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## HALLIBURTON

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19 March 2018

Dr Tom Hatton  
Chair  
Independent Scientific Panel Inquiry  
Locked Bag 33, Cloisters Square, Perth WA 6850

By email: [info@frackinginquiry.wa.gov.au](mailto:info@frackinginquiry.wa.gov.au)

Dear Dr Hatton

Halliburton Australia Pty. Ltd. ("Halliburton") is pleased to have the opportunity to make a submission to the inquiry you are chairing on behalf of the Government into the effects on the environment of the process of hydraulic fracture stimulation in Western Australia.

In 2013, Halliburton lodged a submission and appeared before the Environment and Public Affairs Committee's Inquiry into the Implications for Western Australia of Hydraulic Fracturing for Unconventional Gas.

This submission updates the information we provided to the Parliamentary Inquiry over four years ago.

Halliburton is willing to provide further information to the Inquiry as required.

Please don't hesitate to contact me should you require any further information regarding this submission or any other questions you may have.

Yours sincerely



Jason Jeow  
Senior Area Manager, Australasia

HALLIBURTON AUSTRALIA PTY LTD



**HALLIBURTON**



**Independent Scientific Panel Inquiry into**

**Hydraulic Fracture Stimulation**

**in Western Australia**

**Submission by**

**HALLIBURTON**

**19 March 2018**

# **Halliburton Australia Scientific Inquiry into Hydraulic Fracturing**

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## A. Executive Summary

Over the past decade or so, hydraulic fracturing techniques (HF) have been the catalyst for the 'revolution' in unconventional gas which has produced major economic and energy security benefits for the United States and other nations. Australia is benefitting from the substantial growth in the unconventional gas industry and the country is well placed to expand this industry and the benefits that flow from it.

Halliburton is a leading provider of services to the energy industry and is the global leader with respect to oil and gas production enhancement, and HF in particular. Over the course of nearly 70 years, Halliburton has provided HF services for hundreds of thousands of wells around the world in a wide variety of settings and geological formations. Halliburton's role in the sector is to provide these well services to our customers. Halliburton however, does not own or operate wells in Australia.

The key environmental risk issue that has been raised over recent years in relation to HF is the protection of groundwater. As a result of community concerns there have been numerous inquiries and studies into HF undertaken by various governments and agencies around the world. In over 60 years, in which more than 2.5 million wells have been hydraulically fractured in Australia and internationally, there is no confirmed evidence that HF fluids have ever contaminated groundwater as part of a HF process. Independent scientists such as those at CSIRO have repeatedly identified wellbore integrity as the critical factor in protecting ground water.

A critical factor in the growth and success of the unconventional gas industry in the last decade has been technological advances and innovations in HF fluids and other technologies. Halliburton is a leader in the field having developed innovative new products from ongoing research and development. For example in 2015, Halliburton invested nearly half a billion dollars company-wide on research and development. These innovative new products, the result of R&D investments, deliver economic benefits in terms of production enhancements as well as significant environmental benefits. For example, the innovative 'CleanStim' is a fracturing fluid system developed by Halliburton which is made entirely of ingredients sourced from the food industry and it provides exceptional fracturing and environmental performance as compared to traditional formulations.

Halliburton supports public disclosure of fracturing fluid ingredients and has taken a number of steps to provide the public with information regarding the chemicals used in HF operations, including supporting the disclosure of information regarding the makeup of the fluids used in HF operations at individual well sites in the U.S. through the FracFocus Hydraulic Fracturing Chemical Disclosure Registry ("FracFocus") website: <http://fracfocus.org>. Indeed, the FracFocus website contains detailed, well-specific information concerning the fluids used by Halliburton in hydraulically fracturing tens of thousands of wells.

Australia currently has a thriving natural gas industry, leveraging its significant offshore and onshore deposits. In more recent years, Australia has tapped the additional potential for onshore unconventional gas deposits – including shales, other 'tight' deposits and coal seams -



where technologies like HF sometimes have an important role to play in enhancing production and project viability.

## ***Recent Reviews into Unconventional Gas/Hydraulic Fracturing***

Halliburton has participated in various independent reviews of unconventional gas and HF in Australia over recent years, which have been undertaken by and for state parliaments and governments. These include:

- The Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2016-ongoing)
- West Australian Parliament's Standing Committee on Environment and Public Affairs inquiry into Hydraulic Fracturing for Unconventional Gas (2013-15)
- Independent Inquiry into Hydraulic Fracturing in the Northern Territory (2014, Allan Hawke AC)
- Independent Review into Coal Seam Gas Activities in NSW (2014, NSW Chief Scientist)
- Victorian Parliament's Planning and Environment Committee's Inquiry into Unconventional Onshore Gas (2015)
- South Australian Parliament's Natural Resources Committee inquiry into Unconventional Gas (2015-2016)

There is a consensus in the conclusions of these reviews, including those in the Northern Territory's Draft Report released in December 2017, that the risks associated with unconventional gas production, including HF, are low and manageable, and can be conducted safely. This consensus is similar to the conclusions drawn by independent reviews and substantial scientific evidence from around the world.

## **B. About Halliburton**

Halliburton is a leading provider of services to the energy industry and is the global leader with respect to oil and gas production enhancement, and hydraulic fracturing (HF) in particular. Over the course of nearly 70 years, Halliburton has provided HF services for hundreds of thousands of wells around the world in a wide variety of settings and geological formations.

In more recent years, HF and horizontal drilling has been the catalyst for the 'revolution' in unconventional gas which has produced major economic and energy security benefits for the United States and other nations.

At the core of Halliburton's business is technological innovation and a very strong long-term commitment to research and development. In the area of HF, technological innovation is substantially increasing the efficiency and viability of natural gas production, and doing so in a way that minimizes environmental impact. Halliburton has a strong interest in ensuring that any future hydraulic fracturing operations in Western Australia are performed in the most environmentally responsible and effective manner.

Halliburton commenced operations in Australia in 1958, and now employs around 576 staff across the country including 255 in Western Australia. Our Australian corporate office is in Perth and bases are located in Jandakot and Dampier. In 2017, Halliburton spent US\$56 million

sourcing goods and services from around 634 Australasian vendors, of which around US\$13 million was spent in Western Australia.

Halliburton began providing HF services in Australia in the late 1960s, and has since performed more than 4,000 jobs (in Western Australia, South Australia, the Northern Territory, Victoria, NSW and Queensland) in a broad range of conventional, unconventional and geothermal projects.

Halliburton's initial hydraulic fracturing operation in WA was in the mid 1960s. Due to the passage of considerable time, exhaustive records are no longer available, however based on our investigation into the available records, we estimate having performed hydraulic fracturing treatments on 171 wells in WA to date.

## **C. Opportunities Associated with Unconventional Gas**

In the context of previous Australian policy inquiry processes, APPEA as the peak industry body has provided a comprehensive overview of the role of shale and other unconventional gas and the resources identified in Australia, as well as the history and operational characteristics of HF as a critical production enhancement technology.

While HF has been used over many decades in accessing conventional gas reserves, advances in HF technology over the last 10 to 15 years in particular have seen it become critical to the recovery of oil and gas from shales and other unconventional formations, such as tight sands. These unconventional sources generally must be stimulated to produce oil or gas in commercial quantities.

Natural gas development, particularly relating to unconventional gas sources where HF has been a critical technological catalyst, has yielded important social, economic and environmental benefits over recent years. In the U.S., for example:

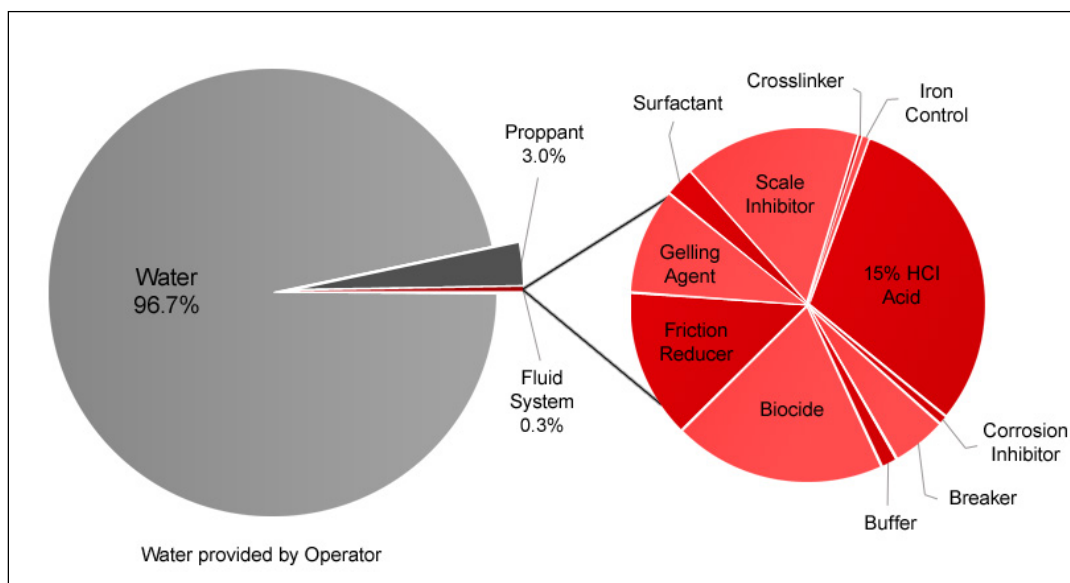
- Natural gas prices have decreased from an average of \$8.89 per MMBtu in 2008 to around \$3.00 per MMBtu today, primarily as a result of large-scale unconventional gas development. This has resulted in major economic benefits, both through the creation of jobs and by providing consumers lower costs for home heating and electricity. HF has boosted U.S. natural gas production by about 30 percent since 2005. Companies who use natural gas as a feedstock have built new manufacturing plants in the U.S. worth over \$100 billion.
- The U.S. EPA has noted that the increase in electric generation from natural gas has led to a decrease in the overall carbon intensity of electricity generation. (U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011*, ES-11 <http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-ES.pdf>). Greenhouse gas ("GHG") emissions were lower in the United States in the first quarter of 2012 than they were during any first quarter since 1992 and overall GHG emissions in 2012 were at their lowest level since 1994, due in significant part to increased electricity generation from natural gas.

## D. Hydraulic Fracturing Fluid Systems

HF specifically refers to the process of pumping fluids and proppant at high pressures to create fractures in the rock. In order to achieve this, a physical pathway from the wellbore to the reservoir must be available. To create a connection, any range of different techniques could be utilised such as: a wireline perforating process using explosive charges; hydrajetting on the end of coiled tubing with abrasive fluids to erode the casing; and cement or sliding sleeve technology. It is important to note that these processes are considered independent of hydraulic fracturing itself as each could also be performed in wells without any hydraulic fracturing treatments pumped.

Water and proppant (sand) typically make up over 99% of the fracturing fluid system. The remaining small percentage is made up of chemical additives that perform a variety of functions depending on the characteristics of the formation being evaluated.

For instance, in the case of deep HF treatment, the following diagram presents the typical composition of a fracturing fluid formulation:



The functions served by the less than 1% of chemical additives used in a typical frac formulation include: increasing the viscosity of the fluid to improve proppant transport, reducing friction, inhibiting bacterial growth, preventing corrosion in the well casing and limiting the formation of scale and other precipitants that could impede the flow of oil and gas and fluids.

Many of the chemicals in the additives used in the process are also found in foods or in household products such as cosmetics, shampoo and cleaning products. See <http://www.energyindepth.org/frac-fluid.pdf>

## E. Benefits of Product Innovation

A critical part of the success of the unconventional gas industry in the last decade has been technological advances and innovations in HF fluids and other technologies. Where companies like Halliburton have developed innovative products, these are the result of significant investments in research and development; for example, Halliburton spent \$487 million company-wide on research and development in 2015. These innovative products provide demonstrable economic benefits in terms of production enhancements as well as significant environmental benefits. For example, studies performed by Halliburton in the Marcellus Basin and the Codell Basin in the U.S. show that:

- The use of Halliburton's proprietary HF products results in an average increase in production of 33% as compared to non-proprietary stimulation fluids.
- The use of microemulsion surfactants developed by Halliburton has been found to result in long-term increases in oil and gas production of as much as 50% as compared to wells hydraulically fractured with conventional fluids.
- 24-41% more wells would need to be drilled to achieve the production enhancement that advanced technology provides.
- Halliburton's innovative products also facilitate the recycling of flowback and produced water.

See: <http://cogcc.state.co.us/RuleMaking/PartyStatus/RebuttalStmts/HESIRebuttal.pdf> at p. 27.

Specific HF and other product innovations by Halliburton that have led to significant environmental and production benefits include the following:

- CleanStim is a fracturing fluid system made entirely of ingredients sourced from the food industry that provides exceptional fracturing and environmental performance as compared to traditional formulations.
- PermStim™ fracturing fluid provides a cleaner, more robust system than typical guar-based fluid systems. PermStim fluid is a derivatised natural polymer that contains no insoluble residue, enabling improved well clean-up and better sustained productivity.
- UniStim™ is a high performance HF fluid that is tolerant of high concentrations of total dissolved solids, including contaminants consistent with heavy produced water brines. This tolerance facilitates recycling because it allows significantly greater use of minimally treated oilfield produced and flowback water, thereby reducing demands on fresh water and the associated need for truck transportation and disposal.
- 'Frac of the Future' reduces our footprint with the use of our SandCastle vertical storage bins, which can reduce the well site size required for HF operations from about four hectares to as little as 1.2 hectares. This size reduction is accompanied by a reduction in noise and emissions through using fewer diesel engines. Reducing the number of

pumping units required is reducing truck traffic to and from the wellsite. Halliburton won the 2012 World Oil HSE Award for this approach.

- CleanStream® Service treats bacteria present in the water provided at the well site with ultraviolet light instead of the biocides that are commonly used. In many cases, the CleanStream process can be 99.9% effective, dramatically reducing the need for chemical biocides.
- ADP™ Advanced Dry Polymer Blender enables mixing any of Halliburton's fracturing fluids using a dry polymer, eliminating the need for liquid gel concentrates and resulting in conservation of petrochemical materials and reduced vehicle miles travelled transporting liquid gelled material. During 2012, the use of ADP blenders and associated dry gel removed over 30 million gallons of hydro-treated light petroleum distillates from HF fluid in North America.
- WellLock Resin is an advanced cementing product developed by Halliburton with significant environmental benefits. WellLock resin is a synthetic thermosetting polymeric material that helps control and prevent annular flow, thereby protecting against potential migration of gas and water. Unlike other resins, WellLock resin is non-flammable and tolerates water (i.e. does not react exothermically) and is designed to work with aqueous-based fluids (i.e. water-based muds, cement slurries).

In short, these and other technologies minimize the use of chemicals, promote recycling, limit fresh water requirements, and reduce traffic and air emissions as well as surface disturbances while enhancing production, resulting in a reduced overall footprint. The recognition and protection of proprietary information in a balanced regulatory framework provides the basis for companies to invest in ongoing technological innovation.

## **F. Environment Risks and Mitigation Issues**

### ***Impacts on Groundwater***

The key environmental risk issue that has been raised over recent years in relation to HF is the protection of groundwater. In over 60 years in which more than 2.5 million wells have been hydraulically fractured internationally there is no confirmed evidence that contamination of drinking water aquifers has ever occurred as a result of HF operations.

The environmental outcomes of hydraulic fracturing of unconventional oil or gas deposits can be influenced by the geology, hydrogeology and hydrology at and in the vicinity of the well site. For example, one consideration in designing an HF operation is the depth of drinking water aquifers relative to the anticipated height of induced fractures; in areas where the separation between the target zone and shallow aquifers is limited (conditions that are more likely to be encountered with Coal Seam Gas (CSG) and that are unlikely to be encountered in Western Australia tight or shale gas plays), the design of an HF operation must be carefully considered. In addition, the location of faults must be taken into account; these areas are generally avoided for a variety of reasons and are unlikely to be the site of HF operations in the first place.

Relevantly for the Western Australia inquiry, sedimentary basins that are the focus of shale projects around the world share a number of characteristics that ensure that the likelihood of fracturing fluids migrating from the target zone to shallow aquifers is remote. Gradient Corporation, one of the world's leading environmental and risk science firms, undertook an extensive analysis of the potential risks to drinking water associated with the use of HF fluids in 2013, evaluating whether it is possible for fluids pumped into a tight formation during the HF process to migrate upward to reach drinking water aquifers. Gradient, *National Human Health Risk Evaluation for Hydraulic Fracturing Fluid Additives* (May 1, 2013) ("Gradient 2013 Study"), available at [http://www.energy.senate.gov/public/index.cfm/files/serve?File\\_id=53a41a78-c06c-4695-a7be-84225aa7230f](http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=53a41a78-c06c-4695-a7be-84225aa7230f).

Gradient determined that once the fracturing fluids are pumped into a tight formation, it is simply not plausible that the fluids would migrate upwards from the target formation through a thousand meters or more of rock to contaminate drinking water aquifers. Gradient found that there are a variety of factors that contribute to the implausibility of this scenario:

- Tight oil and gas formations are found in geologic settings that greatly restrict upward fluid movement due to the presence of multiple layers of low permeability rock. Because studies show that fractures remain at least 500 metres – and usually more than a thousand metres – below the surface fluids would have to migrate an extended distance through multiple layers of rock, many of very low permeability, in order to reach shallow aquifers;
- Another factor inhibiting upward fluid migration is the inherent tendency of the naturally-occurring formation water (brines) to sink and form a stable layer below rather than mingle with or rise above fresh water (density stratification). In order for the fracturing fluids and brines to reach fresh drinking water aquifers, the fluids would have to overcome this natural stratification. However, upward hydraulic gradients that might otherwise be sufficient to overcome this stratification are found only where there is an overlying rock layer of very low permeability, which essentially prevents any upward fluid movement. The effect of these constraints is demonstrated by the fact that the oil and gas and the brines have been trapped in the target formation for millions of years;
- The HF process itself does not create conditions that would overcome these natural restrictions on fluid movement because the associated pressures are too short-term and localized to push fluids through hundreds or thousands of metres of low permeability rock. A typical HF stage lasts only 1-2 hours, and the pressures exerted extend only about 3 meters from the fractures that are created. Moreover, any fluids introduced into a deep shale formation typically will be soaked up and trapped within the shale by natural capillary forces. At the same time, the removal of brine and oil/gas from the well during long-term production reduces the pressure in the target formation near the wellbore over a period of years, meaning that any fluid flow will be in that direction (*i.e.*, towards the wellbore or towards lower pressure in accordance with Darcy's Law). Therefore any remaining fluids would be drawn to the wellbore and would not be likely to migrate away;



- The fractures created during HF are of limited height. This is confirmed by microseismic data from over 12,000 HF operations in shale plays and other formations across the U.S. which show that the “tallest” fracture was less than 600 metres in height with typical fracture heights being far less (the median fracture height was less than 80 meters), and in all cases there were at least 500 metres (and usually more than a thousand metres) of intact bedrock above the fractures. These data are consistent with the limits on fracture height growth suggested by basic geophysical principles, which indicate that fracture heights are limited by fracturing fluid volume and that the amount of fluid used in an HF operation is simply insufficient to propagate a fracture from the typical depth of a shale formation upward to a depth that is anywhere close to drinking water aquifers;
- Additional factors limiting fracture height growth include (i) the existence of stress contrasts between sedimentary layers, which tend to limit the growth of fractures into adjacent layers, (ii) the creation of fracture networks and the leakoff of fracturing fluids that results in the energy created during HF operations by the fluid pressure being spread across multiple fractures rather than being concentrated in driving a single fracture to its maximum possible height, and (iii) the tendency of fractures to become horizontal rather than vertical at shallower depths (above about 600 metres below ground surface). In fact, the few fractures in the extensive database mentioned above that were shallower than 600 metres below ground surface showed essentially no height growth. See also Fisher & Warpinski, *Hydraulic Fracture Height Growth: Real Data*, Society of Petroleum Engineers SPE 145949 (Feb. 2012), available at [http://www.spe.org/atce/2011/pages/schedule/tech\\_program/documents/spe145949%201.pdf](http://www.spe.org/atce/2011/pages/schedule/tech_program/documents/spe145949%201.pdf) ; and
- The same microseismic data show that – despite speculation to the contrary – the presence of natural faults in the bedrock does not significantly contribute to the upward movement of fluids. The data indicate that existing faults are activated to only a very limited extent (movement over a distance of less than 20 metres) during HF operations, resulting in very little additional fluid movement beyond the movement through induced fractures.

Gradient stated that its analysis covered a wide range of sedimentary basins in the U.S. with different characteristics and would apply to sedimentary basins around the world with similar characteristics.

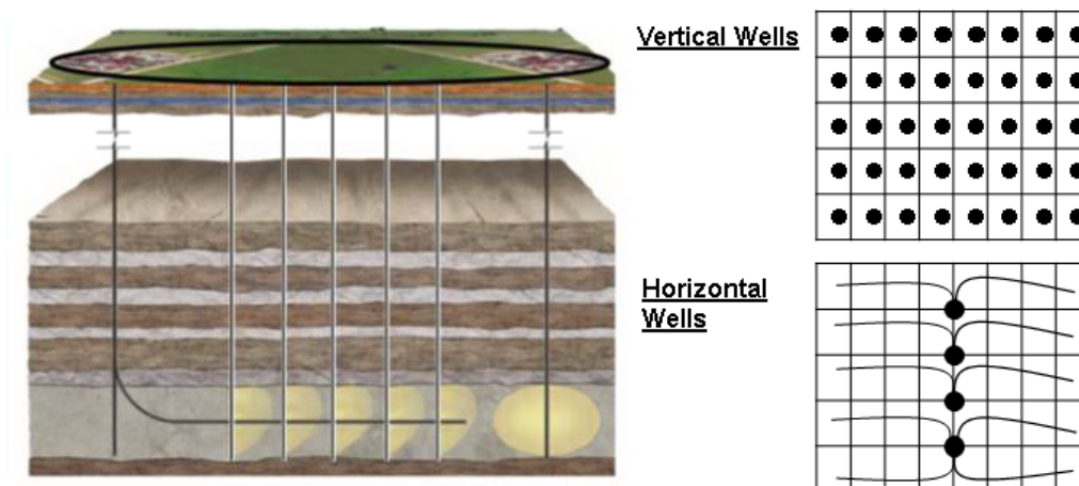
Gradient also analyzed the potential for spills of HF fluids (or flowback fluid) to reach drinking water wells or surface waters. Using a “probabilistic” approach to address a wide range of spill scenarios and hydrologic conditions as well as very conservative assumptions (e.g., no spill mitigation measures in place and no adsorption of chemical constituents to the soil or degradation in the environment), Gradient determined the concentrations at which HF constituents might be found in surface water or a drinking water well as a result of a spill and compared them to levels at which health effects might become a concern. Gradient found that any human health risks would be insignificant because various dilution mechanisms would further reduce the already low concentration levels of HF constituents before they ever reached drinking water sources.

In short, while local conditions should be considered, the common characteristics of sedimentary basins, generally applicable geological and hydrogeological principles and the nature of HF operations mean that the environmental outcomes of hydraulic fracturing of shales and other tight formations will not involve adverse human health impacts to groundwater or surface water.

We have consolidated in [Appendix A](#), for your information, a range of statements and studies from Australian authorities, U.S. Federal officials, U.S. State government agencies, and others to corroborate that there is little or no risk of fracturing fluids contaminating groundwater. In all there are more than twenty studies and inquiries referenced which demonstrate the minimal risks.

### ***Reducing Impact on the Landscape and Use of Water Resources***

Many installations for production now utilise multiple horizontal wells drilled at a common well pad in order to maximize oil and gas production and minimize the amount of land disturbance when developing the well network to extract the oil and/or natural gas. Well pads for multi-well installations may vary somewhat in size, depending on the number of wells installed and whether the operation is in the drilling or production phase. Six to twelve horizontal wells can be drilled from a single wellpad.



Horizontal drilling and hydraulic fracturing reduce the “footprint” of natural gas operations by 400 percent over operations involving vertical wells. This is because with one well pad at the surface, horizontal drilling using hydraulic fracturing can extract the amount of natural gas that would take a number of well pads to extract using vertical drilling only. This reduction in surface use to an area of approximately a hectare has ancillary benefits in terms of less truck traffic, reduced air emissions, a lower risk of spills and stormwater runoff, and reduced use of resources overall.



A single HF process for a horizontal well typically uses 11 to 19 million litres of water. In Australian tight-gas vertical wells, the amount of water used in hydraulic fracturing is substantially less, typically in the order of several hundred thousand litres or less. For Australian vertical shale wells, the water volumes tend to be similar to those of the designs for the horizontals.

Industry recycling efforts minimise fresh water consumption and the costs associated with procurement and disposal, as well as trucks needed to transport water to well sites, meaning less impact on rural communities. In the US, millions of litres of water are currently being treated and reused. For example, regulators in Pennsylvania recently reported that operators in the Marcellus Shale region of the state are recycling up to 90% of their flowback and 65% of their produced water. Halliburton has also assisted its customers in resolving water supply challenges through technology, including the development of fluid systems that use briny or salty water as the base fluid instead of fresh water.

Halliburton encourages the recycling of wastewater by its operators and has developed innovative technologies to support reuse and recycling efforts. For example, Halliburton has developed CleanWave®, a water treatment system that treats wastewater at the well site to enable recycling and reuse of the wastewater for drilling and fracturing subsequent wells. Halliburton has also developed UniStim, a high performance HF fluid that is tolerant of high concentrations of total dissolved solids, including contaminants consistent with heavy produced water brines. This tolerance facilitates recycling because it allows significantly greater use of minimally treated oilfield produced and flowback water, thereby reducing demands on fresh water and the associated need for truck transportation and disposal.

### ***Importance of Well Design, Construction and Control Standards***

The construction of an oil or natural gas well is undertaken in accordance with government regulatory regimes as well as industry standards (such as those developed by API and APPEA) and other good engineering practices.

Multiple layers of cement and steel casings provide zonal isolation – not only to protect the groundwater but also to provide safe conduits for operations – including placing fracturing treatments in the desired formation.

Studies have concluded that the probability of fracture fluids reaching an underground source of drinking water due to failures in the cementing or casing of a properly constructed well is estimated at less than 1 in 50 million wells. See *Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program (ICF Task 1: Technical Analysis of Hydraulic Fracturing)*, available at <http://www.nyserda.ny.gov/Cleantech-and-Innovation/Environment/Environmental-Research-and-Development-Technical-Reports/Natural-Gas-Environmental-Impact.aspx> at p. 21.

There have been isolated incidents unrelated to HF that have been caused by improperly constructed wells. Recent studies confirm that even the risk of such incidents is very low. See [https://fracfocus.org/sites/default/files/publications/state\\_oil\\_gas\\_agency\\_groundwater\\_investigations\\_optimized.pdf](https://fracfocus.org/sites/default/files/publications/state_oil_gas_agency_groundwater_investigations_optimized.pdf)

There is considerable literature available on well integrity and barrier failure of oil and gas wells, primarily in respect to the United States experience. Halliburton considers that the recent paper *Environmental Risk Arising From Well-Construction Failure – Differences Between Barrier and Well Failure, and Estimates of Failure Frequency Across Common Well Types, Locations and Well Age* (King & King, 2013) will assist the Inquiry on the topic of well leak statistics and other matters. A copy of the King and King 2013 paper is included at Appendix B of this submission for information.

The King & King paper is a peer approved publication, and considers an extensive data set of 600,000 wells worldwide. It not only identifies failure rates, but explains the key factors contributing to well failures. The data set available allows a conclusion to be drawn in respect to the overall frequency of leaks from wells and the risk that leaks pose to groundwater. However, it does not quantify the volumes of above surface or subsurface leaks into the outside formation arising from any incidents. Particular summary points that may be of interest to this Inquiry include:

- Oil and gas wells are comprised of multiple layers of steel, cement, seals and valves, providing multiple barriers between well fluids, oil or gas and the surrounding environment. Well design is a geomechanical, fit-for-purpose engineering exercise, with design taking account of unknowns associated with the outside formation and worst-case loads and forces. Wells are engineered to both warn of a potential problem and prevent the occurrence of a problem. One or more individual barriers of a well may fail without creating a pathway to the outside formation and the potential for impact to the environment or groundwater.
- The paper differentiates between individual barrier failures and well integrity failure when all barriers fail, giving rise to the possibility of a leak. While there is considerable variability in failure rates across the globe, King & King conclude that oil, gas or injection wells constructed to current standards have an overall leak frequency ranging from 0.005 to 0.03%. These well integrity failure rates are two to three orders of magnitude less than for single barrier failures. King & King also conclude that the overall risk of pollution to groundwater from producing wells is extremely low.
- The paper refers to a previous study of groundwater contamination incidents relating to 65,000 wells in Ohio and 250,000 wells in Texas<sup>1</sup>. That study identified no incidents that directly involved hydraulic fracturing. The data indicate that historical environmental incidents associated with oil and gas development are more commonly associated with above ground issues – fluid handling, leaking tanks or flowlines or use of surface pits to contain fluids.
- The most common leak points for producing wells are at the surface, such as failed gaskets or valves, which can be easily repaired. Outward subsurface leaks are uncommon due to the lower pressure gradient in the well compared to the outside

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<sup>1</sup> *State Oil and Gas Agency Groundwater Investigations and Their Role in Advancing Regulatory Reforms, A Two State Review: Ohio and Texas* (Groundwater Protection Council, Kell 2012).

formation. Where subsurface leaks occur, these are more likely water from the outside formation leaking into the well.

- The most important factors contributing to well integrity failure are well age and construction era. A number of historical issues identified in the King & King paper will not represent risks in the South Australian context, given the stage of development of the industry here.

In addition, a failure of the cement (if it occurs) is not likely to create a pathway for migration of fracturing fluid up the well annulus to shallow depths. Water is the wetting fluid in shales and the large capillary forces in predominantly oil- and gas-saturated shale would more likely draw fluid into the rock pore spaces (a process called imbibition). Moreover, fracturing fluid is typically denser than shallow groundwater (especially after mixing with naturally-occurring brine near the targeted formations) and migration through a compromised cement barrier toward the surface would not occur in the absence of a mechanism to force the dense fluid upward; this type of mechanism would generally not be present in the vicinity of a producing well, which creates a low pressure zone near the wellbore and draws fluids toward the well rather than allowing them to migrate up along the casing. Moreover, extraction of oil and gas leads to a significant pressure reduction in the targeted formation that is expected to diminish any naturally pre-existing elevated pressure (if present), such that there would not be a long term driving force for upward migration of dense fracturing fluid after a well is plugged and abandoned.

Cement bonds play a critical role in isolating the oil/gas well from other subsurface formations, including water-bearing formations. Monitoring of these seals, referred to as cement bond integrity logging, is conducted to confirm the presence and the quality of the cement bond between the casing and the formation. Such logging is typically conducted using a variety of electronic devices for each cement bond associated with the well (API, 2009). By following these well installation and testing best practices, wells are carefully constructed, with a number of key design and monitoring elements (e.g., well casings/cement bonds, logging to ensure the adequacy of cementing, and pressure integrity testing). These practices protect drinking water aquifers by achieving full zonal isolation from overlying formations.

Prior to commencing the HF treatment, the well casing and all equipment to be used in the process (e.g., pumps, high pressure lines) are pressure tested to ensure that they can withstand the pressure to be applied during HF. Any leaks observed during such testing are addressed. The pressure testing of equipment helps to minimize the likelihood of any fluid spills during the HF process.

Halliburton supports the efforts of the operators to employ best practices and comply with all applicable requirements for well testing and monitoring to ensure well integrity.

### ***Monitoring During HF Operations***

Similar to well design and installation, the HF process is carefully planned and monitored to ensure that the induced fractures are contained within the target formation to the extent possible, and if there are any indications of abnormal conditions (e.g., abnormal pressure drop), immediate actions can be taken to halt the HF operation. The required HF treatment (e.g., the fracturing pressure, the additive mix and sequencing, duration) is designed by experts. In some

cases, these experts will utilize state of the art computer models to ensure that the HF treatment being applied is appropriate for the job and results in fractures that are contained within the target zone. In other cases, experts may rely on prior experience in hydraulically fracturing other wells in the area, the designs for which may have been based in part in models. In addition, a “mini-frac” treatment, utilizing a small volume of HF fluid, may be initially conducted to collect diagnostic data, which are then used to refine the prior computer modeling results and to finalize the HF execution plan.

Data are continuously collected during hydraulic fracturing to monitor operating conditions and to ensure that fractures are propagating in the subsurface consistent with the design. For example, pressure data are collected at several key locations: the pump, wellhead, and intermediate casing annulus (if the intermediate casing has not been cemented to the surface). Typically, pressure variations are minimal and only slight adjustments are required during the HF process. Unusual pressure changes during an HF operation are typically a sign of a problem (such as a surface spill). In such cases, pumping operations are immediately shut down. In addition to pressure monitoring, pressure relief mechanisms are also included in the production wells. For example, API recommends that the intermediate casing annulus should be equipped with a pressure relief valve, with the line from such a valve leading to a lined pit. Such a pressure relief mechanism ensures that if there is a leak from the production casing, any released fracturing fluid is contained within the intermediate casing annulus, and removed before it migrates into the subsurface.

Halliburton has developed a menu of tools to support these monitoring efforts that are available for well operators’ use. These include microseismic monitoring and Halliburton Foray fracture analysis. Halliburton’s microseismic monitoring, or microseismic fracture mapping, provides an image of the fractures by detecting microseisms or micro-earthquakes that are triggered by shear slippage on bedding planes or natural fractures adjacent to the hydraulic fracture. The location of the microseismic events is obtained using a downhole receiver array that is positioned at the depth of the fracture in an offset wellbore. Microseismic fracture mapping helps assure that the fracture stays in the intended zone and minimizes the number of wells and fractures required.

Halliburton Foray fracture analysis services as a part of the PE Tool Kit and Analysis Services can show an operator where and when fractures are propagating. Using highly sophisticated mathematics, Foray turns events in a microseismic cloud into fracture planes. The software then displays those planes to show the dimensions and principal directions of the fractures to reveal the complexity of the fracture network in a specific formation. This helps prevent over-treatment that could waste fluid and proppant. The information also proves useful in optimizing the number and spacing of stages when fracturing. By better understanding how the formation responds, Halliburton can improve the next stimulation design.

The Schedule of Requirements prescribes minimum monitoring during drilling operations. This includes mud monitoring equipment to determine the concentration of gas in the drilling mud, penetration rate and formation pressure monitoring to warn against possible and approaching pressure increases and well performance monitoring. There are also a range of regulatory reporting requirements, from daily drilling reports to incident, injury and emergency notifications.

## G. Regulatory Approach

Halliburton believes that in those Australian jurisdictions where unconventional gas projects are either underway or under development, regulatory frameworks are in place that are robust and effective. Western Australia is no exception in this regard.

Halliburton participated in the previous Parliamentary Inquiry process in Western Australia which made 12 recommendations in their final report related to improving the operations of the unconventional gas industry in Western Australia.

At a global level, Halliburton understands there is an increasing desire on the part of local communities and the public at large for even greater transparency and access to information. At the same time, laws and regulations that protect innovative technology and proprietary information enable the development of greener chemistry and products that deliver greater environmental and production benefits. Accordingly, Halliburton supports public disclosure of ingredient information related to its HF chemical products, provided that proprietary information of Halliburton and other innovator companies is protected.

There is significant experience in the United States and Canada in the design of regulatory frameworks that strike a balance between disclosing information to the public about chemical use and protection of proprietary information in order to promote innovation and the availability of the most efficient and environmentally advanced technologies for use in the oil and gas industry. Based on this experience, Halliburton considers best regulatory practice for a chemical disclosure regime for HF fluids to encompass the following principles and concepts:

- (a) Disclosure must be made of chemicals proposed to be intentionally added to a hydraulic fracturing fluid or mixture through provision of the following details:
  - i. The trade name, vendor and a brief descriptor or function of each additive/product used in the fluid or mixture.
  - ii. An aggregated list of chemical names and CAS numbers (where available, or another appropriate descriptor if unavailable) for each chemical included in the overall fluid or mixture.
- (b) The maximum proposed concentration by mass of each chemical in the overall fluid.
- (c) If any of the information in (a) is claimed to be confidential business information (CBI) it is not required to be disclosed, however:
  - i. Each piece of CBI which is not being disclosed must be identified and a justification for the claim that it is CBI must be provided (unless it has already been accepted as exempt information by NICNAS under the *Industrial Chemicals (Notification and Assessment) Act 1989* (Cth) in which case CBI will be assumed).
  - ii. An alternative description of each piece of information which is claimed to be CBI must be provided. For example, a chemical family name may be used in lieu of a specific chemical name.

- (d) The information disclosed is posted by the relevant government agency to a public website which allows the public to search for individual well sites and obtain a list of the chemicals used in onshore petroleum activities. This is along the lines of the FracFocus model, outlined below.
- (e) In the event of emergency, the relevant CBI must be disclosed to the relevant government agency, an emergency manager or medical personnel. The information will still be deemed to be confidential and emergency managers or medical personnel must enter into confidentiality agreements either before, or if time does not permit it in an emergency situation, after the CBI has been provided.

The benefits of this approach are as follows:

- The government and the public will have routine access to meaningful and detailed information regarding the chemicals used in hydraulic fracturing fluids for individual wells.
- Companies will be able to continue to compete for business and introduce new and innovative hydraulic fracturing fluids which have environmental and production benefits.
- The responsible government agency does not need to devote time and expense to protecting confidential information and instead may focus its resources on other activities that contribute to environmental protection, such as monitoring casing and cementing programs and ensuring wellbore integrity.

## **H. Disclosure Through FracFocus**

Halliburton supports public disclosure of fracturing fluid ingredients and has taken a number of steps to provide the public with information regarding the chemicals used in HF operations, including supporting the disclosure of information through the FracFocus Hydraulic Fracturing Chemical Disclosure Registry (“FracFocus”) website: <http://fracfocus.org>.

FracFocus is a web-viewable system used to obtain, store, and publish information concerning the chemicals used in HF operations at individual well sites. In the U.S., FracFocus is a joint project of the Ground Water Protection Council (“GWPC”) and the Interstate Oil and Gas Compact Commission (“IOGCC”). Halliburton has supported the use of FracFocus as a platform for providing the public with information regarding the fluids used in hydraulically fracturing individual wells. FracFocus has been very successful in the U.S.

The South Australian Resource Information Geoserver (SARIG), the leading online tool of its type in Australia, bears some similarities to FracFocus, but the latter specifically focuses on well-specific chemical disclosure.

The key characteristics of FracFocus are as follows:

- It allows companies to post information about chemicals used in the fracturing of oil and gas zones on a well-by-well basis. Companies upload HF fluid composition information



and the data are made publicly available (no registration required) and searchable at <http://fracfocus.org>.

- The disclosure form is geographically tagged to allow the public and regulators to find and view information about wells based on their location. The system allows website users to locate wells by state, county, coordinates, a unique identifier known as an American Petroleum Institute (“API”) number, well name and number, Chemical Abstracts Service (“CAS”) number, and ingredient (chemical) name.
- The FracFocus disclosure information identifies the base fluid and additive products used to fracture a well and includes information concerning the constituents of those additive products such as ingredient names, CAS numbers, and maximum ingredient concentration in the overall HF fluid. FracFocus allows for companies to protect confidential business information through the use of general chemical descriptors in lieu of providing specific chemical identities for certain proprietary ingredients. The chemical identity and concentration information provided on FracFocus along with hazard information provided by MSDSs is sufficient in many instances to allow regulators to perform any necessary assessments.
- FracFocus has received over 117,000 disclosure records from 1200 different companies and has been visited by over 750,000 people from over 134 countries.
- FracFocus has functioned effectively as a voluntary reporting mechanism. At the same time, 24 U.S. states, representing over 80% of U.S. onshore oil production and 92% of gas production, and the US’ federal Bureau of Land Management have either proposed or have already opted to require or allow companies to use FracFocus to meet state reporting requirements.
- FracFocus has been a successful regulatory tool in the U.S. and Canada because it allows regulators to provide information regarding the fluids used in hydraulically fracturing individual wells to interested members of the public and at the same time obtain information to support various regulatory functions. It is sufficiently flexible that a number of different states have been able to use it to meet their needs.

## I. Appendices

### APPENDIX A

#### (a) *U.S. Federal and International Studies*

- The U.S. Environmental Protection Agency (“EPA”) released its final report entitled “Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States” in December 2016, representing the culmination of a six-year study requested by Congress. The report concludes that hydraulic fracturing (“HF”) “can impact drinking water resources under some circumstances.” EPA identified certain conditions under which impacts from HF activities can be more frequent or severe, including: (1) spills during the management of HF fluids and chemicals or produced water that result in large volumes or high concentrations of chemicals reaching drinking water resources; (2) injection of HF fluids into wells with inadequate mechanical integrity, allowing gases or liquids to move to drinking water resources (wells are generally constructed today with multiple barriers and EPA concluded that a barrier was reported to be compromised in 3% of HF operations and in most of these cases operations were halted until the problem was resolved); (3) injection of HF fluids directly into drinking water resources (which EPA concluded occurs infrequently, i.e., an estimated 0.4% or less of hydraulically fractured wells; and (4) disposal or storage of HF wastewater in unlined pits (a practice that is prohibited in many states and is not consistent with industry best practices, which call for steps to be taken to prevent infiltration of wastewater into the subsurface). U.S. EPA, *Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States* (December 2016), available at <https://cfpub.epa.gov/ncea/hfstudy/recordisplay.cfm?deid=332990>.
- A U.S. EPA study of allegations of contamination from hydraulic fracturing of coalbed methane (“CBM”) wells “did not find confirmed evidence that drinking water wells have been contaminated by hydraulic fracturing fluid injection into CBM wells.” U.S. EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, ES-1 (2004), available at [http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells\\_coalbedmethanestudy.cfm](http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_coalbedmethanestudy.cfm)
- The U.S. Geological Survey released a study in January 2013 that examined groundwater samples representing approximately one-third of the Fayetteville Shale gas production area and found no regional effects on groundwater from activities related to gas production. Kresse, T.M. et al., *Shallow groundwater quality and geochemistry in the Fayetteville Shale gas-production area, north-central Arkansas*, 2011, U.S. Geological Survey Scientific Investigations Report 2012-5273 (Jan. 2013), available at <http://pubs.usgs.gov/sir/2012/5273/sir2012-5273.pdf>



- A USGS analysis of 21 private drinking water wells in northeastern Pennsylvania where homeowners suspected that their well water was contaminated by flowback fluids indicated that in fact none of the wells was contaminated by flowback fluid associated with HF operations. Reilly *et al.*, "Identification of local groundwater pollution in northeastern Pennsylvania," *Environ Earth Sci* (Jan. 3, 2015), available at <http://link.springer.com/article/10.1007%2Fs12665-014-3968-0#>
- A group of USGS scientists who evaluated national USGS surface water data in an attempt to detect trends in surface water quality in regions of oil and gas development found no consistent trends in water quality in areas with increasing unconventional oil and gas development. Bowen *et al.*, "Assessment of Surface Water Chloride and Conductivity Trends in Areas of Unconventional Oil and Gas Development - Why Existing National Datasets Can't Tell Us What We Would Like to Know," *Water Resources Research* (Jan. 30, 2015), available at <http://onlinelibrary.wiley.com/doi/10.1002/2014WR016382/abstract>
- USGS researchers studying water quality in the Monongahela River Basin where shale gas exploration has occurred for eight years compared recent water samples with historical samples and found no significant difference in groundwater quality. Chambers *et al.*, Water Quality of Groundwater and Stream Base Flow in the Marcellus Shale Gas Field of the Monongahela River Basin, West Virginia, 2011–12, USGS Report 2014-5233 (Apr. 2015), available at <http://pubs.usgs.gov/sir/2014/5233/>.
- Another paper recently published by USGS researchers found that water samples collected from 30 randomly distributed domestic wells in 2013 in the area of the Bakken Formation in Montana and North Dakota gave no indication that energy development activities affected groundwater quality. McMahon *et al.*, Quality and Age of Shallow Groundwater in the Bakken Formation Production Area, Williston Basin, Montana and North Dakota, *Groundwater* Vol. 53 (2015), available at <http://www.ncbi.nlm.nih.gov/pubmed/25392910>.
- Researchers from the National Energy Technology Laboratory published a paper and report in September 2014 regarding a study of HF operations at a Marcellus Shale well site in Greene County, Pennsylvania. The researchers took samples from Upper Devonian/Lower Mississippian wells at depths of up to about 4,400 feet below ground surface both before and up to 14 months after fracturing of the deeper Marcellus (at depths of about 8,000 feet). The study found no compelling evidence that the shallower wells – which were still about 4,000 feet below drinking water aquifers – were affected by any upward migrating fluids from the Marcellus over the study period. Indeed, the researchers found that there was no evidence of migration of gas from the Marcellus to the shallower wells over the 14 months. U.S. Department of Energy, National Energy Technology Laboratory, *An Evaluation of Fracture Growth and Gas/Fluid Migration as Horizontal Marcellus Shale Gas Wells are Hydraulically Fractured in Greene County, Pennsylvania*, NETL-TRS-3-2014 (Sept. 15, 2014), available at [http://www.netl.doe.gov/File%20Library/Research/onsite%20research/publications/NETL-TRS-3-2014\\_Greene-County-Site\\_20140915.pdf](http://www.netl.doe.gov/File%20Library/Research/onsite%20research/publications/NETL-TRS-3-2014_Greene-County-Site_20140915.pdf).

- A peer-reviewed paper by researchers at the Lawrence Berkeley National Laboratory reports on some of the results of modeling being conducted for EPA's study of the impacts of HF on drinking water and concludes that the possibility of hydraulically induced fractures at great depths causing activation of faults and creation of a new flow path that can reach shallow groundwater resources is "remote." Rutqvist, J., et al., "Modeling of fault reactivation and induced seismicity during hydraulic fracturing of shale-gas reservoirs," *Journal of Petroleum Science and Engineering* (2013), available at <http://dx.doi.org/10.1016/j.petrol.2013.04.023>
- The New Zealand Parliamentary Commissioner for the Environment issued a report in 2012 finding that "there is no evidence that fracking has caused groundwater contamination in New Zealand." Government of New Zealand, Parliamentary Commissioner for the Environment, *Evaluating the environmental impacts of fracking in New Zealand: An interim report*, 43 (Nov. 2012), available at <http://www.pce.parliament.nz/publications/all-publications/evaluating-the-environmental-impacts-of-fracking-in-new-zealand-an-interim-report/>
- In a May 2012 report, the Council for the Taranaki Region in New Zealand found that there was no evidence of environmental problems related to the HF operations that had been undertaken in the region over a period of almost 20 years and that there is little risk to freshwater aquifers from properly conducted HF operations. Government of New Zealand Taranaki Regional Council, *Hydrogeologic Risk Assessment of Hydraulic Fracturing for Gas Recovery in the Taranaki Region*, 3-4 (May 2012), available at <https://www.trc.govt.nz/council/plans-and-reports/research-and-reviews/hydraulic-fracturing/>
- The South African Department of Mineral Resources has stated that there are "no documented cases of properly placed hydraulic fracturing fluids migrating through the overlying strata to contaminate groundwater." The Department found that "potable aquifers are expected to be far removed from shale gas target formations and safe from contamination from injected fracking fluids, as the latter are immobile under normal conditions with no 'drive' once the fracturing operation is completed." Republic of South Africa, Department of Mineral Resources, *Investigation of Hydraulic Fracturing in the Karoo Basin of South Africa*, 31 (July 2012), available at <http://www.dmr.gov.za/publications/summary/182-report-on-hydraulic-fracturing/852-executive-summary-investigation-of-hydraulic-fracturing-in-the-karoo-basin-of-south-africa.html>
- The United Kingdom Department of Energy and Climate Change concluded in a December 2013 report that groundwater contamination from HF "has not been observed in practice and would be unlikely" and that "it is considered reasonable to suggest that any risk of contamination from fracturing activities is exceptionally low." AMEC Environment & Infrastructure UK Limited, Department of Energy and Climate Change, *Strategic Environmental Assessment for Further Onshore Oil and Gas Licensing*, 96 (Dec. 2013), available at [https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/273997/DECC\\_SEA\\_Environmental\\_Report.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/273997/DECC_SEA_Environmental_Report.pdf)

- The Energy and Climate Change Committee appointed by the British House of Commons concluded in May 2011 that “hydraulic fracturing itself does not pose a direct risk to water aquifers, provided that the well-casing is intact before this commences.” United Kingdom Parliament, House of Commons, Energy and Climate Change Committee, *Fifth Report: Shale Gas* (May 10, 2011), available at <http://www.publications.parliament.uk/pa/cm201012/cmselect/cmenergy/795/79502.htm>

(b) *Statements by Australian and U.S. Federal Officials*

- The Western Australia Department of Mines and Petroleum has stated that “[s]ince 1958, more than 780 petroleum wells have undergone fracture stimulation in WA with no known adverse effects on the environment, water sources or peoples’ health.” WA Department of Mines and Petroleum, *Natural Gas from Shale and Tight Rocks Fact Sheet: Providing responses to misinformation* (August 2013), available at <http://www.dmp.wa.gov.au/shaleandtightgas>
- Then-EPA Administrator Lisa Jackson stated in testimony before the House Committee on Oversight and Government Reform that she was “not aware of any water contamination associated with the recent drilling” in the Marcellus Shale. *Pain at the Pump: Policies that Suppress Production of Oil and Gas*, Hearing Before the H. Comm. on Oversight & Gov’t Reform, Rep. No. 112-54, 87 (May 24, 2011), available at <http://www.gpo.gov/fdsys/pkg/CHRG-112hhrg70675/pdf/CHRG-112hhrg70675.pdf> She again made statements to the press on April 30, 2012 that “in no case have we [EPA] made a definitive determination that [hydraulic fracturing] has caused chemicals to enter groundwater.” See [https://www.youtube.com/watch?v=tBUTHB\\_7Cs](https://www.youtube.com/watch?v=tBUTHB_7Cs)
- Then-U.S. Bureau of Land Management (“BLM”) Director Bob Abbey stated that he had “never seen any evidence of impacts to groundwater from the use of fracing technology on wells that have been approved by” BLM. *Challenges Facing Domestic Oil and Gas Development: Review of Bureau of Land Management/U.S. Forest Service Ban on Horizontal Drilling on Federal Lands*, Hearing before the Subcomm. on Energy and Mineral Resources of the H. Comm. on Natural Resources and the Subcomm. on Conservation, Energy and Forestry of the H. Comm. on Agriculture, 112th Cong. (July 8, 2011), available at <http://www.gpo.gov/fdsys/pkg/CHRG-112hhrg72151/pdf/CHRG-112hhrg72151.pdf>
- U.S. Department of Energy Secretary Ernest Moniz made remarks to the press on August 1, 2013 that, “to my knowledge, I still have not seen any evidence of fracking per se contaminating groundwater.” See <http://thehill.com/blogs/e2-wire/e2-wire/315009-energy-secretary-natural-gas-helps-battle-climate-change-for-now>

(c) *Studies and Statements from U.S. State Governments and Agencies*

- In 1998 the U.S. Ground Water Protection Council surveyed 25 state agencies responsible for oil and gas development and found that there was not a single substantiated claim of contamination of drinking water supplies attributable to hydraulic fracturing. Ground Water Protection Council, *Survey Results on Inventory and Extent of Hydraulic Fracturing in Coalbed Methane Wells in the Producing States* (1998), available at <https://cogcc.state.co.us/RuleMaking/PartyStatus/FinalPrehearingStmts/HESIExhibits.PDF>
- The Interstate Oil and Gas Compact Commission (“IOGCC”) surveyed its state regulatory agency members in 2002 and found that nearly one million wells had been

hydraulically fractured over the course of several decades but again found no evidence of substantiated claims of contamination of drinking water supplies due to hydraulic fracturing. IOGCC, *States Experience with Hydraulic Fracturing: A Survey of the Interstate Oil and Gas Compact Commission* (2002), available at [http://www.mde.state.md.us/programs/Land/mining/marcellus/Documents/Interstae\\_Oil\\_Gas\\_Compact\\_Commission\\_States\\_Experience\\_w\\_Hydraulic\\_Fracturing\\_2002.pdf](http://www.mde.state.md.us/programs/Land/mining/marcellus/Documents/Interstae_Oil_Gas_Compact_Commission_States_Experience_w_Hydraulic_Fracturing_2002.pdf) IOGCC continues to confirm on its website that “IOGCC member states have all stated that there have been no cases where hydraulic fracturing has been verified to have contaminated drinking water.” See <http://www.iogcc.state.ok.us/hydraulic-fracturing>

- The Susquehanna River Basin Commission’s Data Report of Baseline Conditions for 2010-2013 found that conductance and turbidity had not changed over the monitored years, there was no correlation between well pad density and stream temperature or well distance and biotic integrity, and very few water samples exceeded water quality levels or levels of concern. Susquehanna River Basin Commission, *Data Report of Baseline Conditions for 2010 — 2013*, Pub. No. 297 (June 2015), available at <http://www.srbcc.net/pubinfo/techdocs/publications/techreports.htm>.
- Regulators in various U.S. states have likewise affirmed the absence of evidence of groundwater contamination from HF:
  - New York – “[N]o known instances of groundwater contamination have occurred from previous horizontal drilling or hydraulic fracturing projects in New York State.” New York State Department of Environmental Conservation, *Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program*, 6-47 (2011), available at <http://www.dec.ny.gov/energy/75370.html>.
  - Alaska – “In over fifty years of oil and gas production, Alaska has yet to suffer a single documented instance of subsurface damage to an underground source of drinking water.” Alaska Oil and Gas Conservation Commission, *Hydraulic Fracturing in Alaska* (Apr. 6, 2011), available at <http://doa.alaska.gov/ogc/reports-studies/HydraulicFracWhitePaper.pdf>.
  - Colorado – “[W]e have found other instances where activities associated with oil and gas operations have impacted water supplies. These events have typically been tied to incidents such as a leaking storage pit, a poorly cemented oil and gas well, or leaking production equipment. These cases, however, have not been linked to the specific act of hydraulic fracturing hydrocarbon layers thousands of feet below the surface, and typically, thousands of feet below groundwater supplies.” David Neslin, *Written Answers to Follow-up Questions from the Senate Committee on the Environment and Public Works* (May 17, 2011), available at [http://cogcc.state.co.us/Announcements/Hot\\_Topics/Hydraulic\\_Fracturing/EnviroPublicWorksQA.pdf](http://cogcc.state.co.us/Announcements/Hot_Topics/Hydraulic_Fracturing/EnviroPublicWorksQA.pdf).

- In 2012, regulators from a number of states – including Arkansas, Colorado, Louisiana, North Dakota, Ohio, Oklahoma, Pennsylvania and Texas – confirmed to the U.S. Government Accountability Office that, based on state investigations, the HF process had not been identified as a cause of groundwater contamination in their states. U.S. GAO, *Information on Shale Resources, Development and Environmental and Public Health Risks*, 49 (Sept. 2012), available at <http://www.gao.gov/assets/650/647791.pdf>.
- California – “In California it has been used for 60 years, and actively used for 40 years, and in California there has been not one record of reported damage directly to the use of hydraulic fracturing.” See <http://www.nationaljournal.com/new-energy-paradigm/california-s-top-oil-regulator-on-fracking-climate-change-and-fossil-fuels-20131016>.
- Michigan – “As far as migration of gas or fracture fluids, we have never seen an instance where a fracture communicates directly with the fresh water zone.” See <https://www.youtube.com/watch?v=A979CqCeH00>.
- In August 2014, the California Council on Science and Technology, Lawrence Berkeley National Laboratory and the Pacific Institute issued a study conducted for the U.S. Bureau of Land Management regarding the use of HF and other well stimulation technologies in California. The study found that where the target formation is more than 2,000 feet below the overlying aquifers, the creation of migration pathways as a result of HF operations seems unlikely. The report noted that most studies comparing baseline trends to post-stimulation measurements have not found any statistically significant changes in water quality in nearby drinking water wells. The study concludes that the primary impacts to California’s environment from well stimulation activities will be indirect impacts due to increases in oil and gas production, not impacts due to well stimulation itself. California Council of Science and Technology et al., *Advanced Well Stimulation Technologies in California: An Independent Review of Scientific and Technical Information*, 234-37 (Aug. 28, 2014), available at [http://ccst.us/projects/fracking\\_public/BLM.php/](http://ccst.us/projects/fracking_public/BLM.php/).
- The Maryland Department of the Environment (“MDE”) and Department of Natural Resources (“MDNR”) found that “[t]he available scientific evidence indicates that the possibility that fracturing fluids would migrate upward through the overlying rock formations to reach drinking water is extremely remote.” Maryland Department of the Environment and Maryland Department of Natural Resources, *Marcellus Shale Safe Drilling Initiative Study Part II Interim Final Best Practices* (July 2014) available at <http://www.mde.state.md.us/programs/land/mining/marcellus/pages/index.aspx>.
- In January 2015, MDE and DNR issued a joint Risk Assessment for Unconventional Gas Well Development in the state. The assessment concluded that the risks of impact to groundwater from saline intrusion during drilling of vertical and lateral wellbore or due to casing and cement failure are low. The assessment stated that “the best practices for casing and cement reduce the risk of casing and cement failures.” In addition, based on a literature review and the best management



practices available, the risk of impact to groundwater from fracturing fluids and mobilized substances through faults and old wells was also found to be low. Maryland Department of the Environment and Maryland Department of Natural Resources, Assessment of Risks from Unconventional Gas Well Development in the Marcellus Shale of Western Maryland, Appx. H (Jan. 20, 2015), available at [http://www.mde.state.md.us/programs/Land/mining/marcellus/Pages/Risk\\_Assessment.aspx](http://www.mde.state.md.us/programs/Land/mining/marcellus/Pages/Risk_Assessment.aspx).

- The Wyoming Environmental Department of Environmental Quality (“WDEQ”) investigated drinking water quality issues in the rural area east of Pavillion, Wyoming. WDEQ found that evidence does not indicate HF fluids had risen to shallow depths utilized by water-supply wells, and that it is unlikely that HF caused any impacts to the water-supply wells. Wyoming Department of Environmental Quality and Acton Mickelson Environmental, Inc., Pavillion, Wyoming Area Domestic Water Wells Final Report and Palatability Study (Nov. 7 2016), available at <http://deq.wyoming.gov/wqd/pavillion-investigation/resources/investigation-final-report/>. A supporting study by Maurice Dusseault concluded that there is no evidence that HF fluids have migrated upward to reach protected groundwater resources and that the possibility of this occurring is negligibly small.

*(d) Other Statements and Studies*

- Dr. Mark Zoback, Professor of Geophysics, Stanford University and member of the Shale Gas Production Subcommittee of the Secretary of Energy Advisory Board stated that “[f]racturing fluids have not contaminated any water supply and with that much distance to an aquifer, it is very unlikely they could.” See <http://news.stanford.edu/news/2011/august/zoback-fracking-ganda-083011.html>
- The Royal Society concluded in a June 2012 report that a variety of factors constrain fracture height growth and that while it might be theoretically possible to create pressures that would allow a fracture to grow vertically to shallow depths, the “volume of fluid injected is simply insufficient by orders of magnitude to create these pressures” and that “such an enormous pressure could not be sustained.” The report also found that “[u]pward flow of fluids from the zone of shale gas extraction to overlying aquifers via fractures in the intervening strata is highly unlikely” and that, in general, it is “very difficult to conceive” how such upward fluid flow might occur given the hydrogeological conditions found in the relevant areas of the U.K. The Royal Society, *Shale gas extraction in the UK: a review of hydraulic fracturing* (June 2012), available at <https://royalsociety.org/~media/policy/projects/shale-gas-extraction/2012-06-28-shale-gas.pdf>
- MIT performed a study in 2011 on the potential risks of hydraulic fracturing to groundwater aquifers and found that “no incidents of direct invasion of shallow water zones by fracture fluids during the fracturing process have been recorded.” MIT Energy Initiative, *The Future of Natural Gas: An Interdisciplinary MIT Study*, Appx. 2E (2011), available at <https://mitei.mit.edu/publications/reports-studies/future-natural-gas>

- An October 2012 report regarding HF operations in the Inglewood Oil Field in the Baldwin Hills area of Los Angeles County showed that, based on actual groundwater monitoring results, the groundwater quality in the area was not affected by HF activities. Cardno Entrix, *Hydraulic Fracturing Study: PXP Inglewood Oil Field* (Oct. 2012), available at <http://www.inglewoodoilfield.com/fracturing-study/>
- Gradient's 2013 National Human Health Risk Evaluation evaluates whether it is possible for fluids pumped into a tight formation during the HF process to migrate upward to reach drinking water aquifers. Gradient determined that once the fracturing fluids are pumped into a tight formation, it is "simply not plausible" that the fluids would migrate upwards from the target formation through several thousand feet of rock to contaminate drinking water aquifers. Gradient, *National Human Health Risk Evaluation for Hydraulic Fracturing Fluid Additives* (May 1, 2013), available at [http://www.energy.senate.gov/public/index.cfm/files/serve?File\\_id=53a41a78-c06c-4695-a7be-84225aa7230f](http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=53a41a78-c06c-4695-a7be-84225aa7230f)
- A peer-reviewed paper by Gradient discusses the physical constraints on upward fluid migration from black shales to shallow aquifers and concludes that upward migration of frac fluid and brine as a result of HF activity does not appear to be physically possible. Flewelling & Sharma, "Constraints on Upward Migration of Hydraulic Fracturing Fluid and Brine," *Groundwater* (Jul. 29, 2013), available at <http://onlinelibrary.wiley.com/doi/10.1111/gwat.12095/abstract>
- Another peer-reviewed paper by Gradient and a Halliburton expert concludes that it is not physically plausible for induced fractures to create a hydraulic connection between tight formations at depth and overlying drinking water aquifers, even through connections with existing faults. Flewelling et al., "Hydraulic fracturing height limits and fault interactions in tight oil and gas formations," *Geophysical Research Letters* (Jul. 26, 2013), available at <http://onlinelibrary.wiley.com/doi/10.1002/grl.50707/abstract>
- A 2013 paper examines fracture growth data obtained as a result of microseismic monitoring conducted during thousands of HF treatments in unconventional reservoirs across the country along with the reported aquifer depths in the vicinity of the fractured wells. The paper finds that "[f]racture physics, formation mechanical properties, the layered depositional environment, and other factors all conspire to limit hydraulic-fracture-height growth, causing it to remain in the nearby vicinity of the targeted reservoirs." Fisher, K. and Warpinski, N. 2012. "Hydraulic-Fracture-Height Growth: Real Data," *SPE Prod. & Oper.* 27 (1): 8-19, SPE-145949-PA. <http://dx.doi.org/10.2118/145949-PA>.
- Several recently-published peer reviewed papers in the U.S. have likewise found that there are significant constraints on fluid movement that – particularly when considered in combination – lead to the conclusion that migration of fluids from even a moderately deep, tight formation to reach drinking water resources is extremely unlikely. Saiers, J. E. and Barth, E. (2012), Potential Contaminant Pathways from Hydraulically Fractured Shale Aquifers. *Ground Water*, 50: 826–828. doi:



- 10.1111/j.1745-6584.2012.00990.x.; Carter, et al., “Technical Rebuttal to Article Claiming a Link between Hydraulic Fracturing and Groundwater Contamination” (2013); Dusseault, M., *et al.* “Seepage pathway assessment for natural gas to shallow groundwater during stimulation, production and after abandonment,” *Environmental Geosciences* 21 (2014) 107-126; Engelder, T. *et al.*, “The fate of residual treatment water in gas shale,” *Journal of Unconventional Oil and Gas Resources*, 7: 33-40 (2014), available at <http://www.sciencedirect.com/science/article/pii/S2213397614000202>. For example, the paper by Engelder et al. notes gas shales readily absorb (imbibe) water and that fracturing fluids will therefore tend to flow into rather than out of gas shales. The paper also notes that the capillary seals that have prevented gas leakage up existing pathways for hundreds of millions of years will continue to operate.
- A 2014 peer-reviewed paper examined data from thousands of pre-drilling groundwater samples from domestic water wells in northeastern and southwest Pennsylvania, eastern Ohio, and north-central West Virginia. The paper evaluated concentrations of major ions and metals relative to federal drinking-water-quality standards and found that the recent pre-drilling geochemical data is similar to historical data, concluding that there were no broad changes in variability of chemical quality in the large dataset to suggest any unusual salinization caused by possible release of produced waters from oil and gas operations, even after thousands of gas wells have been drilled among tens of thousands of domestic wells within the two areas studied. Siegel et. al, “Pre-drilling water-quality data of groundwater prior to shale gas drilling in the Appalachian Basin: Analysis of the Chesapeake Energy Corporation dataset” *Applied Geochemistry* 63 (2015) 37–57, available at <http://www.sciencedirect.com/science/article/pii/S0883292715300056>.
  - A 2016 peer-reviewed paper studied whether aqueous and gas phases from the D-J Basin in Colorado were transported concurrently to drinking water aquifers, and found that aquifer wells with demonstrated gas phase contamination have not been contacted by an aqueous phase from oil and gas operations according to the methodology used and current groundwater quality data from the Colorado Oil and Gas Conservation Commission. Li et. al, “Concurrence of aqueous and gas phase contamination of groundwater in the Wattenberg oil and gas field of northern Colorado” *Water Research* 88 (2016) 458-466, available at <http://www.sciencedirect.com/science/article/pii/S0043135415302967>.

In light of this extensive evidence, the report on unconventional gas production issued by the Australian Council of Learned Academies notes that the consensus among experts is that, despite significant public concerns about risks to groundwater, the primary risk is to surface water. However, this risk is carefully managed. As the ACOLA report states, “the industry takes great care to avoid spillage” and “already has rigorous systems for dealing with spillage, or from the incorrect disposal of the hydraulic fracturing fluid.” Australian Council of Learned Academies, *Engineering Energy: Unconventional Gas Production* (May 2013), at 16, 112, 131.

**Appendix B – King and King Paper**

# Environmental Risk Arising From Well-Construction Failure—Differences Between Barrier and Well Failure, and Estimates of Failure Frequency Across Common Well Types, Locations, and Well Age

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## Summary

Do oil and gas wells leak to the environment? This paper will show the great majority of wells do not pollute. The purpose of this paper is to explain basic concepts of well construction and illustrate differences between single-barrier failure in multiple-barrier well design and outright well-integrity failure that could lead to pollution by use of published investigations and reviews from data sets of more than 600,000 wells worldwide. For US wells, while individual-barrier failures (containment maintained and no pollution indicated) in a specific well group may range from very low to several percent (depending on geographical area, operator, era, well type, and maintenance quality), actual well-integrity failures are very rare. Well-integrity failure occurs when all barriers fail and a leak is possible. True well-integrity-failure rates are two to three orders of magnitude lower than single-barrier-failure rates.

When one of these rare total-well-integrity failures occurs, gas is the most common fluid lost. Common final-barrier leak points are failed gaskets or valves at the surface and are easily and quickly repaired. If the failure is in the subsurface, an outward leak is uncommon because of a lower pressure gradient in the well than in outside formations. Subsurface leaks in oil and gas wells are rare, and routinely comprise exterior-formation salt water leaking into the well toward the lower pressure in the well.

Failure frequencies are estimated for wells in several specific sets of environmental conditions (i.e., location, geologic strata, produced-fluid composition, and soils). Estimate accuracy depends on a sufficient database of wells with documented failures, divided into (1) barrier failures in a multiple-barrier system that did not create pollution, and (2) well-integrity failures that created a leak path, whether or not pollution was created. Estimated failure-frequency comparisons are valid only for a specific set of wells operating under the same conditions with similar design and construction quality. Well age and construction era are important variables. There is absolutely no universal definition for well-failure frequency.

## Introduction

This paper is a continuation of the work on well-development environmental risk that began with a study of environmental risk from fracturing-related activity, in which the potential for possible pollution from materials transport was identified, as was a much lesser impact from leaks in the finished well (King 2012). Environmental risk to groundwater from the integrity of producing wells is

addressed in this study, which also examines several other possibilities of environmental impact during the producing lifespan, from the end of construction until plugging and abandonment (P&A). For focus and brevity, this work is limited to the failure potential of the constructed barriers remaining in the producing well after drilling (e.g., casing, cement, packers, tubing, wellheads, and other downhole equipment that remains part of the producing well at the handover from drilling to production operations).

Mechanical-barrier failures during well construction, injecting fluid into an underground formation, or P&A are outside the scope of this paper. For studies on those topics, the reader is referred to well-construction studies (Handal 2013; Steinsvik and Vegge 2008; Aadnoy et al. 2008), injection-well studies (US Code of Federal Regulations 2012), and well P&A studies (NPC 2011; Khalifeh et al. 2013; Faul et al. 1999).

The information is from government, academic, and industry reports and care was taken to document the sources of all data. No company comparisons are made. Most of the information in the report is from North America because of the large well population and the wealth of available data from government, academic, and industry sources. Other production-well data sources have been considered to expand the data population for the analyses (Bonn 1998; Bazzari 1989; Liang 2012; Rao 2012; SINTEF 2010b).

## Well-Design Overview—Establishing Redundant Barriers

Barriers may be active, passive, or in some cases, reactive. Active barriers, such as valves, can enable or prevent flow, while passive barriers are fixed structures, such as casing and cement. In the oil and gas industry, a reactive barrier may be a human or mechanical response to an activating or triggering event. When barriers are used in series (nested one inside the other), a multiple-barrier system is created; essentially a “defense-in-depth” barrier system (Hollnagel 1999; Fleming and Silady 2002; Skylet 1999; Sklet 2006a, b). Reactive barriers are invisible or unobtrusive in normal operations, but deploy a containment response when a pressure, flow-rate, or other behavior limit is exceeded.

There are four criteria for developing a mechanical reactive barrier for a well [adapted from Hale et al. (2004)]:

1. Definition or specification of a barrier, understanding of causes of failure, and what signals could be monitored to help predict or detect a failure.
2. A detection mechanism suitable to perceive a present or (preferably) an incipient failure.
3. An activation mechanism that will alarm, notify, or begin a response automatically.
4. A response mechanism that is suitable to prevent, control, or mitigate the failure.

The difference between drilling and production-well barriers is that most production-well barriers are static (available continuously over an extended period of time, usually without requiring

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TABLE 1—EXAMPLES OF OPERATIONS BARRIERS

Barrier Description	Number Present	Pressure Rating of Producing-Well Barriers	Durability of Barrier Elements
Casing + cement	2 to 7	Very High	Very High—many cases of 70+ years producing life
Hangers + seals	2 to 4	High	High—internal seals
Pipe between seals	1 to 3	High	Very High where corrosion inhibition is maintained
Packoffs and some plugs	1 to 2	Moderate	Moderate—internal seal
Safety valves (surface, tubing, or annular)	1	Moderate to High	Moderate—internal seal; frequently tested
Valves, spools, seals in production tree	4 to 20+	Moderate to High	Moderate—can be isolated quickly

human observation or action), whereas most drilling-and-completion (D&C) -activity barriers are dynamic (control is variable with time and activity). Production barriers require less-continuous monitoring compared with D&C barriers, which are dependent on correct human activity.

In most well configurations, uncemented sections of inner pipe strings are designed to collapse under any overpressuring external load in the annulus before the pipe that forms the outer wall of the annulus can burst. This type of reactive barrier protects the integrity of the outer string with a sacrificial collapse of the inner string. While effective, this fixed design is susceptible to changes in how the well is operated, such as converting a primary flowing well to a gas lift with high-pressure lift gas in the innermost annulus. Burst strength of pipe is further reinforced by cement on the outside, although this added burst strength is rarely considered in the typical conservative design (Zinkham and Goodwin 1962). Redundant, sequential design elements control failure-producing forces so a well can survive without loss of well integrity, even with the loss of one or more barriers in a multiple-barrier system. This contained-failure approach, which is basically an overdesign, is the core of engineering design in which safety is paramount. Contained-failure approaches and redundant-barrier systems are common in all risk-based industries. For a well to pollute, a leak path must form and extend from the inner hydrocarbon flow path to the outside environment. Any barrier that interrupts this flow path and prevents formation of a leak path is effective in preventing pollution.

### Barriers and Well Integrity

Oil- and gas-producing wells are a nested collection of pipe, cement, seals, and valves that form multiple barriers between produced well fluids and the outside environment. Barrier and integrity in well-design technology is loosely defined as follows:

- Barriers are containment elements that can withstand a specific design load. These may comprise pipe that is effectively cemented, seals, pipe body, valves, and pressure-rated housings (see Table 1). Typical design-load parameters include operating-environment factors such as temperature, pressure, fluid composition, fluid velocity, and exposure time.
- Multiple barriers are nested individual barriers designed and built to withstand a specific load without help from other barriers. If an inside (or outside) barrier fails, the next barrier will provide isolation so that a leak path will not form. In modern designs, the number of barriers is typically proportional to the hazard potential in specific well areas (Fig. 1). When a barrier failure occurs, an assessment will establish the magnitude of the health and environmental risk posed by the leak so that the repairs can be scheduled appropriately (Humphreys and Ross 2007). In the United States, state and federal regulations cover exemptions that may or may not be granted to continue to operate (Bourgoyne et al. 1999, 2000; Corneliussen et al. 2007; Anders et al. 2008; Browning and Smith 1993; Vignes and Aadnoy 2008; Vignes 2011; Calosa et al. 2010; Crow 2006; D'Alesio et al. 2011; Dethlefs and Chastain 2012; Duguay et al. 2012; Nygaard 2010; Carlsen and Randolph 2008).
- Monitored barriers may have fluid-filled spaces (annuli) between barriers that can be monitored for pressure increase or

fluid invasion. Annular spaces that are cemented to the surface are usually not monitored.

- Well-integrity failure is an undesired result in which all barriers in a potential leak path fail in such a way that a leak path is created. Whether or not pollution occurs, however, depends on the direction of pressure differential and buoyancy of the leaking fluid. There is a natural pressure gradient outside the well, established by fluids and trapped pressure environments. The gradient inside the well is a function of the pressure at the highest point of containment and the fluid-density gradients from top to bottom. Because multiple fluid phases, often with pressure-dependent densities, are commonly present in a wellbore in both flowing and static conditions, the potential for pressure underbalance and/or overbalance is difficult to describe, and a leak path from a well could flow fluid outward in one operating condition and inward in another operating condition.

### Risk

The definition of risk used here includes the recognition that, although there is a degree of risk in every action, the frequency of occurrence and the impact of a detrimental outcome create a risk or threat level that we can understand and accept or reject on the basis of what we believe, hopefully from assessment of facts. When solid occurrence numbers are not available, probability is used as a proxy. While the use of a proxy such as probability is necessary in many cases, an element of uncertainty is inescapably included.

Wells are designed and built as pressure vessels, using exact data on as many variables of the formation and producing conditions as we know and considering how they will change as underground forces are altered by producing or injecting fluids into rocks with fluid-filled porosity that have reached equilibrium. Altering the fluid fill or composition may be followed by stress alteration. One challenge to well design is that every inch of a depositional formation is different from the inch above and the inch below; hence, the need to design for the unknown and the worst load. Well design is a geomechanical, fit-for-purpose engineering effort and definitely not a "one-size-fits-all" approach.

All phases of the well design must consider loads and forces placed on the well from the first cementing operation through fracturing and to the end of production. Well-failure causes include simple, one-variable induced failures and more-complex failure scenarios. Whenever possible, a failure should be traced back to a root cause. Although examining surface failures is a practical approach (in which pollution can be more quickly and unambiguously documented), determining root cause of subsurface failures from which the failed equipment cannot always be retrieved is more difficult, and the direct or indirect environmental damage, if it occurs at all, may not be seen for months after the incident. The most important element of risk control is to prevent barrier failure by predicting the performance of barriers under any operating conditions.

Neither human nor natural endeavors are risk free (Ritchie 2013). To work with risk requires an assessment of the impact and the probability of an undesirable outcome. For this reason, the actual expression of risk must be made on the basis of a quantitative risk assessment and may be compared to other industries in which significant risk is an issue (Oakley 2005; Martland and



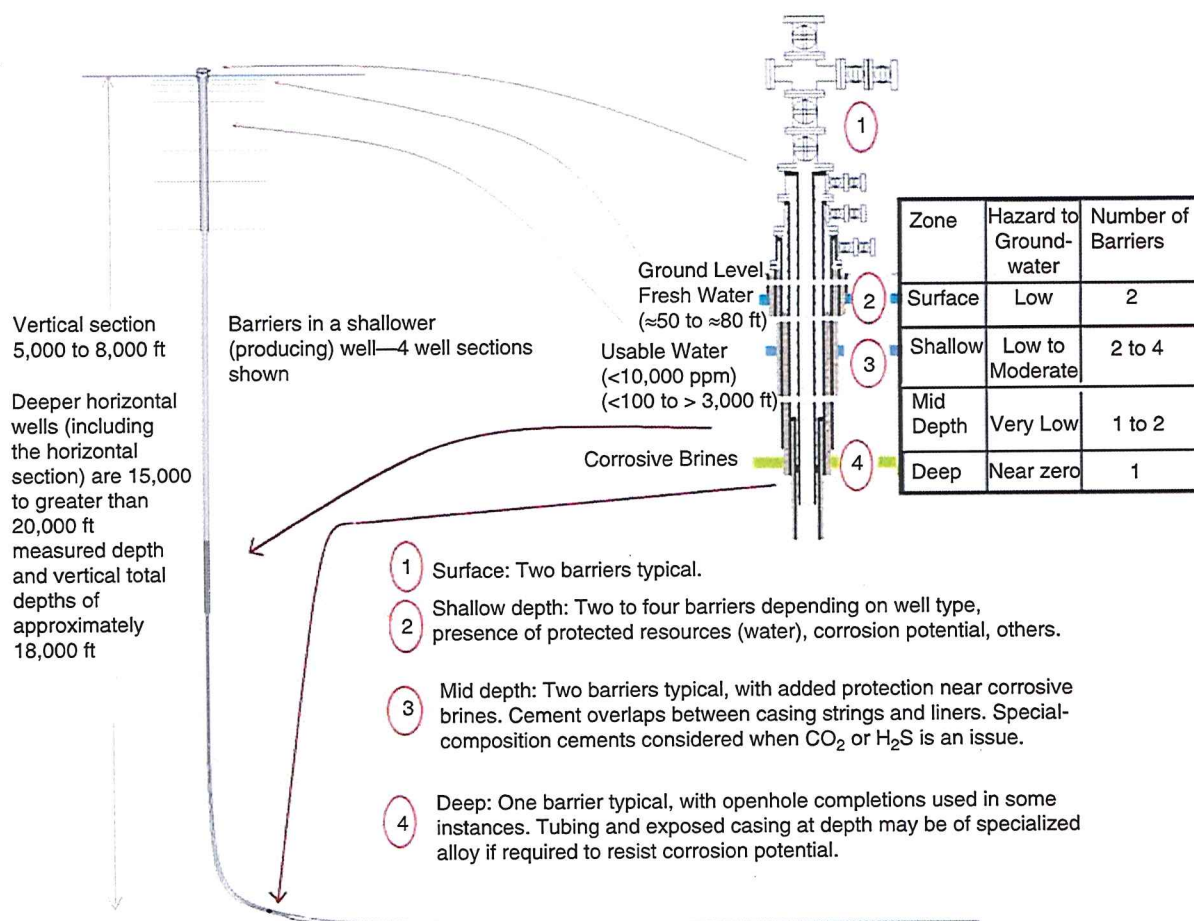


Fig. 1—Examples of well-construction barriers for specific areas of the well.

Mann 2012). The concept of “as low as reasonably practicable” (ALARP) is widely accepted in risk-based industries and by the public, although many people have not heard the term (Fig. 2).

For example, actuarial tables of the life-insurance industry on pilots and onboard staff (showing no elevated life risk from flying in scheduled airlines) and the public’s acceptance of the airlines as a safe way to travel are an educated acceptance of risk. The ALARP term comes from the UK and North Sea and is based on safety practices and law in the area of safety-critical systems [Health and Safety Executive (ALARP) 2013]. The basic principle is that the residual risk shall be ALARP, but all endeavors accept a risk threshold that can be described as a judgment of the balance of risk and social benefit. Within that definition, however, the implied responsibility is that future risk must always be further diminished by applying learnings and developments from study of past operations.

For risks of any type, it is important for decision makers to see more than just a mass of separate pieces of information; it is important to understand the context of the separate risks, how they might interact and either counterbalance or amplify a single risk element (David and Pinons 2009).

Decreasing risk is a primary concern with hydraulic fracturing and well construction. Use of evolving technologies in cementing, pipe alloys, wellhead seals, and even transport has driven occurrence and impact of potential detrimental outcomes from fracturing-related activities to very low levels, as described in Table 2 and illustrated in Fig. 3 (King 2012). The data in Fig. 3 present examples of case histories of both occurrences and impacts and contain real-world examples and outcomes of the interrelated functions of well construction and hydraulic fracturing. The detrimental fracturing possibilities in Fig. 3 are highly region-specific, with major influence exercised by presence of natural seeps, local geology (including near-surface fault presence), natural-fracture

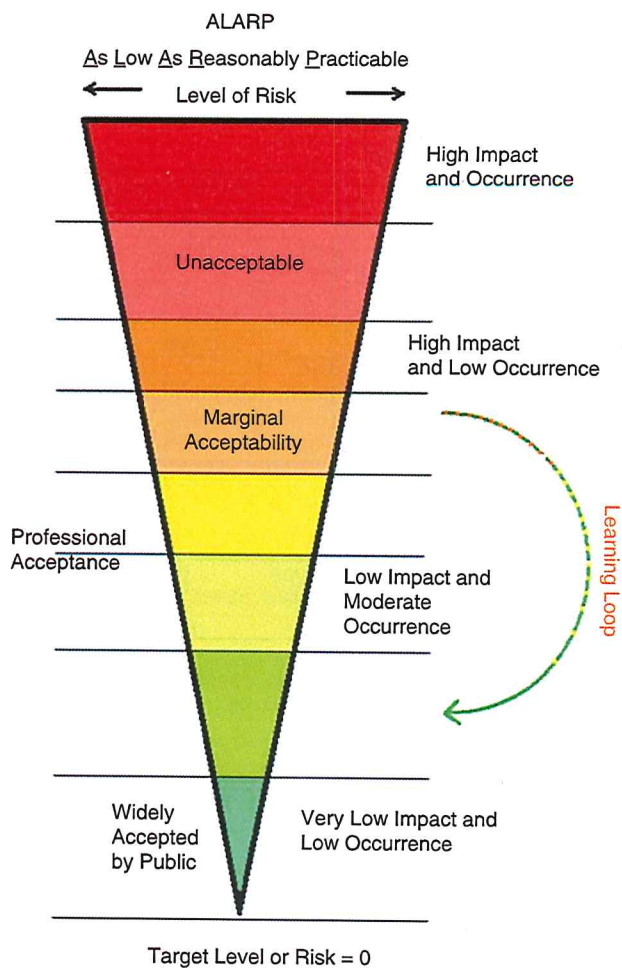
barriers, the presence of natural fractures, variable earth stresses, infrastructure development, and other factors. Frequency of occurrence and the impact of these events are derived from documented sources (King 2012).

### Possibility vs. Probability

Failure frequency, impact assessment, and risk rankings are needed to learn what problems are most important and require rapid attention. Identifying problems without ranking them for frequency and impact is somewhat similar to comparing a large asteroid collision with a tripping hazard created by a wrinkle in the carpet. Both are hazards, but one is catastrophic, with a miniscule chance of occurring and few ways to avoid it, while the other, although frequently encountered, is a minor issue and easily corrected. Impact and frequency are used in every risk-based industry as the basis for preparation, plans, and changes to designs.

### Effectiveness of Barriers

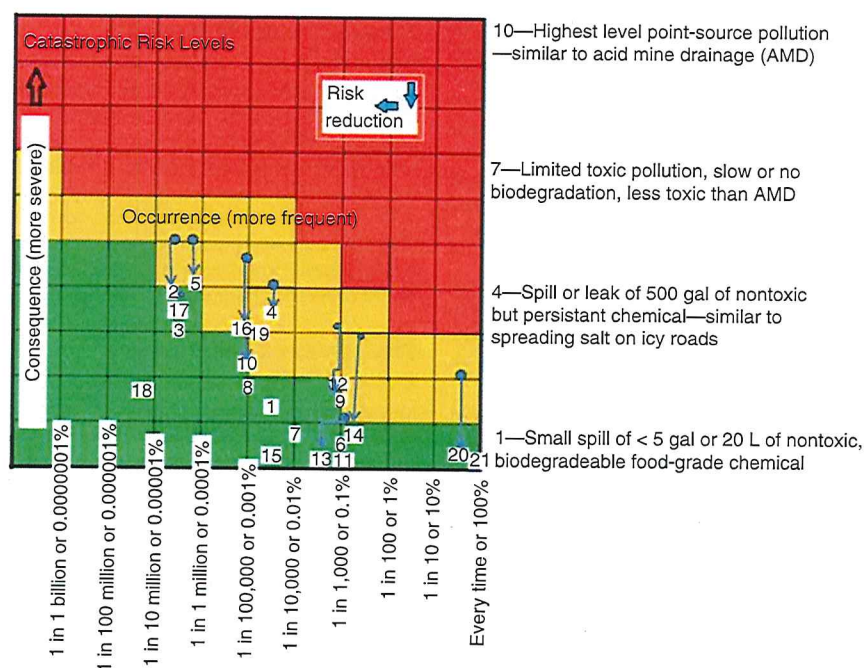
The only constant in the geology of the Earth is change, as attested to by millions of years of earthquakes; volcanic activity; formation flows; mountain erosion; natural seeps of oil, gas, and salt water; and a great many other continuously changing processes, large and small. The natural containment barriers in reservoirs are extremely strong; proved by the fact that low-density oil and gas remained trapped there even after millions of years of major earthquakes and other tectonic events. Some areas, however, such as the northeastern US, have natural-formation arrangements that allow slow movement of oil, gas, and salt water to the surface. These natural pathways (seeps) have been active for millions of years and communities of flora and fauna have developed to make use of the output of these natural hydrocarbon seeps.



**Fig. 2—ALARP (as low as reasonably practicable) risk assessment with generalized acceptance levels and learning loop.**

TABLE 2—FRACTURING RISK EVENTS	
Event	Event Description
1	Spill transport of fresh or low salt water
2	Spill 15 gal biocide
3	Spill 50 lbm dry additives
4	Spill 150 gal from truck wreck
5	Spill 2,500 gal from refueler wreck
6	Spill fracture tank of water, no additives
7	Spill fracture tank of water with food-grade polymer only
8	Spill 10 gal diesel during refueling
9	Spill 100 bbl of produced water
10	Fracture ruptures surface casing
11	Cooling pulls tubing string out of packer
12	Fracture opens mud channel, well < 2,000 ft
13	Fracture opens mud channel, well > 2,000 ft
14	Fracture intersects another well in pay zone
15	Fracture intersects properly abandoned wellbore
16	Fracture intersects improperly abandoned wellbore
17	Fracture to surface or groundwater through the rock, well > 2,000 ft deep
18	Fracture produces earthquake that can be felt at surface
19	Fracture intersects a natural seep
20	Fracture produces emissions in excess of limits
21	Normal fracture operations—no problems

From the study of forces of ruin (wear, corrosion, erosion, decomposition, weather, cyclic loads) that degrade all things natural and man-made, engineers describe behaviors that will destruct and counteractions that will preserve or extend. An engineered structure, perhaps perfect at the time of construction, remains perfect only for a period of time. We trust skyscrapers, ships, airplanes, cars, and bridges to perform over an expected lifetime. They are designed to have an acceptable, although nonzero, risk level as they age or when weather or load conditions change. All



**Fig. 3—Risk reduction achieved in hydraulic fracturing by application of developing technology (King 2012).**



these lessons must enter into both design and maintenance to reduce risk. In engineering design, multiple fail-safe principles and redundant systems are included that both warn of a potential problem and prevent an immediate one. For the oil and gas industry, redundant barriers in well design perform this purpose with great reliability.

A casing string under fracturing conditions will experience large increases in internal pressure as a result of fracturing pressure and decreases in average temperature caused by the fracturing fluids. The forces created by fracturing are attributed to four effects: piston force (pressure changes inside a confined space), buckling effect (pipe-shape deflection caused by higher pressure inside the pipe than outside), ballooning effect (pressure inside the pipe slightly enlarging the pipe diameter and shortening its length), and temperature effect (cooling contracts the pipe and raises tensile loading) (Clark 1987). If the well is a multifractured horizontal well, loads on the coupling through the bend areas and multiple fracture cycles are also added to the stresses (Chambers et al. 1995). Cementing the casing removes many of the problems with buckling (Durham 1987), but the stresses during fracturing are low at the start and usually stabilize and build slowly after the fracture-initiation step, often (but not always) reaching a peak near the end of the job when temperature and ballooning effects have offset part of the buckling loads.

### Age vs. Construction Era or Vintage

From early failures to "old-age" wear, time is portrayed to be the enemy of any engineered structure, regardless of the engineering discipline. Although aging is a significant issue, it must be remembered that failures of the past are what our knowledge of today is built upon, and as learnings progress, the failure rates of a later time should be lower than those of the era before it. Everything we know about success is based on mistakes we have made, but only if we learn from them. A key issue with operators is how they capture and incorporate learnings into the next design.

For any risk rating, time is a consideration that cannot be ignored. In well construction, time has at least four major influences:

1. Time impacts the knowledge available at the time of well construction. This in turn must reflect the knowledge that went into forming the design of the well, the materials available at the time of construction, and the knowledge-based regulations that governed construction at that time. Failure rates measured in a specific time period are artifacts of that period; they should not be reflective of wells designed and completed later. In well construction, the last 15 years have arguably brought more advances (new pipe alloys, better pipe joints, improved coatings, new cements, and subsurface diagnostics by seismic and logging delivering better understanding of earth forces) than the previous 15 decades of oil and gas operations.

2. Early-time failures reflect both the quality of well construction and general early component failure (similar to items on a new car that must be repaired in the first few weeks of operation).

3. Time reflects the potential for natural degradation of materials and changing earth stresses, both natural and man-made. Structures age; that is inescapable. The impact of aging, however, is highly geographically variable and controllable to a degree with maintenance. Structures in dry climates and soils often age slowly, while structures in wet areas, salt-spray zones, acid soils, and tectonically active areas can be degraded and even destroyed in a few years. The oldest producing wells, for example, are more than a century old and many have not leaked, while high-pressure/high-temperature (HP/HT), thermal-cycled, and corrosive-environment wells may have a well life of a decade or less before permanent plugging and isolation is required.

Time has also recorded changes in energy-source availability, from the easily obtainable conventional-reservoir petroleum resources to dependence on and development of resources that are much more difficult to access. This, in turn, has created technology-driven approaches that have been difficult for some, both inside and outside the industry, to learn and accept.

The potential for downhole leaks to the environment may diminish rapidly as the reservoir pressure is depleted. Low-bottom-hole-pressure wells do not have the driving force to oppose constant hydrostatic pressure of fluids outside the wellbore; hence, if a leak path is formed through the sequence of barriers, the highest potential is for exterior fluids (usually salt water) to leak into a wellbore. However, if gas leaks into the well, buoyancy will drive it upward toward the wellhead. Older wells that have been maintained through monitoring and repair can be extended past their design life through programs that assess damage and repair or re-equip wells as needed. An example from a 1932-vintage Bahrain oil field in the Arabian Gulf illustrates a moderate degree of casing damage from exterior corrosion, and how the threat was minimized through design and workovers (Sivakumar and Janahi 2004). Casing leaks (one-barrier failure) seem to have occurred in many of the 750 wells, in which corrosive saltwater flowed into the wells (minimum exterior pollution). In a sequence of design changes dating from 1932 to the early 2000s, casing damage and barrier failures were driven down from 60% frequency to a rare occurrence by inspection, monitoring, and proper maintenance. Another example from Ekofisk fields in the North Sea involved overburden deformation caused by production-induced compaction of highly porous, soft-chalk reservoirs. The compaction and horizontal movement of the chalk formations created more than 150 casing-deformation incidences near or in the deep-chalk reservoir. Significant numbers of collapses began appearing after nearly 8 years of oil production in 1982 to 1984, and by 1994, casing deformations, some to the point of casing collapse, had been measured on wells from all three of the production platforms and both water-injector platforms. Pressure maintenance through addition of water injection in 1987 was the first documented method to completely halt the deformations in older wells, while changes to well design proved effective in handling the deformation problem in new wells (Schwall and Denney 1994; Schwall et al. 1996). In the Ekofisk example, although the deep casing was often collapsed, there was no leak path formed that could allow escape of hydrocarbons to shallow environments.

In general terms, well-construction problems can be caused by leaking pipe connections, inadequate cementing, corrosion, cyclic loads, thermal extremes, earth stresses, abrasion, and other factors. Failures are most commonly reflected by a barrier failure, and few of these failures are severe enough to breach all the barriers and pollute groundwater. The modern US petroleum industry is nearly 100 years old, delineated by creation of effective cementing technology, the birth of modern pressure-control methods. US and dedicated worldwide petroleum-development attempts go back more than 100 years before that. Risk reduction has been driven by changes in technology, with an increasing importance to environmental drivers emerging in the past 25 years.

From the first US gas wells that used wooden pipe (circa 1820s) to a few years after the beginning of the twentieth century, zonal isolation of early wells was haphazard at best. The first true long-term isolation attempts applying Portland cement in 1903 marked the start of the cemented-pipe era. The effective two-plug cementing system invented by Almond Perkins in 1916 moved cement into a proven isolation technique (Oklahoma Historical Society 2013). Along the way, advances in every well-construction technology improved zonal-isolation reliability. Major eras of operation and the notable improvements are shown in Table 3.

Note that the learnings in era time period produce lower rates of well failures afterward. When comparing failure rates of wells, regardless of location, well type, or operator, the wells and the problems associated with those wells should be compared within a single time period of well development. Additionally, technology advances have driven improvements in wells, often without a clear intent to accomplish that goal. For example, rotary drilling enabled development of surface pressure-control systems that eliminated most blowouts, hydraulic fracturing drove better cementing practices, and pipe designs and horizontal wells reduced the total well count in many areas, thereby sharply lowering any risk of surface and subsurface pollution of freshwater formations. Development



TABLE 3—APPROXIMATE TIMELINE FOR POLLUTION POTENTIAL BY ERA

Time Era Approximation	Operation Norms	Era Potential For Pollution From Well Construction
1820s to 1916	Cable-tool drilling; no cement isolation; wells openly vented to atmosphere.	High
1916 to 1970	Cementing isolation steadily improving.	Moderate
1930s to present	Rotary drilling replacing cable tool; pressure-control systems and well-containment systems developed.	Moderate
1952 to present	Hydraulic fracturing commercialized; reduced the number of development wells and required better pipe, couplings, and cement isolation (Clark 1987; Sugden et al. 2012).	Low from fracturing aspects (King 2012)
Mid-1960s to 2000	Gas-tight couplings and joint makeup improving.	Moderate for vertical wells, joint designs improving for horizontal wells.
Mid-1970s to present	Cementing improvements, including cement design software; data on flow at temperature; dynamic cementing; swelling cement; flexible, gas-tight; and self-healing cements entering market (Baumgarte et al. 1999; Beirute et al. 1992; Lockyear et al. 1990; Parcevaux and Sault 1984; Ravi et al. 2002a, b; Chenevert and Shrestha 1991; Holt and Lahoti 2012).	Lower
1988 to present	Multiple-fracture horizontal wells; pad drilling reducing environmental land footprint up to 90%. Improvements in lower-toxicity chemicals from late 1990s.	Lower
2005 to present	Well-integrity assessments; premium couplings; adding additional barriers and cementing full strings (Valigura and Tallin 2005).	Lower, particularly after 2010 when state laws were strengthened on well design.
2008 to present	Chemical-hazard and endocrine disruptors recognized in fracturing chemicals and sharply reduced. Real-time well-integrity needs being studied to achieve early warning and problem avoidance.	Lowest yet, most states caught up with design and inspection requirements.

of HP/HT reservoirs drove development of better seals and pressure-handling technology.

### Studies of Well Failures

According to a review of state-investigated exploration-and-production (E&P) pollution incidences in Ohio (185 cases in approximately 65,000 wells) and Texas (211 cases in approximately 250,000 wells), the majority of pollution incidents were from D&C; production; wells that were no longer operated, but had not been maintained or properly plugged and abandoned (also known as orphaned wells); and waste disposal (Table 4). The production-well problems were dominated by leaks from pipelines and tanks. These data include a significant amount of legacy data before the Texas regulations on pits, cementing, and barrier design were changed in 1969 (Kell 2012). A large overhaul of Texas well regulations in 2012–13 further stiffened well-design and implementation requirements.

TABLE 4—INCIDENTS INVESTIGATED AND IDENTIFIED

Pollution Causes (Kell 2012)		
State	Ohio	Texas
Study period (years)	26	16
Number of wells producing	65,000	250,000
Number of cases investigated	185	211
Site related	0	0
D&C related	74	10
Fracture related	0	0
Producer related	39	56
Orphan-well related	41	30
Waste-disposal related	26	75
P&A related	5	1
Unknown	0	39

Many of the D&C incidents were cement-isolation problems, some before the cementing regulations were changed in 1969 or 1996, and before those being examined again currently. Fifty-seven of the 75 waste-related incidents in Texas during the study period were legacy issues with disposal pits that were outlawed in 1969. Texas has an industry tax-funded program that has reduced the number of orphaned wells from 18,000 in 2002 to less than 8,000 in 2009, and currently is engaging in P&A of 1,400 wells/yr of the remaining total of orphaned wells (Kell 2012).

A review of Ohio wells similarly suggested that the pollution incidents were related to early completion practices. Direct quotes from the report of Kell (2012) report follow.

“During the 25 year study period (1983–2007), Ohio documented 185 groundwater contamination incidents caused by historic or regulated oilfield activities. Of those, 144 groundwater contamination incidents were caused by regulated activities, and 41 incidents resulted from orphaned well leakage. Seventy-six of the incidents caused by regulated activities (52.7 percent) occurred during the first five years of the study (1983–1987).”

“When viewed in five year increments, the number of incidents caused by regulated activities declined significantly (90.1 percent) during the study period. Seventy-eight percent (113) of all documented regulated activity incidents were caused by drilling or production phase activities. Improper construction or maintenance of reserve pits was the primary source of groundwater contamination, which accounted for 43.8 percent of all regulated activity incidents (63) in Ohio.”

“During the 16 year study period (1993–2008), Texas documented 211 groundwater contamination incidents. More than 35 percent of these incidents (75) resulted from waste management and disposal activities including 57 legacy incidents caused by produced water disposal pits that were banned in 1969 and closed no later than 1984. Releases that occurred during production phase activities including storage tank or flow line leaks resulted in 26.5 percent of all activity regulated by the Texas Railroad Commission (TRC) incidents (56) in Texas.”

“During the study period, over 16,000 horizontal shale gas wells, with multi-staged hydraulic fracturing stimulations, were



TABLE 5—PERCENTAGE OF WELLS WITH SINGLE-BARRIER ISSUES IN OFFSHORE ENVIRONMENTS					
Geographic Area	Number of Wells	Wells With Barrier Issues	Major Problem	Percentage of Wells With Barrier Issues	Source
Gulf of Mexico	14,927	6,650	Leaks in tubulars	45%	Howard (2004)
North Sea, UK	4,700	1,600	Tubing connection, cement	34%	SPE (2009)
North Sea, Norway	2,682	482	Tubing connection, cement	18%	SINTEF (2010)

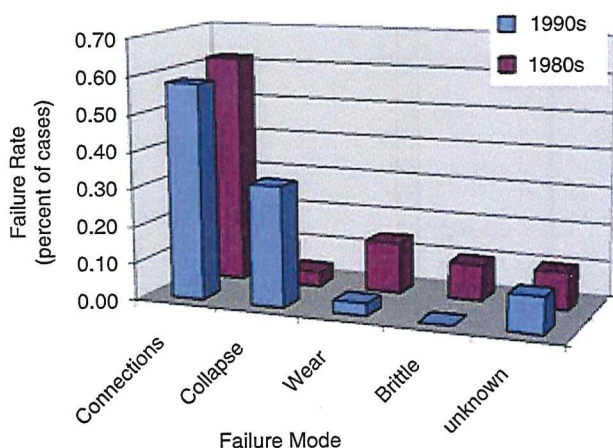


Fig. 4—Examples of failure by era (Schwind et al. 2001). The data provide a limited sampling from a failures database and are valid only for comparison of causes.

completed in Texas. Prior to 2008, only one horizontal shale gas well was completed in Ohio. During their respective study periods, neither the oil nor gas regulating bodies of the states of Texas (TRC) or Ohio (Division of Minerals Resource Management) identified a single groundwater contamination incident resulting from site preparation, drilling, well construction, completion, hydraulic fracturing stimulation, or production operations at any of these horizontal shale gas wells.”

The incident rate of problems from exploration to P&A, if based on the number of producing wells, would be 1 in nearly 1,200, while the rate of incidents on total wells drilled in Texas (more than one million, with more than 250,000 in operation), would be approximately 1 in 5,000. Note that there were no incidents that directly involved fracturing. This is consistent with recent studies (King 2012). These data also indicate that historical environmental incidents associated with oil and gas development were more commonly associated with aboveground fluid handling, leaking tanks or flowlines, or use of surface pits to contain fluids, and were less commonly associated with actual well design and construction. Steps have been taken to improve the safety and protection provided by all aspects of hydrocarbon production and transport, as documented in the data by the reduction in incidents in recent wells.

On a worldwide scale, the barrier-failure rate varies considerably. In a study that examined well-integrity issues, not failures, a wide variance between barrier failures in different regions indicates that conditions, and perhaps perceptions, may play a role in how well-barrier failures are reported and treated; Table 5 (Feather 2011).

Significant reductions in failures can only be accomplished when the causes of the failures as a component of a system are known and understood. For example, the data in Fig. 4 indicate a decrease in some forms of casing failures between the 1980s and the 1990s, but show a very significant increase in collapse failures. Only when the era of work is examined does this figure begin to make sense. The 1980s marked a low point of exploring and a return to safe infield drilling, where conditions were well known. In the 1990s, however, there was a significant movement to deeper wells and deepwater operations in which collapse forces were not adequately predicted. Almost unchanged in these early data is the fact that connection leaks are a definite problem within the industry. Pipe-thread leaks of some vintages or time periods of wells have been estimated to be involved as an element or as a direct cause in up to 90% of all barrier failures (Schwind et al. 2001). “Twice as many field failures occur from connections than all other failure modes combined. Connection qualification has eliminated field failures for those qualified, however, 55% of connection failures involve American Petroleum Institute (API) connections, and 45% involve unqualified premium” (Schwind et al. 2001).

In the early 1960s (1961–64), when the 8-round thread was widely popular, an API-organized survey of tubular-string failures indicated that 86% of the reported casing-string failures and 55% of the reported tubing-string failures occurred in connections (Kerr 1965; Weiner and True 1969). These coupling failures are also indicated in many sustained-casing-pressure (SCP) examples. During this 1950 to 1960 period, exterior pressure testing of more than 300,000 casing and tubing couplings made up during pipe running in the well-construction step showed a high number of well-coupling leaks, ranging in worst cases between 1 and 3% of individual couplings (Kerr 1965). A number of data-gathering and coupling-redesign efforts followed this period, and along with recommendations for joint makeup, resulted in sharply reduced connection problems when the procedures were rigidly enforced (Day et al. 1990).

Uptake of correct tubular-makeup procedures is highly company dependent and is a likely indicator for proper management. As late as the 1980s, tubing leaks were still a prevalent issue with a low time between failures (Table 6) (Molnes and Sundet 1993).

TABLE 6—TUBING FAILURE MODE		
	Number of Failures	Mean Time To Failure (MTTF) (years)
Burst tubing	3	3,113
Collapsed tubing	7	1,334
Restriction in tubing (scale or collapse)	18	519
Tubing parted (broken)	6	1,557
Tubing leak	182	51
All	216	22

SINTEF data: 17 participating companies, 800 total completion failures, and 6,600 well years of operation.



TABLE 7—WELL-INTEGRITY ISSUE

	Percent of 406 Norway (Offshore) Wells With the Issue
Tubing (connections leak)	7.1%
Annular safety valve (ASV) (offshore only)	2.2%
Cement-isolation leak	2%
Inner-casing failure (connection or collapse)	2%
Wellhead	1%
Packer	1%
Downhole safety valve (DSV)	0.7%
Conductor	0.5%
Packoff	0.5%
Design	0.5%
Gas lift valve (GLV)	0.25%
Fluid barrier	0.25%
Chemical-injection valve	0.25%
Formation	0.25%

When compared to other tubing failures, connection leaks were an obvious problem.

In a case history from Norway covering 406 wells, the main problem leading to a barrier failure was tubing (Table 7; Vignes and Aadnoy 2008), which is consistent with other reports on barrier failure both initially and with increasing age. Looking at the barrier failures by age shows the principal problems in 5-year age groups up to 19 years (Fig. 5), with the number of problems per year for different equipment. Because the well age was not given, only limited inferences can be made on improvements with time for this data set. The number and distribution of these tubing-connection leaks illustrate a technology gap that requires continuous attention.

Connection-reliability focus, beginning in the late 1950s, has provided improvements in thread design and improvements in overall barrier reliability. Connection reliability still requires proper makeup—a very human impact. For modern connections, coupling-makeup procedures and metal-to-metal seals in premium threads have eliminated many leak problems from the 1950s and 1960s (Payne et al. 2006; Bollfrass 1985). Leaking threads in a single tubular string do not necessarily mean the well will pollute. A tubing or casing string is a component in a single barrier. An outer barrier can often contain the leaked pressure or fluid until the leak can be found and repaired (Johns et al. 2009; Julian et al. 2007; Cowan 2007; Cary et al. 2013). Cementing the outside of casing, the second component of the barrier, will eliminate the potential for pipe-thread leaks if cement covers the thread leak (MacEachern et al. 2003).

Acceptance of premium threads, with superior sealing capacity for critical applications, is helping replace the 8-round thread in areas of tight gas and/or higher pressure ratings, but connection selection and makeup remains an issue in areas with older wells and for companies that do not accept best practices on joint

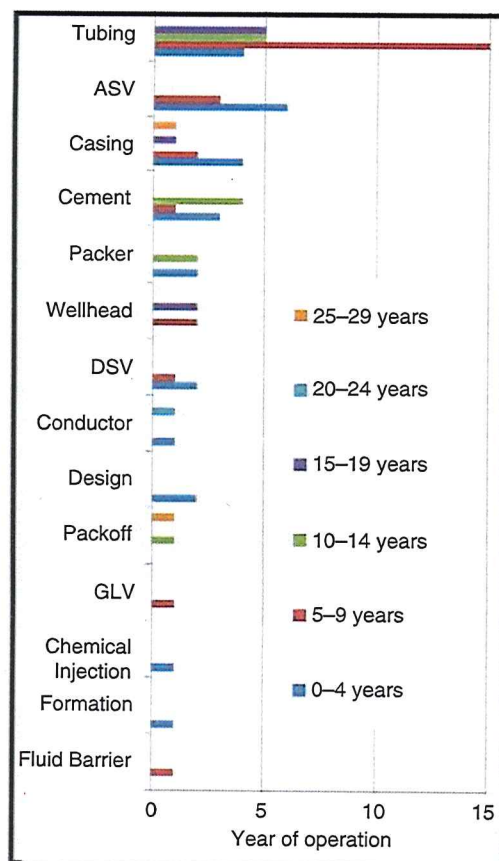


Fig. 5—Component failure by age (Vignes and Aadnoy 2008).

makeup. Premium threaded connections with metal-to-metal seals have been used in hundreds of North Sea and Gulf of Mexico (GOM) wells with an exceptionally low incidence of leaks or other failures (Gibson 1998). Table 8 illustrates the improvements in connection threads by era. The sharp drop in leaks by coupling selection and proper makeup is a high-value learning that can sharply reduce problems with SCP.

#### Other Barrier Equipment and Importance of Well Maintenance and Monitoring

The failure rate of properly maintained wellheads is low and is commonly limited to seals that isolate the top of tubulars, seals between the hangers, and valves. Failures in surface barrier systems can be inspected and repaired easily and quickly, without significant cost or risk. Failure databases on topside (surface) equipment and some subsurface equipment (e.g., subsurface safety valves) are available through joint-industry projects (SINTEF 2010a).

TABLE 8—TUBULAR-CONNECTION FAILURES BY CONNECTION TYPE AND ERA

Era or Time of Data Collection/Number of Completions	Tubing Length and/or Number of Connections	Connection Type	Failure Rate Per Joint Attempted	Failure Rate (Leaks Per Completion)	Source
1961–1964; 1,000 completions	300,000 connections	API 8-round	1–3%	56.7%	Kerr (1965)
1961–1964; 822 completions	253,000 connections	Early premium threads	0.26–0.72%	40% average	Kerr (1965)
1990–1998: >180 completions	>587,000 ft >19,500 connections	Premium (three major brands)	0	0	Gibson (1998; 2013*)

\*From a personal conversation on coupling testing in June 2013.

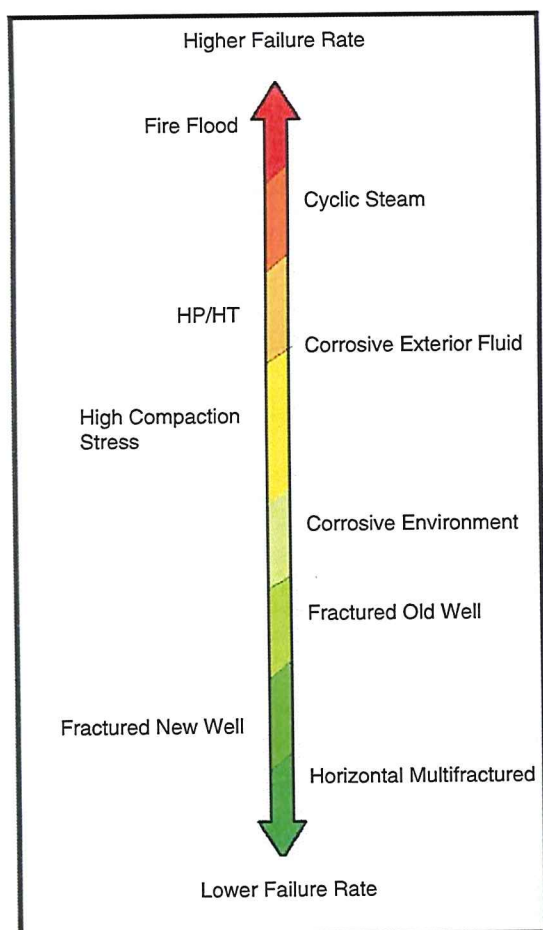


Fig. 6—Estimate of failure frequency by well type.

### Geographic and Well-Type Variance of Risk in Well Completions

The type of well and its location form the largest variable on risk to well completions. Wells must be designed to handle the specific environment, both inside and outside the well. A simplistic view of how certain well types might be viewed for barrier-failure risk is shown in Fig. 6.

Although the well-type comparison of failure estimates is simplistic, it highlights issues created by thermal and pressure loading in cyclic operations and the effects of corrosive environments inside and outside the well that must be properly handled in the design phase. Lower risks of horizontal multiple-fracture wells may be a surprise to some, but observations in Kell (2012) regarding the absence of incidences in the previously referenced Texas study of 16,000 horizontal wells provide significant proof and substantiate engineering expectations that wells properly designed for hydraulic stimulation with modern techniques and materials can provide excellent environmental protection.

A first-pass comparison of failures as they relate to well type is given in Table 7 (Molnes and Sundet 1993). MTTF data are useful as a general comparison of longevity of well equipment as compared to other equipment or similar equipment in different wells. As recognized in the industry, the produced-fluid type has a significant influence on the durability and longevity of the tubing string. The MTTF shows oil production to have the least “wear” impact, and water injection to have the most wear because corrosion and thread leaks affected by corrosion are the dominant failure mechanisms (Table 9). This has significant impact on barrier longevity and reinforces the expectation that wells designed for water injection typically require more attention during metallurgy selection and ongoing inspection than wells handling a less corrosive hydrocarbon stream.

TABLE 9—TUBING-SERVICE TIME BY WELL TYPE (SINTEF DATA)

Well Type	Service Time (tubing years)	Number of Failures	MTTF (years)
Oil Production	5,496	3	3,113
Gas/Condensate Production	1,522	7	1,334
Water Injection	1,756	18	518
Gas Injection	533	6	1,556

Data from Molnes and Sundet (1993). Total tubing base of 9,333 well years.

**SCP.** One of the first signs of a compromised barrier is SCP or sustained annular pressure (SAP), known also as surface casing-vent flow (SCVF) when the casing vent is opened to relieve the pressure (API RP 90 2006; Attard 1991; Bourgoyne et al. 1999; Soter et al. 2003; Tinsley et al. 1980; Watson and Bachu 2009; Bachu and Watson 2006, 2009). SCP or SAP is described as development of a sustained pressure in between the tubing and casing or between a pair of casing strings that is not caused solely by heating of the well when placed on production. A sustained pressure may be bled off quickly, but returns over hours or days after the annulus is shut in. Each of the annular spaces (Fig. 7) is a separate pressure vessel, and the casing strings are nested to provide redundant barriers. Although one barrier may develop a leak, secondary barriers will contain the pressure and prevent a leak to the outside.

Depending on the type, pressure, and depth of a well, there may be two to five or more annular spaces in a well. The presence of sustained pressure in the annulus area indicates two things:

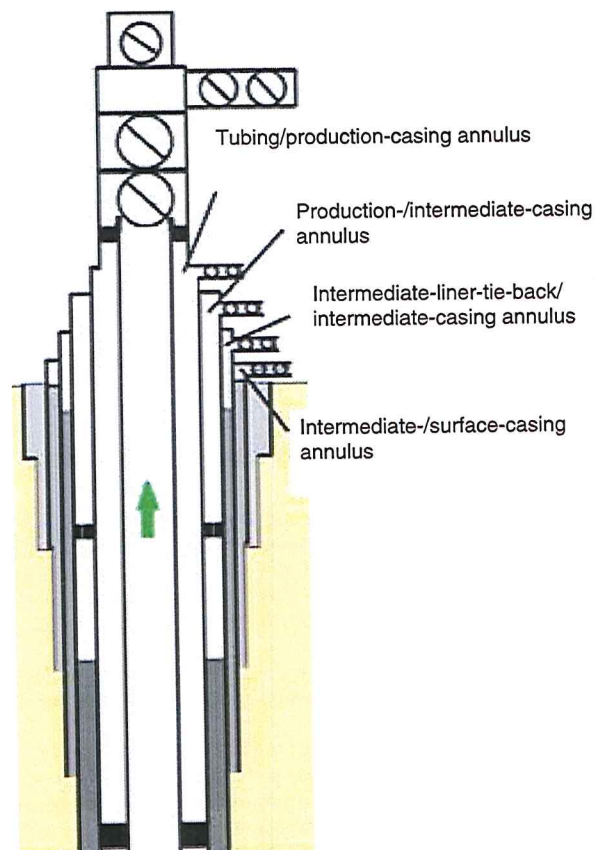


Fig. 7—A well schematic showing five casing strings and a tubing string with a packer set in the tubing/production-casing annulus.



**TABLE 10—DISTRIBUTION OF BARRIER FAILURES AND WELL-INTEGRITY FAILURES SHOWING IMPROVEMENT BY ERA (ALL LAND WELLS)**

Area/Number of Wells	Number of Construction Failures	Barrier-Failure Frequency Range (Containment)	Well-Integrity Failure Range (Containment Lost)	Leaks to Groundwater by Sampling	Data Sources
OH/64,830	74 fail initial cement test; 39 fail in production.	1983–2007 0.035% in 34,000 wells (0.1% in older wells—worst case)	0.06% for all wells	Detail not available	Kell (2012)
TX/253,090	10 fail initial cement test; 56 fail in production.	0.02% all wells	0.02% for older era wells; 0.004% for newer wells	0.005–0.01% for producers; 0.03–0.07% for injectors	Kell (2012) Texas Groundwater Protection Council (TGPC) data (1997–2011)
TX/16,000 horizontal, multifractured	No reported failures—added barrier.	No failure reported	No failure date or pollution reports	No well-associated pollution	Kell (2012)
MN/671	Salt-creep crush casing	5.5%	Unknown	None reported	Clegg (1971)
Alberta/316,000	Total vent-flow data	No separation data available	4.6% taken as worst case.	No data—mostly gas escape	Watson and Bachu (2009)

1. There may be a seepage-rate flow through at least one tubing string or casing string or through the cement. From this and other studies, the flow path is most likely either in a pipe coupling in an uncemented steel-pipe string or a microannulus or other type of leak in the cement sheath surrounding the pipe.

2. The pipe and cement on the outside of the annulus are containing the pressure (and fluids), and there may be no significant leak to the environment outside of the well, known also as gas migration (Watson and Bachu 2009).

Wells are created with nested redundant barriers that are designed so that a secondary, and sometimes a tertiary, barrier backs up the primary barrier. When SAP is detected in a well, the well must be assessed for safety and containment before further well operations can be considered. If remaining barriers are not capable of containing pressure and fluids, the well must be shut in and secured.

The presence of SAP appears to be related to geographic location and geology of the sediments (presence of soft formations and natural seepage paths of gas or oil), the operator's construction procedures, the type of well (corrosive-fluid production, high-pressure, cyclic behavior, high-temperature formations), and the age of the well. Complications from reservoir compaction in young weak rocks often cause casing or tubing collapse, requiring changes in design (Bruno 1992; Burkowsky et al. 1981; Fredrich et al. 1996; Hilbert et al. 1999; Li et al. 2003).

### Barrier- and Well-Failure Frequency From Case Histories and Databases

Using extensive presented literature from several technical societies, Table 10 captures ranges of barrier failures without apparent leaks and well-integrity failure (all barriers in a sequence fail) in which fluids (oil and gas) may move from inside to outside the well (contamination/pollution) or from outside to inside the well (intrusion of salt water).

Reported leak rates without specific leak-path determinations were assumed under worst-case scenario to be leaks rather than barrier failures.

Offshore wells are examples of the high end of the barrier-failure range, even though completed production wells in this group present virtually no potential for groundwater pollution because of the absence of subsurface freshwater aquifers offshore. The data are presented for comparison purposes to well construction for land-based wells with higher-strength formations.

US GOM offshore well data show the worst-case barrier failure and pollution potential reporting because the wells are mainly in gas-charged, often high-initial-pressure (overpressured), geologi-

cally young and soft marine sands—a combination of geologic and production extremes that presents a difficult well-construction environment. Interestingly, for at least the past 3 decades in the GOM, excluding the outlier of the Macondo D&C blowout in 2010, the amount of oil entering the GOM from natural seeps is 50 to 500 times the amount spilled or leaked from producing wells (National Research Council 2003; BOEM 2010) (Fig. 8).

GOM-produced-oil leakage by decade as a percentage of oil produced ranges from a low of 0.00005 (1990–99) to 0.007% (1960–69). Macondo (D&C-activity failure) was the clear outlier in GOM oil spills with just less than 1% spillage in 2010. Natural seeps are shown as constant-volume estimates, but many of the natural seeps are episodic in nature.

**SCP.** Industry experience on the GOM offshore continental shelf has shown that the most serious problems with SCP have resulted from tubing leaks. Pollution from SCP is minor, but a risk of a blowout is increased in some cases (Bourgoynne et al. 1999, 2000). Examples of wells with high barrier failure and low well-integrity failure in these offshore environments document the higher barrier-failure rate offshore and the positive effect of the multiple-barrier system in controlling pollution (reduction of well-integrity failures to levels far below barrier failure) (Table 11).

The sixth example, a study of 175 wells in Sumatra Island showed the consequences of time in a changing environment coupled with lack of sufficient maintenance. This combination created a barrier-failure rate of 43% and a well-failure rate (with potential exterior leakage) of up to 4% (Calosa et al. 2010).

### Why Well-Integrity Failures Produce Few Pollution Incidents

As opposed to loss of control during drilling in high-pressure reservoirs, such as the Macondo well, loss of control from completed and producing wells occurs very infrequently for several reasons:

- Many drilling failures are the result of unexpected high pressure or other drilling-related factors in which the pressure barriers are mostly dynamic (mud weight and blowout-preventer control) and before the full range of permanent barriers are installed that exist in a completed well. The expected frequency of surface releases in production wells (completed wells) is between one and two orders of magnitude lower during production than during drilling (Fischer 1996). Workovers during the life of the producing wells do raise the risk of a release, although the frequency is still approximately one order of magnitude lower than during drilling activities (Edmondson and Hide 1996).



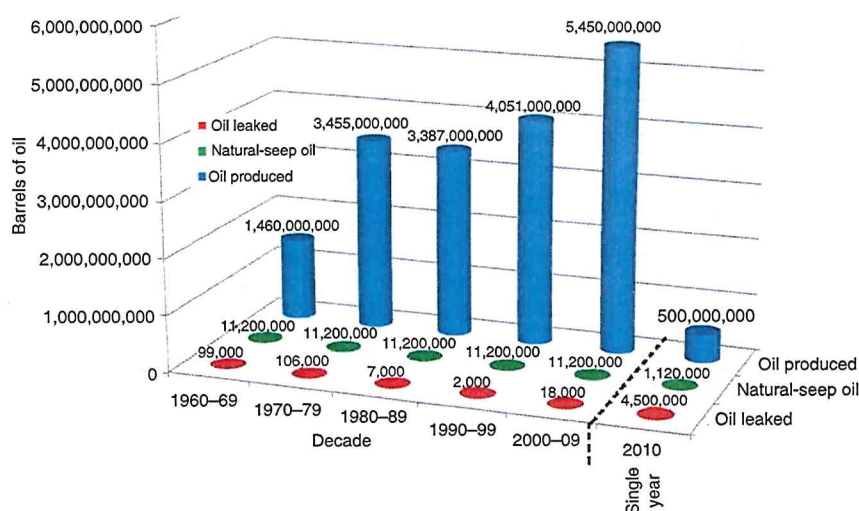


Fig. 8—Fifty years of GOM oil production, natural-seep estimates, and oil leaks by decade. The 2010 Macondo spill volume was a very high-side outlier, but is a reminder of spill potential.

- Completed wells are constructed of multiple barriers that have been tested and are monitored where applicable.
- Most importantly, the pressure inside a completed producing oil or gas well drops constantly during primary production. In oil wells, with little or no gas pressure, the potential for liquids inside the well to flow to the outside of the well is sharply reduced considering the outside fluid gradients that increase the outside (leak-opposing) pressure with increasing depth. Gas wells are not affected in quite the same manner. Although decreased pressure in the gas well diminishes the driving pressure, the lack of liquid hydrostatic backpressure allows more pressure near the surface than would be possible in an oil well.

### Cementing Basics

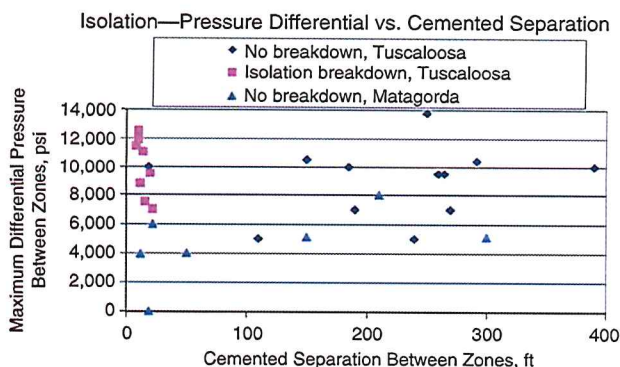
Casing and cement barriers in a well result from running casing to an acceptable depth in the formation after drilling a section of a

well. Each section is cased and cemented before the drilling can be continued to deepen the well. If the cement in a section of the well fails to pass testing requirements, the cement isolation must be repaired before drilling of the next section can commence. The steel casing provides burst, collapse, and tension strength, and the cement fill of the annular space between the drilled hole and the outside of the casing string provides the seal that isolates fluids and pressures. The cement on the outside of the specific string may reach the surface or to a lower level, depending on the needs of the completion and the threat level of an isolation failure in the overall design. The amount of cement required to isolate a pipe string depends on the pressures to be isolated and the quality of the isolation (pressure test and bonding to inner pipe and outer pipe or formation). The overall effectiveness of the seal depends on the amount of cement fill, the properties of the set cement, elimination of mud and gas channels within the cement, and the

TABLE 11—SCP REPORTS—BARRIER AND WELL FAILURE FOR PLATFORM-BASED DEVIATED OFFSHORE WELLS

Area/Wells	Barrier-Failure Frequency (Containment Maintained)	Well-Integrity Failure (Containment Lost)	Data Source
US GOM—11,498 wells (3,542 active)	30% overall had barrier failure with (tubing/production casing) SCP of 50% of cases. 90% of SCP had less than 1,000 psi. 10% more serious form of SCP requiring immediate shut-in to avoid pollution.	0.01–0.05% of wells leaked. This compared to total measured losses of oil of 0.00005% to 0.0003% of all produced oil (1980–2009).	Bourgoyne et al. (1999; 2000); National Research Council (2003); BOEM (2010); Wojtanowicz et al. (2001)
UG GOM—4,099 wells (shoe test only; all repaired)	12–18% of all wells failed one cement test. All required repair before continuing drilling.	Zero—cement repaired and tested successfully.	Harris et al. (2001)
Norway—406 compaction, shear, and sand failures	18%	None reported (barrier failure and shut in for repair).	Vignes and Aadnoy (2008)
GOM and Trinidad—2,120 sand-control failures	0.05 to >1% sand-control failures, well control maintained.	Approximately 0.0001% failure at surface because of erosion.	King et al. (2003)
Matagorda Island Platform—17 wells—subsidence and compaction	80–100% had some level of SCP; the high number is because of high pressure and formation compaction.	Wells routinely shut in and repaired before restart.	Li et al. (2003)
Sumatra—175—Example of no maintenance	43% had some form of barrier failure.	Well leaks were reported as 1 to 4% before repairs were started.	Calosa et al. (2010)





**Fig. 9—Zone-to-zone isolation testing rub by Amoco on Matagorda (GOM) and Tuscaloosa (Pointe Coupe Parish, Louisiana) from 1990 to 1997 (from an internal Amoco report).**

bonding of the cement to the pipe and the formation (Watson and Bachu 2009; Lockyear et al. 1990).

The cement does not need to be perfect over every foot of the cemented area, but at least some part of the cement column must form a durable and permanent seal that isolates fluids from moving behind the pipe that could contaminate or cause detrimental mixing of fluids from one formation with fluids from another formation (i.e., provide hydraulic isolation). The required amount of this “perfect” cement in a longer column of cement has been shown to be at least 50 ft (Fig. 9). This figure documents 27 short-term comparisons of successful isolation of pressure in a stacked and sequentially completed pay with as much as 14,000-psi pressure differential between zones in high-pressure gas wells along the soft sediments of the Louisiana Gulf Coast and the GOM. Industry commonly uses from 200 to 600 ft of cement in overlap sections.

Additional barriers in a well may include a tubing string and packer with a monitored annulus between the tubing (the flow path) and the inner casing string.

Depending on the region and the specific geologic conditions, there may be need for one to three barriers in a simple completion with low risk, and likely two to five barriers in higher-risk areas. The differences in design consider pressure, depth, separation, presence of usable water, corrosion potential, and cementing effectiveness in an area, as well as operator expertise in both design and execution (Smith et al. 2012; Popa et al. 2008). Some annuli between casing strings are cemented to surface and some are left open to enable monitoring of any leak potential from the inside string (O’Brien 1996). A cement sheath is expected to provide mechanical support to the casing string and must provide both mechanical and hydraulic isolation for all productive horizons for the life of the well (Gray et al. 2009).

### Cement Effectiveness in Reducing Pollution Risk

Using results from a study of subsurface water-injection operations in the Williston basin, a model was developed to assess the maximum quantifiable risk that water from water-injection wells would reach an underground source of drinking water. The upper bound of the probability of injection water escaping the wellbore and reaching underground sources of drinking water (USDW) is seven chances in one million well years where casing and cement cover the drinking-water aquifers. Where surface casings do not cover USDW, the probability is six chances in 1,000 well years (Michie and Koch 1991). The 1,000:1 improvement is a testimony to the efficiency of annular cement.

### Cement Bond, Isolation Quality, and Bond Testing

The question of how to most effectively test the cement isolation is more involved than most people anticipate. Cement-bond logs (CBLs), for example, are not always the best investigation tool.

Whether or not a bond log should be run depends on the accuracy and usefulness of the information it gives in a particular application.

CBLs, which may be sonic or ultrasonic, range from simple averaging instruments (similar to those that came out in 1960) to the more-sophisticated models that investigate 60° segments of the cemented annulus around the tool (Grosman et al. 1961; Flournoy and Feaster 1963; Fertl et al. 1974; Fertl and Pilkington 1975; Pilkington 1992; Bigelow 1985; Jutten et al. 1991; Goodwin and Crook 1992; Gai et al. 1996; Frisch et al. 2000, 2002; Garnier et al. 2007). A properly run and executed CBL or cement-evaluation tool (CET) can provide some information on cement fill behind the pipe, going past the single area of the cemented shoe and upward and along the wellbore, where a pressure test will not reach.

CBLs are widely used as indicators to help achieve a good cement job in the first few wells in an area and validate a good cementing program that will be used on subsequent wells. CBLs may also be needed after a pressure test has failed on a section of the well during initial construction. For well rework and suspected changes in integrity, many other leak-detection methods offer more-accurate determination of leaks than can be produced with a CBL (Johns et al. 2009; Julian et al. 2007). CBLs can give a reasonable estimate of bonding and a semiquantitative idea of presence or absence of larger cement channels, but will not certify pressure or hydraulic isolation of a zone. Field performance for a properly run and calibrated CBL is approximately 90% in finding channels of 10% or more of total annular space (Albert et al. 1988). Smaller annular channels are not easily identifiable with a bond log because of variations in cement composition that create density differences in the cement. This finding was proved by long-term production without problems, water-free well performance (water isolation), and pressure measurements over time (Flournoy and Feaster 1963). Data in these field tests showed many wells with effective isolation even though the percentage of acceptable bond ranged from 31 to 75%. Error within the application and interpretation of CBLs has resulted in numerous workovers to repair cement that was not faulty, resulting in high workover costs and a decrease in the well integrity by unnecessary perforating and attempting to block squeeze cement that was effective in isolating a zone but “appeared” to have poor bond characteristics on an imprecise CBL.

With the exception of a pressure test, requiring a CET on every cement job appears to be a questionable policy, with possible detrimental economic and structural consequences for squeeze cementing attempts made on wells with cement indicated as suspect by CBL investigation, but proved to be effective by a pressure test and long-term production.

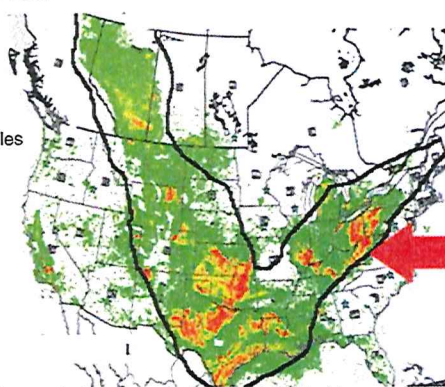
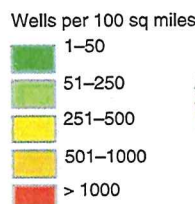
Methane leakage from the ground may also be associated with well construction by soil and rock disturbance as the well is being drilled or for a short time after completion (Dusseault et al. 2000, 2001). Soil gas disturbance and subsequent venting either around the casing (short term) or into the well (longer term) are usually found where a large amount of organic materials and/or small gas accumulations are found and either continuously produced or trapped near surface. Examples are swamp lands, muskegs, tar sands, and some permafrost areas (Slater 2010; Macedo et al. 2012; Dousett et al. 1997). Of 316,000 wells in the province of Alberta, Canada, an estimated 4.6% had small SCVFs that lasted a few hours or more after completion (Watson and Bachu 2009). In a 20,500-well subset of steam-injection wells in the shallow tar-sands area in Alberta, almost 15% experienced SCVFs (Nygaard 2010). This drives home the point of geographical location and illustrates the difficulty of achieving effective seals in shallow, highly gas-productive areas that also are rich in gas seeps and often are poorly consolidated.

### Natural Surface Seeps of Gas and Oil—Natural Pathways and Natural Pollution Sources

Understanding hydrocarbon movement within natural seeps of oil and gas is critical to the realization that many forms of methane

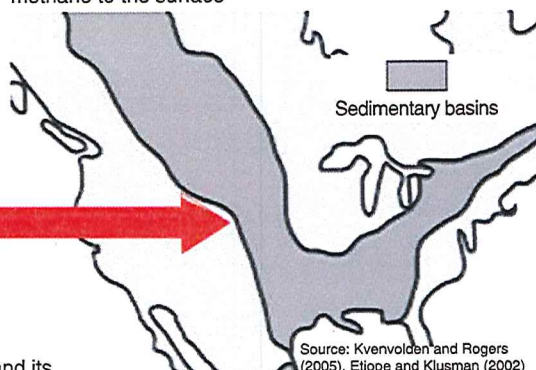


Total: 4.3 Million Wells



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Well Density in US and Canada

Areas of possible micro- and macroseeps of methane to the surface



Sedimentary Basins in US and Canada

Fig. 10—Comparison with well density and natural-seep location.

migration are, in fact, a part of nature. Seep maps from the 1930s and 1940s (Link 1952) show a direct correlation with many fields, and hundreds of oil seeps are documented in the GOM and more than a thousand on land in North America, with perhaps as many as 10,000 seeps worldwide (Etiope 2009a, b). While many uninformed observers may recognize the correlation between documented hydrocarbon emissions and the presence of oil and gas wells, they may misread the causality. The presence of natural gas or oil seeps is often the first indicator of highly prospective drilling locations.

Wells are concentrated where significant hydrocarbons accumulations and natural seepage exist (Fig. 10)—a comment so evident as to not need stating, except for the strident dialogue against the smallest leakage of hydrocarbon to the surface of the Earth. It is, in fact, these small methane leaks that drew attention to the larger mass of hydrocarbons that lay deep beneath the surface. Producing hydrocarbon accumulations have a common trait—natural seeps of gas and oil bring hydrocarbon fluids to the surface through natural pathways in significant quantities (Wilson et al.

1974; Kvenvolden and Cooper 2003; Kvenvolden and Rogers 2005; National Research Council 2003). Organisms in water and soil have evolved to degrade and use these hydrocarbon sources as food.

Natural seeps are significant contributors to the global atmospheric-methane budget in which the worldwide total global methane seep of 5 to 10 Bcf/D ranks just behind the wetlands emissions of 10 to 15 Bcf/D (Kvenvolden and Rogers 2005; Leifer et al. 2006; Etiope and Klusman 2002; Wilson et al. 1974).

Fig. 11 presents a compilation of the most severe US oil spills from wells and transport. Because spill volumes are rough estimates, several sources were used to achieve a reasonable assessment of oil lost. Spills may originate from many sources, but transportation is a primary source. Of the three major spills in the table from the upstream end (E&P) of the oil business, all three are from drilling- or workover-related causes, not from producing wells.

The yearly ranking of natural-seep contributions of oil into waters off California from the Coal Point seep (largest natural oil seep in the world with daily seep rates of 2,000 to 3,000 gal of oil and 2 MMscf/D of gas) and the oil leakage by the 600+ natural seeps underlying productive areas of the GOM). The Kuwait well-sabotage incident was where more than 600 wells were opened or the wellheads shattered with explosives. Interestingly, the use of up to 700 lbm (approximately 320 kg) of high explosives in direct contact with each wellhead only damaged the casing to a depth of approximately 8 to 13 ft (2.4 to 4 m) (Cudd 1992). The average yearly flow from the GOM and land-based natural seeps that are carried into the GOM every year is estimated to be approximately 25% of the volume spilled by the 99 days of uncontrolled flow from the Macondo well (National research Council 2003).

The information on seeps and spills from tanker and pipeline sources is shown only to put the leak volumes in perspective on a total oil-leakage basis, not to attempt to excuse spill behaviors. Seep volumes have a high degree of volume variance because most seeps are episodic in nature.

Surface flow rates of many oil and gas seeps have dropped sharply in the past century as wells produced fluids from the reservoirs that fed the seeps (Quigley et al. 1999). Edwin Drake followed the oil and gas seeps along Oil Creek, near Titusville, Pennsylvania and, in 1859, developed the first purpose-drilled US well for oil that achieved commercial production. The well hit oil at a depth of 69.5 ft, which is shallower than many current Pennsylvania water-supply wells.

Hydrocarbons are generated in two ways—by thermal maturation of organic materials that form a range of alkanes from  $C_1$  (Methane) to oils of  $C_{20+}$ , and by biologic activity that forms most short-chain alkanes such as methane gas. Hydrocarbons and fresh-/usable-water aquifers often share pore space within many

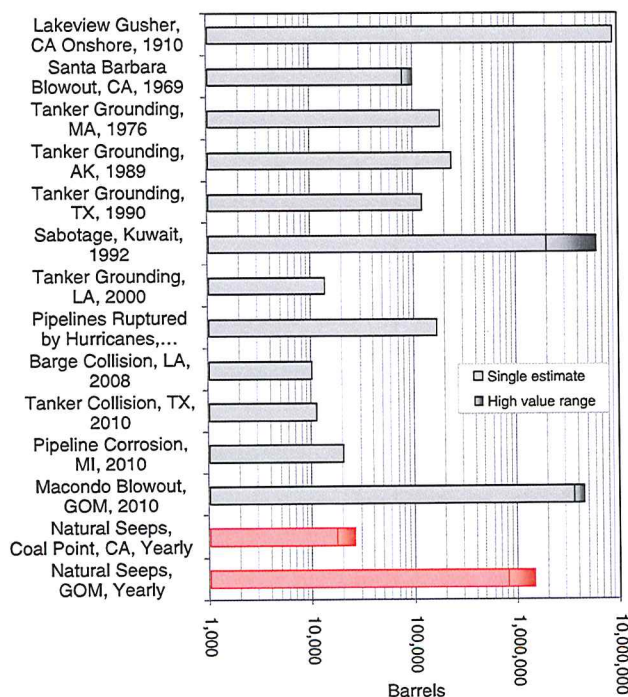


Fig. 11—Spills within the US with reference to the sabotage releases in Kuwait of 1991 and yearly US natural-seep volumes.



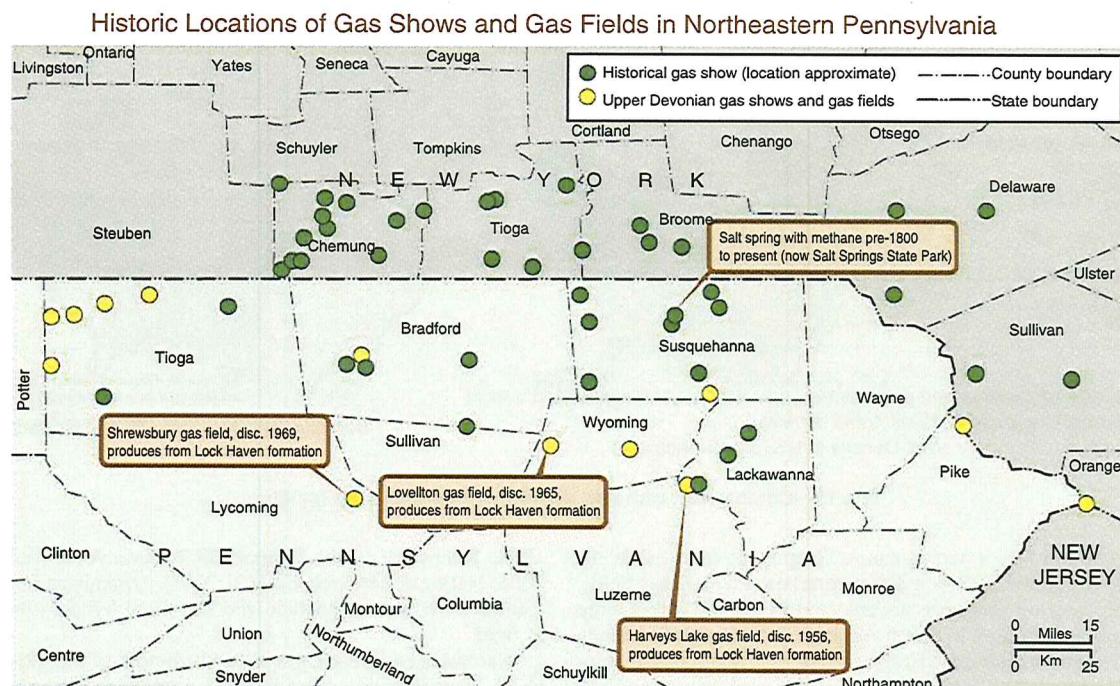


Fig. 12—Examples of historical Pennsylvania and New York gas shows predating Marcellus development, including multiple 1954–1969 era gas fields known to have commercially produced from freshwater sands.

formations in their undisturbed states. In many cases, even freshwater sands such as the Catskill and Lock Haven formations in the northeastern US have sufficient organic material and burial exposure to create thermogenic gas in the water sands themselves. Several gas fields produced commercial gas from the Lock Haven and Catskill from 1955 to the late 1960s (Fig. 12), predating all deeper shale gas development in the area (Molofsky et al. 2011; Baldassare 2011).

While methane can be released from activities involving gas-well development, properly run scientific studies on large scales have shown no correlation between gas-well development and the presence of methane in drinking water (USGS 2012; Molofsky et al. 2011; Baldassare 2011).

Oil also seeps into upper strata through natural pathways. Natural seepage rate of oil is estimated to approximately 600,000 tons/yr or 4 million bbl (170 million gal) (Wilson et al. 1974; Kvenvolden and Cooper 2003).

### Groundwater Variation

Groundwater, brine zones, and produced water from oil and gas operations in a specific area do not have a constant composition. Variability in any groundwater is well documented (Missouri Department of Natural Resources 2007; Nelson 2002; NETL 2010; Reedy et al. 2011; Uhlman et al. 2009; Alley et al. 1991; Nelson 2013; Otten and Mercier 1995). Factors in natural variation in mineral and methane content in groundwater and brine zones include seasonal variance, barometric-pressure changes, changes produced by runoff, water recharge routes into the reservoir, recharge sources, recharge rates, depth of withdrawal, rate of groundwater withdrawal, and even earth tides. According to groundwater experts, overdrawn or overdrafting a groundwater reservoir (withdrawing water faster than it can be recharged) can produce notable changes in the reservoir-water composition, including pulling contaminants in from above and salt from below (CTIC 2010). This variability makes single-point comparisons of water quality practically worthless. Many fresh groundwater aquifers are laterally or vertically connected to more saline water sources. Salinity, within a single unit, often varies with depth.

Sudden changes in pressure within a groundwater reservoir will also change the amount of free methane gas by causing gas

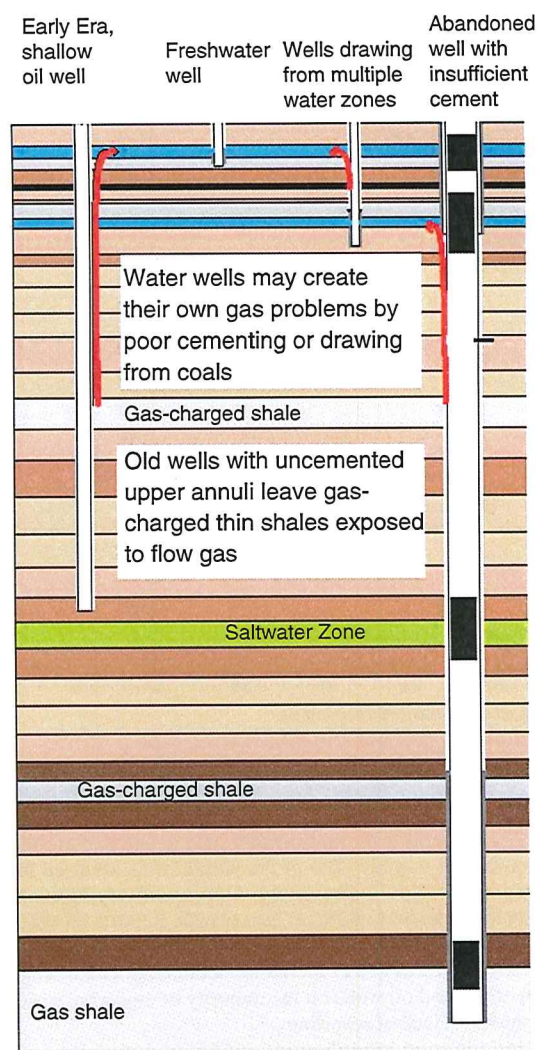
exsolution into free gas phase. The only way to assess changes in a groundwater source is to establish a trend range and include seasonal variations, withdrawal rate, and other variables. Investigations of stray natural-gas incidents in Pennsylvania reveal that incidents of stray-gas migration were not caused by hydraulic fracturing of the Marcellus shale (Baldassare 2011; Molofsky et al. 2011). The possibility of some gas-migration events being related to drilling cannot be dismissed because air drilling, when practiced, may be a cause for temporary upsets in shallow-well-water color and odor, although the worst of these migrations appear to be in areas with known examples and history of shallow gas flows that predate drilling (Kappel and Hamilton 2012).

Gas migration in the subsurface occurs principally by advective transport (dissolved in water) from areas of high pressure and is influenced by temporal changes in barometric pressure, soil/bedrock porosity, permeability, and precipitation that influence subsurface water levels. Incidents of stray combustible gas are not recent occurrences. Historic gas and oil flows into water wells and creeks were documented more than 200 years ago in New York and Pennsylvania.

### Methane in Groundwater and Methane Migration

Methane is the most common gas in groundwater. Shallow methane may be from sources both thermogenic (maturation of depositional organics in the reservoir) and biogenic (biological breakdown of organic materials carried into the reservoir) (Burruss and Laughrey 2012). Depending on the area of the country and the specifics of the aquifer, groundwater—fresh or saline—may dissolve and carry methane gas in concentrations of 0 to 28 mg/L. Free (nondissolved) methane gas exists in many aquifers under the caprock or in rock layers, and methane gas is frequently desorbed from organic formations such as coal or shale as the pressure is reduced by producing the water from these formations. As water flows out of a rock formation and into a wellbore, pressure is lowered, creating opportunity for some dissolved methane gas to exsolve out of the water and become a free gas phase (similar to the CO<sub>2</sub> escaping as a fresh bottle of carbonated soda is opened). Higher drawdowns (increased differential pressure) will enable more gas to come out of solution. Any free gas will rapidly rise in the well and can accumulate into the highest part of the



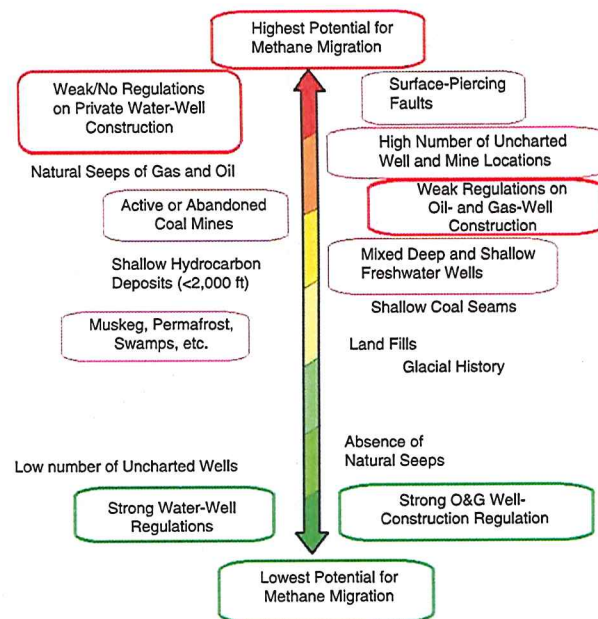


**Fig. 13—Gas migration may be from single or multiple sources, and may involve gas wells if insufficient annular cement is present to isolate gas-charged formations, including shales or coals.**

well piping system, and, if not vented by proper water-well construction, will follow the moving water when the water tap is opened in the house. This is the cause of burnable gas seen in 200-year-old historical reports on igniting water wells and in more recent dramatic TV and movie shots of burnable gas quantities in faucets and garden hoses. If the well is constructed correctly, a vent cap allows the methane to escape from the well (Swistock and Rizzo 2013) and prevents most gas accumulations.

Flow paths of methane gas into a water well may be from the fresh water itself or by communication with old gas wells or deeper water wells that do not effectively isolate gas-charged formations such as coals, thin shale beds, or shallow gas accumulations (Fig. 13).

The frequency of gas appearance in groundwater is linked to a number of factors, most of which can be more geographically or geologically influenced than impacted by oil- or gas-well presence. One major factor and difference in northeast Pennsylvania and southern New York is the presence of historic gas seeps. Fig. 14 shows a number of these factors as positive or negative influences. Perhaps surprisingly, many of the influences are natural in origin. Wells, particularly those drilled with air, can play a significant local role in gas-migration disturbances (Soeder 2012), either by air charging shallow water sands or by displacing shallow pockets of methane into the low-pressure areas caused by groundwater withdrawal. The number of water-supply wells in the US is near 15 million, not counting those that have been dug,



**Fig. 14—Factors involved in gas migration may include natural sources and both water-well construction and gas-well construction or abandonment.**

driven, or drilled before being abandoned. There are very few mandatory water-well standards enforced in the US and improperly constructed, poorly maintained and improperly abandoned water wells can be a primary pathway for aquifer contamination by a variety of materials, both from surface and subsurface inflow, regardless of the source of the gas.

### Bubbles Around a Wellhead

The presence of bubbles in well cellars or through soil around the wellhead may or may not be an indicator of leaks from the well. Any disturbance of soil by drilling, digging, pile driving, or even walking through a swampy area is frequently accompanied by release of methane gas, particularly where natural methane in the soil is more highly concentrated (swamps, muskeg, tundra). This type of seepage is usually short lived, except in the presence of natural seeps fed by deeper reservoirs along an established seep path. Depending on depth of disturbance, the bubbles may decrease or stop in seconds to days (Naftz and Hadley 1998). Composition of this gas may be biogenic or thermogenic because composition of natural seep gas is commonly from deeper reservoirs and therefore overwhelmingly (approximately 96%) thermogenic (Kvendvolden and Rogers 2005).

### Major Sources of Groundwater Pollution—Where Do Oil and Gas Wells Rank?

Groundwater pollution continues to be a major issue in the US, but what are the primary causes and pathways? The indisputable major sources of US groundwater contamination over the past few decades are (1) leaks from underground storage tanks (gasoline, diesel, and chemicals) at filling stations and industrial sites with buried tanks, (2) improper residential septic systems, and (3) poorly constructed landfills (EPA 2000) (Fig. 15).

In 2000, the first appearance of a potential E&P upstream groundwater-pollution source was from unspecified shallow injection wells at number 17 of the top 20 frequency-reported sources, although other industries also use wells of this type. Oil wells, gas wells, and deep injectors did not make the list.

**Case History—Texas Aquifers, Oil and Gas Wells and Pollution.** To check the potential of groundwater contamination in a high-density oil- and gas-well environment, data from Texas Commission on



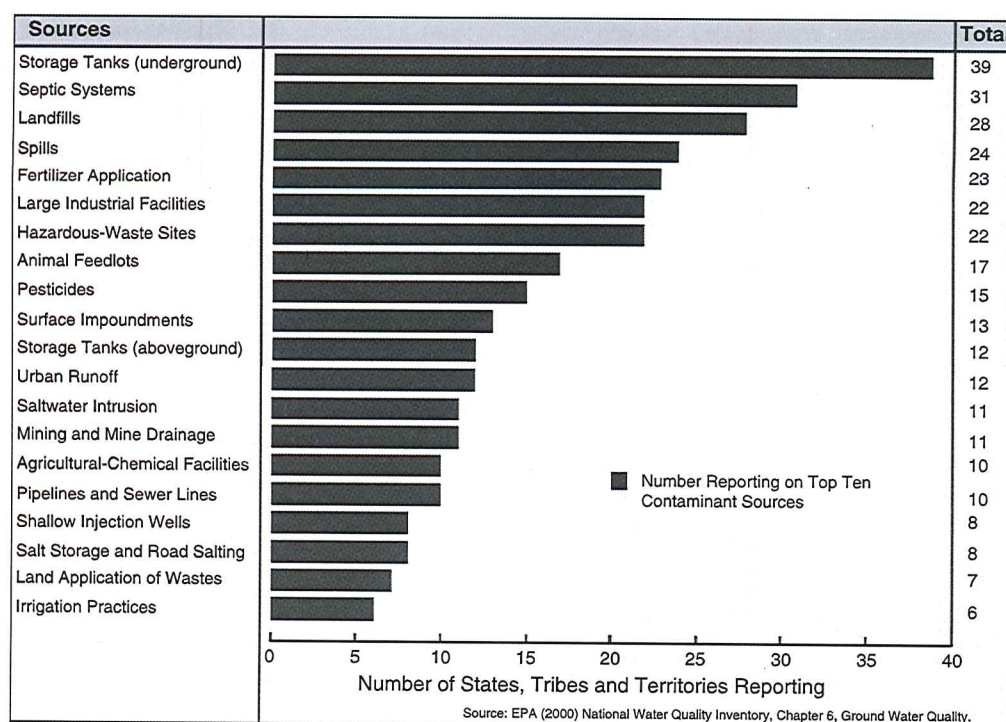


Fig. 15—EPA data collected in 1999 from states, tribes, and territories on reported incidents of groundwater pollution (EPA 2000).

Environmental Quality (TCEQ) and TGPC pollution reports were reviewed for specific references to reported oil-, gas-, and injection-well relevance. The state of Texas was used as an example, specifically to examine reports of pollution in high-density oil- and gas-well areas on a county-by-county basis. Fig. 16 is a map of the major aquifers of Texas, overlaid with hundreds of thousands of oil and gas wells drilled through those aquifers. Studies of pollution reports from counties show a higher correlation of oil and saltwater pollution in surface facilities (plants, compressor stations, and tank storage), but few direct downhole results linked to wells (TGPC

1998; 2011). Texas is the number two state in terms of groundwater withdrawal and roughly 80% of the withdrawals are used for agriculture and municipal water supply. Aquifers of varying quality and quantity lie under 80 to 90% of Texas lands. Reports of water quality from properly built water-supply wells affecting public health or crops is absent from the literature, indicating either very little impact of gas and oil wells on the majority of aquifers, or a curious and unheard-of lack of reporting.

Texas pollution records were examined for major causes of pollution and for possible links to oil and gas wells. The reported

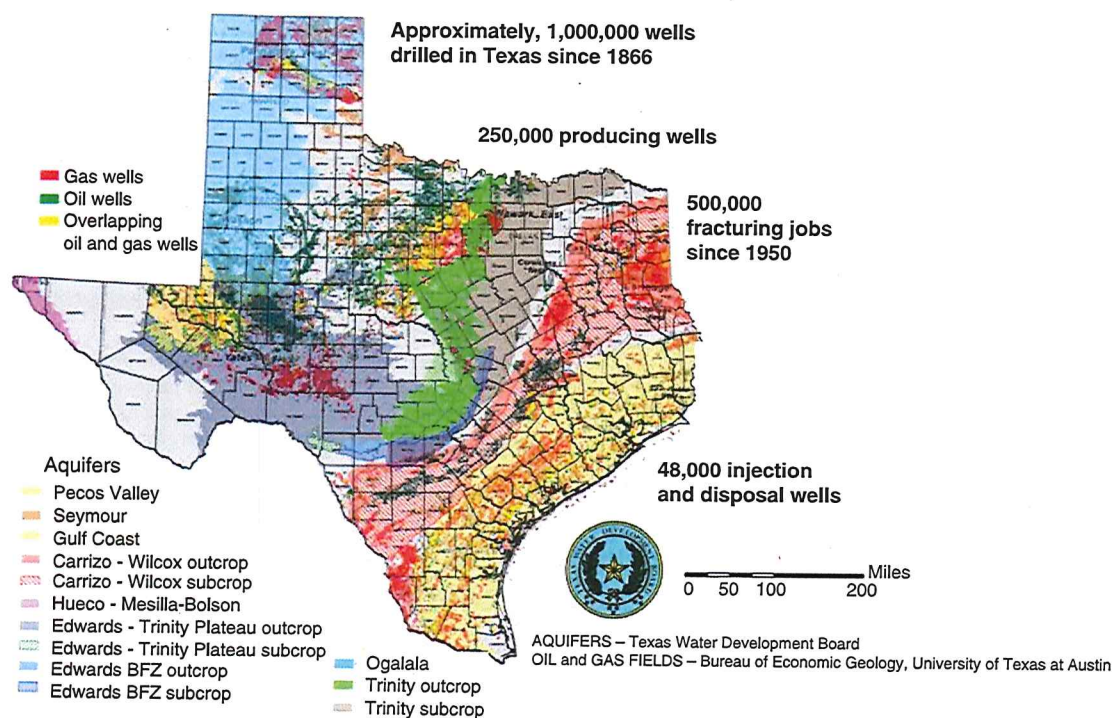


Fig. 16—Overlay of oil and gas wells over areas of major aquifers in Texas [modified download from Texas Water Development Board (2013)].

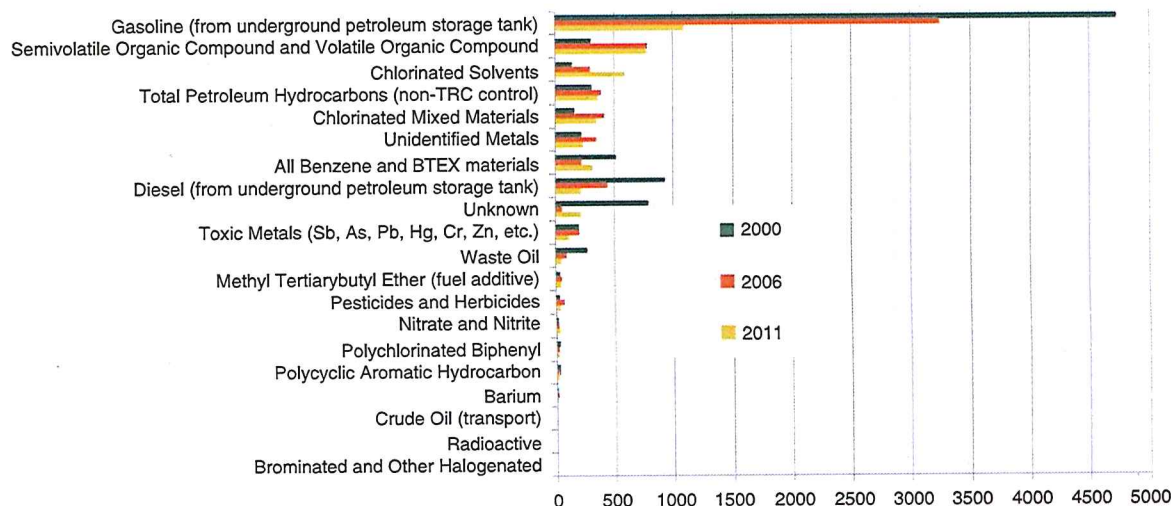


Fig. 17—Reported incidents of groundwater pollution in Texas (TGPC records from 2000 to 2011; BTEX = benzene, toluene, ethylbenzene, and xylene).

information (volumes of pollutant released) was not available. Fig. 17 shows a strong, but decreasing reporting frequency of impact from underground gasoline and diesel storage tanks at filling stations, and variable exposure to manufacturing chemicals, solvents, and waste oils, and very small incidents of spills involving road transport of oil.

The percentage of pollution reports that TCEQ and TGPC identified as under TRC authority varied between less than 1% to a maximum of approximately 10% of the total new pollution reports each year. Further analysis of these reports showed a breakdown of cases in which surface facilities (tanks, separators, gas plants, compressors, and gathering lines) and pipelines were responsible for approximately 90% of the pollution incidents under TRC jurisdiction. The remaining reports of pollution, roughly less than 1% of the total reported each year, concerned the 200,000 to 250,000 wells that are producing, injecting, or shut-in in Texas during the respective time period. All leaks were ascribed to wells whether they had been investigated or not—a worst-case approach. No leaks from abandoned wells were listed, although these may have been addressed under the Texas orphan-

well program, which ranks and then plugs and abandons more than 1,400 wells/yr, on the basis of proceeds from a tax on permits and operators. The breakdown is shown in Fig. 18.

### Conclusions

1. Current redundant-barrier well design with nested cemented casing strings is effective in sharply reducing pollution potential from oil and gas wells.
2. One or more barriers in a properly designed and constructed oil or gas well may fail without creating a pollution pathway or significantly raising the risk of groundwater pollution.
3. The overall risk of groundwater pollution from a producing well is extremely low.
4. Individual barrier-failure rates and well-failure rates vary widely with type of well, geographical location, and maintenance culture of the operator, as well as with the regulatory regime in place in the respective jurisdiction.
5. Individual well-barrier element failure rates are often one to two orders of magnitude greater than well-integrity failures in

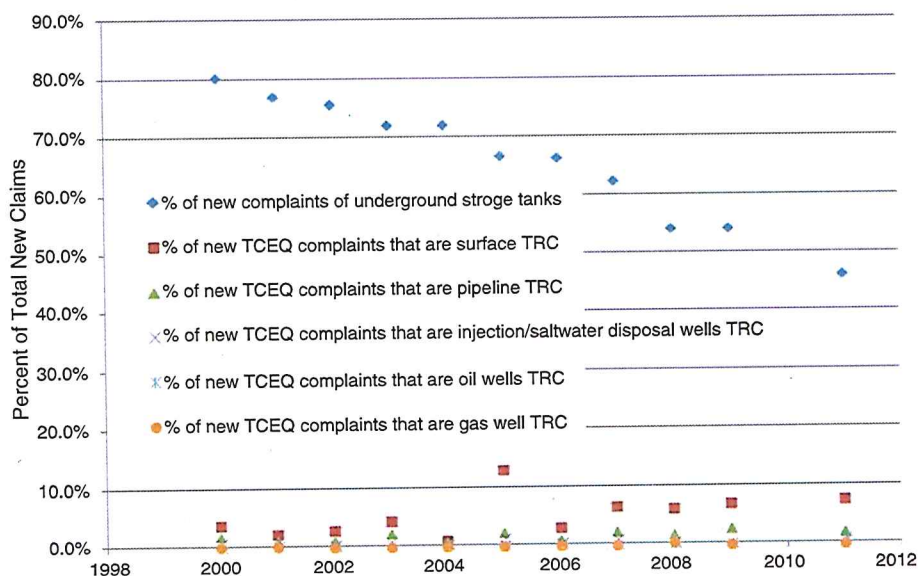


Fig. 18—Comparison of new underground-storage-tank pollution reports from possible well-pollution claims and reports separating subsurface from surface (facility, tank batteries, compressor locations, and gas plants), pipelines and injection, and oil and gas wells using data from TGPC, TCEQ, and TRC pollution reporting from 2000 to 2011.



which all barriers in a protection sequence fail and pollution can or does happen.

6. Failure rates of well barriers and well-integrity failures, measured on wells constructed in a specific time period, are artifacts of that era; they are not identical to failure rates of wells designed and completed later.
7. Oil, gas, or injection wells have an overall leak frequency ranging from 0.005 to 0.03% of wells in service at this time; however, areas with older wells and surface facilities tend to have higher leak frequencies, while more-recent development areas (such as the Barnett shale in northeast Texas) have lower leak frequencies. Accuracy of these pollution-frequency data obviously depend on the ability to detect the leaks and the ability to identify the sources of the leaks after they are detected.
8. The formation-fluid pressure differential between exterior formations and depressured low-gas-content oil-well environment favors fluid flow into the well instead of out of the well because downhole pressure in an oil or gas well is reduced as reservoir fluid is removed.
9. Gas-migration potential varies primarily with location and appears to be highest where natural seeps of gas or oil are present. Gas from discrete natural seeps is overwhelmingly thermogenic gas. Large volumes of biogenic gas are released from swamps, landfill, tundra, etc.
10. Methane gas migration from deep drilling does not appear to be connected to oil and gas production, but rather, it does appear to be connected to other drilling and development factors, such as unknown location of improperly abandoned wells or shallow trapped gas and coal gas.
11. Improperly constructed and maintained water-supply wells and improperly plugged oil or gas wells may be conduits for methane migration into fresh water supplies.
12. Groundwater composition may change because of numerous factors, most of which are unrelated to oil and gas operations.

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