moderate	Extremely unlikely	Very low
Lock-in to potentially obsolete energy infrastructure	Reference Case	National	Severe	Very unlikely	Low	Severe	Extremely unlikely	Very low
	Exploration Only		Severe	Very unlikely	Low	Severe	Extremely unlikely	Very low

			Without mitigation			*With mitigation*		
Impact	**Scenario**	**Location**	**Consequence**	**Likelihood**	**Risk**	**Consequence**	**Likelihood**	**Risk**
Investment into large energy infrastructure that does not match domestic shale gas supply	Small Gas		Severe	Not likely	Moderate	Severe	Very unlikely	Low
	Big Gas		Extreme	Likely	High	Severe	Not likely	Moderate
Emissions Increased emissions as a result of cheap shale gas that results in a relative change in future portfolio mix (less VRE, more gas)	Reference Case	National	Substantial	Extremely unlikely	Very low	Moderate	Extremely unlikely	Very low
	Exploration Only		Substantial	Extremely unlikely	Very low	Moderate	Extremely unlikely	Very low
	Small Gas		Substantial	Very unlikely	Low	Moderate	Very unlikely	Low
	Big Gas		Substantial	Likely	Moderate	Moderate	Very unlikely	Low
Availability of sufficient network capacity to evacuate gas and gas-fired power generation	Reference Case	National	Severe	Extremely unlikely	Very low	Slight	Extremely unlikely	Very low
	Exploration Only		Severe	Extremely unlikely	Low	Slight	Extremely unlikely	Very low
	Small Gas		Severe	Very unlikely	Low	Slight	Very unlikely	Very low
	Big Gas		Severe	Likely	High	Slight	Very unlikely	Very low

2.4 Best practice guidelines and monitoring requirements

Best practice with respect to shale gas production and energy planning is best referenced to the US experience in recent years.

The story of North American shale gas, particularly within the United States, offers a deep set of experiences as to how the onset of large scale shale gas production impacts long-term energy planning decisions. However, it is an important element in the US story to understand that until shale gas took off, few could have truly anticipated such a pronounced and prominent future for shale gas. Figure 2.14 illustrates the sources of US natural gas production through its rapid transition to dominance of US natural gas production.

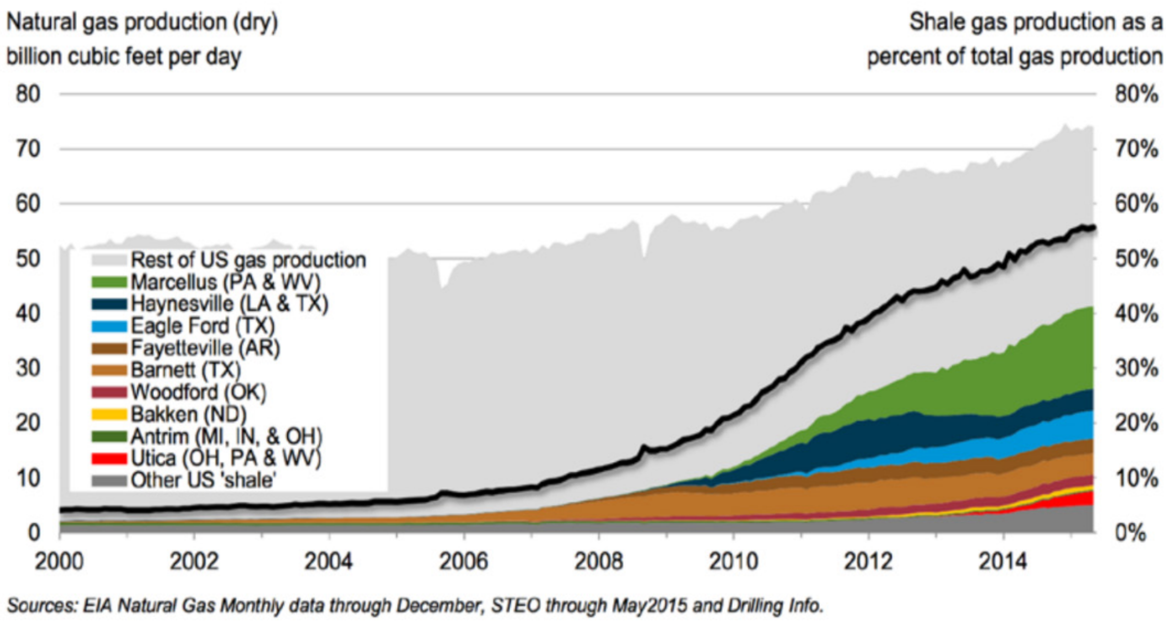

Figure 2.14: Sources of US Natural Gas Production (solid black line represents shale gas production as a percent of total gas production) (Staub, 2015).

It is also important to note that between 1999 and 2005, over 200 GW of new natural gas generation capacity was installed, reflecting an expectation of massive private sector investment in LNG import terminals, strong economic growth, lower capital intensity of new gas CCGT capacity relative to coal, and a variety of technological advancements which shifted the competitive landscape of natural gas CCGT generation over coal. While LNG import terminals never materialised, this massive (and largely underutilised) fleet was well positioned when abundant, low-cost shale gas began flooding the US market. Figure 2.15 illustrates natural gas generation quickly increasing and displacing coal-fired generation, reflecting many natural gas generators reaching a "tipping point" with respect to generation costs (driven by low fuel costs) where they could produce electricity at or below the cost of coal-fired generation, and in some cases, nuclear generation as well. Given that most CCGTs in the US currently sit beyond the aforementioned baseload "tipping point" of cost-competitiveness with nuclear and coal-fired generation, these facilities are often evaluated as the most economic candidates for providing baseload power (on top of being used for mid-merit and peaking services) during IRP processes. Given the cost of coal-fired generation in South Africa, and that in the immediate-term South Africa intends to import LNG, this baseload tipping point for CCGTs in South Africa is likely quite far away.

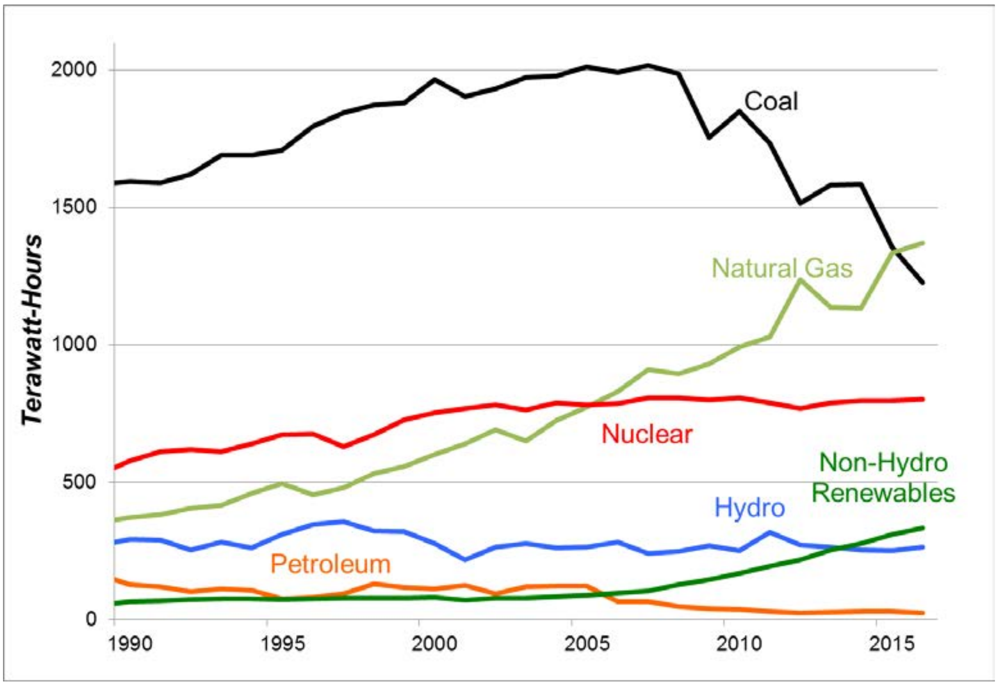

Figure 2.15: Annual US Generation by technology category 1990-2016 (EIA, 2016)

In order to understand how planning decisions were affected by the relative surge of US shale gas, it is first necessary to establish how US energy planning decisions are made in practice. Relative to the South African approach of more centralised and integrated energy plan with controlled private participation and competition, energy planning related activities are decentralised in the US, and nearly exclusively conducted by private sector entities with regulatory oversight. There is significant heterogeneity in the US market in terms of actors, interests, and activities.

Private sector planning activities, as they relate to shale gas, touch upon investment decisions for *inter alia*:

- Production, processing, storage and delivery infrastructure for shale gas.
- LNG export facilities.

- End-use investments across multiple industries (e.g., electric generation capacity, chemical production facilities, transportation fleet and refuelling infrastructure, heating and cooling infrastructure).

The private sector actors that develop shale-related infrastructure investment are a diverse and nimble group, having experienced massive and foundational market transformation in a very short period of time. They exhibit highly diverse characteristics with respect to:

- Expectations and risk tolerances for long-term price fluctuations due to evolving market dynamics and physical/market disruptions;
- Expectations of trends for various end-use sectors and regions across multiple timeframes;
- Expectations of the direction of the US LNG export market;
- Access to capital, financing, and hedging mechanisms;
- Existing investment portfolios and risk diversification strategies; and
- Regulatory paradigms (if any) to navigate.

Electricity planning processes for electric utilities, such as IRP, frequently employ natural gas price projections (informed by, *inter alia*, expectations of shale gas production) to inform and balance new investment decisions for generation capacity. Throughout procurement processes for new generation capacity, various mechanisms can be employed to manage risk and secure favourable natural gas prices. In some regions of the US utility planners are risk averse when it comes to natural gas price volatility and are currently reluctant to plan for gas-dominant generation mixes as a result. However, in other regions of the US, natural gas now accounts for over 50% of the electricity mix with many planners in these regions being urged by some stakeholders to not become over-exposed to gas as a generation source.

Perhaps salient for South Africa's natural gas related power sector planning is that new natural gas power plants in the US are typically proposed by utilities and approved by regulators upon demonstrating that:

1) From a power system perspective, the economics of a proposed natural gas power plant must be proven as the most cost-effective option, relative to other generation options to meet grid requirements.
2) From a power system perspective, a given proposed project meets an expected and concrete need of the system (i.e. peaking, mid-merit, baseload) as demonstrated by a techno-economic modelling exercise that assumes a given price of natural gas fuel, among a variety of other input assumptions. This model will simulate dispatch of the generation portfolio based on lowest short-run marginal cost (*not* a Power Purchase Agreement (PPA) price) to meet

projected demand, as this is what the grid operator is obligated to do in real life, and quantify the need for new natural gas generators and their expected generation behaviour on this basis.

3) From the utility/regulator perspective, that the compensation level for the proposed plant (either via PPA price, or rate-based CapEx and OpEx) is efficiently discovered (often via public tender) and is near, at, or below the assumed short-run marginal cost modelled from the system perspective (a convergence between modelled cost and procured price).
4) From a project developer perspective, the proposed project will be a bankable investment based on the aforementioned compensation level and the expected generation profile over the economic lifetime of the facility.
5) From a gas market perspective, that natural gas fuel will be available when it is needed (and at a reasonable price) to meet demand and reliability requirements.

In the US context, the gas market is assumed to be deep and liquid during planning and procurement exercises, with minimal constraints with respect to fuel availability, storage, or contractual constraints (such as take-or-pay stipulations).There is generally strong convergence between the assumed/modelled short-run marginal cost of the facility in planning exercises and the overall compensation level for the proposed plant over its economic lifetime, such that projects are bankable and utilities/consumers are paying a fair price for electricity.

The South African context offers a unique set of circumstances with strong implications for planning. First, given the relative economics of all new-build generation options in South Africa, the power system will almost certainly require natural gas power plants for mid-merit and peaking services, and not for baseload. Second, without prior experience, it is unclear to what extent there will be convergence between assumed short-run marginal prices in planning exercises and compensation levels for project developers, and whether or not those compensation levels will make for bankable investments given the expected generation profiles of the projects. There is, however, a great degree of certainty that GTP PPAs will be higher than those of coal-fired power plants, but lower than diesel. Finally, South Africa does not have a deep and LNG market and must procure LNG from the global market, likely through a long-term take-or-pay contract.

Table 2.5 compares the relevant USA and South African solutions to a range of questions that might be raised while evaluating a prospective natural gas power plant investment, organised by stakeholder perspective.

Table 2.5: Questions for evaluating a prospective natural gas power plant investment by stakeholder perspective for the US and South Africa

Perspective	*United States of America (USA)*	*South Africa*
Power System – Energy Planner		
1. *Is this investment the most cost-effective option to meet the needs of the power system?*	**1.** Commonly addressed using a combination of techno-economic power sector modelling and engineering judgment.	**1.** South Africa's IRP process has addressed this question directly and allocated a defined, cost-effective capacity of natural gas power plants to be built using transparent assumptions about natural gas prices.
Power System Operator		
2. *Does the proposed project meet an expected and concrete need of the power system? What is the power plant's expected generation profile?*	**2.** Techno-economic modelling helps to ensure a concrete need is being met. Given the competitive landscape of generation technologies in the US, natural gas power plants are likely candidates for **baseload**, **mid-merit**, and **peaking** services.	**2.** Techno-economic modelling (via the IRP) helps to ensure a need is being met. Given the immediate-term expectations of imported LNG costs and competitive landscape of generation technologies, natural gas power plants are likely candidates for **mid-merit** and **peaking** services.
Utility/Regulator		
3. *Is the compensation level for the proposed plant fair? Was it efficiently discovered?*	**3.** There are a range of procurement mechanisms utilised by US utilities to ensure efficient price discovery.	**3.** The DoE Independent Power Producer Office (IPPO) has shown immense global leadership in ensuring efficient price discovery for renewable energy, and will likely be able to do the same for natural gas power plants.
4. *To what extent is there convergence between assumed/modelled costs and developer compensation levels?*	**4.** There tends to be strong convergence in the US context.	**4.** There is no experience as of yet to indicate the extent of convergence.
5. *To what extent are developer compensation levels near expected costs of other technologies?*	**5.** In the event that developer compensation levels are quite close to other expectations of other generation technologies, modelling and/or procurement processes may be revisited.	**5.** No experience as of yet. However, in South Africa, natural gas generation short-run marginal cost will almost certainly be more expensive than coal, but less expensive than diesel. Thus, there will not be a need to re-visit modelling or procurement processes.
Project Developer		
6. *Given the compensation level and expected generation profile, is this project bankable?*	**6.** Generally speaking, natural gas power plants that are centrally procured in the US are considered bankable investments.	**6.** There is no experience as of yet. After Round 1 of IPPO's GTP Programme, more information will be available.

Perspective	*United States of America (USA)*	*South Africa*
Natural Gas Market		
7. *Will natural gas fuel be available when it is needed and at a reasonable price to meet the power plant's needs?*	**7.** The natural gas market in the US is deep and liquid. In the current regime of abundant, low-cost shale gas, this answer to this question, generally speaking, is yes.	7. Natural gas will need to be purchased from the global market, likely via a long-term take-or-pay contract. An on-site offtake storage facility will need to be refuelled on a contractually agreed upon. Global LNG market, likely on a take-or-pay contract.
8. *Is the demand from the plant significant enough to obtain an economical fuel price?*	**8.** Yes (see #7)	**8.** There is no experience as of yet. Natural gas purchases will be to procure gas at volumes that stimulate market interest.
9. *What happens if the plant does not use all of the fuel it procures?*	**9.** Because of the deep and liquid market, there are a variety of contractual protections, hedges, storage schemes and alternative uses that can generally be used.	**9.** Natural gas power plants are expected to serve as the anchor customer in the immediate term, while a secondary market for LNG builds up. LNG procurement contracts should be tied to the expected generation profile of power plant, with some storage available to absorb fluctuations in utilisation between LNG top ups.

Shifting away from the US experience with shale gas, regarding procurement of gas-fired power generation in South Africa, the following is noted:

- The techno-economic parameters utilised in procurement should be informed by the power system cost minimisation (with policy adjustment considerations) analysis performed by the IRP or similar studies. Such parameters should include the capacity, year of commercial operation, dispatch profile, provision of reserves and other ancillary services. The IRP should hence provide the use-case specification for procurement. Going forward, the IRP should model anticipated gas price elasticity whereby gas volumes and pricing inter-dependencies are considered.
- The procurement process should be technology agnostic, allowing developers to select and optimise technology choices to minimise total cost for the anticipated dispatch profiles, gas pricing and other parameters (such would include open/close cycle operation, unit sizes and gas-engines/turbines).

- Gas fuel supply agreement will need to be tightly integrated with the power station PPA, ensuring synergy in gas volumes, gas quality, variability and reliability with the PPA dispatch regime and tariff.
- Power generation capacity and dispatch profiles should consider gas price elasticity. Anticipated gas volumes should be at levels that are anticipated to stimulate market interest and competitive gas pricing.
- Certainty in gas volumes should be provided via take-or-pay gas supply contracting for an initial period of time. Such certainty must however support flexibility in power generation dispatch as linked to the gas storage and logistical implications and constraints.
- The contracting must support the provision of flexible power in alignment with the IRP use-case. Current expectations are for high levels of operational flexibility via rapid starting, ramping, reserve provision, and load following.
- Gas fuel supply agreements for the power generation anchor demand should provide access to gas for third parties such as industrial gas users.
- Gas infrastructure and fuel supply agreements should be structured to allow future switching from e.g. imported LNG to future domestic shale gas. Such should include gas specifications that ensure that future indigenous gas sources are not prejudiced. Project bankability must be supported via ensuring adequate compensation for fixed assets that may be stranded in switching to alternative gas supplies e.g. LNG import infrastructure.

2.5 Gaps in knowledge

Available gas volumes and expected prices of domestic shale gas greatly impact the mix in the long-term energy planning (IEP, GUMP, IRP, and SGP). Research in this regard (volumes and expected prices) is the most needed type of research from a pure energy-planning perspective. This will likely be informed by the publication of the final versions of the IEP, IRP and GUMP (as well as associated data and studies that informed them).

The implementation of drilling and exploration by stakeholders with exploration rights in the study area will likely add significant knowledge from a near zero baseline at this stage.

If higher levels of shale gas volumes in the Big Gas scenario are considered (to become a ‘game changer’ scenario), who would be the primary anchor demand sectors (power generation, industrial, residential, commercial, mining, manufacturing) and at what prices would these demand sectors start to use or switch to natural gas provided by shale gas? Would supply of natural gas from other sources be more/less competitive at an aggregate level e.g. imported LNG, regional pipeline import, domestic offshore finds etc.?

Globally, recent publications like Bazilian et al. (2014) outline a research agenda on economic, environmental, and social dimensions of natural gas to ensure benefits of SGD are ensured (with a specific focus on the US but with applicability globally in many respects). At a high level, the following research agenda related to natural gas is as follows (as extracted from Bazilian et al. (2014)):

1) *Increased empirical research into environmental impacts from natural gas, including fugitive emissions of methane and water contamination issues (both surface and subsurface);*
2) *Comprehensive and integrated economic, environmental, and social research in order to understand trade-offs and interactions between different sectors and impacts; and*
3) *Development of decision support tools to convey results of integrated modelling to decision makers in an engaging and informative fashion. Given the scale of possible benefits and impacts from natural gas development, there is no time to waste in clarifying these choices.*

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