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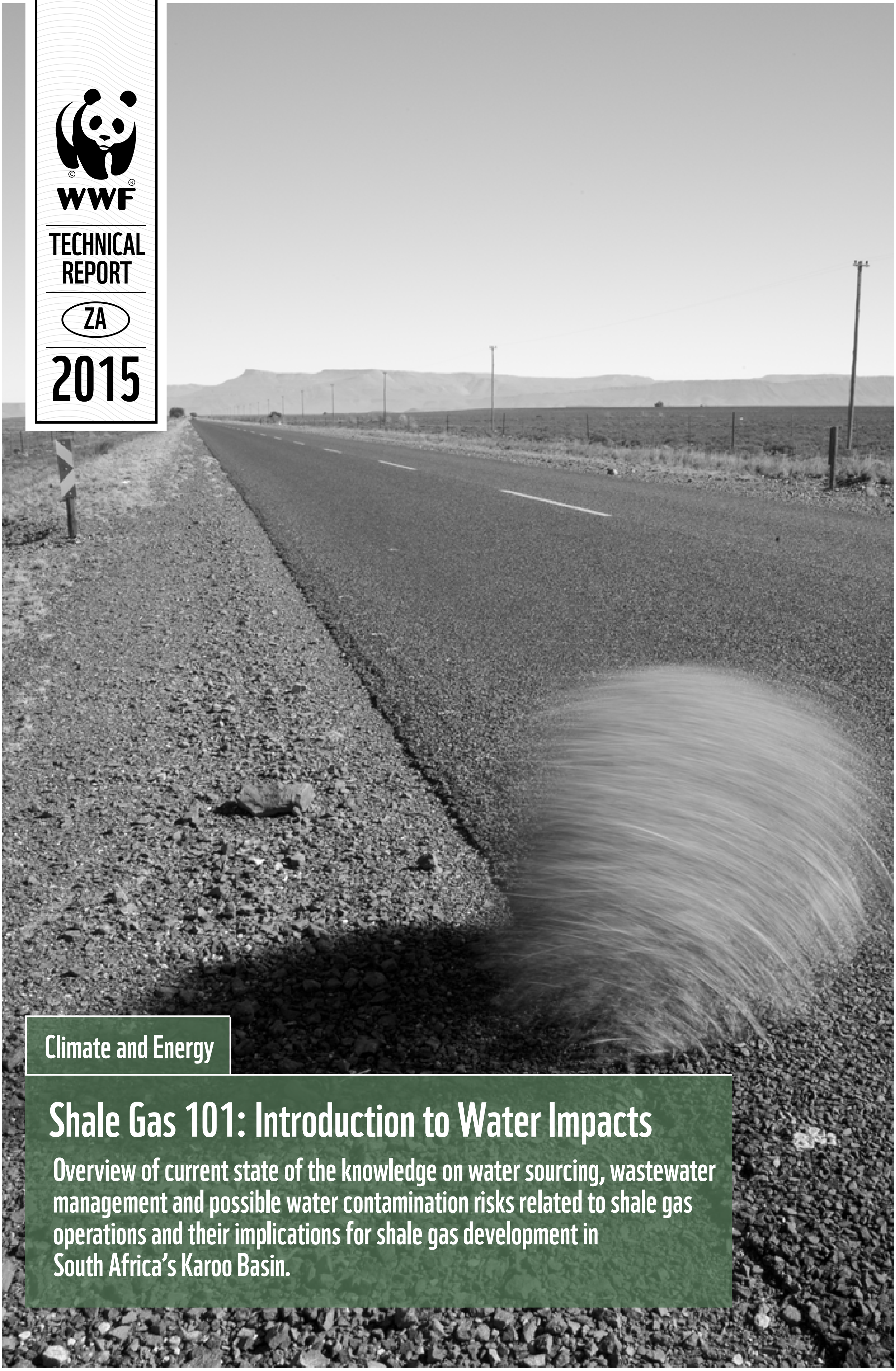

Climate and Energy

Shale Gas 101: Introduction to Water Impacts

Overview of current state of the knowledge on water sourcing, wastewater management and possible water contamination risks related to shale gas operations and their implications for shale gas development in South Africa's Karoo Basin.

ABOUT WWF

WWF is one of the world's largest and most experienced independent conservation organisations, with over 5 million supporters and a global network active in more than 100 countries.

WWF's mission is to stop the degradation of the planet's natural environment and to build a future in which humans live in harmony with nature, by conserving the world's biological diversity, ensuring that the use of renewable natural resources is sustainable, and promoting the reduction of pollution and wasteful consumption.

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Any errors contained in the document remain the responsibility of the author.

Designed by Apula
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ABBREVIATIONS

BCM	*billion cubic metres*
BPD	*barrels per day*
BTEX	*benzene, toluene, ethylbenzene and xylene*
CH4	*methane*
CSIR	*Center for Scientific and Industrial Research*
DBP	*disinfection by-product*
DWA	*Department of Water Affairs and Sanitation*
EOR	*enhanced oil recovery*
GE	*General Electric*
GHG	*greenhouse gasses*
GtL	*gas-to-liquid*
HVSWLL	*high-volume slick-water long-lateral*
MMBtu	*million British thermal units*
MPa	*mega Pascal*
NORM	*naturally occurring radioactive material*
NOx	*nitrogen oxide*
PPM	*parts per million*
TDS	*total dissolved solids*
TOE	*tons of oil equivalent*
VOC	*volatile organic compound*

PREFACE

This report is being done under the auspices of the Policy and Futures Unit (PFU) of the WWF-SA. This unit was established at the beginning of 2015 and became operational in July 2015. Its primary purpose is to provide both the WWF, and the wider society as whole, analytical capabilities for long-term thinking and planning. Our vision is to work with other stakeholders in building a more diversified and sustainable economy.

In its work, the unit applies analytical, political and economic thinking to unpack challenges of a transition to a more sustainable and equitable future, looking for solutions that are technological, organizational, social and economic in nature.

The PFU is an unconventional model within the WWF family. All organizations have to adapt to a fast changing world. For that they not only need good intelligence, sound empirics but also a diverse set of worldviews that is able to define a new agenda and pathway for society through debate, insights and consensus building. The role of the PFU is to facilitate robust analytics and engagement with diverse interests and stakeholders.

It is within this changing context of the WWF itself that this report needs to be read and assimilated. This report started out with the explicit purpose to build on the work done by WWF-SA in an earlier report that established a framework to assess the economic reality of shale gas in South Africa, by estimating the water costs associated with shale gas development. We still believe that water input and output costs will make or break shale-gas economics in South Africa.

However, it was soon realised such an analysis is premature in the South African context due to lack of data to support even the basic assumptions necessary. While researching the costing exercise, it was realised there is a need for a report that is comprehensive (addresses all the main water-related issues associated with shale gas development), up-to-date (considering the amount of relevant research that has been published on this issue in the past few years) and accessible to the wider audience.

Our own need to understand the water issues associated to shale gas led to a multitude of literature reviews, conversations and analyses of the technical material in order to undertake a proper unpacking of possible risks to South Africa's water resources, which are already under severe pressure. This work is part of a suite of reports compiled by WWF-SA on various aspects of South Africa's future energy sources. On the specific topic of water issues associated to shale gas development, in addition to this report, WWF-SA is also publishing a series of quick-reference FAQ for decision makers when confronting local challenges with water use and management for fracking.

The hope is for this research to contribute to a better informed debate on the possible role of shale gas in South Africa's future energy mix and flag areas of concern related to water sourcing, contamination and wastewater management of possible shale gas developments in the country. While the report draws heavily on the experience in US shale plays, it recognizes, and indeed stresses, the need for local adaptation of these lessons and therefore provides a description of local conditions to provide a local contextualisation to the issues raised.
Many risks flagged in this report can be minimised with appropriate and effectively enforced regulation. While it is not within the scope of this report to conduct an assessment of the suitability of the existing regulatory framework for shale gas exploration and production, it is hoped, that the information contained herein will help inform the evolving regulatory landscape.

We look forward to your feedback and help in adding to the knowledge base.

Saliem Fakir

Head of Policy Futures Unit
WWF-SA
South Africa

1. BACKGROUND

Key massages:

- As shale gas seeks to increase its role as energy source, there is growing public concern about the shale industry's possible impacts on the environment. These include water shortages, groundwater and surface-water pollution, fugitive greenhouse gas (GHG) emissions, local air quality degradation, induced seismicity, ecosystems fragmentation, and various community impacts.
- These concerns led to shale gas development being banned in some countries and very closely scrutinised in others.
- Shale gas developments' true impact levels on water resources are the subject of engaged scientific and popular debate.
- The majority of water-related issues of shale gas development can be grouped into three categories: 1) water sourcing, 2) wastewater management and disposal, and 3) possible water contamination.
- Shale gas wastewater consists of drilling waste, flowback and produced water, which includes formation water. Distinguishing the different wastewater flows is often very challenging, with the industry often referring to them all as produced water.

1.1 STUDY MOTIVATION AND FOCUS

Shale gas is seeking to become a major player in the energy supplies of a number of countries. Although its large-scale exploitation is still concentrated in North America, particularly the US, several other countries are exploring for shale gas or ways so as to achieve its successful commercialisation. These include South Africa, with the Whitehill formation earmarked for development.

At the same time, a number of countries have instituted full or partial bans on shale gas development, primarily owing to public opposition to perceived environmental externalities associated with shale gas operations. These include the potential to create water shortages, cause groundwater and surface-water pollution, local air quality degradation, induced seismicity, ecosystems fragmentation, incur fugitive greenhouse gas (GHG) emissions, and various community impacts (Jackson, et al., 2014).

While all the above potential impacts are relevant and worthy of further exploration, this report focuses on water issues associated with shale gas development. Potential competition for scarce water resources is a particularly pressing concern in a semi-arid region such as the Karoo, as is the potential contamination of these scarce water resources. Water availability and wastewater management are also crucial determinants of the profitability of shale gas operations, making this an equally relevant discussion for the industry.

There has already been significant debate on these issues in South Africa, at various levels, from involvement by the general public in protests, to dedicated scientific conferences. The true magnitude of water-related risks posed by shale gas activities continues to be the subject of engaged scientific and popular debate worldwide.

This report seeks to provide a concise overview of the current state of knowledge on the main water issues associated with shale gas development, in the hope that it will contribute to a better understanding of the risks faced by water resources and their users in the South African shale play, as a baseline in developing approaches to manage these risks.

The main water-related issues of shale gas developments can be summarised as:

1. **Water sourcing:** Drilling and completion of shale gas wells require water inputs in the order of several million litres per well, which can impact on local ecosystems and can compete with existing local and regional water uses.

2. **Water contamination:** There are several possible pathways for water contamination by shale gas developments, both below and above the ground level, caused by faulty well construction, migration of fracturing fluid in natural pathways, or the mishandling of the chemicals used for hydraulic fracturing or its wastewater.

3. **Wastewater management and disposal:** Some portion of the injected fracturing fluid returns to the surface through the well, following the well's completion. This water can run into millions of litres and is high in dissolved minerals, including trace amounts of naturally occurring radioactive metals (NORMs), residual fracturing chemicals and dissolved hydrocarbons. If managed improperly, it represents a significant threat to human health and the environment.

Considering the generally low levels of compliance with environmental legislation by large companies in South Africa[1] provides legitimacy to concerns that the abovementioned risks might well materialise. At the same time, it must also be acknowledged that the shale gas industry is evolving in the direction of reducing its water-related impacts. To what extent the innovations that reduce the environmental externalities will be implemented depends on a number of factors, including their cost, regulatory framework and awareness of the many stakeholders involved in the upstream shale gas value chain. This report focuses on risks and potential solutions to them, while the conditions that are needed to implement those solutions, including specific regulatory initiatives, are beyond its scope.

1.2 DEFINITIONS

The discussion of water issues surrounding shale gas development requires the clarification of a number of recurring terms:

"Shale" is a soft and finely stratified sedimentary rock that formed from consolidated mud or clay and can be split easily into fragile plates[2]. In the energy field it is also used as an umbrella term for a large and highly variable family of rocks rich in hydrocarbons.

"Shale gas" is natural gas derived from organic-rich shale formations, which act as both the source and reservoir for the gas (API, 2015). Because the geological characteristics of its reservoir rock differ from that of "conventional" natural gas, it is often referred to as an "unconventional" resource.

"Hydraulic fracturing" is a process whereby large volumes of fracturing fluid is pumped down a wellbore at high pressure to create a network of cracks in the source rock, which increases the rock's porousness and thereby allows the gas to flow (DMR, 2012).

However, this definition leaves considerable room for interpretation of the specific technology (or group of technologies) that is used to achieve the release of gas from source rock. What is proposed in the Karoo, is actually **"high-volume slick-water long-lateral"** (HVSWLL) stimulation, which combines the following four elements: i) directional drilling; ii) high frack-fluid volumes; iii) "slick-water" additives; and iv) multi-well drilling pads (Hartnady, 2011). This particular combination of technologies is notably different from those used in early applications of hydraulic fracturing in vertical wells (Gallegos & Varela, 2015), which has been used for well stimulation and enhanced

[1] A recent report by the Centre for Environmental Rights found that 20 listed South African companies that have regularly appeared on the JSE's Socially Responsible Investment Index (SRI Index) have in many cases mislead their shareholders about their environmental impacts and non-compliances, or provided insufficient information, making it impossible to verify claimed commitments to sound environmental management (CER, 2015).

[2] http://www.oxforddictionaries.com/definition/english/shale

hydrocarbon recovery since the end of the 1940s (Gandossi, 2013). The most current hydraulic fracturing materials and methods have emerged at the end of the 1990s (Gandossi, 2013) and therefore have a considerably shorter (although not insignificant) track record.

"Fracturing (or fracking) fluid" is primarily made up of carrier fluid (water, most commonly) and proppant (≈98 per cent by volume) as well as a cocktail of chemicals (including acids, biocides and polymerising gels to prevent scaling, to facilitate large fractures and to deter biochemical oxidation of the hydrocarbons) to achieve the maximum gas flow (DMR, 2012).

"Carrier fluid" is the largest component (by volume) of *fracturing fluid*. While the most common carrier fluid is fresh water, different quality brines, liquid hydrocarbons, liquid nitrogen and liquid carbon dioxide can also be used (DMR, 2012).

"Flowback water" " is the fracturing fluid that returns to the surface following an injection event. It is made up of clays, chemical additives, and dissolved ions and solids, and its exact chemical composition depends on the composition of the injected fracking fluid, the rock it fractures and the gas it releases. Most of the flowback occurs in the first seven to 10 days after hydraulic fracturing takes place, while the rest can occur over a period of three to four weeks (Schramm, 2011)

"Produced water" is the water being discharged at surface after the initial flowback. As its name suggests, produced water is the water that is brought to the surface during the production of oil and gas. It is a mixture of the remaining flowback and water that occurs naturally in the shale (formation water), now released from the formation as a result of fracturing. It has high concentrations of total dissolved solids (TDS) and leaches out minerals from the shale rock including barium, calcium, iron and magnesium. It also contains dissolved hydrocarbons such as methane, ethane and propane, and sometimes NORMs such as radium isotopes (Schramm, 2011)[3].

The transition between flowback and produced water can be difficult to distinguish, but can often be identified by the return rate, measured in barrels per day (bpd) and by looking at the re-surfacing water's chemical composition. Flowback water produces a higher flow rate over a shorter period of time, usually greater than 50 bpd, while produced water produces a lower flow over a much longer period, typically from 2 to 40 bpd (IEER, 2011). The chemical composition of flowback and produced water can sometimes be very similar, demanding a detailed chemical analysis to distinguish between the two (IEER, 2011), while at other times it can vary significantly, with flowback water resembling the hydraulic fracturing fluid, and produced water more closely resembling the brine naturally present in a formation (Clark, Burnham, Harto, & Horner, 2013). Produced water tends to have higher salinity levels.

If differentiated at all, the terms are typically defined by operators based on the timing, flow rate or sometimes composition of the water produced, rendering an objective quantification of the different flows very difficult. Most operators actually refer to all water coming back from the well as "produced water" (water that is co-produced with the hydrocarbons). If pressed, they will identify "flowback" as the part of produced water that comes out in the first 30 days after the last frack is completed.

A possible visualisation of the various wastewater flows arising from a shale gas well is provided in Figure 1. As the figure shows, flowback gradually becomes produced water and the two waste streams cannot be clearly separated; rather, the former has a gradually increasing amount of the latter, until the chemical composition of formation water becomes predominant.

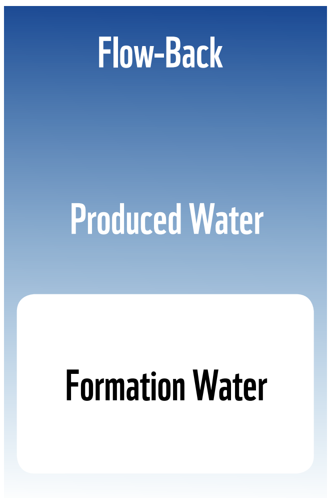


Figure 1 Diagram of shale gas wastewater flows (excluding drilling waste)

[3] The shales of the Karoo Supergroup were found to be free of radioactive elements (Svensen, Planke, Chevallier, Malthe-Sorenssen, Corfu, & Jamtveit, 2007).

In any event, both are wastewater categories that pose significant environmental and human health risks unless managed properly, as will be discussed in Section 4.

1.3 SHALE GAS DEVELOPMENT IN SOUTH AFRICA

In South Africa, shale gas exploration has recently been re-vitalised after a period of uncertainty, and exploration license holders are proceeding with preparatory activities. Shale gas exploration license applications cover an area of about 200,000km^2, mostly in the Karoo Basin, but also in parts of the Free State and KwaZulu-Natal. About half of the Karoo and one-fifth of South Africa's land surface has been earmarked for shale gas exploration (TKAG, 2011).

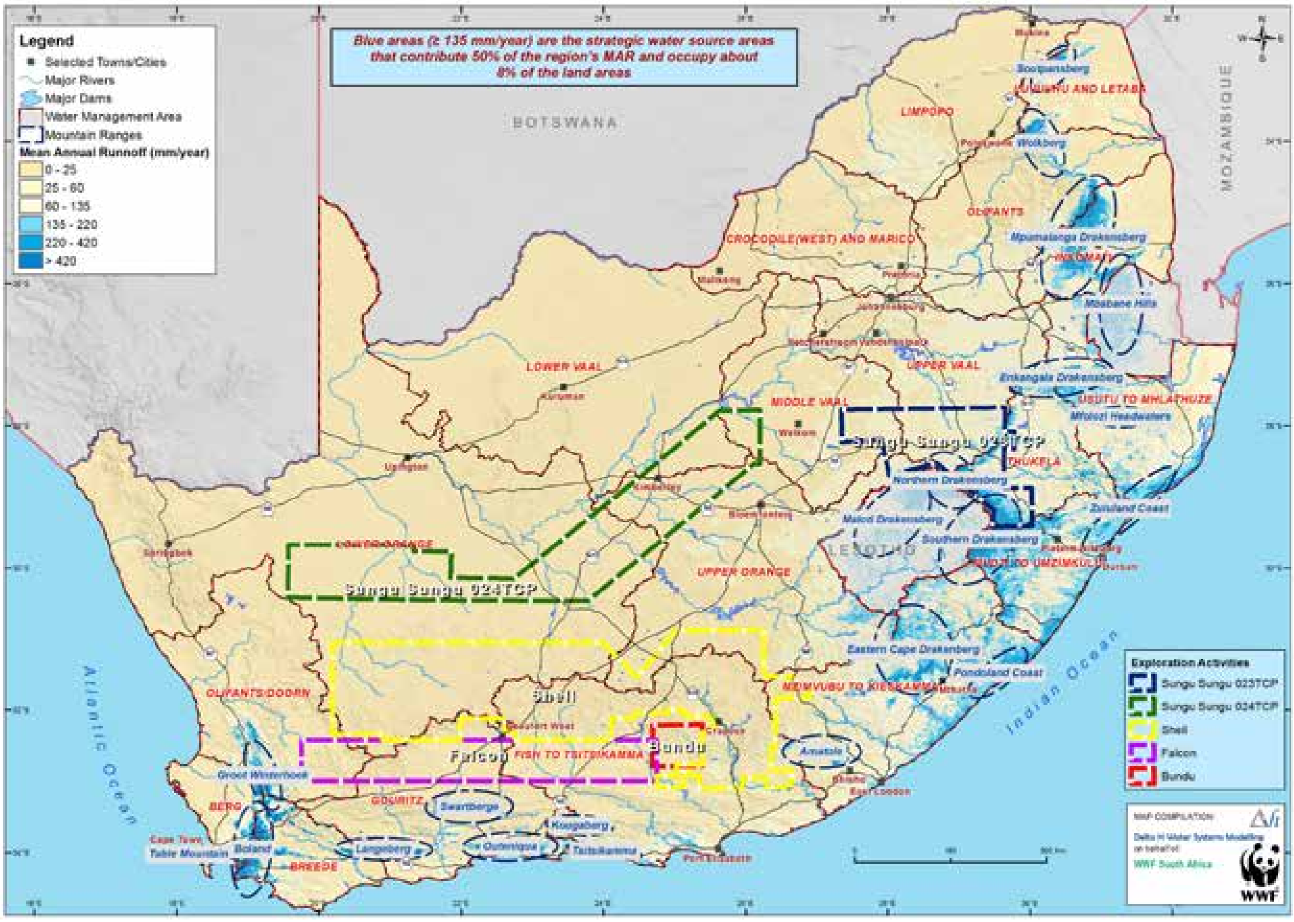
Some areas under exploration right application encompass areas of strategic water importance (the so-called South Africa's Strategic Water Source Areas) (WWF, 2013), as shown in Picture 1[4]. Areas under exploration license applications as per mid 2015. These are the areas that together contribute 50 per cent of the country's river runoff (expressed as Mean Annual Runoff – MAR), yet only occupy 8 per cent of the land surface. They supply water to major industrial and agricultural activities and support domestic water needs across the country. The potential contamination within these strategic water source areas could impact significantly on downstream users.

Importantly, many of these areas are vulnerable to shallow groundwater contamination in case surface contamination takes place, mainly owing to the permeability of shallow geology. Areas that are highly vulnerable to groundwater contamination occupy some 15 per cent of Shell's licence area, and 10 per cent of Falcon's licence area (as can be seen in Picture 2).

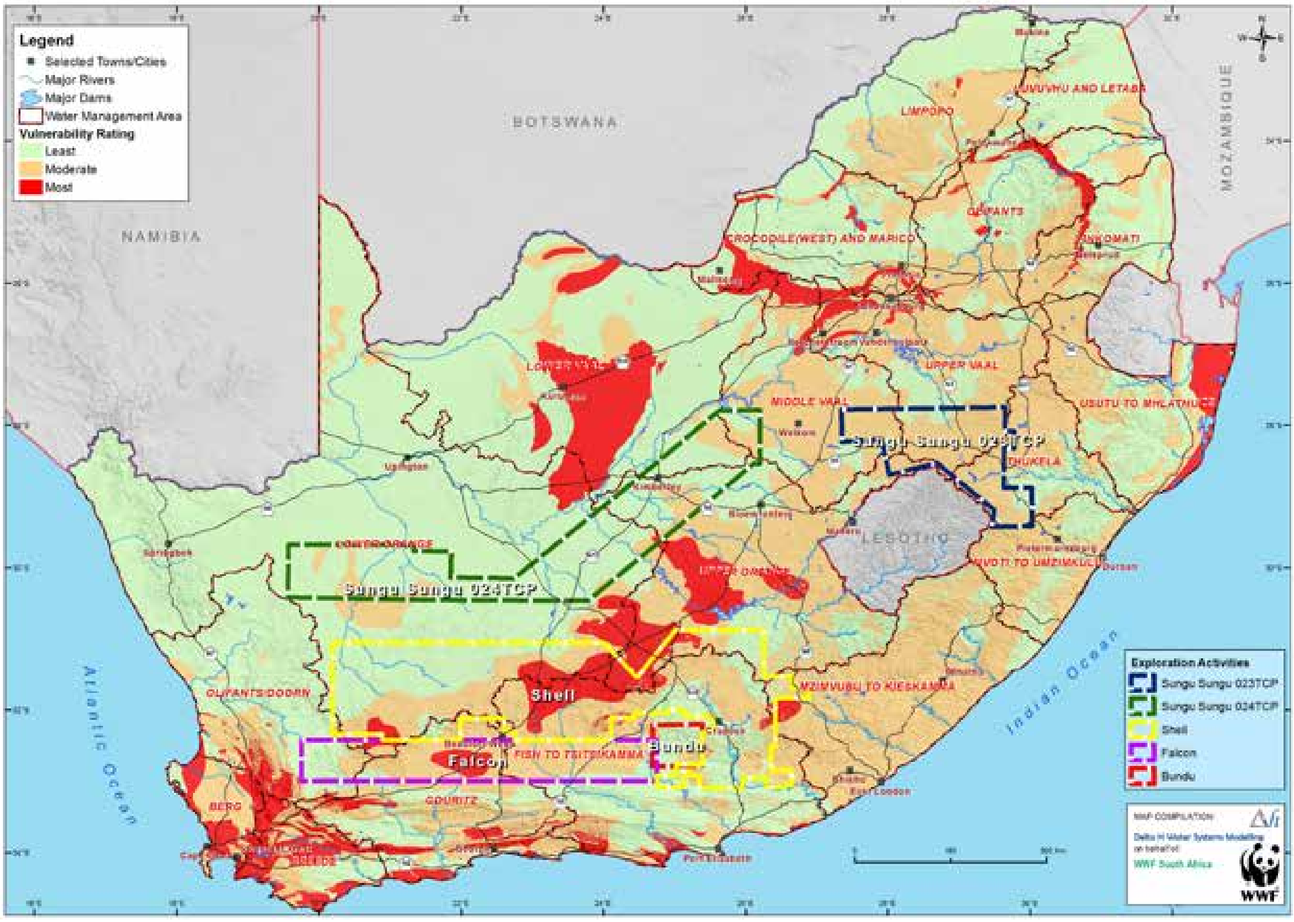
The likelihood of shale gas development taking place in the Karoo requires a full understanding of possible risks to the region's water resources and the mitigation measures available. This report seeks to provide such an overview. The remainder of the report is structured as follows: Section 2 lays out the hydraulic fracturing water cycle; Section 3 provides an overview of water demand by shale gas operations and possible water supply sources; Section 4 explains possible wastewater management options while Section 5 discusses the contentious issue of the contamination of freshwater sources. Section 6 reflects on the previous sections and provides some recommendations for future work.

[4] 15 per cent of the Sungu Sungu 023TCP licence area overlaps with the Northern Drakensberg Strategic Water Source Area.

Picture 1 Strategic water source areas and shale gas prospecting areas



Picture 2 Vulnerability of groundwater to contamination and shale gas prospecting areas



2. THE SHALE GAS WATER CYCLE

Key massages:

- *The shale gas water cycle consists of water acquisition, chemical mixing, drilling and well injection, flowback and produced water, and wastewater treatment and disposal.*
- *There are risks – as well as available mitigation measures – associated with each stage of the cycle.*

Before addressing water-related issues in some detail, it is useful to present an overview of the water cycle of shale gas operations. The US Environmental Protection Agency (EPA) offers a practical overview of its five stages (EPA, 2014):

Stage 1: Water acquisition

During this stage, large volumes of water are sourced for drilling and hydraulic fracturing. Most commonly, this involves withdrawing fresh water from groundwater and surface water sources. Depending on the water source's yield in the area of extraction, this can have significant impacts on the availability of fresh water.

Because such concerns can sometimes prevent fracking operations, the industry is increasingly using grey water, such as recycled industrial wastewater (including their own) and other water sources of different salinity levels, instead of extracting fresh water from ground or surface sources. In these cases, the water must be treated or diluted before it can be used in hydraulic fracturing.

Stage 2: Chemical mixing

The water is then delivered to the well site, where it is combined with chemical additives and proppant (usually sand) to render the hydraulic fracturing fluid. Water and proppant constitute about 95 to 98 per cent of the fracturing fluid, with the balance constituted by a blend of chemicals (often proprietary) (Clark, Burnham, Harto, & Horner, 2013).

The additives used in each well or group of wells can differ based on considerations of the physical and chemical properties of the shale and the carrier fluid, as well as the depth and temperature at which the fracturing will take place (DMR, 2012). Some of the most common chemical additives used in hydraulic fracturing and their uses are described in Table 1.

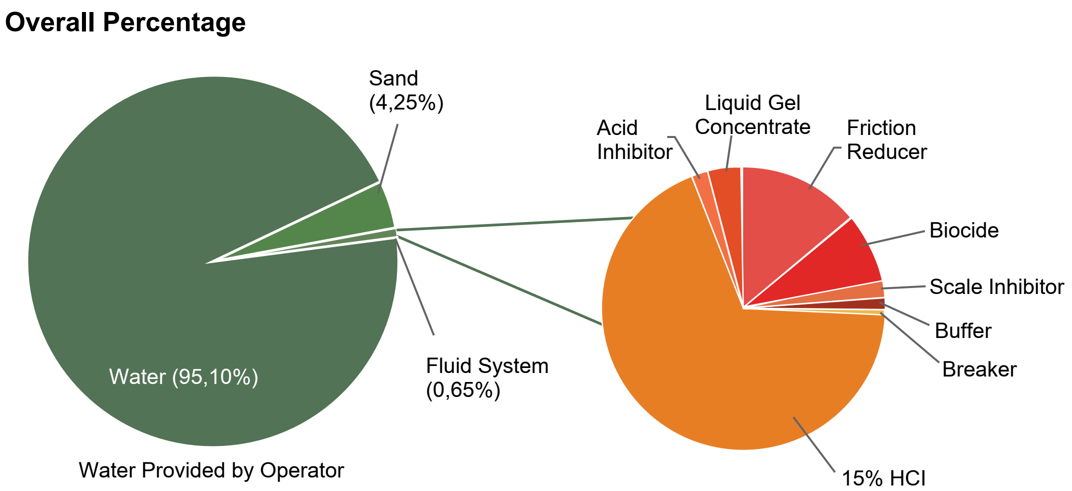
Table 1 Common chemical additives for hydraulic fracturing

ADDITIVE TYPE	EXAMPLE COMPOUNDS	PURPOSE
Acid	Hydrochloric acid	Clean out the wellbore, dissolve minerals and initiate cracks in rock
Friction Reducer	Polyacrylamide, petroleum distillate, Isopropanol, acetaldehyde	Minimise friction between the fluid and the pipe
Corrosion Inhibitor	Citric acid, thioglycolic acid	Prevent corrosion of pipe by diluted acid
Iron Control	Citric acid, thioglycolic acid	Prevent precipitation of metal oxides
Biocide	Glutaraldehyde, 2,2-dibromo-3-nitrilopropionamide (DBNPA)	Bacterial control
Gelling Agent	Guar/Xantham gum or hydroxyethyl cellulose	Thicken water to suspend the sand
Crosslinker	Borate salts	Maximise fluid viscosity at high temperatures
Breaker	Ammonium persulfate, magnesium peroxide	Promote breakdown of gel polymers
Oxygen Scavenger	Ammonium bisulfite	Remove oxygen from fluid to reduce pipe corrosion
pH Adjustment	Potassium or sodium hydroxide or carbonate	Maintain effectiveness of other compounds (such as crosslinker)
Proppant	Silica quartz sand	Keep fractures open
Scale Inhibitor	Ethylene glycol	Reduce deposition on pipes
Surfactant	Ethanol, isopropyl alcohol, 2-butoxyethanol	Decrease surface tension to allow water recovery

Source: (Vidic, Brantley, S.L., Vandenbossche, Yoxtheimer, & Abad, J.D., 2013)

Slick-water systems are the most commonly used chemical mixes in hydraulic fracturing and are deemed the most likely cocktail to achieve the release of gas from the shale rock in the Karoo (DMR, 2012). An example of the composition of fluid for a slick-water hydraulic fracturing operation is provided in Figure 2 below.

Figure 2 Composition of fracking fluid in slickwater systems



Source: Halliburton, cited in (DMR, 2012)

Compared to other fracking water systems, the *slick-water system* does not contain viscosity modifiers that are often added to facilitate better proppant transport and placement (Vidic, Brantley, Vandenbossche, Yoxtheimer, & Abad, 2013).

Stage 3: Drilling and well injection

Water is needed both for drilling and hydraulic fracturing, although the drilling usually consumes less than 10 per cent of the total water requirement of the shale gas operation (Hoffman, Olsson, & Lindstrom, 2014). After the vertical and horizontal drilling have been completed and the casings are in place, the casing in the wellbore's horizontal leg is perforated, and pressurised fracturing fluid is injected into the wellbore and through the perforations (Hoffman, Olsson, & Lindstrom, 2014). This process cracks the shale rock and releases the gas, which escapes through the well to the surface.[5] The pressures at which the fracking fluid can be injected vary, but can reach up to 100MPa (1,000bar), with flow rates of up to 265 litres/second (Hoffman, Olsson, & Lindstrom, 2014).

Stage 4: Flowback and produced water

The primary categories of wastewater associated with shale gas operations are flowback and produced water, as described in Section 1.2. *Flowback* flows up the wellbore when pressure in the well is released, which causes the direction of fluid flow to reverse, clearing the way for the oil or gas. In addition to this, produced water surfaces along with the natural gas.

The proportion of the injected fracking fluid that flows back after the fracture system has been created can vary from 0 to 100 per cent, but is most often less than 50 per cent, implying that the larger proportion remains in the artificial fracture system created by the shale gas operation (DMR, 2012).[6] Nevertheless, in most cases there will be hundreds of thousands of litres of this combination of fluids, containing hydraulic fracturing chemical additives and naturally occurring substances, which must be stored onsite – typically in tanks or pits – prior to treatment, recycling or disposal.

Wastewater is also produced during the vertical and horizontal drilling of the well, although this represents the smallest part of shale gas operations wastewater streams.

Stage 5: Wastewater treatment and disposal

The wastewater produced by the shale gas operations must be collected, treated and disposed of safely, or recycled and re-used in other fracking operations. This cannot continue indefinitely and, eventually, all wastewater must be treated and permanently disposed of.

There are several ways to dispose of wastewater produced in shale gas wells, depending on economics and geology of the region where the gas is produced. If geology allows it, the most popular disposal route is injection into underground wells. This disposal pathway gives the shale gas water cycle a distinct feature. If the water that is used for drilling and well-stimulation is drawn from surface or groundwater sources and then disposed of in underground wells[7] at the end of its productive use, it is permanently removed from the biosphere. This can have negative effects on local hydrological cycles, which should be included in environmental impact analyses of proposed shale gas operations. However, this is not the case if the water is drawn from a deep saline/brackish aquifer, or if the water is treated to drinking water quality and returned into surface water bodies or used for residential or industrial water needs.

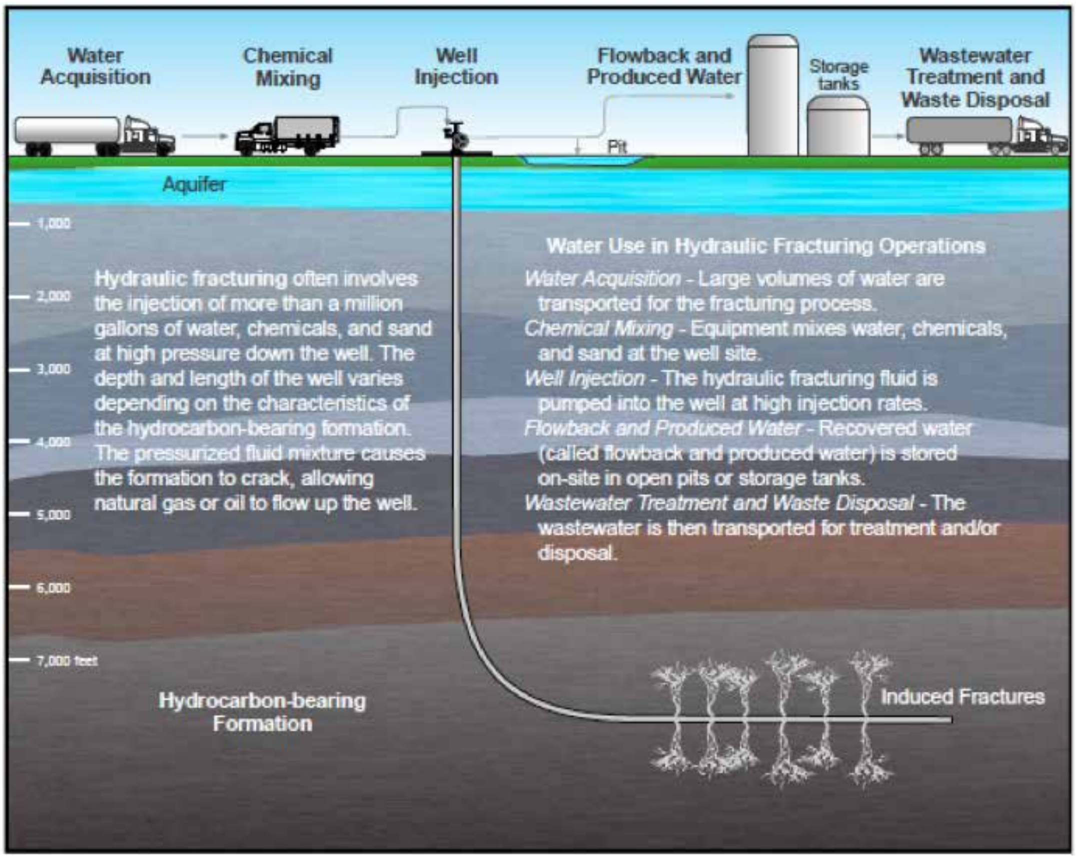
The stages of the hydraulic fracturing water cycle are summarised in Picture 3.

[5] These cracks usually extend 50m to 100m from the horizontal wellbore and are typically less than 1mm wide (Hoffman, Olsson, & Lindstrom, 2014).

[6] Very low or null flowback rates are not very common. There have been instances of almost no flowback in the Eagle Ford play in Texas, for instance, which is attributed to imbibition of water by the shale (DMR, 2012).

[7] As will be discussed further in the report, this is not going to be an option in South Africa.

Picture 3 The water cycle stages in hydraulic fracturing



Source: (EPA, 2011)

Next, the amounts and possible sources of water required for shale gas operations are presented. While the introduction to the following section will show that other economic activities consume as much or more water than shale gas operations, in certain local contexts, the latter can take competition for water resources to levels where its uses need to be prioritised.

3. WATER DEMANDS OF SHALE GAS OPERATIONS AND POSSIBLE SUPPLY SOURCES

Key massages:

- *While globally, agriculture is still the largest source of water consumption, regional and local patterns often show a different picture.*
- *Energy and water systems depend on each other, and water constraints already threaten the viability of various energy projects, including the development of unconventional gas resources, and not only in water-stressed areas.*
- *Compared to other fossil fuel sources in terms of water requirements, shale gas does not compare unfavourably, especially considering water demands of sythetic liquid fuels such as gas-to-liquid and coal-to-liquid, and biofuels based on irrigation agriculture. However, the local context is always the most relevant comparison frame and in certain local contexts, competition for water resources can reach levels where its uses need to be prioritised.*
- *Water demand by shale gas operations depends on a number of factors, including local geological setting, well depth, gas recovery rates, number of fracturing stages, amount of flowback and produced water, and the flowback and produced water recycling rates.*
- *In the US, most shale gas operations require between 10 and 20 million litres of water to fracture one well. The transferability of this figure to the Karoo cannot be safely assumed at this point.*
- *Recent technological advances are broadening the spectrum of water sources that can be tapped by shale gas operations. Besides surface water and shallow groundwater, these now include brackish and brine water from deep aquifers and various industrial wastewaters. The actual extraction rate from any of these sources will depend on the resource's size and competing uses.*

3.1 GLOBAL, REGIONAL AND LOCAL WATER CONTEXTS

The water demand of shale gas operations and their possible competition with other water users is one of the key public concerns related to shale gas developments. Before focusing on experiences in active shale plays, it is useful to contextualise the energy sector's water demand in general and that of the shale gas sector in particular, by comparing their average water consumption with other economic activities.

Globally, agriculture is still the biggest user of water, accounting for some 70 per cent of total water withdrawals, followed by industrial uses (19 per cent) and municipal uses (11 per cent) (FAO, 2015). Agriculture is also the biggest user of water in South Africa (almost 60 per cent), and even more so in the Karoo. In the Gouritz Water Management Area in the Klein Karoo for example, some 75 per cent of all the water is used for irrigation, while in the Lower Orange water management area that comprises a large portion of shale gas prospecting areas this figure rises to over 90 per cent (DWA, 2004).

Energy production is the largest user in the industrial uses category, having claimed some 15 per cent of the world's total water withdrawals in 2010. In absolute terms, this equals 583 billion cubic metres (bcm) in 2010, of which water consumption (the volume withdrawn but not returned to its source) was 66bcm (IEA, 2012).

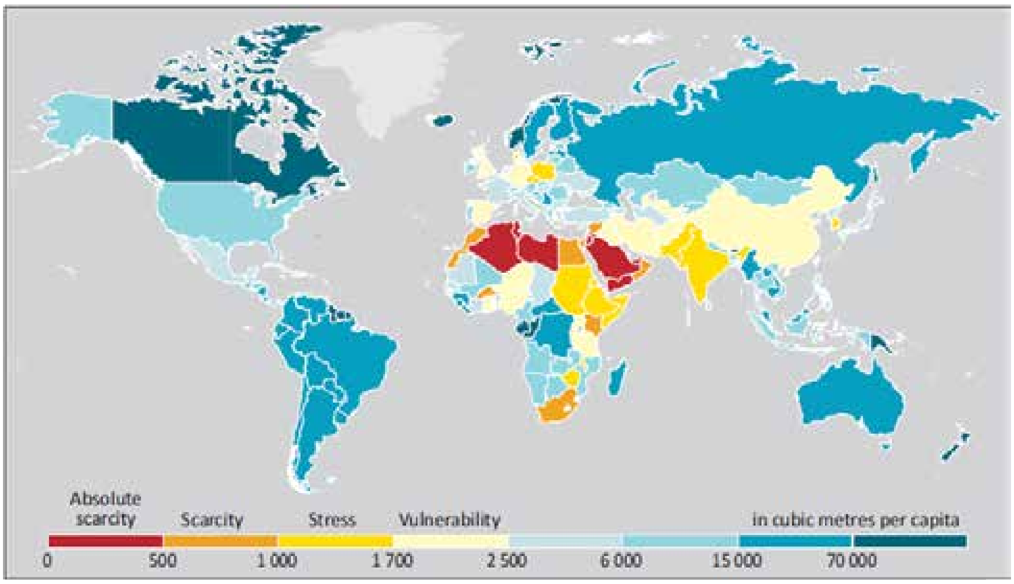
While the energy sector's water demand may seem relatively modest compared to agriculture on a global scale, regional patterns can paint a very different picture. In a number of developed economies such as many EU countries and the US, the energy sector now accounts for 40 to 50 per cent of national water demands, and similar patterns can be observed in emerging economies (Hoffman, Olsson, & Lindstrom, 2014).

Water and energy systems are inextricably linked. Water is a crucial input in the entire value chain for most forms of energy. It is used in the extraction, transportation and processing of fossil fuels, in power generation and – increasingly – in irrigation to grow feedstock for biofuels (IEA, 2012). Similarly, energy is needed for the provision of water. Energy powers systems that collect, transport, distribute and treat water used by people, in agriculture and by industries (IEA, 2012).

Both water and energy sources are experiencing rising demand in many regions as a consequence of economic and population growth and climate change (IEA, 2012). Globally, water demand is projected to grow by more than 50 per cent over the next few decades, while 40 per cent of the world's population will be living in water-scarce areas (WWAP, 2014). Picture 4 shows the renewable water resources per capita across the world and classifies countries based on this resource's availability. It shows that South Africa is already a water-scarce country, with only 500 to 1,000 cubic metres of fresh water available per capita per year, compared for instance with the US, where per capita water availability is between 6,000 to 15,000 cubic metres per capita per year.

In several water-stressed countries, water supply is already a limiting factor for agriculture and food production, drinking-water supply, energy generation and different industrial sectors (Hoffman, Olsson, & Lindstrom, 2014)

Picture 4 Renewable water resources per capita



Source: (IEA, 2012), based on the UN FAO Aquastat database

While a high-level global overview might be useful to identify areas of long-term water scarcity, the local context matters most in assessing the risks of possible water shortages caused by shale gas development. Examples from the US show that here too there are significant differences between national and local impacts. For instance, the amount of water used for hydraulic fracturing across the state of Texas is less than 1 per cent of total annual water use (Nicot & Scanlon, B.R., 2012), which doesn't sound substantial. However, for smaller areas and specific windows of time, the picture looks very different. In counties associated with the Haynesville, Eagle Ford and Barnett Shales, unconventional energy extraction was responsible for 11 per cent, 38 per cent and 18 per cent of total groundwater use (Nicot & Scanlon, B.R., 2012).

In the Eagle Ford Shale area of West Texas, where rainfall is low and so are the aquifers levels – in some cases having less than 30 days' supply of fresh water – the situation was particularly acute in 2011, a drought year, when local residents from about 30 communities were nearly forced to buy and truck in water from elsewhere at significant cost (Hoffman, Olsson, & Lindstrom, 2014). Fort Worth, also close to the Texas shale gas region, is now number six on the top 10 list of water-scarce cities (Hoffman, Olsson, & Lindstrom, 2014). While the poor state of Texas's water resources cannot be fully attributed to shale gas operations (with years of drought, decades of industrial over-use and residential over-use playing the bigger parts, and climate change worsening matters), they do aggravate an already very tight water supply.

There are even more localised examples where depletion of small aquifers are directly linked to the gas industry. Records show that some farmers and landowners in Texas have sought to make money from water by selling groundwater to the oil and gas industry, drying up their aquifers. One farmer is known to have earned some $60 per truckload and could sell 20 to 30 truckloads per day (FracDallas, 2014). While this allowed him to make significant short-term profits, he was eventually left with a dry well, and could no longer produce any food or supply the area with water (Hoffman, Olsson, & Lindstrom, 2014). While this is only one documented example and cannot be used as grounds to generalise depletion of water resources held by private parties who supply to the shale gas industry, it does offer a warning to farmers in the Karoo who might be approached for their water.

Local water use of shale gas operations relative to local water resources is gaining increasing research attention, and while such figures (estimating local water consumption by shale gas operations) are still relatively rare, they are likely to become increasingly common, and will allow for a more nuanced view of the pressures that unconventional gas extraction exerts on local water resources.

Finally, the large amounts of water required by shale gas operations can become a hindrance to the gas industry itself, as the IEA warned in its 2012 World Energy Outlook. Water availability constraints can challenge the reliability of existing shale gas operations (or any energy projects, for that matter), and the viability of proposed new projects, by imposing additional costs for necessary adaptive measures (IEA, 2012). Water supply restrictions are inhibiting shale gas industry expansion in a number of existing plays in China (especially since Chinese shale seems to require more water to frack than the US formations), and in Mexico, which suffered a severe drought in 2012 and does not seem to have sufficient water supplies to expand its fracking efforts, and even in the south-east of England, where extreme weather events (both droughts and floods) have impacted water delivery systems and held back the industry (Hoffman, Olsson, & Lindstrom, 2014). Water scarcity is also a critical issue in South Africa, and the likely sources of water to supply shale gas operations in the Karoo have yet to be identified.

Even the US shale industry is not immune to setbacks caused by water supply shortages, as shown by the case of Pennsylvania, which is generally considered a relatively water-rich state. In 2011, 13 previously approved water withdrawal permits in Pennsylvania's Susquehanna River Basin were temporarily suspended owing to low stream levels; 11 of these permits were for natural gas projects (Susquehanna River Basin Commission 2011, cited in (Donnelly & Cooley, 2012).

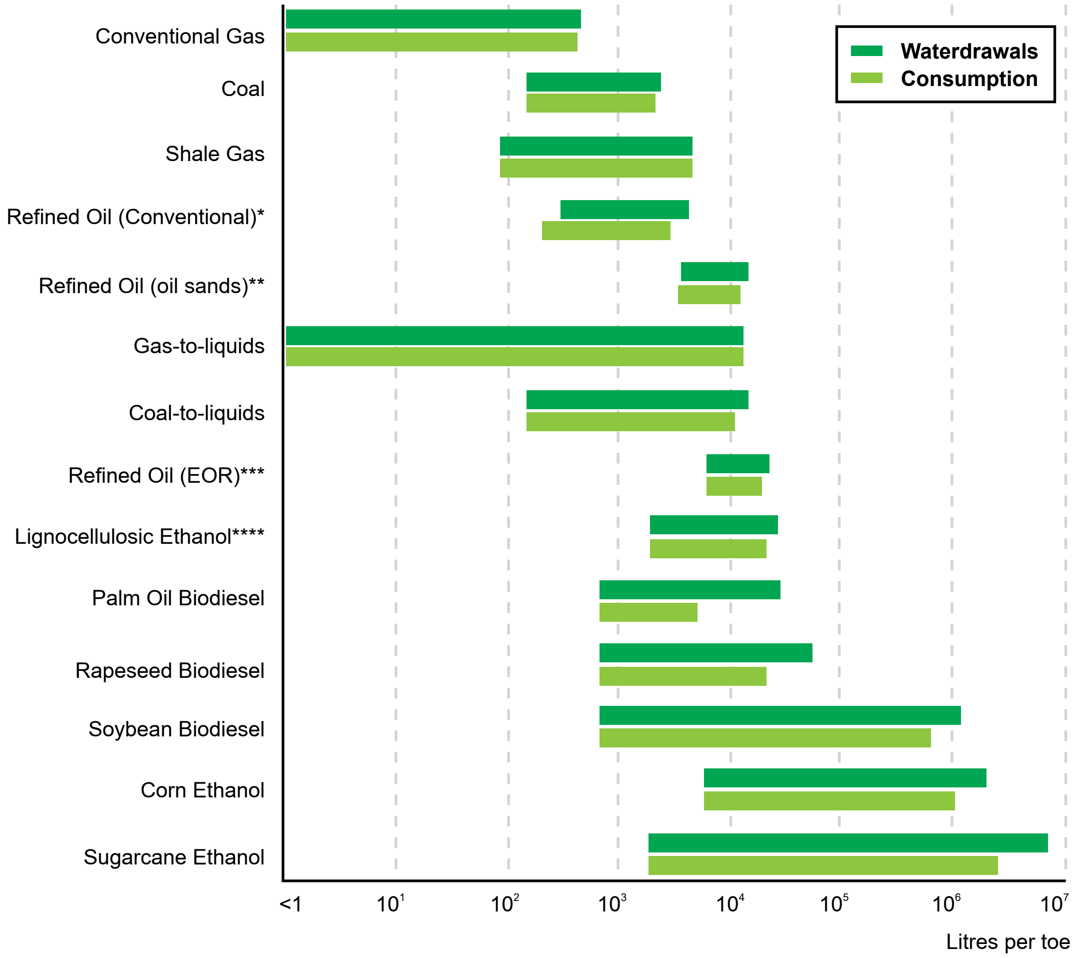
Besides the negative loop whereby water scarcity, whether created or just exacerbated by shale gas developments, negatively affects gas operations, these cases also seem to indicate that gas companies are often willing to take on water supply risks. The misconception of water availability is fuelled by the fact that water is often made available free of charge to the gas producers, or at a nominal fee payable to local entities, which does not reflect the water's actual value or scarcity (Hoffman, Olsson, & Lindstrom, 2014).[8] Clearly, water scarcity and the resulting competition for water resources call for greater integration of energy and water policies to ensure fair and efficient allocation of this scarce resource to the energy sector (IEA, 2012).

[8] For instance, in the Barnett Shale in Texas, drillers paid only 0.06 cents/m3 in 2009 (Hoffman, 2014).

3.2 SHALE GAS' WATER DEMAND RELATIVE TO OTHER ENERGY SOURCES

Shale gas also does not appear to be an extreme water user when compared to other energy sources. Although water scarcity concerns are often directed at shale gas operations, Figure 3 shows that production of other hydrocarbon fuels, especially the synthetic liquid fuels, such as gas-to-liquids (GtL) and coal-to-liquids (CtL), can be similarly or even more water-intensive. First-generation biofuels based on irrigated food crops can be significantly more water-intensive.

Figure 3 Water withdrawals and consumption for the production of various fuels



Sources: Schornagel (2012); US DOE (2006); Gleick (1994), cited in (IEA, 2012)

** The minimum is for primary recovery; the maximum is for secondary recovery. ** The minimum is for in situ production; the maximum is for surface mining. *** EOR = enhanced oil recovery, includes CO2 injection, steam injection and alkaline injection and in-situ combustion. **** Excludes water use for crop residues allocated to food production.*

Notes: Ranges shown are for source-to-carrier primary energy production, which includes withdrawals and consumption for extraction, processing and transport. Water use for biofuels production varies considerably owing to irrigation need differences among regions and crops; the minimum for each crop represents non-irrigated crops whose only water requirements are for processing into fuels.

If electricity generation is added to the comparison, it will be noted that for fossil fuel and nuclear fuels, the power plant's cooling-water needs are far greater than the water used to produce the fuel. In this case, electricity produced from shale gas scores better than most other fossil fuels and nuclear energy. Although the amounts of water withdrawn and consumed range greatly depending on the technologies used, a natural gas combined cycle (NGCC) plant consumes half to one-third of the water that a nuclear or pulverised coal power plant does, which is attributable to the higher energy content per carbon atom of methane as well as the greater efficiency of the combined cycle plant (Jackson, et al., 2014). The relative difference diminishes or disappears for dry-cooled power plants.

Important distinction between other energy sources that can be as - or even more - water-intensive than shale gas, is that if water availability is an issue in a certain area, they need not be produced there. For instance, sugarcane for ethanol will never be grown in the Karoo, because setting up the necessary irrigation scheme would be prohibitively expensive. Shale gas production, on the other hand, has to take place where the resource is, regardless of water availability. This is why an increasing number of authors caution that shale gas development could lead to potential water shortages in water-stressed areas (Hoffman, Olsson, & Lindstrom, 2014; Freyman, 2014; Vengosh, Jackson, Warner, Darrah, & Kondash, 2014).

3.3 ESTIMATES OF WATER DEMAND FROM SHALE GAS OPERATIONS

As tempting as it may be, an ex-ante estimation of water demand of shale gas operations is subject to several uncertainties. The water requirements for shale gas wells depend on the following factors (IEA, 2012; Freyman, 2014):

- the well depth,
- gas recovery rates,
- the number of fracturing stages,
- the amount of flowback water and produced water, and
- the flowback recycling rate.

Concerning water demand by shale gas operations, it is probably more accurate to distinguish between *external water demand* (demand for water sourced *outside* of the shale gas extraction operation), which may or may not be the same as *total water demand,* depending on the amount of flowback water and produced water, and their recycling rates. The more recycled flowback water and produced water a well operator uses, the smaller the *external water demand* will be, compared to the total water demand.

Factors affecting total water demand vary across shale plays, between operators and even from well to well, making any comparisons extremely difficult. Keeping this in mind, Table 2 below summarises some water consumption estimates of shale gas wells available in the literature.

Table 2 Estimates of water demand per shale gas well per fracking event

SOURCE	AMOUNT OF WATER PER WELL	NOTES
DMR, 2012	24 million litres	1.6 million litres per fracking stage x 15 stages; average, not related to a specific shale play
Clark, C., Burnham, A., Harto, C., & Horner, R., 2013	10–22 million litres	Of which 0.8–1.2 million litres for drilling and 8.7–20.8 million litres for fracking
Lutz, Lewis, A.N., & Doyle, M. W., 2013	11.5–19 million litres	In the Marcellus shale, Pennsylvania
Freyman, 2014	9.5 million litres	Average across all US shale plays
Slingerland, Rothengatter, van der Veen, Bolscher, & Rademaekers, K., 2014	15–20 million litres	Average, not related to a specific shale play
US DoE cited in Hansen, Mulvaney, D. , & Betcher, M., 2013	11–19 million litres	Average, across all US shale plays
De Wit, 2011	10–20 million litres	Average, not related to a specific shale play
Jackson, et al., 2014	8–20 million litres	Across all US shale plays

As the figures in Table 2 show, most shale gas wells seem to require water volumes in the order of 10–20 million litres per well per fracking event. These figures are primarily based on experience from North America, especially the US, where shale rock is often found in lower-lying geological strata, sometimes as shallow as 500m below ground level. This is unlikely to be the case in the Karoo, where most of the shale rock is found at depths of about 2,500m, which will require much deeper drilling and, therefore, more water. On the other hand, well depth is only one of the several parameters that affect water demand by shale gas operators, and can be compensated by shale rock that is easier to fracture and other factors.

Considering that there is as yet no experience with shale gas in the Karoo, there are also no reliable estimates on possible water use by shale gas operations there. Companies that have applied for exploration licenses have made some preliminary estimates on their water requirements. Shell for instance, breaks down its possible water requirements for a well with a typical depth of 2,500m and a diameter of 100cm as follows:

- 1–2 million litres of water for the vertical borehole (mainly for drilling mud).
- In case the horizontal well finds shale rock, there is lateral drilling. The lateral borehole used to typically extend for about 500m–1,500m, but rapid technological development is now making horizontal well sections of 3,000m–4,000m (depending on geology) a possibility. The length of the well's horizontal section defines the number of fracking stages, which are usually 10 or more. Horizontal drilling and fracking are expected to require another 6–12 million litres of water.
- In summary, *dry wells* are expected to use the 1–2 million litres needed for drilling, while *production* wells are expected to use between 7–14 million litres of water[9] (if no re-fracking needs to take place over the well's lifetime).

It is also important to note that all the figures above refer to a single hydraulic fracturing operation (at a well). An increasing number of wells are being re-fractured every three to five years to maintain their production flow over their production life of 20–40 years (Hoffman, Olsson, & Lindstrom, 2014). As re-fracturing increases, the water intensity of extraction rises, with the total volume of water used over the lifetime of such wells being several times the volume required for one fracking operation (Jackson, et al., 2014). Re-fracturing also increases the relative water intensity of shale gas compared to other energy sources, making it considerably more water-intensive (on an energy unit produced basis) than coal; however, even in this case, shale gas-based electricity is still less water-intensive compared to most coal-based electricity (Jackson, et al., 2014).

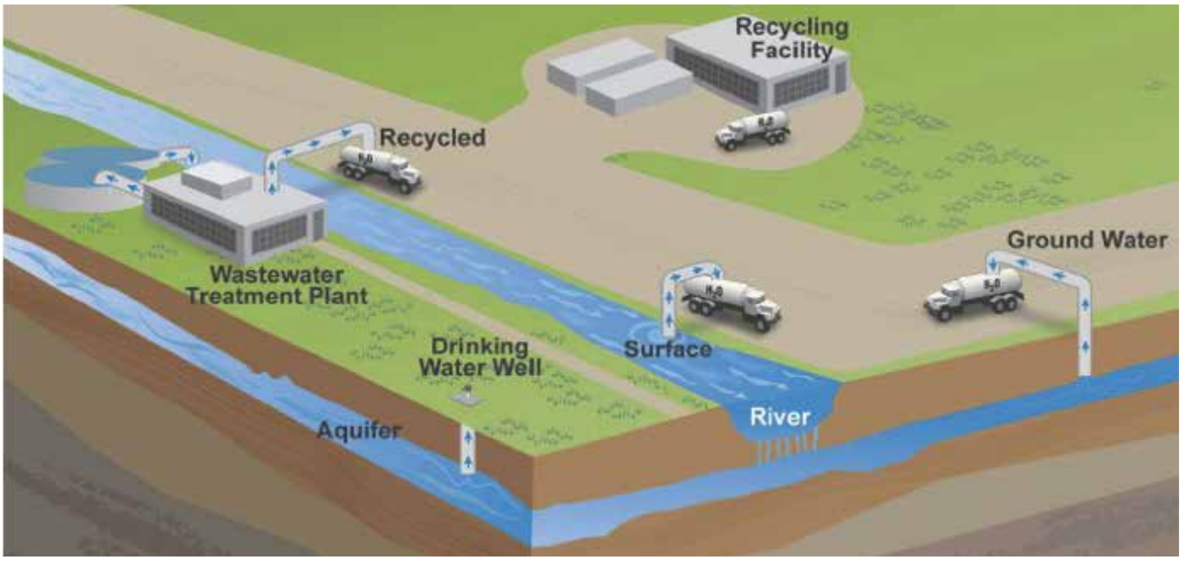
As mentioned, freshwater is not the only possible water source used in shale gas operations. The industry is constantly innovating so as to allow usage of other water sources, as is discussed next.

3.4 POSSIBLE WATER SOURCES FOR SHALE GAS OPERATIONS

Water for shale gas operations can be obtained from a variety of sources, most commonly from: surface water, groundwater, or water recycling facilities, as shown in Picture 5 (Freyman, 2014). The actual extraction rate from any of these sources will depend on the resource size and the competing uses at the local level.

[9] Shell public information.

Picture 5 Water sources for hydraulic fracturing operations



Source: (US EPA, 2012)

The first and generally least expensive source considered is surface water, where available. Widely distributed surface water bodies are generally not large, and large-volume sourcing from numerous small surface waters may reduce in-stream flow rates and may degrade local environmental quality (Montgomery & Smith, M. B., 2010).

In many countries, groundwater resources are generally less regulated than surface water, which makes them more attractive to gas companies, but also puts them at higher risk of over-extraction (Freyman, 2014). Fortunately, this is not the case in South Africa, where groundwater and surface water are equally regulated under the National Water Act. Since groundwater supplies are often interconnected with surface water bodies, their over-usage can impact surface water resources and potentially lead to land subsiding (Freyman, 2014). While groundwater supplies do get replenished by precipitation, in dry regions, this process may take decades if not centuries or even longer (Freyman, 2014).

Groundwater withdrawals exceeding natural re-charge rates can potentially compromise water availability in terms of quantity as well as quality. A decrease in water storage in aquifers can potentially mobilise contaminants or can allow infiltration of lower-quality water from the land surface or adjacent formations (US EPA, 2012). Sustained groundwater pumping could also decrease groundwater discharge to streams, potentially affecting surface water quality, especially in drought-prone regions (US EPA, 2012).

Another possible water source for shale gas operations is brackish or even brine water found deeper underground[10]. Brackish groundwater usually has salinity levels in the range of 1,000mg/l to 30,000mg/litre, which is generally compatible with most frack water components that perform satisfactorily in the presence of high total dissolved solids (TDS) (Mauter, et al., 2014). Recent technology developments apparently now even allow operators to use brines (water with very high salinity levels – in excess of 200,000mg/litre TDS)[11].

Improved salinity tolerance of drilling and fracking equipment broadens the spectrum of water sources that well operators can use – including partially treated wastewater, municipal water or industrial water (including flowback water and produced water from fracked wells), or brine water from deep aquifers[12]. This is motivating gas companies to drill for gas and deep water aquifers at the same time, owing to potential logistical synergies[13].

[10] Brackish water is water containing salt concentrations between 0.05 percent and 3.5 percent, while brine water contains salt concentrations exceeding 5 percent (with saline water being in-between with salt concentrations of 3 percent to 5 percent).
[11] Shell public information.
[12] The fact that flowback, produced water and deep water aquifers are not included in the EPA's representation of water sources for hydraulic fracturing operations from 2012 speaks of the recentness of this development.
[13] Shell public information.

Where flowback recycling is not viable, the use of municipal wastewater is another interesting option. It has the double benefit of relieving competitive pressures on local water resources while saving energy, because the municipality now doesn't have to treat the water to a high standard (Freyman, 2014). On the other hand, however, municipal wastewater diverted for hydraulic fracturing use means less water is returned to local surface water bodies, potentially compromising the hydrogeological cycle (Freyman, 2014).

While use of high-salinity water can reduce the demand for fresh water from shale gas operations, fresh water is still required in high quantities during the drilling stage (in the order of few million litres), since salt water is more likely to damage the drilling equipment (Accenture, 2012). Fresh water is also still required for diluting recycled flowback water and produced water and in cases where flowback and produced water rates are not high. In the Marcellus shale area, re-using even 100 per cent of the flowback and produced water for the hydraulic fracturing of new wells has only reduced the volume of fresh water per well by some 10 to 30 per cent (Mantell, 2011).

In the future, demand for fresh water could be further reduced by the use of acid main drainage (AMD) effluent as carrier fluid in hydraulic fracturing in combination with recycled flowback water and produced water. This has the double advantage of further reducing the pressure on freshwater resources and lowering the costs of treating and disposing of acid mine water. Initial research suggests that blending acid mine water and recycled flowback water and produced water could be an effective management practice for both remediation of the often high NORM present in produced water and beneficial utilisation of AMD that otherwise risks contaminating waterways (Knodash, Warner, Lahav, & Vengish, 2014). While this is still at an experimental stage and its practical applicability at scale is likely to take several more years to be fully understood, it is an option South Africa should follow closely considering its substantial AMD problem.

Lastly, LPG, liquid nitrogen, liquid CO2, diesel and other liquid hydrocarbons can theoretically all be used for fracturing; however, using any of them as carrier fluid would make shale gas recovery exceedingly expensive, in addition to - in some cases - carrying all the risks associated with handling flammable gases.

While concerns about the availability of fresh water in shale gas-producing areas is legitimate, it needs to be acknowledged that the industry is investing significantly in R&D to find technical solutions that will continue to reduce the water demands of hydraulic fracturing (Freyman, 2014). However, until such efforts bear fruit, it must be noted that no single water source will meet all the water requirements of shale gas operations in a region, and fresh water will continue to be an important input into the fracturing operation, in combination with other sources described above[14].

3.5 CONTEXTUALISING SHALE GAS WATER DEMAND IN SOUTH AFRICA AND THE KAROO

A number of authors have cautioned that extraction of water resources for high-volume hydraulic fracturing could conflict with other (existing and future) water uses and could even cause water shortages, particularly in water-scarce areas (Vengosh, Jackson, Warner, Darrah, & Kondash, 2014). This is a key concern for a semi-arid country such as South Africa, where water security is already a concern, especially in the drier regions such as the Karoo (DMR, 2012).

[14] Regardless of the source, moving around the large quantities of water required for hydraulic fracturing is a major logistical exercise. A single shale gas well usually requires in the order of 1,000 truck trips over its lifetime. Of these, trucking in the water required for the drilling and as carrier fluid accounts for more than half of the trips (Halliburton, 2014). However, as fields develop, generally there is a greater use of pipelines and pumps to move water, rather than trucks.

In South Africa, nearly 80 percent of water supply comes from surface water (with the balance coming from groundwater and return flows from major urban and industrial developments) (DWA, 2004), and more than 97 per cent of the available surface water has already been licensed for existing uses (at 98 percent assurance of supply), which clearly indicates that competition for the country's scarce water resources is already extreme. In fact, 11 of the 19 water management areas in South Africa, local water demand already exceeds the local reliable yield (at 98 percent of assurance of supply) (DWA, 2004). The situation is similar in the target shale gas exploration areas with groundwater accounting for over 80 percent of available water resources in the water management areas spanning across the Karoo (DWA, 2004), with most of it fully allocated. For instance, the Gariep (formerly Orange) catchment has been proposed as a possible surface water source, however the formerly upper Orange catchment area is close to being fully allocated, and the formerly lower Orange catchment is already fully allocated (DWA, 2014). It is estimated, that by 2025, the Lower Orange water management area, which encompasses the biggest shale gas prospecting area will require water imports almost twice the current local reliable yield to meet expected demand, and this without taking into consideration possible shale gas developments in the area.

Currently under-utilised water sources such as dams owned by some farmers, may seem to be an obvious choice, however, they are a critical buffer in periods of drought and may well be unable to provide this important service if tied into a long-term water supply agreement with gas companies.

With regard to local groundwater resources, it is important to note that they take long to re-charge. While calculated water requirements by shale gas wells may fall within current estimated groundwater re-charge on an annual scale, in semi-arid areas, average annual values do not reflect reality, as full re-charge is not reach every year. This means that pumping significant amounts of water over a short period of time (i.e. 1 year) could cause the water table to decline for a prolonged period of time before recovering during a re-charge event of extreme rainfall. As the water table falls, shallow farm boreholes and springs, rivers and/or wetlands linked to groundwater can be deprived of their water source.

Zooming down to local level, thirty-three towns within the shale gas prospecting areas are solely dependent on groundwater for their domestic supply, and a further six are dependent on conjunctive use of surface water and groundwater. Seventeen of these towns currently have inadequate water supply in relation to their demand (towns marked in red in Picture 6), and a further 20 towns are projected to experience water supply shortages within the next 10 years. Additional groundwater, or alternative sources such as treated effluent, will be required to meet future demands.

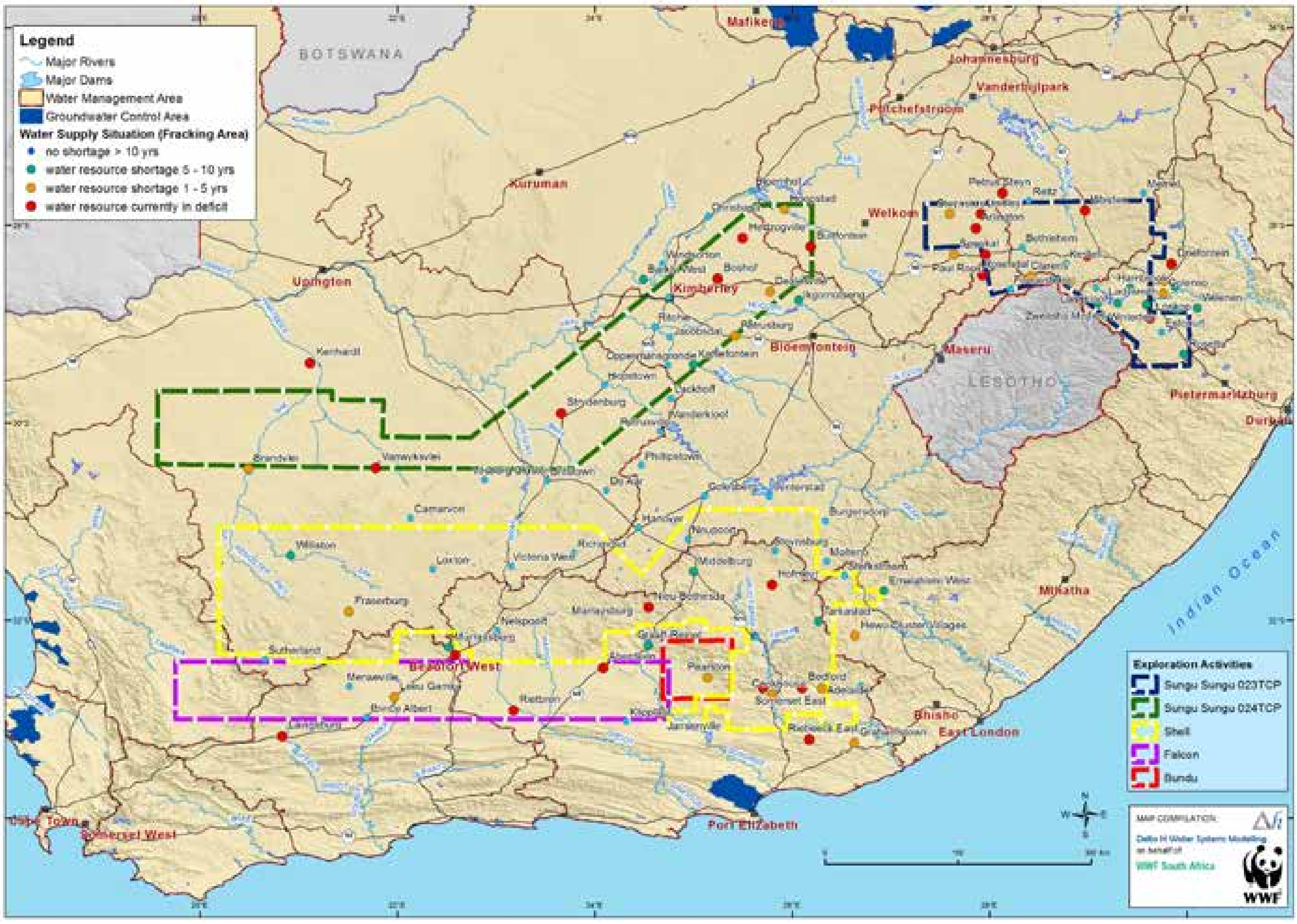
While it is not yet possible to predict the amount of water that will be required by the gas industry in South Africa, it is nonetheless interesting to compare the average water demand of a single well with other uses, based on current water usage in the Karoo. Taking the DMR (2012) estimate of 24 million litres (or 24,000m3) for a single fracking event and comparing it to other uses shows that the same amount of water could supply:

- Fraserberg, a town within the Shell license area with a population of around 2,400 people, and an average daily water demand of around 438m^3/day for more than 50 days[15].
- Loxton (a hamlet within the Shell license area with a population of 600 people, and an average daily water demand of around 118m^3/day) for more than six months.
- All the small towns in the Shell license area for one to two days.
- The irrigation requirement for approximately 3ha of lucerne for one year or an average sheep farmer's water requirement for almost two years (DMR, 2012).

[15] Calculated from the DWA's Development of Reconciliation Strategies for All Towns in the Central and Southern Regions, all strategies are available online from the DWA's Integrated Water Resources Planning document portal (https://www6.dwa.gov.za/DocPortal/).

Besides surface and groundwater sources, deep (>1km) brackish groundwater for exclusive use by gas production operations and recycled wastewater can also be viable water sources for shale gas operations. The first option is already being considered by gas companies looking to develop South Africa's shale gas[16]. Recycled wastewater from shale gas operations is also an increasingly important water source, however, it is as yet not possible to predict its availability in the South African context, since the amount of flowback water and produced water that can be re-used varies widely, even between wells, let alone shale plays. What is almost certain is that this source alone would not be able to meet the water demands of shale gas operations, and will have to be supplemented by other sources.

Picture 6 Domestic water supply situation for SA towns within shale gas prospecting areas



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16 Shell public information

4. WASTEWATER ISSUES

Key massages:

- *The generation of wastewater is an inevitable consequence of shale gas operations. The actual amounts vary widely across wells and plays, and no good estimate on the amount of wastewater likely to be produced in the Karoo can be offered at this stage. However, it is likely to be in the order of millions of litres per well.*

- *Despite requiring significantly more water, shale gas wells generally produce much less wastewater per unit of gas produced than conventional gas wells. On the other hand, the generally higher concentration of shale wells in a region can lead to high amounts of wastewater generation, overwhelming existing local wastewater management capabilities.*

- *The shale gas industry employs three main wastewater management strategies: disposal by injection into a deep underground well, treatment at a centralised wastewater treatment facility (public, or privately owned) and eventual release into the environment or partial treatment and re-use in future fracking operations.*

- *Recycling of fracking fluid is becoming increasingly relevant owing to both cost and environmental considerations, and is made possible by recent technological advances that allow shale gas equipment to tolerate water with very high salinity levels.*

- *The high variability of wastewater quality across shale plays restricts the transferability of experience gained in wastewater management elsewhere. Lack of any sort of experience of the management of wastewater produced by natural gas extraction in South Africa is likely to exacerbate the risks associated with wastewater management in the Karoo.*

4.1 WASTEWATER QUANTITY AND QUALITY

As mentioned in Section 1.3, shale gas production generates large quantities of wastewater, for which few accurate quantification attempts exist. Unlike other environmental concerns, the occurrence of which is subject to various degrees of uncertainty, a certain amount of wastewater is an unavoidable aspect of shale gas production.

The amounts of wastewater produced by shale gas operations can vary widely, depending mainly on the geology of the drilled area. Table 3 below shows the amount of wastewater from shale gas operations documented in the literature to date, attesting to this variability.

Table 3 Wastewater generation of shale gas wells reported in the literature

STUDY	% OF RETURNED WATER	AMOUNT OF WASTEWATER PER WELL	NOTES
DMR, 2012	<50% of frack fluid	Up to 12 million litres	
Lutz, Lewis, A.N., & Doyle, M. W., 2013	10%–70% of frack fluid	5.2 million litres on average, (12% drilling fluids, 32% flowback and 55% produced water/ brine)	Study did not differentiate between vertical and horizontal wells, so this can probably be considered a conservative estimate
API, 2010	10%–70%		
Hansen, Mulvaney, D. & Betcher, M., 2013	6% and 8% of water injected		In Pennsylvania and West Virginia, respectively
Mantell, 2011	10%–300%		Produced water over the lifetime of a well (does not distinguish between flowback water and produced water)
De Wit, 2011	40% of injected fluid		On average
Vengosh, Jackson, Warner, Darrah, & Knodash, 2014a		3.5–7.2 million litres	
Jackson, et al., 2014 based on other sources		5–12 million litres	Across all US shale plays; excludes plays with highest water demand per well

As is evident from this table, most estimates do not differentiate wastewater streams, making it difficult to quantify the amount of flowback water vs produced water (noting of course that any cut-off point between the two is a somewhat arbitrary marker). This is due to insufficient reporting requirements in the US. As a result, most studies likely underestimate the total wastewater volumes generated (Lutz, Lewis, & Doyle, 2013).

In response to the lack of clarity on the different wastewater flows from shale gas operations, Lutz et al. (2013) collected data from 2,189 shale gas wells operating on the Marcellus shale play in Pennsylvania and contrasted them with conventional gas wells. Their results are presented in Table 4. These figures must, however, be interpreted with some caution, precisely because operators must often arbitrarily define the distinction between wastewater types (Lutz, Lewis, & Doyle, 2013).

Table 4 Mean estimates and ranges of wastewater and gas production of conventional and shale gas wells in Pennsylvania

WASTEWATER CATEGORY		CONVENTIONAL GAS WELL	SHALE GAS WELL
Drilling waste (million litres per well)	Average	0.116	0.654
	Range	0.098–0.141	0.556–0.767
Flowback (million litres per well)	Average	0.107	1.683
	Range	0.102–0.113	1.537–1.843
Brine (million litres per well)	Average	0.291	2.874
	Range	0.291 (0.093–0.112 million litres in year 1, declining to 0.038–0.045 million litres in year 4)	2.874 (1.231–1.511 million litres in year 1, declining to 0.116–0.189 million in year 4)
Total wastewater (million litres per well)	Average	0.514	5.211
Gas production (million litres per well)	Average	1,050.1	30,038.7
Gas production (million litres per well)	Average	13.4	4.8

Source: (Lutz, Lewis, A.N., & Doyle, M. W., 2013)

Notes: *Figures for drilling waste and flowback are per well, while figures for brine and gas production are for the first four years of well operation.*

The six times higher amount of drilling waste of an average Marcellus shale well compared to the average conventional well is likely the result of more extensive drilling associated with longer wellbores (Lutz, Lewis, & Doyle, 2013). Shale wells also generate a much higher amount of flowback compared to conventional wells, amounting to some 8 to 15 per cent of the 11.5 to 19 million litres of fracking fluid typically injected into each well during the completion phase. Additional flowback is usually recovered over the gas production phase, although this wastewater is typically reported as brine (Lutz, Lewis, & Doyle, 2013). Shale gas wells also produce on average almost 10 times the amount of brine compared to conventional wells. Notably, brine accounted for the majority of the total wastewater generated for both well types, indicating that the vast majority of the total pollution load produced by Marcellus shale gas wells actually derives from the sub-surface and often has high concentrations of a variety of inorganic ions, metals, organics and radioactive materials (Haluszczak, Rose, & Kump, 2013). This is important to note, considering that the concerns related to potential negative environmental effects from shale gas operations have to date mainly focused on the chemicals present in the fracturing fluid. Flowback in fact accounted for only 32.3 per cent of the total wastewater generated by shale gas wells in the Marcellus region (Lutz, Lewis, & Doyle, 2013).

While shale gas wells on the Marcellus play produce on average much larger quantities of wastewater, they also produced much more gas. Thus, even though the total amount of wastewater produced by an average shale gas well is of an order of magnitude large than that of a conventional well (5.211 million litres, as opposed to 0.514 million litres per conventional well), the significantly larger gas output of shale gas wells bring the ratio of wastewater per unit of gas produced in favour of shale gas wells, which produce on average only some 35 per cent of the amount of wastewater per unit of gas recovered when compared to conventional wells (Lutz, Lewis, & Doyle, 2013)[17].

Another important lesson from the development of the Marcellus shale play is that, despite a relatively favourable wastewater to gas production ratio, the sheer size of the development (i.e. the number of wells) and the cumulative volume of wastewater generated in the region is growing dramatically. Because of the longer history of conventional gas operations in the region, at the onset of the shale gas boom, Pennsylvania already had much experience and infrastructure needed to provide the necessary treatment and disposal of wastewater from gas operations. Despite this, the existing wastewater treatment capacity is becoming overwhelmed by the fast-growing volumes of wastewater (Lutz, Lewis, & Doyle, 2013). The situation in the Karoo is likely to become unsustainable at much lower levels of wastewater production, because the necessary infrastructure and experience is not present in the region.

To predict wastewater volumes generated by shale gas wells in a region, the following needs to be known:

- the number of wells drilled and placed into production;
- the rate of decline in gas production over the long term;
- the amount of flowback and produced water generated by each well, which in turn depends on the geology of the area being drilled.

Such information is currently not available for the Karoo.

Not only the quantity but also the quality of the wastewater has important implications for its management. One of the most important parameters of wastewater is the total dissolved solids (TDS) levels. As Table 5 shows, this can vary significantly between shale plays.

[17] These results are specific for the Marcellus play and should not be generalised across other plays without a similar analysis being undertaken.

Table 5 Average TDS levels in flowback and produced water across different shale plays

SHALE PLAY	AVERAGE TDS FOUND IN FLOWBACK AND PRODUCED WATER
Marcellus	20,000–100,000
Bakken	150,000–300,000
Eagle Ford	15,000–55,000
Permian	20,000–300,000
DJ Basin	20,000–65,000

Source: (Halliburton, 2014)

TDS level is one of the most important determinants of wastewater treatment options. Large variability in TDS levels across plays reduces the transferability of wastewater management experience from one play to the next.

4.2 MANAGEMENT AND DISPOSAL OPTIONS FOR FRACKING WASTEWATER

Fracking wastewater (flowback water and produced water) has high concentrations of a number of pollutants. The wastewater's composition and highly variable quantity pose a significant challenge for effective wastewater treatment and disposal (Veil, Puder, Elcock, & Redweik Jr, 2014; Krupnick, 2013), which is an important part of operational costs. In the US, wastewater management costs incurred by the industry exceed US50 billion per year (Halliburton, 2014).

As shown by Table 3, the wastewater production across shale plays varies widely, and so do wastewater management practices. Broadly speaking, there are three options for the handling of wastewater (Krupnick, 2013):

- injection into a deep disposal well (also known as underground injection);
- treatment at a centralised wastewater treatment facility (public, or privately owned) and eventual release into the environment;
- treatment for recycling and re-use as fracking injection fluid (onsite, or transport to a fracking operation that requires injection water).

When due consideration is given to each of these options, it becomes clear that each has distinct advantages and disadvantages.

4.2.1 UNDERGROUND INJECTION

In the US, most wastewater generated by unconventional gas and oil operations is disposed of by means of underground injection (Harkness, Dwyer, Warner, Parker, & Mitch, 2014). However, geological formations that allow for this form of disposal are not equally geographically distributed. Proximity of fault systems preclude this option in some US states, making it illegal (for instance in Pennsylvania) (Mauter, 2015). This causes well operators located in those states to incur large wastewater storage and transportation costs between gas extraction areas and wastewater disposal sites located further afield (Mauter, 2015).

Another major concern associated with the disposal of fracking wastewater in deep injection wells is the possibility of triggering small earthquakes (Ellsworth, 2013). This arises from the lubricating effect of the pressurised injected water on underground geological faults. According to the US Geological Survey (USGS), such injection "...has been linked to a six-fold jump in quakes in the central US from 2000 to 2011" (Hoffman, Olsson, & Lindstrom, 2014). As a result of this increased seismic activity in the mid-US, and despite denials of a possible linkage between fracking and earthquakes by the American Petroleum Association (Shale Energy: 10 Points Everyone Should Know, API, October 2013), state officials from Oklahoma, Ohio, Texas and Kansas have recently initiated efforts to coordinate and strengthen regulations and permitting standards for fracking operations.

The Karoo region is generally deemed unsuitable for disposal by underground injection owing to limited permeability at depth and its many sub-surface faults. In fact, the Department of Water and Sanitation has indicated that injection of wastewater will not be permitted in South Africa[18]. The unavailability of underground disposal, as the simplest solution, will force gas companies to consider alternatives.

All other wastewater management and disposal options discussed below are likely to be costlier and involve significantly more logistical effort than permanent storage in underground wells. In the Marcellus shale play, where underground injection is not an option and operators have to find alternative wastewater management options, the average waste transport distance in 2011 was greater than 100 miles (Mauter, Palmer, Tang, & Behrer, 2013), while the average in the Barnett play, where underground well injection is the predominant means of disposal, the average waste transport distance was only 10 miles (Prozzi, Grebenschikov, & Bannarjee, 2011). The difference in associated transport costs is clear.

4.2.2 TREATMENT AT MUNICIPAL WASTEWATER TREATMENT PLANTS

Any other form of disposal other than underground injection will require a certain amount of treatment. In theory, this can be done in municipal wastewater plants, existing industrial treatment plants, or plants that are privately owned by gas companies for the specific purpose of treating fracking wastewater.

In practice, municipal plants have proved an unfeasible option, mainly because they are not designed to treat wastewater with high TDS levels, and if they were to treat such water, the majority of such TDS would pass into the discharging water body (Ferrar, Michanowicz, Christen, Mulcahy, Malone, & Sharma, 2013). It is also very likely that both municipal and existing industrial plants would quickly become overloaded, as has happened in Pennsylvania (Lutz, Lewis, & Doyle, 2013).

[18] Anet Muir, DWA, speaking at a symposium about fracking, 18-19 August 2014, CSIR, Pretoria

4.2.3 RECYCLING AND RE-USE

This wastewater management option has been made possible by technological advances that have increased the salinity tolerance of equipment used in shale gas operations (now in excess of 300,000ppm TDS)[19] (Halliburton, 2014), and has in some plays been facilitated by high wastewater disposal costs. Marcellus shale gas operators without easy access to underground injection wells collectively re-use some 90 per cent of their wells' wastewater (Maloney & Yoxtheimer, D. A, 2012; Mauter, et al., 2014), with some companies recycling up to 100 per cent (Freyman, 2014).

Wastewater is typically stored in a storage tank at the surface and used directly, or after dilution or pre-treatment (Vidic, Brantley, Vandenbossche, Yoxtheimer, & Abad, 2013). The recycling of fracking wastewater is driven by both economics and sustainability concerns. It offers several important cost savings benefits, namely:

- It reduces the cost of acquiring fresh water (with this aspect gaining importance in proportion to the distance the water must travel to reach the well);
- It significantly reduces the amount of energy required to treat the wastewater, thereby lowering the costs, compared to a full set of treatments to bring the water up to the quality required for surface discharge (most crucially, this water doesn't need to be desalinated);
- It reduces the amount of wastewater that needs to be trucked away from the well site, which represents huge energy costs for gas companies[20].

If treatment is required, flowback water and produced water[21] are usually partially treated onsite in privately owned (by shale gas operators), modular, transportable wastewater treatment plants[22], which further lowers total wastewater treatment costs by eliminating the transport costs of trucking wastewater to a centralised wastewater treatment plant.

Primary treatment typically involves the removal of suspended solids, oil and grease, bacteria and organics (solvable and insolvable). Most equipment needed for this is well established; it has been used by the natural gas industry for decades, and has now been adapted for use by shale gas producers[23]. The residual waste from an onsite treatment plant is collected in evaporation ponds, and the leftover solid waste is finally disposed of in hazardous waste landfills[24]. This is not a particularly popular option owing to the risk of surface spills as well as air pollution concerns, and in fact will not be allowed in South Africa (DMR, 2015).

While very recent technical advances now allow high-salinity water or brine (in excess of 300,000ppm TDS) to constitute even up to 100 per cent of carrier fluid (Halliburton, 2014), most of the time, recycled flowback fluid is still being treated and diluted with fresh water (Hansen et al., 2013). In addition, there are also logistical issues surrounding the timing and transportation of water generated at one well to the next (Lutz, Lewis, & Doyle, 2013).

[19] This is still not enough to allow for flowback recycling in all shale areas. In Williston Basin, North Dakota for instance, TDS levels reach up to 400,000 mg/l (Harkness, Dwyer, Warner, Parker, & Mitch, 2014).

[20] For instance, the wells drilled in 2011 in Pennsylvania alone generated 26 million miles of waste transportation (Mauter, 2015).

[21] Drilling wastewater is normally not recycled, since its treatment costs would be too high (Shell public information).

[22] Personal communication with GE water expert.

[23] Personal communication with GE wastewater expert.

[24] Personal communication with wastewater treatment experts at Miwatek.

A study done by Slingerland et al (2014) suggests that the same 15,000m3 of water can be used for up to three wells, after which it becomes too costly to purify and has to be stored elsewhere, although industry claims there is no limit to how many times produced water can be recycled, especially if diluted with fresh water if need be. Ultimately, the quality of the wastewater, the quantity of available fresh water and the availability and affordability of wastewater management options defines the upper threshold of how much flowback water and produced water will be re-used (Clark, Burnham, Harto, & Horner, 2013). A common mistake observed by experts is for operators to take wastewater quality from one well and extrapolate it to all other wells[25]. Even on the same shale play, there can be very different qualities of produced water, although some commonality typically does exist.

Considering the limited availability of freshwater and unavailability of underground injection as a wastewater disposal option, wastewater recycling and re-use is likely to be an important option in South Africa. While there is no way of knowing how much water will be returned to the surface until the exploration phase is completed, gas companies seem to be planning on recycling most of whatever amount is returned to the surface. Shell, for instance, reportedly aims to recycle 75 per cent of the wastewater (other than the initial 1–2 million litres used during drilling) and to re-use it as carrier fluid in the next wells[26].

Factors that can limit the recycling rate of flowback and produced water are:

- Salinity levels: some formations have salinity levels exceeding 300,000ppm TDS, which are too high to allow for no treatment or simple treatment before re-use (or conversely, would make treatment for re-use too expensive);
- The use of certain chemicals: the most appropriate chemical cocktail to fracture the shale in a specific reservoir might not tolerate high salinity levels[27];
- Production schedule: if flowback and produced water flow rates are low, it might take too long to accumulate sufficient carrier fluid for the fracturing of the next well.

Another fact to be considered is that re-using fracking wastewater for fracturing new wells is a temporary wastewater management solution. As the gas field matures and the rate of hydraulic fracturing decreases, the field becomes a net water producer, because the volume of produced water will exceed the amount of water needed for new hydraulic fracturing operations (Vidic, Brantley, Vandenbossche, Yoxtheimer, & Abad, 2013). When this happens, there will be hundreds of millions of litres of slightly radioactive wastewater that will need to be disposed of[28].

Where underground injection is not an option for final disposal, the remaining wastewater will need to undergo secondary treatment, before it is released into the environment or sold to other users. This is usually done in a centralised treatment plant that processes flowback water and produced water that is no longer needed into water and salt. Centralised plants are usually based on a hub-and-spokes model, whereby a number of well operators reach a joint agreement to build such a plant and supply it from multiple well sites. In Pennsylvania, for instance, companies are known to have raised venture capital to build such commercial treatment plants.[29]

[25] Personal communication with GE wastewater expert.
[26] Shell public information.
[27] Shell public information.
[28] Radium is commonly present in flowback or produced water and is usually incorporated in the solids that form in the wastewater treatment process, which must be handled appropriately and has implications for human health (Vidic, Brantley, Vandenbossche, Yoxtheimer, & Abad, 2013).
[29] Personal communication with GE wastewater expert.

The main challenge at this stage is to remove TDS from the wastewater. A number of technologies are available for this, each with their own set of advantages and shortcomings:

- Thermal technologies: They are usually not as modular and cannot handle high variability in flow and TDS, although they can handle fairly high levels of constant TDS (up to 200,000ppm).

- Membrane technologies: They include reverse osmosis, forward osmosis and membrane distillation. Membrane distillation in particular seems to hold much promise, because it can handle very high salinity levels in brines (up to 300,000ppm of TDS), as opposed to reverse osmosis (which only tolerates up to 35,000ppm of TDS) (Mauter, 2015)

Considering the growing importance of active wastewater management in shale gas operations, innovations in wastewater treatment are focusing on two primary issues: reducing the de-salinisation cost and cleaning up the by-products that could be sold for other purposes[30].

In principle, secondary treatments already offer the possibility to treat the wastewater to drinking-water quality and possibly sell it back to municipalities or allow for surface discharge[31]. However, as experience with acid mine drainage in South Africa has shown, the presence of large waste management challenges close to the end of a resource's productive life can present a significant risk of environmental degradation, since companies try to push back their environmental responsibilities in view of an imminent exit from the area, leaving the state – and, thus, the tax-payers – to foot the bill of a long-term solution.

Finally, it is worth noting that, notwithstanding differences in wastewater qualities, management of wastewater from conventional and unconventional gas resources presents similar challenges, but also – to a certain extent - transferability of learning. This has enabled gas companies in the US to shorten their learning curve on shale gas wastewater management. Not having had any other experience with natural gas production, accumulating the necessary knowledge and expertise for wastewater management from shale gas operations will be yet another challenge for South Africa. Concerning the transferability of knowledge between shale plays, experience has shown that the transferability of experience between regions is very limited; an operator needs to build experience in each play (Mauter, 2015).

Finally, it must be noted that there are risks associated with storage and transport between fracture operations (Mauter, Palmer, Tang, & Behrer, 2013), which need to be properly addressed.

[30] Personal communication with GE wastewater expert.
[31] Shell public information.

5. WATER CONTAMINATION RISKS FROM SHALE GAS OPERATIONS

Key massages:

- *The discussion on water contamination risks from shale gas operations has mainly focused on hydraulic fracturing, while overlooking other aspects of the gas extraction process that represent more significant threats to water resources.*

- *Surface spills of fracking chemicals, inappropriate wastewater disposal and drinking-water contamination through poor well construction are the most often documented threats to water resources posed by shale gas operations to date.*

- *Hydrogeology can cause fluid migration through connection of natural and induced fractures, the fractured area in horizontal wells intersecting existing vertical faults or natural fracture systems or when a shallow section of a new well permits temporary communication between a shallow gas-bearing area and freshwater aquifers. All of these are real possibilities for the Karoo.*

- *Each shale gas extraction area is unique and presents its own set of challenges. The Karoo's hydrogeology is highly complex, which limits the transferability of experience in dealing with issues associated with hydrogeology from other shale plays.*

- *Unequivocally proving a water contamination event (below surface) caused by a shale gas operation represents a great challenge, due to a number of issues:*

    - *Effects or events in the environment adjacent to fracking operations are often evident only sometime after the operations have taken place;*
    - *Lack of baseline information on water quality prior to the commencement of shale gas operations – in this respect South Africa has a unique opportunity to determine the baseline prior to reservoir development;*
    - *Complexity of natural variations in water quality and the related difficulty in differentiating natural from anthropogenic sources of contamination;*
    - *A lack of methods to simultaneously determine the source, timing and mechanism(s) of pollutant migration into shallow aquifers;*
    - *Numerous other variables involved in groundwater contamination studies.*

- *Despite these challenges, a (relatively small) number of contamination events have now been confirmed to date with research suggesting that stray gas contamination is the main threat from shale gas operations' sub-surface activities. There is insufficient evidence to confirm systemic contamination of groundwater by fracking fluid or produced brine.*

5.1 OVERVIEW OF POSSIBLE CONTAMINATION SOURCES

Potential risk of freshwater contamination by shale gas production is one of the most contentious issues in the debate around shale gas development. It is also one that has failed to focus on the real threats, while overstating others. In most public debates and the popular media, hydraulic fracturing was highlighted as the main "villain" of unconventional gas extraction, yet many other aspects of shale gas (and other forms of unconventional gas) operations present greater environmental risks. Thus, while the oil and gas industry's claims that hydraulic fracturing in a properly cased and cemented wellbore is one of the lowest risks for shallow groundwater contamination in the entire well development process (King, 2012) might have some merit, there is no shortage of other contamination pathways that to date have been largely ignored. This section seeks to provide an overview of these, and a discussion of the difficulties of unequivocally proving a contamination event from shale gas operations and the implications for other water users.

A number of authors have documented potential sources of contamination during every stage of the hydraulic fracturing cycle (EPA, 2012; Vengosh, Jackson, Warner, Darrah, & Kondash, 2014; Jackson, et al., 2014; Vidic, Brantley, Vandenbossche, Yoxtheimer, & Abad, 2013; Mauter, et al., 2014). They can be summarised as follows:

- During chemical mixing: release into surface and groundwater through onsite chemical spills and/or leaks;

- During drilling and well completion:
  - Release of hydraulic fracturing fluids to groundwater owing to inadequate well construction or operation;
  - Movement of hydraulic fracturing fluids from the target formation to drinking-water aquifers through local man-made or natural features (e.g. abandoned wells and existing faults);
  - Movement into drinking-water aquifers of natural substances found underground, such as metals or radioactive materials that are mobilised during hydraulic fracturing activities;

- During and after production:
  - Potential contamination of aquifers with fugitive hydrocarbon gases
  - Potential release of flowback water and/or produced water to surface and/or groundwater through spills and/or leaks;

- During wastewater treatment and disposal:
  - Contaminants reaching drinking-water owing to surface water discharge of inadequately treated wastewater;
  - By-products formed at drinking-water treatment facilities by the reaction of hydraulic fracturing contaminants with disinfectants.

For the purposes of this report, these contamination sources can be grouped into those associated with above surface and below surface activities. The following sections briefly discuss each of them separately.

5.2 CONTAMINATION SOURCES ASSOCIATED WITH SUB-SURFACE ACTIVITIES AND PROCESSES

As one would expect, the most contentious contamination sources are those that occur below the surface, where fracturing fluid, natural gas or other contaminants found in the target formation, or on the way to it, could escape through unexpected pathways and cause water contamination. Despite the fact that this source is contested by proponents of shale gas who argue that gas leakages are a rare phenomenon because they are not in the interest of gas producers (as they represent lost revenue) and that these risks can be avoided altogether by following good well construction practices, methane leaks from shale gas wells have been well documented[33].

5.2.1 CONTAMINATION SOURCES ASSOCIATED WITH WELL ENGINEERING

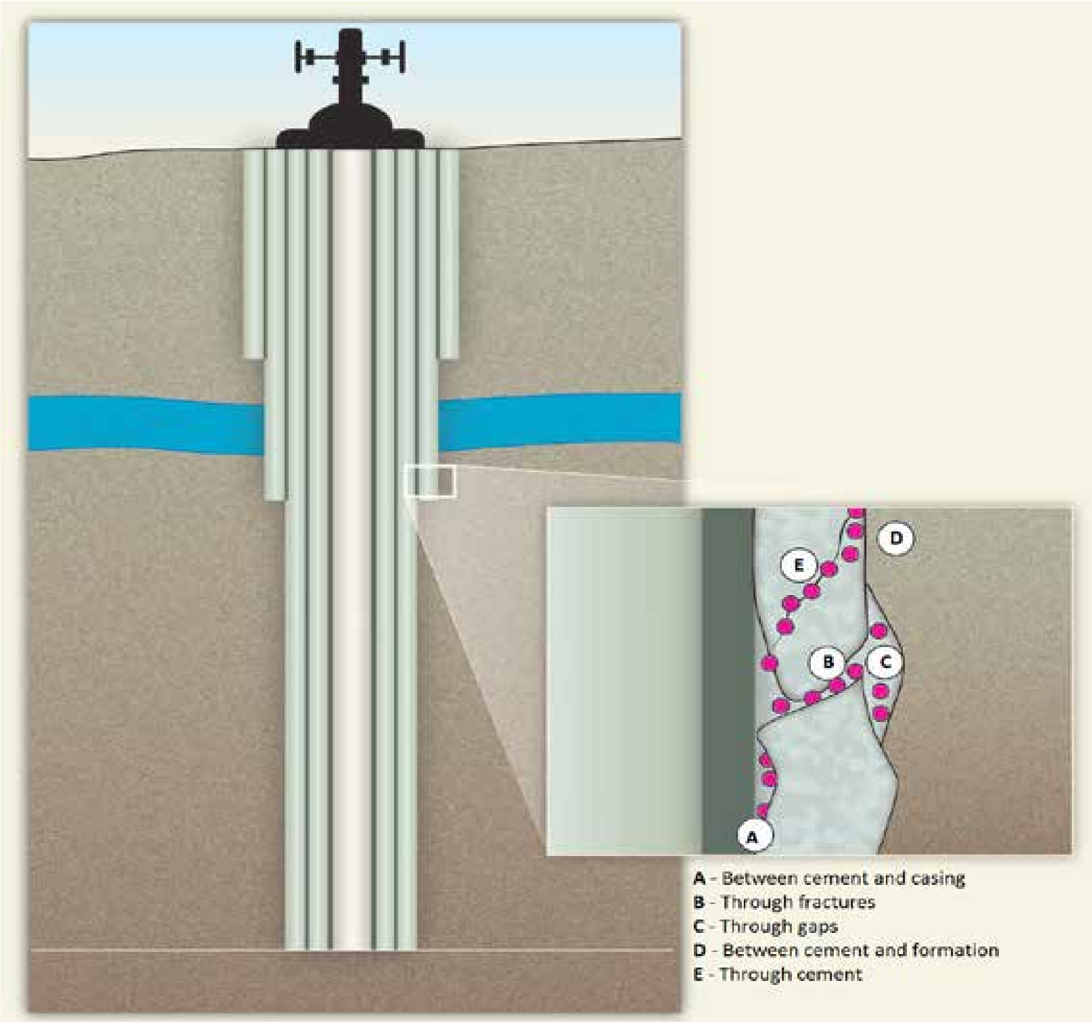
The literature documents the following mechanisms through which fluid (liquid or gases) leakages can occur that are linked to well engineering (Bourgoyne Jr, Scott, & Manowski, 2000; Brufatto, et al., 2003; Jackson, et al., 2014):

- holes or defects in the steel casing,
- through joints between casing,
- through defective mechanical seals or cement inside or outside the well,
- degradation of well steel and cement through reactions with brines or other fluids that form corrosive acids in water.

Potential leaks start with well construction. The most common problem here is a faulty seal in the annular space around casings that is placed to prevent gas leakage from a well into aquifers (Gorody, 2012; Vidic, Brantley, Vandenbossche, Yoxtheimer, & Abad, 2013). In case a wellbore passes through and beneath potable water aquifers to a gas-bearing formation and has a poorly cemented casing structure, in the presence of sufficient pressure differential, it could cause natural gas to reach the water zone (Vengosh et al., 2013). An example of how this could happen is if high-pressure gas creates micro channels on the integrity of the outer cement annulus (Vidic, Brantley, Vandenbossche, Yoxtheimer, & Abad, 2013). This is an even more legitimate concern in relation to abandoned wells. Poorly cemented wellbores from abandoned (or orphan) wells, in combination with higher-pressure gas from deeper formations, could potentially offer a path to a shallower, lower-pressure zone of past production, which in turn connects with an even shallower aquifer via the abandoned wellbore (Hoffman, Olsson, & Lindstrom, 2014).

[33] For instance, see the sources quoted in (Howarth, Santoro, & Ingraffea, 2011).

Picture 7 Key pathways for gas migration from upper gas-bearing formations or from the target formation



Source: (Vidic, Brantley, Vandenbossche, Yoxtheimer, & Abad, 2013)

While the majority of methane that escapes shale gas wells surfaces with the initial flowback, more methane is emitted during the drill-out stage, when the plugs set to separate fracturing stages are drilled out to release gas for production (Howarth, Santoro, & Ingraffea, 2011). Based on data collected by the US Environmental Protection Agency, Howarth et al. (2011) estimate that 0.33 to 0.62 per cent of the total lifetime production of wells is emitted as methane during the drill-out stage[34]. And this is only the fugitive methane that is recorded at surface. What amount might escape through the geological strata in other directions (if connectivity is established between natural and artificial fractures, as is discussed in the next section) is impossible to estimate. In Pennsylvania, analyses of state records for the Marcellus Shale from 2008 to 2013 revealed that well construction problems such as casing or cementing incidents occurred in about 3 per cent of the wells (Vidic, Brantley, Vandenbossche, Yoxtheimer, & Abad, 2013).

[34] In total, Howarth et al (2011) calculated that 3.6 percent to 7.9 percent of the methane from shale gas production escapes to the atmosphere in venting and leaks over a well's lifetime and, based on this, concludes that shale gas has a greater GHG footprint than even coal (in addition to posing water contamination risks) (Howarth, Santoro, & Ingraffea, 2011). Their methodology has been criticised by (Cathles III, Brown, Taam, & Hunter, 2012), who argue that their high-end estimate of total methane leakages from well drilling through delivery is unreasonably high, while the low-end estimate is in line with other peer-reviewed estimates. Overall, it appears that a consensus is emerging that methane losses are larger than what previous estimates show, but more work is needed to determine whether they are large enough to offset the advantage in methane's combustion efficiency compared to coal in electricity generation (Jackson, et al., 2014).

In addition, a buildup of pressure inside the well annulus, called sustained casing pressure (SCP), can force fluids (liquid or gases) out of the wellbore and into the environment (Jackson, et al., 2014). Results from surveys of both onshore and offshore wells show distinct differences in SCP rates in various regions, reflecting the importance of geology and well construction (Bourgoyne Jr, Scott, & Manowski, 2000; Watson & Bachu, 2009). Of the 8,000 wells surveyed in the Gulf of Mexico, 11 to 12 per cent showed SCP on outer casing strings, with results ranging from 2 to 29 per cent across fields (Bourgoyne Jr, Scott, & Manowski, 2000). Across Alberta, 3.9 per cent of 316,000 wells showed evidence of SCP, with one region east of Edmonton having 15.3 per cent SCP (Watson & Bachu, 2009). A recent global review of SCP studies found that studies that surveyed more than 100 wells reported SCP rates between 3 to 43 per cent in wells in Bahrain, Canada, China, Indonesia, the UK, the US, offshore Norway and the Gulf of Mexico; 12 of 19 studies showed SCP values for ≥10 per cent of wells (Davies, et al., 2014). Importantly, non-vertical wells were found to be three to four more times more likely than purely vertical wells to show SCP and gas migration (Watson & Bachu, 2009). It is as important to note that the failure of a single barrier does not always result in environmental contamination (Jackson, et al., 2014).

Despite SCP being a bigger issue for vertical wells, a number for authors (Dusseault, Jackson, & MacDonald, 2014; De Wit, 2011; Kresse, Warner, Hays, Down, Vengosh, & Jackson, 2012) argue that threats linked to the horizontal part of the well exceed those linked to the horizontal part and that the most likely contamination pathway of groundwater from methane released from the shale rock is one where methane gas travels up the wellbore and out into shallow formations along poorly cemented annulus sections of the wellbore near the surface. This is because achieving the perfect wellbore casing is subject to a number of challenges, including microannuli , channels and fractures owing to poor mud removal, invasion by fluids during setting, and stresses imposed by operations (Dusseault, Jackson, & MacDonald, 2014).

Even if perfect well integrity is achieved, maintaining it over time represents the next major challenge. The same technologies that allow for the exploitation of unconventional hydrocarbon resources – horizontal drilling and hydraulic fracturing – are the biggest adversaries of long-term well integrity (Jackson, et al., 2014). Even if primary cementation initially achieved an adequately sealed wellbore, multiple episodes of fracking can put excessive pressure on the casing and cause it to rupture, allowing gas and fracking fluid to escape through, with this risk increasing with every re-fracking event (De Wit, 2011). In addition, the possibility that a leakage problem may develop owing to corrosion or cement shrinkage remains for the lifetime of the well, including its abandonment (Dusseault, Jackson, & MacDonald, 2014).

Finally, abandoned (orphaned) wells can also pose a significant threat. In the US, about 60,000 documented orphaned wells and potentially more than 90,000 undocumented orphaned wells have been inadequately plugged. Orphaned wells could act as vertical conduits for gas (IOGC, 2008).

Dusseault (2014) contends that the well integrity failure rates and the related frequency of groundwater contamination (and GHG emissions) are still poorly understood and will remain so until quantitative measurements are conducted more frequently as well as publicly reported. In any event, the amount of literature on the issues of wellbore integrity suggests that it is not easily achieved and that avoiding leakages owing to poor well construction is by no means a given, lending legitimacy to concerns of possible water contamination occurring through any of the pathways associated with well engineering.

[35] Microvoids between any piping, tubing or casing of the well and the piping, tubing or casing immediately surrounding it.

5.2.2 CONTAMINATION RISKS ASSOCIATED WITH HYDROGEOLOGY

The second important group of unknowns that can cause a contamination event to occur during drilling or well completion is simply geology, which remains highly unpredictable despite the geological surveying that gas companies undertake during the exploration phase.

Conceivable contamination pathways caused by geological unknowns include (De Wit, 2011; Jackson, et al., 2014; Vengosh, Jackson, Warner, Darrah, & Kondash, 2014)

- The possibility of the fractured area in horizontal wells (which extends over large distances) to intersect existing vertical faults or natural fracture systems in the surrounding rocks, permitting gas, fracking fluids and formation water to escape upward, perhaps into aquifers;

- Drilling through a shallow section of a new shale gas well can, for instance, permit communication between a shallow gas-bearing area and freshwater aquifers – even if temporarily.

The question whether fluids could migrate to shallow layers through conduits generated by well stimulation, and if they do, could contaminate shallow groundwater, is controversial. Numerical modelling can be useful to assess the possibility of gas or fluid migration from depth via natural underground fractures or fractures induced by injection activities. However, here too, scientific literature offers conflicting evidence. Based on conservative yet feasible assumptions of the natural faults and induced fractures, Ewan et al. (2012) carried out model simulations that showed that injected fracking fluid can only percolate around 50m upward, and only while the fluid is being pumped into the well. On the other hand, (Myers, 2012) argues there is substantial geologic evidence that natural vertical flow drives contaminants, mostly brine, to near the surface from deep sources. Fluid migration, where it occurs, generally requires thousands of years to move contaminants to the surface; however, Myers's (2012) study suggests that fracking the shale could reduce this transport time to less than 10 years. While offering a reason for a radical re-think of fluid migration pace, this study has received much criticism for its simplified assumptions, which may compromise the validity of its conclusions (Saiers & Barth, 2012; Cohen, Parratt, & Andrews, 2013).

The potential for migration of fracturing fluids, formation water or methane can increase where the target formation is shallower, and the separation distance between the gas production zone and the shallow groundwater is reduced (Warner, et al., 2012). According to the DMR (2012), in the Karoo, a potential shale reservoir will typically lie between 1,500m and 4,000m below the surface, which is normally at least 1,000m below any known groundwater resources. In addition, the targeted shales are overlayed by very tight, less carbonaceous shale deposits, which are up to 800m thick in places and are expected to minimise the vertical migration of stray gas, should it occur (DMR, 2012; Steyl, van Tonder, & Chevallier, 2012). Similarly, the low permeability of the stack of sedimentary strata above the targeted formations in the Karoo would considerably retard the migration of hydraulic fracturing fluid (Svensen, Planke, Chevallier, Malthe-Sorenssen, Corfu, & Jamtveit, 2007).

However, there are exceptions to this rule: when deep confined groundwater is under artesian pressure, fracking fluid can percolate upward if there is a suitable continuous pathway (i.e. a fault or a wellbore) (DMR, 2012). And the possibility for man-made fractures to connect to a natural fault or fracture, an abandoned well or some other underground pathway, allowing fluids to migrate upward, is plausible (Flewelling, Tymchak, & Warpinski, 2013), especially in the Karoo. What is known about the first 200m to 300m below the surface of the shale gas prospecting area indicates a very complex and unpredictable hydrogeological system:

- The dolerite sills and dykes and the kimberlites that are present in the Karoo Basin adopt very complex structures and may represent both barriers to, and fractured conduits for, the movement of groundwater (DMR, 2012).

- Dolerite intrusions can cause fractures in the sedimentary rocks, thereby increasing their transmissivity and permeability causing the water to flow into the fracture spaces[36]. Such open fractures can extend laterally for hundreds of metres and are usually not directly linked to the overlaying shallow aquifers. However, vertical and horizontal drilling may create an artificial connection between these aquifers, leading to leaking of hydraulic fluid or gas in the event of improper grouting of casing (DMR, 2012). Dolerite intrusions are present over about 390 000 km^2 of the main Karoo Basin, but no information on them is available for depths greater than 300m (Svensen, Planke, Chevallier, Malthe-Sorenssen, Corfu, & Jamtveit, 2007), with only the southernmost part of the basin being free from them (Water Research Commission, 2012).

It must be noted that these prolific dolerite sills and dykes and kimberlites, which affect the Karoo Basin, do not occur in other shale gas basins, diminishing the transferability of the experience accumulated elsewhere. Owing to these unknowns, the study by the Department of Mineral Resources into the feasibility of developing shale resources in South Africa recommends that deep hydrogeological investigations and groundwater modelling need to be completed during the initial exploration phase, in order to improve understanding of the potential mobility of sub-surface fluids, and particularly the influence of the dolerite and kimberlite intrusives (DMR, 2012).

As of 2014, there were no recorded contamination impacts that can be directly linked to a fracking injection event via the enhancement of a natural pathway. However, there are records of groundwater contamination by chemicals used in fracking, and by methane gas released from deep shales. Perhaps because of a lack of alternatives, these have been attributed to leaking casing caused by improper sealing or by erosion over time.

Despite the controversy, it appears that this contamination pathway remains a theoretically plausible option for the Karoo, mainly owing to the numerous unknowns on its deep geology. The need for a much better understanding of the Karoo Basin's hydrogeology and the presence of naturally occurring fractures are not only relevant for a better assessment of water contamination risks, but also for the shale gas operations themselves. If considerable in size, the naturally occurring fractures could cause loss of 'mud' used in drilling (which is also used to fill and block minor fractures), which can increase drilling costs. It is also possible that the pressure of hydraulic fracturing can re-open naturally occurring fractures in the fracturing zones and can trigger movement (minor tremors) or, in more severe cases, prevent the buildup of pressure to the point where the creation of artificial fractures is no longer possible (DMR, 2012).

5.3 RISKS ASSOCIATED WITH SURFACE ACTIVITIESS

The last (but not least) group of possible contamination pathways occurs on the surface, at the well site or en route to or away from it. This group of impacts is the best documented and therefore least controversial one. It includes possible spills of fracking chemicals during the mixing stage, flowback water and produced water spills from the well, wastewater spills from onsite storage tanks, etc.

The release of fracking wastewater into the environment is one of the major risks associated with the development of shale gas resources. According to Hoffman (2014), in the US, a number of cases have been documented where tankers leaked and valves were accidentally or intentionally opened, allowing the produced water to flow out onto roadways and roadsides, where traffic accidents resulted

[36] Owing to this phenomenon, Karoo aquifers are generally classified as *fractured rock* aquifers.

in chemical spills, or where water was illegally dumped onto private or public land or surface water bodies rather than being properly disposed of.

Onsite waste ponds can overflow, spill or leach into groundwater and into streams close to a site. Fracking wastewater contains high concentrations of TDS, from around 5,000mg/l to more than 100,000mg/l (Hoffman, Olsson, & Lindstrom, 2014), which would cause the groundwater resources it comes into contact with to become unsuitable for the purposes of drinking or agricultural use.

Disposal or accidental release of high-salinity wastewater to surface water also runs the risk of increasing the halide concentrations downstream of discharge sites (Harkness, Dwyer, Warner, Parker, & Mitch, 2014). If this water is then used as source water by downstream drinking-water treatment plants, reactions of disinfectants with halides can form carcinogenic disinfection by-products (DBPs) (Jones, Saglam, Song, & Karanfil, 2012; Richardson, Plewa, Wagner, Schoeny, & De Marini, 2007). This has occurred in the past. For example, elevated bromide (a halid ion) concentrations resulting from oil and gas wastewater discharges along the Monongahela River and Clarion River in the US, increased DBP concentrations in municipal drinking-water in Pittsburgh, Pennsylvania (States, et al., 2013).

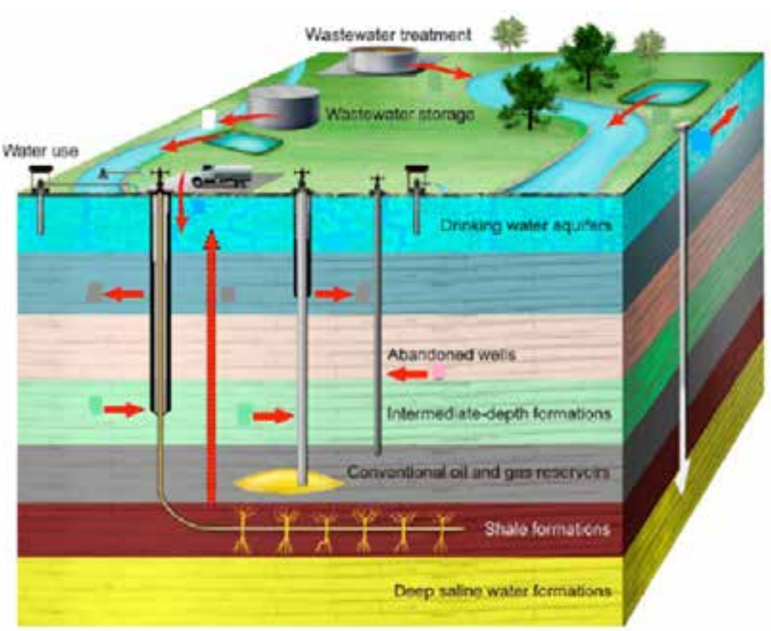
In addition to threatening water sources, the risk of spilling chemicals or wastewater also represents an important risk to soil, as does spilling of brine from deep water aquifers, which is becoming an increasingly interesting water source for hydraulic fracturing. A brine spill effectively sterilises soil it comes into contact with.

Besides accidental leaks from surface impoundments, intentional illegal disposal of wastewater has also been documented in areas of extensive shale gas development (Venhosh, Jackson, Warner, Darrah, & Knodash, 2014a).

Even when flowback water and produced water are processed in wastewater treatment plants according to regulations, they can still pose serious environmental and human health risks. For instance, the accumulation of toxic and radioactive elements (i.e. radium isotopes) in soil or stream sediments has been known to happen near disposal or treatment plants (Vengosh, Jackson, Warner, Darrah, & Kondash, 2014).

Picture 2 provides an overview of the possible contamination sources discussed above.

Picture 2 Water contamination pathways from shale gas operations.



Source: Vengosh et al. (2014)

[37] Typically fluoride, chloride, and bromide that have a number of adverse effects on ecosystems and human health.
[38] For instance, near the Josephine treatment plant site in Pennsylvania (Vengosh, Jackson, Warner, Darrah, & Kondash, 2014)

5.4 CHALLENGES OF PROVING CORRELATION BETWEEN SHALE GAS OPERATIONS AND GROUNDWATER CONTAMINATION

Possible degradation of groundwater quality is one of the most common concerns related to shale gas developments. Local and regional news media from shale areas in North America are replete with examples of contamination of domestic wells by shale gas operations. They include the story of the small town of Dimock in the Appalachian section of Pennsylvania, on the Marcellus shale play, where the residents' water began to turn brown and made them and their animals sick soon after shale gas operations begun under their land (Donnelly & Cooley, 2012). Another is the case of Pavillion, in Wyoming, where local residents filed similar complaints (US EPA, 2011).

Such cases are often dismissed as anecdotal and unsubstantiated. Even where they are investigated, indisputable proof that the water quality has been compromised by nearby shale gas operations is difficult to achieve. For instance, complaints of water contamination by the citizenry in Pavillion were followed by an EPA investigation that confirmed that the area's water quality had indeed been compromised. Despite the coincidence in time and space of the development of the Pavillion gas field, and compelling evidence of a link with nearby shale gas operations, the gas extraction industry challenged the EPA on methodological grounds, and the case was eventually dismissed as lacking unequivocal proof (DMR, 2012).

Unequivocally proving a water contamination event caused by a shale gas operation is a very challenging undertaking. The main reasons for this are (DMR, 2012; Kresse, Warner, Hays, Down, Vengosh, & Jackson, 2012; Darrah, Jackson, Vengosh, Warner, & Poreda, 2015):

- Effects or events in the environment adjacent to fracking operations are often evident only some time after the operations have taken place;
- A lack of baseline information on water quality prior to the commencement of shale gas operations;
- Complexity of natural variations in water quality and the related difficulties in differentiating between natural and anthropogenic sources of contamination;
- A lack of methods to simultaneously determine the source, timing and mechanism(s) of pollutant migration into shallow aquifers;
- Numerous other variables involved in groundwater contamination studies.

Even where baseline samples are available, experience has shown that analyses of single samples from either a potential contamination point or groundwater and surface water sources may not always be sufficient to satisfactorily document site-specific baseline conditions (Gorody, 2012). Rather, continued sampling and analyses of a variety of baseline groundwater and gas composition screening parameters are necessary (Gorody, 2012), but this is rarely feasible due to the high costs associated with it.

5.5 EVIDENCE OF GROUNDWATER CONTAMINATION BY SHALE GAS OPERATIONS TO DATE

Uncertainties surrounding evidence of water contamination by shale gas operations cause the discussion of this topic to be highly polarised. As noted, the most contentious debate is around contamination occurring below the surface, although this does not mean that possible above-surface contamination represents a smaller risk.

Considering the amount of debate surrounding the possibility of unconventional resource extraction compromising freshwater quality, there is a surprisingly low number of peer-reviewed studies on the topic (Jackson, et al., 2014). Confidentiality requirements dictated by legal investigations, the expedited rate of development and the limited funding for research are some of the primary obstacles to peer-reviewed research into environmental impacts of unconventional hydrocarbons (Vidic, Brantley, Vandenbossche, Yoxtheimer, & Abad, 2013). Nonetheless, a few studies are available and these show that shale gas operations can pose a threat to water resources. At the same time, such studies are typically strongly opposed by the industry, via industry associations or sponsored consultants hired to question the validity of the scientific approach used to reach such conclusions. Some of those peer-reviewed studies and their critiques are reviewed next, pointing to the difficulty of establishing the contamination link – even where it exists.

5.5.1 CONTAMINATION FROM SUB-SURFACE ACTIVITIES

Despite claims by proponents of shale gas that shale gas developments pose no threat to water resources, there is evidence that the opposite is true. In the US, the number of complaints related to possible impacts of drilling on local water resource quality has increased with the drilling intensity. More importantly, evidence of contamination events has moved from anecdotal, to confirmed by authorities. For instance, state regulatory agencies in Pennsylvania, Ohio and West Virginia have confirmed 116 cases of well-water contamination in recent years associated with drilling activities (Associated Press, 2014).

In the state of Pennsylvania, several shale gas drilling operations were halted in 2009 owing to concerns of possible groundwater contamination, but no comprehensive investigation of these complaints have been published in the peer-reviewed literature (Mauter, et al., 2014). This could at least partly be due to the fact that the study of sites where contamination may have occurred has often been restricted by the terms of the legal settlement (Mauter, et al., 2014).

One of the few studies documenting possible water contamination by hydraulic fracturing is the EPA's study of groundwater quality in Pavillion, where EPA investigators found the carcinogen benzene at 50 times that of safe level in groundwater, in addition to other hazardous pollutants, including a solvent that is common in hydraulic fracturing fluids (DiGiulio, Wilkin, Miller, & Oberley, 2011). Although the exact source and contamination pathways could not be indisputably determined (partly owing to the lack of pre-drilling data at the site), hydraulic fracturing in this area occurred at depths as shallow as 322m, and local drinking-water wells are as deep as 244m (DiGiulio, Wilkin, Miller, & Oberley, 2011), substantially increasing the likelihood of induced connectivity and related contamination (Jackson, et al., 2014).

Two other recent studies have documented higher concentrations of metals and other elements near gas wells, as well as increases in endocrine-disrupting chemicals in drinking-water wells in the vicinity of shale gas wells. Fontenot et al. (2013) sampled 100 drinking-water wells overlaying the Barnett Shale and documented significantly higher levels of arsenic, selenium, strontium and total dissolved solids in water wells within 3km from shale gas wells. Another study conducted by the University of Missouri found that water samples from a drilling-rich area of western Colorado had substantially higher estrogenic and androgenic activities than water from reference sites with limited drilling operations (Kassotis, Tillit, Davies, Hormann, & Nagel, 2014). However, other experts in the field believe both studies need follow-on testing so as to confirm results (Jackson, Vengosh, Darrah, Warner, & Down, 2013).

Concerning contamination from stray gas, the body of studies proving or disputing it is significantly larger. While several studies have suggested that shale gas operations can lead to stray gas contamination in a sub-set of drinking-water wells in the vicinity of shale gas wells (Osborne, 2011a; Jackson, Vengosh, Darrah, Warner, & Down, 2013; Darrah, Vengosh, Jackson, Warner, & Poreda, 2014), others have challenged such findings, arguing that methane in these areas occurs naturally and is unrelated to shale gas development (Kornacki & McCaffrey, 2011; Molofsky, Connor, Wagner, Farhat, & Wylie, 2013; Baldassare, McCaffey, & Harper, 2014) or have challenged the findings on methodological grounds (Saba & Orzechowski, 2011; Davies, 2011; Schon, 2011). Geochemical forensic techniques and other methods used to evidence gas sources and their migration pathways are constantly being improved, regularly bringing to light new evidence that disputes or confirms earlier findings.

I will now present a brief summary of selected papers from both sides. The overview presented here is by no means exhaustive, and merely outlines the level of complexity that proving or dispelling a correlation between groundwater contamination and shale gas operations entails.

In a highly contested study, Osborne et al. (2011) surveyed 68 drinking-water wells drawing from shallow groundwater in north-east Pennsylvania and upstate New York, and detected methane concentrations in 51 of them, regardless of gas industry operations. However, in active gas extraction areas[39], average and maximum methane concentrations in drinking-water wells increased with proximity to the nearest gas well, reaching 19.2mg and 64mg CH_4/l respectively, representing a potential explosion hazard[40]. By contrast, neighbouring non-extraction sites[41] within similar geologic formations and hydrogeologic regimes averaged only 1.1mg CH_4/l (Osborn, 2011). Crucially, isotopic signatures of the samples taken in active gas extraction areas indicate the presence of deeper thermogenic methane from a source such as the underlying shale formations, while the methane found in lower concentrations in non-extraction areas was of mainly of biogenic and mixed origin (Osborn, 2011). The authors of the study believe that in their study area, leaky well casings are the most likely contamination pathway. Methane migration could in theory also have occurred through the 1km to 2km thick geological formations that overlay the local shales (Marcellus and Utica) owing to extensive fracture systems in these formations, or through the many older, uncased wells drilled and abandoned over the last 150 years in the area; however, this is less likely. It also important to note, that this study found no evidence of contamination of drinking-water samples by brines or fracturing fluids (Osborn, 2011).

[39] Those with one or more gas wells within a distance of 1km.

[40] While dissolved methane in drinking water is currently not classified as a health hazard if ingested, it is an asphyxiant in enclosed spaces and both an explosion and fire hazard (Osborn, 2011). In addition, it can be oxidised by bacteria, resulting in oxygen depletion, which in turn increase solubility of elements such as arsenic or iron (Vidic, Brantley, Vandenbossche, Yoxtheimer, & Abad, 2013). Therefore, in the US, the Department of the Interior recommends a warning if water contains 10 mg/l of methane and immediate action if concentrations reach 28 mg/l (Eltschlager, Hawkins, Ehler, & Baldassare, 2001).

[41] Those with less than one gas well within 1km

Osborne's study (2011) was criticised by a number of other authors (Davies, 2011; Schon, 2011; Saba & Orzechowski, 2011; Molofsky, Connor, Wagner, Farhat, & Wylie, 2013), who question its validity for the small, non-random dataset, the fact that it covers a geologically diverse area that is up to 200km wide, and the lack of baseline data. In addition, several of the contaminated water wells are from around Dimock in Pennsylvania, where aquifer contamination was already known to have been caused by casing leaks in at least three wells in 2009 and 2010 (rather than by hydraulic fracturing) (Davies, 2011). Finally, Davies (2011) and Schon (2011) reprimand Osborn et al. (2011) for not considering microseismic evidence that shows that the hydraulic fractures generated in the Marcellus formation are located deeper than 1km below the aquifers and that are not connected (Davies, 2011). Hence, Davies (2011) concludes that while Osborn et al. (2011) show that contamination may have occurred, they fail to prove the association with hydraulic fracturing.

Davis's (2011) and Schon's (2011) criticisms seems somewhat misplaced, as Osborn et al. (2011) clearly state in their paper that the methane contamination of shallow groundwater resources they detected is more likely to derive from leaky well casings than upward gas migration through geological strata, made possible by artificial connectivity inducted by hydraulic fracturing. Even if fracking did not create connectivity between artificial and natural fractures that allowed the methane to migrate upward towards the surface, repeated fracturing episodes, which occur during multistage fracking and re-fracking, still do represent a threat to well casing integrity (De Wit, 2011). Fracking could therefore still be contributing to methane contamination of groundwater, albeit indirectly.

Schon (2011) also argues that natural migration of thermogenic gas from the Marcellus to shallower horizons has been occurring over geological time and that local groundwater was known to have a significant methane level as a natural constituent long before shale gas resources began to be developed in the region. However, he fails to explain the "coincidence" of much higher methane concentration levels found in proximity of shale gas wells. Schon and Saba (2011) also argue that not all water samples taken in close proximity to natural gas wells showed high concentrations of methane and that this shows that elevated methane concentrations are not an inevitable effect of drilling. Again, if shale gas operations would "inevitably" cause groundwater contamination, there would be no contention. What Osborne's (2011) study did show is that groundwater sources in active gas extraction areas are subject to higher risk of contamination, with only a sub-set of wells affected, which neither Davis (2011) nor Schon (2011) are able to disprove. In fact, their suggestions that the contamination is most likely to have been caused by well leakage rather than hydraulic fracturing is in line with the conclusions presented by Osborne et al. (2011)[42].

Arguing more convincingly against the correlation between shale gas extraction and groundwater contamination in north-eastern Pennsylvania are Molofsky et al. (2013), who point out that historical data suggest that methane has been present in local groundwater resources long before shale gas extraction started in 2006. They reviewed data from 1,701 water wells sampled in Susquehanna County in north-east Pennsylvania in an attempt to establish a water quality baseline between the years 2008 and 2011. They found that 78 per cent of the 1,701 water wells sampled contained detectable concentrations of methane, and that higher concentrations (>7,000µg/l) were found in 3.7 per cent of the wells in active gas extraction areas, as opposed to 3.3 per cent of wells in non-active gas extraction areas, and find topography to be the main reason for the slight difference (Molofsky, Connor, Wagner, Farhat, & Wylie, 2013). They also argue that the outcome of the chemical analysis of the methane present in the water samples in the study by Osborne et al. (2011) shows that the detected gas does not originate from the Marcellus shale formation, but rather from a Middle and Upper Devonian formation that overlays the Marcellus, and thus cannot be attributed to shale gas operations (Molofsky, Connor, Wagner, Farhat, & Wylie, 2013).

[42] For a more detailed deconstruction of the critiques presented by (Davies, 2011), (Schon, 2011) and (Saba & Orzechowski, 2011), please see the responses prepared by Osborne et al. in (Osborne, 2011a) and (Osborne, 2011b).

The paper by Molofsky et al. (2013) was sometimes used to dispel the conclusion that shale gas activities have caused methane contamination of some drinking-water wells in the study area previously researched by Osborne et al. (2011), thereby seeking to exonerate the shale gas industry of any impacts on groundwater quality. However, further studies employing new techniques subsequently disputed conclusions reached by Molofsky et al. (2013). Darrah et al. (2014) argue that while analysing hydrocarbon abundance and isotopic compositions, one can distinguish between thermogenic and biogenic gas contributions and differentiate between gases of differing thermal maturity (e.g. Middle-Devonian (Marcellus)-produced gases vs gases from the Upper Devonian layers), microbial activity and oxidation can alter the gas's original geochemical signature and can obscure the sources or mechanisms of fluid migration (Darrah, Vengosh, Jackson, Warner, & Poreda, 2014). Therefore, they employ noble gas elemental and isotopic tracers that constitute an appropriate complement to hydrocarbon geochemistry, because they remain unaffected by chemical reactions or microbial activity and have well-characterised isotopic compositions in the crust, hydrosphere and atmosphere (Darrah, Vengosh, Jackson, Warner, & Poreda, 2014). They analysed more than 100 samples from drinking-water wells overlaying the Marcellus and Barnett shales and, based on this extended analysis, they conclude that gas leakage has occurred through failures of annulus cement, faulty production casings, and underground gas well failure, thereby not only re-asserting the original findings of Osborne et al. (2011) that shale gas operations have caused hydrocarbon gas contamination in some wells, but that a lack of well integrity can cause contamination of stray gases not only from the target formation, but also from overlaying geological strata. At the same time, the new analysis using noble gas data appears to rule out contamination by upward migration of the gas through overlaying geological strata, which could be triggered by horizontal drilling or hydraulic fracturing (Darrah, Vengosh, Jackson, Warner, & Poreda, 2014). Again, well integrity – mostly problems associated with casing or cementing issues – has emerged as the most likely contamination source (Darrah, Vengosh, Jackson, Warner, & Poreda, 2014).

In addition to Osborn et al. (2011), who focused on shale gas wells, wellbore leakages[43] from conventional gas wells are known to have caused a number of other documented cases of groundwater contamination (Dusseault et al. (2014) provide a list of studies documenting them). This again points to the fact that achieving perfect well integrity and avoiding any possible leaks in all wells remains an engineering utopia.

At the same time, it must be noted that not all active gas extraction areas seem to experience groundwater contamination. Following complaints from local residents about changing water quality, the US Geological Survey (USGS) initiated a survey of groundwater quality in the Fayeteville shale gas production area in north-central Arkansas. The study found no evidence of either produced water or methane contamination of local groundwater resources (Kresse, Warner, Hays, Down, Vengosh, & Jackson, 2012). The analysis compared chloride concentration in groundwater samples collected for the study (which can serve as an early indicator of infiltration of production water associated with gas extraction activities into the shallow aquifer system) to historical data and found that in fact, chloride concentrations were much higher in the historical data than they were in the samples collected for this study (Kresse, Warner, Hays, Down, Vengosh, & Jackson, 2012). In addition, no statistical difference was found between chloride concentrations in water from the wells located within two miles from a gas production well and those located further away (Kresse, Warner, Hays, Down, Vengosh, & Jackson, 2012). Water samples were also tested for methane concentrations and, while methane was detected in more than half of the study samples (32 of 51), with concentrations ranging upward to 28.5 mg/l, the isotopic analysis of these higher-concentration samples concluded that the methane was largely biogenic in origin and thus could not be attributed to shale gas activities in the region.

[43] Wellbore leakage refers to all processes whereby fluids (oil, gas, brine, fracturing fluids) migrate from depth to the surface or near-surface during and after active operations (Dusseault, Jackson, & MacDonald, 2014).

[44] The two-mile distance threshold was selected as a conservative estimate for the length of possible plume migration (Kresse, Warner, Hays, Down, Vengosh, & Jackson, 2012).

Rather, it appears that the groundwater chemistry in the shallow aquifer system in the study area is the result of natural processes (Kresse, Warner, Hays, Down, Vengosh, & Jackson, 2012). Thermogenic methane signatures were noted in samples with low methane concentrations, some of them from wells that were significantly distant (>5 miles) from the nearest active production well, but this most likely indicates that upward migration of thermogenic gas can occur naturally in some areas and can produce low thermogenic methane concentrations in the shallow aquifer (Kresse, Warner, Hays, Down, Vengosh, & Jackson, 2012)[45].

Considering the randomness of groundwater contamination from shale gas operation, the question then becomes: *"How prevalent are these events across all shale gas wells?"* Or in other words: *"What is the likelihood of a contamination event occurring?"* Despite important evidence of stray gas contamination, establishing the likelihood of occurrence for contamination events for a population of wells is still not possible, because there are few comprehensive studies documenting the frequency, consequences and severity of well integrity failures (Jackson, et al., 2014).

Even though they do not directly look at contamination pathways, studies testing for gas migration offer some insights into the size of the risk and they seem to suggest this risk is not negligible and should not be dismissed. Testing for gas migration in the soil around wellheads in a specific locality in Alberta for a sample of 1,230 oil and gas wells revealed that 23 per cent of wells showed surface and soil gas leakage, from negligible to substantial amounts of leaked gas (Erno & Schmitz, R., 1996). There have been instances where gas leakage figures reported by the industry on a voluntary basis have been found to be substantially lower than those where reporting is mandatory[46]. These are only some of the examples of well leakages presented in the overview compiled by (Jackson, et al., 2014).

While it must be acknowledged that well engineering has improved since the publication of some of these studies, well integrity failures still represent the biggest risk to groundwater contamination from sub-surface activities of shale gas operations. The partial evidence addressing well leakages in specific areas and for a specific failure type also means that any generalisation of contamination evidence presented above remains unwarranted. As Vidic (2013) notes: "Although the primary mechanisms contributing to gas migration and stray gas are understood, it is difficult to predict the risk at individual sites because of varying geological conditions and drilling practices." To achieve a better understanding of the risks associated with this contamination pathway, we need the following (Vidic, Brantley, Vandenbossche, Yoxtheimer, & Abad, 2013):

- Reliable models that incorporate geological characteristics;
- The ability to distinguish between natural and anthropogenic causes of migration;
- A better understanding of geological factors that exacerbate such migration;
- To understand the likelihood of ancillary problems of water quality related to oxygen depletion;

The evidence that has been collected to date, thus suggests that stray gas contamination is the primary threat from shale gas operation's sub-surface processes. There has been insufficient evidence to unequivocally determine systemic contamination by fracking fluid or produced brine in groundwater.

[46] For instance, this was the case in Alberta, where industry-reported data across Alberta suggested gas migration occurrences in only 0.6 percent of wells, while a test area east of Edmonton, where soil tests were mandated, in 5.7 percent of wells (1,187 out of 20,725) showed gas migration (Watson & Bachu, 2009).

5.5.2 CONTAMINATION FROM ABOVE SURFACE ACTIVITIES

Despite the fact that much (even most) of the controversy on possible water contamination by shale gas operations surrounds sub-surface activities, protecting water resources from the wastewater generated during production seems to be the biggest challenge (Jackson, et al., 2014).

As mentioned, the main contamination sources from wastewater are surface leaks and spills from well pads and wastewater holding ponds, and inadequate treatment before wastewater discharge (Jackson, Vengosh, Darrah, Warner, & Down, 2013). In Pennsylvania alone, there have been over 100 leaks and spills reported since 2008 (Venhosh, Jackson, Warner, Darrah, & Knodash, 2014a). In a high-density hydraulic fracturing area in Colorado, there were 77 surface spills (representing some 0.5 per cent of active wells at the time) that were affecting groundwater documented over a 12-month period, which resulted in increased levels of benzene, toluene, ethylbenzene and xylene (BTEX) in groundwater at the spill sites (Gross, Avens, Banducci, Sahmel, Panko, & Tvermoes, 2013). Where remediation steps were taken, they were effective at reducing BTEX levels in 84 per cent of the spills (Gross, Avens, Banducci, Sahmel, Panko, & Tvermoes, 2013).

The second most prevalent contamination source is wastewater discharge without adequate prior treatment. At least three water treatment facilities in Pennsylvania were documented as discharging water with very high TDS values of 120,000mg/l (some four times the concentration of sea water) and with elevated levels of barium, radium and organics, such as benzene (Ferrar, Michanowicz, Christen, Mulcahy, Malone, & Sharma, 2013). Another study of a Pennsylvania treatment facility found that while more than 90 per cent of metals were successfully removed, salt concentrations in the effluent were 5,000 to 10,000 times more concentrated than in river water upstream from the facility, and were responsible for some 80 per cent of the total salt level for the river at the point of release (Warner, Christie, Jackson, & Vengosh, 2013). The same study also found that radium activities in the stream sediments near the discharge point were 200 times higher than in background sediments just upstream and above levels requiring disposal at a licensed radioactive waste facility (Warner, Christie, Jackson, & Vengosh, 2013).

Similarly, Lutz et al. (2013) also report that the Monongahela River in Pennsylvania saw its water quality decline as effluent discharges from industrial wastewater treatment facilities were increasing along with the number of shale gas wells in the region.

Furthermore, the mentioned work by the University of Missouri, involved testing not only groundwater but also surface water samples, and found higher-than-average endocrine-disrupting activities in both, compared to samples taken from sites not associated with fracking operations (Kassotis, Tillit, Davies, Hormann, & Nagel, 2014).

While existing tools and methods are being used to grow the body of evidence on environmental contamination caused by fracking wastewater, new methods for definitively distinguishing them in the environment are still being developed and tested and may reveal even wider environmental and health impacts than those presented here. The use of chemical tracers (for instance, boron isotopes) is showing great promise in their ability to distinguish small amounts of flowback water and produced water in the environment (Warner, Darrah, Jackson, Millot, Kloppmann, & Vengosh, 2014).

5.5.3 IMPLICATIONS FOR GROUNDWATER USERS AND OWNERS OF CONTAMINATED WELLS

Despite the fact, for now, that exact sub-surface contamination pathways remain contentious territory, what cannot be argued against is that shale gas developments have brought about methane water contamination in some areas of active gas extraction. Based on the evidence to date, it now also appears that the discussion on water contamination threats from shale gas operations initially erroneously focused only on hydraulic fracturing, and neglected other parts of shale gas operations that represent a much more significant threat to surrounding water resources. And while a number of technological and organisational practices can be found in the literature to minimise the environmental risks associated with natural gas production (be it from conventional or unconventional resources), the industry is simply not implementing them successfully or sufficiently. This could be for cost reasons, a lack of regulatory demands, or simply the inability to keep pace with the latest R&D in the oil and gas industry.

In any event, minimising the risk of water contamination requires continuous monitoring of well operations by independent forensic experts, which can significantly increase the cost of the gas operations (De Wit, 2011). This is a crucial consideration for the development of regulations governing possible shale gas development in South Africa, especially in view of the very limited water resources available to support human needs and economic activity in the Karoo. Most crucially, before any drilling occurs, the baseline quality of the water sources of the wider Karoo region must be established (De Wit, 2011). Such baseline studies would form crucial evidence in case water sources become compromised.

However, even where baselines are present, the complexity of the discussion and the challenges of proving a correlation between a water contamination event and shale gas operations have important implications for the ability to establish liability, should a contamination event occur. As described in Section 5.2, identifying the source of stray gas in drinking-water supplies principally relies on comparing the gas composition in affected water supplies with gas samples collected from point sources such as drilling sites, produced gases, casing head gases, pipeline gases and other (Gorody, 2012). This is why Osborn et al. (2011) suggest that baseline data include dissolved-gas concentrations and isotopic compositions. However, underground gas migration can modify both the concentration and the composition of the gas between its point source and the groundwater sample (Gorody, 2012). Therefore, baseline development and subsequent forensic investigations of possible gas contamination events need to address the effects of mixing, dilution and oxidation reactions in the context of regional and local hydrology (Gorody, 2012). Achieving this will require analysing multiple samples from baseline groundwater investigations, potential point sources and impacted water resources (Gorody, 2012).

It is clear from the examples presented above that a single well owner in the Karoo, or even a group of owners, will find it exceedingly difficult to prove that a shale gas development in their vicinity has compromised the quality of their water. It might take years of analysis and counter-analysis to establish the link, and even if shale gas development did cause the contamination to occur, the well owner might never be able to prove it unequivocally and thus to achieve compensation.

5.6 MITIGATION MEASURES FOR WATER-RELATED ISSUES

There are a great many technologies that can be implemented, regulatory demands that can be put in place and management practices that can be taken up to minimise the risks of water contamination by shale gas operations.

Some service companies and operators have already embarked upon programmes to minimise the potential environmental impacts of their operations by reducing the use of potential toxic additives or replacing them with non-toxic alternatives (DMR, 2012). Rigorous adherence to construction best practices that help ensure the integrity of the wellbore (including isolation of groundwater sources) would also minimise the potential for pollution incidents (DMR, 2012). Model-assisted optimised well completion – as opposed to the most commonly used geometrical completion – can significantly reduce both the amount of water required and the amount of wastewater produced (Mauter, Palmer, Tang, & Behrer, 2013). Real-time monitoring, such as 3-D seismic monitoring, can identify and this assist in contain spills or leaks if they occur (De Wit, 2011). Leaking wells can be tested for in real time by spiking fluids with tracer chemicals and fingerprinting gases by using their indigenous isotopic signatures, which allows for gas and fluid tracking (De Wit, 2011). While some sources suggest that this can be achieved by encoding industry best practice in the regulations (DMR, 2012), regulations means little without a regulator able to effectively monitor and enforce them.

In 2013, Mauter et al. compiled a good but still not comprehensive overview of measures available to the shale gas industry that can aid it to minimise the environmental risks associated with its activities (presented in Table 6). The authors qualitatively assessed the mitigation opportunities considered along four dimensions: (1) the scale of technology implementation, from the single-well level (Well) to the development scale (i.e. all the sites owned in an area by a particular operator - Area); (2) the scale of technology benefits, from the local level (Loc), to the regional level (Reg), to the global level (Glbl); (3) the present degree of adoption, from an emerging technology embraced by early adopters (Emg), to widespread implementation (Wide), to regulations mandating adoption (Law); and (4) the types of mitigation measures (discrete technology (T), shift in management practices (M), or feasible regulatory intervention (R).

Since 2013, even more mitigation measures have become available to the industry, as it seeks to appease public and governmental concerns over its environmental impacts, while at the same time improving its production practices. It is beyond the scope of this report to provide a comprehensive overview of all possible mitigation measures available to the industry and to the regulators to minimise all possible impacts of the shale gas industry on water resources. It must be noted that, despite the existence of a great array of such measures, many of which are cost-effective, there is still a detectable lag in their implementation when adoption is voluntary, as research by Mauter et al. (2013) has shown. Cost-effectiveness seems to be a “necessary but insufficient condition” for the voluntary adoption of environmental mitigation technologies in unconventional oil and gas extraction (Mauter, 2013). Time, capital and environmental trade-offs have been cited as primary barriers to adoption (Mauter, Palmer, Tang, & Behrer, 2013). This suggests that there is an important role for regulations in promoting – or simply requiring – the best available technologies and management practices. However, with South Africa’s limited ability to enforce strict regulations, their mere existence does not represent a safeguard to minimising environmental risks associated with unconventional gas extraction.

Table 6 Candidate technologies and practices for reducing the environmental impacts of hydraulically fractured wells

MEASURE	SCALE OF IMPLEMENTATION	SCALE OF BENEFITS	DEGREE OF ADOPTION	POTENTIAL ENVIRONMENTAL BENEFITS	TYPE
Laying impermeable liner over wellpad site	Well	Loc	Wide	Reduces risk of soil and surface water contamination	TR
Laying re-usable mats over wellpad site and planned access routes, rather than laying gravel	Well	Loc Reg	Emg	Reduces risk of soil and surface water contamination; speeds reclamation process once well is put on production; reduces risk of erosion damage	TR
Installing containment walls or dikes around all equipment used to store hydrocarbons	Well	Loc	Wide Law	Contains potential spills and fires	TR
Setting surface casing at greater depths (API recommendation is 100 foot below the deepest aquifer)	Well	Loc	Wide Law	Provides additional separation of groundwater from drilling activities	MR
Cementing intermediate casing, if present, to surface	Well	Loc	Wide Law	Provides additional layer of pipe and cement between borehole and the aquifers it passes through *(may not be applicable for all wells)*	MR
Extending cementing on production casing further above the fracturing zone – to the surface if practicable (API recommends 500 foot above the highest formation to be fractured)	Well	Loc	Wide Law	Reduces risk of interzone migration of sub-surface hydrocarbons	MR
Collection and analysis of surface and sub-surface data, used to inform planning and real-time management of hydraulic fracturing	Well	Loc Reg	Emg	Optimises fracturing programme, reducing water use and wastewater associated with non-productive fractures, thereby also decreasing truck trips required per well; reduces risk of fracturing beyond desired zone; enables detection of wellbore instability induced by high pressures, reducing risk of rapture and leakage of fluids	TMR
Transitioning to more environmentally benign hydraulic fracturing fluids	Well	Loc Reg	Emg Wide	Reduces chemical hazard of wastewater **May conflict with water re-use strategies*	TR
Including non-radioactive tracers in injected proppant	Well	Loc	Emg	Facilitates monitoring of fractures' locations and fluid flow within them, detection of communication with aquifers	TR
Conducting small-scale test run (mini-frack) before commencing full hydraulic fracturing job	Well	Loc	Emg Wide	Reduces risk of casing and cement failure under fracturing pressures	TMR
High-density selective batch fracturing (open-hole completions only)	Well	Glbl	Emg	Increases efficacy of fracturing job when paired with optimised completion design, thereby increasing production trade off for drilling operation *(may be most compatible with non-cased / open-hole completion designs*	TM

Installing remote-controlled downhole system of permanent monitors, packers and sealing elements, used to optimise flow rates of hydrocarbons and wastewater (intelligent completion)	Well	Glbl	Emg	Allows dynamic adjustment of in-hole equipment throughout the life of the well, increasing production tradeoff for drilling operation	TM
Air and water quality sampling throughout the life of the well (including baseline), used to inform operations	Well Area	Loc Reg	Wide Law	Enables immediate detection and mitigation of spills and leaks	TMR
Wastewater recycling and re-use, through blending and/or treatment	Well Area	Loc Reg	Emg Wide	Reduces volumes of freshwater input and wastewater output of each well (requires coordinated completions scheduled across development area and may require alteration of fracking fluid composition to accommodate higher concentrations of dissolved minerals)	TMR
Reuse of drilling fluids and muds (closed-loop drilling)	Well Area	Loc Reg	Emg Law	Reduces solid waste; for 100% recycling, requires coordinated drilling schedule and/or large-volume storage capacity across the development area to make use of fluids	TMR
Using double-ditching (preserving topsoil layering) when burying equipment in undisturbed areas	Well Area	Loc Reg	Emg Law	Reduces land use impact by preserving soil integrity, native plant root structure and seedstock, and existing microfauna	MR
Capturing fugitive methane by implementing reduced emission completions (green completions) replacing high-bleed valves, installing vapor-recovery units on tanks, etc.	Well Area	Loc Reg Glbl	Emg Wide Law	Reduces carbon footprint of individual wells and development area; reduces emissions of ozone precursor compounds, such as VOCs and NOx from wells, flares and equipment	TMR
Implementing an inspection plan on a set schedule for all pipes and equipment	Well Area	Loc Reg	Emg Wide	Enables immediate detection and mitigation of spills and leaks	MR
Clustering wells around a centralised water supply of sufficient volume	Area	Loc Reg	Emg	Reduces freshwater transport distances; with planning, reduces flow reduction impact of water sourcing on small-surface waters by allowing small withdrawals over time rather than larger ones at the time of use	M
Cantralised pumps and impoundments with pipes, used to hydraulically fracture multiple surrounding sites *(centralised fracturing)*	Area	Loc Reg	Emg	Reduces truck trips needed to move fluids and equipment to individual sites	TM
Installing temporary pipes to transport large volumes of water for short-term needs (e.g. hydraulic fracturing)	Area	Loc Reg	Wide	Reduces truck trips required for freshwater	TMR
Burying corrosion-resistant lines and pipes for longer-term operations	Area	Loc Reg	Emg Wide Law	Reduces truck trips where used as an alternative; reduces collective surface impacts of infrastructure within greater development area; may reduce the risk of rupture relative to above-ground lines;	TMR

Planning multiple wells per pad	Area	Loc Reg Glbl		reduces collective land use footprint of operation; reduces trucking distances (equipment centralised); maximises production tradeoff for well pad	MR
Surveying and data collection to choose the least environmentally sensitive site from which the target formation may be effectively accessed	Area	Loc Reg	Emg Law	Reduces land use conflicts and/or absolute magnitude of ecological impact	TMR

Source: (Mauter, Palmer, Tang, & Behrer, 2013)

Notes: *scale of implementation: single-well pad vs development area as scale of technology implementation; scale of benefit: scale(s) at which environmental benefits of technology are most applicable (local, regional or global); adoption: prevalence of technology (legally required in some places, widely used and/or emerging); type: T = discrete technologies, M = shifts in management decisions, R = feasible regulatory intervention points.*

6. CONCLUSIONS AND FURTHER WORK

Key messages:

- *Different water-related issues can have greater or lesser prominence in different shale plays, depending on water availability, geology, land availability and use, population density and other factors.*
- *It can be reasonably expected that in the Karoo, both water sourcing and wastewater disposal will be more challenging than in most shale plays developed to date.*
- *Minimising water-associated impacts of shale gas development requires an understanding of the unique regional water stressors posed by shale gas development.*
- *Good regulation that is effectively enforced can minimise all the risks identified in this report, however, South Africa does not have a strong track record of effectively enforcing regulation to extractive industries.*
- *Water-associated issues are a crucial parameter in shale gas economics. A modelling framework is proposed to capture the main cost items related to water in shale gas development, which in turn affects the viability of the industry.*

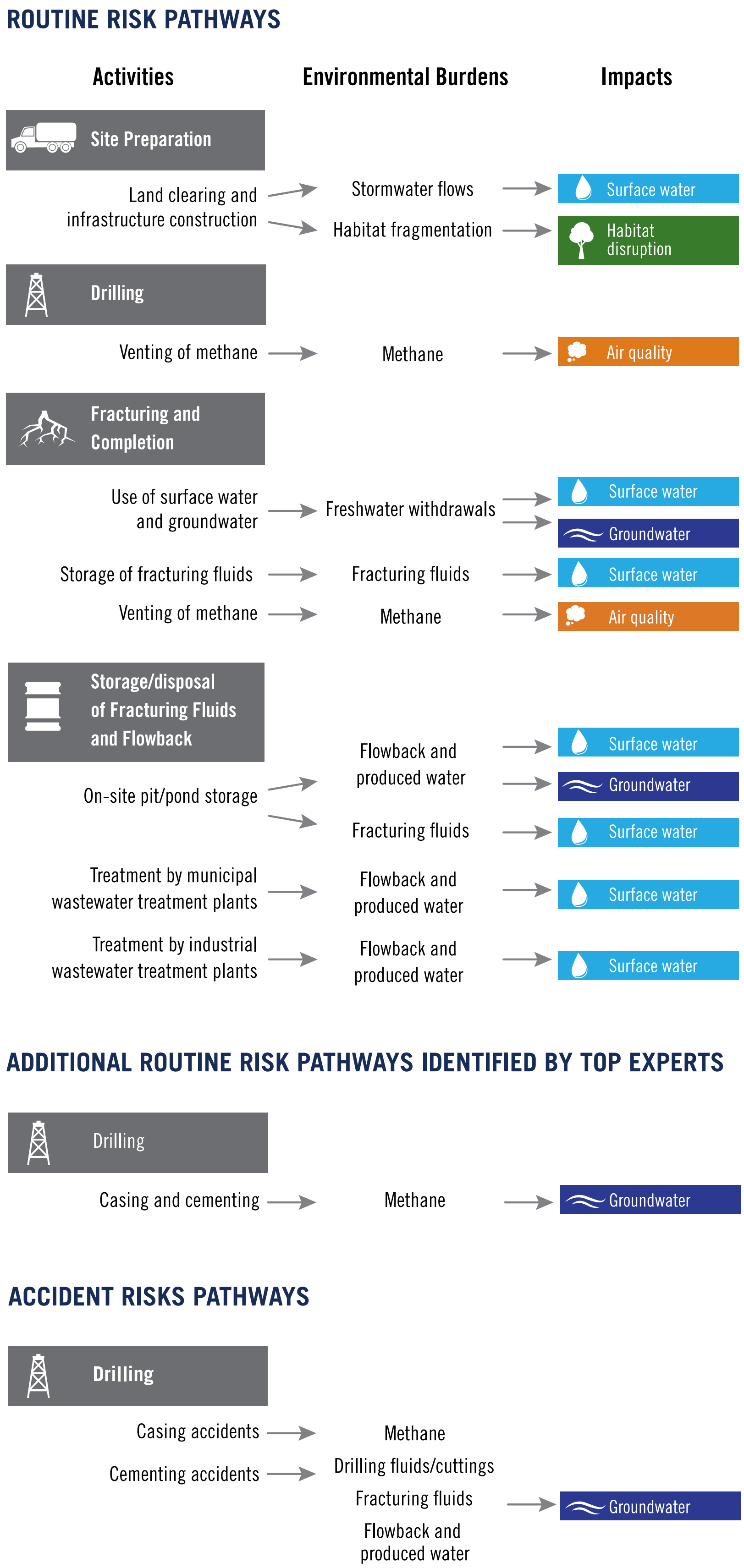
6.1 SUMMARY OF WATER IMPACTS BY SHALE GAS DEVELOPMENT AND IMPLICATIONS FOR SOUTH AFRICA

As this report shows, despite being profiled as a "clean" energy source, shale gas carries a number of environmental risks (as summarised in Picture 8 below). While air quality and habitat disruption can also occur as a result of shale gas operations, most risks relate to compromising the integrity of water resources that are used, or are located in the vicinity of extraction areas.

In the popular media, fracking is usually the focus of the debate on risks associated with shale gas development, however, to date there is very limited evidence that this particular activity poses significant risks to water resources. A long-awaited US Environmental Protection Agency report on the impact of hydraulic fracturing has found no evidence that this technique has had a widespread effect on the nation's water supply. It did however, note several specific occurrences where the chemicals used in fracking led to contamination of water, including drinking water wells, albeit in a small number of cases (compared with the number of fracked wells) (The New York Times, 2015).

Taking the narrow view and focusing on risks associated with hydraulic fracturing only may miss the bigger threats to water resources associated with shale gas developments. As Picture 8 shows, there is a number of shale gas extraction activities besides fracking that can impact water resources both in terms of their quantity and quality. The volume of water required by a single shale gas well is in the order of 10 – 20 million litres. While there are alternatives to the use of potable water as the base fluid, it is currently still the main carrier fluid used by the industry. The volume of wastewater generated by a fully developed shale gas industry is likely to reach hundreds of millions of litres. Experience in the US suggests that treatment facilities for flowback water and produced water may need to be purpose-built. While the DMR (2012) study suggests that this is a short-term issue, this is not supported by experiences to date, especially in areas where underground injection is not permitted, which will also be the case in South Africa. Therefore, wastewater management is likely to be a major long-term issue for the industry.

Picture 8 Environmental impacts associated with shale gas operations



Source: (Krupnick, 2013)

There is evidence of groundwater contamination with methane in some but not all active shale gas extraction areas. Well construction, combined with geology, determine the possible leaking of gas from wells. To date there is no evidence of groundwater contamination by fracking fluid or produced water that has migrated upward through the geological layers to the groundwater table. Nevertheless, this contamination pathway has been proven to be feasible, and currently the main contestation is the fluid migration pace to shallower layers that hold groundwater sources.

Depending on its specific context, different water-related issues can have greater or lesser prominence in a shale play. For instance, in the US Barnett shale, a dry area with high population density, the biggest water-related concern is water scarcity and the resulting competition for scarce water resources. The situation is similar in the fast-growing Bakken play[47], which has a high density of agricultural land and rangeland activity, where the most prominent issues are land and water use conflicts between the extraction industry and the area's farmers and ranchers (Mauter, Palmer, Tang, & Behrer, 2013). In the Marcellus, with its well-developed pipeline network stemming from past conventional drilling activity and close proximity to gas demand centres, the primary environmental challenge is wastewater disposal (Mauter, Palmer, Tang, & Behrer, 2013).

In the Karoo, with its limited availability of water and inappropriateness for underground wastewater injection, it is not inconceivable that both these issues would rise to prominence. Possible competition for water sources could have perhaps been relaxed somewhat if exploration licenses would have been linked to a requirement of simultaneously looking for shallow water reservoirs, which have been poorly explored in the Karoo (De Wit, 2011), although this is now probably a missed opportunity. The significant uncertainty that remains about the Karoo's hydrogeology amplifies contamination risks from sub-surface activities. The attributes of the dolerite and kimberlite intrusions at greater depths remains unknown, and may act either as conduits for fracturing fluids or as barriers to flow. This clearly calls for further research before exploration and production drilling begins.

To minimise the risks to (fresh)water resources and the surrounding environment from the contaminants inside the well, we need a better understanding of site-specific risk factors that might contribute to gas leaks and stray gas, and improvements in the diagnostics of cement and casing integrity for both new and existing wells (Vidic, Brantley, Vandenbossche, Yoxtheimer, & Abad, 2013). Finding solutions to these problems will provide environmental agencies with the knowledge needed to develop sound regulations and operators with the ability to prevent gas migration and stray gas in more efficient and economical ways (Vidic, Brantley, Vandenbossche, Yoxtheimer, & Abad, 2013).

While water pollution is a risk in any industrial process, it can in principle be minimised by enforcing best practice regulations across the shale gas water cycle. A number of relevant regulatory requirements are already in place, such as the execution of a water withdrawal impact assessment, the installation and monitoring of an observation well if there is a freshwater supply well within one-quarter mile of the shale gas well, while others are still under development. At the same time, good regulations are of limited value, if they are not effectively enforced, which requires significant resources and capacity. Unfortunately, experience in South Africa suggests that achieving this is unlikely; with the case of acid mine drainage showcasing environmental tragedies caused by ineffectively regulated extraction industries. Even in the US, the likelihood of effective enforcement has been called into question, considering that "the industry has developed so rapidly that it has often outpaced the availability of information for regulators to develop specific guidance" (Accenture, 2012).

[47] That is, where the focus is unconventional oil rather than gas.

US experiences, accumulated across a number of shale plays that differ significantly concerning their geological, hydrological, environmental, regulatory and infrastructure resources offers useful insights into the variance that can be expected between international shale plays and that can be used to identify the major categories of water-related risks (Mauter, et al., 2014). The impacts in each play depend on their specific environmental context (including the geology), the technology employed to extract unconventional gas, and the ability to implement available control technologies, to adopt responsible environmental management practices, and improve regulatory oversight (Mauter, 2015). Minimising water-associated impacts of shale gas development will require an understanding of the unique water stressors posed by shale gas development in a particular region (Mauter, et al., 2014). This limits the transferability of experiences across shale plays and implies the need to build domestic expertise on every aspect of water management in specific locations where shale gas resources are developed. This capacity building process is a long-term process that is already under way in South Africa. However, the concern is that industrial development will not wait for the necessary knowledge pool to be ready, so that operations can proceed with the adequate understanding of the local situation.

Water is a scarce resource, and its scarcity is becoming more acute with increasing climate change impacts. Limits on its availability, economics and the politicised nature of the discussion about competing water uses are driving the industry to become more efficient and less reliant on freshwater sources for its operations. While this trend is likely to continue, it cannot be assumed that it is in any way sufficient to protect South Africa's water sources from over-exploitation and pollution. A strong regulatory regime will therefore be necessary, coupled with active capacity-building in both the private and public sectors, to ensure that sufficient knowledge is available in the country to adequately address the multifaceted and complex issues related to water in shale gas development.

As water-related costs critically impact the economics of shale gas, understanding the economics of water in South African shale gas operations will be crucial for the Government, the regulators and other stakeholders. Most of the information that would be needed for such an assessment is not yet available. However, a framework for assessing the water costs of shale gas operations is useful to provide insights into the complexity of the matter. Such a framework is outlined in the final paragraphs of this report.

6.2 TOWARDS A WATER-COSTING MODEL FOR SHALE GAS DEVELOPMENTS IN SOUTH AFRICA

To be able to provide at least a first-level estimate of the amounts and costs of water supplied to shale gas operations, a benchmark well would be needed, to provide a figure of average water use per well. The approximate number of wells and their distribution across the prospecting areas would be required. None of this information will be available until the exploration phase is completed. The re-fracking rate also plays an important role in determining total water requirements by the shale gas industry.

What will be needed next is the compilation of a comprehensive overview of all available water sources in the prospecting areas and in the wider region. Water sources to be included in such an overview are:

- Surface water and groundwater (non-licensed and licensed but not used),
- Municipal and industrial wastewater (treated),
- Deep water aquifers found during exploration,
- Recycled fracking wastewater,
- Sea water (up to a limited amount).

Other data that will be needed to complete the costing exercise includes:

- The de facto water price (for the various sources),
- The costs of treating the wastewater for re-use and for final disposal,
- Logistical costs (trucking or piping water from source to well, and from well to centralised wastewater treatment and final storage),
- The infrastructure investments needed to enable the necessary water-related logistics.

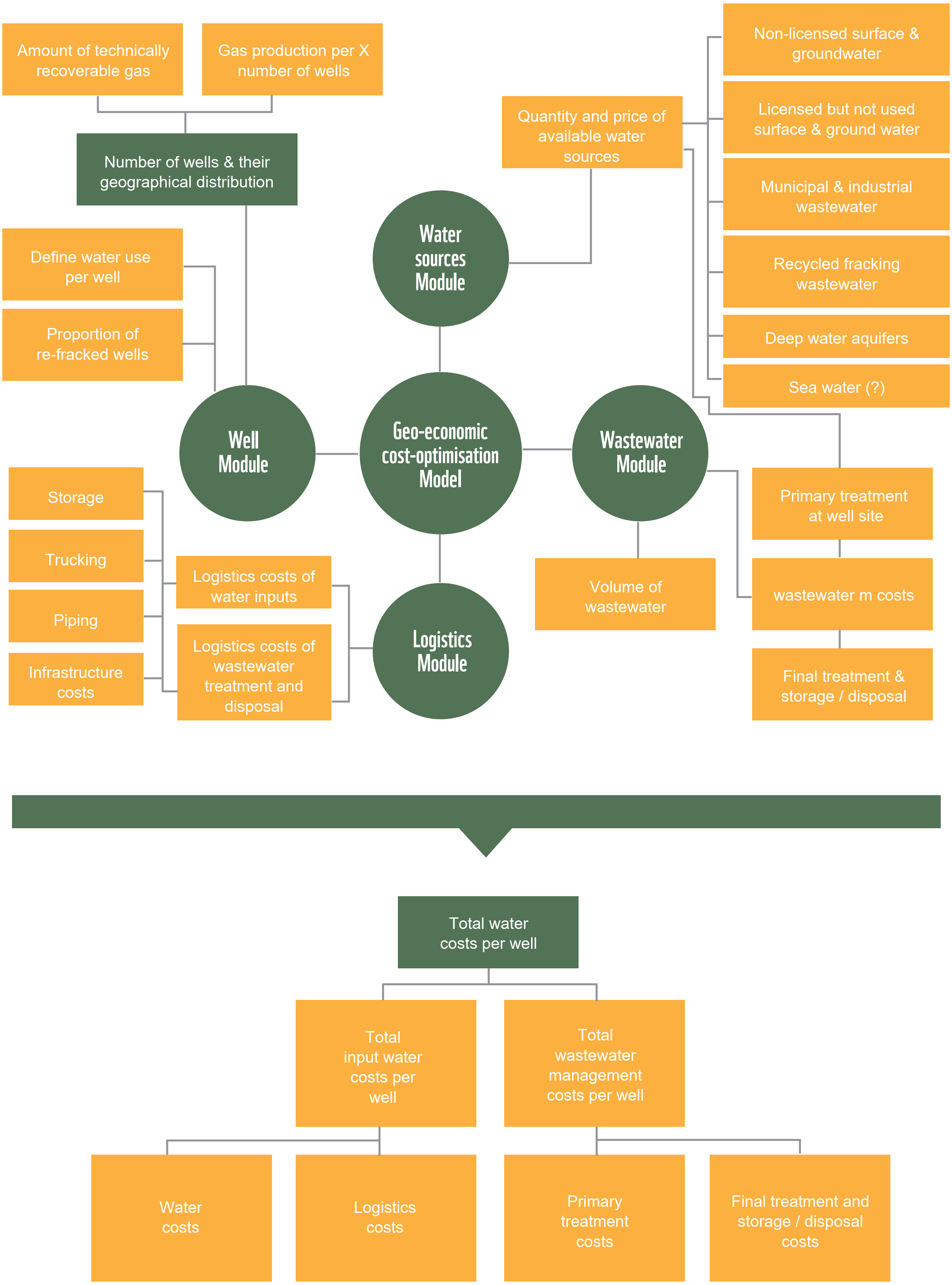
A spatial economic cost optimisation model would need to be constructed that would match the cheapest water sources with each well, considering the water price (or cost in the case of recycled wastewater), and the cost of logistics to get it to the well; add together, this would form total input water cost per well. It will probably have to be composed of four modules:

- A well distribution and production module that will include number and position of wells;
- A water source module that will include volume and price/cost per water source;
- A wastewater treatment module that will include volumes and technology costs of two wastewater streams – one for re-use and one for final treatment and disposal. The part of the module dealing with wastewater for re-use will need to feed into the water source module;
- A logistics module that will allow for the costing of getting the water from the various sources to the wells, and from the wells to treatment plants, and on to re-use locations or final storage/ disposal.

The model should continue to match the least-cost water source with wells until the assumed recoverable amount of gas is extracted, all water sources are depleted, or the cost of their exploitation becomes prohibitive, whichever happens first.

The framework for assessing the water-related costs of shale gas operations is summarised in Picture 9. The author hopes that such an analysis, one based on real, site-specific data, can be undertaken soonest to provide better insights into the economics of shale gas in South Africa.

Picture 9 Water costing framework



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