CHAPTER 3

Air Quality and Greenhouse Gas Emissions

CHAPTER 3:
AIR QUALITY AND GREENHOUSE GAS EMISSIONS

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Executive Summary

Shale gas development (SGD) presents opportunities and risks with regards to air pollution and greenhouse gas (GHG) emissions. There is a potential opportunity to reduce emissions, if shale gas replaces 'dirtier' (more emissions-intensive) fuels, however, there is also a risk of increased emissions if shale gas is added to the existing energy mix, and displaces cleaner fuels for new capacity. Emissions of GHGs have global impacts, while impacts from air pollution are generally assessed at local and regional scales.

The highest risks assessed are due to leakage of methane prior to end-use, a potent GHG; and the exposure of workers to air pollutants on the wellpad. For all three SGD scenarios considered in this assessment, the scale of SGD in South Africa is assumed to be smaller than SGD in the United States of America (USA), which results in lower estimates of air pollution and GHG emissions for South Africa as compared to the USA, even in the Big Gas scenario (Figure i)[1].

An urgent priority is the early establishment of baselines (through air quality and GHG monitoring stations in the study area, and inventories for air pollutants and GHG emissions), to be followed by the design of continuous monitoring systems.
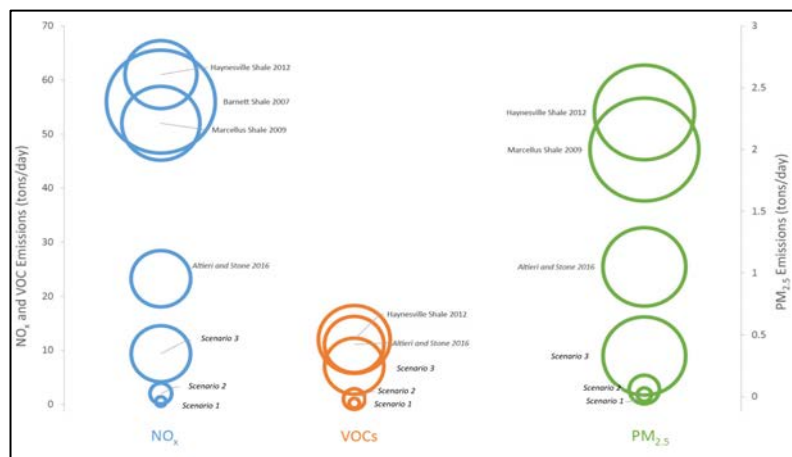
Figure i: Air pollutant emissions from bottom-up inventories for Karoo shale gas compared to main shale plays in USA.

Based on the scientific assessment, it is recommended that further research into the existing regulatory framework and its capacity to deal sufficiently with SGD, along with the potential to enhance institutional and human capacity be explored. Industrial activity in the study area is currently low and the need for this type of regulatory capacity does not currently exist. Good practice guidelines are needed to minimise impacts on air quality and reduce GHG emissions, with guidelines for control technologies, consideration of effective legal regulation, early establishment of baselines and

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[1] Further details on figures in the executive summary are in the text surrounding the same figure in the main body of this Chapter.

continuous monitoring, and good governance enabled by coordination across several institutions (see Section 3.4).

Local air pollution

Both workers and the local and regional communities may be exposed to local air pollutants during the course
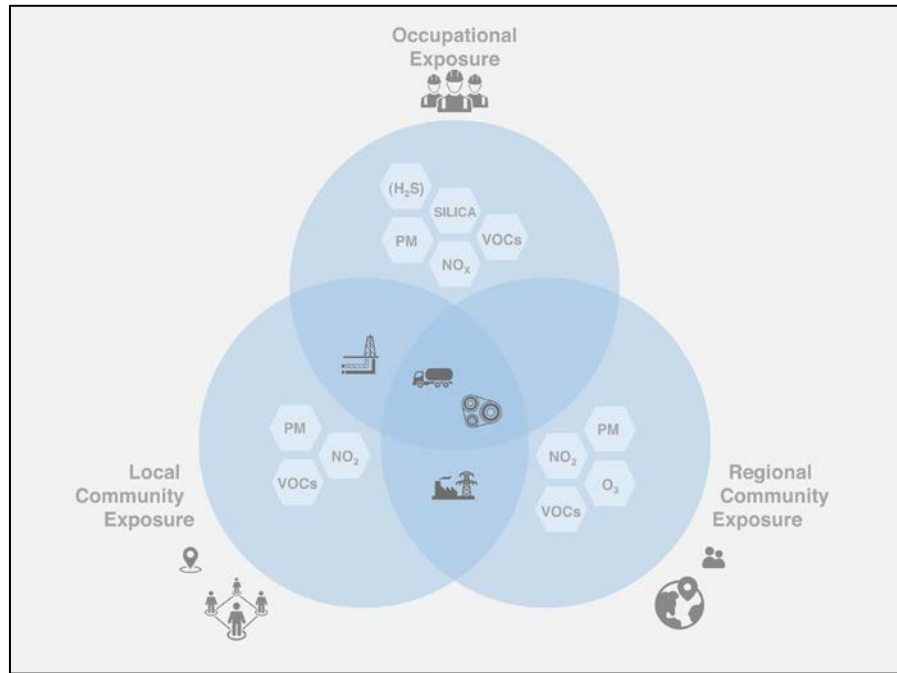
Figure ii: Air pollutants associated with occupational exposure, and local and community exposure.

of SGD (Figure ii). The air pollutants considered in this assessment are nitrogen oxide (NO_x), carbon monoxide (CO), volatile organic compounds (VOCs), diesel exhaust, particulate matter ($PM_{2.5}$ and PM_{10}), hydrogen sulfide (H_2S), ozone (O_3) and respirable crystalline silica. Activities which lead to air pollutant emissions include wellpad and infrastructure preparation (i.e. trucking of equipment), vertical and horizontal drilling, hydraulic fracturing, well completion, transportation (e.g. transport of water and waste materials), production stage distribution of the gas, and associated end-use of the gas. Table 3.6 summarises the main risks to deterioration of air quality.

There is a high risk of workers on the wellpad being exposed to air pollution, if mitigation is absent. This is driven by emissions of respirable crystalline silica, diesel exhaust and VOCs. It is anticipated that the risk of silica exposure can be effectively mitigated, although exposure to VOCs and diesel exhaust will be harder to mitigate. Thus, even with mitigation, occupational exposure is still assessed as a moderate risk.

Risks to human health from local and regional community exposure are assessed as low to moderate, in the Exploration Only (Scenario 1), Small Gas (Scenario 2) and Big Gas (Scenario 3) scenarios for SGD. For local communities, the risk of exposure to air pollution is driven by the increase in ambient PM concentrations, which already occasionally exceed national ambient air quality standards (NAAQS). For communities that are more than 10 km from a production block, the risk is driven by

the potential exposure to increased truck traffic, which can be mitigated. The air quality impacts on agriculture and ecosystems are assessed as low or very low. Even at the lowest estimate for exploration alone (Exploration Only scenario), NO_x emissions from unconventional natural gas would dominate regional emissions due to the current low level of industrial activity in the Karoo. SGD on its own is unlikely to cause material exceedances of legal limits of nitrogen dioxide (NO_2) and ozone concentrations, even in the Big Gas scenario. For ozone and PM, no concentration limit has been determined below which there is no impact on human health. It is important to note that the confidence level of findings related to ambient concentrations is limited by the lack of regional air quality information (including measurements and photochemical modeling).

There is some opportunity for shale gas to improve indoor air pollution, which depends on displacing wood, coal and paraffin as domestic fuels. To realise the potential for air quality improvements through replacement of dirtier fuels, the fuel switch should happen in the same geographical area.

Greenhouse gas emissions

SGD presents both risks to increase and opportunities to reduce GHG emissions. The opportunity of emission reductions depends crucially on whether gas displaces coal (the main fuel in South Africa currently, with higher GHG emissions intensity), or gas displaces even lower-emission alternatives (such as renewable energy, nuclear, imported or domestically refined fuel). Even with the worst leakage rates, the 'worst shale gas' is roughly as emissions intensive as the 'best coal'. But if gas displaces even lower-emitting alternative energy supply, GHG emissions would increase. The main risks of increased GHG emissions are summarised in Table 3.9.

Fugitive methane emissions are identified as a high risk in this assessment, and depend significantly on leakage rates and global warming potential (GWP) values (Figure iii). The risk of fugitive methane emissions under the Big Gas scenario might be reduced from high to moderate with mitigation and use of good practice in control technologies and systems.

Shale gas would reduce GHG emissions compared to coal by 0.54 t CO_2-eq per MWh. If Combined Cycle Gas Turbine (CCGT) plants displace nuclear or renewable energy plants, this would increase emissions intensity by +0.45 t CO_2-eq per MWh. By comparison, the emissions intensity of current coal plants is 0.99 t CO_2-eq per MWh.
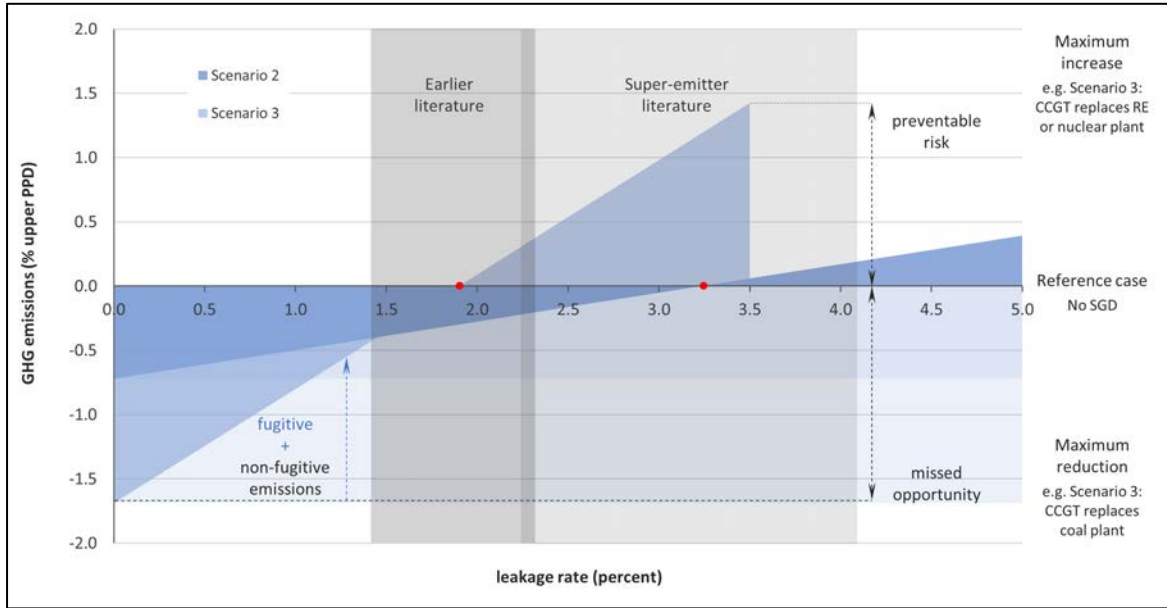
Figure iii: Implications for national GHG emissions for different leakage rates of fugitive methane.

Absolute changes in GHG emissions depend on projections of electricity produced, which is a matter of energy planning (see Wright et al., 2016). Making simple assumptions for this Chapter; the consequences of increased or reduced GHG emissions were calculated as slight to moderate in relation to the national emissions trajectory. An indicative scale of consequences, in absolute units (Mt CO_2-eq per year) was developed for this assessment drawing on the literature (Figure iv and Table 3.8).
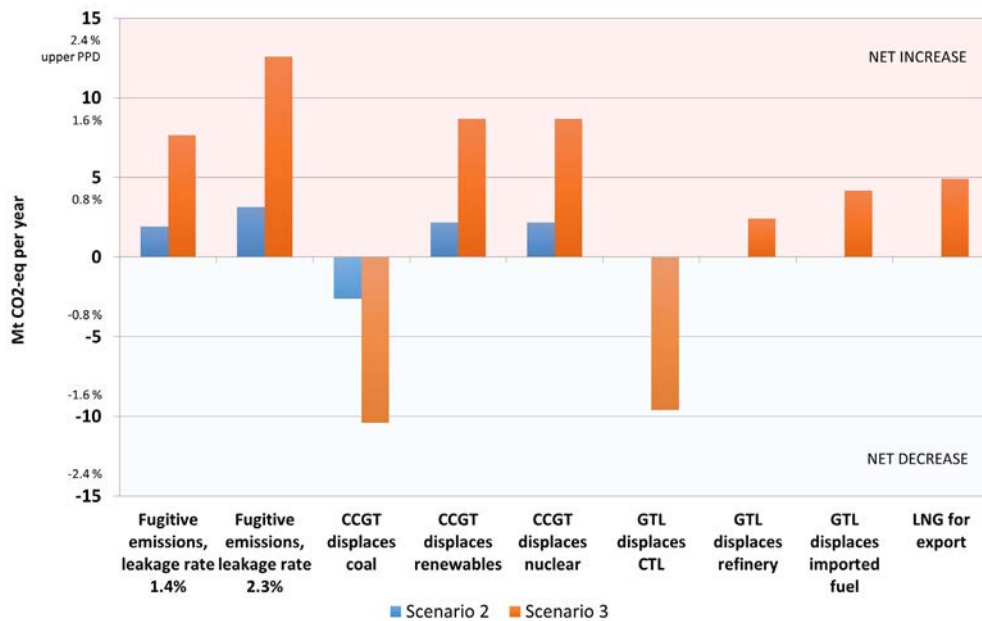
Figure iv: Indicative consequences of increases in GHG emission reductions and opportunities for reductions.

Severe consequence can be seen in Figure iv for fugitive methane leading to a net increase in GHG emissions, assuming a Big Gas scenario and higher leakage rate. CCGT displacing new renewable energy or nuclear power has substantial consequences; whereas if gas displaces coal, this is the biggest opportunity to for a net decrease of GHG emissions in Figure iv. Replacing fuel produced from importing crude oil and refining it locally with GTL from shale gas has a low risk of increases, given that is assessed as likely with moderate consequences. The consequence for imported fuel is moderate (4.2 Mt CO_2-eq per year), which is still the case with mitigation but at lower scale (2.8 Mt CO_2-eq per year). The latter consequence comes close to the consequence of GTL displacing imported fuel refined locally (2.4 Mt CO_2-eq per year). Some relative emissions factors need further study, notably for coal- and gas-to-liquids.

International experience regarding leakage rates deserves further study, as the range in the earlier literature is being extended by recent findings on super-emitters – low-frequency but high-consequence events.

CHAPTER 3: AIR QUALITY AND GREENHOUSE GAS EMISSIONS

3.1 Introduction

One dimension of assessing the risks and sustainability of shale gas development (SGD)[2] is the impacts of air pollutant and greenhouse gas (GHG) emissions; these emissions, while they have similar sources, have varying spatial and temporal aspects. Air pollution can have near-source local impacts (e.g. impacts from occupational exposure and impacts to nearby communities), as well as regional impacts. The potential risk of SGD to impact air quality is assessed through its potential to harm human health, with considerations for impacts on ecosystems and agriculture also discussed. GHG emissions, which contribute to climate change "unequivocally" (Intergovernmental Panel on Climate Change (IPCC), 2007; 2013; 2014), add to global concentrations in the atmosphere no matter where in the world they are emitted, and thus the GHG emissions from SGD are global in nature. For both air pollutants and GHGs, there are risks of negative impacts with higher levels of emissions, e.g. negative impacts to human health from exposure to air pollution, or increased levels of GHG emissions in South Africa. There are also opportunities to reduce impacts from other fuel sources.

The overall scope of this Chapter covers emissions of gases to the atmosphere, with impacts at various spatial and temporal scales. Emissions of air pollutants with impacts at local and regional scale are referred to in this Chapter as simply 'air pollutants', resulting in changes in 'air quality'. The impact of GHGs is at a global scale. A more detailed scope is discussed for air quality in section 3.2.1 and for GHGs in section 3.3.1.

For both air quality and GHG, the use of shale gas and possible alternative fuels matters. There is a potential opportunity to reduce emissions, if shale gas replaces 'dirtier' (more emissions-intensive) fuels. There is also a risk of increases of emissions, if shale gas is added to the existing energy mix rather than technologies using cleaner fuels. The GHG risk assessment considers cases where shale gas is used in addition to existing electricity generation and liquid fuel supply technologies, as well as cases where shale gas replaces coal, renewable energy or nuclear power; and coal-to-liquids (CTL) or domestically refined products from imported crude oil (see section 3.2.1). Similarly, some of the potential benefits of reducing indoor air pollution depend on shale gas displacing other fuels (e.g. coal), in the form of electricity or piped gas. However, a key difference between air quality and GHG considerations is the spatial component. The source and location where GHGs are emitted is not directly related to where its impacts are felt (which is a function of global emissions), whereas location matters for air quality. Electricity generation from coal for example; also produces air

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[2] See definition for shale gas development in Burns et al. (2016).

pollution – but in a different geographical area to the study area. While there is some transport of air pollutants over the distance between Mpumalanga and Karoo, the concentrations of the air pollutants transported would generally be much smaller than the potential impacts from the local SGD (Abiodun et al., 2014; Freiman & Piketh, 2003; Nzotungicimpaye et al., 2014; Piketh et al., 1998).

Emissions of air pollutants and GHGs are closely associated with activities covered in other Chapters of the scientific assessment, notably energy supply and use – as the previous paragraph makes clear (see Wright et al. 2016). Impacts of air pollution are also associated with visibility (Oberholzer et al., 2016), spatial planning (i.e. location of human settlements) (Van Huyssteen et al., 2016), health (Genthe et al., 2016) and agriculture (Oettle et al., 2016).

This rest of this Chapter is organised as follows. Section 3.2 is the major section dealing with air quality, its scope, potential impacts, limits of acceptable change, in order to conduct an analysis of risks and opportunities, with risks summarised in section 3.2.5 and Table 3.6. Section 3.3 is the main section dealing with GHG emissions, with the overview of risks in section 3.3.5 and Table 3.9. Note that in both sections 3.2 and 3.3, consistent with guidance to the scientific assessment, the risk assessment matrices include only risks, while opportunities are dealt with in the text of the section. Section 3.4 considers good practice for minimising impacts, for both air quality and GHG emissions. Section 3.5 identifies gaps in knowledge.

3.2   Air quality

3.2.1   Scope

Air quality concerns related to SGD and usage include the emission of air pollutants during all phases, i.e. exploration, development, use of the gas (in transport and energy sectors), and decommissioning. The pollutants considered here include some of the so-called 'criteria' pollutants, identified in Table 3.1 and described in more detail in Text Box A. Volatile organic compounds (VOCs), including those with carcinogenic potential, are considered, as is diesel exhaust, respirable crystalline silica and hydrogen sulphide (H_2S).

> ### *Text Box A: Species of local air pollutants*
>
> NO_x are nitrogen oxides ($NO + NO_2 = NO_x$) and CO is carbon monoxide. Volatile organic compounds can also be referred to as non-methane volatile organic compounds, and are hereafter referred to as "VOCs" (Brantley et al., 2015; Gilman et al., 2013). Atmospheric particulate matter is referred to as PM and regulated by particle size ($PM_{2.5}$; $\leq 2.5\mu m$ in aerodynamic diameter, PM_{10}; $\leq 10 \mu m$ in aerodynamic diameter and see Table 3.1 below) (Armendariz, 2009; Grant et al., 2009; Roy et al., 2014). Ozone is a secondary pollutant that is formed in the atmosphere from reactions of its precursors (i.e. nitrogen dioxide (NO_2) and VOCs). For emissions related to diesel engine operation, >90% of the NO_x emitted is in the form of nitrogen monoxide (NO), which scavenges available ambient ozone and may lead to near-source ambient ozone reduction, although solar-radiation driven dissociation of the NO_2 that is formed may lead to overall regional increases in ambient ozone concentration (Clapp, 2001; Han et al., 2011; Seinfeld & Pandis, 2006; Song et al., 2011). Diesel exhaust has been classified as a human carcinogen and is most frequently characterised and regulated in terms of its particulate matter content (DPM) (International Agency for Research on Cancer (IARC), 2012).

The air pollutants identified have impacts on communities (locally and regionally) and through exposure in the work place. These are illustrated in Figure 3.1, together with key activities that emit the air pollutant, which are discussed in more detail in the following sections.
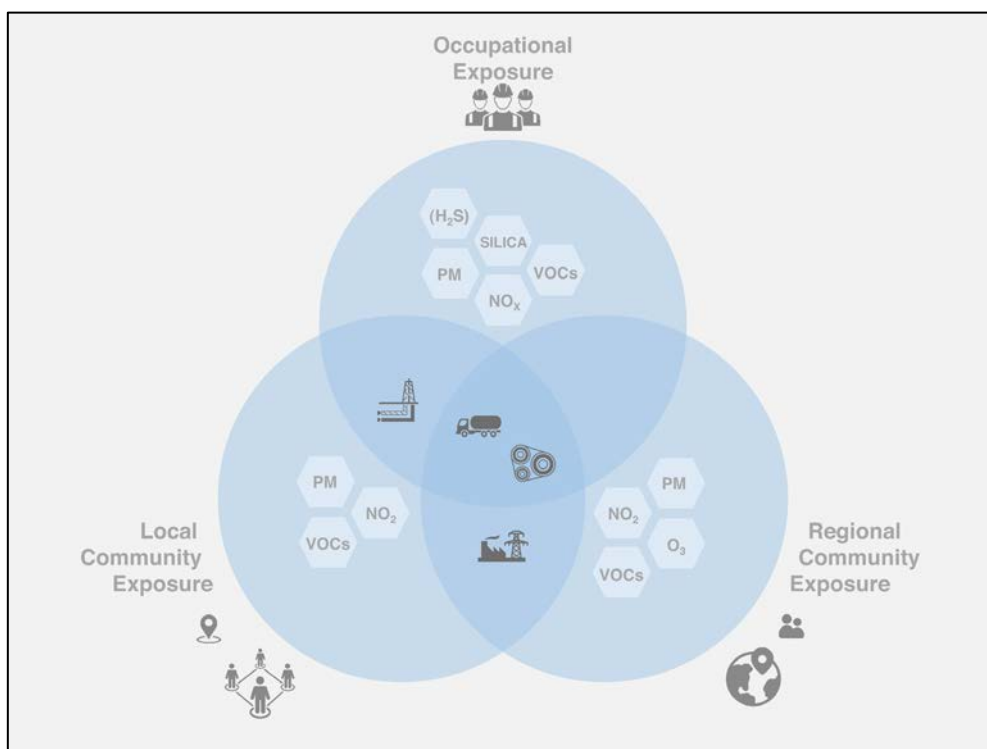
Figure 3.1:   Air pollutants associated with occupational exposure and local and community exposure[3]

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[3] "Builder" icon by To Uyen, "SAGD" icon by Adam Terpening, "Water Truck" icon by Juan Pablo Bravo, "motor" icon by Aaron K. Kim, "Power Plant" icon by Dimitry Sunseifer, "Map Marker" icon by Alex Almqvist, "community" icon by parkjisun, "people" icon by Berkay Sargin, "Map Marker" icon by Calvin Goodman from thenounproject.com

Note: H_2S is in parentheses to highlight it will be a risk only if H_2S is present in gas deposits.

Ambient (i.e. outdoor) air quality is impacted by emissions from industrial and mining activities, vehicles, power generation, and natural causes such as veld fires, while indoor air pollution can result from burning wood, coal and paraffin in households. The relative contribution of these emission sources likely vary spatially across the Northern, Western, and Eastern Cape Provinces located in the study area. However, it is important to note that there is no ambient monitoring station within the study area, and as such very little is known about the current state of air quality in the region considered in the scientific assessment.

In South Africa, regulatory standards exist for the ambient concentrations of certain air pollutants and the emissions of air pollutants from selected activities. Air quality is governed by the National Environmental Management: Air Quality Act (39/2004), with municipalities responsible for generating and maintaining air quality management plans. Emission limits have been set for certain industrial categories, including the petroleum industry, but no subcategory yet exists for unconventional gas extraction (Republic of South Africa (RSA), 2013). National ambient air quality standards (NAAQS) set limit values over relevant averaging periods for seven air pollutants viz. PM, sulphur dioxide (SO_2), NO_2, O_3, CO, lead (Pb) and benzene (C_6H_6), with PM being divided into two particle sizes (RSA, 2009a; 2012) (Table 3.1). These ambient standards are set to protect communities from air pollution exposure. In South Africa, there is not an ambient standard for H_2S, a gas which is highly toxic and has a pungent odour. The World Health Organization (WHO) recommends that "to avoid substantial complaints about odour annoyance" by communities, the 30-minute average ambient H_2S concentration should not exceed $7\mu g/m^3$ (WHO, 2000). Occupational exposure to air pollutants is governed by the Occupational Health and Safety Act (85/1993). Table 3.1 includes the occupational limits for H_2S and respirable crystalline silica, which are potential occupational health risks. There is also a risk to occupational health from inhalation of VOCs, however the applicable regulated exposure limits depend upon the composition of the VOCs. As the composition is not yet known, no limits with regards to VOCs are listed in Table 3.1.

Table 3.1:   South African ambient air quality standards and allowable frequency of exceedance of the standard as a function of pollutant and averaging time

Species	Averaging time	South African National Standard Concentration	Allowable frequency of exceedance
SO_2	10 minutes	500 µg/m^3 (191 ppb)	526
	1 hour	350 µg/m^3 (134 ppb)	88
	24 hours	125 µg/m^3 (48 ppb)	4
	1 year	50 µg/m^3 (19 ppb)	0
NO_2	1 hour	200 µg/m^3 (106 ppb)	88
	1 year	40 µg/m^3 (21 ppb)	0
PM_{10}	24 hours	75 µg/m^3	4
	1 year	40 µg/m^3	0
$PM_{2.5}$	24 hours	40 µg/m^3 (25 µg/m^3 from 1 Jan 2030)	4
	1 year	20 µg/m^3 (15 µg/m^3 from 1 Jan 2030)	0
O_3	8-hours running	120 µg/m^3 (61 ppb)	11
C_6H_6	1 year	5 µg/m^3 (1.6 ppb)	0
Pb	1 year	0.5 µg/m^3	0
CO	1 hour	30 mg/m^3 (26 ppm)	88
	8 hour	10 mg/m^3 (8.7 ppm)	11
South African Occupational Standards (Department of Labour (DOL), 1995)			
Species	TWA OEL-RL * (mg/m^3)	Short term OEL-RL** (mg/m^3)	TWA OEL-CL *** (mg/m^3)
H_2S	14 (10 ppm)	21 (15 ppm)	NA
Respirable crystalline silica[4]	NA	NA	0.1

Source: (DOL, 1995; RSA, 2009a, 2012)

*   TWA OEL-RL Time Weighted Average Occupational Exposure Limit - Recommended Limit
**   Short-term exposure is for 15 minutes.
***   TWA OEL-CL Time Weighted Average Occupational Exposure Limit – Control Limit: this is the maximum concentration that employees may be exposed to through inhalation averaged over the reference period under any circumstances. Silica CL was updated in 2008 with an amendment to the Occupational Health and Safety Act (85/1993).

3.2.2   *Key potential impacts on air quality*

3.2.2.1   <u>Emissions</u>

SGD activities lead to air pollutant emissions at several points across the life cycle (see Burns et al. 2016). Within these life cycle steps, notable activities that lead to air pollutant emissions include wellpad and infrastructure preparation (i.e. trucking of equipment), vertical and horizontal drilling,

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[4] The Department of Labour (DOL) defines that "the concentration of respirable dust shall be determined from the fraction passing a size selector with an efficiency that will allow: 100% of particles 1 µm aerodynamic diameter, 50% of particles of 5 µm aerodynamic diameter, 20% particles of 6 µm aerodynamic diameter, 0% of particles 7 µm aerodynamic diameter and larger, to pass through the size selector"

hydraulic fracturing ("fracking"), well completion, transportation (e.g. transport of water and waste materials), production stage distribution of the gas, and associated end-use of the gas.

The life cycle of SGD results in a large number of relatively small point sources of air pollutants spread out over a potentially large geographical area (wellpad activities), as well as mobile sources (truck traffic) and fugitive sources (equipment leaks) (Field et al., 2014). A key feature of shale gas technologies is that several wells can be drilled from one wellpad, which focuses intense industrial activity in one area (Adgate et al., 2014). New wells are drilled regularly as a result of rapid decline in the rate of gas production from a well (Burns et al. 2016), and once drilling commences in a shale play it operates continuously (IEA, 2011). This creates a constant (i.e., 24-hour) output of air pollutants from diesel generators, stationary engines and truck traffic. The activities during well exploration, appraisal and development lead to emissions of NO_x, SO_2, particulate matter ($PM_{2.5}$ and PM_{10}), diesel particulate matter (DPM), VOCs, CO, silica, and H_2S, as indicated in Table 3.2.

Table 3.2:   Summary of air pollutant emissions from sub-activities of life cycle stages from Burns et al. (2016)

	CO	NO_x	SO_2	PM	VOCs	Resp. Silica	H_2S
Well Exploration, Appraisal and Development							
Trucking (equipment, water, waste)	x	x	x	x	x		
Drilling (vertical and horizontal)	x	x		x	x	x	xx
Hydraulic Fracturing		x		x	x	x	
Well Completion					x		xx
Production							
Pneumatics					x		xx
Fugitives					x		xx
Wellhead Compressors	x	x		x	x		xx
Blowdown Venting					x		xx
Decommissioning							
Leakage							xx

Notes: PM in this table includes DPM as well as $PM_{2.5}$ and PM_{10}. Those processes where H_2S emissions would occur if H_2S is present in gas deposits are indicated with "xx". SO_2 emissions will depend on the sulphur concentration of the diesel fuel utilised in transport. Methane is not included under "decommissioning" as it is a global GHG discussed below in Section 3.3.

3.2.2.1.1   On-site emissions

On-site emissions could include H_2S, which is a highly toxic gas that is naturally occurring in some natural gas deposits. However, previous studies suggest that the probability of H_2S emissions in the study area is low (Burger, 2011). Silica sand is the most commonly used proppant in the fracking fluid, and can be lofted into the air where workers may be exposed, leading to the risk of respiratory diseases.

The drilling of a well requires five to seven diesel-fired compression-ignition engines, which range from 300 to 1000 kilowatts (kW) (Grant et al., 2009; Roy et al., 2014) while fracking requires the use of stationary pump engines. These engines on-site will emit NO_x, PM, CO, SO_2 and VOCs.

The well completion process requires flowing the well via venting or flaring for a sustained period of time to remove any debris or mud, and to remove any inert gases present from the well stimulation process. This can result in a significant amount of vented gas, and as such can be a large source of VOCs (Pacsi et al., 2013), which in these scenarios is assumed to be controlled by flaring to reduce emissions (Burns et al., 2016). Production emissions on the well-site are primarily VOC emissions, except in the case of the use of wellhead compressors, which also release small amounts of NO_x and DPM. VOCs are released from production fugitives, pneumatic devices, and blowdown venting. Production emissions are assumed to derive from devices and compressors that operate continuously.

3.2.2.1.2 Mobile emissions

Truck traffic will increase substantially with SGD and will lead to emission of NO_x, diesel exhaust (including DPM), $PM_{2.5}$, VOCs and road dust (Adgate et al., 2014; Roy et al., 2014). Trucks will be used initially to transport all of the necessary materials to the well site, including the engines, water, chemicals, and equipment. In addition, trucks will be used to transport materials from one well to another as needed. A potentially large source of truck traffic, and one with a considerable amount of uncertainty in South Africa, is associated with the transport of water to the well for fracking, as well as the transfer of flowback water to wastewater treatment sites or storage ponds. These mobile sources will expose a larger geographical area to the emissions of air pollutants, though it is important to note that if the scale of the resource warranted the necessary infrastructure investments, piping water would help to minimise truck transport emissions.

3.2.2.2 <u>Fate of pollutants</u>

The magnitude and spatial extent of the impact of atmospheric emissions on air quality are influenced by the rate at which pollutants are emitted (as discussed above), and their fate in the atmosphere (i.e. dispersion, transformation (e.g. chemical reaction), and removal). The local dispersion is influenced by the height, velocity, and temperature of release of the emissions, as well as meteorological factors (e.g. wind speed and direction, ground-based inversion layers). In addition, air pollutants can be transported long distances; for example, smoke from biomass burning activities in Zambia may be distributed across southern Africa by prevailing winds in the late winter and spring (RSA, 2009b; Swap et al., 2003). As such, for SGD, pollutants emitted in the study area may be transported outside of its borders. The dominant wind directions as a yearly average reported in Burger (2011) for Beaufort West, which is the only wind analysis that could be found for the study area, were from the

east to northeast, and west to southwest, with very few days having calm conditions (i.e. wind speed <1m/s). The Wind Atlas for South Africa[5] has detailed wind climatologies of the study area, which could be used together with measurements for detailed studies on the dispersion of pollutants once the specific locations are selected for SGD. The removal of pollutants from the study area can occur through dry deposition, wet deposition, transport from the area, and transformation to secondary pollutants. The study area is arid and thus wet deposition through precipitation should be a relatively small removal process.

3.2.2.3   Ground-level ozone

Ozone (O_3) is a secondary pollutant, which means it is not released into the atmosphere, but rather is formed in the atmosphere through reactions of its precursors (i.e. NO_2 and VOCs). As SGD activities emit both NO_2 and VOCs, there is potential for significant regional effects on ambient ground-level ozone concentrations (Katzenstein et al., 2003; Kemball-Cook et al., 2010; Monks et al., 2015; Swarthout et al., 2015). Modelling studies in the US have shown that increased SGD and associated emissions of precursors has led to increases in ozone concentrations (Kemball-Cook et al., 2010; Olaguer, 2012; Rodriguez et al., 2009). However, if the use of gas decreases the use and thus emissions from coal-generated electricity, there can also be overall decreases in O_3 and NO_x, although in South Africa these reductions would occur in a different geographic area (Pacsi et al., 2013; 2015). High levels of ozone have been observed in the winter in US northern oil and gas basins, and studies suggest that the elevated ozone levels are correlated with snow cover (Carter & Seinfeld, 2012; Edwards et al., 2014; , 2013; Helmig et al., 2014; Oltmans et al., 2014; Rappengluck et al., 2014; Schnell et al., 2009). An important limitation noted for many air quality modelling studies of shale gas is the lack of an accurate and comprehensive emissions inventory for specific study sites. This is attributed to factors such as variability in well operations (i.e. flaring, number of active well heads), the large number of activities that emit pollutants, the type of gases emitted, and a lack of field observations (Field et al., 2014; Monks et al., 2015; Petron et al., 2012).

3.2.2.4   Reference case (Scenario 0)

There is one air quality monitoring station near the, study area, although it is not within the boundaries of the study area. The Karoo Background monitoring station (31°22'S, 19°6'E) is run by the South African Weather Service (SAWS) and data and monthly reports are available at the South African Air Quality Information System[6]. Hourly monitoring data from 2014 to 2015 were analysed to establish the background level of air quality in the study area. NO_x ranges from 0-12.6 μg/m$_3$ (0-6.7

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[5] Available at: (http://www.wasaproject.info/)
[6] Available at: (www.saaqis.org.za)

ppb), with an average of 0.95 µg/m^3 (0.5 ppb), values which are typical of a remote location with few industrial sources. Hourly NO$_2$ values never exceed or even approach the South African NAAQS of 200 µg/m^3 (106 ppb) (Table 3.1) and have little seasonal variability. Ambient concentrations of PM do exceed the 24-hour limit value more frequently than the legally allowed NAAQS standard for PM$_{10}$ and PM$_{2.5}$ (75 and 40 µg/m^3, respectively; Table 3.1) at the Karoo station. PM values are highest in spring and autumn. Ozone ranges from 40-60 µg/m^3 (20-30 ppb), significantly lower than the NAAQS value of 120 µg/m^3 (61 ppb), and is typical for a rural background site with low levels of NO$_x$ and VOC emissions (i.e. the precursors required for photochemical ozone formation). The Reference Case includes increased road activity in the study area due to tourism and economic diversification. This will likely lead to increased PM and NO$_x$ emissions, unless offset by more stringent vehicle standards. In addition, there is currently no air quality management plans for the regions within the study area, but considering that PM concentrations currently exceed national ambient standards, the plan(s) under development will have to include a management plan for PM emissions and ambient concentrations. The lack of significant VOC sources increasing over time suggests that there should be little to no increase in regional ozone for the Reference Case. **There are no air quality monitoring stations within the study area and no emissions inventory, critically limiting information on air quality even in the absence of shale gas exploration and development.**

3.2.2.5   SGD Scenarios

3.2.2.5.1   Emissions

The air pollutant emissions for the Exploration Only, Small Gas and Big Gas scenarios (Table 3.3) were calculated from the emission factors, number of days to drill one well, the total number of wells per year, and the total number of truck trips per year as determined by Burns et al. (2016) (see supplementary Digital Addenda for calculations for the present Chapter). Silica is required in all scenarios with SGD, although the amount of silica needed locally is unknown, therefore emissions cannot be calculated. However, a study in the US states that millions of pounds of silica-containing sand may be needed in total for one well (Esswein et al., 2013).

Table 3.3: Calculated air pollutant emissions in tons/day.

tons/day	Exploration Only	Small Gas	Big Gas
CO	0.07	0.24	0.95
NO_x***	0.51	1.9	9.3
Hydrocarbons/VOCs	0.22	0.98	7.1
$PM_{2.5}$**	0.02	0.06	0.33

Notes: Emissions were calculated for seismic surveys, exploration and appraisal drilling, and truck trips based on activities in Burns et al. (2016). Emissions factors were constant across scenarios (Burns et al., 2016) with key drivers including the number of wells and truck trips per year for each scenario (Supplemental Information).
** PM2.5 calculation based on emissions factor from (Altieri & Stone, 2016).
*** The majority of NOx emitted by diesel engines is in the form of NO which is slowly converted to NO2 in the atmosphere, with the rate dependent on atmospheric conditions. Maximum conversion is generally accepted to be approximately 75%.

The scale of air pollutant emissions calculated in Table 3.3 can be compared to the Western Cape Emissions Inventory (Western Cape Department of Environmental Affairs, 2010). The Central Karoo District Municipality is the area closest to where the SGD will take place in which an emissions inventory exists for comparison purposes. There are only four point sources and 11 petrol filling stations within this district municipality, and as such, NO_x emissions are estimated to be only 0.002 tons/day (Western Cape Department of Environmental Affairs, 2010). **Even at the lowest estimate for exploration alone (Exploration Only scenario), NO_x emissions from SGD would dominate regional emissions**. The highest NO_x and VOC emissions, for the Big Gas scenario, are comparable to South Africa's national domestic shipping NO_x emissions (10 tons/day; (Scorgie & Venter, 2006)), and the total industrial VOC emissions from Durban (7 tons/day; (FRiDGE, 2004)). Western Cape VOC emissions total 0.295 tons/day, which is comparable to the estimates presented here for Exploration Only scenario, but lower than estimates for the Small Gas and Big Gas scenarios. In general, such large increases in ozone precursors from shale gas exploration and development (as detailed in Table 3.3) in an area with little current emissions of these precursors, would lead to an increase in ozone production. However, ozone production is dependent upon local atmospheric and meteorological conditions and its formation is not linearly related to precursor concentrations, thus ozone concentrations cannot be quantified for the scenarios (Carter & Seinfeld, 2012; Cooper et al., 2012; Monks et al., 2015; Pacsi et al., 2015; Rutter et al., 2015; Swarthout et al., 2015).
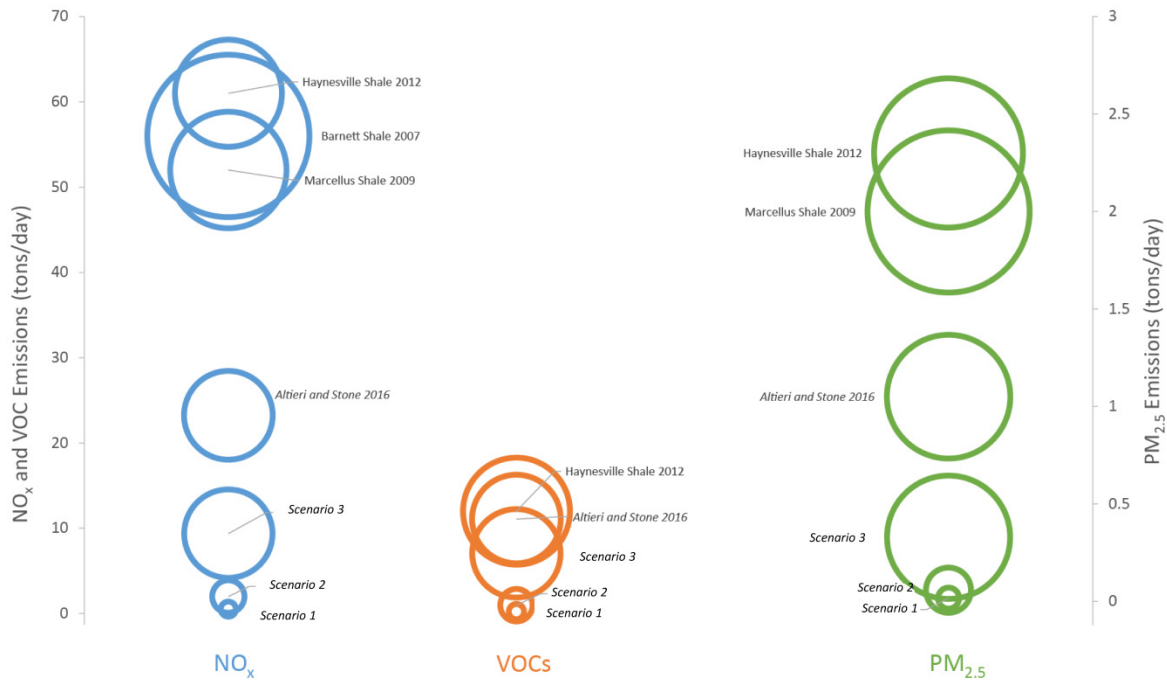
Figure 3.2:   Air pollutant emissions for scientific assessment scenarios compared to bottom-up emissions inventories for Karoo shale gas and main shale plays in USA

Note: Air pollutant emissions (tons/day) for SGD in the Karoo, comparing values for the scientific assessment scenarios (as in Table 3.3) to bottom-up emissions inventories for Karoo shale gas (Altieri & Stone, 2016), and the main shale plays in the US (Haynesville from Grant et al. (2009), Barnett from Armendariz (2009), and Marcellus from Roy et al. (2014)). The colour of the circle denotes the pollutant, the size of the circle scales to the number of wells per year, and gray shading and italicised labels denote a South African-specific estimate. The South African estimates are much lower than the US estimates for three reasons: 1) the number of wells in the US is larger than anticipated for South Africa; 2) some states in the US have weak regulatory regimes; and 3) the newer technology which would be applied in South Africa is anticipated to be less polluting.

NO_x and $PM_{2.5}$ emissions from the three main shale plays in the US are considerably higher than any estimates for South Africa (see Figure 3.2), due primarily to the larger number of wells drilled each year in the US than assumed in Small and Big Gas scenarios (Burns et al., 2016), and the use of engines with a wide range of emissions factors (Armendariz, 2009; Grant et al., 2009; Roy et al., 2014). The existing on-shore oil and gas industry in the US is in close proximity to the more recently developed unconventional natural gas extraction areas, allowing for older engines with higher emissions factors to be utilised for shale gas extraction. Figure 3.2 also shows that the emissions calculated for the Exploration Only and Small and Big Gas scenarios are lower than previous estimates for Karoo shale gas exploration and development (Altieri & Stone, 2016). Though the estimates for the size of the resource and the number of wells per year were similar, Altieri & Stone (2016) used emissions factors significantly higher than those reported in Burns et al. (2016).

Using a simple Lagrangian dispersion model (limited to the prediction of worst-case impacts, and not taking atmospheric chemistry into account) and the emission inventory of Table 3.3 above, worst-case

NO_x concentrations were calculated for single wells (Exploration Only scenario) and well fields (Small and Big Gas scenarios).

For single wells, the maximum NO_x concentration is approximately 9 μg/m³ at a distance of 200 m from the source; for a well field of 30 by 30 km with 410 production wells being drilled the maximum is of the order of 42 μg/m³ 7 km downwind of the field, assuming release at 5 m height. In both cases, average concentrations should be considerably lower. **This would lead to the preliminary conclusion that the development of wellfields even at the Big Gas scale would not lead to material exceedances of the NAAQS threshold values for NO_2 due to shale gas activities alone. Although ozone concentrations may increase, ozone limit values would likely not be exceeded even in the Big Gas scenario, although no concentration limit has been determined below which there is no impact on humans. However, for PM, as there are already exceedances of the national standard, it is likely that shale gas exploration and development will lead to more exceedances (see Table 3.7).**

3.2.2.5.2   Use of natural gas and impact on net emissions

Natural gas-fired electricity generation leads to lower air pollutant emissions per kWh of generation relative to coal-fired electricity generation (Allen, 2014). The reduced emissions from electricity generation are slightly offset by the increased emissions associated with the exploration, development, and production of unconventional natural gas. In addition to understanding the net emissions reductions (or increases) due to switching from coal to unconventional natural gas for electricity supply, is a need to recognise that the spatial distribution of these emissions will vary. In the case of South Africa, it is a shift from emissions in the Highveld Priority Area and the Mpumalanga coal region to the Karoo basin, and potentially in future in the Waterberg (see Wright et al., 2016). Emissions of air pollutants are estimated for a 1000 MWe (Small Gas scenario) electricity generating plant operating with water/steam injection for NO_x reduction, and 4000 MWe (Big Gas scenario); both are shown in Figure 3.3.

	NOx	CO	N2O	Total PM	SO2	VOC
CCGT 1000 Mwe (Scenario 2)	29 328	6 780	694	1 514		
CCGT 4000 MWe (Scenario 3)	117 314	27 121	2 775	6 055		
GTL production 65,000 bpd (Scenario 3)	23.7		4.7	-	-	
LNG plant 8700 tpd (Scenarios 1, 2 and 3)	212			15.5	27.8	1
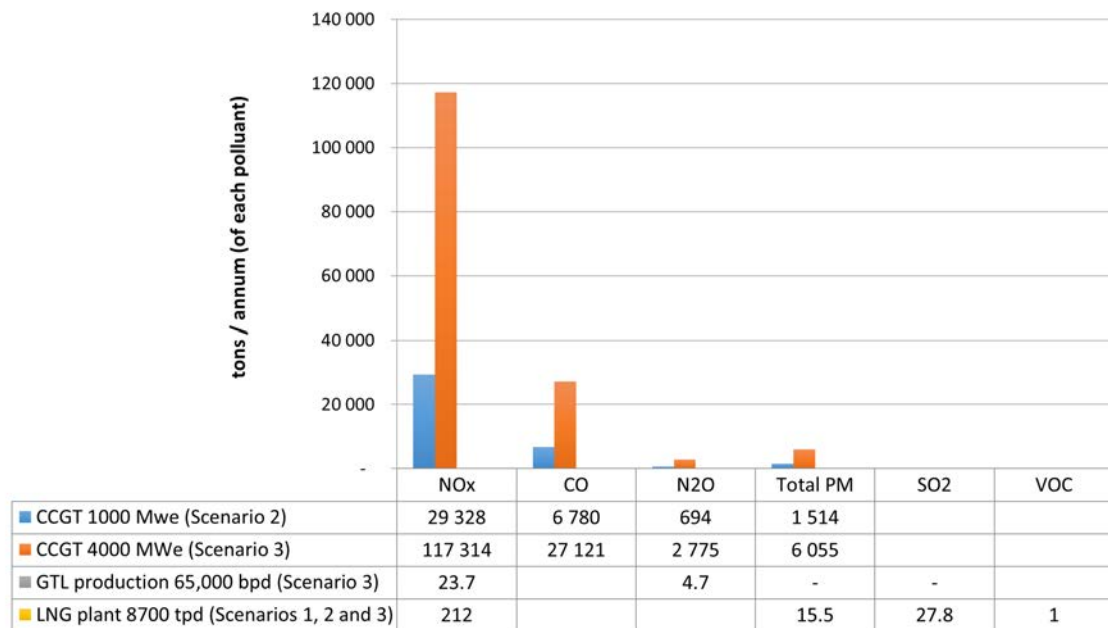
Figure 3.3:   Emissions of local air pollutants associated with shale gas used for CCGT, GTL and LNG.

Note: Tables for each of electricity generation using CCGT, GTL and LNG are available separately in the supplementary information in the Digital Addenda (start with worksheet 'Fig 1 AQ for CCGT GTL LNG').

Comparing the figures in Figure 3.3 to those provided by Eskom as a national grid average for 2014, Eskom estimates that 4.22 tons of NO_x are emitted per GWh of power generated, compared to the approximately 6 ton NO_x/GWh derived from figures shown below Figure 3.3.

While GTL and LNG plants are envisaged at the coast (see Burns et al., 2016), and are therefore outside the study area, the atmospheric emissions or reductions are associated with shale gas and are therefore included in this assessment. Under the Big Gas scenario (Burns et al., 2016), a GTL plant "replacing one of the existing aging refineries" is envisaged. Although the capacity of this is given as 65 000 bpd (barrels per day) of liquid fuels, for purposes of this study we have also considered a 120 000 barrels per day (bpd) plant, as the conventional existing refineries range from 100 000 to 180 000 bpd. The emissions in Figure 3.3 are calculated using emission estimates produced by the US National Energy Technology Laboratory (National Energy Technology Laboratory et al., 2013) and reporting by an existing GTL facility (Oryx GTL Ltd, 2011), both using internally-generated electricity due to energy integration.

On a life cycle basis, some emissions for the two 2000 MWe power plant would be used by the GTL plant. Burns et al. (2016) does not include vehicles directly using compressed natural gas (CNG), which might lead to a lower emissions pathway than converting gas to liquid, and then using it in vehicles.

Alternatively, liquefaction of the shale gas to LNG has been suggested as a product outlet under the Big Gas scenario; a plant equivalent to a 65 000 bpd GTL plant would produce approximately 8 700 ton per day of LNG or 16,000 tpd equivalent to a 120,000 bpd GTL plant's production. The estimated emissions, drawing on the literature (Delphi Group, 2013; SNC Lavalin, 2015), are shown in Figure 3.3 (for calculations, see the Digital Addenda).

3.2.3 *Limits of acceptable change*

There is an important distinction between exposure limits and emission limits. Exposure limits seek to limit human and ecosystem exposure to harmful pollutants. Emission limits are limits on how much can be emitted by specific processes, such that people are not exposed to harmful levels of pollutants. With regards to exposure limits, it is useful to make a further distinction between occupational exposure limits and community exposure limits, with the former often being an order of magnitude higher than the latter (Table 3.1). Workers consist of a healthy, age-specific group exposed for a limited time per week, whereas communities include vulnerable sub-groups such as the very young, the aged and sick persons. The air quality risk assessment draws on both local/ regional and occupational / community exposure distinctions (see Section 3.2.4).

The South African NAAQS referred to in Section 3.1 are community exposure standards which are implicitly health-based, being largely based on the WHO guidelines for the ambient limit values of the major pollutants, with some local adaptations (South African Bureau of Standards (SABS), 2009). For those pollutants where local exposure limit values have not been specified, a number of widely-referenced sources for health-based exposure limits from foreign agencies are available; these have been summarised in the NAAQS (RSA, 2009a) and include values for carcinogenic pollutants. To determine overall risk, it would thus be necessary to determine the concentration of each of the pollutants to which communities would be exposed and determine the probability of different health endpoints for short- and long-term exposure. For the VOCs, such an estimate would entail considerable uncertainty due to the location-specific composition of these compounds.

Occupational exposure standards will apply on both the well drilling sites and downstream processing facilities under all scenarios. In South Africa, occupational exposure from non-mining activities is regulated under the Hazardous Chemical Substances (HCS) regulations of the Occupational Health and Safety Act (85/1993). The regulations specify the allowed exposure limit over eight hour shifts, and are generally based on the guidelines produced at regular intervals by the American Conference of Governmental Industrial Hygienists (ACGIH). Because the South African regulations have not

been updated for some time, it would be prudent to consider a revision of the regulations, taking into account good practice internationally (see Section 3.4).

Minimum emission standards exist in South Africa for the activities in the petroleum refinery industry (RSA, 2013), but at this stage do not include unconventional gas recovery and the processing of the gas. The setting of emission standards in South Africa has previously followed the principle of "Best Practical Environmental Option" and has depended largely on international best practice in this regard. The most complete set of emission standards for unconventional gas exploration and recovery has been developed by the United States Environmental Protection Agency (US EPA) (US Federal Register, 2012). These rules are currently undergoing further review and refinement. In terms of the National Environmental Management: Air Quality Act (NEMAQA), 2004; Sections 21 and 22, read with Government Notice Regulation 248 which lists activities requiring an atmospheric emissions licence (AEL), any legal person undertaking SGD will require an AEL, if they have an incinerator capacity of 10 kg or more of waste processed per hour.

Internationally, there are guidelines for critical levels for air pollution related to impacts on crops and vegetation (Convention on Long-range Transboundary Air Pollution (CLRTAP), 2015); however, South African standards do not exist. Ozone impacts agriculture and ecosystems at concentrations lower than ambient air quality standards for health, partially due to the importance of cumulative exposure of crops and vegetation. The UK critical level using AOT40 for ozone (i.e. cumulative exposure above 40 ppb during daylight hours over a three month growing season) for crops and semi-natural vegetation is 3000 ppb hours (Air Pollution Information System (APIS), n.d.). However, it is not known what the critical level may be for the vegetation in the study area.

3.2.4   *Analysis of risks and opportunities for local air pollution*

There are risks of increased emissions of air pollutants from SGD, as well as opportunities to reduce exposure where shale gas displaces fuels that emit more air pollutants. The opportunities to reduce indoor air pollution for (mainly poor) households are explored in Section 3.2.4.1 below. The risks of exposure to local air pollutants are assessed in relation to four categories: 1) occupational exposure; 2) local community exposure; 3) regional community exposure; and 4) agriculture and ecosystem exposure. These risks are considered in turn, in Sections 3.2.4.2 to 3.2.4.4 below. The summary risk matrix is presented in Table 3.6.

In this assessment, the likelihood is defined as the likelihood that someone in the study area will be exposed, while the consequence is if a person is exposed, on a scale of consequences ranging from 'slight but noticeable' to 'extreme'. The consequence is considered 'slight' if ambient values will be

below regulatory limits (e.g. NAAQS), 'moderate' if ambient values are at or close to regulatory limits, 'substantial' if ambient values exceed regulatory limits, and 'severe' if multiple pollutants exceed regulatory limits, and 'extreme' if multiple pollutants greatly exceed regulatory limits. The "likelihood" increases as SGD increases to cover a larger proportion of the study area.

3.2.4.1   Opportunities for air pollution reduction

Shale gas presents opportunities for air pollution reduction as well as risks. Should exploration lead to Small or Big Gas levels of development, the potential exists to use natural gas for domestic energy supply, replacing or partly replacing wood used extensively by poor households all over South Africa, but in this context mainly in the Eastern, Western and Northern Cape. Reductions in indoor air pollution exposure could be achieved under the Big Gas scenario by replacing the use of wood for cooking and space heating, although such interventions would have to be carefully considered with regards to cost and social acceptability. Such benefits might be achieved especially in low-income households, who typically use more fuels other than electricity (Davis, 1998; Tait, 2015). This is demonstrated by the emission factors given in Table 3.4 below (FRiDGE, 2004).

Table 3.4:   Emission factors for various pollutants from household energy use.

Fuel	Unit	SO_2	NO_x	VOC	PM_{10}	CO_2	CH_4
Coal	g/kg	19	1.5	5	4.1	3000	3.6
Paraffin	g/l	8.5	1.5	0.09	0.2	n.a.	n.a.
LPG	g/kg	0.01	1.4	0.5	0.07	2080	n a
Wood	g/kg	0.18	5	22	15.7	1540	13.6

Source: data from FRiDGE, 2004

The emission factors for the direct use of shale gas are comparable to those for the use of LPG, while gas as a source of household energy is considerably more efficient than wood, which is often used with open fires or unsophisticated appliances (Msibi, 2016). **A considerable health benefit could ensue if shale gas displaced other fuels for use indoors, as the emissions from wood and coal have been shown to create large health risks and associated societal costs** (Annegarn et al., 2000; FRiDGE, 2004; Friedl et al., 2008; Mehlwana, 1999; Spalding-Fecher, 2005; Terblanche et al., 1992; WHO, 2002).

3.2.4.2   Occupational exposure to air pollutants

In the Reference Case there are no shale gas workers, and as such the likelihood of occupational exposure is very unlikely, and the risk is very low, even without mitigation (Table 3.6). However, in the Exploration Only, and Small and Big Gas scenarios, occupational exposure to air pollutants is very likely and the consequences are severe, leading to a high risk for occupational exposure to air

pollutants without mitigation. The main drivers of this risk are respirable crystalline silica, diesel exhaust and VOCs. Inhalation of respirable crystalline silica can lead to many negative health impacts (American Thoracic Society, 1997). Respirable crystalline silica is a known carcinogen and is associated with lung cancer (Department of Health and Human Services, 2014). Exposure can also cause the lung disease silicosis, which in severe or chronic cases can increase the risk of tuberculosis (American Thoracic Society, 1997; Castranova & Vallyathan, 2000). In a study by the National Institute for Occupational Safety and Health (NIOSH) in the US, the occupational exposure to crystalline silica in eleven shale gas sites in five US states was investigated (Esswein et al., 2013). They found that the occupational exposure thresholds for a full-shift were exceeded at all 11 sites, with 31% of samples showing an exceedance of more than ten times the NIOSH recommended exposure limit (Esswein et al., 2013). This led the Occupational Safety and Health Administration (OSHA) and NIOSH to release a Hazard Alert stating that they, "identified exposure to airborne silica as a health hazard to workers conducting some hydraulic fracturing operations during recent field studies" (OSHA, 2016). This study identified seven points of dust generation that were found at all 11 work sites (Esswein et al., 2013). **Occupational exposure to respirable crystalline silica can be a serious health hazard to workers during shale gas exploration and development (Exploration Only, and Small and Big Gas scenarios).**

Diesel exhaust was classified as carcinogenic to humans by the IARC that is part of the WHO (IARC, 2012). This finding was based mostly on occupational exposure to diesel exhaust; however, the committee commented that exposure to workers and the general public should be reduced. The quantitative relationship between cancer risk and distance from source is not yet clear. Exposure to NO_2, which can be elevated in concentration by roadways, can have negative effects on the respiratory system including inflammation and reduced lung function growth (WHO, 2005). The results of a systematic review on outdoor air pollution and asthma concluded in part that, prevalence of asthma is associated with reported exposure to truck traffic. The evidence does suggest that this association only exists in those living very close to the roadside, however, the proximity to roads was less consistently and strongly associated with asthma prevalence than the exposure to heavy good vehicle traffic (Gowers et al., 2012 and references therein).

Increased PM is associated with increased hospital admissions, chronic respiratory and cardiovascular diseases, decreased lung function, and premature mortality, with the health impacts of $PM_{2.5}$ exceeding those associated with PM_{10} (Kim et al., 2015). In 2013, IARC classified outdoor air pollution and PM from outdoor air pollution as carcinogenic to humans (IARC, 2013). It was highlighted by the panel that almost all of the studies that showed an association between increased health risk and exposure to outdoor air pollution were performed in areas with annual average $PM_{2.5}$

concentrations in the range of 10-30 µg/m^3 (IARC, 2013). VOC emissions, also known as petroleum hydrocarbons, include aromatic and aliphatic compounds emitted during exploration, production and distribution stages (Adgate et al., 2014 and references therein). Health effects are compound specific, but many known shale gas-related VOCs are carcinogenic, while some cause eye irritation, headaches, and asthma. **The use of heavy diesel trucks, stationary engines and associated rig equipment for SGD, as well as some VOCs emitted from the fracking process and use of silica, leads to occupational health exposure assessed as high risk at the well site without mitigation due to emissions of diesel exhaust, NO$_2$, PM, and VOCs.**

There is a potential risk from H$_2$S emissions, if it is present. H$_2$S is flammable and has a strong smell of rotten eggs that becomes obvious at concentrations of 0.01 -1.5 ppm (OSHA, 2005). People who are exposed to low to moderate levels of H$_2$S can experience symptoms such as irritation to eyes, nose and throat, headaches, tiredness, poor memory, and nausea (Agency for Toxic Substances and Disease Registry (ATSDR), 2014; OSHA, 2005). Asthmatics may also experience difficulty in breathing, at higher concentrations, people can lose consciousness, and exposure can lead to death (ATSDR, 2014). Oil and gas companies in the US do use mitigation measures to reduce worker exposure to H$_2$S, however the frequency of worker exposure to H$_2$S from SGD in the US is not known (Witter et al., 2014). **If H$_2$S is present in the geological formation, there is a risk of it being released at various stages during the shale gas exploration and development process, leading to occupational exposure.**

The occupational risks are assessed as 'very likely' for the Exploration Only and Small and Big Gas scenarios, as once a wellpad is established there will be workers exposed to air pollutants. The consequence is considered severe in all three cases with no mitigation due to the high likelihood of workers being exposed to pollutant levels that exceed regulatory limits, leading to a high risk of occupational exposure in these three scenarios. However, the consecutive increase in the number of wellpads from the Exploration Only scenario through to the Big Gas scenario does not increase the consequence, as the workers are only exposed to wellpad emissions from the site they work on, and the increase in the number of sites in the region does not increase the potential for risks related to occupational exposure.

With mitigation measures, the high risk of occupational health exposure assessed for the three scenarios decreases to moderate risk. While there were high levels of crystalline silica sampled at sites in the US (Esswein et al., 2013), the study also developed a management plan to mitigate the potential impact. This is attached in Digital Addendum 3b. Thus, occupational exposure to respirable silica could be decreased through the application of these mitigation measures, which should include a

combination of the appropriate use of personal protection equipment, and engineering and administrative controls. However, exposure to diesel exhaust and VOCs will be harder to mitigate. Different fuels could be used to mitigate diesel exhaust (e.g. the natural gas itself in CNG vehicles), however, VOCs would still be released. The VOCs will be difficult to mitigate as they are emitted at source as part of the process. The potential risk to health will be easier to evaluate once the composition of the VOCs are known. **The risk to occupational health can be mitigated to a moderate risk by decreasing respirable crystalline silica emissions using best practice. It is more difficult to mitigate the risk from diesel exhaust and VOCs.**

3.2.4.3   Local community exposure to air pollutants

The risks associated with local community health due to emissions of diesel exhaust, NO_2, PM, and VOCs need to be considered. As discussed in Section 3.2.2.5, the ambient concentrations of PM in the study area are already above NAAQS standards. As such, there already exists likely exposure to PM for local communities with a moderate consequence, and therefore a low risk is assessed in the Reference Case (with and without mitigation). Local community exposure derives from a production block being placed within 10 km of a community, regardless of the population size of that community. In Digital Addendum 3a the spatial distribution of risks is only shown for existing communities; however, the risk assessment would be for any person within 10 km of a production block.

The average hourly ambient concentrations of NO_x at the Karoo background monitoring site (0-12.6 µg/m^3) are more than 25 times lower than the South African hourly standard. In the Small Gas scenario, the increase in emissions leads to NO_x concentrations increasing near wellpad activity (estimated maximum increase of 9 µg/m^3; section 3.2.2.5.1). Even with this maximum increase, the NO_x concentrations would likely remain well below the NAAQS threshold for NO_2, which results in an overall low risk. The Small and Big Gas scenarios lead to order of magnitude increases in all emissions. For NO_x, with the maximum increase in ambient concentrations estimated at 43 µg/m^3, the NAAQS threshold for NO_2 would not be exceeded. However, with larger increases in PM direct emissions and PM precursors (e.g., VOCs that can react and condense to increase PM mass concentrations), the risk to local health is assessed as a moderate risk with no mitigation.

In addition, NO_2 can react to form ozone and PM, which can in turn have negative health impacts locally. Exposure to ozone is linked to asthma, decreased lung function, and premature mortality (Levy et al., 2001). The WHO has stated that for PM and ozone exposure there is not clear evidence of a lower threshold where adverse health effects do not occur, with some evidence suggesting that the guideline and standards cannot fully protect public health (WHO, 2005). Thus, it is likely that

ozone concentrations would increase (both locally and regionally); however, it is unlikely that these increases would be large considering 1) the estimated emission levels of NO_x and VOCs (Table 3.3), and 2) the current ambient ozone concentrations measured near the study area are well below the NAAQS thresholds.

Local community exposure to emissions of diesel exhaust, NO_2, PM, and VOCs is assessed as a low to moderate risk without mitigation.

Mitigation technologies can significantly reduce local community exposure to air pollutants. According to Burns et al. (2016), flaring will be used to minimize VOC emissions from the completion venting process, however, green completions are the recommended standard for emissions reductions as this also minimises GHG emissions (Field et al., 2014). Emissions modelling from the Marcellus shale play in the USA demonstrated that NO_x emissions could be reduced by 85% if control methods were used for all equipment, while VOC emissions could be reduced by 88% (Roy et al., 2014). Assuming control measures are successfully implemented for NO_x and VOCs, the drilling emissions in Table 3.3 can be significantly reduced (Table 3.5). This assessment assumes a roughly linear response to decreasing consequence (and thus risk) with decreasing emissions. Thus, the local community exposure to air pollutants can be mitigated to a low risk for all scenarios.

Table 3.5:   Emissions assuming a reduction of 85% of NOx emissions and 88% of VOC emissions using best available control technologies

tons/day	Exploration Only	Small Gas	Big Gas
NO_x	0.08	0.30	1.41
VOC	0.03	0.12	0.85

Drilling, fracking and trucking emissions can be mitigated using ignition timing retard and selective catalytic reduction for NO_x, diesel particulate filters for PM, and diesel oxidation catalysts for VOCs (Grant et al., 2009; Roy et al., 2014). With mitigation, local community exposure is assessed as low risk.

3.2.4.4   Regional community exposure to air pollutants

Community exposure at the regional scale may occur due to emissions of diesel exhaust, NO_2, PM, VOCs, and resultant formation of ozone, associated with SGD regardless of the population size within the study area. Similar to the risk to local communities, the risk of exposure to air pollutants for the region is assessed to be a low risk in the Reference Case (with and without mitigation), because currently only PM concentrations are above the NAAQS threshold (Section 3.2.2.5). Diesel exhaust, ozone, and PM (both directly emitted and secondary particles produced from gaseous emissions) are

the main pollutants that are considered for regional air quality. There is a risk of exposure to diesel exhaust if communities are close to roads where the long-haul trucks will travel, with the risk decreasing with distance from the road (potential health risks are summarised in Section 3.2.4.2). Without mitigation, increases in regional ozone and PM ambient concentrations would be expected due to the increase in emissions of precursors and direct emission of PM. The relationship between health impact and both PM and ozone concentrations is linear (WHO, 2005), however the relationship between precursor emissions and resultant ambient concentrations of ozone and PM is not. This non-linearity makes it difficult to quantify the potential resultant ozone and PM concentrations on a regional level.

The Exploration Only scenario is assessed as low risk (with and without mitigation), as it is not likely that the increases in emissions will have a marked impact on air pollution at the regional scale. In the Small and Big Gas scenarios, even though emissions increase as compared to the Exploration Only scenario, it is not likely that on a regional scale the ambient PM and ozone concentrations will see great increases as the dispersion of the pollutants over the region will dilute the average exposure of people in the region. The Small and Big Gas scenarios do have large increases in truck traffic volume and the amount of the study area that will experience increases in truck traffic; as such the Small and Big Gas scenarios are assessed as moderate risk without mitigation. **The use of heavy diesel trucks increases the potential for people within the region to be exposed to increased levels of air pollution. This risk can be mitigated by routing trucks away from communities.**

Gas phase species and particles can scatter and absorb light, thus deteriorating visibility. However, in general, particles have the greatest impact on visibility as they can scatter significant amount of light (Seinfeld & Pandis, 2006). The impact that particles have on visibility is related properties such as the particles' size, shape, optical properties, composition, and ability to take up water. It is difficult to assess the potential risk to visibility without information on these characteristics, and thus visibility is not considered further in this chapter (see Oberholzer et al. 2016).

Agriculture and ecosystem exposure to air pollutants

With increasing SGD, it is increasingly likely that forage will be exposed to increasing ozone levels. A critical level for accumulated ozone (AOT40, see above) of 3000 ppb hours is associated with a 5% reduction in yield of wheat cultivars; plant sensitivity does vary and it is not known how sensitive the forage or the grazing animals will be to ozone in the study area (CLRTAP, 2015). In this assessment, it is not likely that there will be large increases in ambient ozone concentrations in the study area in the Exploration Only and Small and Big Gas scenarios. Currently, the background ozone concentrations are low (~40-60 $\mu g \ m^{-3}$), and thus it is not likely that the small increase in ozone would

be a risk to agriculture. As the spatial extent of SGD increases in the Small and Big Gas scenarios, the likelihood of plants across the study area being exposure was assessed to increase to likely, with the consequence slight but noticeable. **Overall, agricultural exposure (with and without SGD) is assessed as very low risk.** Ozone can impact the yield and nutritional content of grass and shrubs for foraging, which in turn can have nutritional impacts on the grazing animals (Booker et al., 2009).

3.2.5   *Summary of risks to air quality*

In summary, SGD provides a potential opportunity to reduce indoor air pollutants, if the gas displaces other fuels such as wood, coal and paraffin, especially in poor households. The risk assessment matrix in Table 3.6 summarises the main risks to deterioration of air quality. Occupational exposure refers to workers on the production block or wellpad. Local exposure refers to communities near the 30x30 km production block (within 10 km). Regional refers to the entire study area, defined in Burns et al. (2016). Opportunities are addressed in Section 3.2.4.1 and mitigation of risks in Section 3.4, considering how they might apply in the South African context. It is important to note that the total emissions as calculated based on the scenarios here are much smaller than emissions in the USA (Section 3.2.2.5 and Figure 3.2), which has resulted in significant impacts on air quality in the US that are not anticipated to be as severe in the South African context. In reading the table, note that "with specified mitigation" assumes that good practice, governance and enforcement are implemented.

Figure 3.4 presents a risk map of local community exposure to air pollutants across four SGD scenarios, with- and without mitigation.

Table 3.6:   Risk assessment matrix for air quality

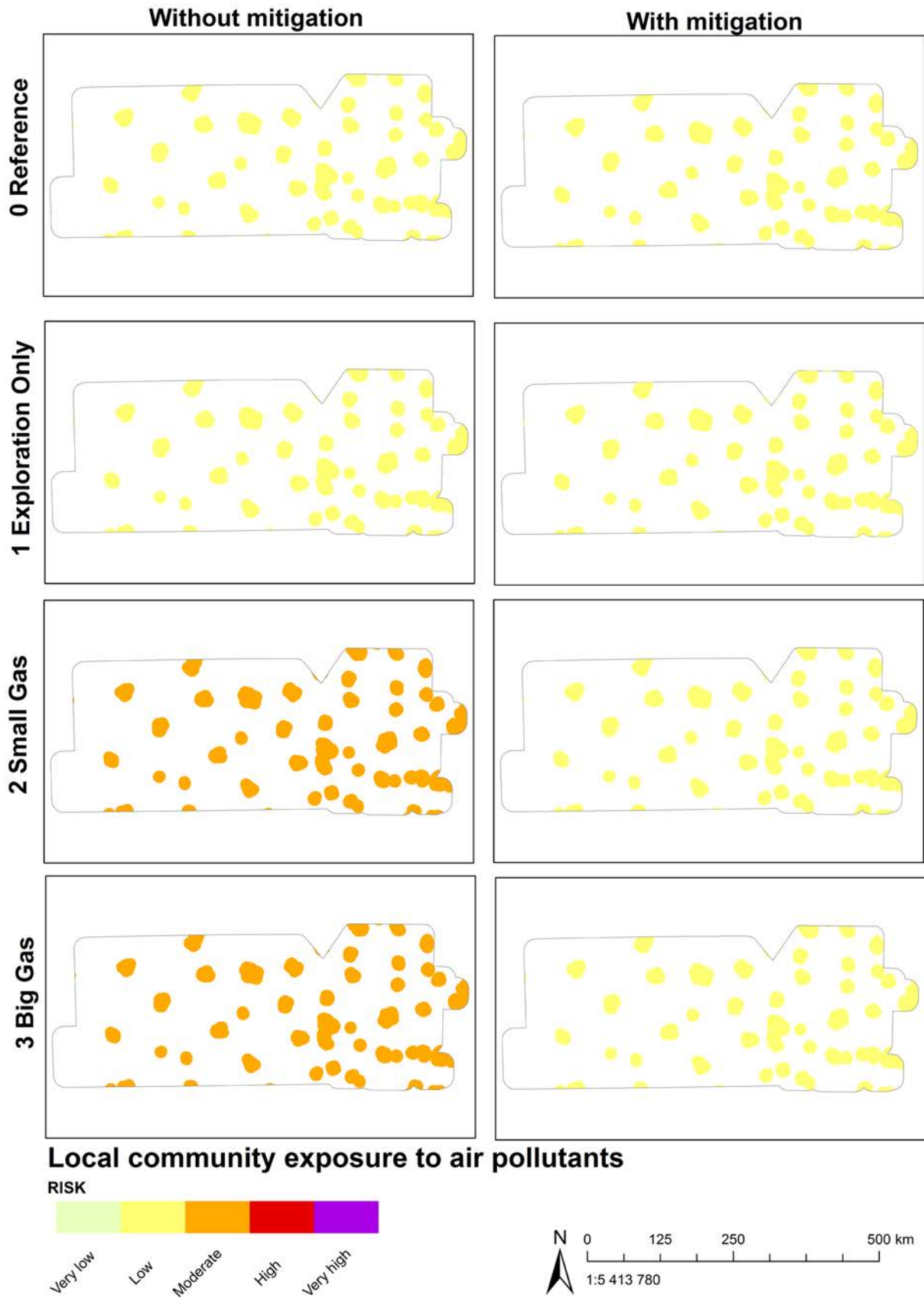| Impact	Scenario	Location	Without mitigation			With mitigation		
			Consequence	Likelihood	Risk	Consequence	Likelihood	Risk
Occupational exposure to air pollutants	Reference Case	On wellpad	None	Very unlikely	Very low	None	Very unlikely	Very low
	Exploration Only		Severe	Very likely	High	Substantial	Very likely	Moderate
	Small gas		Severe	Very likely	High	Substantial	Very likely	Moderate
	Big gas		Severe	Very likely	High	Substantial	Very likely	Moderate
Local community exposure to air pollutants	Reference Case	Local (a production block placed within 10 km of a town)	Moderate	Likely	Low	Moderate	Likely	Low
	Exploration Only		Moderate	Likely	Low	Moderate	Likely	Low
	Small gas		Substantial	Very likely	Moderate	Moderate	Very likely	Low
	Big gas		Substantial	Very likely	Moderate	Moderate	Very likely	Low
Regional community exposure to air pollutants	Reference Case	Regional (production blocks placed anywhere within study area)	Moderate	Likely	Low	Moderate	Likely	Low
	Exploration Only		Moderate	Likely	Low	Moderate	Likely	Low
	Small gas		Substantial	Very likely	Moderate	Moderate	Likely	Low
	Big gas		Substantial	Very likely	Moderate	Moderate	Likely	Low
Agriculture and ecosystems exposure to air pollutants	Reference Case	Regional	Slight but noticeable	Extremely unlikely	Very low	Slight but noticeable	Extremely unlikely	Very low
	Exploration Only		Slight but noticeable	Extremely unlikely	Very low	Slight but noticeable	Extremely unlikely	Very low
	Small gas		Slight but noticeable	Likely	Very low	Slight but noticeable	Likely	Very low
	Big gas		Slight but noticeable	Likely	Very low	Slight but noticeable		Very low

Figure 3.4:   Map indicating the risk of local community exposure to air pollutants across four SGD scenarios, with- and without mitigation.

Without mitigation, most risks to human health from local and regional community exposure in the Exploration Only and Small and Big Gas scenarios are assessed as low or moderate risk, with occupational exposure assessed as high risk. With mitigation using control technologies – suitably enforced by capable regulatory institutions and systems – the air quality risks decrease across both community and occupational exposure.

The risk of workers being exposed to air pollution is driven by emissions of respirable crystalline silica, diesel exhaust and VOCs. It is anticipated that the risk of silica exposure can be effectively mitigated, although exposure to VOCs and diesel exhaust will be harder to mitigate. Thus even with mitigation, occupational exposure is still assessed as a moderate risk.

For local communities, the risk of exposure to air pollution is driven by the increase in ambient PM concentrations, which already exceeds NAAQS. For communities that are more than 10 km from a wellpad, the risk is driven by the potential exposure to increased truck traffic, which can be mitigated by routing trucks away from communities or by treating the road surface.

The air quality impacts on agriculture and ecosystems are assessed as very low (with and without mitigation). While ozone can impact the yield and nutritional content of grass and shrubs for foraging, which in turn can have nutritional impacts on the grazing animals; it is not likely that there will be such large increases in regional ozone to begin to put agriculture at risk.

3.3   Greenhouse gas emissions

3.3.1   Scope

Key SGD activities pertinent to GHG emissions include vertical and horizontal drilling; fracking; and well completion, with upstream fugitive emissions of methane the most material concern (Burns et al., 2016). The major potential risks and opportunities are elaborated in Section 3.3.1. The scope of GHGs includes CO_2, methane (CH_4; especially fugitive emissions) and nitrous oxide (N_2O). Perfluorocarbons, hydrofluorocarbons, and sulphur hexafluoride are not included in the scope, as they are not considered material in shale gas and also considered less material in South Africa's Intended Nationally Determined Contribution (INDC) (RSA, 2015b). Short-lived climate forcers (SLCFs) are not considered as GHGs, though they are receiving some attention internationally (United Nations Environment Programme (UNEP), 2011). However, two SLCFs, being ozone and PM, are considered in the air quality assessment as air pollutants.

The biggest challenge is South Africa's energy economy which is GHG-intensive (DOE, 2015a) due to extensive use of coal. Seventy-seven percent (77%) of the total primary energy supply and 90% of electricity supply are provided by coal (DOE, 2015a). The largest sources of GHG emissions in South Africa are from activities in the energy sector – electricity generation, liquid fuel from coal and energy use in industry and transport, with smaller shares of national emissions from land use and waste (Department of Environmental Affairs (DEA), 2014c). GHG emissions from residential, commercial and industrial use of shale gas will be smaller, as is energy demand (see Wright et al., 2016); the current literature does not provide a basis for assessing shale gas use in these sectors.

A different energy path will be required to make any dent in South Africa's emissions (Winkler & Marquard, 2009). Gas is less emissions-intensive than coal at the point of combustion, but emits more GHGs than renewable energy or nuclear power (GEA, 2012). The Department of Energy's (DoE's) Integrated Energy Plan (IEP) and Integrated Resource Plan (IRP) (DOE, 2011, 2015b) considers GHG emissions, and provides opportunities to revisit our energy mix (see Wright et al., 2016).

3.3.2   *Key potential impacts on GHG emissions*

The opportunities of reducing, and risks of increasing GHG emissions from shale gas depend on:
- The extent of fugitive emissions, i.e. physical leakage of methane to the atmosphere;
- Which other fuels would have been used instead of gas;
- Global warming potential (GWP) values; and
- Extent to which control technologies and good practice are employed.

These are also key uncertainties. Given the uncertainties, a careful assessment should compare shale gas against different scenarios (as described by Burns et al., 2016). Different findings in the literature to a significant extent reflect different assumptions about the uncertainties, including scenarios of different uses of shale gas, in each case compared to other fuels. The extent of use of shale gas is considered in Wright et al. (2016), which assumes expansion plans will be based on the IRP for 2010-2030 and an update in 2013 for electricity supply (DOE, 2011; 2013), while projections for liquid fuel supply are consistent with the IEP (DOE, 2015b[7]; see Wright et al.; 2016).

Among the hotly debated concerns associated with shale gas is the cumulative impact that shale gas may have on global GHG emissions compared with conventional fuel use and, as such, on global climate change (Bradbury et al., 2013). In assessing the literature, it is important to distinguish two

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[7] Note that the IEP has draft status, is not ready for publication nor has been officially adopted by government. The IRP 2013 Update was published, but not officially adopted.

aspects, firstly the overall effect of gas, and which other fuels it displaces, and secondly, the emissions intensity of shale gas.

3.3.2.1   Overall effects

Some researchers have observed that abundant natural gas substituting for coal could reduce CO_2 emissions globally (Hultman et al., 2011; Levi, 2013; Moniz et al., 2011). For example, certain studies show shale gas as having a lower emissions intensity compared with conventional fuels (particularly coal) (e.g. Broomfield, 2012; Burnham et al., 2012; Cathles et al., 2012) and thus having the potential to reduce global emissions should the gas replace conventional fuels. On the other hand, there are studies that suggest that shale gas has, under certain circumstances, a greater GHG emissions intensity than that of conventional fuels (e.g. Howarth et al., 2011; Wigley 2011[8]; Jiang et al., 2011[9]).

Many comparisons in the literature on the GHG 'value' of the various fuels assume other fuels are displaced, and in South Africa with increasing demand, it is also possible that shale gas may be used in addition to existing fuels – in which case there is an emissions increase, though less than business-as-usual (Cohen & Winkler, 2014). Wood et al. (2011) show that there is little evidence to suggest that shale gas is currently or is expected to substitute coal in a significant manner. Indeed, suggestions indicate that it will continue to be used in addition to coal in order to meet increasing energy demand (Wood et al., 2011). McJeon et al. (2014) show that market-driven increases in global supplies of unconventional natural gas do not discernibly reduce the trajectory of GHG emissions or climate forcing. Feng et al. (2015) show that from 2007 to 2009, when carbon emissions in the USA declined the most, 83% was due to economic factors, including consumption and production changes. Just 17% of the decline was due to changes in the USA's fuel mix.

Shale gas is considered by some to be a 'transition' or 'bridge' fuel that will allow time for energy systems to adapt from carbon-intensive fuels to renewables (Bradbury et al., 2013). However, others disagree with the need for a 'transition' fuel by debating that present technology could allow for an immediate shift to a 100% renewable energy system if energy systems were reconceptualised[10]

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[8] This study considered a scenario where a portion of coal usage was replaced with shale gas usage (considering a methane leakage rate) over a period of time. The findings suggest that the methane leakage counteracted the reduction in carbon associated with a switch from coal combustion to gas combustion.

[9] When comparing shale gas to conventional natural gas. Their results show shale gas has approximately 3% more emissions than conventional gas but they conclude that this is '*likely within the uncertainty bounds of the study*'.

[10] An example of an alternative strategy to energy systems that would make an energy system entirely renewable is to include various energy storage systems, such as pumped storage hydroelectric power plants, and molten salt storage for concentrated solar power, in the system, to maintain the baseline load of energy without the need of fossil fuels (Glasnovic & Margeta, 2011).

(Glasnovic & Margeta, 2011; Lund & Mathiesen, 2009). The scale of investment required will depend on the existing infrastructure and South Africa does not have extensive transmission and distribution networks for gas (see Wright et al., 2016).

3.3.2.2   GHG intensity and emission factors

There is little doubt that, at the point of combustion, natural gas, including from fracking, emits lower quantities of GHG emissions per unit of energy produced than other fossil fuels (Alvarez et al., 2012). There is less certainty when broadening the assessment beyond the point of combustion, to include particularly fugitive methane emissions (see Section 3.3.4.1). Figure 3.5 shows GHG emission factors for different fossil fuels, illustrating that gas is comparatively better relative to other fossil fuels, but is higher than renewable energy, which has zero GHG emissions in operation. Because of this, using natural gas in favour of other fossil fuels should result in less GHG emissions, with positive implications for global climate change (Wigley, 2011). Figure 3.5, however, does not provide an illustration of the GHG impacts of the various fuels across the full life cycle; key points during shale gas exploration and production are discussed in Section 3.3.2.3, and various end-uses of shale gas in Section 3.3.2.5.
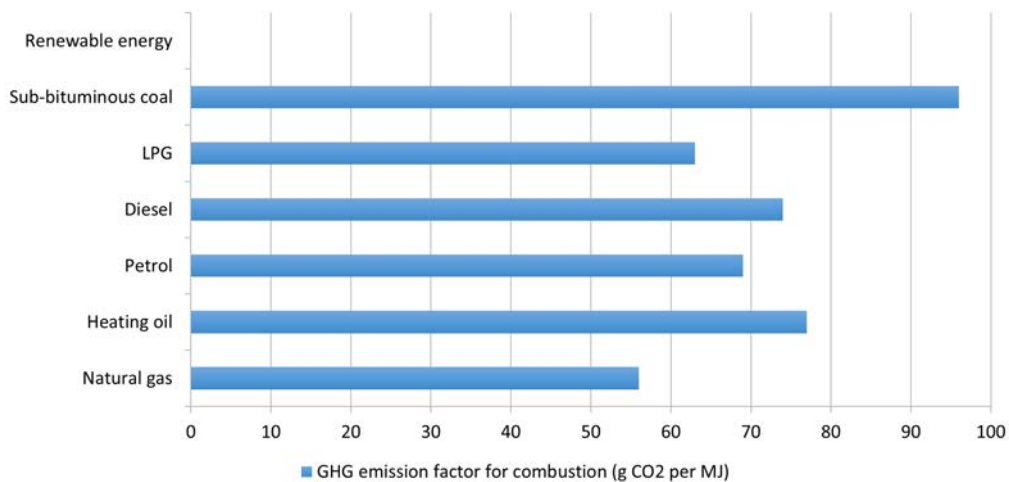

Figure 3.5:   GHG emissions factors for different types of fuels

Source: Based on data in (IPCC, 2006)

The differences in opinion are often linked to system leakage rates of methane, which has a high global warming potential, further explored in the sub measured oil and gas methane emissions - section on fugitive methane emissions of Section 3.3.2.3 below.

3.3.2.3 <u>**GHG emissions during shale gas exploration and production**</u>

The GHG emissions prior to use or conversion, primarily from fugitive methane emissions, are likely the biggest contributor to overall GHG emissions. In the absence of appropriate controls, fugitive emissions as a result of leaks, and flaring and venting during extraction, production and transportation have the potential to be high, which can increase the life cycle GHG emissions profile of shale gas (Bradbury et al., 2013; Stephenson et al., 2011). The risks of increasing, and opportunities to reduce GHG emissions are explored further in the risk assessment (see Section 3.4.2).

Detail on the typical phases of a SGD includes exploration, appraisal, development, production and decommissioning. The primary GHG emissions during these phases (i.e. all activities prior to use of the shale gas) include, but are not restricted to:

- Carbon losses and GHG emissions resulting from changes in land use type (e.g. the removal of vegetation/ carbon stocks) (Forster, Perks, & AEA, 2012).

- Combustion of fuel for transport of the fracturing materials needed, including water, chemicals and sand, to the well site (Broderick et al., 2011);

- Combustion of fuel associated with the prime mover, the power source of the shale gas extraction rig, which can be run on diesel, petrol, electricity or natural gas (Broderick et al., 2011).

- Combustion of fuel for compression and injection of the base fluid into and out of the well (Broderick et al., 2011);

- Fugitive emissions resulting from flowback. After the process of fracking, the base fluid injected at pressure into the well returns to the surface, which is known as 'flowback' (Broderick et al., 2011). Natural gas flows to the surface within the flowback at increasing concentrations over time. The gas is not immediately of adequate quantity or quality for sale and, as such, quantities of the gas are often initially vented or flared (Barcella et al., 2011). The GHG emissions associated with flowback can be high (Bradbury et al., 2013; Jiang et al., 2011), but estimates vary across studies;

- Flaring, which involves purposely burning the methane in an open flame through a flare stack, emitting CO_2 instead of CH_4 to the atmosphere (noting the GWP100 of CH_4 is 34 times that of CO_2);

- Fugitive emissions via leaks and fuel usage involved to enable the assembly of equipment during well completion, which involves bringing the gas well into production after the completion of drilling and fracking operations (Branosky et al., 2012);

- The processes associated with gas plant operations and maintenance, which involves the drainage of hydrocarbons from a gas field, are significant sources of GHG emissions (Branosky et al., 2012). These processes include both venting and flaring during workovers

(where shale plays are fractured again) and liquids unloading as well as methane leakage and routine venting from equipment (includes pumps, valves, connectors, compressors, pneumatic devices, acid gas removal units, and dehydrators);

- Off-site processing, which involves the removal of liquid hydrocarbons and impurities from the extracted gas (Branosky et al., 2012) generates fugitive emissions from the equipment components, and GHG emissions from the combustion needed to operate the processing system. Such components include pumps, valves, connectors, compressors, pneumatic devices, acid gas removal units, and dehydrators;

- Temporary storage of the gas and distribution to the compressor stations generates fugitive emissions resulting from leaks and vented GHG emissions from pipeline or compressor blow down, as well as combustion GHG emissions from engines that drive the compressors that push the gas through the system.

In relation to the emissions intensity of shale gas, the balance of evidence suggests that shale gas is less emissions-intensive than coal, though much depends on methane leakage rates (see Section 3.3.2.4 below). Even with the worst leakage rates, the 'worst shale gas' is roughly as emissions intensive as the 'best coal'. In terms of the overall effect on GHG emissions in a country, key factors include which energy sources are displaced, and how much electricity or liquid fuel is produced from each source.

3.3.2.4   Fugitive methane emissions, leakage rates and GWP values

Fugitive emissions of methane pose a key risk of increased GHG emissions with SGD and production (Howarth et al., 2011; Jiang et al., 2011; Wigley, 2011). Estimates of gas leakage rates are expressed as a percentage of total production and a range of leakage rates are found in the literature. A study based on direct measurements of fugitive emissions by Allen et al. (2013) reports the rate as lower than commonly reported (0.42% of gross shale gas production). Fugitive emissions rates of between 3.6 – 7.9% were estimated in some earlier literature (Howarth et al., 2011). Reviewing the international literature to draw lessons for South Africa, the DEA (2014b) study considered the different ranges (mainly due to different assumptions and methodologies, see Section 3.4.1) and noted that a "commonly cited rate of fugitive emissions is 2.3% of total natural gas production as reported on by the US EPA in their 2011 National Greenhouse Gas Inventory" (DEA, 2014b). This was then updated in the 2013 National Greenhouse Gas Inventory to 1.4%. Zavala-Araiza et al. (2015) showed that measured oil and gas methane emissions are 90% larger than estimates based on the US EPA's Greenhouse Gas Inventory and correspond to 1.5% of natural gas production. Brandt et al. (2014) also demonstrated that measurements at all scales show that official inventories consistently underestimate actual methane emissions.

Some of the key estimates of methane leakage rates, building on the analysis by Hope (2014), are shown in Figure 3.6.
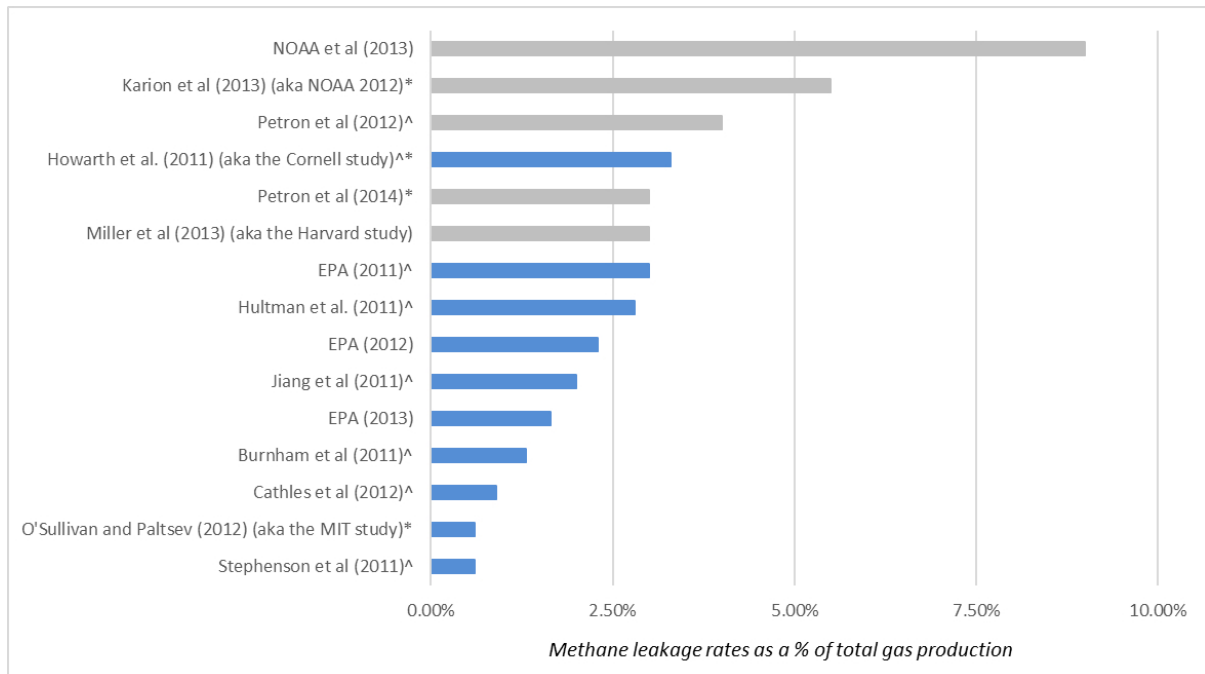
Figure 3.6:   Estimate of methane leakage rates in literature, with both bottom-up and top-down approaches.

Source: cited in figure and drawing on literature (Hope, 2014) from top-down (grey bars) and bottom-up (blue bars) approaches, as described in text.
Note: ^ means value is for unconventional - i.e. shale - gas wells only, * means the value in the graph is the mid-estimate or mean of a range where a 'best estimate' is not given.

There are a number of reasons the results have such a wide range. Perhaps the most important is how the data were collected (Hope, 2014). Broadly speaking, there are two approaches to measuring fugitive emissions: bottom up and top down. Bottom-up approaches, using on-site measurement equipment - the blue bars on the chart above, are better at measuring emissions from a particular well, but do not necessarily accurately reflect the emissions of the whole production process. Top-down approaches, using for example aeroplanes, tend to come out with higher measurements - the grey bars, as they potentially capture a wider source of emissions (e.g. methane emissions from livestock and landfills).

Recent evidence related to 'super-emitters' suggests that bottom-up approaches may under-estimate leakage rates, but that the bottom-up and top-down estimates can be reconciled when the 'super-emitters' are taken into account, and that reconciled figures still lie within the 1.4 - 2.3% of production estimates. More recent literature on super-emitters has a mode (2.2%) falling within that

range, but a long tail pushing the mean up to 4.1% (Zimmerle et al., 2015), seeking to reconcile diverging estimates (Zavala-Araiza et al., 2015). Actual leakage rates are significant to the risk (or reduced opportunity) and would warrant monitoring under SA conditions, should SGD proceed. The formal definition of super-emitters also would allow for focused management measures for these sources to be implemented (Zavala-Araiza et al., 2015).

From the assessment of the literature, it is clear that leakage rates of fugitive methane have major implications for GHG emissions. Figure 3.7 relates various leakage rates to national GHG emissions (as a share of the "peak, plateau and decline GHG emissions trajectory range" (PPD; see RSA 2011a, 2015b)), with ranges of leakage rates of fugitive methane from the earlier literature and adding the range from the super-emitter literature. Depending on the leakage rate of methane, this has the potential to reduce or even negate any climate benefit associated with replacing conventional fuels with shale gas (Alvarez et al., 2012; Bradbury et al., 2013).
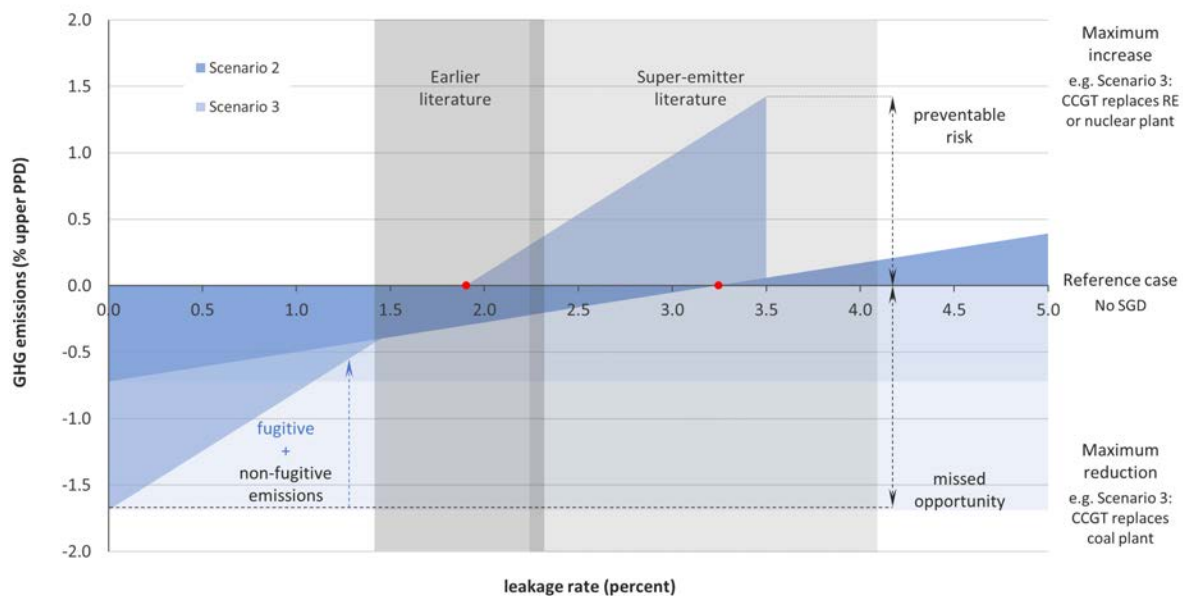
Figure 3.7: Ranges of leakage rates of fugitive methane from earlier and recent literature, for Small and Big Gas scenarios, and points where opportunity to reduce turn to risks of increased GHG emissions.

Figure 3.7 shows that the opportunity to reduce GHG emissions is reduced, as leakage rates increase. At some point, the opportunity turns into a risk of increased emissions. The cross-overs are not as precisely known as the single red dots in the figure might suggest, given uncertainties.

Leakage rates cannot be known for South Africa, until SGD takes place. For this assessment, a leakage rate of fugitive methane between 1.4 and 2.3% is assumed, noting that more recent literature

has assessed low-frequency, high-impact events with a mode in this range, but a mean shifted up to 4.1%.

Another key factor in assessing the risks of increased GHG emissions from shale gas is GWP value used. Methane is a particularly potent GHG with a greater effect than the same amount of CO_2.

Text Box B: Global warming potential - GWP

GWP is defined as the global mean radiative forcing per unit mass emitted over a particular timescale relative to the forcing from CO_2 (IPCC, 2013), or the total amount of heat absorbed by a GHG over a particular timescale compared with the amount of heat absorbed by CO_2 over the same timescale (IPCC, 2007). Essentially, GWP looks to compare the relative radiative impacts of different GHGs against that of CO_2 (Burnham et al., 2012). The GWP of a GHG depends on the timescale considered (typically 20, 100 or 500 years) because atmospheric lifespans of GHGs differ. Over a 100-year timescale, for example, methane has an estimated GWP of 34 times that of CO_2 whereas over a timescale of 20 years methane's GWP is estimated to be 86 times that of CO_2 (IPCC, 2013). Without climate-carbon feedback, the GWP_{100} of methane is equivalent to 28 tons of CO_2 (ibid, Table 8.7). A local study also suggests that a 100-year GWP is appropriate for climate change (Cohen & Winkler, 2014). GWP100 is applied in this assessment.

3.3.2.5   Various uses of shale gas and associated GHG emissions

Both conventional and unconventional gas has a number of different end uses, with different GHG intensities per unit of energy used (e.g. kg CO_2-eq per kWh or per litre of fuel used). Common uses of shale gas include electricity generation; conversion to transport fuels; direct use in industry or households (for heating and cooking), and conversion to LNG for export.

The key points at which GHGs are emitted during shale gas use are described in this section, with opportunities and risks being quantified to the extent supported by existing literature in Section 3.3.4). A summary of risks and opportunities related to GHG emissions is presented in Section 3.3.5 and the risk matrix in Table 3.9.

Electricity generation: Electricity generation using natural gas involves combustion, which is the process of igniting the natural gas to release energy in the form of heat (Branosky et al., 2012). This process has been assessed internationally the greatest amount of GHG emissions among all of the stages of the life cycle of shale gas. Indeed, Bradbury et al. (2013) estimate combustion to comprise approximately 80% of the total GHG emissions associated with SGD over a 100-year timescale when the end use is electricity; AEA (2012) estimate the share to be as high as 90%.

Coal is often compared to shale gas in GHG Life Cycle Assessment (LCA) studies because of the focus on the shift away from coal for energy generation due to its GHG emissions-intensive nature. Despite the influence of different assumptions employed regarding fugitive emissions, GWP and energy conversion efficiencies, the literature generally finds shale gas to be less GHG emissions-intensive than coal, when considering electricity generation (Broderick et al., 2011; Chang et al., 2015; Cohen & Winkler, 2014; Heath et al., 2014).

Regarding energy conversion efficiency, natural gas-fired power plants are typically more efficient than coal-fired power plants (Bradbury et al., 2013). For example, electricity generation using a boiler using shale gas resulted in 31% fewer GHG emissions than a coal-fired boiler over the 100-year timescale (Burnham et al., 2012). The reduction in GHG emissions is estimated to be as high as 52% when considering a natural gas closed cycle plant (compared to a coal boiler) (Burnham et al., 2012). The UK Department of Energy and Climate Change (UK DECC, 2013), estimates the GHG emissions of shale gas when used for electricity generation to be in the range of 117.5 – 148.6 g CO_2e per MJ[11], while the GHG emissions of coal (for electricity generation) are estimated to be between 232.5 – 313.9 g CO_2e per MJ. Considering electricity generation in South Africa, and depending on the control of fugitive emissions (and which other factors relating to coal are assumed); Cohen & Winkler (2014) found a specific emissions intensity between 0.3 tCO_2/MWh and 0.6 tCO_2/MWh, compared with about 1 tCO_2/MWh for coal-fired electricity in South Africa.

Conversion to transport fuel and chemicals using GTL processes: Substituting imported fuel produced from crude oil refineries, whether located outside of South Africa or within our borders, with fuel produced from the GTL process in South Africa with shale gas as a feedstock will likely increase GHG emissions associated with liquid fuel supply in the country. The reason is that the upstream emissions from crude oil refining of the imported fuel are not accounted for as they occur outside of South Africa's boundaries. GTL is approximately 50% less emissions-intensive than CTL processes. This is assessed further in Table 3.7 below.

A straight comparison of GTL versus an oil refinery, ignoring the geographical location of where the emissions take place, presents conflicting results; likely a result of the different assumptions employed in the different studies. Edwards et al. (2011) for example, concludes that the life cycle GHG emissions of GTL-produced diesel marginally exceed those related to conventional diesel production, when considering the gas source as a field site close to the plant (note; a conventional gas source). On the other hand, Forman et al. (2011) found that the life cycle GHG emissions associated

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[11] Original in g CO_2-eq per kWh.

with GTL-derived diesel (using conventional natural gas) were lower than those associated with the production of oil-refinery diesel.

Liquefaction to LNG: LNG is natural gas that has been converted to liquid form for ease of storage or transport. Natural gas is typically converted to LNG in order to transport the gas long distances, e.g. for export purposes. At the receiving end, LNG has to be re-gasified for use. LNG is distinct from GTL process, which produces diesoline or naphtha. The use of shale gas for the production of LNG may increase South Africa's GHG emissions assuming that all of the LNG is exported out of the country and is not used to substitute other fossil fuels that would have been combusted in South Africa.

Direct use in the residential, commercial and industrial sectors: The use of shale gas as a direct source of energy for heating and cooking may have GHG mitigation benefits if it is substituting coal based electricity. However, if shale gas were to displace electricity from low-GHG-emitting sources (e.g. renewable energy or nuclear power), then it would add to GHG emissions. In industry, shale gas could support fuel switching, for example from coal- to gas-fired boilers. This would assume sufficient gas (so more likely in the Big Gas scenario) and pipeline infrastructure being installed.

3.3.3   *Metrics to compare GHG emissions and limits of acceptable change*

In 2015, all countries signed an agreement under the United Nations Framework Convention on Climate Change (UNFCCC, 1992), for the first time committing each one to reduce their GHG emissions[12]. The aggregate of countries' INDCs falls short of the emission reductions required to keep temperature below 2°C (UNEP, 2015), and the total effect of all INDCs is likely to exceed the small remaining global carbon budget (Rogelj et al., 2016).

In absolute volumes of GHG, South Africa is a relatively small emitter albeit among the top 20 in the world (World Resources Institute (WRI), 2015). South Africa's contribution to the collective climate challenge is framed by our National Development Plan (National Planning Commission (NPC), 2012) and the National Climate Change Response White Paper (RSA, 2011a). Based on the PPD emissions trajectory range in the White Paper, South Africa's INDC (RSA, 2015b) states that the country's emissions as of 2025 and 2030 will fall between 398 and 614 Mt CO_2–eq.

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[12] Reducing GHG emissions is known as 'mitigation' in the climate change literature. However, in this scientific assessment, mitigation means reducing impacts, as in the environmental management literature. The phrase "climate change mitigation" is used in this Chapter, where it is necessary to refer to the sense of reducing GHGs. The impacts of climate change are not in the scope of this Chapter; addressing the adverse impacts in the climate change literature is known as 'adaptation'.

Economic and regulatory instruments, and sectoral plans, are being developed to remain within the PPD emission trajectory range. Six GHG are being declared 'priority pollutants' under the NEMAQA; companies which directly emit over 100 000 tonnes of GHG (expressed as a CO_2 equivalent) annually must produce a regular 'pollution prevention plan' (DEA, 2016a); the DEA will allocate company-level 'carbon budgets'; and Treasury plans a carbon tax (RSA, 2015a). The Industrial Policy Action Plans (IPAP) (Department of Trade and Industry (DTI), 2015) and the New Growth Path (NGP) (RSA, 2011b) consider GHG reductions.

The GHG emissions associated with a particular set of activities can be expressed as an absolute volume of emissions per year, or as an emissions intensity, that is GHG emissions per unit of output. The latter appears frequently in the literature.

National climate policy envisages reporting of GHG emissions that is "mandatory for entities (companies and installations) that emit more than 0.1 Mt of GHGs annually" (RSA, 2011a). DEA has published for comment draft regulations declaring GHGs as priority air pollutants (DEA, 2016a), regulations requiring the submission of Pollution Prevention Plans (DEA, 2016b) and GHG reporting guidelines (DEA, 2015, 2016b). With SGD likely to exceed 0.1 Mt CO_2-eq per year, it is expected that developers will be subject to these and any further regulations, including possible company-level carbon budgets. Such reporting will contribute to South Africa's reporting on the implementation and achievements of its NDC (RSA, 2015b), as required under the Paris Agreement (UNFCCC, 2015).

3.3.4 *Quantifying risks and opportunities in relation to GHG emissions*

SGD presents both a risk of increased GHG emissions, and opportunities to reduce GHG emissions. The opportunity of emission reductions depends crucially on whether gas displaces coal (the main fuel in South Africa), gas displaces even lower-emission alternatives (such as renewable energy, nuclear, imported or domestically refined fuel), or gas is the fuel and technology chosen to meet increasing energy demand. Wright et al. (2016) assesses projections of growing energy demand, and the fuels and technology mix for energy supply. The use of shale gas leads to an increase in emissions measured in *absolute* units (e.g. Mt CO_2-eq), when gas adds to existing capacity to meet increasing demand, but that same case may reduce GHG emissions relative to a Reference Case. Both risks and opportunities are part of balanced approach to risk management. The following text includes quantification of opportunities, with the risks of increases in GHG emissions summarised in Table 3.9.

3.3.4.1 Risk of fugitive methane emissions

Studies indicate conflicting results regarding the percentage of fugitive methane emissions (leakage) and the value applied for global warming potential. Depending on the leakage rate of methane, this has the potential to reduce or even negate any climate benefit associated with replacing conventional fuels with shale gas (Alvarez et al., 2012; Bradbury et al., 2013). Leakage rates cannot be known for South Africa, until SGD takes place. For this assessment, a leakage rate of fugitive methane between 1.4 and 2.3% is assumed, noting that more recent literature has assessed low-frequency, high-impact events with a mode in this range, but a mean shifted up to 4.1%. Applying the 1.4%-2.3% range to the Small and Big Gas scenarios over a period of 24 years (middle of the 13-35-year range, see Burns et al., 2016) of production and development, as well as a GWP_{100} of 34, then the Exploration Only scenario might increase GHG emissions by 46 -75 Mt CO_2-eq over the 24-year period, or 1.9 - 3.1 Mt CO_2-eq per year (lower and higher leakage rate respectively[13]), which are considered 'moderate' consequences. The Big Gas scenario has a 'substantial' to 'severe' consequence of 8 – 13 Mt CO_2-eq each year, with and without mitigation, or 184 – 302 Mt CO_2-eq over the quarter-century. The occurrence of fugitive emissions is very likely, though consequences can be reduced from severe to substantial with mitigation, i.e. better control technologies to reduce leakage rates. **For the Big Gas scenario, the risk of fugitive methane emissions is assessed as high without mitigation, which might be reduced to moderate with mitigation and use of good practice in control technologies** (see Section 3.4). The assessment is based on the Big Gas scenario being limited to 20 tcf and implicitly assuming that relatively few operators introduce rigs in a well-planned fashion. Should the economic potential be a larger share of the technical potential than identified in Burns et al. (2016), the consequences would be more severe. For SGD beyond 20 tcf, the risks might be very high in the no-mitigation scenario. However, this chapter assesses the common scenarios as identified in Burns et al. (2016). For the Small Gas scenario, the risk is of increased GHG emissions is assessed as low. For exploration, the risks are very low, given only slight but noticeable consequences.

3.3.4.2 Other GHG emissions prior to transmission

In addition to fugitive methane emissions as discussed above, there are exploration and production activities that also lead to upstream GHG emissions prior to shale gas transmission and use, denoted as "other GHG emissions prior to transmission." These exploration and production processes involve both fugitive and deliberate industrial methane emissions and it is important that fugitive components are not counted twice. There is, however, considerable uncertainty surrounding the scale and likelihood of other upstream GHG emissions from SGD. In their assessment of the literature on the

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[13] If the actual leakage rate for fugitive methane emissions turned out to be 4.1% (median for the super-emitter literature), then the emissions would 5.6 and 22.4 Mt CO_2-eq for the Small and Big Gas scenarios, respectively.

life cycle carbon footprint of shale gas, Weber & Clavin (2012) indicate that reworking might occur once in 10 years; perhaps not at all. Similarly, the US EPA reports CH_4 emissions from liquids loading of 3 and 96 Mt per year for sites comprising 1,379 and 1,784 wells respectively (US EPA, 2014), though Weber & Clavin (2012) (also see the supplementary information to their article) indicate that these are intermittent fugitive emissions associated with conventional gas wells only.

3.3.4.3   GHG from electricity generation – shale gas compared to alternatives

Shale gas used for electricity would displace other fuels used for electricity generation. CCGT could displace either existing plants (below the line 'existing capacity' in Figure 3.8); or add to existing capacity to meet growing demand in a Reference Case (see Wright et al., 2016). So what might be displaced can be divided into cases:

1. Coal for electricity generation, compared to shale gas ('gas displaces coal'), replacing either existing or new coal plants, both with a higher emissions intensity; or
2. Two options with lower emissions intensity than CCGT using shale gas, that is
   a. renewable energy (RE) technologies (wind, solar, others; 'gas displaces RE'); or
   b. nuclear power ('gas displaces nuclear').

Figure 3.8 illustrates how CCGT might replace other electricity generation technologies, and their difference in terms of GHG emissions-intensity. CCGT either displaces existing plant (mostly coal) below the line indicating existing capacity (the 'gas displaces coal' case). The area between the two arrowed lines assumes new capacity is built, and either displaces new coal plant with a higher emissions intensity; or options with lower emissions intensity – 'gas displaces RE' or 'gas displaces nuclear'.
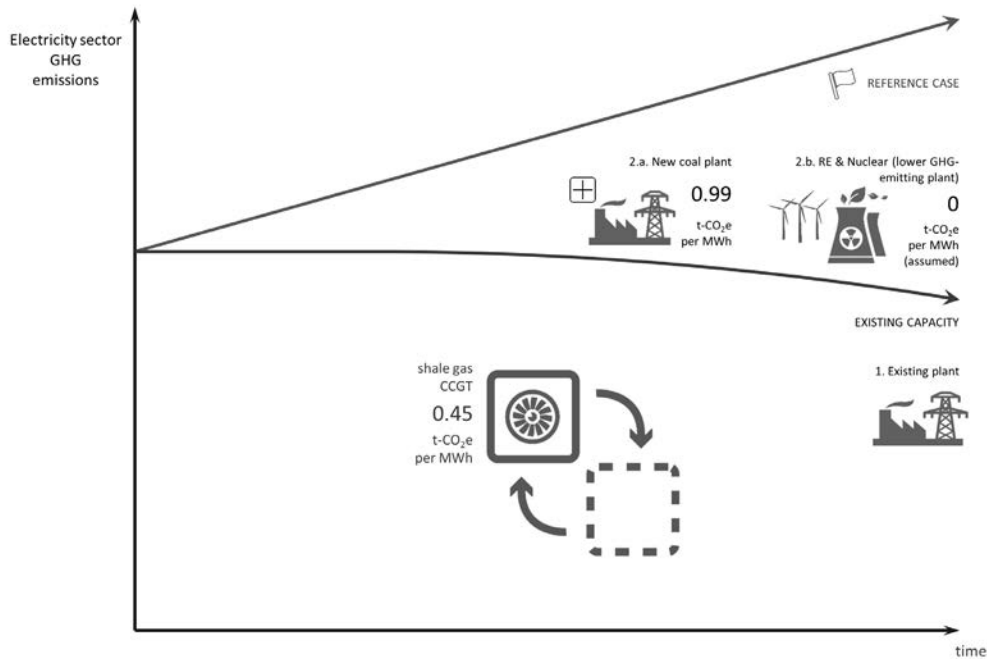
Figure 3.8:   GHG implications of shale gas used in CCGT displacing other fuels for electricity generation[14].

With regards to shale gas for electricity generation, an average emissions intensity of 0.45 t CO_2-eq per MWh is used, noting the ranges reported between a maximum of 0.31 and 0.59 t CO_2-eq per MWh (Cohen & Winkler, 2014) depend significantly on fugitive methane emissions, the risk of which is separately assessed here. Coal-fired electricity in South Africa is assumed to be 0.99 t CO_2-eq per MWh as reported in Eskom annual reports; earlier studies had a slightly lower factor, 0.957 t CO_2-eq per MWh (Spalding-Fecher, 2011), but with recent challenges in the electricity system, a figure close to 1 seems appropriate. A difference of 0.54 t CO_2-eq per MWh is multiplied by assumed production for the Small and Big Gas scenarios. Nuclear power and renewable energy are assumed to have no GHG emissions during operation; there is literature on non-zero life cycle GHG emissions (GEA, 2012), but the other technologies do not factor in up- and down-stream emissions either. An increase of 0.45 t CO_2-eq per MWh for shale gas compared to nuclear and renewable energy is assumed.

Conversely, if shale gas were used to add power plants to the existing fleet, and provide additional total electricity consumed and produced – for whatever reason, then the same 0.45 t CO_2-eq per MWh would be added. **In terms of emissions intensity, shale gas would reduce GHG emissions compared to coal by 0.54 t CO_2-eq per MWh, whereas if shale gas were added to the grid or replaced electricity from nuclear or renewable energy sources, this would increase emissions**

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[14] "Flag" icon by Alexander Smith, "add" icon by Designify.me, "Power Plant" icon by Dimitry Sunseifer, "wind turbines" icon by Tina Rataj-Berard, "nuclear power" icon by Siwat Vatatiyaporn, "replace" icon by Didzis Gruznovs, "jet engine" icon by Arthur Shlain from thenounproject.com

intensity by +0.45 t CO_2-eq per MWh (see Figure 3.8); note the numbers are similar but the one is a negative (reduction) the other a positive (increase). No mitigation is assessed for renewable energy or nuclear power, considered zero GHG emissions in operation for this assessment; mitigation of coal emissions is considered.

Note that Figure 3.8 shows GHG intensities (in CO_2-eq per kWh). The absolute emissions reductions or increases would depend on the amount of electricity generated from each source, and analysis of energy system modelling is beyond the scope of this Chapter (see Wright et al., 2016). It might be that electricity from shale gas was additional to existing generation. In the 'additional gas power' case, taking the 1000 and 4000 MW of CCGT (Burns et al., 2016), respectively, and further assuming a typical load factor of 55% (run as mid-merit plant) electricity generated would be 4818 GWh per year in the Small Gas scenario and 19,272 GWh per year in the Big Gas scenario[15].

In the 'gas displaces coal' case, diversifying the energy mix has long been a goal of SA's energy policy (DME, 1998), new capacity is needed with an ageing fleet of power plants and gas is potentially more available – both as LNG and shale gas. Using the same assumptions about OCGT in the Small and Big Gas scenarios, and multiplying by the difference in GHG emission intensity, there would be a reduction in emissions (shale gas relative to coal) of 2.6 Mt CO_2-eq per year for Small Gas and 10.4 Mt CO_2-eq per year for Big Gas, a slight but noticeable reduction. To put this in some context, these reductions are expressed as shares of national emissions limits under upper limit of 'peak, plateau and decline' (upper PPD), as in national policy and communicated in the INDC: so reductions in the Small Gas scenario are 0.4% of upper PPD and 1.7% in the Big Gas scenario, for both 2025 and 2030. **Shale gas for electricity provides a likely opportunity to reduce GHG emissions when displacing coal, but the scale of reductions is slight in relation to the national emissions trajectory.** Further research would be helpful to put GHG emission reductions from shale gas in the context of overall mitigation potential (as distinct from GHG emissions).

The 'gas displaces nuclear' and 'gas displaces RE' cases have very similar consequence in terms of increases of GHG emissions; they are therefore discussed together. Using shale gas for electricity generation, rather than renewable energy sources or nuclear power, is very likely to increase GHG emissions. For the Small Gas scenario, this might add 2.2 Mt CO_2-eq per year, and 8.7 Mt CO_2-eq per year for the Big Gas scenario; considered 'moderate' to 'substantial' consequences. It is very likely that the substantial consequence would occur, so that in the Big Gas scenario the risk is assessed as moderate. Emissions of 8.7 Mt CO_2-eq in the Big Gas scenario are equivalent to 1.4% of the national

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[15] See calculations, the supplementary material in Excel file, worksheet 'Scale of GHG' in Digital Addenda.

emission limits represented by upper PPD, and 2.2% of the lower PPD limit. **If shale gas displaces electricity from nuclear or renewable energy, it will very likely increase GHG emissions, assessed as 'moderate' risk with Big Gas or 'low' in the Small Gas scenario.**

Mitigation is considered only for coal-fired electricity, in that a control technology of carbon capture and storage (CCS) may be applied. Adding CCS could reduce emissions (to say 0.22 t CO_2-eq per MWh (IPCC, 2014a)), but the technology is less likely to be implemented at the scale required and in time-frames considered here, than coal without CCS. A demonstration plant of CCS technology might only be available in South Africa in 2025. Emission would likely increase by 1.1 and 4.4 Mt CO_2-eq per year for the Small and Big Gas scenarios respectively, which are 'slight but noticeable' and 'moderate' consequences. **If shale gas displaces electricity from coal with CCS, it will likely increase GHG emissions, 'very low' to 'low' risk for Small and Big Gas scenarios.**

3.3.4.4 GHG from liquid fuels

Shale gas may be used in GTL plants under the Big Gas scenario (see Burns et al., 2016). Shale gas for GTL would displace other liquid fuel supply. As for electricity, this might be either existing plants; or new supply to meet rising liquid fuel demand (see Wright et al., 2016). Three options are considered in the risk assessment, illustrated in Figure 3.9 below:

1. The fuel and associated emissions from the GTL process substitute an equivalent amount of fuel produced from the CTL process ('GTL displaces CTL').
2. The fuel and associated emissions from the GTL process substitute an equivalent amount of fuel produced from importing crude oil and refining it locally ('GTL displaces refinery').
3. Imported petroleum products, in which case the associated emission are outside of South Africa's borders and in that sense considered zero ('GTL displaces imported fuel').

Figure 3.9 shows the different options, with GTL displacing one of the above options. As for electricity, the area between the two arrowed lines represents additions to existing capacity (but within a Reference Case, see Wright et al. (2016)), which is below the line.
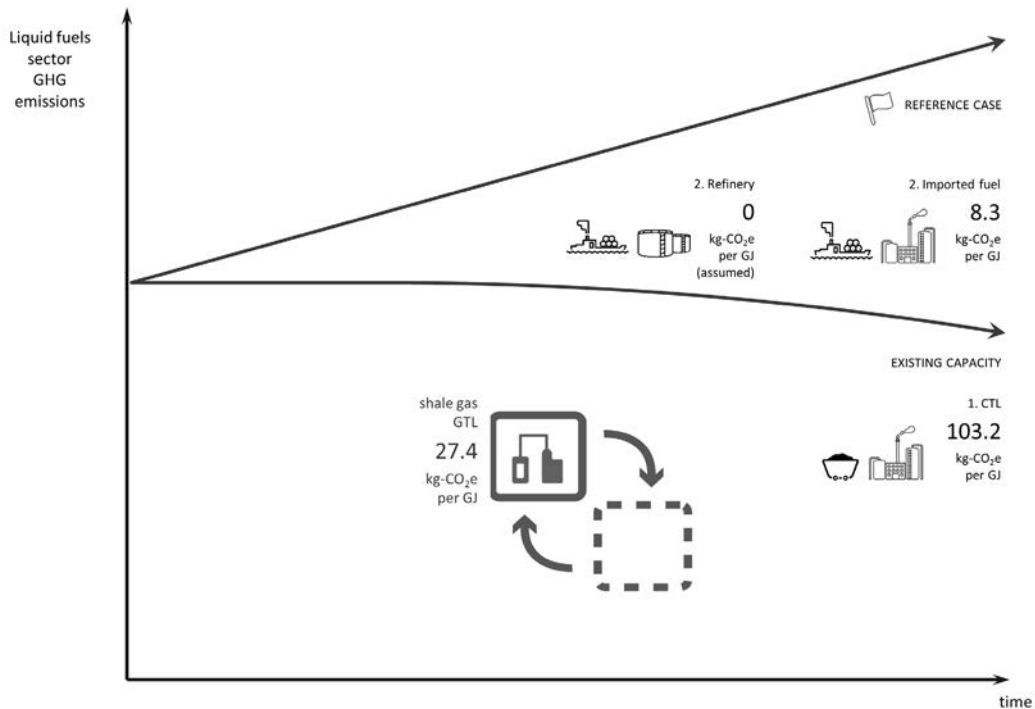
Figure 3.9   GHG implications of shale gas used for GTL displacing other liquid fuel supply[16].

In the case of 'GTL displaces CTL' is the main situation in replacing existing capacity, with an opportunity for lower GHG emissions intensity. The two new options are not quite the same intensity, with imported fuels being zero (in South Africa) compared to some GHG intensity in the 'GTL replaces refinery' case – but both are lower in emissions-intensity than GTL. New CTL is not an option assessed as there are no plans for such facilities.

In the case of 'GTL replaces CTL', all of the petrol and diesel products produced locally from CTL are replaced by locally produced syn-fuels manufactured through the GTL process using local shale gas as the feedstock. The GTL and CTL processes have different product slates, whose combustion downstream would have different GHG implications. There is insufficient literature including life cycle analyses to assess the downstream risks. The difference in emissions intensities at plant level is derived as reported in Table 3.7.

Table 3.7:   Emission intensities for shale gas for GTL, CTL and oil refinery.

Emissions intensity	kg CO2e/GJ	Difference vs. shale gas
Shale gas for GTL	27.4	
Coal to liquids	103.2	-76
Oil domestically refined, imported oil	12.0	+15

Sources: Authors' calculations, drawing on (Argonne National Laboratory, 2016; Karras, 2011; National Energy Technology Laboratory et al., 2013)[17]

Given the 600 MMscf per day GTL plant envisaged in the Big Gas scenario, this would produce about 127 TJ of liquid fuel per year, with annual emissions of 13.1 Mt CO_2-eq. **In the 'GTL replaces CTL' case, emissions are reduced by 9.6 Mt CO_2-eq per year, which is a very significant opportunity**[18].

The 'GTL replaces refinery' case would increase GHG emissions by 2.4 Mt CO_2-eq per year; a 'moderate' consequence. The increases and decreases are likely, with the uncertainty lying mainly in emissions factors – with CTL not being used outside South Africa, and GTL investments occurring in few other countries. The consequences, making simplifying assumptions, may be in the range between 0.4% and 0.6% of national emissions limits under PPD for 2025 and 2030, as in national policy and communication in the INDC.

Literature on refineries in the US indicates about 100 lb of CO2 emitted per barrel of crude, though there is a range depending on technologies (Karras, 2011). Applying conversion factors (density, heat content), and assuming a range of technologies, an emissions intensity of 0.0083 t CO_2-eq GJ is derived; which is lower than the emissions intensity for GTL from shale gas (0.0274 t CO_2-eq GJ); these values are used for an assessment in the South African context (see digital addenda for calculations). **There is a low risk of increased GHG emissions with GTL displacing a refinery in a Big Gas scenario.**

The reason is that the upstream emissions from crude oil refining of the imported diesel and petrol are not accounted for as they occur outside of South Africa's boundaries. The upstream emissions from SGD and processing in the GTL process are accounted for and thus there would be additional emissions.

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[17] CTL is used commercially by SASOL, but no emissions intensities are published. This assessment has drawn on the GREET model – from a US national lab - in the absence of published data on CTL in South Africa (Argonne National Laboratory, 2016).

[18] The term 'very significant' is not precisely defined, but is used here as a 9.6 Mt CO_2-eq increase in emissions which would have been called 'severe' consequence.

Shale gas can be used for the production of liquid fuels such as diesel, petrol etc. in a GTL process. This fuel can also be imported, in the 'GTL displaces imported fuel' case. Applying the consumption of 600 MMscf (Burns et al., 2016) per day in a GTL facility over a period of 24 years (13-35-year range) of production and development, then the Big Gas scenario is likely to increase GHG emissions with a 'moderate' consequence of between 2.8 Mt CO_2-eq (with mitigation) and 4.2 Mt CO_2-eq (without mitigation) per year. Here, mitigation refers to technologies and measures that can be used to prevent increased GHG emissions along the South African GTL supply chain, including the transport and distribution of gas. These may include technologies such as CO2/steam reforming or CCS during production, as well as proactive equipment maintenance and close monitoring of fugitive emissions during transport, transmission and distribution of the gas and end-products (see Figure 3.11). **The risk of increased GHG emissions from shale gas if GTL displaces imported fuel is low, with and without mitigation.** To get a sense of scale and consequence, over the 24-year period, increased emissions would add up to between 67 with mitigation and 100 Mt CO_2-eq without mitigation. Another reference is that annual emissions increases in the Big Gas scenario range from 0.5% of PPD (with mitigation, as share of upper PPD emissions, 614 Mt CO_2-eq per year) to 0.7% (without mitigation). This only applies to the Big Gas scenario as there is insufficient gas to run a GTL facility in the other scenarios and thus the risks for other scenarios are not assessed.

3.3.4.5   GHG from LNG Export

This case is a stand-alone case and differs from the other cases in that it does not require comparison. Any GHG emissions from the production of LNG would be additional to South Africa's current GHG footprint. Since LNG is exported from the country the GHG emissions associated with its combustion occur elsewhere and are not included in national GHG inventories. All the gas extracted from the Karoo is converted to LNG for export over a 24-year period. One terminal will be developed in the country to process the gas. Assuming all of the shale gas that would have been consumed in the GTL and power plants (780 MMscf per year) in the Big Gas scenario will be processed and exported as LNG. The LNG will not be combusted in South Africa and hence there are no combustion related emissions. However, the emissions produced are all additional to what is already being produced locally. The probability of an increase is thus 'very likely'. The increase in emissions, making simplifying assumptions, might be 3.2 to 4.9 Mt CO_2-eq per year, with and without mitigation – that is 'moderate' consequences, or 'substantial' ones without mitigation. The risk of increased GHG emissions can be mitigated by monitoring and controlling venting, flaring, and fugitive emissions, both during normal operation, i.e. from liquefaction to eventual regasification and transport, and during malfunctions. **The overall risk of shale gas for exported LNG is assessed as moderate for the Big Gas scenario – without any mitigation. Provided mitigation is implemented, this can reduce the risks to low for a Big Gas scenario.**

3.3.5   Overview of risks of GHG emissions

Based on the assessment for shale gas compared to various alternative uses, replacement of existing or new technologies using other fuels, and risks of fugitive emissions, a risk assessment matrix for GHG emissions is presented in Table 3.9. Note that the text above presents both opportunities (positive impacts, in this case, reductions of GHG emissions) and risks of increased GHG emissions; whereas Table 3.9 only presents the risks, consistent with general guidance for all Chapters of the risk assessment. This should not be understood to mean that there are no opportunities to reduce GHG emissions through use of shale gas. Shale gas presents both a risk of increased GHG emissions, and opportunities to reduce GHG emissions. The opportunity of emission reductions depends crucially on gas displacing coal (the main fuel in South Africa). This applies to gas rather than coal used for producing liquid fuel and electricity, which is a significant opportunity for GHG emission reduction.

The likelihood of various risks was determined by expert judgement; that is the author team's rating having assessed the relevant literature. A scale of consequences that emerged, with 'break points' established between different consequence levels with increases of GHG emissions in Mt CO_2-eq per year, is shown in Table 3.8. The table also shows the percentage of upper PPD emissions trajectory, i.e. as a share of 614 Mt CO_2-eq in 2025 to 2030 (see Section 3.3.3).

Table 3.8:   Scale of consequences for GHG emissions

	Mt CO_2-eq per year	**% of upper PPD**
Slight but noticeable	0.0 - 1.1	0.0 - 0.2
Moderate	1.2 - 4.5	0.2 - 0.7
Substantial	4.6 - 8.7	0.7 - 1.4
Severe	8.8 <	1.4 <
Extreme	-	-

Given that GHG emissions are well mixed in the atmosphere in short timeframes, the location of sources is not material; the matrix therefore does not refer to area. Risks with mitigation are assessed for some but not all options, depending on control technologies available (see Section 3.4). Note that 'shale gas displaces coal' is presented only 'with specified mitigation', i.e. with CCS, as coal without CCS is an opportunity to reduce GHG emissions, and opportunities are not included in a risk matrix.

Table 3.9:   Risk assessment matrix for GHG emissions

Impact	Scenario	Without mitigation			With specified mitigation		
		Consequence	Likelihood	Risk	Consequence	Likelihood	Risk
Fugitive emissions							
	Exploration Only	Slight but noticeable	Very likely	Very low	Slight but noticeable	Very likely	Very low
	Small Gas	Moderate	Very likely	Low	Moderate	Very likely	Low
	Big Gas	Severe	Very likely	High	Substantial	Very likely	Moderate
Use of shale gas for electricity generation, additional to existing or compared to alternative end use							
'Gas displaces RE': Electricity generation using shale gas in CCGT, displaces renewable energy	Small Gas	Moderate	Very likely	Low			
	Big Gas	Substantial	Very likely	Moderate			
'Gas displaces nuclear': Electricity generation using shale gas in CCGT, displaces nuclear power	Small Gas	Moderate	Very likely	Low			
	Big Gas	Substantial	Very likely	Moderate			
Gas displaces coal with CCS': Electricity generation using shale gas in CCGT, displaces electricity generation at coal-fired power stations with CCS	Small Gas				Slight but noticeable	Likely	Very low
	Big Gas				Moderate	Likely	Low
Use of shale gas for liquid fuel, additional or compared to alternative end use							
'GTL displaces imported fuel': Fuel from shale gas for GTL displaces imported fuel	Big Gas	Moderate	Likely	Low	Moderate	Likely	Low
'GTL displaces refinery': Fuel from shale gas using GTL displaces liquid fuels from oil imports refined in SA	Big Gas	Moderate	Likely	Low			
Export shale gas in form of LNG							
'Gas for LNG export' Shale gas liquefied to LNG and exported	Big Gas	Substantial	Very likely	Moderate	Moderate	Very likely\	Low

A high risk of increased GHG emissions is assessed for the risk of fugitive methane emissions associated with large SGD (Big Gas scenario). This can be reduced to moderate with mitigation. Good governance, ensuring that good practice and effective control technologies are implemented is therefore important, as the decreased risk due to mitigation assumes good governance.

Replacing fuel produced from importing crude oil and refining it locally with GTL from shale gas has a moderate risk of increases, given that is assessed as likely with substantial consequences. The consequence for imported fuel is moderate (4.2 Mt CO_2-eq per year) which is still the case with mitigation but at lower scale (2.8 Mt CO_2-eq per year); which comes close to the consequence for 'GTL displaces refinery' (2.4 Mt; see Digital Addenda for calculations). The relative emissions factors need further study.

The scale of these consequences is put into context of other cases, with indicative consequences shown in Figure 3.10. The figure shows opportunities to reduce GHG emissions as bars below the line, and risks of increases as bars above the line. The consequences were based on simple calculations drawing information from the literature and should not be taken as precise, even though the units are Mt CO_2-eq per year.
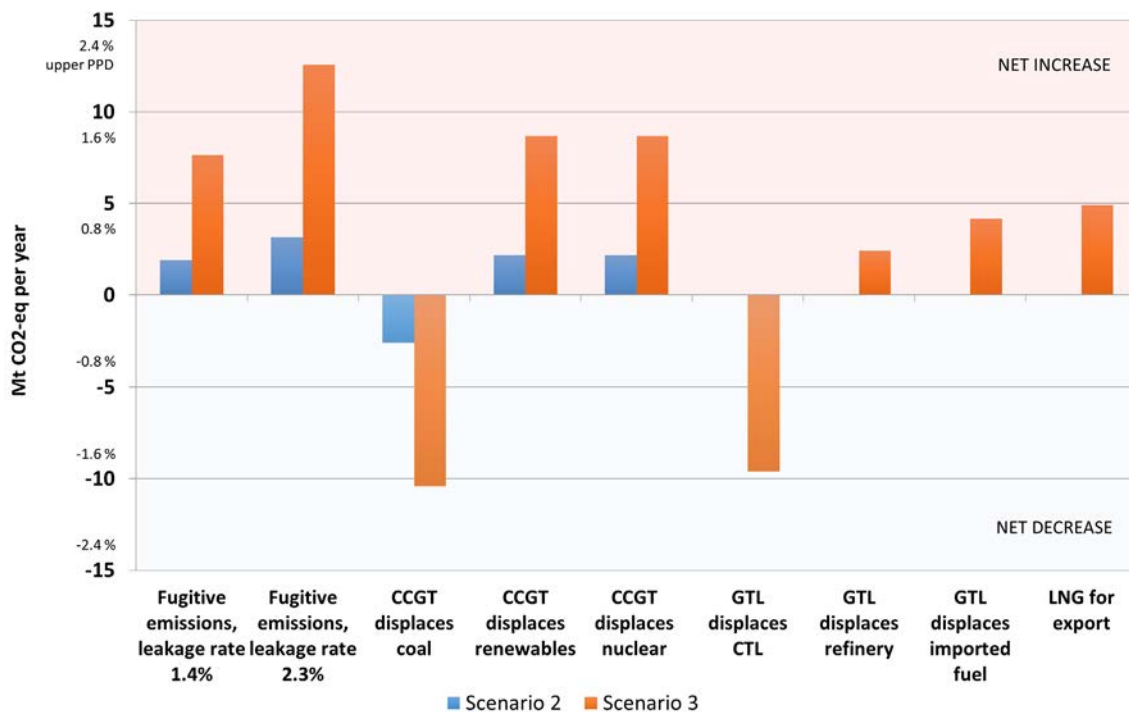

Figure 3.10:   Indicative consequences of increases in GHG emission reductions and opportunities for reductions, in Mt CO_2-eq per year, as calculated for this assessment.

Considering the emissions intensity of shale gas used for electricity generation, the cases illustrated in Figure 3.8 focus on CCGT displacing coal-fired power plants (an opportunity to reduce) or even lower GHG-emitting technologies (renewable energy and nuclear power). In terms of emissions intensity, shale gas would reduce GHG emissions compared to coal by a similar amount (-0.54 t CO_2-eq per MWh) to the increase in GHG emissions (+0.45 t CO_2-eq per MWh) if shale gas were added to the grid or replaced electricity from nuclear or renewable energy sources. The likely opportunity to reduce GHG emissions is slight for a Small Gas scenario, and moderate for large SGD (Big Gas scenario), in relation to the national emissions trajectory. Shale gas displacing electricity from nuclear or renewable energy risks increasing GHG emissions, though at a scale assessed as 'slight but noticeable' to 'moderate' consequence. The changes are very likely, given well-understood emission factors, and risk of increases are low to very low.

The risk of shale gas for exported LNG is assessed as low for the Big Gas scenario – without any mitigation, very low with control technologies and effective governance.

The main risk for increased GHG emissions that is shown in Table 3.9 is from fugitive methane emissions, which is sensitive to leakage rates (see Figure 3.7).

3.4 Good practice guidelines

There are a number of approaches to minimise the impacts of the shale gas life cycle on air quality and to reduce GHG emissions. These include control technologies and engineering actions or alterations of equipment, as well as a strong emphasis on good governance, transparency and strong regulatory and enforcement frameworks. Monitoring is crucial and baselines need to be established before shale gas exploration takes place.

3.4.1 Control technologies

Control technologies to minimise air pollutant emissions are focused on vehicles, drilling rig engines, pump engines and compressors. Having a high level of fuel-efficiency standards is also a means to limit emissions (IEA, 2012). As outlined in Section 3.2.4.3, technologies such as ignition timing retard and selective catalytic reduction can limit NO_x emissions, while diesel particulate filters can limit PM emissions, and diesel oxidation catalysts can limit VOC emissions (Roy et al., 2014). Once the shale gas is produced from a well, compressed natural gas engines could be utilised in place of diesel engines, greatly reducing emissions (Burns et al., 2016). Occupational exposure to air pollutants can be greatly mitigated with best available mitigation technologies based on the EPA Oil

and Gas rules, Tier four emissions standards, and silica mitigation measures (Digital Addendum 3b). It is proposed that these be used to determine environmental impacts of this activity in the absence of local rules.

Mitigation technologies can reduce local community exposure to air pollutants. According to the scenarios described in Burns et al. (2016), flaring will be used to minimize VOC emissions from the well completion process; however, green completions are the recommended standard for emissions reductions as this also minimises GHGs (Field et al., 2014). Emissions modelling from the Marcellus shale play in the USA demonstrated that NO_x emissions could be reduced by 85% if the control methods discussed above were used for all equipment, while VOC emissions could be reduced by 88% (Roy et al., 2014). Assuming control measures are implemented for NO_x and VOCs, the risk of emissions in Table 3.3 can be significantly reduced.

Mitigation efforts on SGD would not directly decrease the risks of increased ozone and PM concentrations. However, the decreased emissions of NO_x and VOCs through mitigation efforts would lead to decreases in ozone and PM concentrations, and thus a risk reduced indirectly.

In relation to GHG emissions, control technologies will be key to limit the venting of methane to the atmosphere, realising opportunities of shale gas to reduce GHG emissions, and limiting the risk of any increases. Figure 3.11 highlights specific mitigation technologies and systems identified in a South African study. The risk of fugitive methane emissions, without any mitigation or control technologies, appears very likely.

Figure 3.10/...

Life cycle stage		Emission sources	Source significance	Mitigation technologies
Stage I	Exploration	Transport Fuel combustion Fugitive emissions	Low 330 to 390 t CO_2e per well	
	Site preparation	Transport Fuel combustion Land use change		
	Vertical & horizontal drilling	Fuel combustion	High 49 to 1100 t CO_2e per well (drilling) & 3443 to 27 247 t CO_2e per well (flowback)	• Green completion • Reduce flaring & venting • Leak detection & repair • Monitoring & measuring of fugitive emissions
	Hydraulic fracturing	Fuel combustion Fugitive emissions Transport Flowback treatment		
	Well completion	Fuel combustion Fugitive emissions	Insignificant	
Stage II	Well production	Fugitive emissions (venting/ flaring)	High	• Desiccant dehydrators • Glycol dehydrator emissions controls • Low/ no bleed pneumatic controllers • Pipeline maintenance & repair • Plunger lift systems • Improved reciprocating compressor maintenance
	On- & off-site processing	Fugitive emissions Fuel combustions	High	
Stage III	Transmission	Fugitive emissions Venting Fuel combustions	Medium	• Dry seal systems • Improved reciprocating compressor maintenance • Leak detection & repair • Monitoring & measuring of fugitive emissions
	Storage	Fugitive emissions Fuel combustion		
	Distribution	Fugitive emissions Fuel combustion		

Figure 3.11:   Mitigation measures for different stages of shale gas development.

Source: Figure 2.6 in DEA (2014a)

With control technologies it is suggested that up to 88% of upstream fugitive emissions (prior to combustion of the gas) can be captured by implementing mitigation efforts (Harvey et al., 2012). The literature also advises requiring best emission controls and rigorous testing for leaks (Field et al., 2014). Control technologies include improving the existing field equipment to reduce leaks; using additional technology designed to capture emissions; and minimising and monitoring fugitive emissions.

The consequences of exposure to air pollutants can be significantly mitigated in occupation, local, and regional exposure by technological interventions and best practice. An exception is occupational exposure to diesel exhaust, which are difficult to mitigate. The assumptions regarding the efficacy of mitigation depend on the adoption of strong regulatory frameworks with appropriate monitoring and enforcement. This leads to an additional risk not evaluated here, which is the risk that capable

regulatory institutions and systems will not be put in place or will not be managed successfully. Indeed, the large number of sources and large spatial scale of the shale gas industry in the US has rendered effective monitoring and enforcement very challenging.

An impact specific to South African SGD is the fugitive dust related to vehicle movements on unpaved roads, which may be exacerbated by the remote locations and the requirement for transporting large quantities of water. This will require careful planning of routes and, once planned, traffic densities or traffic frequency thresholds, and then the mitigation of this source by chemical stabilisation or paving of roads. Such measures would assist in mitigation regional community exposure to truck emissions.

3.4.2 Legislation and regulation

Good practice may be required under the Mineral and Petroleum Resources Development Act (Act No. 28 of 2002; MPRDA: as amended and read with two proclamations). The Department of Mineral Resources (DMR) has gazetted regulations under the MPRDA which include a section on "management of air quality" and specifically paragraph 127 requiring license holders to minimise fugitive emissions, including natural gas during hydraulic fracturing operations by various means, or if those are not feasible, to flare the gas (DMR, 2015). These regulations seek to avoid venting methane to the atmosphere and to minimise flaring.

It is recommended that there should be an assessment of existing regulations and legal frameworks applicable to SDG across all impacts. Environmental legislation under the National Environmental Management Act No. 107 of 1998 will be applicable to SGD. A Specific Environmental Management Act (SEMA) could be passed. The regulatory mechanisms available under NEMAQA should be assessed and the most relevant options applied to SGD. It is important to note that SGD is a complex emissions source consisting of a combination of point and diffuse emissions which vary spatially and temporally.

The IEA (2012) established a set of 'Golden Rules' for shale gas with the aim to address environmental and social impacts. The IEA's 'Golden Rules' advise to "target zero venting and minimal flaring of natural gas during well completion and seek to reduce fugitive and vented GHG emissions during the entire productive life of a well [as well as to] minimise air pollution from vehicles, drilling rig engines, pump engines and compressors" (IEA, 2012). For mitigation of venting and flaring, measures consistent with the Global Gas Flaring and Venting Reduction Voluntary Standard (part of the World Bank Group's Global Gas Flaring Reduction Public-Private Partnership)

should be adopted when considering flaring and venting options for onshore activities; again venting only for safety and listing several specific control measures when flaring (International Finance Corporation, 2007). This is consistent with regulation elsewhere (e.g. the UK, which aims to minimise venting - only for safety reasons - and it is preferable to use gas on-site and flare (UK DECC, 2014).

The IEA estimated the cost of applying its 'Golden Rules', which "could increase the overall financial cost of development a typical shale-gas well by an estimated 7%" (IEA, 2012). These relatively modest costs of mitigation, which can be offset by lower operating costs, should be included by developers in considering the full costs of the investment and its returns. Estimates for specific technologies are included in a study for South Africa (DEA, 2014d).

Legal research indicates that is "valuable to aggregate all regulatory provisions into a single set of regulations, [but] those regulations must be appropriately authorised by statute (Centre for Environmental Rights, 2013). The same point is made in a Water Research Commission (WRC) report which points to the need for "alignment and cooperative governance between different government departments and alignment between different pieces of legislation" (Esterhuyse et al., 2014). The WRC report also suggests that monitoring should ask why, what, how, where, when and who (ibid).

3.4.3   *Establish baselines and monitoring of air quality and GHG emissions*

The Centre for Environmental Rights (2013) recommends establishing baselines for and disclosing key environmental indicators including air quality and emissions. World Bank guidelines also recommend baseline air quality assessments and air quality models to establish potential ground level ambient air concentrations during facility design and operations planning, to avoid impacts on human health and the environment (International Finance Corporation, 2007).

There is an urgent need for at least one monitoring station for local air quality *within the study area*, well before shale gas exploration and development begins. Effective monitoring is an essential information base for management plans for both air quality and GHG. Baseline and monitoring methodologies are best designed together, as the baseline stations can be utilised as monitoring stations.

Baseline monitoring before any shale gas exploration occurs would be critical to understand the background concentrations of methane and air pollutants (NO_x, SO_2, PM, and VOCs). A baseline air quality monitoring study should be at least 12 months long in order to capture seasonal differences, however studies longer than a year are needed to understand differences between years. As noted in

Section 3.2.1, there are currently no ambient air quality monitoring stations in the study area. As more information on the location of drilling and exploration activities is made available, sites should be identified for intensive air quality monitoring. This baseline information should be made publicly available to inform stakeholders on the current status of the area.

In addition, due to the potential for regional impacts, air quality monitoring sites are needed throughout the Karoo, in addition to monitoring near the shale gas activities.

Monitoring of air pollutants on-site would be necessary throughout all stages of the shale gas life cycle (Burns et al. 2016). The on-site monitoring would include species that are an occupational risk, which would include VOCs. Well completions in particular are a potentially large source of VOCs that must be mitigated. Green completions are by far the recommended best practice for minimising VOC emissions, with flaring being a less desirable alternative. As the health impacts from VOCs are composition-specific, speciation of VOCs would be needed to understand what species are present, their associated risk and associated occupational health guidelines. Oil and gas operations can have VOC source signatures distinct from vehicles and other industrial processes. For example, propane, C_2-C_7 alkanes and C_5-C_6 cycloalkanes were used to determine the relative contribution of oil and gas operation VOCs to all ozone precursors in Colorado (Gilman et al., 2013). In addition, for local and regional air quality concerns, the speciation of VOCs will aid in modelling their ozone production and secondary aerosol production potential. In order to attribute pollution to different activities, air quality modelling that includes photochemistry and chemical transformation of pollutants would be necessary.

In order to manage the potential risks from increased emissions of air pollutants, the development of an Air Quality Management plan for the region, as well as an Occupational Health and Safety Plan for the work sites is needed. The recently published US EPA guidelines (US Federal Register, 2012) could serve as a useful reference point on good practice. The plans will identify species of concern, the necessary monitoring plan, as well as mitigation policies to be enacted to decrease exposure. A baseline air pollution emissions inventory of the region would assist in modelling not only the current atmospheric concentrations on the pollutants of concern, but also to model the impact that SGD scenarios would have on regional air quality (e.g. through ozone formation). Such scenarios could also include the potential impacts of climate change to air quality (e.g. changes in precipitation, temperature, meteorology, etc.). The potential impacts of climate change on air quality are extremely complex, but should be considered when developing a comprehensive air quality management plan.

It is important to establish a baseline to enable clear attribution of any increased GHG emissions due to SGD. Methane is the most material GHG in this context, but a baseline might also be established for CO_2 and N_2O, with little additional cost. Studies in the US state of Pennsylvania used instrumented aircraft platform to identify large sources of methane from some wellpads, with further work being required for attribution to specific sources (Caulton et al., 2014). It may be possible to use high precision measurement combined with inverse modelling, and information about local wind patterns, to improve attribution, if shale gas exploration and development takes place. The immediate priority, as for air quality, should be to establish baseline values for any methane emissions in the Karoo.

GHG monitoring methodologies should draw on both top-down and bottom-up approaches. Methane can be released naturally, and thus in order to understand at a later stage the impact of SGD on regional methane emissions, it is necessary to develop a baseline; initial approaches might use methodologies for GHG inventories. Inventory methodologies often assume average activity levels, and standard emission factors. Monitoring systems should be designed for continuous improvement, and specifically to ensure that "sampling strategy must capture the low-probability, high-emitting sources" (colloquially known as super-emitters) (Zavala-Araiza et al., 2015), including for example rare but high-emitting liquid unloading events (Heath et al., 2014). Methane leakage rates should be established soon, to avoid problems with attribution in future, where developers might claim that fugitive methane was not higher than 'natural' rates.

The DEA is declaring GHGs as priority pollutants (DEA, 2016a) and the DMR has listed fugitive emissions in the air quality section of regulations for petroleum exploration and exploitation (DMR, 2015). DEA and DMR might involve other agencies in the design, commissioning and finalisation of a baseline study.

3.4.4 *Institutional responsibilities*

National DEA would lead the development of policy to regulate the emissions of GHG and air pollutants from SGD.

Institutionally, the opportunities to reduce GHG emissions if substituting higher carbon fuels and risks of increased emissions when displacing even lower emission fuels (or being entirely additional to the energy system) will likely lie with the DEA, as the focal point for climate change. The DEA should work with the DoE, DMR, Science & Technology (DST) and Water & Sanitation (DWS) in developing an effective regulatory framework for GHG emissions associated with SGD. It is

recommended that these departments develop and legislate domestic "best practice" emissions standards for SGD and develop appropriate human, institutional and technical capacity.

With regards to air quality impacts of SGD, DEA needs to develop policy for regulating the emissions. As indicated earlier, this could include application of NEMAQA, possible amendments of its regulations and / or a SEMA. Implementation of these would require strengthening of capacity within district municipalities to ensure licensing and implementation; especially given that district municipalities in the affected areas have had limited experience in the practice of air quality management and SGD is a unique combination of emissions hitherto unknown in South Africa. In addition, as the highest risks with regards to air pollution exposure were assessed for workers, DEA must work with the Departments of Health and Labour in order to develop and implement appropriate occupational health regulations for SGD.

Good practice guidelines are needed to minimise impacts on air quality and reduce GHG emissions, with guidelines for control technologies, consideration of effective legal regulation, early establishment of baselines and continuous monitoring and good governance enabled by coordination across several institutions.

3.5   Gaps in knowledge

The literature on SGD is largely international, particularly from the USA, with relatively few studies undertaken in South Africa. There are little data available from the rest of the world on GHG emissions specific to South Africa, only two studies specific to the South African context (DEA 2014b; Cohen & Winkler 2014) and one on air quality (Altieri & Stone, 2016). This partly reflects different levels of development of shale gas, but points to the overall need for more research, including on air quality and GHG risks under South African conditions. This also reflects on that fact that many specifics of SGD will only be known if and when exploration and development begins. At that point, empirical studies in South Africa would become possible; the current assessment can only draw on international literature for empirical findings.

Specific emission factors for CTLs in particular are needed for South Africa. Emission factors for GTL are studied slightly more widely, though specific studies under South African conditions would be beneficial; whereas analysis of emissions oil refineries are appropriately supported by international literature.

Relatively few studies undertake a full life LCA for GHG emissions from SGD, and further work should compare this to life cycle GHG emissions for other energy end uses, for both liquid fuels and

electricity. Additional research is required to conclude whether the use of shale gas as a source of fuel for transport in the form of CNG is better or worse from a GHG perspective.

Further research is needed to quantify the risks and opportunities of SGD for GHG emissions, for example through energy modelling. Energy modelling would provide information on how the energy system might respond to shale gas becoming available at different scale, assumed prices and the extent to which gas might displace other fuels for various end uses. No dedicated modelling study has been undertaken recently, other than a 'Big Gas' scenario in the unofficial IRP 2013 update.

The majority of the gaps in understanding the risk to air quality from shale gas stem from the uncertainty in the emissions and speciation of emissions (e.g. exact chemical compositions of all VOCs) from the exact processes and activities that will occur, and what fuel source shale gas may replace. A comprehensive emissions inventory that could be used for air quality modelling for the area would assist in understanding the potential ambient air pollution impacts from shale gas, and the resultant potential health impacts. The speciation of VOCs would assist in developing appropriate mitigation measures for occupational health (the standards are species-specific) as well as their ozone and secondary aerosol production potential. This detailed emissions inventory could then be used for air quality modelling to quantify the impact that SGD has on ambient air quality, and the resultant impacts.

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3.7 Digital Addenda 3A – 3B

SEPARATE DIGITAL DOCUMENT

Addendum 3A: Spatial distribution of risks

Addendum 3B: Taken directly from "Controls and Recommendations to Limit Worker Exposures to Respirable Crystalline Silica at Hydraulic Fracturing Work Sites," Online Supplemental, Esswein et al., 2013