Unconventional Gas in Australia – Infrastructure Needs

Report for the Australian Council of Learned Acadamies

(SKM ref SH43389)

30 January 2013

SINCLAIR KNIGHT MERZ

SKM

Unconventional Gas in Australia – Infrastructure Needs

Document title:	Unconventional Gas in Australia – Infrastructure Needs
Version:	Final for submission to client
Date:	30 January 2013
Prepared by:	Richard Lewis
Approved by:	Mathew Maliel
File name:	Unconventional Gas in Australia 30-01-13.docx

Sinclair Knight Merz
ABN 37 001 024 095
Level 11, 452 Flinders Street
Melbourne VIC 3000

Tel: +61 (3) 8668 3000
Fax: +61 (3) 8668 3001
Web: www.globalskm.com

Contents

Executive Summary

The Australian Council of Learned Academies (ACOLA) has appointed Sinclair Knight Merz (SKM) to advise on the infrastructure needs associated with the development of unconventional gas resources, in particular shale gas, in Australia. This study is part of ACOLA's project, *Engineering energy: unconventional gas production*, which is itself Project 6 of ACOLA's broader *Securing Australia Future* research program.

This advice comprises responses to a series of shale gas infrastructure related questions posed by ACOLA, which we refer to as the ACOLA Terms of Reference. In responding to the questions SKM has relied primarily on material drawn from the two industries that provide the closest exemplars, namely US shale gas and Australian coal seam gas (CSG) industries, both of which have enjoyed spectacular, sector changing growth over the past five years. The advice is based on previous SKM studies, the opinions of SKM' sector specialists and desk top research.

For some of the questions, where a quantitative response is required, we have conceptualised a shale gas development project on a scale that is plausible from both production and market perspectives and responded in terms of the resources, such as drilling rigs and labour, that this project would require. The data provided can be scaled up or down as required by ACOLA.

In addition to responding to the questions some supporting background information on shale gas and CSG developments in the US and Australia is provided.

1. Introduction

1.1 The Study

The Australian Council of Learned Academies (ACOLA) has commenced a multi-year multi-disciplinary research program 'Securing Australia's Future' (SAF) and will undertake a series of projects considering long-term issues to be delivered to the Prime Minister's Science Engineering and Innovation Council (PMSEIC) through the Office of the Chief Scientist (OCS) and the Australian Research Council.

Project 6 of the SAF program is *Engineering energy: unconventional gas production*. Project services are provided by the Australian Academy of Technological Science and Engineering (ATSE) on behalf of the ACOLA Secretariat. The project, which is due to report by March 2013, will be overseen by an Expert Working Group chaired by Professor Peter Cook CBE FTSE including:

Dr Vaughan Beck FTSE (Deputy Chair)
Professor David Brereton
Professor Robert Clark FAA FRSN
Dr Brian Fisher AO PSM FASSA
Professor Sandra Kentish
Mr John Toomey FTSE
Dr John Williams FTSE

Scope

Energy needs will require us to keep turning to opportunities for alternative sources such as shale oil, shale gas and coal seam gas. As technology and geological knowledge continue to advance, and the consequent economics of extracting unconventional natural gas become more acceptable, Australia could be in a position to exploit unconventional gas. This will require a comprehensive look at the scientific, social, technological and economic issues surrounding the reality of alternative energy sources such as unconventional gas.

Aim:
To explore the scientific, social, cultural, technological, environmental and economic issues surrounding alternative energy sources, with particular reference to unconventional gas extraction.

Purpose
Producing an evidence based document that identifies the potential environmental, economic and community impacts of shale gas production in the Australian context, and the potential for and requirements for, a sustainable development pathway

1.2 SKM's Brief

SKM submitted an expression of interest in contributing to Project 6 and has been engaged to provide advice on the technical and market issues covered in the ACOLA Terms of Reference (ToR) which are set out in section 3 of this report. A summary of preliminary findings was presented at a workshop in Canberra on 13 and 14 December 2012 by the principal author of this report.

In order to respond to the ACOLA ToR, SKM has created a context which: 1) conveys SKM's understanding of shale/unconventional gas issues; and 2) establishes a platform for quantitative responses that ACOLA can scale up or down to meet its needs. These two elements form the bases of sections 2 and 3 of this report. The key aspect of item 2 is the selection of a potential future shale gas project, namely one that produces approximately 50 PJ of gas for twenty years, which is plausible from both production and market perspectives, as a basis for discussing the issues raised by ACOLA.

2. Unconventional Gas Background Information

This section conveys SKM's understanding of shale/unconventional gas issues, contrasts them with conventional gas and provides a framework for responding to ACOLA's brief. SKM understands that ACOLA will form its own views on these issues and this material is not intended for use by ACOLA or to be reproduced outside this report.

2.1 Definition

Conventional – gas that flows at commercial rates under in-field pressures

– typically, gas in permeable sandstone and carbonate traps

Unconventional – gas that needs stimulation to flow at commercial rates (or, uninfluenced by hydrodynamic influences)

– typically, gas in coals seams, shale beds and less permeable traps (tight gas)

Figure 2.1 : Schematic showing gas accumulation types

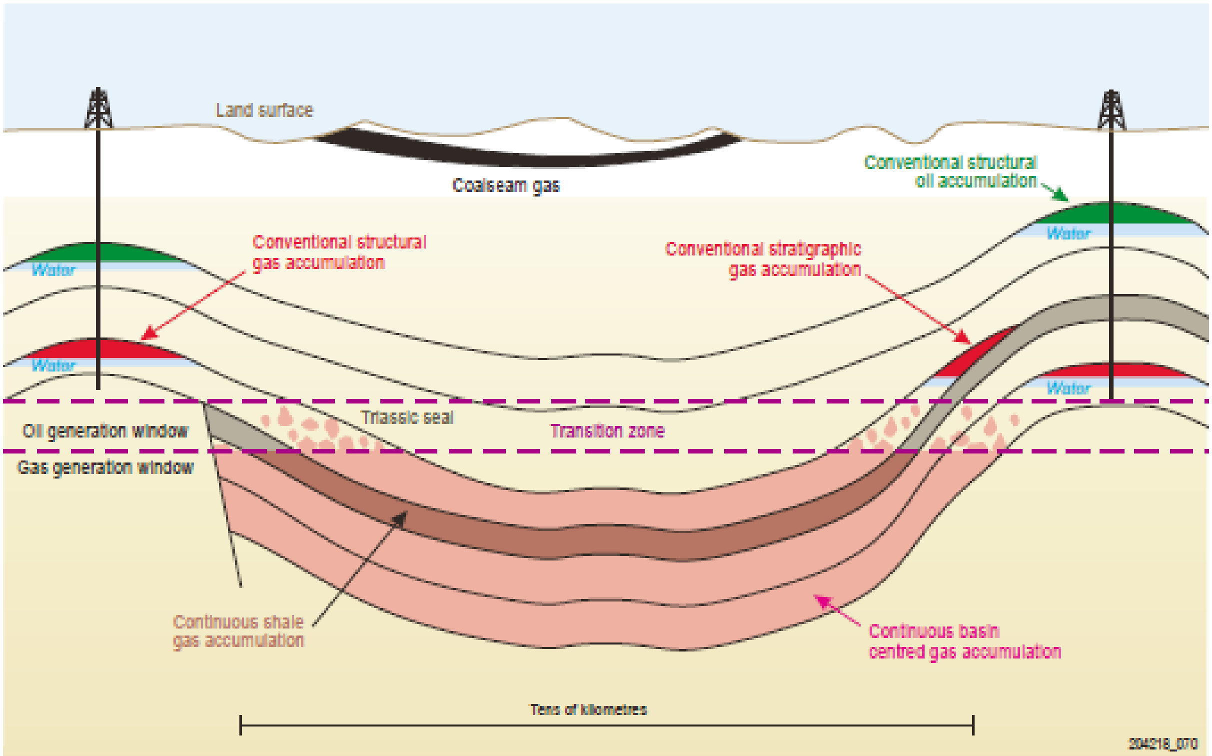


Figure 1.4 Schematic diagram showing conventional and unconventional oil and gas accumulation types (source: Beach Energy Limited. Amended from Schenk and Pallastro, 2002)

2.2 Major Differences

Conventional

Small fields, extensive exploration to discover

High flow rates, so a small number of wells required

Key technologies are deep-sea drilling and platforms or subsea operations (most new conventional finds are offshore)

Unconventional

Extensive fields or coal deposits, extensive appraisal to prove commerciality

Low flow rates, large number of wells (onshore only)

Key technologies are rapid drilling and fraccing

2.3 History

Most gas produced to-date around the world has been ***conventional***.

Unconventional gas production has developed primarily in the US and Australia

US

Tight gas – since before 1970; now 25% of US production

CSG aka CSM (Coal Seam Methane) and CBM (Coal Bed Methane) – since 1980s; now 10%

Shale gas – since before 1970; rapid expansion since 2005 now 25%

Australia

Tight gas – since 1970; not recorded separately

CSG – since 1995; now 30% of East Coast production

Shale gas – since 2012; one well in production

2.4 Development influences

US

<u>CSG</u> – Wellhead price regulation (ended 1982); rising gas prices during the 1970s; and tax breaks (ended ca 1990).

<u>Shale gas</u> – US gas shortage, prices rose to $8/mmbtu in mid 2000s. LNG imports contemplated but shale gas production was stimulated and grew to 25% of supply. LNG imports abandoned, replaced by export projects in 2012, responding to oversupply/low prices in $2-3/mmbtu range.

Australia

CSG – Perceived East Coast gas shortage; PNG imports considered. Gas Electricity Certificates (GECs) scheme promoting gas-fired generation in Queensland. CSG captures generation opportunities; PNG project abandoned. CSG reserves growth exceeds domestic requirements; LNG export markets targeted and captured, resulting in undersupply, high prices for new gas.

Shale gas – East Coast undersupply as above, potential in domestic and export markets. In WA, a shortage of supply due to limited onshore resources and offshore resources suitable for domestic scale development. Future offshore development may be floating LNG with no domestic contribution.

US shale gas and Australian CSG influences have commonalities including leading to LNG exports that could not have been contemplated in earlier periods of short supply.

Influences on shale gas in East Coast and WA are different. In East Coast shale gas will compete mainly with CSG which is likely to be lower cost, whereas in WA shale gas will be competing initially with limited onshore conventional gas.

2.5 Australian Prospects

CSG – over 40,000 PJ 2P reserves, production to expand from 200 PJ/yr to 1700PJ/yr by 2016 for LNG.

Shale gas – no 2P declared, 2000 PJ of 2C resources. Resources estimated by US Energy Information Administration (EIA) as below – their study covered four of the nine basins with known shale gas resources.

Table 2.1 : Australia's Shale Gas Resources

	Basin				
Parameter	**Cooper**	**Maryborough**	**Perth**	**Canning**	**Total**
Area (sq mi)	5,810	1,555	2,180 x 2 formations	48,100	59,825
Recoverable Resources (TCF[1])	85	23	29 + 30	229	396
Active operators	Santos Beach	N/a	AWE	Buru New Standard Energy	

Source: US EIA (area and resources, units as per EIA) and SKM

[1] Trillion Cubic Feet. 1TCF = approx 1,000 PJ

2.6 Australian Activity

CSG

3 CSG-LNG projects are under development at Gladstone; each 2 trains of 4 Mtpa capacity (1 Mtpa = 55PJ net, 60 PJ gross); approx 500 wells per train, 3000 total.

Shale gas

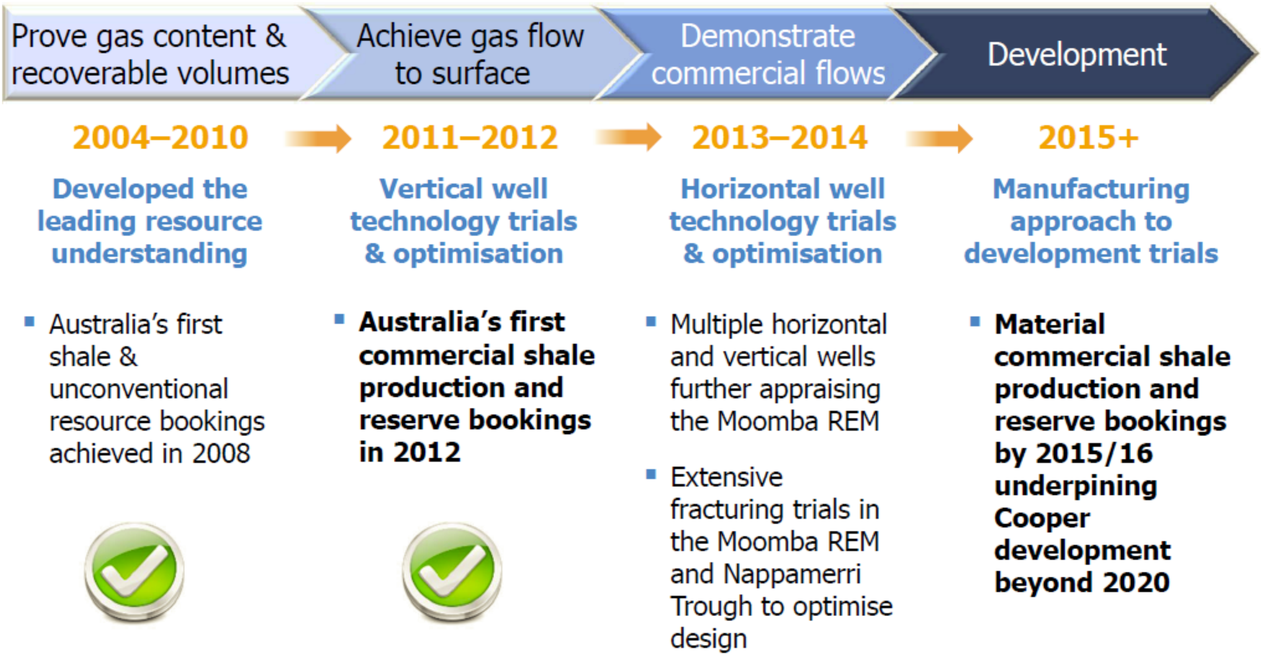
Santos and Buru Energy have each reached the stage of sufficient certainty in their resources to put forward development plans.

Santos[2]

Santos has been operating the Cooper Basin Joint Venture for over 50 years, producing gas from conventional and tight formations since 1969. In 2004 Santos established a dedicated unconventional reservoir team and has since drilled a number of wells targeting shale formations at levels below the conventional reservoirs. In 2012 the Moomba 191 vertical well intersected significant gas in the Murteree shale and produced over 3 mmscfd (approximately 3 TJ/day) after fracturing. The well is now in production. Based on this and parallel observations with US experience, Santos estimates that an optimised vertical well would cost $10m and yield 3-6 PJ over its production life at a cost of $6-9/GJ.

Santos objective is to deliver material commercial production by 2015, in line with the timetable below. A key to this program is optimisation of horizontal wells, including optimum horizontal lengths and fraccing programs and techniques.

Figure 2.2 : Santos shale gas development timetable



2 Cooper Basin Unconventional Gas Opportunities and Commercialisation, Santos November 2012. Available from Santos website

Buru Energy

Buru Energy holds 75,000 km of permits in the Canning Basin and together with partner Mitsubishi, which holds 50% of the majority of the permit area; is looking to confirm the basin's potential for conventional oil and gas, tight gas and shale gas. The Yulleroo-1 and -2 and Valhalla 2 wells have confirmed tight gas accumulations with substantial liquids content over a 1,300m section of the Laurel formation, indicating the presence of several Tcf of gas and up to 50m bbl of oil and the Ungani conventional oil discovery is already producing oil in pre-production testing[3].

Buru has announced the following timetable for gas production:

- 2012/2013 Exploration Stage – Completion of quantification of 3C resources by current drilling program. Stimulate and test up to 7 wells
- Stage 2: 2014 Pilot projects - Pad cluster developments on Valhalla and Yulleroo with gas production used for supply of small quantities of compressed natural gas (CNG) to regional markets.
- Stage 3: 2015 Supply of gas to WA domestic gas customers via a pipeline to Port Hedland with first deliveries in late 2015 and ramping up to approximately 200 TJ/day by 2017.
- Stage 4: Certification by the end of 2017 of a reserves base to underpin the development of gas supply for large scale Pilbara LNG and a large diameter pipeline from Valhalla to Karratha

Buru has recently entered a state agreement with the WA Government which provides for: exemption from permit relinquishment until 2024 subject to meeting permit commitments; cross-permit credits for appraisals; and delivery of a material domestic supply project prior to entering any export commitments – the target is 1,500 PJ over 25 years, i.e. 164 TJ/d on average.

2.7 Technology Issues

Unconventional wells flow at low rates compared to conventional ones. Production from shale wells tapers off rapidly, to the extent that 65% of volume is produced by year 10 and 83% by year 20 out of a notional 40 year life. Well productivity can be partially restored by re-fraccing, at a cost of 40–50% of a new well.

The rate of decline is difficult to estimate, along with the ultimate recovery volume, but the front-ending of production does mean that 90% of value, in NPV terms, can be extracted by year 10. Recovery rates in reasonably well established US basins remain contentious.

So a lot of wells are required and they cover a much larger area than conventional gas. CSG wells have similarly low rates but a generally flat production profile over the first 5-8 years before tapering off.

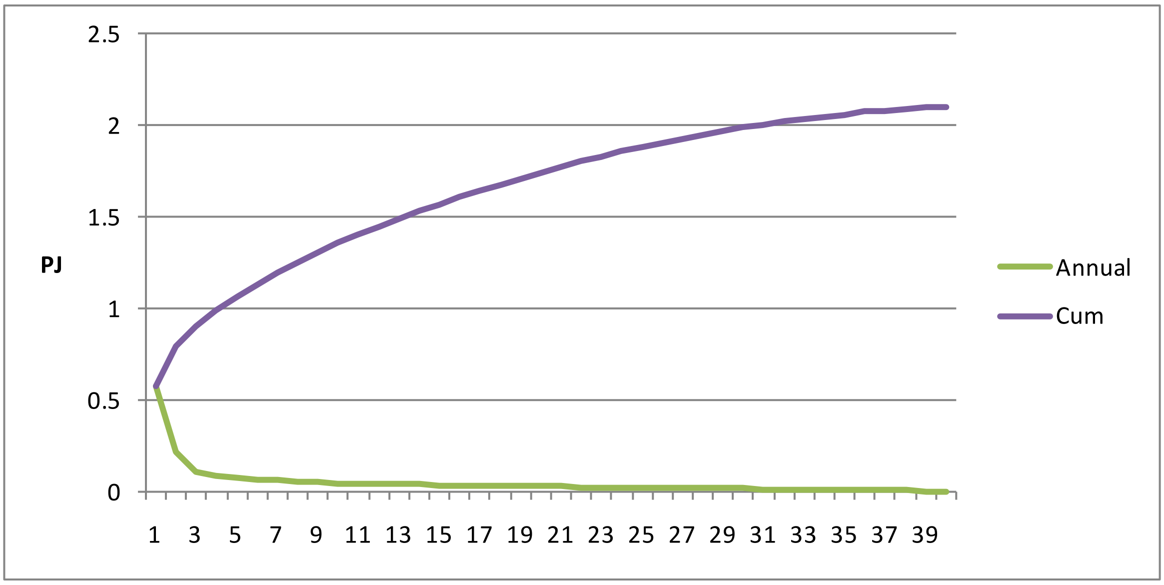
Rapid drilling, standardisation of facilities and managing the "production line" are critical to success, as is maintaining the social licence to operate in both less and more remote areas

Company operations in all of these areas have evolved rapidly in both the US and Australia over the past five years.

Shales have variable properties and best practice must evolve for each field and subfield. Cost optimisation is a trade-off between standardisation to minimise cost and customisation to maximise individual well flows.

[3] Buru Corporate Update September 2012. Available from Buru website.

Figure 2.3 : Shale well production profile



Based on "Well Production Profiles for the Fayetteville Shale Gas Play", Oil & Gas Journal April 4, 2011

2.8 Stages of Production

2.8.1 Drilling

Specialised rigs, highly automated multiple wells drilled at angles from a single pad – faster and less ground disturbance. Horizontal drilling along the seam to maximise length of pipe along seam

Table 2.2 : Drilling rig developments

Conventional	**Special purpose**
Mechanical drive	Electric drive
Manual pipe handling	Automated pipe handling
Rig jacking company	Hydraulic self-levelling substructure
Rotary table and Kelly bar	Top drive
Manual slips	Automated slips
Pipe tongs	Automated pipe connection
700 HHP mud pumps	1000 HHP mud pumps
Ring 2 drill pipe	Ring 3 drill pipe

Source: EnCana 2006

2.8.2 Completion

Completion is the lining of the well with steel pipe and cementing it in place. The pipe ensures separation of well fluids from rock strata between the surface and gas bearing formation. Completion can also include fraccing.

2.8.3 Stimulation/Fraccing

This aims to increase the surface area of coal or shale so that gas flows more freely. In vertical CSG wells it can be done by reaming out the bottom of the well. Horizontal CSG wells up to 3 km can create sufficient exposure depending on the coal cleat structure. Shale needs fracturing by injecting fluids and sand, and then withdrawing the fluids to allow gas to flow – the sand remains in place to keep the fractures open.

The fluids must have the correct viscosity and low friction to flow when pumped and should breakdown rapidly after the treatment is over. The fluids can be water, oil or acid-based depending on the shale formation. Water-based is most widely used because of low cost, effectiveness and ease of handling. Water-based fluids are 99% water and 1% additives such as: gelling agents (eg guar gum) to adjust viscosity before fraccing; oxidisers (ammonium, potassium or sodium salts) to increase viscosity after fraccing; biocides to prevent bacterial degradation; and methanol or sodium thiosulfate for high temperature stability[4].

Potential for fraccing to lead to contamination of aquifers continues to be debated. In the US saline frac water is disposed into surface waters or by re-injection into deep wells. This is currently exempt from relevant US regulations.

2.8.4 Gathering pipelines

Up to 200 wells each of 1 TJ output are connected by a network of low pressure (LP) HDPE pipe to a single processing plant (the APLNG project will have 7 plants each of 200 TJ/day or 70 PJ/year). Exact numbers depend on well productivity and are limited by distances that can be transported on LP pipes. For CSG a separate water gathering network is installed (water is separated at the wellhead and processed centrally)

2.8.5 Processing plant

For CSG, which is composed mainly of methane and inerts and no hydrocarbon liquids, only water extraction and drying is required. For shale gas other liquids must also be separated.

2.8.6 Compression

The processed gas needs to be compressed up to transmission pipeline pressure, 15,000 kPa for modern pipelines. Typically compressors are gas engine or gas turbine driven – the current large LNG related projects in the Surat are moving to electric compression, potentially saving costs and gaining operational flexibility

2.8.7 Water

Acquisition

A single frac for a shale well takes about 2m litres of water (500,000 gallons) and multiple fracs can take 4m litres for a vertical well and 12 m litres for a horizontal well. In the US water is taken from both surface reservoirs and subsurface aquifers.

[4] Unconventional gas shales: development, technology and policy issues. Congressional Research Service, October 30, 2009.

Figure 2.4 : Hydraulic fracturing, Marcellus Shale, West Virginia

Source: Chesapeake Energy Corporation, 2008.

Notes: The yellow frac tanks in the foreground and along the tree line hold water, the red tanker holds proppant; hydraulic pumps are in the center.

Disposal

CSG produces quantities of saline water. For test wells this is stored in plastic lined ponds and allowed to evaporate. For production wells it is now generally desalinated by reverse osmosis (RO) plants and used for arboriculture projects, watering livestock or community consumption. Disposal of residual salt remains a material issue. CSG producers are looking for alternatives to landfill such as conversion to soda ash. Shale gas production releases less significant volumes of water.

Some 80% of fraccing water returns to surface[5] and is stored in ponds before disposal or reusing. In the US it is disposed of into local surface waters, reinjected into deep wells or trucked to central processing sites, either on-site or off-site. On-site processing by RO retrieves up to 70% to potable standard for reuse, potentially 80% if a lower standard of water is suitable for fraccing[6]. The remaining 20-30% is sent offsite for disposal.

The extent of fraccing chemical recovery and reuse associated with water recovery is not stated in any of the references sighted. This appears to be due to the limited experience with water recovery.

[5] Ibid

[6] Ibid

3. The ACOLA Terms of Reference

3.1 Technology Issues for Australia

Can the benchmark (complex) US technical infrastructure overhead for economic shale gas production be simplified in Australia?

This issue has two dimensions:

- the technology and other infrastructure that is used to extract shale gas and dispose of by-products
- the organisational structures that allow the technology to be developed and deployed

SKM considers that the first will of necessity have to replicate the US but the second will be somewhat simplified

3.1.1 Technology

The key shale (as opposed to conventional gas) technologies are:

- Geological modelling to determine volumes, recovery profiles and well paths
- Rapid drilling of multiple deep horizontal wells from a single pad
- Fraccing techniques to stimulate increased production

Geological modelling is currently being extended from conventional fields to shale – in the Cooper Basin there is a wealth of existing knowledge of the shale structures that underlie fields that have already been produced.

The Australian gas industry has successfully developed rapid drilling techniques for CSG, partly as a result of learnings from US CSG and shale gas and partly from its own experience. The industry is already drilling shale appraisal wells, one of which has gone into production, and we see no reason it should not be able to extend this to large scale production.

The key technology for rapid CSG drilling down to 1200m, involving coil tubing rigs (refer to Table 3.1) is not applicable to deeper shale wells however. These require more traditional jointed pipe drilling rigs ("triples") that are designed or modified to reduce drilling times, primarily through increased power, more efficient pipe and materials handling and optimised rig move capabilities. SKM also understands that while conventional rigs in Australia can drill shale wells there are insufficient of them for a material shale gas program. Consequently synergies between shale gas and CSG or conventional drilling are limited. We do note however that hybrid rigs combining coil and conventional drilling advantages are now emerging in the US[7]. These rigs use coil to a set depth then drill to full depth with jointed pipe. The major design constraint, as with bigger coil rigs, is fitting within road size limits.

Table 3.1 : Drilling technologies

	Conventional Rig	**Coil Tube Rig**
Drill pipe	Jointed pipe sections	Continuous tube
Power	On rig, whole pipe is turned	On drill bit
Advantages	Thicker pipe can be used More power can be applied	No stoppages, faster drilling
Disadvantages	Drilling stops to attach new section	Coil size limits tube diameter
Main uses	Deep wells Wells with multiple turns	Shallower wells Completion, logging, fraccing

[7] www.nabors.com

Fraccing (refer to section 2.8.3) has previously been applied to tight gas fields, particularly in the Cooper Basin, with over 70 wells fracced[8]. This is a modest number compared to the hundreds of wells required to produce a material volume of shale gas and will require a considerable build-up in resources by the service companies such as Baker Hughes, Halliburton and Schlumberger, which provide most fraccing services.

In drilling these wells a wide range of new conditions will be experienced, requiring further trials and development, particularly in regards to fraccing water acquisition and treatment/disposal. In the US the preferred water approach to disposal is injection into deep wells and in many areas where shale gas is produced, disposal facilities are run by municipalities. Such facilities are not present in most remote areas of Australia.

3.1.2 Organisational structures

The organisational structures required include:

- Development and deployment of a manufacturing approach i.e. repeated application of the same approach and designs rather than development of bespoke designs for each well.
- Application of continuous improvement to technology and organisation
- Staff/contractor acquisition and retention
- Inclusion of social engagement in the business process

All of these are already present in the Australian CSG industry to some extent and will be subject to significant further development over the next 3 years as the CSG-LNG projects ramp-up to first production in 2014 and 2015. Real implementation experience will however be largely restricted to three operators and their contractors: QGC/BG Group (QCLNG); Santos (upstream operator for GLNG); and Origin Energy (APLNG), only one of which, Santos, is currently involved in shale development. Experience will spread to others in shale by skills movement and mergers/takeovers. .

Australia's major deficit relative to the US is a smaller and less competitive services sector, such as drilling contractors. In the rapidly expanding iron ore and CSG-LNG sectors this has led to cost blow outs and delays, The Australian gas services sector should be strengthened by its current growth, though much of the growth could be serviced from overseas.

3.2 Infrastructure

3.2.1 What new infrastructure (drilling capability, well pad infrastructure, pipelines, roads and support services) will be necessary to enable the exploitation of likely shale gas resources? Give a 'best case' estimate (probably related to horizontal drilling) and a 'worst case' estimate (vertical drilling).

To provide an understanding of these issues we need to consider the likely timing and scale of developments. We consider it most likely that developers will select whichever drilling method they believe will yield the optimal cost/productivity compromise for the relevant resource. As such, the best case/worst case contrast is not particularly informative and therefore has not been addressed

3.2.1.1 Timing

Beach, Buru and Santos have all recently outlined plans to commercialise shale gas production by 2015 (refer to section 2.6 for summaries of Buru's and Santos's proposals). Given the potential for delays in many elements of the plans, including resource appraisal and approvals, we view this as the earliest date of material shale production.

[8] Cooper Basin unconventional gas opportunities and commercialisation. Santos November 2012

By 2015 some progress will have been made in cost optimisation but we would expect Australian shale production costs to still be higher than US costs at that time, i.e. $6/GJ and above (section 3.2.8).

Markets that can absorb gas at a price of $6/GJ plus transmission include:

- WA domestic market, in which recent new contracts have been priced at $6/GJ and above[9]
- Eastern States domestic market. Although gas in current contracts is priced at $4/GJ, the most recent new contracts have been entered at higher prices under the influence of LNG export demand.
- LNG exports. Well head netback value of recent export contracts ranges from $4/GJ to $12/GJ depending on oil prices and liquefaction costs. SKM understands that exporters have paid prices in the middle of this range for third party gas (GLNG purchases from Origin Energy and Santos).

It is noted, however, that competition from US exports is expected to erode the netback value and weaken the oil linkage in future LNG arrangements.

3.2.1.2 Scale

The scale of initial shale gas developments will be defined by the interaction of market requirements, technology and risk factors

3.2.1.2.1 Market requirements

Current indicative market scales are:

- Eastern domestic market 700 PJ
- WA domestic market 350 PJ
- New export projects, one 4 Mtpa LNG train LNG, 250 PJ including fuel for power

Opportunities to supply domestic markets depend upon expiration of existing long-term supply arrangements and/or market growth. Opportunities are currently limited in both markets but expected to open up over the period 2015-2018 (SKM internal data).

Based on these factors, SKM considers that initial shale gas production will be subject to the following constraints:

1. Domestic market, field near infrastructure

   Min – none, any quantity of gas can be marketed and transported economically

   Max – 50-100 PJpa, limited by market opportunities to replace old contracts and supply new growth markets

2. Domestic market, field 500 km from infrastructure

   Min – 50 PJ, determined by transmission cost

   Max – 50-100 PJpa, as above

3. Export Market

   Min – same as domestic if gas is sold to a third party exporter

   Max – 500 PJ (2 trains) for a new integrated producer/exporter

[9] SKM MMA WA Strategic Energy Initiative study

3.2.1.2.2 Risk factors

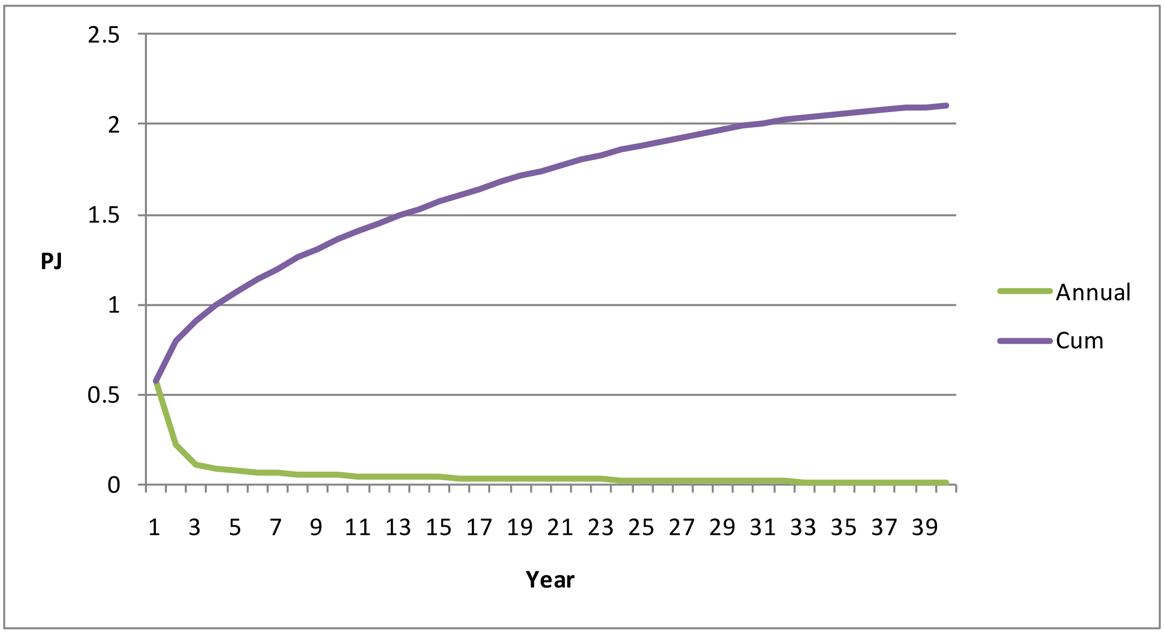
New gas supply projects in Australia are typically underwritten by long-term purchase agreements that guarantee gas off-take volumes. In order to enter such agreements, buyers require reserve and delivery certainty. To supply 50 PJpa, 2P reserves of 500 PJ would need to be proved up prior to finalisation of the agreement and final investment decisions for the projects.

The cost of proving up reserves and the risk that reserves are overstated means that initial production cannot be targeted too optimistically. SKM considers that shale gas production needs to be demonstrated at the 50PJpa level for a number of years before LNG export levels can be contemplated.
.
Individual buyers would typically not risk contracting their entire demand with “unproved” sources such as shale gas, so the contract volumes may need to be spread across multiple buyers.

3.2.1.2.3 Technology Issues

The critical factor with all unconventional gas types is that each well produces a limited volume of gas, typically 2-6 PJ over a 40 year lifetime, with production heavily front ended in the case of shale gas.

Figure 3.1 : Typical shale well production profile



Based on the example above, the requirements for developing an initial shale gas project capable of producing 50 PJ per year for 20 years have been estimated. As will be seen this provides a useful benchmark but is not economically optimal.

Essential assumptions are:

- Resource density: 5.6 PJ/km2 (typical of Australian basin estimates)
- Wells per pad: 6 (typical of US but the number is likely to increase. This will reduce the amount of land alienated for pads and reduce the amount of time lost moving rigs between pads)
- Resource per well: 2.1 PJ extracted over 40 years

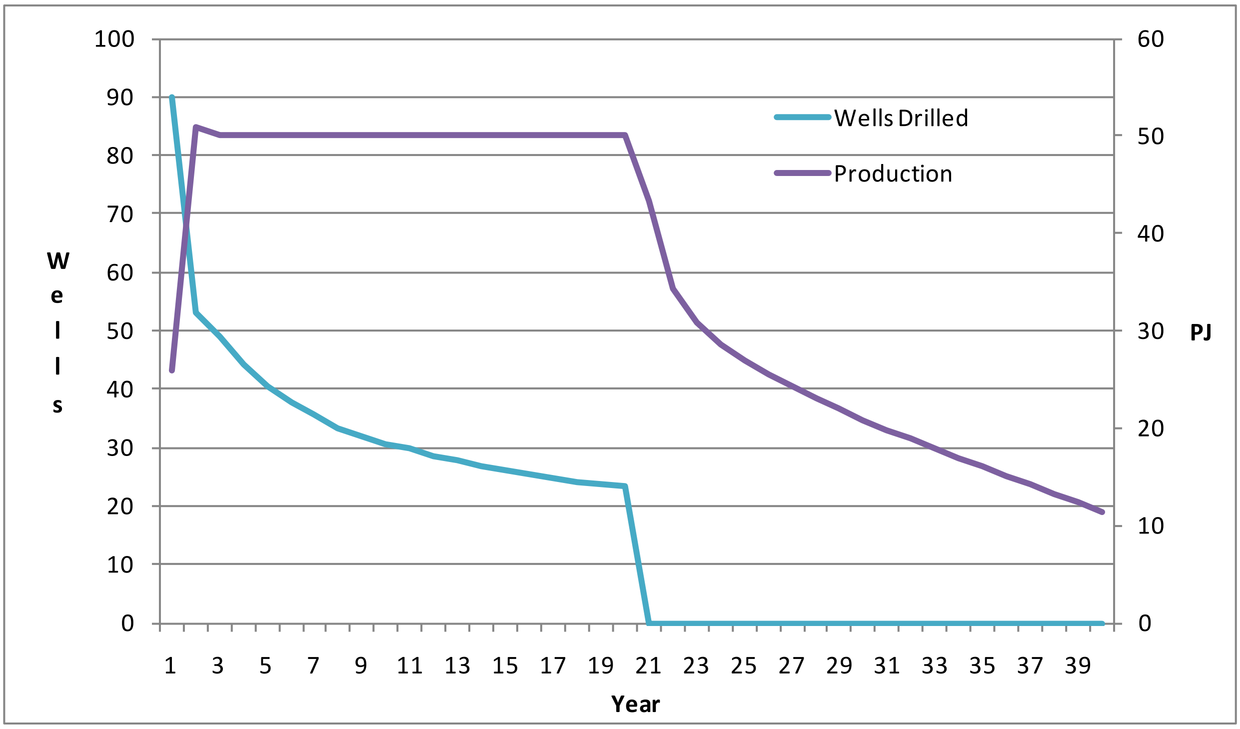
Consequently:

- Resource area covered per pad: 2.25 km2
- Horizontal well length: 1050 m
- Road and gathering pipeline per pad: 1.5 km

A further critical assumption is the drilling productivity – the number of days per well. Current US shale gas rigs take 6 to 10 days or more, however the current Australian figure appears to be 20 days per well[10], or about 18 per year per drilling rig, which we have assumed in this analysis. Timing for well completion & fraccing are 4 days and 7 days per well respectively and one completion rig is required for five drilling rig and one fraccing spread is required for every 3 drilling rigs. Efficient use of completion and fraccing resources, i.e. avoiding significant down time, therefore requires a shale project to use 5-6 drilling rigs.

The well drilling profile required to develop a shale gas project capable of producing 50 PJ per year for 20 years (with approximately 50% of output available in year 1) is illustrated below.

Figure 3.2 : Hypothetical shale project well drilling and production profile



The first year drilling rate, 90 wells, fits neatly with five drilling rigs, one completion rig and two fraccing rigs and would maximise productivity. However, from year two onwards the necessary drilling rate falls to 50 and continues to decline, suggesting only two to three drilling rigs are required, with consequent inefficiency in use of completion and, later, fraccing rigs, unless they can be shared with other projects.

Once multiple shale gas projects are underway, rigs can be moved from project to project as required but for the first shale gas project in any area some inefficiencies will most likely have to be accepted, unless offtake agreements allow volume flexibility. Some off-take flexibility will have to be tolerated anyway, to allow for variability in production from well-to-well and for the effects of drilling interruptions eg due to flooding.

As noted in section 3.1.1 there are unlikely to be synergies between shale gas and CSG or conventional drilling, so shale gas projects will require new rigs (new to Australia), leading to a substantial increase in the total number of rigs in this country. The increase is clearly contingent on the rate of shale gas development but could be a factor of two to three if shale development follows the same trajectory as CSG.

[10] Roadmap

In the first year this 50 PJpa development will also require:

- 15 new pads
- 22 km of new roads (unsealed) and gathering pipeline
- 1020 ML of water for fraccing (based on US 3m gallons/well).
- 9 ML of fraccing chemicals

It will also need:

- 50 PJ of gas processing capacity, constructed in year 1.
- 10 to 15 MW of compression capacity, depending on transmission pipeline operating pressures.
- An initial construction force of 450 as tabled below. Highly detailed estimates of drilling labour are provided in the reference at footnote 8.
- Operational staff of 75 - much of the operation will be conducted remotely from Perth, Adelaide or Brisbane.

Table 3.2 : Shale production labour requirements (full time equivalents)

Element	Per Rig[11]	Number of Rigs	Total
Drilling	28	5	139
Completion	14	1	14
Fraccing	59	2	118
Other drilling	10	1	10
Processing, compression etc			170
Total Construction			**450**

These figures exclude downstream items such as transmission pipelines.

The above are reasonably consistent with recent estimates for CSG. For constructing 210 PJpa CSG capacity in NSW average employment over 4 years construction is estimated at 1050. For the operational phase employment is estimated at 200[12]. At typical NSW well productivity of approximately 0.6 TJ/d, this project requires 960 wells at 240 per year.

We assume that the CSG construction employment splits 40:60 drilling to other i.e. 420:630. For shale gas we assume that the additional requirements for fraccing double the drilling labour to 840 for 240 wells or approximately 315 for 90 wells, compared to 281 in the above table. For non-drilling activities we assume the lower requirements for water disposal reduce the other labour requirement by 30% to 440 for equivalent sized shale gas plant. Allowing for the different scale and construction periods, for the 50 PJ shale project considered above the other labour is 210, compared to 170 in the above table.
.

3.2.2 If the drilling infrastructure is to be deployed in a rural or isolated area (such as the Canning or Cooper basin), is it feasible to develop manufacturing or assembly facilities locally, or will it be necessary to transport fully assembled surface and subsurface modules from a centralised location elsewhere in Australia?

The current practice in CSG in Queensland is for most large pieces of equipment to be imported from overseas. Examples include:

Drilling rigs

APLNG[13] uses Savannah 406 rigs sourced from Canada
GLNG[14] uses Saxon deviated well rigs also sourced from Canada

[11] Based on appendix 2a in “Roadmap for Unconventional Gas Projects in South Australia”

[12] The economic impacts of developing CSG operations in Northwest NSW. Allen Consulting Group submission to Santos.

[13] FID presentation

Gas processing

90% (by weight) of APLNG plant will be offsite fabricated/pre-assembled
Processing modules are being assembled in Thailand

Compressors

APLNG compressors are to be shipped from Germany (APLNG upstream delivery)

Pipeline

APLNG is sourcing pipe from Metal One (Japan)

Reverse osmosis desalination plant

Desal plant in the CSG industry in Australia comes from a range of local Australian and overseas suppliers. Most membrane is manufactured in US.

Australian companies have operated in all sectors except compression. However the limited domestic gas market and the small number of items required have until now prevented a competitive sector from emerging. At present exchange rates it appears unlikely that Australian manufacture would be competitive, except perhaps in pipe supply, and that the fabrication of drilling rigs will be done regionally outside of Australia, due to lower labour rates, and in countries having the requisite rig fabrication expertise. One potential area of Australian manufacturing involvement is drilling consumables, such as drill bits and rig spares. Competitive manufacture is more likely to emerge in existing industrial centres where there is a skills base than in rural or isolated areas.

For CSG the plant is delivered to the nearest port and trucked to an agents holding yard in a suitable location, such as Toowoomba or Dalby for Queensland CSG, before installation. It is imported in a high state of completion – most recent CSG processing plant is designed to require only one weld for installation.

Local assembly or construction applies to: road building; accommodation; drilling pad construction; gathering and transmission pipeline construction (trenching & welding); and water holding ponds.

3.2.3 If the infrastructure is manufactured or assembled locally, what labour pool and resources would be required? What would be the timelines needed to supply, train up and equip such a labour force? Would the labour force be local residents or fly in/fly out? What housing and services would be needed to support the labour force?

The labour force required for a 50 PJpa shale gas project is approximately 450. It would have similar skill requirements to CSG projects and could transfer from Queensland projects if or when the rate of CSG development there slows. Currently each of the CSG-LNG projects has a labour force of 5,000 to 7,000.
SKM considers it likely that a majority will be fly in/fly out, particularly in more remote areas.

[14] Investor Presentation November 12

3.2.4 If developed remotely, what road, air or rail infrastructure would be required to facilitate delivery to site?

In existing gas production areas such as the Cooper Basin we consider the existing road and air infrastructure would provide adequate but not exceptional service. According to the "Roadmap" users of the existing road infrastructure into Moomba place a high priority on the sealing of all unsealed sections between Leigh Creek and Moomba. Increased traffic on these roads, due to shale gas industry developments for example, could make sealing economically attractive compared to the increased cost of maintenance of unsealed roads.

For the large scale CSG developments now occurring in Queensland there is increasing preference for staff to fly in rather than drive. QGC has a policy that where possible, all staff will fly into site rather than drive[15]. QGC has provided significant resources to upgrade the Chinchilla Airport and its daily chartered services from Brisbane to have increased from one each way each day to more than 8 each way each day. Santos has upgraded the Roma Airfield and operates similarly increased daily flights.

New areas such as the Canning Basin would require air infrastructure suitable for 10-seater aircraft rather than the 6-7 seater aircraft typical of current outback services with greater availability during the wet season. As noted above, Gas companies have proved willing to fund these improvements when they are critical to their operations.

Roads would need to be upgraded to suit heavier, wider vehicles such as B-doubles and –triples carrying large items of plant.

3.2.5 Is there the capability within Australia to manufacture the necessary drilling equipment and surface facilities, or would it be necessary to import some equipment? If so, where would equipment be sourced and what would be the timelines for delivery?

Current drilling operators offering oil & gas services in Australia are listed below – those listed have been selected from the list of associate members of APPEA. To the best of our knowledge Australian drilling manufacturers offer products suitable only for mining samples and water wells. In the early days of CSG some water drills were used and smaller projects may still be using this technology, however large CSG projects have moved to more sophisticated drills capable of drilling horizontal wells.

Drilling shale wells that are typically 1000m deeper than CSG will require at least the same level of technology. Local manufacture is possible but failure of local industry to take up the CSG opportunity suggests there are significant economic barriers to be overcome.

Refer also to section 3.2.2.

Table 3.3 : Drilling operators offering service in Australia

Supplier	Sectors served	Oil & Gas	Rigs	Rig manufacturer
AJ Lucas	Energy	CSG	77 rigs	No
Drillstralis	Energy	Coal and CSG	N/a	No
Energy Drilling Australia (Ausdrill)	Energy, mining (Ausdrill)	CSG, shallow conventional wells	Foremost Explorer III-65 modified for local conditions	No

[15] Private communication

Supplier	Sectors served	Oil & Gas	Rigs	Rig manufacturer
Halliburton Australia	Oil & gas	All incl shale gas	N/a	No
Labrador Petro Management	Oil & gas	All incl shale gas	Drilling project specialists	No
Maersk Drilling Australia	Oil & gas	Conventional	Offshore	Outside Australia
Transocean	Oil & gas	Conventional	Offshore	Outside Australia

At times some equipment is in high demand and there are waiting lists, so that plant needs to be ordered early.

3.2.6 Would such importation, manufacturing and transportation costs make drilling significantly more expensive than in the USA? How much more expensive? How would the costs compare to coal seam gas drilling in Queensland and NSW?

The costs of drilling will be higher than in the US, possibly up to 100% initially, and higher than CSG because of greater depth of wells and fraccing requirements. However the cost of gas depends as much on flow rates as on drilling costs.

Estimated breakeven costs of production ex gas-plant including capital and operating costs, royalties and a commercial rate of return are:

- US Shale gas - $US3-7mmbtu, approximately $A3-7/GJ. (Refer to Figure 3.3, high and low values excluded from the range)
- Australian CSG (Bowen-Surat, Camden, Gloucester, Gunnedah) - $3-6/GJ[16]
- Australian Shale gas - $6-9/GJ (Santos, for Cooper Basin[17])

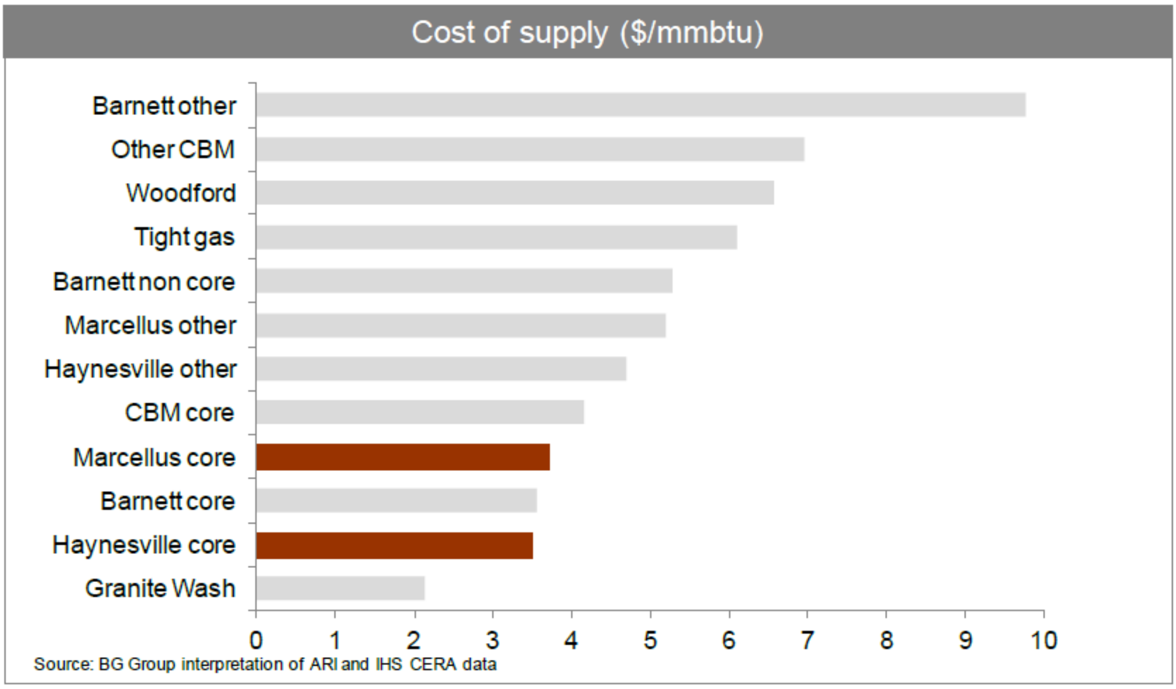
SKM considers it likely that Australian shale gas production costs will decline over time under the following influences:

- Increased understanding of the shale gas resource, leading to selection of the most productive areas
- Development and application of lower cost drilling and production methods
- Optimisation of recovery rates per dollar of development cost at both the macro (production project) level and the micro (well) level.

[16] Gas production costs report, August 2012. Prepared for the 2012 Gas Statement of Opportunities by Core Energy.

[17] Cooper Basin Unconventional Gas Opportunities & Commercialisation, Santos, November 2012

Figure 3.3 : Cost of US Shale gas production



3.2.7 Similarly, what infrastructure will be required for:

Water supply and storage?

The 50 PJpa shale production project outlined in section 3.2.1 requires 1020 ML of water for fraccing in its first year, declining to 500 ML by year 4 and 350 ML in year 10, in parallel with declining new well requirements. To date in the US most water used for fraccing has been fresh (dissolved solids less than 1,000 mg/L) as the friction modifying and other additives operate most effectively in fresh water[18].

In general the water can be supplied from surface, groundwater and by recycling. In many areas the seasonality or simple non-availability of surface water would make groundwater the natural choice. It is recognised that in areas with only brackish surface or groundwater fraccing techniques will need to be adapted to the available water quality.

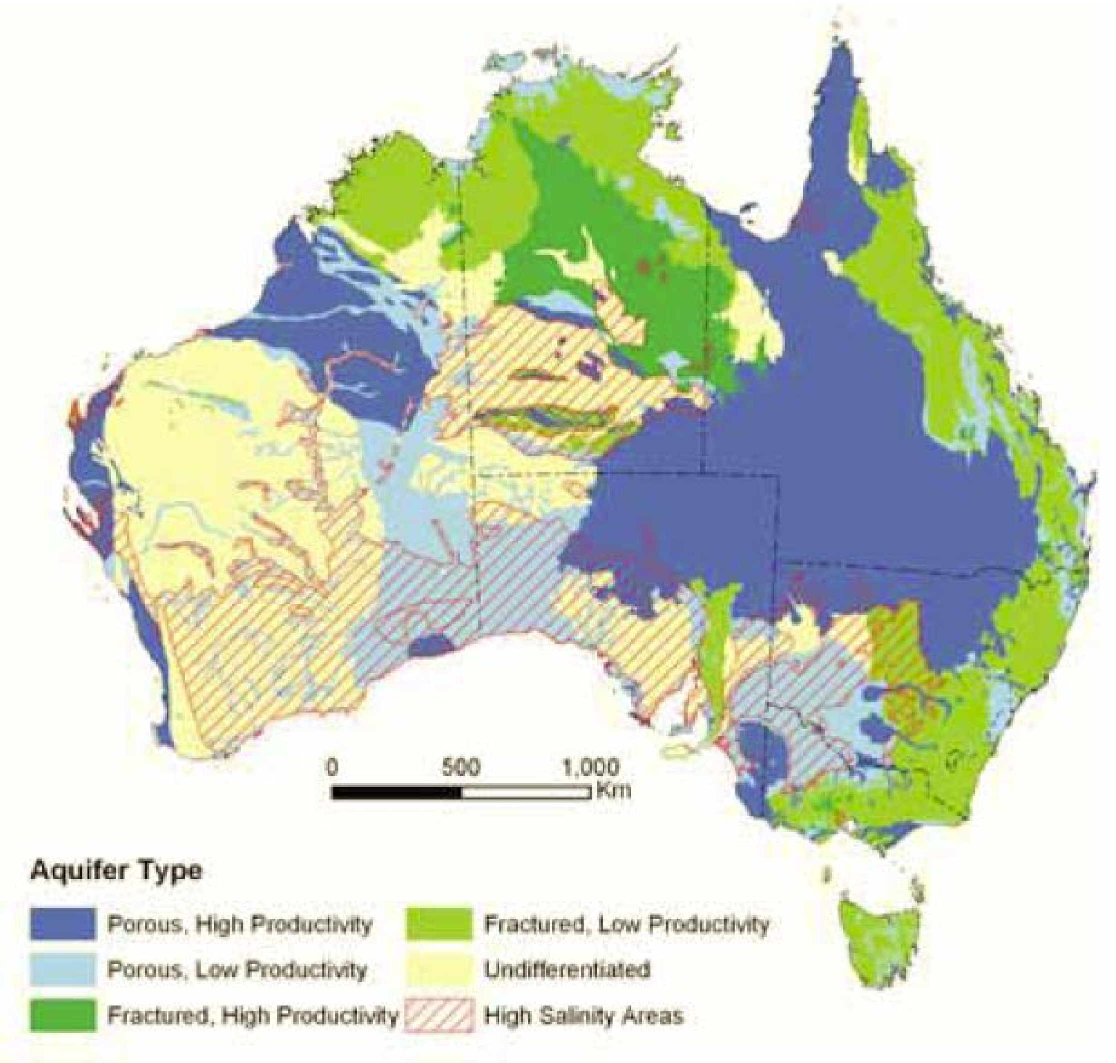
Ground water is widely available in Australia (Figure 3.4) but in many areas it is highly saline, which preclude its use in fraccing. Of the basins considered for shale gas production this would seem to affect only the eastern Perth Basin and the Otway basin, which may however have sufficient surface water.

Total sustainable groundwater availability is estimated at 21,000GL/yr and recent extraction has been up to 8,000 GL/yr[19]. Of this the 50 PJ project would require only 0.013% in its first year and a full LNG project (8Mtpa or 500 PJpa) would be only 0.13%. On this basis we can say that groundwater use for fraccing will not affect other uses in general, though on a local level there could be some impact.

[18] Water use for shale gas production in Texas, US, JP Nicot and BR Scanlon, Environmental Science and Technology, March 2012

[19] Understanding Groundwater. A Plazinska, September 2007.

Figure 3.4 : Groundwater availability



SCIENCE *for* DECISION MAKERS • Understanding Groundwater

The first year pumping requirement is equivalent to 2,000 L/min, similar to a large agricultural well, so at most two wells would be required, plus a modest surface storage dam. SKM estimates that the cost of these facilities will be $2-3m, i.e. modest relative to other shale production costs.

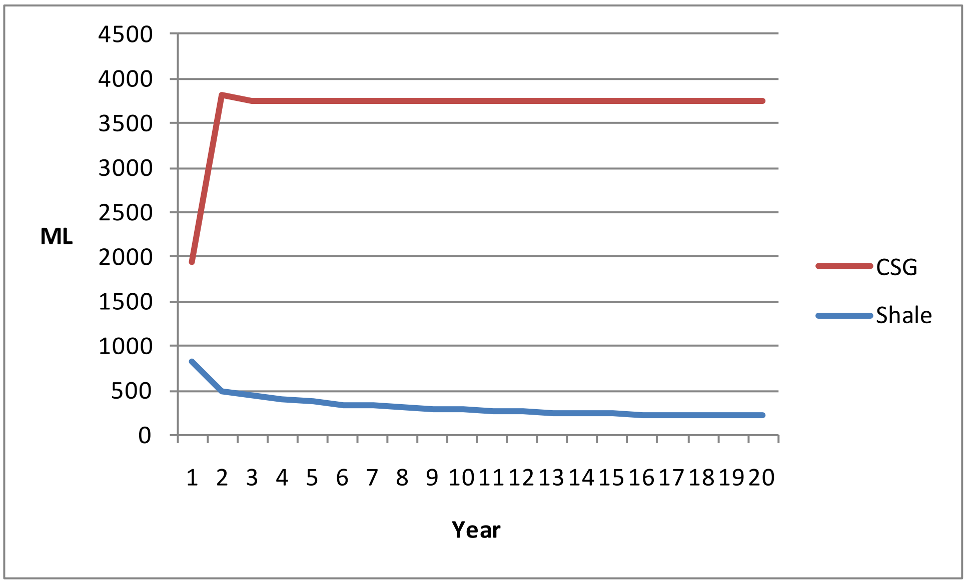
Produced water treatment?

There is significantly less produced water with shale gas production than CSG or conventional gas and treatment and disposal is required mainly for fraccing water. Figure 3.5 shows the volumes of water for disposal associated with shale gas and CSG projects producing 50 PJ per year. The shale estimate is based on the fraccing requirements for the project discussed in section 3.2.1 and the CSG estimate is based on 75 L/GJ[20], for

[20] Queensland LNG Industry Viability and Economic Impact Study. McLennan Magasanik Associates report to Qld DIP, 1 May 2009

comparable production. The CSG volume is an order of magnitude greater than the shale volume.

Figure 3.5 : Water for disposal, CSG and Shale comparable volumes



Some 80% of fraccing water returns to surface[21] and is stored in ponds before disposal or reusing. In the US it is disposed of into local surface waters, reinjected into deep wells or trucked to central processing sites, either on-site or off-site. Unlike CSG, where water production is prolonged and requires a water pipe network to centralised processing plants, fraccing water re-emerges quickly and permanent pipes are not needed.

Re-injection appears to be the industry preferred option, where re-injection sites are accessible. On-site processing by RO retrieves up to 70% to potable standard for reuse, potentially 80% if a lower standard of water is suitable for fraccing[22]. The remaining 20-30% is sent offsite for disposal.

Fraccing water contains sand that did not remain in the well as a proppant and chemicals such as: gelling agents (eg guar gum) to adjust viscosity before fraccing; oxidisers (ammonium, potassium or sodium salts) to increase viscosity after fraccing; biocides to prevent bacterial degradation; and methanol or sodium thiosulfate for high temperature stability. The chemicals are useful and extraction and re-use is desirable but it is not clear to us that this is economic as they may remain in the brackish water component after RO treatment.

[21] Ibid

[22] Ibid

Gas sweetening and purification?

US shale gases have a broad range of compositions similar to conventional gases, rather than the narrow spectrum associated with CSG, which is generally 96% methane. Some, such as Eagle Ford in the figure below, have high liquids contents (C4+) and many appear to be relatively high in ethane. As there is little gas communication across fields, there are substantial compositional differences within fields[23]. The liquids are extracted and transported separately, while ethane can either be separated and transported separately as at Longford and Moomba in Australia, or left in the gas stream.

Little is known about Australian shale gas composition at present, except that Cooper Basin shales are similar to conventional gas in the same area, i.e. many will have high CO_2 levels.

Figure 3.6 : US shale gas compositions

	Example El Paso Energy Shale Gases[5] (major components, before processing) (Volume %)			
Component	**Marcellus**	**Appalachian**	**Haynesville**	**Eagle Ford**
Methane	97.131	79.084	96.323	74.595
Ethane	2.441	17.705	1.084	13.824
Propane	0.095	0.566	0.205	5.425
C_4+	0.014	0.034	0.203	4.462
Hexanes+	0.001	0.000	0.061	0.478
Carbon Dioxide	0.040	0.073	1.816	1.536
Nitrogen	0.279	2.537	0.369	0.157
Total Inerts (CO_2+N_2)	0.318	2.609	2.184	1.693
TOTAL	**100.0**	**100.0**	**100.1**	**100.5**
HHV (BTU/SCF)	1,031.6	1,133.2	1,009.8	1,307.1
Hydrocarbon Dew Point (°F)	-96.8	-41.3	9.7	119.6
Wobbe Number (BTU/SCF)	1,367.1	1,397.0	1,320.1	1,490.0

Source: Shale gas measurement and associated issues. Pipeline and Gas Journal, July 2011

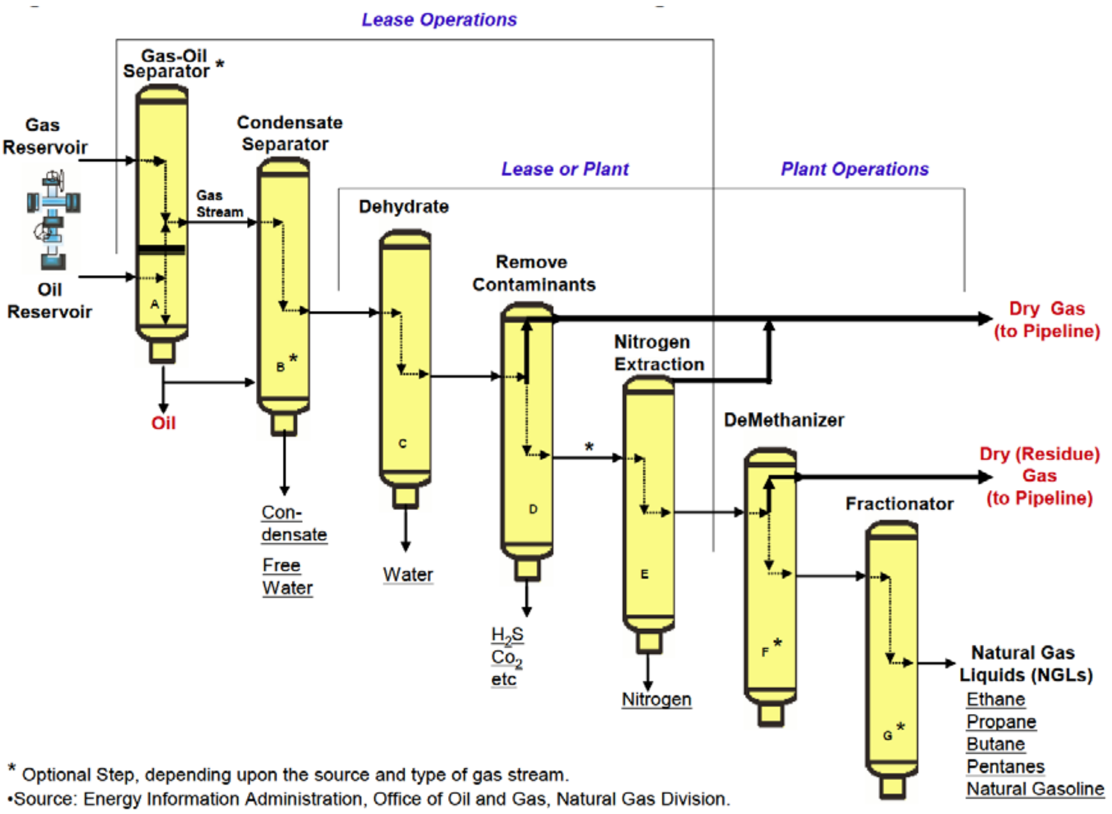
Shale gas processing plants are therefore likely to resemble the more complex conventional plants rather than CSG plants, some of which do little more than separate water and dry the gas. In the case of liquids, the value of the liquids will pay for the additional cost and may be used to support gas production, but with CO_2 the costs will be a burden to project economics. A natural gas processing plant schematic illustrating the various components is presented in Figure 3.7.

In the US Barnett Basin the majority of processing plants include compression, CO2 treating with amine units, cryogenic separation, and fractionation whereas Fayetteville shale only requires dehydration[24].

[23] Composition Variety Complicates Processing Plans for US Shale Gas, Keith Bullin, Peter Krouskop, Bryan Research and Engineering Inc
[24] Ibid

It is noted that in North America it is common for gas processing to be undertaken by third parties rather than gas producers, which facilitates market entry by smaller producers. Third party processing is not common in Australia.

Figure 3.7 : Natural gas processing plant schematic



The functions of, and methods used in, each stage of processing are:

- Gas-oil separator: multi-stage gravitational separation of light & heavy hydrocarbons (oil = C12+)
- Condensate separator: mechanical separation of condensates using a slug catcher (condensates = C2 to C12)
- Dehydrator: water removal by absorption using ethylene-glycol or dehydrator towers with silica gel or activated alumina desiccants
- Contaminants: removal of hydrogen sulphide, carbon dioxide, oxygen and helium, typically using amine towers. Products vented, sequestered or stored and sold in the case of helium.
- Nitrogen extraction: cryogenic separation using molecular sieves. Nitrogen is vented.
- De-methaniser: cryogenic or absorption separation methane from heavier gas components and lighter liquids
- Fractionator: separates NGLs using their different boiling points

Should such infrastructure be distributed at a small localised scale or developed as a large centralised facility?

Gas processing locations for shale will most likely be determined by a compromise between reasonable plant scale and the distances gas will flow through the low pressure gathering system, similar to CSG.

CSG plants are typically 200 TJ/d (70 PJpa) and about 15 km apart. This contrasts with Cooper Basin conventional gas processing which takes place at Moomba and Ballera, 180 km apart.

What labour pool would be required for the construction of these operations?

Estimates of labour requirements for the first year of a shale project designed to produce 50 PJ per year are provided in section 3.2.1.

3.2.8 What is the likely expense, relative to current shale gas operations in the USA and current coal seam gas operations in Queensland and NSW?

Estimates are provided in section 3.2.6.
.

3.2.9 What is the labour requirement for maintenance of drilling and surface facilities once operational? Can this be supplied locally, or will labour be fly in/fly out?

The labour requirement for pure operating activities is estimated at 75 for a 50 PJ per year plant (refer to section 3.2.1). However owing to the rapid decline in production from individual shale wells, the shale industry involves continual drilling to maintain production levels, with a labour requirement of 110 per drilling rig, including completion and fraccing.

Increasingly, operating staff will be centralised in capital cities, directing maintenance staff to any equipment problems. The remoteness of some likely shale producing areas, such as the Canning and Cooper Basins, ensures that labour there will be fly in/fly out, mainly from Australian capital and larger cities though also possibly from Asia. In other areas such as the Otway or Maryborough basins, there is a greater probability that some workers will be existing locals or people who re-locate to local towns.

3.2.10 Do the infrastructure requirements change if contained liquids or shale oil form the main target of the operation?

We are not aware of any differences in drilling infrastructure. The gas processing schematic in Figure 3.7.shows the facilities required to separate liquids from gas.

The additional task of transporting the liquids to a customer or refinery would initially, at low volumes, be undertaken by truck. Each truck would carry approximately 200 bbl of oil, so production of 1,000 bbl/day would mean 5 truck loads/day and 10,000 bbl/day would mean 50 truck loads/day.

The volume at which a pipeline becomes more economic than trucking depends on a range of factors including distance, road network quality, the timescale for oil production and safety and road congestion factors. About10,000 bbl/day seems an appropriate volume at which a pipeline should be considered in many situations.

In the US some oil is transported by rail but the Australian rail network does not appear to extend to any potential oil producing areas so this is unlikely to occur here.

3.2.11 What is the feasibility of further processing of shale gas resources to provide a 'value-add' and what infrastructure development and labour would be required? This processing might encompass gas to liquids (GTL), liquefied natural gas (LNG) or olefins production. In these instances, what are the advantages and disadvantages of small scale distributed processing versus large scale operations at a single site? What would be the potential location of a single site processing facility relative to a gas supply from the Canning or Cooper basins?

Value adding opportunities

The markets for shale gas are the same as the markets for conventional gas and CSG: power generation, industrial fuel and feedstock, commercial, residential and export as LNG. Feedstock includes ammonia and Gas to Liquids (GTL). Gas producers prefer to supply markets with the highest margins, which are determined by the value of the end use, which is itself partly determined by competing fuels and gas supply competition. The following table provides an indication of market values (including scale) and key determining factors.

Table 3.4 : Major markets for Australian Shale Gas

Market	Market Scale	Key factors	Max Value range
Generation (base load)	200 PJ East Aust 100 PJ WA	Cost of coal fired plant Carbon costs	$7-9/GJ
Ammonia	30 PJ East Aust 40 PJ WA	World ammonia price	$4-6/GJ
Alumina	30 PJ East Aust 100 PJ WA	World alumina price Cost of coal	$6-8/GJ
Industrial general	300 PJ East Aust 100 PJ WA	Value of output	$4-10/GJ
Commercial and residential	150 PJ East Aust 12 PJ WA		$6-10/GJ
LNG	10,000 PJ global	Cost of oil and conversion	$4-10/GJ
GTL	Unknown	Cost of oil and conversion	$3-4/GJ

Source: SKM estimates
Note: value ranges are expressed at the gas plant, net of typical transmission costs.

Locations of gas processing

Further processing is most likely to take place in locations where existing processing takes place or where there are proposals for other gas to be processed. Processing into export products such as LNG or ammonia will most likely take place in locations with port access. Specific examples for the Canning and Cooper Basins are tabled below.

Table 3.5 : Potential market locations for Canning and Cooper Basin Shale Gas

Market	Canning Basin	Cooper Basin
Generation	Kimberley, Pilbara, SWIS[25]	SA, NSW, Qld
Ammonia	Dampier	Brisbane, Mt Isa
Alumina	South West WA	Gladstone
Industrial general	Perth region	SA, NSW, Qld
Commercial and residential	Perth region	SA, NSW, Qld
LNG	James Price Point (Kimberley) or Dampier	Gladstone or SA
GTL	James Price Point or Dampier	Gladstone or SA

Notes:

- Planning is in progress for a pipeline linking Canning Basin production to Broome and thence to Karratha and the existing WA transmission network
- The Cooper Basin is connected by transmission to all Eastern States markets except Townsville

3.2.12 Overall, what will be the 'value-add' for Australia and for the local community of these new infrastructure developments?

In 2009 SKM MMA completed a study of the economic impact of the Gladstone LNG projects for the Queensland Government[26]. The central scenario anticipated construction of 8 LNG trains of 3.5 Mtpa capacity and associated upstream CSG capacity, the last train starting up in 2021. This compares to the current construction of 6 trains with last start up in 2017, with two additional trains in prospect. By 2021 incremental CSG production would be approximately 1800 PJ in this scenario.

The overall economic impact of this scenario in $2009, evaluated by KPMG Econtech for SKM MMA using a general equilibrium model of the Australian economy, is summarised below.

[25] South West Integrated System (Electricity)

[26] Queensland LNG Industry Viability and Economic Impact Study. McLennan Magasanik Associates report to Qld DIP, 1 May 2009

Benefits accruing from shale development on the same scale are likely to be similar or slightly less, owing to the higher cost of shale relative to CSG.

Table 3.6 : Economic impact of 8 train LNG export scenario

Variable	$m	%
GDP	1,034	0.10%
GSP (Qld)	3,056	0.98%
Royalties[27]	850	
Employment	18,195	0.82%
HHFCE[28]	815	0.13%

3.3 Coal Seam Gas - Lessons Learned

Provide comment on whether the development of an SG Industry in Australia will be located close to existing gas pipelines, or located elsewhere.

The SG industry is currently developing in locations that are both served (Cooper Basin, Perth Basin) and not served (Canning Basin) by existing pipelines and processing infrastructure. The advantage of being close to existing pipelines is that gas production of any kind can develop incrementally on any scale that is economic for production and rely upon transmission to market at a known, reasonable cost. Small scales of production are economic for all forms of onshore gas. The key advantages of this are: acceleration of revenue because any exploration wells that produce commercial quantities can be connected and produce revenue immediately

New transmission pipelines however have significant economies of scale and production in areas like the Canning Basin needs to be able to reach a minimum scale for the pipeline to be economic. SKM estimates that that for Canning Basin gas to reach existing WA markets this threshold is of the order of 50 PJpa. This means sufficient reserves have to be built up to support production for a minimum period (at least ten years); hence a more extended and financially risky exploration and appraisal process before an investment decision can be made. Projects in this situation need to find local markets that can be supplied by trucking out CNG or LNG (compressed or liquefied natural gas) before the pipeline is built, if they are to build up production progressively. We note that there are one CNG[29] and two LNG[30] trucking operations in WA at present, mostly supplying gas to remote power stations.

There is little doubt that Queensland CSG development initially took place in the Surat and Bowen Basins because of access to the Roma-Brisbane Pipeline and the Queensland Gas Pipeline, whereas development of the Galilee Basin has been held back by the absence of pipeline access (and possibly poorer coals). We note however that development of CSG at Moranbah for Townsville was not held back by the absence of pipeline infrastructure and resulted in construction of the North Qld Pipeline.

[27] In $2008

[28] HHFCE = Household final consumption expenditure, an estimate of the impact on the standard of living

[29] Supply of gas to Exmouth power station

[30] Supply of gas to Kimberly power stations (EDL) and to power and industrial users in the South-West (Kleenheat)

Unlike CSG however, shale gas development can also be stimulated and financially supported by liquids production, as is happening in the Canning Basin, in the absence of any gas infrastructure. .

It is reasonable to expect that smaller companies will focus their unconventional gas development strategy near existing demand markets and transportation infrastructure that either has incremental capacity or that can be readily expanded to increase tie-in connectivity and "take-away" capacity, such as with the Perth or Gippsland Basins. However other factors, such as liquids production, may be equally influential.

3.4 Differences Between Coal Seam Gas and Likely Shale Gas Developments

If applicable, compare and contrast the differences between coal seam gas development and likely shale gas development in Australia

CSG and shale have both similarities and differences.

Similarities

- Extensive resources – key issue is not "where are they" but "how can they be extracted economically"
- Projects occupy an extensive area – interactions with other land uses and users requires intensive management
- Low flow rates per well – large number of wells required (hundreds), drilling is the key technology
- Well productivity varies from one well to the next – technology selection is a trade off between standardisation to minimise cost and customisation to maximise individual well flows
- Horizontal wells and pad drilling are common
- Tendency for smaller "explorer" companies to take early running with high risk appraisals requiring corporate flexibility, then taken over by "producers" with sufficient capital to fund the manufacturing stage.

The following table presents aspects in which CSG and Shale developments differ.

Table 3.7 : CSG and Shale differences

Feature	CSG	Shale
Resource location	Mainly Queensland and NSW	All mainland states
Well depth	Coal beds, 500-1000m	Shales, 2,000-3,000m
Drilling method	Coil tube	Standard tubing
Fraccing	Not essential on all wells	Required on all wells
Production profile	Flat 5-8 years	Rapid decline
Gas composition	Mostly methane	Wider range including liquids
Water produced	Significant, average 75 L/GJ	Limited, more fraccing water
Processing plant	Simple water/gas separation	More complex separation of gas/liquids/contaminants
Costs of production	\$3-6/GJ	\$6-9/GJ initially, reducing