The relationship between energy and water in unconventional gas

Source, fate and water-energy intensity

Energy resources underpin and drive industrialised economies. Because of the intricate relationship between water and energy, and as a consequence of economic development, conflict often results. This is mostly due to expansion by the energy sector and the impact on water resources and the environment.

Hydroelectric schemes have an obvious and direct relationship between energy generation and environmental water factors. But what about other energy resources such as 'unconventional' coal seam gas (CSG) and shale gas – which are widely debated and polarise interest groups? This paper looks at the unconventional gas industry with a focus on water related issues.

The global rise of unconventional gas

In many petroleum and gas basins across the world, unconventional gas is taking over as production declines from depleting conventional gas reserves. Technological advances including hydraulic fracturing and horizontal 'in-seam' drilling have gradually opened up many unconventional gas plays for commercial production. In the US, this has redefined energy markets with substantial demonstrated and producing reserves of on-shore gas from low-permeability formations.

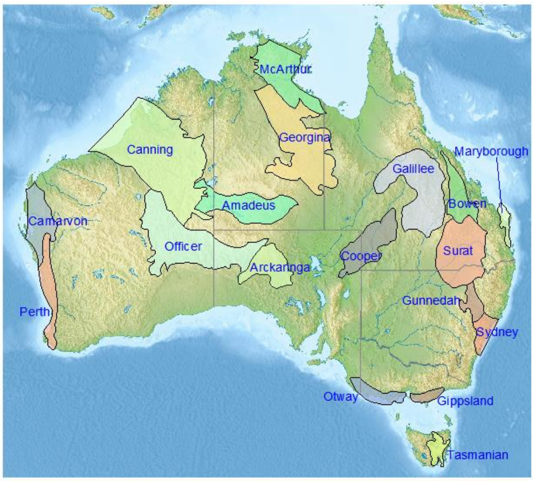
Unconventional gas assets have become strategically important, leading to a revolution in energy economics. However this revolution has also generated a level of conflict surrounding water issues, triggering opposition from environmentalists, community groups and filmmakers. Regrettably, the public debate has been tarnished by misinformation, and in some jurisdictions, regulation has been influenced by the pressure of populist causes on political process, at the ignorance of science. In addition, geographic and demographic issues have led to conflict between developers and communities in both rural and urban areas in Australia and elsewhere.

Unconventional gas in Australia

In Australia, CSG and shale gas resources dwarf conventional on-shore oil and gas resources; but despite this, they're expected to contribute greatly to Australia's energy mix over the next 20 years (NWC, 2011).

Prospective unconventional gas fields occur in geological sedimentary basins (Figure 1) with significant development prospects predominantly in Mesozoic and Palaeozoic settings.

Figure 1 - Prospective onshore gas basins in Australia



In Queensland, CSG is largely found in the Surat Basin (Jurassic), Bowen Basin (Permian) and the Galilee Basin (Permian). Production of CSG in Australia first commenced in 1996 in the Bowen Basin (Baker and Slater, 2008). In New South Wales (NSW) coal seams are prospective for gas in the Sydney, Gunnedah and Gloucester Basins (Permian), and the Clarence-Moreton Basin (Jurassic). In NSW CSG production commenced in the Sydney Basin at Camden in 2001.

In Victoria, some exploration has occurred in the Otway and Gippsland Basins but with mixed results (Baker and Slater, 2008). In South Australia, the Arckaringa Basin is prospective, and targets for CSG in Tasmania include the Fingal-Dalmayne coal fields on the east coast. CSG prospects are less significant for Western Australia, with some interest and exploration in the north Perth Basin.

Australia's major CSG reserves are strategically located near existing infrastructure and shipping facilities. This geographic alignment has led to rapid exploration and development, and as a result the Bowen and Surat Basin reserves in Queensland are the low-hanging fruit of the industry. In NSW, the adverse regulatory environment has dampened expansion of the existing (small) CSG industry. This is despite the strategically advantageous resource locations and comparatively dry coal formations.

Currently, Australian CSG proven and probable reserves are almost fully committed to export (Cook et al., 2013). However with further exploration of potential resources, demonstrated reserves are certain to increase over time.

Shale gas resources in Australia are significantly less explored and developed than CSG resources. Estimates carry uncertainty, and range from 396 trillion cubic feet (TCF) technically recoverable resources (US EIA, 2011), to as high as 1,000 TCF (Cook et al., 2013). Many of the more prospective shale gas basins are geographically remote, and (with the exception of the Cooper Basin and Tasmanian Basin) located away from existing pipeline infrastructure and processing facilities.

The Cooper Basin in south-west Queensland and northern South Australia is Australia's most prospective and commercially viable shale gas target, with 342 TCF of gas in place and an indicated risk recoverable amount of 85 TCF (CSIRO, 2012). Production commenced at Australia's first commercially producing shale gas well (Santos Moomba-191) in 2012 (Hoff, 2013). Although remote, the Cooper Basin enjoys the convenience of existing production facilities from conventional gas fields, with established pipelines to the eastern seaboard. In Tasmania, exploration licences have been granted in the Tasmanian Basin that straddles the gas pipeline from Longford in Victoria.

The largest indicated shale gas resources are located in Western Australia, where there are substantial prospects both on-shore and off-shore, including Mesozoic shales of the Perth and Carnarvon Basins, and Palaeozoic shales of the Canning Basin. These resources (not yet demonstrated as economic reserves) make Western Australia the world's 5th largest shale gas province (CSIRO, 2012).

Australia also has substantial estimated tight gas resources in place. In particular within the Perth, Cooper and Gippsland basins; however these are not certified reserves (Geoscience Australia, 2012). Tight gas production is technology dependent, and it's likely that in the near future technical advances and reduced drilling costs will lead to the delineation of economic reserves from these deep low-permeability resources.

Comparison with the US

In the United States, extensive sedimentary basins also contain unconventional gas prospects. Significant development has occurred in the Barnett Formation, Haynesville Shale and Marcellus Shale. The Barnett Formation located in Texas, has over ten years of production; whilst development of the extensive Marcellus Shale is progressing rapidly.

Although the development cost for these deep shale targets is high, this is offset by the close proximity to industrial and metropolitan centres. This is also a key factor driving structural changes in the US energy market, with falling gas prices and 40% of natural gas production now from shale gas (US EIA, 2012).

In Australia, the locations of shale gas targets are less favourable, and combined with low global gas prices, recovering these resources may not be as easy or profitable. Significant shale gas development in this country will require longer lead times due to the lower population density, limited industrial demand and high cost of establishing infrastructure such as processing plants, pipelines and shipping facilities in remote areas.

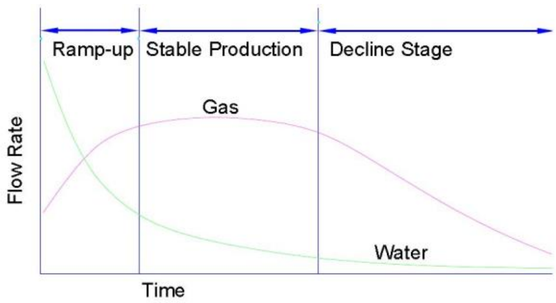
Water in coal seam gas and shale gas

Co-produced (pumped) water from coal seam gas

The fractures (known as 'cleats') within a coal seam contain groundwater, with the gas content held to the coal by a pressure dependent process called adsorption. The adsorbed gas can be liberated from the coal seams and mobilised by pumping water to reduce the hydrostatic pressure within the formation. As a result, gas production and water production occur simultaneously. The pumped water is referred to as co-produced water or associated water, and production rates per unit of gas vary provincially, with some basins having greater gas to water ratios compared with others.

Figure 2 shows a typical water production curve associated with a CSG well. Water production is initially high and gas flow low, however as pumping reduces the formation pressure in the well vicinity, gas flow increases. Over time, water production, and eventually gas flow, declines.

Figure 2 – CSG gas and water production relationship



The quality of produced water from CSG target formations is typically poor. The water chemistry is influenced by the geology and hydrology of the basin, and the characteristics of the coal. Generally, deep CSG target seams contain water that is geologically old, and has acquired hydrochemical characteristics influenced by the host formation. CSG water is commonly of the sodium chloride type, although sodium bicarbonate type waters are also encountered. Total dissolved solids, which is a measure of salinity, range between a few hundred mg/L to more than 10,000 mg/L. For comparison, seawater has a salinity of around 35,000 mg/L and potable drinking water is usually below 500 mg/L. Trace metals and dissolved hydrocarbons may also be present and some form of treatment is required for many reuse applications.

The main CSG producing basins in Australia are also home to extensive agricultural lands. They also contain Tertiary and Quaternary shallow aquifer systems that provide significant groundwater resources for rural towns, farmers and communities.

The National Water Commission projects the Australian CSG industry – predominantly in Queensland and New South Wales - could extract around 7,500 gigalitres of co-produced water over the next 25 years, approximately equivalent to 300 gigalitres per year. Dealing with these significant quantities of saline water is one of the main environmental challenges. To avoid environmental impacts as well as social and economic impacts caused by competing resource demands, water issues need to be carefully managed and competently regulated.

Nevertheless, if appropriately regulated and managed through treatment, and with beneficial uses offsetting existing extractive uses, the gross water balance impacts in these basins are likely to be bearable in the short term and sustainable in the long term. Beneficial use offsets include providing alternative supply to existing groundwater and surface water users, such as irrigators, industrial users and urban water supply users, through negotiation and regulation.

Co-produced (pumped) water from shale gas

Shale gas differs from CSG in that little co-produced water is generated as a by-product of gas production. Chesapeake Energy in the US report long-term produced water from shale gas ranging from 0.6 to 1.8 gal/MMBtu, approximately equivalent to 2.2 to 6.5 megalitres per petajoule. However these estimates are representative of their assets and may differ from Australian shale gas tenements, for which data is not currently available. Nevertheless, the range is consistent with US Geological Survey estimates of 1.2 to 1.3 gal/MMBtu.

It's not possible to develop shale gas resources without some form of well stimulation, such as hydraulic fracturing, to increase the permeability of the host formation. In contrast, many coal seam gas targets are sufficiently permeable to enable development without additional stimulation. This is due to the intrinsically fractured nature of these shallower and weaker rocks.

Water use in hydraulic fracturing (fraccing)

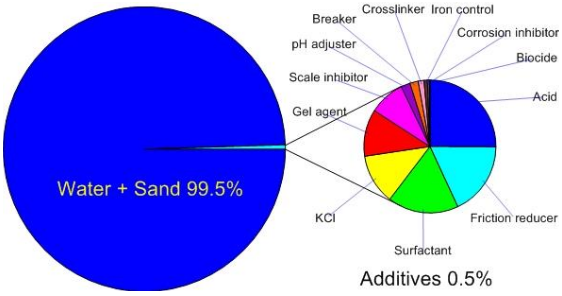
Water usage in hydraulic fracturing operations is well understood based on the extensive experience gained in the US and Australia in recent decades. Large volumes of water based fraccing fluid, in the range of 10 to 30 megalitres (DECC, 2013), are required on average to stimulate a shale gas well prior to production. As a result, shale gas development is water intensive but 'front-loaded' with little ongoing water requirements, unless additional late stage fraccing is necessary. Normally little co-produced water is generated - a significant contrast with many CSG projects.

Typically 90% of shale gas water use is incurred prior to gas production (Accenture, 2012). In Pennsylvania USA where shale gas has become a substantial component of the energy sector, water consumption by the industry is less than 0.2% of the total state water use (Accenture, 2012). However the relative impact of water use is closely related to available water supply, and in arid and semi-arid Australian shale gas environments, competition with other freshwater users may be unavoidable.

Despite public perception that fraccing fluid is a cocktail of toxic chemicals, this is not generally true. In reality, the fluid compositions have evolved over time. In the US, for example, gel-based fluids are replaced by 'slickwater' fluids that incorporate friction reducing additives (Accenture, 2012).

Figure 3 shows a typical fraccing fluid composition (Primer, 2009). The bulk of the fluid, greater than 99%, comprises water with sand or ceramic particles. These function as a 'proppant' to hold the fractures open following the fraccing event. A range of additives (<1%) are tailored to suit the well and formation, and these include functional chemicals such as biocides, surfactants, acids and inhibitors. In practice, fraccing may involve several stages using a range of different fluid compositions.

Figure 3 – Typical fraccing fluid composition



Following a fraccing operation, large quantities of 'flowback' water may be returned to the surface, comprising a mixture of degraded fluid and formation water. The fluid recovery rates vary from well-to-well and depend on the geology – this makes it difficult to generalise. However returns can exceed 75% of the injected fluid. This flowback water may be returned to the surface rapidly – often many megalitres over a time range that could be as little as a few hours, to several weeks (Accenture, 2012). Following this, as gas production rises from the newly stimulated well; these produced water volumes diminish rapidly.

Flowback water contains the legacy of any additives used in the fraccing water, as well as salts and organics leached from the formation, including potential naturally occurring radioactive materials at low concentrations (US EPA, 2013). The high TDS and composition of flowback water from many formations has important implications for reuse and recycling, and the ultimate fate of the water.

Disposal and fate of water

Due to the large volumes and often poor quality, the management of co-produced water presents significant technical and environmental challenges. In the conventional petroleum sector, reinjection of co-produced water to maintain reservoir pressures may account for significant volumes. However maintenance of reservoir pressure is not necessary for unconventional gas plays, where reduction of pressure is necessary to liberate adsorbed gas.

The CSG industry faces the greatest challenges, due not only to the high volumes of produced water in most (although not all) CSG developments, but also due to the locations of many developments in agricultural basins where consumptive water conflicts may arise, such as perceived impacts to existing water sources.

Nevertheless, the industry is gaining experience rapidly as flagship projects achieve environmental approval and commence development. Together with this, regulatory evolution has allowed legislation to adapt to the industry enabling more efficient outcomes. One key change has been the push away from large evaporation basins as a disposal method for co-produced water. This is due to the salt legacy that can lead to negative environmental impacts including land degradation if poorly managed.

Beneficial use water disposal

The greatest opportunities for successful water management involve applying treated co-produced water to direct beneficial use, including irrigation re-use, industrial use, livestock watering, farm water supply and supplemented urban supply. Indirect beneficial uses include recharge to depleted groundwater systems, or managed aquifer storage and recovery schemes. In particular, a significant benefit can be had where supply offsets reduce third party demand on surface or groundwater resources, such as irrigation and urban supply extraction.

A fundamental problem arises where desalination is required to reduce TDS, such as for irrigation or potable reuse. A range of technologies are applicable, including reverse osmosis and ion-exchange, but the salt problem does not completely disappear and the secondary brine waste stream requires careful management. Solar evaporation is still useful for brine disposal. In this situation, salt can be recovered for industrial use or refinement (desirable) or ultimately landfill (less desirable). Deep injection of brines to non-resource or saline aquifers is another option.

Environmental outcomes can be improved with innovative and targeted beneficial uses, particularly in the power generation sector, where water supply from CSG operations can be provided for coal washing, power station boiler feed and cooling tower supply.

The economics of infrastructure investment for some beneficial uses may be challenging, despite the low cost of the water. This is due to limited reliability of supply caused by the moving source of water following progressive gas field development, as well as the relatively short life of CSG projects which is around 20 to 35 years. As a result of these and other factors, not all CSG co-produced water may find the highest beneficial use.

Non-beneficial use water disposal

Non-beneficial disposal options include deep aquifer injection of untreated co-produced water and discharge to surface water systems. The latter can have some beneficial effect where the water supports environmental flows, but salt load must be managed, surface water ecosystems protected and partial treatment prior to disposal may be required.

Shale gas water disposal

In the US, large volumes of shale gas water are increasingly recycled, however freshwater is still required in large quantity to account for formation loss (imbibition). In addition, more freshwater is needed for drilling than CSG, due to the greater depths and lateral extent of shale gas wells. As a result, attendant recycling and disposal is required.

Disposal in underground injection wells is the most widely used option in the US for flowback and co-produced water (Accenture, 2012). However in Australia, the higher cost and reduced availability of water in the arid and semi-arid shale gas basins may improve the economics for significant recycling. The specifics of basin geology will exert an influence over this, as demonstrated in the US. For example, high rates of recycling are reported for the Marcellus Shale gas fields compared with low rates for the Haynesville Formation, where high TDS (110,000 mg/L) and low returns of flowback water are experienced. Data is currently unavailable to support further comment regarding Australian shale gas basins, due to the infancy of the industry.

Water-energy intensity of unconventional gas and thermal fuels

The impact of energy resource development on water resources is a primary environmental concern in the parched Australian setting. A useful metric for water usage associated with energy production is water-energy intensity in megalitres per petajoule (1PJ = 10^{15} joules) of energy content.

Putting this in context, Australia's domestic energy consumption was 4,083 PJ in 2011-12 (ABS, 2014), approximately equivalent to 3.85 TCF of natural gas, based on sales gas conversion rates.

Table 1 and Figure 4 provide both US and Australian data for water-energy intensity of unconventional gas, together with conventional fossil fuels and biofuels. Hydroelectricity is included for comparison.

Table 1 - Water-energy intensity comparison

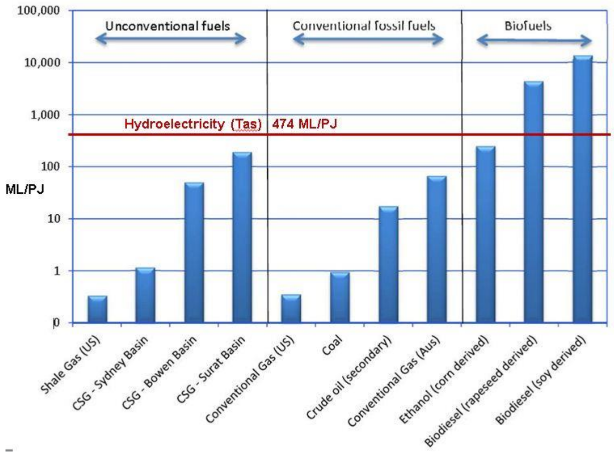
Fuel Type	Energy Intensity (ML/PJ)	Notes (refer below)
Shale gas (US) (average)	0.33	a
Conventional gas (US)	0.35	b
Coal	0.95	c
CSG – Syd. Basin	1.15	d
Crude oil (secondary)	17.3	b
CSG – Bowen Basin	50.4	d
Conventional gas (Aus)	67	d
CSG – Surat Basin	192.5	d
Ethanol (corn derived)	250	e
Biodiesel (rapeseed derived)	4436	f
Biodiesel (soy derived)	14111	c
Hydroelectricity	474	g

a – USGS data
b – Mielke (2010)
c – US Department of Energy data
d – RPS (2011)
e – Wu et al. (2009) cited in Mielke (2010
f – Berndes (2008) cited in Mielke (2010)
g – Authors calculation from Hydro Tasmania data

CSG is variable but comparable in terms of water-energy intensity to conventional gas in Australia. It's important to note the significant difference between the comparatively dry coal seams of the Sydney Basin, with the wet coal seams of the Surat Basin. Water production per unit of energy differs by more than an order of magnitude between these basins.

In comparison, the water-energy intensity of biofuels is very high. Shale gas, in contrast, ranks very low.

Figure 4 – Water intensity comparison (logarithmic value axis)



Hydroelectricity is presented as a non-fuel based energy source. Electrical energy is normally measured in gigawatt-hours, but has been converted to petajoules for this comparison on the basis that 1 joule = 2.78×10^{-7} kilowatt-hours. However recognise that gas or coal fired electricity generation will not be 100% efficient and generation efficiency should be considered before drawing conclusions.

In considering the relative water-energy intensity differences between energy sources, it's important to consider additional factors related to specific projects and energy end uses. One of these factors is whether the water usage accounted for is consumed water or co-produced water. An example of consumed water includes environmental water take for irrigation of biofuel feed-crops or for coal washing. Where CSG developments provide beneficial uses of co-produced water that offset existing environmental takes, such as provision of alternative supplies for industrial or irrigation uses, the effective water-energy intensity will be reduced. Consider also that the bulk of the water co-produced from CSG and shale gas developments is sourced from non-resource aquifers.

Another factor is the full energy to end-use lifecycle. Where unconventional gas is used largely for electricity generation, advantages can be had through technology or offsets. For example, water consumption rates for combined-cycle gas turbine power plants are lower than other major technologies such as gas or coal fired steam turbine plants, or coal-fired IGCC plants (integrated gasification combined cycle) (Mielke et al., 2010). In addition, development integration may enable co-produced water use in power plant cooling and boiler feed for steam turbine plants.

In contrast however, where gas production is destined for offshore markets as LNG, limited opportunity is available for direct benefits in Australia through full lifecycle offsetting. At present, offshore supply contracts represent a significant portion of the Australian coal seam gas industry sales.

Opportunity and challenge for the water industry and regulators

Significant opportunities will arise as the unconventional gas industry expands over the next few years. These opportunities will include application and development of infrastructure and technology for brine waste stream processing, and supply chains.

For CSG the primary opportunities are associated with water treatment and distribution of co-produced water for beneficial use. The cumulative impact of multiple CSG developments provides significant opportunity to develop regional crystallisation plants to manage brine streams. This could also lead to improved opportunity for commercial use of salts as an end product, rather than landfill. On a large scale and by adopting innovative technology, further research may be justified. For shale gas, where co-produced water is a relatively small component, the primary opportunities for the water industry may be associated with water supply and flowback water recycling to support the ongoing development of well fields. Injection of brine waste streams from treated flowback water to deep aquifers may remain the most practical solution (consistent with US practice) and have less environmental dis-benefit compared with evaporation basins.

Regulators have experienced major challenges in recent years to adapt to the CSG developments. In particular, this has accelerated significant legislative and policy change. The Environment Protection and Biodiversity Conservation (EPBC) Act (Commonwealth) was amended in 2013. The Act states that any CSG development that is likely to have a significant impact on a water resource is to be referred for assessment and approval. In Queensland, changes have been made to the Petroleum and Gas (Production and Safety) Act, the Water Act (Qld), the Environmental Protection Act 1994, the Water Supply (Safety and Reliability) Act 2008, and to a range of other plans, policies and regulations.

For shale gas, regulators can look to the North American industry, not to follow US regulatory practice, but rather to leverage the significant data available. A key need is to ensure suitable reporting frameworks are emplaced to enable a developing understanding of the full lifecycle and cumulative impacts, and to facilitate proactive water resource and waste management regulation.

For more information

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Appendix 1

Understanding unconventional gas

In conventional gas production, wells are drilled to target accumulations of free gas that have been trapped over geological time in permeable porous rocks such as sandstones. The gas in these formations has migrated from source rocks (such as organic shales) and become trapped between underlying water and low-permeability 'seal' rocks. These traps have typically resulted from faulting, folding, or other stratigraphic and structural features. In contrast unconventional gas is dispersed within predominantly low-permeability formations such as shale, coal, and low-porosity or 'tight' sandstone. In coal seam gas and shale gas plays, the host formation is also usually the source rock, and hence the gas in these targets has not migrated significantly.

Coal seam gas

Coal seam gas (also known as coal-bed methane) occurs in geological basins where methane bearing coal seams occur, usually between 200 m and 1000 m depth. The produced gas comprises predominantly methane, sometimes with minor ethane, carbon dioxide and nitrogen. Water content of the coal seams is often very high.

Shale gas

Shale is a low porosity sedimentary rock comprised of clay and silt-sized mineral grains. Shales that are high in organic material – known as black shales – may host commercially economic quantities of natural gas as well as some low density petroleum liquid. The gas is contained within pore spaces in the rock, in fractures, and adsorbed onto carbonaceous matter (kerogens). Due to the low porosity, the water content of the shale is low.

Gas Play	Tight Gas	Shale Gas	Coal Seam Gas
Rock Type	SANDSTONE	ORGANIC SHALE	BLACK COAL
Target Depth (m)	>1000	1000 to 4000	300 to 1000
Reservoir Occurrence	Reservoir separate from source	Reservoir in source rock	Reservoir in source rock
Gas Phase	Free gas in pores	Free gas in pores and adsorbed gas	Mainly adsorbed gas
Organic Carbon %	0.01 to 3 (low)	1 to 8 (low-med)	50 to 98 (high)
Permeability (milliDarcies)	<3 (low)	<0.001 (very low)	0.5 to > 150 (low to high)
Co-produced Water	💧💧	💧	💧💧💧💧💧💧

Hydraulic fracturing (fraccing)

Because of the very low permeability of shale (and some coals), to develop these rocks as gas resources, it's necessary to artificially fracture the formation to improve permeability and enable transmission of gas to the well. This hydraulic fracturing process (well-stimulation) involves pumping fluids at very high pressures into the formation at depth to generate fractures in the rock, and in doing so, connects the gathering well to a greater extent of gas-bearing formation. During production, gas migrates to the well from the low permeability rock via the fractures. Although essential for shale gas development, hydraulic fracturing is not always necessary for CSG. Many CSG tenements produce economically without well-stimulation.

Appendix 2

Timeline of key gas development events

1821	First commercial gas well – producing from Devonian shales (New York State)
1836	First producing gas well in Britain Lights Railway station in Sussex
1859	First commercial oil well drilling in USA
1940s	Sydney Harbour colliery methane compressed and sold as motor fuel
1947	First hydro-fracturing of petroleum well in Kansas
1991	First horizontal shale gas well in Barnett Shale, Texas
1996	First CSG production in Australia – Dawson Valley, Queensland
2012	First shale gas production well in Australia – Cooper Basin, South Australia