Engineering Energy: Unconventional Gas Production

A study of shale gas in Australia.

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Summary

Many Australian sedimentary basins are prospective for unconventional gas and the undiscovered resource base is very large. The technology (such as horizontal wells, multi-well pads and hydraulic fracturing) is available to produce shale gas (and shale oil and tight gas) in Australia, but production costs are likely to be significantly higher than those in North America and the lack of infrastructure will further add to costs. Shale gas will not be cheap gas in Australia, but it is likely to be plentiful and it has the potential to be an economically very important additional energy source. Increased use of shale gas (and other gas) for electricity generation could significantly decrease Australia's greenhouse gas emissions based on gas replacing coal. Because of the manner in which shale gas is produced it has the potential to impact on the landscape, on ecosystems, on surface and groundwater, on the atmosphere, on communities, and rarely may result in minor induced seismicity. It will be vital for industry and government to recognise the complexity of the challenges posed by these possible impacts. However, most can be minimised where an effective regulatory system and best monitoring practice are in place and can be remediated where they do occur. If the shale gas industry is to earn and retain the social licence to operate, it is a matter of some urgency to have such a transparent, adaptive and effective regulatory system in place and implemented, backed by best practice monitoring in addition to credible and high quality baseline surveys. Research into Australia's deep sedimentary basins and related landscapes, water resources and ecosystems, and how they can be monitored, will be essential to ensure that any shale gas production is effectively managed and the impacts minimised.

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Project aims

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

Securing Australia's Future, Project Six, Engineering energy: unconventional gas production, aimed to undertake a study of shale gas in Australia which looks at: resources, technology, monitoring, infrastructure, human and environmental impacts, issues communication, regulatory systems, economic impacts, lessons learned from the coal seam gas industry, and impacts on greenhouse gas reduction targets.

Executive summary

The development of the shale gas industry in the United States over the past decade has had a major impact on the energy market in that country and on its economy, but has also raised a number of environmental questions. The Australian shale gas industry is very small by North American standards but has had some early success, and together with work on tight gas, it expects to spend more than $500 million on exploration over the next 1-2 years. Given that the momentum of the industry in Australia is increasing, it is a matter of some urgency to more fully assess the nation's shale gas resources and reserves (as well as the more limited tight gas resources) because of their potential impact on the Australian gas market and gas prices, on jobs and on the economy more broadly. But equally importantly, the urgency arises because of the need to understand (whilst the industry is at an early stage) what the potential environmental, social and related impacts might be and the need to regulate the industry in an effective and transparent manner that will help to minimise or prevent any adverse impacts in order to establish and retain a "social licence" to operate.

A driver for an Australian shale gas industry is that most of the announced coal seam gas (CSG) reserves are committed to the LNG industry from 2015-2016, with the potential for domestic gas shortages in eastern Australia and the prospect of large increases in gas prices. It is very likely
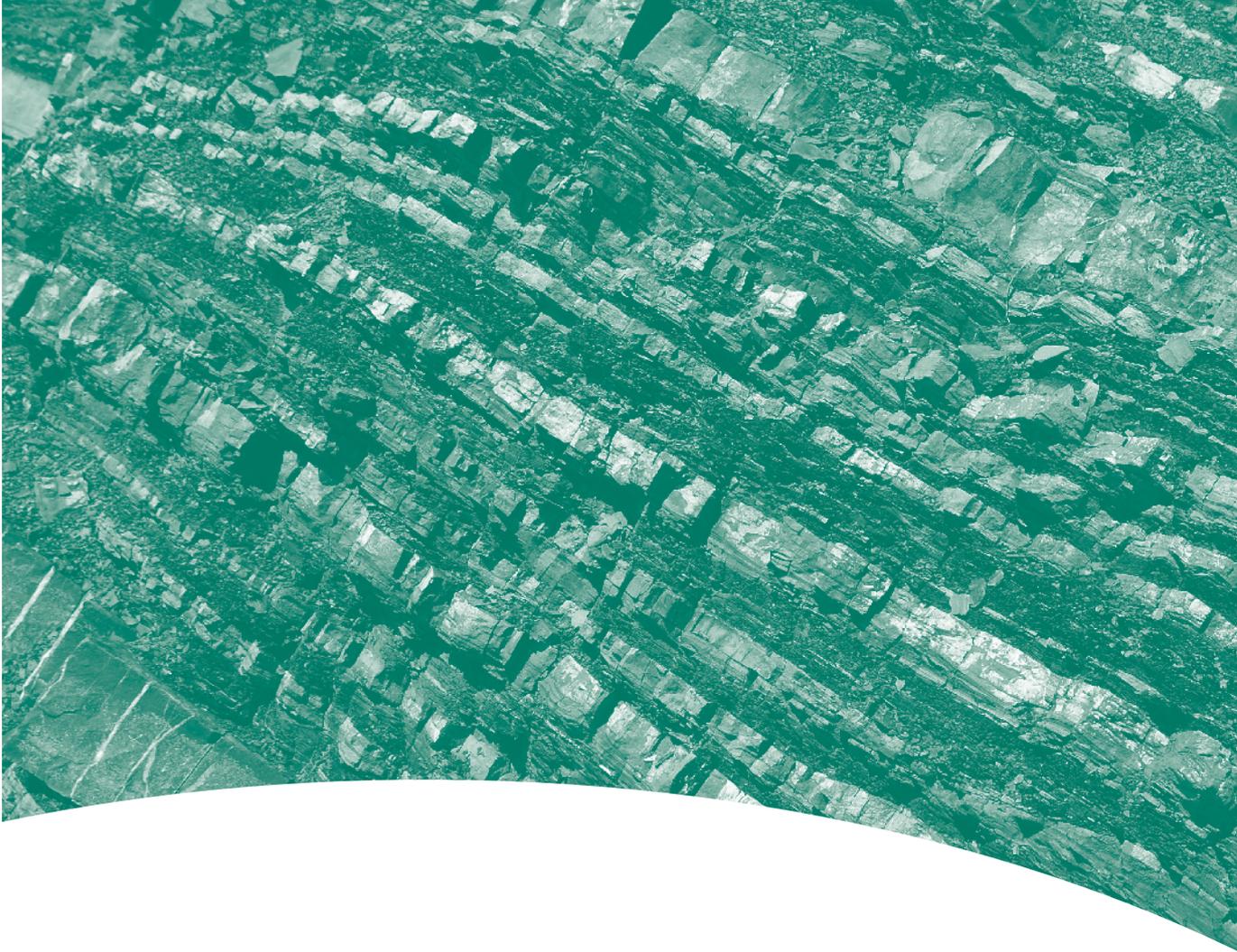
that abundant shale gas will be found in Australia and this will help to ensure that there is no gas shortage. But shale gas will not be cheap gas in most circumstances. It will require a relatively high price to make it profitable to produce. The current low price of shale gas in North America is not sustainable but production there is being maintained, despite the low price, either for contractual reasons and/or because some of the gas is produced as a by-product of higher value oil derived from the shales. In Australia, shale gas will require a price of the order of $6-9 a gigajoule to make its production and transport profitable compared with the current East Coast wholesale gas price of about $6 a gigajoule. The suggestion has been made that a proportion of future shale gas should be reserved for domestic use, as a mechanism to hold down domestic gas prices. The Expert Working Group saw this as a challenge to implement in a market economy, but an alternative suggestion that

Government could work with industry to create vital infrastructure, particularly in remote parts of Australia, to encourage the development of a more cost effective and more widespread shale gas industry, warrants consideration.

Australia has large undiscovered shale gas (and probably some shale oil) resources in many basins, mostly though not exclusively in remote parts of the country. Shale gas has many similarities with tight gas, but the resource is thought to be much smaller than that of shale gas. The available undiscovered resource figures for shale gas have a high degree of uncertainty attached to them. The commonly cited resource estimate of 396 trillion cubic feet (tcf) of gas is based on only four basins; if all prospective basins are considered, the undiscovered resource could be in excess of 1000 tcf, though the value has a high degree of uncertainty. Far more exploration is needed to turn those resource estimates into economic reserves. In the Cooper Basin,

existing markets and available infrastructure can be rapidly deployed to accelerate shale gas (and tight gas) production. Elsewhere, the lack of infrastructure could hold back shale gas developments, but at the same time, major new finds could also provide the stimulus for new infrastructure. The technology to explore for and produce shale gas that has been developed largely in North America, is in general applicable to Australian geological conditions. There are no insurmountable technology barriers relating to shale gas production but there will be a need to adapt to particular geological features, such as high heat flow in parts of central Australia, which limit the applicability of some monitoring techniques. Also, variations in the stress field may require modified hydraulic fracturing (fracking) techniques in some basins. There are skill shortages in some areas of shale gas production which will need to be addressed if the industry is to progress and there may be an initial shortage of suitable drilling rigs, but overall it will be the lack of more basic infrastructure (roads, pipelines) and markets, that will slow shale gas growth in Australia compared to the rapid growth of the industry in North America.

A number of environmental issues related to the shale gas industry have arisen in the United States and similar questions have been raised about potential impacts in Australia. A large number of impacts are possible, but the likelihood of many of them occurring is low and where they do occur, other than in the case of some biodiversity impacts, there are generally remedial steps that can be taken. Nonetheless it is important that the shale gas industry takes full account of possible adverse impacts on the landscape, soils, flora and fauna, groundwater and surface water, the atmosphere and on human health in order to address people's concerns. This will require improved baseline studies against which to measure future change and to compare natural change and change resulting from industry activities. The footprint and regional scale over which shale gas operations may occur can be minimised by measures such as drilling multiple wells from one drill pad, but nonetheless there will be some cumulative regional, ecological and hydrological impacts, including

fragmentation of habitats and overall landscape function. These will need to be carefully assessed and managed using best practice.

Impact on groundwater is likely to be a particular issue in many areas. Large amounts of water are used in hydraulic fracturing operations. In general, brackish or salty water can be used; small quantities of chemicals and sand are then added to the water to give it the right properties for the development of induced permeability, which in turn allows the gas to then flow from the shale. The water that flows back from the wellcan then be re-used or it may be disposed of at an approved site. Contamination of aquifers and surface water can result from chemical spillage. The industry already has rigorous systems for dealing with spillage, or from the incorrect disposal of the hydraulic fracturing fluid (already controlled by regulators under most jurisdictions), or from produced water. Contamination can also potentially occur via leakage from a borehole into a freshwater aquifer, due to borehole failure, particularly from abandoned bores, or (though less likely) from an incorrect hydraulic fracturing operation. These are unlikely to occur if best practice is followed, but regulations need to be in place and enforced, to help to ensure this.

Induced seismicity associated with shale gas operations has given rise to concern overseas, but the number of damaging seismic events that can be related to shale gas is very small indeed. The injection of large volumes of fluid (for example during geothermal projects) has been shown overseas to be more likely to cause a magnitude 3-4 seismic event than a hydraulic fracturing operation. This also is likely to be the case in Australia, with the risk arising from induced seismicity regarded as low. However an uncertainty for Australian operations is that the current seismological record has relatively coarse resolution and would not be adequate to detect 'natural' small magnitude earthquakes in areas where shale gas operations might be underway. There is seen to be a need to improve and prioritise the current seismic network. Best practice involving specific seismic 'triggers' for cessation

of hydraulic fracturing may be usefully applied to minimise the prospect of damaging seismicity.

A vigorous scientific debate is underway about the level of greenhouse gas emissions associated with shale gas production and there are uncertainties in the estimates. At the early 'flowback' stage there can be methane emissions to the atmosphere unless so-called green completions, that minimise methane emissions, are used. It is desirable to put effective methane mitigation steps in place as soon as possible. The data available on natural and industrial methane and CO_2 emissions is quite limited and steps will need to be taken for methane monitoring of natural systems (for background) and shale gas operations. Using shale gas in gas turbines for electricity production will result, on average, in approximately 20% more emissions than using conventional gas, but 50-75% of the emissions than when using black coal, assuming green completions (based on life cycle emission considerations) for power generation. Increased use of shale gas (and other gas) for electricity generation could significantly decrease Australia's greenhouse gas emissions based on gas replacing coal-fired generation; the extent to which this actually occurs will depend on the price of shale gas compared to alternative energy sources.Some shale gas is likely to be high in carbon dioxide; depending on the cost, application of carbon capture and storage could be used to limit those CO_2 emissions.

Gaining and retaining a 'social licence to operate' will be important to all shale gas operations and will need to be approached not just as a local community issue, but also at regional, state and national levels. In order to develop effective relationships with communities potentially impacted by shale gas developments, it will be necessary to have open dialogue, respect and transparency. It will also be important there is confidence in the community that not only are shale gas operations and impacts being effectively monitored, but also that concerns will be identified and remediated, or operations stopped before a serious problem arises. Many of the most prospective areas for shale gas are subject to Native Title or are designated

Aboriginal Lands and it will be important to ensure that traditional owners are aware of the nature and scale and the possible impact of shale gas developments from the start. The industry also has the potential to help address the aspirations of Aboriginal people to build greater economic self-sufficiency.

The possible impact of shale gas production on human health has received some attention overseas. There are limited overseas data suggesting some increased health risk. There are no Australian data to suggest that major health risks are likely to arise from shale gas operations (a recent Australian CSG study did not indicate any significant health risk), but the issue should not be ignored. The potential for health impacts will need considered attention in Australia, including the collection of baseline information for populated areas that are likely to have nearby shale gas operations.

Monitoring of shale gas production and impacts is likely to be undertaken by petroleum companies as part of their normal operations, but in order to win community confidence, truly independent monitoring will need to be undertaken by government or other agencies and/or credible research bodies. Induced seismicity, aquifer contamination, landscape and ecosystem fragmentation, greenhouse and other emissions to the atmosphere, together with potentially adverse social impacts, are all likely to be areas of community concern that will need to be monitored and for which baseline surveys will be required. It will not be feasible to monitor large areas for extended periods of time and therefore monitoring will need to be carefully and cost effectively targeted to answer specific questions and transparently address particular concerns. This will require a robust regulatory regime, which will build on existing regulations and which will also fully take account of the need for sensible and multiple land use, based around well-resourced regional planning and cumulative risk assessment. The regulation of abandoned wells, the abandonment process and the long-term prospect of 'orphan wells' are topics that require more careful consideration by regulators. A difficulty for governments if a

shale gas industry rapidly expands, will be to find regulators with appropriate experience. It is in the interests of government and industry to ensure that this issue is addressed, particularly to ensure that companies less experienced in shale developments can be enabled to follow best practice.

Whilst there are no major technology gaps that relate to shale gas production, there are significant gaps in our knowledge of the way that sedimentary basins work and exploring for and producing shale gas will provide an unprecedented opportunity to undertake research and gather large amounts of new information on Australia's most important sedimentary basins. This will be of great value to the future assessment and management of landscape biodiversity and water resources particularly groundwater. Further research towards improved strategic accumulative risk

assessment tools and methodologies that can assist in the minimisation of biodiversity loss, is an identified knowledge gap. Governments will need to take steps to adequately curate this new information, including perhaps placing requirements on industry to ensure that data is not lost and is made available. The same applies to the large amount of baseline and monitoring data that will be collected which will need to be over extended periods. New research will be important in addressing some of the particular issues facing the shale gas industry, such as understanding how shale gas systems work, developing innovative ways to minimise greenhouse gas emissions and ecological impact, improving ways to monitor hydraulic fracturing, particularly at high subsurface temperatures and establishing better ways to ensure resilient systems and minimise adverse impacts. A major coordinated program of research should be initiated at an early stage.

Some people have raised the question "Why extract shale gas? Why not spend the money on cleaner renewable energy?" But that is not a question that was in the terms of reference of this Review. It has also been suggested that a "business as usual" energy mix should not be assumed for the future. This may be so, but it was not possible (or appropriate) for the Expert Working Group to consider this question given the terms of reference. Additionally it should be recognised that we already have a nascent shale gas industry in Australia and that the signs are that its momentum will increase. The Review did not gain the impression that shale gas in Australia will be a great bonanza that will be easily won. Rather it became evident that whilst shale gas has enormous potential, it will require great skill, persistence, capital and careful management of any impacts on ecosystems and related natural resources, to realise that potential. It will also need an informed and supportive community, and transparent and effective regulations and companion codes of practice. Provided we have all these in place (and the right rocks), shale gas could be an important new energy option for Australia.

Key findings

Supply and demand economics of natural gas

1. The discovery of very large shale gas resources and the exploitation of shale gas (and shale oil) reserves have transformed the energy market in North America and have the potential to have a major impact on global gas supplies. The Expert Working Group considers that there is a clear need for Australia to quickly move to better assess its shale gas resources and reserves and to consider their potential social, economic and environmental impact, whilst exploration in Australia is still at an early stage.

2. There are currently three independent domestic gas markets in Australia – the western and northern markets already linked to export markets for gas through LNG production and exports and the eastern market, which has a significant domestic customer base but will also soon be linked to LNG export via facilities at Gladstone, Queensland. Shale gas resources (and more modest tight gas resources in some basins) have the potential to contribute to all three of these markets.
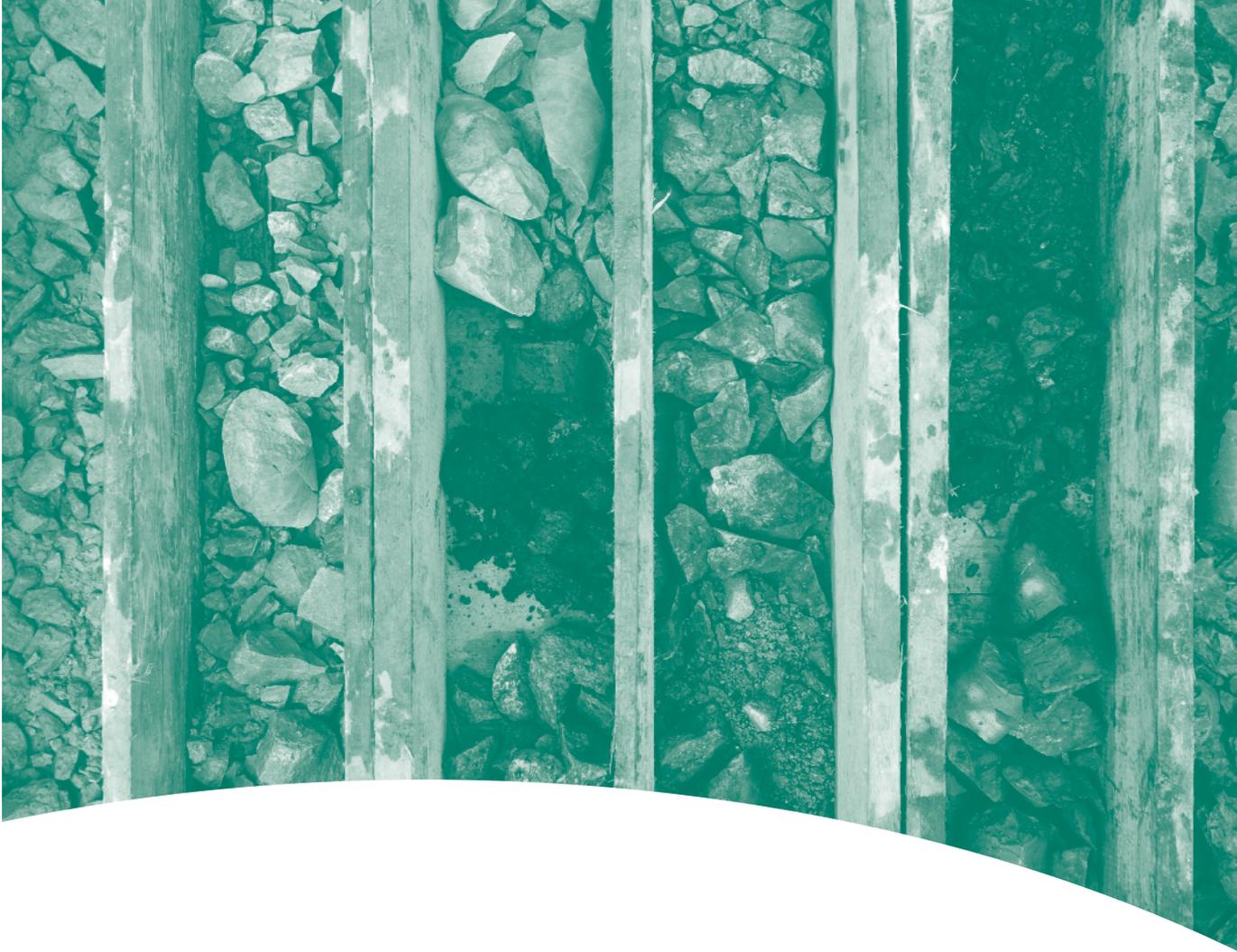
Reserves and resources

3. The Expert Working Group recognises that not all coal seam gas (CSG) reserves have been announced, but current Proven and Probable (2P) CSG reserves for Eastern Australia are almost fully committed to Liquefied Natural Gas (CSG-LNG) export requirements over the next twenty years. This tightness in the market could be compounded by movement from coal-fired to gas fired power generation and by declining conventional gas production. At the same time gas prices will rise, with significant flow-on effects to domestic retail electricity and gas prices. There will be an opportunity for cost competitive shale gas to contribute to this need for additional east coast gas.

4. The projected cost of producing at least some of Australia's shale gas reserves is at or below some future gas price projections for Eastern Australia, and shale gas will contribute to Australian gas supplies in the coming decades. Shale gas could be available to both Western Australia and the Northern Territory as a potential new domestic energy source, particularly for some of the more remote energy users.

5. Australia has a number of sedimentary basins, particularly in northern, central and western Australia, which are prospective for shale gas, based on the abundance of shales, their likely maturity and their total organic carbon content. Because of its established infrastructure (such as the gas processing facility at Moomba and pipelines), shale gas (along with tight gas) in the Cooper Basin could be the first to be developed at a large scale.

6. Although the most prospective Australian shale gas basins are located inland, in arid sparsely populated areas, it is likely that some shale gas resources will also be found in more densely populated parts of Queensland, New South Wales, Victoria and SW Western Australia and the presence of existing gas infrastructure there, could mean that it may be economic to develop shale gas in these areas as long as social and environmental issues are appropriately addressed.

7. Estimates of Australian shale gas resources are considerable, but have a high degree of uncertainty attached to them. The commonly cited undiscovered resource value of 396 tcf(trillion cubic feet) of gas is based on only four basins, but if all prospective basins are considered, the undiscovered resource could be in excess of 1000 tcf. Reliable economic reserve figures for shale gas are not available, largely because there has been little or no exploration or drilling in most basins. The Expert Working Group considers that there is an urgent need to encourage shale gas exploration in Australia to provide a clearer picture of the extent of the resources and to safeguard Australia's position as a major world gas exporter and to improve resource and reserve estimates.

Technology and Engineering

8. The Expert Working Group considers it unlikely there will be technology barriers related to gas production that will inhibit the development of a shale gas industry in Australia. The central technology components developed by industry for shale gas extraction, namely well drilling, well completion, hydraulic fracture stimulation and production, including real-time sensing technology to monitor and minimise risks, will be applicable in Australia. However, some of these existing technologies and exploration models will need to be tailored to suit particular Australian geological, environmental and economic conditions.

9. A key breakthrough in the United States has been to reduce the time and cost of shale gas extraction by drilling a number of deep horizontal wells from a single pad. Horizontal shale gas wells require an *in-situ* stress regime that sustains vertical fracture planes at the many fracture stages along the lateral length. Local stress regimes in parts of some Australian basins may lead to fractures developing significant horizontal components; this results in less efficient extraction of gas. Whilst this will not necessarily be the case throughout a particular basin, or in all Australian basins, knowledge gained from Australian shale gas wells in the near future will considerably clarify the situation.

10. In addition to shale targets, overlying and underlying rock formations, in some basins such as the Cooper Basin, contain tight gas in deep low permeability sandstones, which similarly require hydraulic fracturing for extraction. This vertical column of deep gas-bearing strata, with higher permeability than shale, can be accessed by hydraulic fracturing at several depths in the same well bore; this is compatible with drilling a number of near-vertical wells from a single pad.

Infrastructure considerations

11. Access to appropriate drilling rigs may delay the early development of the shale gas industry.

12. Pipe line and road networks are much less developed in Australia than in the United States and this will have a significant impact on the rate of development of shale gas in remote regions where much of the shale gas opportunities are likely to be found and on access to potential gas consumers. However, there are opportunities to utilise the road, rail, human resources and water infrastructure that will be required to also develop and assist other local industries and community amenity.

13. Although many skills will be transferable from the CSG industry, access to a skilled workforce is likely to be an issue for the shale gas industry in specialist areas such as hydraulic fracturing and will need consideration by the education and training sector and governments. The industry should be encouraged to provide on-the-job experience to graduates and tradespeople.

14. An Australian shale gas industry could provide direct employment to thousands of people. However, Australia currently lacks some of the essential skills and the domestic capacity to cost-competitively manufacture much of the drilling, production and transport infrastructure that would be required by a major expansion into shale gas production.

Financial analysis of shale gas

15. An important parameter dictating the threshold gas price that would make shale gas economic is capital intensity, that is, the ratio of drilling and completion costs to initial gas production. At present, based on limited recent production data and forecast drilling costs, the capital intensity for shale gas extraction in Australia is significantly higher than in the United States.

16. Shale gas production differs from conventional gas and CSG in that the shale gas well production decline rate is rapid, meaning that capital expenditure needs to be approximately maintained each year because of the need to drill and complete new wells to maintain production from a field.

17. Natural gas liquid (NGL) content in shale gas is important, since the market for shale oil, condensate and liquefied petroleum gas (propane and butane) can be a driver of overall shale gas economics. The market for ethane from shale gas is less certain and the potential to value-add through production of chemicals would depend upon the price of ethane versus the price of natural gas and the competitiveness of a domestic chemicals industry.

18. Sustainable shale gas development in Australia requires that suppliers receive a price for the gas they produce that at least covers their marginal cost of production. Best estimates of the current wellhead costs of production of Australian shale gas, range from around $6/Gigajoule (GJ) to about $9/GJ. By comparison, the wholesale gas price for long-term contracts of gas for the domestic market in eastern Australia is around $4/GJ while current eastern Australia domestic wholesale prices are about $6/GJ and the current netback price for Australian gas exported to Japan is around $10/GJ. Based on these estimates, development of Australian shale gas marketed on the east coast is unlikely to occur until domestic and international netback prices are equalised (assuming international netback prices remain above about $10/GJ in real terms).

19. It has been suggested that reserving a proportion of Australia's shale gas could be a way of providing Australia with cheaper and more secure energy but the Expert Working Group was not persuaded that this was a practical mechanism, given that modelling suggests that for eastern Australia at least, shale gas prices would need to be approximately double the existing gas price to provide an economic return. Government and industry cooperation in the development of shale gas infrastructure warrants consideration.

Landscape and biodiversity

20. Strategic Environmental Assessment prior to development, including the use of cumulative risk analysis tools applied at the catchment and appropriate regional scales, are now technically feasible. Provided they are supported by an enabling regulatory environment and spatially adequate and explicit ecological, hydrological and geological data, these tools and the social consideration involved, have the potential to contribute to the management and minimisation of regional environmental impacts arising from shale gas developments.

21. Shale gas developments can extend over large land areas and have aggregated and cumulative environmental impacts through surface disturbance and clearing of native vegetation for drilling pads, roads, pipelines and related infrastructure. These activities need to be effectively managed to avoid impacts such as destruction and fragmentation of habitats and the overall landscape function, loss of threatened species habitats and ecological communities or an increase of invasive species. The use of cumulative risk assessment and best practice in minimal impact infrastructure will be crucial to the future of the shale gas industry.

22. The potential exists for conflicts between current land, water and infrastructure use and competition by new multiple or sequential uses (e.g. traditional land owners, conservation, agriculture, other resource projects, tourism and urban development). The shale gas industry, governments and the community needs to learn from experience of the CSG industry to avoid these conflicts. Use of best practice tools including cumulative risk assessment and strategic land use planning and policies such as the proposed Multiple Land Use Framework developed by the Land Access Working Group under the Standing Council on Energy and Resources should assist to resolve potential conflicts.

Water

23. The volume of water required to hydraulically fracture shale gas strata can be an order of magnitude larger than that for coal seam gas depending on well depth and extent of horizontal drilling. Conversely, the total volume of produced water in shale gas operations is orders of magnitude less than the total amount produced during CSG operations. The information available to the Expert Working Group leads it to conclude that while initial extraction of water for

shale gas operations will be significant, shale gas operations will not be faced with the ongoing disposal and subsequent replacement of large volumes of produced water as is the case for CSG operations.

24. During the early stages of shale gas operations, the large quantities of water (including saline water) used for hydraulic fracturing will need to be extracted from surface and/or groundwater resources. The extraction and subsequent disposal will need to be managed within regulatory processes including water entitlements (in most circumstances) and aquifer management plans in order to minimise changes to flow regimes and the potential for contamination of aquifers.

25. Contamination of freshwater aquifers can occur due to accidental leakage of brines or chemically-modified fluids during shale gas drilling or production; through well failure; via leakage along faults; or by diffusion through over-pressured seals. Contamination of terrestrial and riverine ecosystems may occur from spills associated with chemicals used during the early stages of production; from impoundment ponds and holding tanks; and because of the volume of traffic needed to service operations. The petroleum industry has experience in managing these issues and remediating them, but in a relatively new shale gas industry, unanticipated problems may arise and it is important to have best practice in place, to minimise the possibility of this risk.

26. All gas wells pass through aquifers ranging from freshwater to saline and at depths ranging from very near surface (tens of metres) to deep (hundreds to thousands of metres), and are subject to well integrity regulation. In important Australian basins such as the Cooper-Eromanga Basin, in addition to surface aquifers, shale gas wells (like conventional gas wells) pass through deep aquifers of the Great Artesian Basin. To minimise the risk to this vital groundwater

resource, best practice should be adopted in both well integrity and the use of sensing technology to accurately and closely monitor the hydraulic fracturing process, particularly the potential for extended vertical growth of fractures.

Induced seismicity

27. Although there is ample evidence in Australia of induced seismic activity associated with large dams, mining operations and geothermal operations, there is currently no seismic risk data for gas-related activity in Australia, such as hydraulic fracturing operations. Overseas evidence suggests that induced seismicity of magnitude 3 to 4 can be generated by the reinjection of large volumes of produced water in deep wastewater wells or in geothermal operations, particularly at or near a critically-stressed fault, but hydraulic fracturing is unlikely to lead to damaging or felt seismic events. Best practice mitigation involves better knowledge of fault structures close to disposal sites, and control of volume and pressure of produced water re-injection.Such measures should, when necessary, be put in place for shale gas.

28. Overseas evidence from extensive shale gas operations documents only a few cases involving low magnitude seismic events, where the hydraulic fracturing process itself has resulted in induced seismicity. These few events have been linked to the intersection of active fault structures by hydraulic fractures. Best practice mitigation involves the identification and characterisation of local fault structures, avoidance of fracture stimulation in the vicinity of active faults, real-time monitoring and control of fracture growth through available sensing technologies and the establishment of 'cease-operation' triggers based on prescribed measured seismicity levels. Such best practice approaches will need to be utilised in Australia.

Greenhouse gas emissions

29. Like all other natural gas activities, the production, processing, transport and distribution of shale gas results in greenhouse gas (GHG) emissions. In addition, shale gas can also generate emissions associated with the hydraulic fracturing and well completion processes, particularly during the flowback stage prior to gas production. The magnitude of the emissions is not known with great accuracy and published results normally include wide uncertainty bands. Initiatives have commenced in Australia to collect greenhouse gas data for CSG but all of the available data for shale gas is from overseas, and its applicability to Australia is not clear. Data applicable to Australian conditions will need to be collected to monitor and comprehensively report emissions and to have strategies to mitigate risks.

30. In general terms the GHG emissions associated with combustion of natural gas to generate energy are greater than emissions occurring during production processing, transport and distribution, and in turn these are greater than those emissions generated during the flowback stage and the pre-production stage. Total lifecycle analysis (LCA) of emissions has limited sensitivity to very substantial differences in emissions at well completion. Emissions, particularly during the flowback stage, can be ameliorated by the implementation of best practice strategies such as the use of so-called "green completions", including the adoption of emission capture and/ or flaring rather than venting. Some Australian shale sedimentary basins may also contain high CO_2 levels, which will need to be removed from the gas before transmission via pipeline;CO_2 sequestration is a possible process strategy.

31. There are uncertainties in estimating the total lifecycle greenhouse gas (GHG) footprint of electric power generating technologies. These uncertainties are quantified for a number of technologies

in this report. The implications, based on the mean valuesof the total lifecycle GHG footprint (from distributions of uncertainty) of the use of shale gas for electricity production (with green completion schemes) are: emissions will be approximately 10% to 20% higher than that of conventional gas; higher efficiency combined-cycle gas turbines will have approximately half to three quarters the emissions of black coal, and; open-cycle gas turbines will have approximately 70% to 90% the emissions of black coal. Based on an analysis of uncertainty there is a low chance that the performance of somecombined cycle gas turbines (CCGT) using shale gas in the future will have larger emissions than higher efficiency black coal sub-critical generators.

32. Government projections indicate that gas may grow to 30% of the technology mix by 2030. Based on gas supplying either 30% or 50% of electricitygeneration in 2030, analysis indicates that this could lead to reductions of either 27% or 52% respectively in terms of the current GHG emissions for electricity production– based on gas replacing coal-fired generation. These are mean value estimates (from distributions of uncertainty) and are applicable to low values of CO_2 in the gas stream being vented to atmosphere during processing.The large amount of gas required for this to occur could be provided, in part, by shale gas.

Community issues

33. Gaining and retaining a 'social licence to operate' will be crucial to all shale gas projects. It will not be possible for a shale gas development to be approached as just a 'local issue' given that there will be stakeholders at the regional and national and global levels whose views will need to be taken into account. Experience with other resource projects demonstrates that a 'one size fits all' approach to communication

and engagement will not work for shale gas; different groups will have different concerns and will require different communication strategies. Respect and transparency are critical elements of effective engagement.

34. Building trust is key to securing a social licence for any major resource project, including shale gas project developments, and it is essential to have a transparent approach to collection and dissemination of reliable data. Many people are distrustful of the information provided by industry and government and also from research and academic bodies where there is a perceived close financial relationship with industry. Communities are more likely to accept information as credible if it comes from a source such as CSIRO or universities, but only if they are perceived to be truly independent. Opportunities should also be explored to involve local people and landowners in the collection and understanding of environmental monitoring data, as this has also been shown to increase trust.

35. There is an opportunity to initiate a dialogue at both the national and regional level to develop one or more linked narratives around shale gas that go beyond economic contribution or energy security. The dialogue could focus on how shale gas development might be used to address other societal priorities, such as enhancing productivity of agricultural regions, enabling development in remote regions of Australia or facilitating the transition to a low carbon economy.

36. If shale gas development is to occur on a large scale in Australia, it is likely that much of this will occur on lands over which Native Title has either been recognised or is subject to a claim pursuant to the Native Title Act 1993, or which are designated Aboriginal Lands under the Aboriginal Land Rights (Northern Territory) Act 1976.Understanding Indigenous parties' aspirations, and ensuring that the parties have an informed understanding of the scale of the proposed

project and the expected impacts, should be the starting point for any developer seeking to enter into an agreement with traditional owners. There is potential to use shale gas developments to help address the aspirations of Aboriginal people to build greater economic self-sufficiency. In addition to direct employment in the sector, there may be significant opportunities for Aboriginal people to be engaged in land protection and rehabilitation activities associated with shale gas projects.

37. The issue of compensation for landowners directly affected by resource projects such as shale gas, is complex and controversial. There is a need to consider whether current compensation schemes are appropriate and whether there could be a system that would provide more direct returns to communities most impacted by shale gas projects.

Monitoring, governance and regulation

38. Emissions of hydrocarbons and other atmospheric pollutants can arise from shale gas extraction and production as they can arise from other forms of production. The possible impact of shale gas production on human health has received some attention overseas. There are limited overseas data suggesting some increased health risk. There are no Australian data to suggest that major health risks are likely to arise from shale gas operations (a recent Australian CSG study did not indicate any significant health risk), but there will need to be health risk assessments (particularly where shale gas production takes place in populated areas), together with baseline monitoring including local and regional atmospheric monitoring regimes and transparent reporting of pollutants.

39. A number of the activities associated with shale gas exploration development and production have the potential to have an adverse impact on the natural and the human environment and therefore it is essential that shale gas activities are carefully and comprehensively monitored and transparently regulated to best practice. These include monitoring of surface and subsurface water, air quality, greenhouse gas emissions, and seismicity.The current lack of baseline data in many areas and lack of information on natural variability in particular need to be addressed. Many existing Australian regulations for onshore conventional and unconventional gas production will be applicable to shale gas. Nonetheless the overlapping and regional aspects of shale gas impacts will confront Australian regulators with new challenges.

40. The likelihood of shale gas operations producing damaging induced seismicity is low; but there is a need to better understand and mitigate the risk of induced seismicity and this will require site, local and regional monitoring of earthquakes at a far greater resolution in key areas than is currently the case in Australia. It is also important to address uncertainty, including through the use of remote sensing technology, and close monitoring of the hydraulic fracturing process.

41. At the present time there is a lack of reliable dataon the release of methane and related hydrocarbons to the atmosphere along with other gaseous constituents. There will be a need to implement baseline and ongoing atmospheric monitoring of shale gas because of the nature of the production process, together with a code of practice for the management of GHG emissions.

42. The concept of risk-based and play-based regulation proposed by Alberta could be applicable to the Australian regulatory framework for shale gas and warrants further consideration. The related issue of orphan wells also requires further consideration and the trust fund approach adopted by Alberta may be appropriate for Australia.

43. There are effective regulations in place covering abandonment for conventional gas wells, but shale gas regulations will need to take account of the fact that there could be hundreds of abandoned wells, many of them penetrating major aquifers; long term monitoring will be needed.

44. There are opportunities to learn from the CSG experience in Queensland, including what appear to be some of the more significant initiatives such as the Gasfields Commission, the establishment of regional and local consultative committees, the Royalties for Regions Program and the use of Social Impact Management Plans to proactively address anticipated impacts. A more direct financial return to communities most affected by shale gas developments may facilitate ongoing access and maintain the social licence to operate.

45. Shale gas developments will need to work within a robust legislative and regulatory framework to ensure sensible and equitable multiple land use, based around well-resourced regional strategic biophysical and geological resource planning and cumulative risk assessment.

46. Exploring for and producing shale gas will provide an unprecedented opportunity to acquire subsurface information on some of Australia's most important sedimentary basins, that will be of great value to the future assessment and management of major resources, such as ground water. To capture and curate this information will require new measures by government, including new requirements on industry to ensure that this information is not lost and that it can be made publicly available.

47. Most governments have only limited experience in regulating shale gas (or tight gas) production. Government and industry need to jointly address this issue, particularly to ensure that new companies with only limited experience of shale gas are effectively regulated as these companies gain experience.

Knowledge Needs

48. While techniques and practices used in other countries will need to be adapted in some cases to Australian conditions, there are no major technology gaps relating to shale gas production which would constitute grounds for delaying the development of a shale gas industry in Australia. However, there are knowledge gaps in the environmental and social areas that will require the collection of more data and additional research to ensure that the impact of the industry is minimal and that any potential difficulties can be adequately remediated, or stopped if a significant threat were to arise, so that the industry and the community can move forward confident in the knowledge that resilient systems are in place.

49. It is important to start collecting baseline information and undertake researchnow on groundwater chemistry, ecological systems, landscape changes, methane emissions and seismic activity, at a level of resolution and accuracy that would enable any future impacts to be clearly identified at an early stage.

50. This report catalogues potential hazards that might arise from shale gas activities, but other than for operational risk (where industry has extensive data and well established risk management strategies in place) there is little or no information available to quantify the likelihood of an environmental or health event occurring or the impact of that event. Industry, regulators, environmental authorities, scientists and the community need to collect data to quantify the risk of an event occurring, so that a full and transparent risk management approach can be developed for shale gas projects.

51. Well abandonment is not just a regulatory issue but is also an issue that requires more research and development in areas such as the very long-term behaviour of cements and extended monitoring under hostile subsurface conditions.
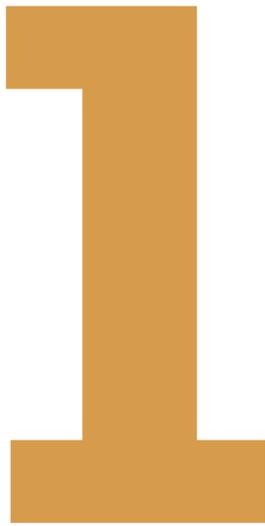
1 Introduction

The discovery of major new resources of natural gas in North America has transformed the United States energy market (US Energy Information Administration, 2011). These resources, primarily unconventional gas (especially shale gas, accompanied in some areas by shale oil) have the potential to have a major impact on future global gas supplies and for this reason, a number of other countries have started to assess their own unconventional gas resources, with a particular focus on shale gas (Nakano, *et al*., 2012).

Australia already has defined massive economic reserves of conventional and unconventional natural gas (Department of Resources, Energy and Tourism, 2012) and the prospect and impact of a major new gas source such as shale gas, warrants careful consideration; including the potential future availability and pricing of gas and related market uncertainties, together with the potential environmental, social, and human risks. While there is a vigorous debate underway on what might be a preferred future energy mix for Australia (Department of Resources, Energy and Tourism, 2012), this Review was not asked to consider the relative merits of all energy sources; its terms of reference relate very clearly to unconventional gas and with a particular focus on shale gas. Shale gas (and shale oil)
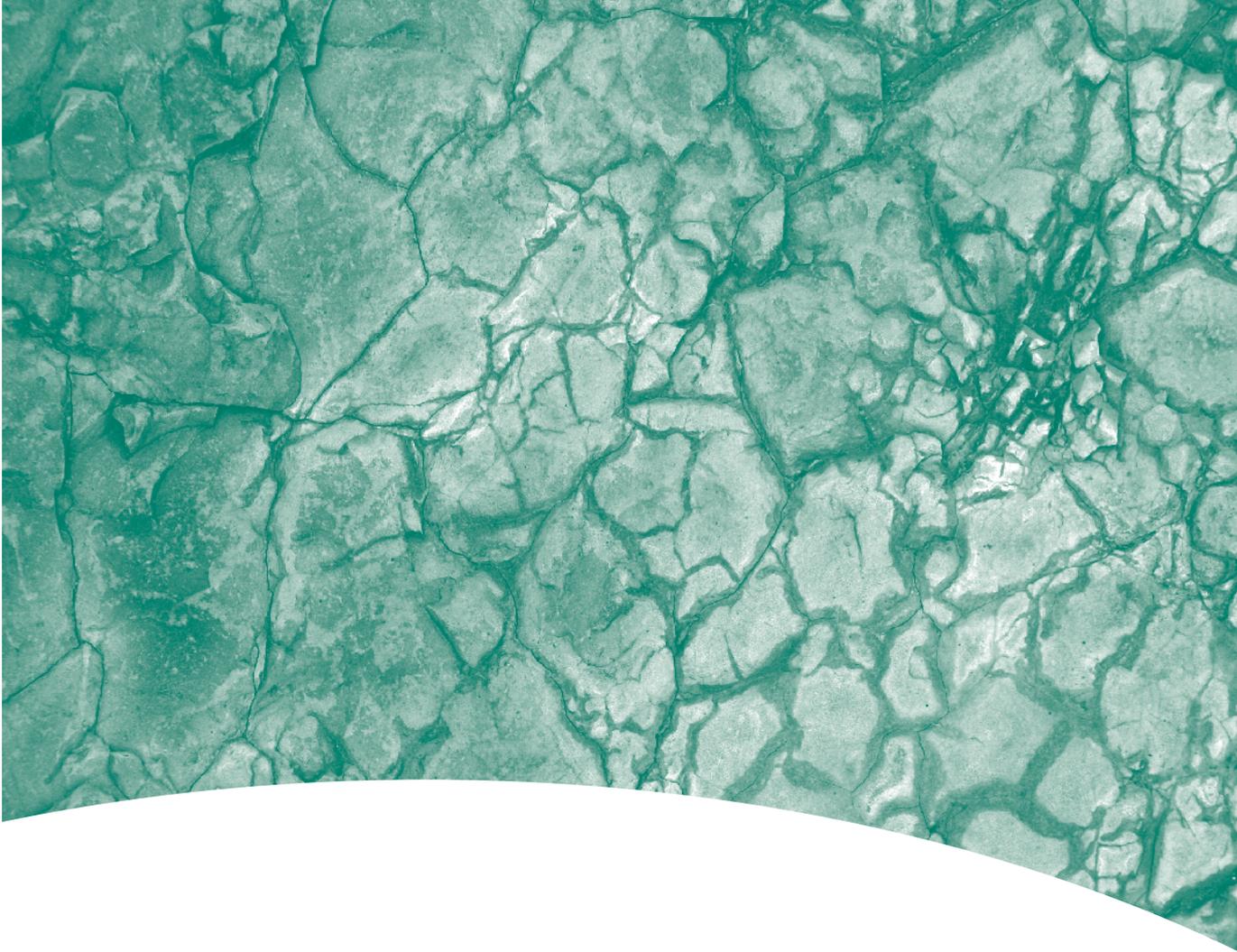
exploration (together with tight gas exploration) is already underway in Australia with some early successes, and therefore it could be argued the issue is less about will there be a shale gas industry in Australia and more about what form the industry should take. Accordingly, it is important to examine the potential future size this industry might be, what benefits it might bring with it, what adverse impacts might arise and how they might be prevented or minimised.

There is of course an underlying and in some ways an overarching issue, namely how might a shale gas industry win and retain the social licence to operate? This will require the development of a shared vision for the future of natural gas, particularly shale gas, amongst key stakeholders, which will in turn need, amongst other things, a transparent regulatory regime and an acceptable balancing of social, economic and environmental benefits and impacts.

Bearing all this in mind, the fact that shale gas exploration is underway (and the remarkable speed with which the gas situation changed overseas), it is necessary for Australia to now quickly move to better assess its shale gas resources and reserves and consider what the positive and the negative impacts might be if they are developed. The role of shale gas as a component of the portfolio of Australia's natural gas assets also warrants consideration in the context of regional energy supplies as well as its potential impact on globally significant issues such as greenhouse gas emissions.

The Australian Council of Learned Academies (ACOLA) and its ability to bring together experts across a wide range of disciplines, was seen as the appropriate vehicle for undertaking such a Review and this report sets out the main findings. At the same time it is important to point out that the time frame within this report was prepared

Figure 1.1: The range of conventional and unconventional hydrocarbons

Conventional			Unconventional			
			CSG	Tight	Shale	Methane Hydrate
Gas	Oil		Gas	Gas / Oil	Gas / Oil	Gas
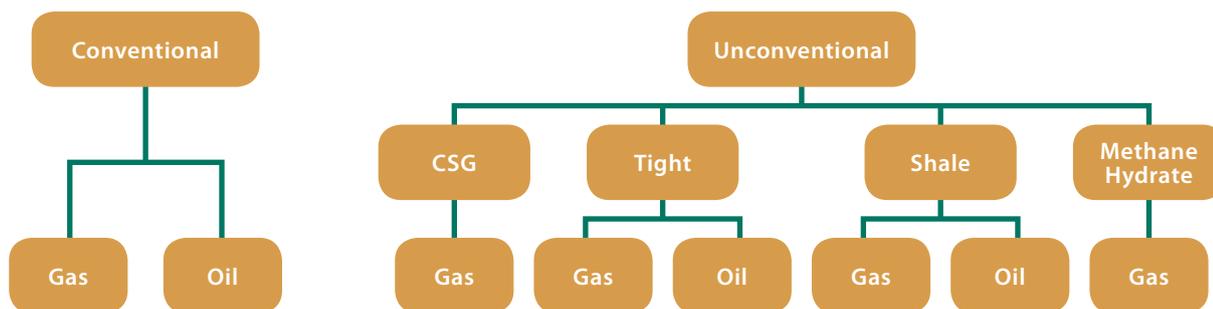
(less than six months), was quite short compared to other national reviews and it does not claim to consider every issue in detail or to have all the answers. A number of areas were identified where evidence was sparse (such as health issues), or where the Expert Working Group did not have sufficient time to address matters, such as the full range of industrial opportunities that might arise from a shale gas industry.

In order to further set the scene of the Review, it is appropriate to consider some of the broader gas related issues including the question of why this Review has focused on shale gas, given that its terms of reference refer to unconventional gas.

Natural gas is found overwhelmingly in sedimentary basins, in a number of geological settings and within various rock types. It is important to note that it is largely the rock type and the trapping mechanism which defines whether a gas is regarded as "conventional" or "unconventional" (Figure 1.1) and not the composition of the gas. All natural gas is composed predominantly of methane (CH_4), with variable but usually only minor quantities of other hydrocarbons.

Conventional natural gas (and oil) is trapped in porous and permeable reservoir rocks, such as sandstones, in favourable geological structures or traps, such as anticlines, and within sedimentary basins. Porosity is the space between the grains that make up a reservoir rock, in which fluids such as water or gas occur. The higher the porosity, the greater the quantity of a fluid, whether water or hydrocarbons, that can be potentially trapped within the rock. Permeability is a measure of the level of interconnectivity between the pores and is an indication of the

ease or difficulty encountered in extracting fluids from the rock, or injecting fluids into the rock. The higher the permeability the easier it is to produce gas or liquids from a rock. Typically, the gas (and associated oil) in conventional oil or gas reservoirs is found in sandstone, less commonly in limestone, with high porosity and high permeability. The depth, pressure and thermal history within a sedimentary basin defines whether oil or gas is likely to have been generated from the remains of ancient algal bacteria and plants, and then migrated within the basin; the structure of the basin determines whether generated oil or gas is likely to have been trapped. To date, most of the gas that has been produced, globally and in Australia, has been conventional gas. Conventional gas and conventional oil has underpinned twentieth century economic and social development.

Unconventional gas includes shale gas, tight gas, coal seam gas (CSG) and methane hydrates; all of them composed predominantly of methane (US EIA, 2011a). They are found in a variety of geological settings (Figure 1.2). Methane hydrate occurs in vast quantities under the deep continental shelves in various parts of the world and in onshore or near-shore locations at high polar latitudes. It presents a number of unique technical challenges and is not currently being exploited. Methane hydrates may be an important energy source in the long-term but are not considered in this report. The other non-conventional hydrocarbon resource not considered in this report is oil shale, which is a fine-grained rock type mined at quite shallow depths then retorted, or subjected to *in situ* thermal treatment, to release the hydrocarbons.

Tight gas (and tight oil) is not dissimilar to conventional gas, in terms of geological setting, except that the reservoir sand has a low permeability, meaning that it more difficult to extract the gas than is the case for conventional high permeability sands. Tight gas has been exploited for some decades, including in Australia, and is fairly well understood. It also has a number of similarities with shale gas in terms of production processes such as the use of hydraulic fracturing and for example in the Cooper basin, tight sands occur in close geological proximity to shale gas.

Coal seam gas (CSG) occurs within coal seams, adsorbed onto organic particles, in the formation waters, and also within cleats or fractures and cracks within the coal. Most, though not all coals have a low permeability and to produce the methane it is usually necessary to dewater the coal by extracting the formation water and lowering the water table in the vicinity of the drill hole in order to depressure the coal and induce gas flow. It is also frequently necessary to drill horizontal wells and in some instances

to also hydraulically fracture the well to increase the permeability of the coal and maximise the volume of the rock from which the CSG (methane) can be extracted. CSG is exploited in many parts of the world including Australia, where there has been a massive increase in the amount of CSG extracted in recent years, particularly in Queensland (Department of Resources, Energy and Tourism, 2012).

Shale gas, sometimes together with shale oil, occurs in very fine-grained low permeability organic-rich sediments, such as shales mudstones and silty mudstones, usually in deeper parts of basins. Gas was formed when the organic matter within shales was subjected to high temperatures and pressures, but unlike in conventional deposits, the gas or oil remained within the impermeable shale. In other words the shale is both the source rock and the reservoir rock. It is therefore necessary to create permeability to allow the gas, or oil, to flow from the rock. This can be done by hydraulically fracturing (fracking) the rock to create an artificial reservoir composed of fine fractures; a favourable stress field and the presence of brittle

Figure 1.2: Geological settings for unconventional gas
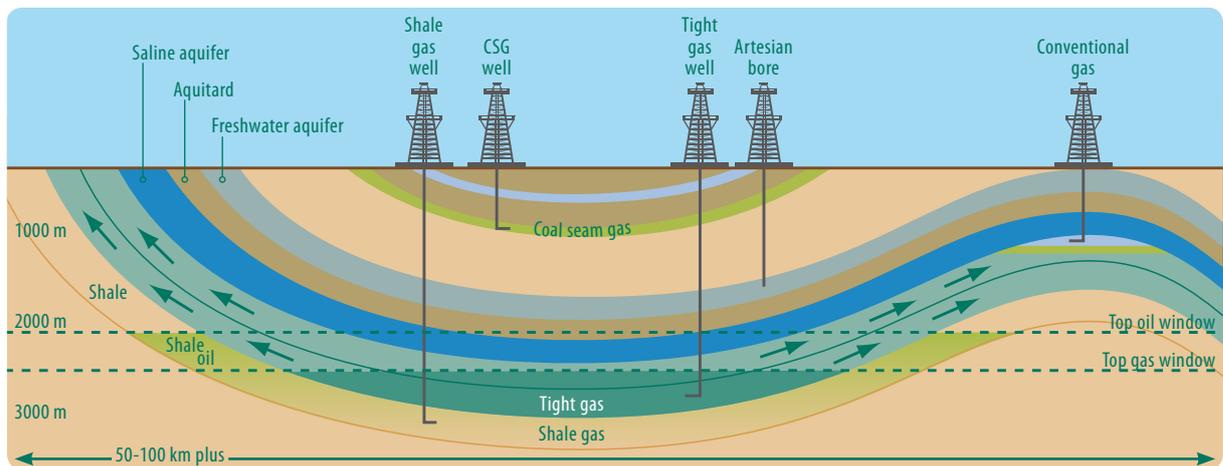
Source: US Energy Information Administration 2010.

Shale oil is *not* oil shale

This report considers *shale oil* – the oil found at very deep levels underground in combination with shale gas. It does not consider *oil shale* – this is a rock generally mined at quite shallow depths of tens of metres then retorted, or subjected to *in situ* thermal treatment, to release the hydrocarbons.

rocks within the shale, facilitates the hydraulic fracturing and the subsequent extraction of the shale gas and shale oil.

Whilst it is possible to classify these various types of unconventional gas (Figure 1.1), in reality the distinctions between shale gas, tight gas and coal seam gas is not always clear and they can be found in close proximity to each other. Further, unconventional gas is often found in basins in which conventional gas occurs and as pointed out earlier, no matter what the gas 'type', in every case the predominant hydrocarbon is methane. One approach might be to consider them all simply as "onshore gas", given that they have many technical and developmental issues in common. However the terms 'conventional' and 'unconventional' are well established, as are the terms 'shale gas' and 'coal seam gas' or 'CSG'. Although they may occur in close association, shale gas, tight gas and CSG are distinguished by the properties of the host rock, the amount of associated water and to a lesser extent by the technologies and processes that are used to produce the gas. Therefore, whilst there are many similarities, there are significant differences between them, in terms of exploration, production, economics and environmental impact. To attempt to deal with all gas under the single heading of 'onshore gas', whilst providing the opportunity for a simpler communications strategy, could also be seen as inconsistent with widely accepted terminology and possibly even disingenuous. Therefore the terms used throughout this report are shale gas, shale oil, CSG, tight gas and tight oil.

Why then, given that the remit of the Review is to consider 'unconventional gas production' does this report focus on shale gas? Why not also consider CSG for example, given that in some areas, the CSG industry is facing challenges, such as those relating to land access or environmental and social impacts?

In the case of CSG, a great deal of work is underway in Australia at the present time and governments have put in place a number of mechanisms, scientific activities and communication strategies to address challenges currently facing the industry. Given the short time available to undertake the Review, it was considered that the opportunity for a review to add value to the current debate surrounding CSG was limited. CSG is not ignored in this Review, because there are many lessons, some negative, some positive, to be learned from the technical experience of the CSG industry and from its interface with the community over the past decade in Australia. This report discusses some of those lessons, but does not seek to add to the range of scientific, social and environmental discussions on CSG that are underway at the present time.

What about tight gas? Whilst there are some technical challenges, such as improving the extraction of tight gas, this is largely the realm of the petroleum industry, which is well aware of any technical issues and is working to address them. In addition it does not appear to face any unique environmental or social challenges and seems to operate satisfactorily under the present regulatory regime governing conventional oil and gas. An ACOLA Review was considered unlikely to add great value to the technical questions regarding tight gas at this time, though there are many similarities in the way that shale gas and tight gas are produced, including the need to hydraulically fracture in both cases.

Shale gas on the other hand, whilst it can be seen as just another component of Australia's gas portfolio, represents in many ways a major newly identified energy source that has already had a profound impact on the energy scene in the United States and is likely to do so in the future in other countries, including Australia (US EIA, 2011a; Shell International, 2013). Despite the fact that most of the technology applied to shale gas has been used by the industry for producing conventional oil and gas for decades, it is no exaggeration to describe its successful application to shales, as representing a paradigm shift in fossil fuel availability. At the same time, the community at large has also become aware not only of the potential importance of shale gas and the economic benefits that can be derived from it, but also of the possible social and environmental consequences of shale gas development, concerns reinforced by media reports about the triggering of earthquakes due to hydraulic fracturing or contamination of groundwater. These environmental concerns are considered later in the report.

In contrast to the United States, whilst there is some exploration underway in Australia and some early indications of success, for example in the Cooper Basin (Energy Resources Division (Department for Manufacturing, Innovation, Trade, Resources and Energy), 2012), there is as yet very little production of shale gas; we do not know a great deal about the geology of many of our deep shale-bearing basins; the economics are uncertain; it is unclear whether all existing technologies will be applicable; and there are uncertainties about the environmental consequences of shale gas developments.

Added to this, concerns have been expressed concern about potential environmental and social impacts, ranging from groundwater contamination (Osborn, *et al.*, 2011) to the impact of increased gas production and use on greenhouse gas emissions (Hughes, 2013; Hou, *et al.*, 2012). At the same time, governments and industry are eager to know whether the advent of a shale gas industry, could bring about new commercial opportunities, major economic benefits and/or a rebalancing of energy profiles, not just nationally but also internationally.

These are questions, concerns and opportunities that cut right across science, technology, social, ethical and economic issues. The debate around them is at a relatively early stage in Australia and is often hampered by a lack of reliable information, uncertainty in the minds of many people about what shale gas is and what it might mean to them. Consequently the potential is there for the debate to become polarised and politicised. Bearing all this in mind, there was considered to be merit in having an impartial, dispassionate and evidence–based review focused on shale gas which could potentially fill knowledge gaps, identify and consider community concerns; and address both the opportunities and the challenges that might arise from shale gas.

The remainder of this report considers in some detail the range of issues that the Expert Working Group believes will be important to governments, industry and the community regarding the future of shale gas in Australia and presents findings that it believes will help those considerations.

2

Global supply and demand economics of natural gas

The Global Scene

Natural gas accounts for 21% of the global primary energy mix, after oil and coal, and almost two thirds of it is produced in non-OECD countries. World natural gas reserves are estimated to be 27,900 tcf (790 tcm)[1], which at current production rates could meet demand and accommodate expansion for another 230 years. The principal driver of gas demand is the power generation sector, expected to grow at an average annual rate of 1.6% and therefore increase by 50% by 2035, assuming business-as-usual. The technical and economic advantages of gas-fired power make it an attractive source of energy in OECD countries, where it now accounts for about 80% of incremental power output. Industry is the end-use sector where the demand for natural gas is projected to grow the fastest, at an annual rate of 1.9% over the period 2010-2035 (IEA, 2012a).

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[1] Trillion (10^{12}) cubic metres. 1tcm = 35.3 tcf (trillion cubic feet, tcf). tcf = trillion (10^{12}) cubic feet. One cubic foot is equal to 0.0283 cubic metres.

The largest consumers of natural gas are the United States (21%) Russia (14%), Iran (4%), and China (3%). Over the period 2010-2035, global demand is projected to increase from its current level of 120 tcf (3.4 tcm) per annum to about 177 tcf (5 tcm) per annum, at a rate of 1.6% per year, driven by the power sector in most countries (IEA, 2012a). Asia/Oceania, accounts for 46.8% of the overall projected growth in global gas demand over the period 2010-2035, followed by the Middle-East and the rest of the world (26.7%), Europe/Eurasia (15.2%), and North-America (11%) (Figure 2.1). The rapid urbanisation of China makes its demand for residential and commercial gas a key driver of overall future demand. Over one-third of the global increase in gas use

in buildings during the period 2010-2035 is projected to be attributable to China (IEA, 2012a).

The key feature of the gas market on the supply side in the near future is the growth of North American unconventional (shale and tight) gas and increasing Asian demand, mainly from China, which is expected to have the highest growth in demand in absolute terms. China is also amongst the three largest holders of undiscovered resources of unconventional gas, with North America and Australia. Together the three will account for about 50% of the overall increase in global gas production. However, prospects for unconventional gas are uncertain and global (conventional) gas production will continue to be dominated by the Middle East

Figure 2.1: Projected world natural gas demand by region
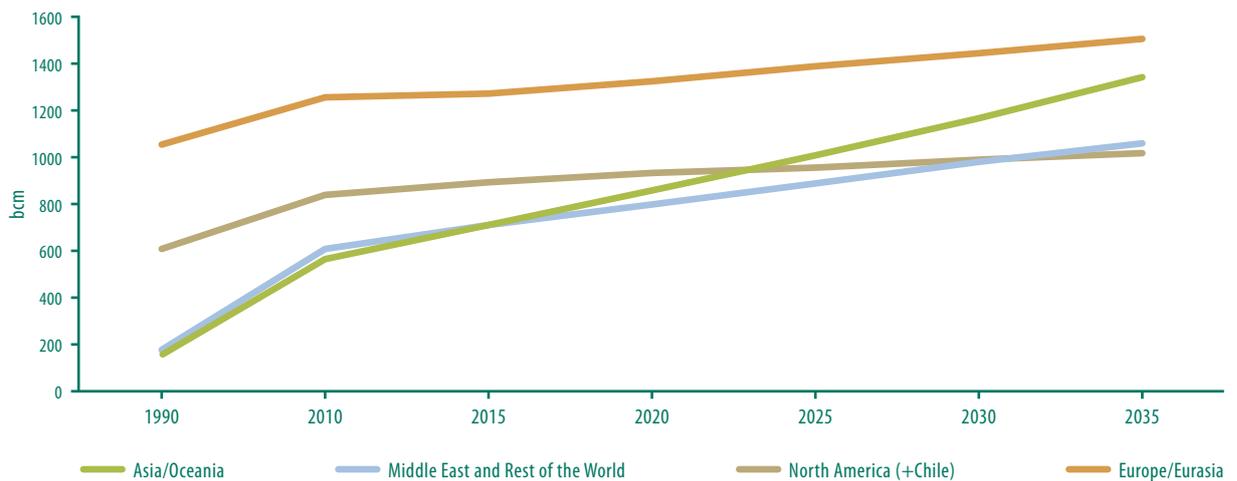
Figure 2.2: Projected world natural gas production by region
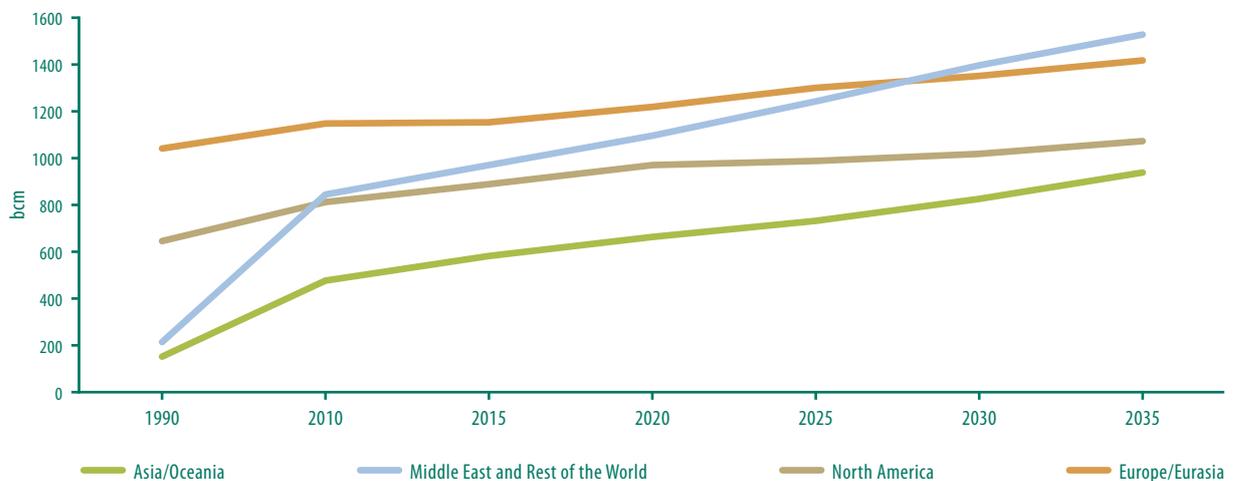
Source: International Energy Agency (IEA 2012a). IEA projections: New Policies scenario, under which current policies are maintained and new policy commitments (announced and/or recently introduced) are included. Examples of new policy commitments are national targets to reduce emissions such as the 2010 Cancun Agreements, renewable energy targets, gradually eliminating fossil-fuel subsidies as brought in by G-20 and APEC, or improving energy efficiency.

Figure 2.3: Wholesale gas prices in major OECD gas markets 2009-12
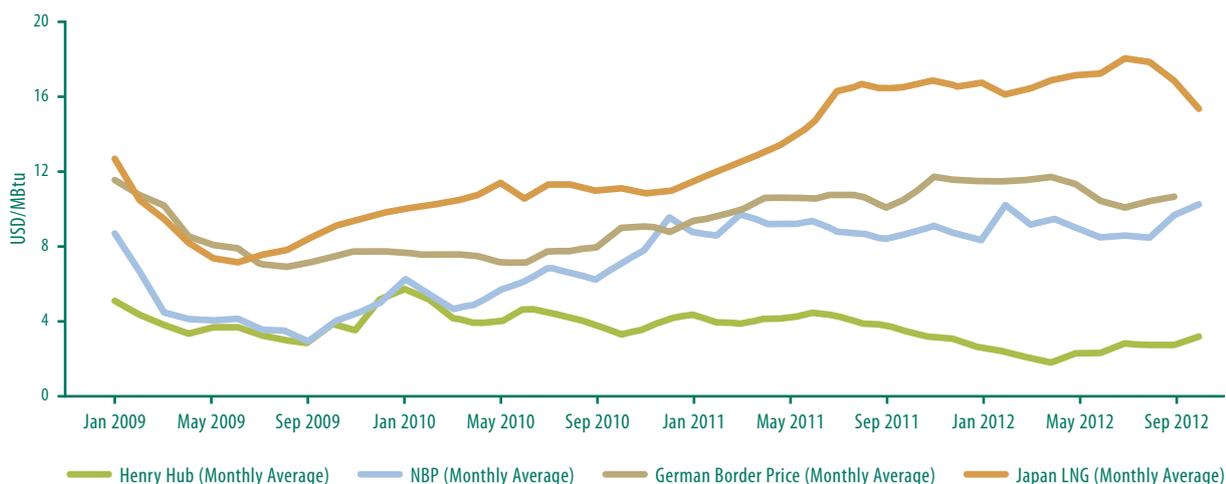
Source: International Energy Agency (IEA 2012a).

and Europe/Eurasia, the smallest holders of undiscovered unconventional gas resources (2% and 6% respectively) but the largest holders of remaining conventional gas resources (31% and 27% respectively) (Figure 2.2).

Future Price Evolution in International Gas Markets

There is no unified global market for gas as exists for oil, but rather a series of regional, unintegrated markets, with price competitiveness. These markets are nevertheless linked to some extent, and gas supply, demand and pricing decisions are influenced by developments and events far beyond their geographical regions. Each regional market has its own pricing rules.

LNG trade is usually done under medium- to long-term contracts, and spot markets and short-term contracts only account for 15-20% of total LNG trade. Half of global gas consumption is set either through gas-on-gas pricing (or *hub-based pricing*), determined by supply and demand, or set through oil indexing. The four major gas markets are: the Henry Hub (North America); the National Balancing Point (UK), the Japan LNG (Asia) and the German Border Price (proxy for continental Europe). Wholesale prices in these markets over the past four years are shown in Figure 2.3. The other half of global gas consumption is state-regulated. Gas-on-gas

pricing is the dominant mechanism and applies to 40% of domestically traded gas, while oil indexed pricing prevails on international markets, where it accounts for 70% of LNG trade and 60% of the pipeline trade.

In Asia-Pacific markets, oil indexation is the main pricing mechanism for LNG trade, sold under long-term supply contracts, and is likely to remain so for the foreseeable future. For instance, Japan LNG prices are tied to oil prices, hence their 2012 and early 2013 level at $US14-16/GJ[2]), which is well above the past peak levels of the Henry Hub, at $13.35/GJ in October 2005 and $11.65/GJ in June 2008. However, short-term and spot trade is rising and expected to become more important, which could help moving further toward a hub-based pricing mechanism, like the Henry Hub in North America. For this reason and because of the increasing LNG supplies in future, there are likely to be better price linkages across markets and a certain degree of convergence between regions (Bureau of Resources and Energy Economics, 2012c). Within two decades, inter-regional trade is expected to increase by 80%, which is faster than demand, set to grow by 50% within the next two decades. LNG currently accounts for 30% of inter-regional gas trade and by around 2030 is projected to account for half of it, with more short-term contracts.

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2   MMBtu = Million British Thermal Units (petroleum industry nomenclature). 1 Btu = 1,055 Joule, 1MMBtu = 1.055 GJ.

Figure 2.4: The shift in drilling activity from shale gas plays to liquid plays in the United States
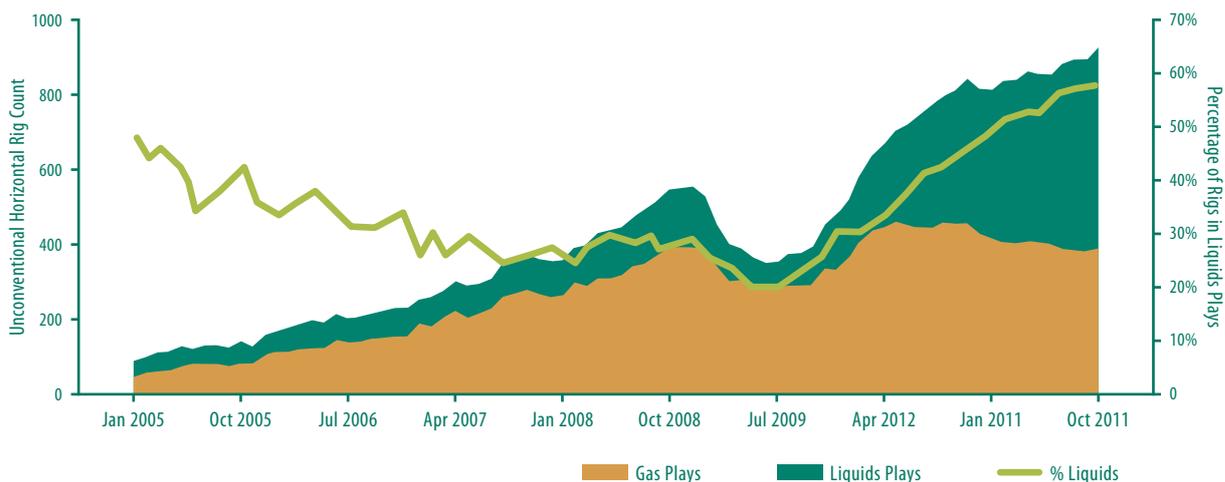
Source: Bernstein Research, 2011.

Gas prices have decoupled from oil prices in the past decade as a result of growing supplies of unconventional gas and more spot supplies of cheaper LNG available in Europe and the Asia Pacific. But in the long run, global LNG prices are expected to follow the same direction as oil prices, and indexation will most likely continue to be the predominant pricing mechanism in the Asia-Pacific in particular (Bureau of Resources and Energy Economics, 2011).

Abundant supplies of unconventional (mainly shale) gas in North America have removed the anticipated need to import LNG into the USA and caused the Henry Hub price to fall from $US12/GJ in 2008 to below $US4/GJ in 2012 (IEA, 2012a). At this price most domestic dry shale projects are not viable, but because some production is hedged at higher gas prices and because of some tenement requirements, output has not declined to the extent that would seem justified simply on the basis of current prices.

The extraction of natural gas liquids and oil from the shale has become increasingly important in the United States (Figure 2.4), due to declining gas prices. Indeed, in many cases now, the gas may simply be a by-product obtained from liquid hydrocarbon production. By the end of 2011, 60% of drilling rigs were focused on liquids recovery in the United States (Bernstein Research, 2011).

Prices in the United Sates are expected to remain lower than in Asian markets until 2020 and therefore there is a growing interest in exporting LNG priced off the Henry Hub to Asia.

In 2011, exports from the United States to Japan would have brought a notional net-back margin (difference between prevailing market price and notional supply costs) of more than $US6/GJ, and price estimates show a $US4/GJ margin for 2020 (IEA, 2012a). By comparison, margins on exports to Europe were below $US1/GJ in 2011 and are expected to be $US1.40/GJ in 2020.

Conclusions

Whilst it is recognised by the Expert Working Group that there may be profound changes in the global energy mix in the future, that is not something the Review was asked to consider and therefore natural gas is considered here within a "business-as-usual" context. Within that context, gas is likely to be an increasingly important energy source. The discovery of very large shale gas resources and the exploitation of shale gas (and shale oil) reserves has transformed the energy market in North America and has the potential to have a major impact on global gas supplies. The Expert Working Group considers that there is a clear need for Australia to quickly move to better assess its shale gas resources and reserves and considers their potential social, economic and environmental impact, whilst exploration in Australia is still at an early stage. The extent to which Australia's shale gas potential is realised will be highly dependent on the price of shale gas compared to the cost of other energy sources.

3 Shale gas resources and reserves

The confidence with which the quantity of oil or gas in a deposit can be determined and the cost of extraction (specifically whether or not extraction is economic), together determine whether the quantity of gas in a field is referred to as a 'resource' or a 'reserve'. If the quantity of gas in the field is poorly known, perhaps only in a very speculative way, then it is likely to be classed as a resource. If it is known with great confidence because it has been extensively drilled and tested and it is very likely to be economic to extract the gas, then the quantity of gas in the field is referred as a reserve. In reality the delineation of resources and reserves is much more complicated than this (see Society of Petroleum Engineers (SPE), 2012 website for definitions of resources and reserves)[3] but is based on '*an explicit distinction between (1) the development project that has been (or will be) implemented to recover petroleum from one or more accumulations and, in particular, the chance of commerciality of that project; and (2) the range of uncertainty in the petroleum quantities that are forecast to be produced and sold in the future from that development project*' (SPE Oil and Gas Reserves Committee, 2011).

3   www.spe.org/glossary/wiki/doku.php

Figure 3.1: Two-axis resource-reserve system
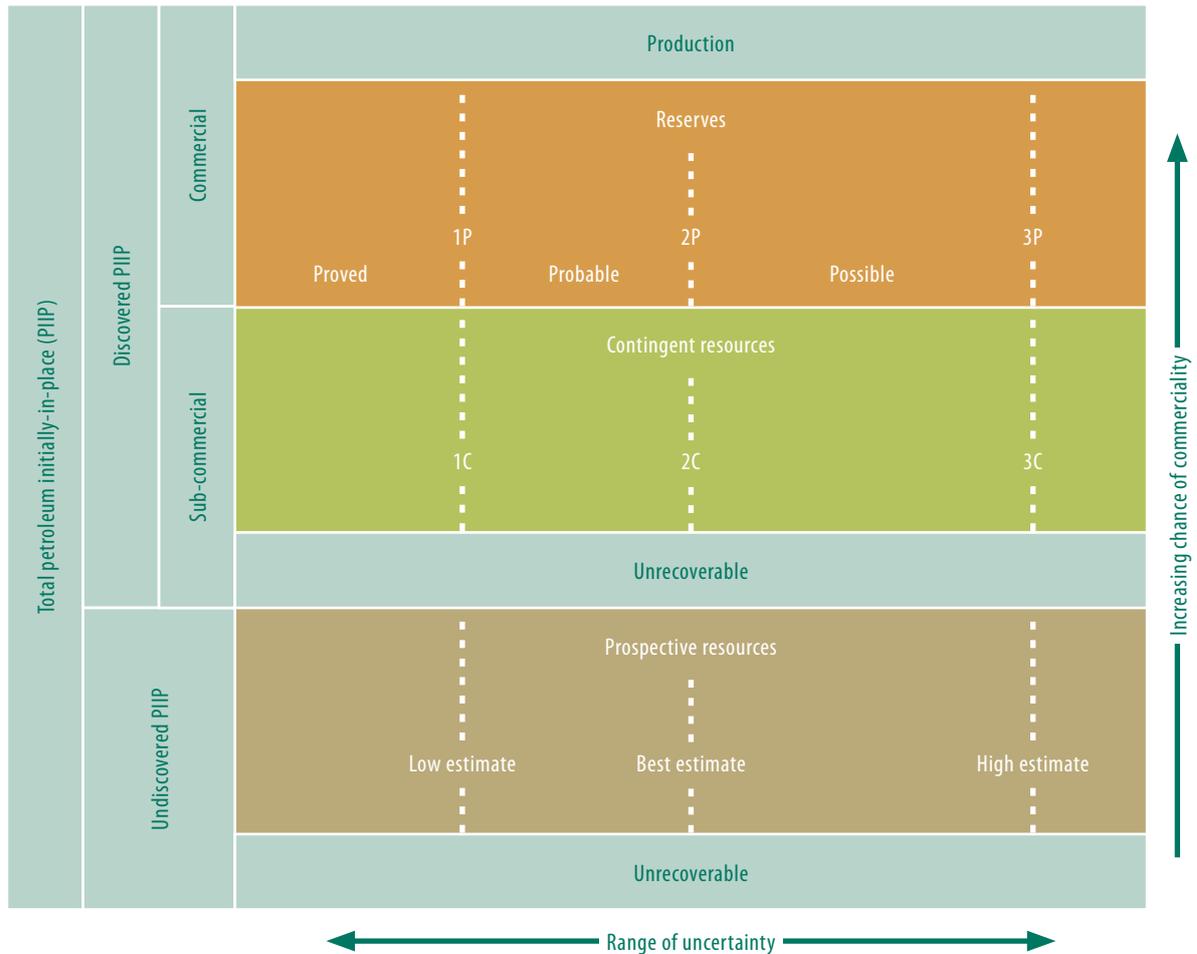
Source: Society of Petroleum Engineers, www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf
Copyright: Society of Petroleum Engineers, 2007.

The two-axis resource-reserve system used by the SPE is illustrated in Figure 3.1.

A project is classified by the Society of Petroleum Engineers (SPE Oil and Gas Reserves Committee, 2011) according to its maturity or status (broadly corresponding to its chance of commerciality) using three main classes – Reserves, Contingent Resources, and Prospective Resources. Separately, the range of uncertainty in the estimated recoverable sales quantities from that specific project is categorised based on the principle of capturing at least three estimates of the potential outcome: low, best, and high estimates. For projects that satisfy the requirements for commerciality, Reserves may be assigned to the project, and the three estimates of the recoverable sales quantities are designated as 1P (Proved), 2P (Proved plus Probable), and 3P (Proved plus Probable plus Possible) Reserves. The equivalent categories for projects with

Contingent Resources are 1C, 2C, and 3C, while the terms low estimate, best estimate, and high estimate are used for Prospective Resources. The lesson from this is that there are fundamental differences between resources (often a very large, ill-defined number, which may or may not be commercially viable) and reserves (usually a much smaller number but commercially significant).

The concept of reserves and resources is often represented as a triangle (Figure 3.2), with the area at the base of the triangle representing the gas resource. As the gas resource becomes better defined and better understood and the proportion of the gas that can be commercially extracted can be more confidently predicted, the gas 'moves' up the triangle, with the relatively small area at the apex representing the reserve. If the cost of gas increases then the area of the triangle representing the reserve may increase in size as the amount that can be extracted

commercially becomes greater. If the price falls then the reserve becomes smaller, this is an oversimplification of the resource-reserve relationship, but does perhaps serve to illustrate the point made by Powell in a submission to the Review, that resource figures may be of limited value in indicating whether or not a deposit will ever be commercially extracted, whereas a high level of confidence can be attached to reserve figures. It also illustrates that reserve figures can increase or decrease depending on price or technology and even factors such as loss of social licence to operate.

Figure 3.2: Concept of Reserves and Resources
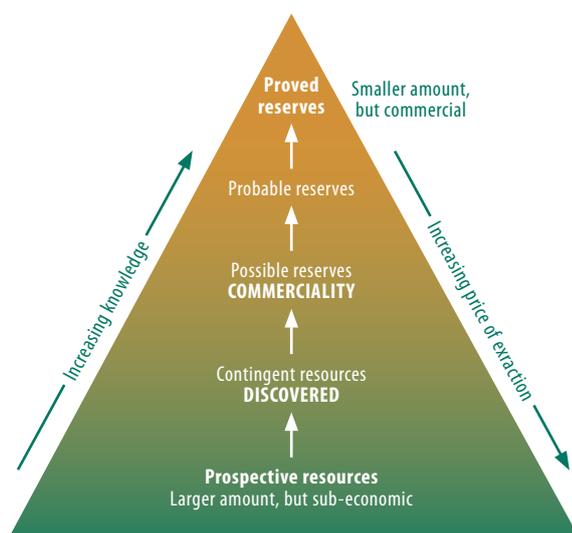
Deposits of shale, which are prospective for oil or gas resources, are found in sedimentary basins in many parts of the world, including Australia. They can range in thickness from a few metres to hundreds of metres, though the most prospective intervals may be just a few tens of metres thick. Shales can be laterally very extensive, underlying many thousands of square kilometres, or of more limited extent. Some shale-bearing basins are far more prospective than others, depending on their structural and thermal history. If basins have been very intensely folded or faulted, they are less likely to hold significant shale oil or gas; if they have been deeply buried and/or subjected to high temperatures and pressures, then they may be 'overcooked' and any hydrocarbons broken down. If, on the other hand, the basin has not been heated to any extent and has

always been at shallow depths, then it is likely that hydrocarbons, whether oil or gas, have never been generated. Therefore to have a shale-bearing basin rich in shale oil or shale gas requires the right depositional and post-depositional conditions. The characteristics of shale oil deposits are summarised in Table 3.1 (Submission to this Review by (CSIRO, 2012f).

Much of what we know about shale gas and shale oil and their prospectivity has resulted from a decade of shale gas exploration and production in the United States. Over that decade, the technological combination of horizontal drilling and hydraulic fracturing or fracking of shales, coupled initially with a high gas price, has enabled large volumes of previously uneconomic natural gas (and varying amounts of shale oil) to be produced in that country (US Energy Information Administration, 2011; US EIA, 2011a).

It is no exaggeration to say that the shale gas 'revolution' in the United States is the most dramatic example in the past decade or more of the effect that the application of new technologies can have on the energy scene and on a national economy. This production of gas has rejuvenated the natural gas industry in the United States and this has had flow-on consequences to other industries. It is also an excellent illustration of how a new technology can help to convert a large but totally uneconomic resource into a very important economic reserve of great commercial and national significance (Boulton, 2012). The role of existing and new technologies is discussed later in some detail in this report, but in essence, the 'game changers' in the United States were the application of long-reach horizontal drilling coupled with hydraulic fracturing, together with (at that time) a relatively high price for gas, an established infrastructure and a large market. In other words it was no one factor that resulted in the development of shale gas but a number of factors which came together to create favourable conditions for the development of shale gas in the United States. The transformation of the energy scene in the United States over recent times and its projected trajectory in the coming decades is illustrated in Figure 3.3. The large projected growth in shale gas production is clearly evident.

Table 3.1: Comparison of CSG, tight gas and shale gas

	Coal seam gas	Shale gas	Tight gas
Location	Particularly in Qld and NSW.	Includes remote locations in WA, Qld, NT and SA.	Onshore WA, SA and Vic. Largest known resources are in the Perth (WA), Cooper and Gippsland basins.
Commercial production	Significant exploration and characterisation of known resources. First commercial production of CSG began in 1996. CSG contributes about 10% of Australia's total gas production and greater than 70% of Qld's gas production.	Currently minor commercial production and resources are currently poorly understood and quantified.	Known tight gas reserves in existing conventional reservoirs that are well characterised will be primary targets for production.
Source rock	Coal seams (also the reservoir rock).	Low permeability, fine grained sedimentary rocks (also the reservoir rock).	Various source rocks that have generated gas, which has migrated into low permeability sandstone and limestone reservoirs.
Gas occurrence	Primarily adsorbed within organic matter.	Contained within the pores and fractures ('free gas') and adsorbed within organic matter.	Contained in pores
Typical depth	300-1000 metres (shallow compared to conventional and other unconventional gas). Deeper coals exist but are not currently economic as CSG reservoirs.	1000-2000 plus metres	Depths greater than 1000 metres
Composition	Mostly methane (>95%). CO_2 can be present but makes production less economic. Minor 'higher' hydrocarbons, nitrogen and inert gases.	Mostly methane. The presence of other hydrocarbons could make the resource more valuable.	Mostly methane.
Estimated Resource volume (for Australia)	Total identified resources estimated to be 203 tcf (DRET, 2012).	Total identified resources (discovered and undiscovered) are approximately 396 tcf (11.2 tcm) (IEA, 2011).	The in-place resources (total discovered) are 20 tcf (0.566 tcm), which is expected to increase with further exploration. (GA, 2012)
Transport and market network	Existing infrastructure for transportation and established market structures, particularly in Qld.	Cooper Basin region has existing gas infrastructure, however resources in WA and NT are generally in remote locations with limited infrastructure. Use by local mines is being considered in some cases.	Existing tight gas resources have been located in established conventional gas producing basins (Cooper and Perth basins), close to established infrastructure for commercial production. Other tight gas resources are in more remote locations.
Technology/ infrastructure required	Hydraulic fracturing used for less than half of the wells but this use is expected to increase as lower permeability seams are targeted.	Hydraulic fracturing and horizontal wells commonly required.	Large scale hydraulic fracturing treatments and/or horizontal wells required.
Water usage	Water produced from dewatering (pumping water out of the reservoir to reduce reservoir pressure and allow gas flow). Water required for hydraulic fracturing if used.	Water required for hydraulic fracturing	Water required for hydraulic fracturing
Key extraction challenges	Removal of water and recycling or disposal of produced water necessary.	Overcoming low permeability Minimising amounts of water to be sourced for hydraulic fracturing. Reducing infrastructure footprint.	Reducing infrastructure footprint.

Source: CSIRO, 2012f.

The economic reserves of conventional gas are very large in many parts of the world, including Australia, and currently provide the basis of the global gas industry, whether the gas is used locally, transported through pipelines, or transformed into Liquefied Natural Gas (LNG) for export. Given that the reserves of conventional gas are adequate for many decades to come (IEA, 2012a), why is there a need to consider an unconventional gas such as shale gas, which is usually more costly to produce than conventional gas? An obvious reason is that whilst conventional gas is abundant in many regions and countries, it is not abundant everywhere. In some instances, conventional gas reserves have already been depleted. In addition, whatever its advantages, conventional gas (or its LNG derivative) is not necessarily low cost energy as far as many importing countries are concerned. Finally despite its abundance, conventional gas is a finite energy source and many countries and companies wish to secure their long-term energy base. For all these reasons and others, such as ease of access or security of supply, there is now great interest in many parts of the world in unconventional gas and especially shale gas.

Figure 3.3: Current and projected dry gas production in the United States
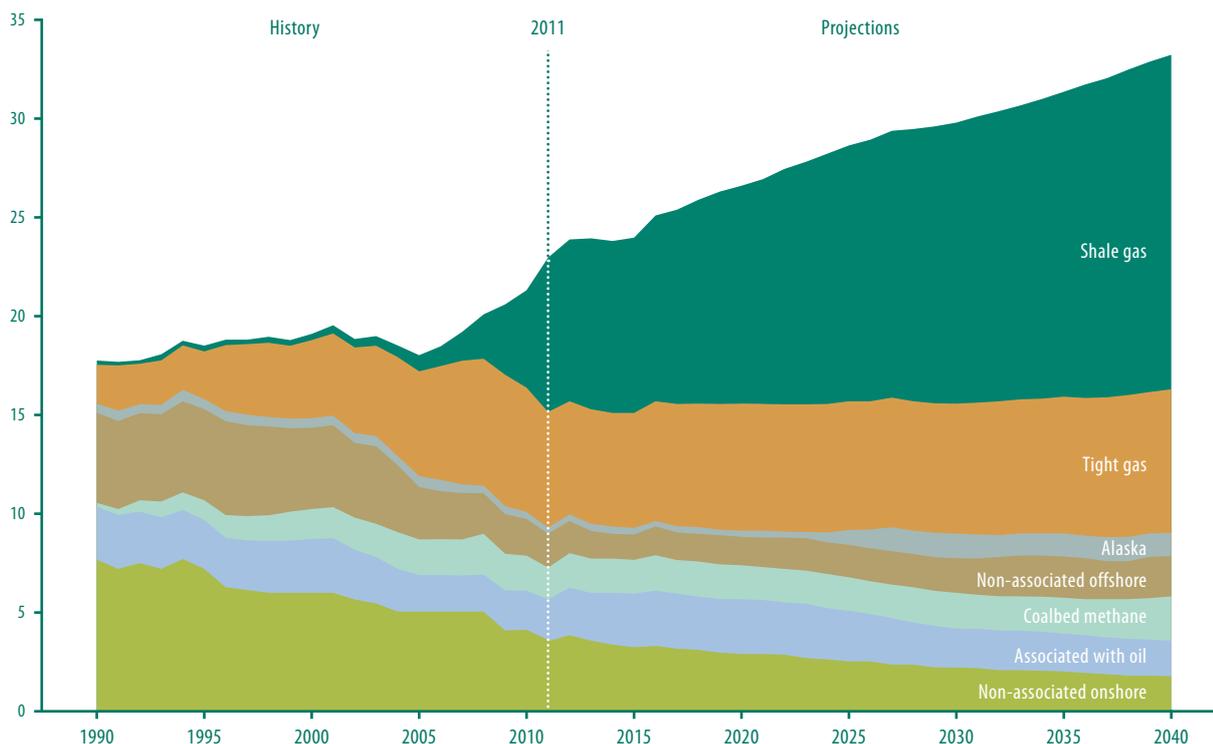
Source: US Energy Information Administration, 2013b.

Estimated shale gas resources throughout the world are very large. The International Energy Agency (IEA) has provided an estimate of these resources, and these are shown in Figure 3.4 (IEA, 2012a). As can be seen, there are large shale gas resources in the United States, Canada, Mexico, Argentina, China and Australia (Central Asia, the Middle East, South East Asia, and Central Africa were not considered). In Australia's case, the estimated undiscovered shale gas resources (based on assessment of only four basins) are 396 tcf (11.21 tcm) which compares with conventional gas reserves of 167 tcf (4.73 tcm) and CSG reserves of 235 tcf (6.65 tcm). Estimates of undiscovered conventional gas and CSG are not available and therefore the numbers for the resources and reserves cannot be compared.

In Australia there has been considerable growth in conventional gas and CSG reserves over the last decade, with most of the new and projected production being for the LNG export industry. There has been some growth in the domestic market as well, driven in part by the lower carbon intensity of gas compared with coal and the growth of intermittent renewable energy. The United States has shown that exploitation of

unconventional (shale) gas, of which there are very large reserves, can offer major commercial opportunities and can transform the energy and industrial scene and this is the impetus for much of the current Australian interest in shale gas. However, as discussed earlier, there were particular features of the United States energy picture that facilitated the shale gas opportunity there. Nonetheless, it is reasonable to pose the question in the medium term (and perhaps sooner): could there be new commercial opportunities for shale gas in Australia? The opportunity has already developed for CSG through the LNG industry and perhaps there will be a parallel for shale gas; not necessarily as an entirely new industry but as part of the continuum of onshore gas resources with which Australia is well endowed. The opportunity could be further enhanced if at least some of the shale gas in Australia proves to be 'wet' *i.e.* rich in high-value liquid hydrocarbons.

At the present time, there is only limited information on shale gas in Australia. However, based on the US experience, favourable features for the occurrence of shale gas include:

- Fine-grained lithology (shale/siltstone/mudstone).

Figure 3.4: World shale gas resources
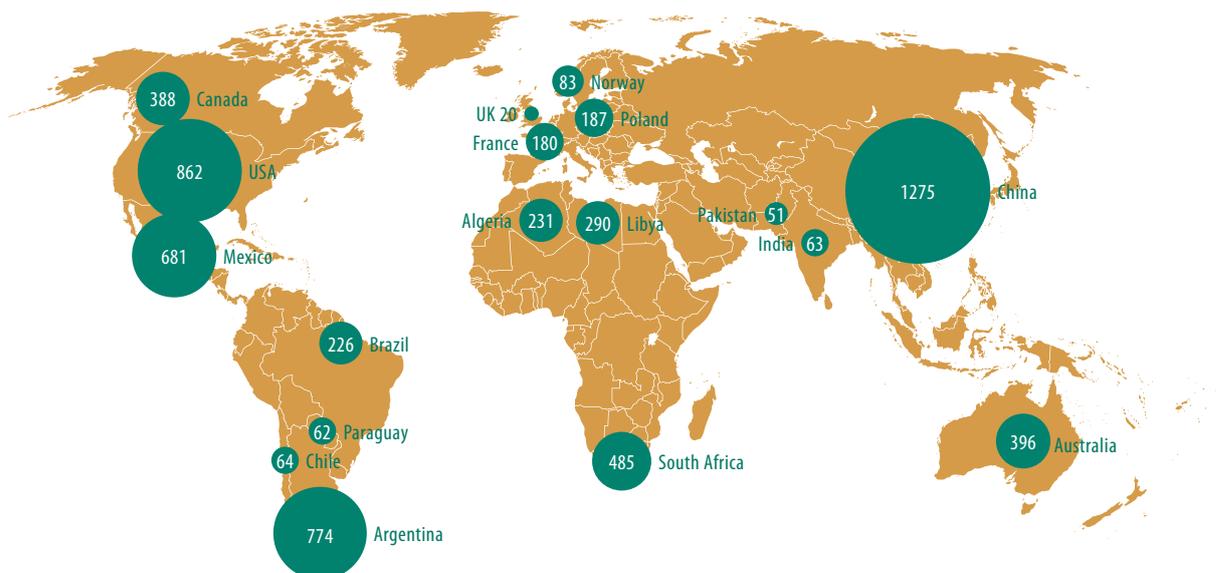
Estimates of technically recoverable shale gas resources (trillion cubic feet, tcf) based on 48 major shale formations in 32 countries (EIA 2011) Russia, Central Asia, Middle East, South East Asia and central Africa were not addressed in the Energy Information Administration report from which this data was taken.

Source: International Energy Agency (IEA, 2012a).

- Sufficient total organic carbon (greater than 2%).

- Thickness greater than 30m.

- Maturity – Wet Gas window 0.8 - 1.2 VRo[4] and Dry Gas window greater than 1.2 VRo.

- Moderate to low clay content (less than 40%) with very low mixed layer clays.

- Brittle composition (low Poisson's ratio and high Young's Modulus).

- A rock fabric (natural fractures) that enhances productivity.

- High lateral continuity of reservoir conditions.

- Organic matter is not oxidised.

Some of Australia's prospective sedimentary basins show a number of these features, though by no means all. There are also some marked geological differences between many North American and Australian prospective basins, including predominantly extensional stress in the United States versus compressional stress in Australia; Permian (approximately 250-300 million years)

and younger basins in the United States versus basins as old as mid-Proterozoic (approximately 1500 million years) in Australia though also including younger ones; and a dominance of marine sedimentary basins in the United States compared to predominantly non-marine basins in Australia. Therefore new shale gas models are likely to be needed in Australia to identify favourable basins and to identify the "sweet spots" (CSIRO, 2012a; CSIRO, 2012b; CSIRO, 2012c). Given that development costs for shale gas are likely to be much higher in Australia than in the United States (see Chapter 6 of this report), it is important to be able to identify the sweet spots and thereby drill fewer dry holes. The other way of countering high development costs through geology may be by better identifying areas where the shale gas is likely to be 'wetter' *i.e.* a greater proportion of valuable liquid hydrocarbons in the shale gas. These associated liquids include ethane, propane and butane; which are often referred to collectively as natural gas liquids (NGL), condensate and oil. A typical composition of the natural gas liquids produced from a well is provided in Figure 3.5. The relative abundance of these liquids appears to be a function of depth and thermal history (see Figure 3.6), but there may be other factors in play that need to be better understood in Australia.

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4   VRo – vitrinite reflectance, a measure of the temperature history of sediments that have undergone metamorphosis from kerogens to hydrocarbons, measured from reflected light from a sample containing vitrinite.

Figure 3.5: Estimated average composition of the natural gas liquids (NGL) produced from wells in the United States
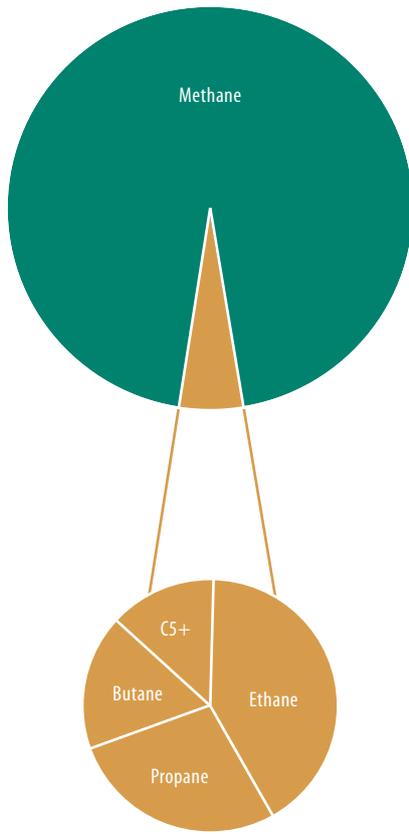
C5+ refers to condensate. The oil content (C12+) is not included. Adapted from: Bernstein Research, 2011.

Figure 3.6: The thermal transformation of kerogen as a function of depth showing the oil and gas "windows" after Tissot and Welte (1984)
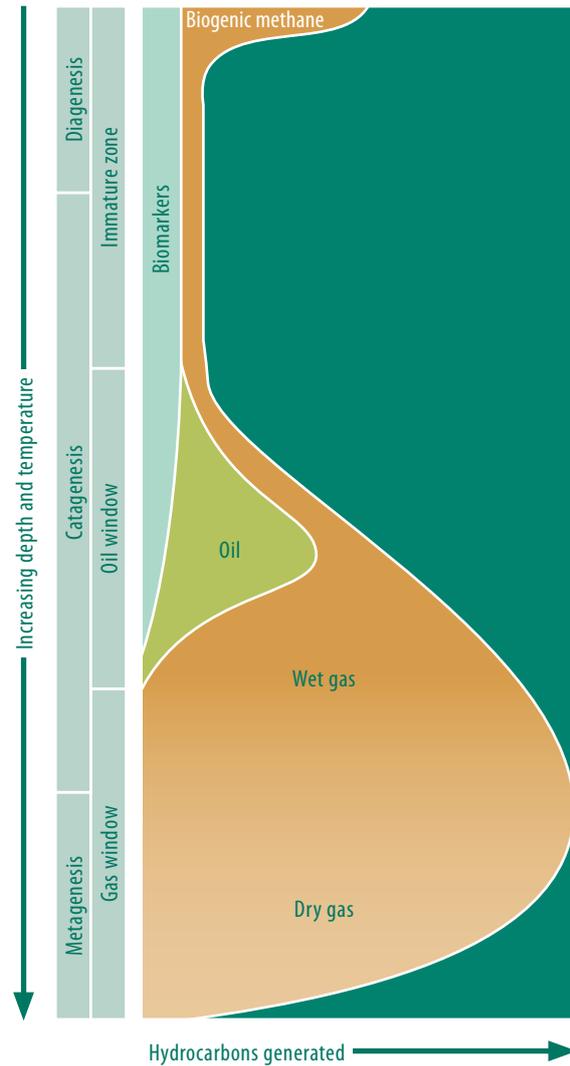
Exploration for and production of unconventional hydrocarbons is not a new phenomenon in Australia. Exploration for CSG has been occurring in eastern Australia from approximately 1976, and since 1996 CSG production has been underway. More recently the growth in this industry has greatly accelerated, with the construction of Liquefied Natural Gas (LNG) facilities for gas export on the east coast of Queensland (Department of Resources, Energy and Tourism, 2012).

As mentioned previously, identified reserve figures for conventional gas are 167 tcf (4.73tcm) and total CSG identified reserves are 235 tcf (6.65 tcm) but there are as yet no identified shale gas reserves in Australia. There are large shale gas undiscovered resources of 396 tcf (11.2 tcm) based on four prospective basins (See Appendix I). As

technology and geological knowledge continue to advance, and if the economics of extracting shale gas are favourable, Australia would be in a position to exploit its shale gas resources. There are currently three independent domestic gas markets in Australia – the western and northern markets, already linked to export markets for gas through LNG production and exports, and the eastern market, which has a significant domestic customer base but will also soon be linked to LNG export via facilities at Gladstone, Queensland. Shale gas resources (and more modest tight gas resources in some basins) have the potential to contribute to all three of these markets. However the extent to which this occurs will be highly dependent on the price of shale gas compared to the cost of other energy sources.

Resource potential and assessment

Australia's total unconventional hydrocarbon resource endowment is poorly constrained. Currently available national resource estimates have very large associated uncertainties and, in the case of shale and tight gas, are only based on a partial assessment of selected basins.

In 2011, the United States Department of Energy, Energy Information Administration (US EIA), completed a shale gas resource assessment of the Perth, Canning, Cooper and Maryborough basins. The report concluded that these four basins collectively contained in excess of 435,600 petajoules (PJ) or 11.21 tcm of technically recoverable shale gas (US EIA, 2011a). Although shale gas production has commenced in the Cooper Basin, there are no production or reserve statistics currently available. Moreover, there are no current national resource estimates for shale oil (not including oil shales) in Australia.

Geoscience Australia, in collaboration with its counterparts in the States and Northern Territory, has commenced an assessment of Australia's unconventional hydrocarbon resource potential. In consultation with the United States Geological Survey (USGS), a nationally consistent assessment methodology is being developed to derive unconventional hydrocarbon resource estimates of Australia's prospective onshore basins that conform to an internationally accepted standard. In this approach, the technically recoverable resource estimates are constrained by probability-based, well productivity models, derived from existing production data. In frontier areas with no production history, as in the case of Australian shale and tight gas/oil plays, models based on the productivity characteristics of other potentially comparable areas (e.g. North America) are applied. Uncertainties regarding the geologic input data are also captured by the assessment methodology, such that the final resource estimates are expressed as a range of values and associated probabilities. This methodology avoids the overestimation of resource volumes that may potentially arise from deterministic methods.

Source: Geoscience Australia.

The extent to which United States shale gas serves as a potential geological analogue for Australian shale gas exploration and production may be limited. Nonetheless, despite the comparative lack of information on Australian basins compared to American basins, it is reasonable to conclude that Australia has significant potential for shale gas. Quantification of this potential is a function of the amount of information that is available. The assessment of petroleum resources, whether conventional or unconventional, is important from a commercial and financing perspective, and it is also important from the perspective of developing national policy. Determining prospectivity and resource/reserve figures for conventional gas resources is a well-accepted methodology (Figures 3.1, 3.2) and is used widely for making major commercial decisions (see previous discussion). Applying this approach to unconventional gas reserve is more difficult, but a methodology has been developed by a number of organisations including the Society of Petroleum Engineers (SPE) and the United States Geological Survey.

In Australia, the Commonwealth Department of Resources, Energy and Tourism (DRET), Geoscience Australia (GA) and the Bureau of Resource and Energy Economics (BREE), have assessed the gas resources of Australian basins in terms of conventional gas, CSG, tight gas and shale gas (see Table 3.2 and Figure 3.7). Their work suggests that the potential in-ground shale gas resources make up a significant component of Australia's undiscovered gas resources, although it is important to again point out that for the moment they comprise none of the identified reserves.

From their initial world shale gas assessment, the US Energy Information Administration provided shale gas estimates for four Australian sedimentary basins (Cooper, Canning, Maryborough and Perth). These are summarised in Table 3.3.

Table 3.2: Total Australian gas resources

Resource Category	Conventional Gas		Coal Seam Gas		Tight Gas		Shale Gas		Total Gas	
	PJ	tcf	PJ	tcf	PJ	tcf	PJ	tcf	PJ	tcf
Economic Demonstrated Resources	113400	103	35905	33	-	-	-	-	149305	136
Subeconomic Demonstrated Resources	59600	54	65529	60	-	-	2200	2	127329	116
Inferred resources	~11000	~10	122020	111	22052	20	-	-	155072	141
All identified resources	184000	167	223454	203	22052	20	2200	2	431706	392
Potential in ground resource	unknown	unknown	258888	235	unknown	unknown	435600	396	694488	631
Resources – identified, potential and undiscovered	184000	167	258888	235	22052	20	435600	396	900540	819

Source: Geoscience Australia and BREE (2012). Conventional gas demonstrated resources as of January 2011; CSG demonstrated resources as of January 2012. Note CSG 2P reserves and 2C resources are used as proxies for Economic Demonstrated Resources and Subeconomic Demonstrated Resources respectively.

Figure 3.7: Map of gas resources in Australia
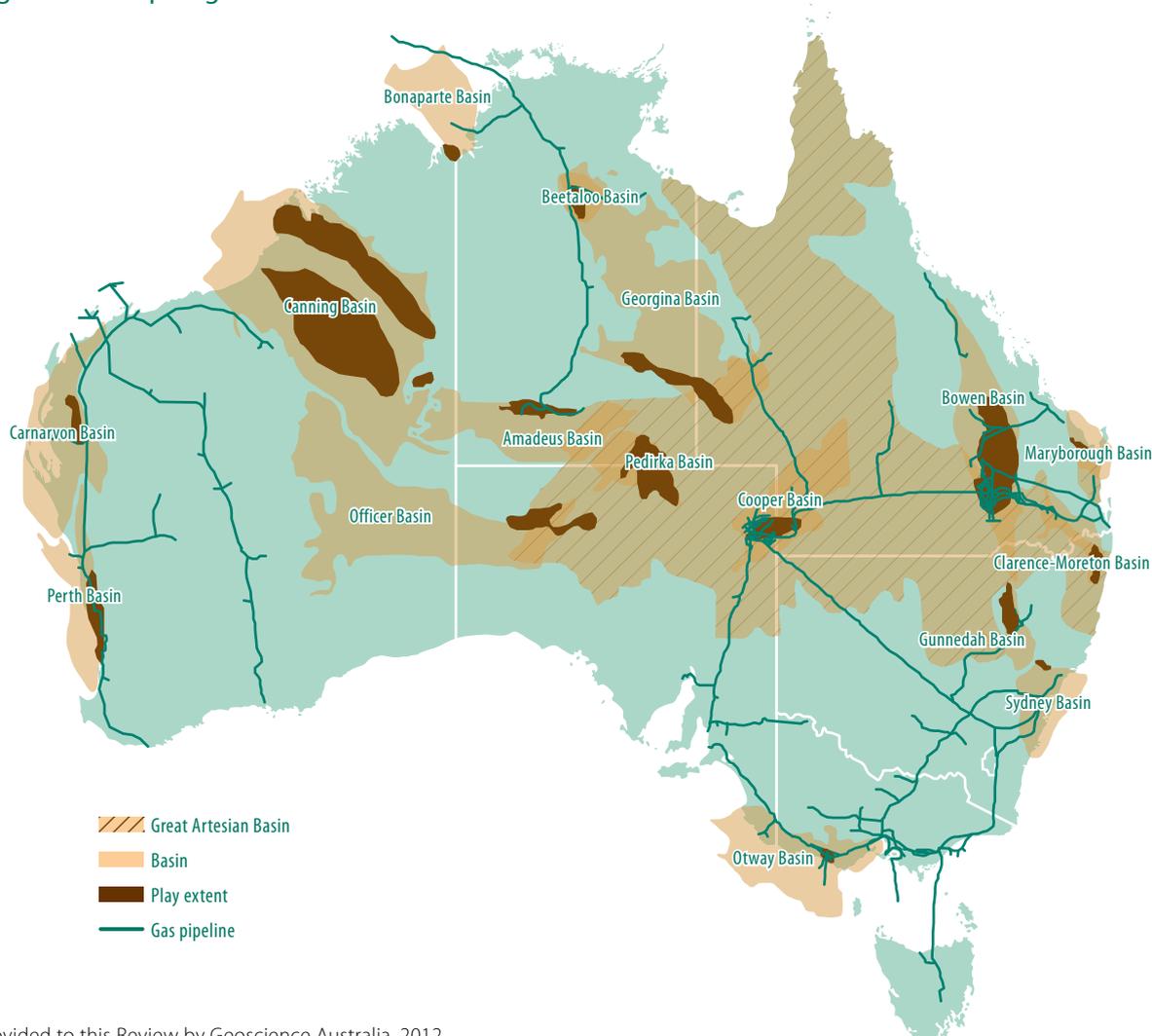
Provided to this Review by Geoscience Australia, 2012.

In order to gain an additional perspective on the shale gas potential of Australia, this Review commissioned AWT International to undertake a resources assessment using SPE guidelines (Report to this Review by AWT International, 2013). AWT was also requested to make a preliminary assessment of which basins might have only 'dry' gas and which might have 'wet gas'. Based on the SPE methodology for shale gas plays and a "best estimate" (p_{50}) of prospective

Table 3.3: Shale gas reservoir properties and resources of Australia

		Cooper Basin (121,000 km²)	Maryborough Basin (11,106km²)	Perth Basin (32,517km²)		Canning Basin (486,609km²)
Basic Data	Basin/Gross Area	Cooper Basin (121,000 km²)	Maryborough Basin (11,106km²)	Perth Basin (32,517km²)		Canning Basin (486,609km²)
	Shale Formation	Roseneath-Epsilon-Murteree	Goodwood/Cherwell Mudstone	Carynginia Shale	Kockatea Fm	Goldwyer Fm
	Geologic Age	Permian	Cretaceous	Upper Permian	Lower Triassic	M. Ordovician
Physical Extent	Prospective Area (km²)	15,042	4,026	5,644	5,644	124,530
	Thickness (m) — Interval	0 − 550	92 − 915	92 − 458	92 − 915	92 − 736
	Thickness (m) — Organically Rich	153	381	290	702	396
	Thickness (m) — Net	92	76	76	70	76
	Depth (m) — Interval	1,830 − 3,965	1,525 − 5,032	1,220 − 5,032	1,007 − 5,032	1,007 − 5,032
	Depth (m) — Average	2,592	2,898	3,264	3,050	3,660
Reservoir Properties	Reservoir Pressure	Moderately Overpressured	Slightly Overpressured	Normal	Normal	Normal
	Average TOC (wt. %)	2.5%	2.0%	4.0%	5.6%	3.0%
	Thermal Maturity (%Ro)	2.00%	1.50%	1.40%	1.30%	1.40%
	Clay Content	Low	Low	Low	Low	Low
Resource	GIP Concentration (bcf/km²)*	40.54	42.47	41.31	42.47	40.92
	Risked GIP (tcf)	342	77	98	100	764
	Risked Recoverable (tcf)	85	23	29	30	229

*See Scientific and Engineering Units and Conversions, page 192.
Source: Data sourced from 'World shale gas resources: An initial assessment of 14 regions outside the United States (US EIA, 2011a).

Table 3.4: Prospective resource estimates for Australian shale gas plays that meet screening criteria

Basin	Play	Gas Pod	Area (km²)	Best Estimate Recoverable Resource (tcf)	BOE volume (MMbls)	BOE/km²	Recoverable Resource bcf/km²
Amadeus	Horn Valley	Dry	7,267	16	2777	0.38	2.19
Beetaloo	Kyalla	Dry	898	3	467	0.46	2.62
	Velkerri	Dry	6,092	16	2796	0.46	2.62
Bonaparte	Milligans	Dry	2,752	6	1090	0.28	1.60
Bowen	Black Alley	Dry	51,252	97	16979	0.33	1.89
Canning	Goldwyer	Wet	147,305	409	71306	0.48	2.77
	Goldwyer	Dry	139,321	387	67444	0.48	2.77
	Laurel	Wet	48,285	106	18459	0.38	2.19
	Laurel	Dry	28,704	63	10973	0.38	2.19
Carnarvon	Byro Group	Dry	6,162	9	1575	0.25	1.46
Clarence-Moreton	Koukandowie	Dry	4,407	11	1901	0.43	2.48
	Raceview	Dry	4,407	10	1677	0.38	2.19
Cooper	Roseneath, Epsilon, Murteree (REM)	Wet	3,604	14	2385	0.66	3.79
	Roseneath, Epsilon, Murteree (REM)	Dry	9,106	35	6026	0.66	3.79
Eromanga	Toolebuc	Dry	93,263	82	14244	0.15	0.87
Georgina	Arthur Creek	Dry	14,433	50	8731	0.51	2.91
Gunnedah	Watermark	Dry	8,631	13	2185	0.25	1.46
Maryborough	Cherwell	Dry	3,264	7	1289	0.41	2.33
McArthur	Barney Creek	Wet	2,867	7	1304	0.51	2.91
	Barney Creek	Dry	158	0.44	72	0.51	2.91
Otway	Eumeralla	Dry	4,109	9	1563	0.38	2.19
Pedirka	Purni	Dry	29,357	43	7470	0.25	1.46
Perth	Kockatea	Wet	5,818	7	1184	0.20	1.17
	Kockatea	Dry	14,123	16	2874	0.20	1.17

Source: Report to this Review by AWT International, 2013.

resource numbers, 26 Basins were assessed and 19 individual shale gas plays identified that met the screening criteria. Many of these resources were not considered in the estimate provided by the IEA, (Figure 3.4). Using this approach, the ATW prospective resource estimate for Australian shale gas plays is in excess of 1000 tcf, as shown in Table 3.4. It should be noted that this aggregate number is to be treated with caution, since there is a great deal of uncertainty attached to it. It is also important to again point out that the issue of whether or not a shale gas resource will ultimately become a recoverable reserve could be significantly affected by whether or not the gas is 'wet', for if there is a high proportion of liquid hydrocarbons then gas might be produced (whatever the gas price) as a consequence of the production of high value oil. The decision on whether or not to ship that gas to market then becomes a function of transport costs to a significant degree.

Conclusions

Using multiple approaches to estimate resources, it appears likely that Australia's prospective resources of shale gas are very large and may include significant quantities of 'wet' gas. However a great deal more information will be required to turn the prospective resource estimates for shale gas (and shale oil) into contingent resources and then into commercial reserves. Given the level of commitment of existing CSG reserves to Liquefied Natural Gas (CSG-LNG) export requirements over the next twenty years, there will be an opportunity for cost competitive shale gas to contribute to this need for additional east coast gas particularly as the projected cost of producing at least

some of Australia's shale gas reserves is at or below some future gas price projections for Eastern Australia. Australia has a number of sedimentary basins, particularly (though not exclusively) in northern, central and western Australia, which are prospective for shale gas, based on the abundance of shales, their likely maturity and their total organic carbon content. Because of its established infrastructure (such as the gas processing facility at Moomba and the pipelines), shale gas (along with tight gas) in the Cooper Basin could be the first to be developed at a large scale. Estimates of Australian shale gas resources are considerable, but have a high degree of uncertainty attached to them. The commonly cited undiscovered resource value of 396 tcf of gas is based on only four basins, but if all prospective basins are considered, the undiscovered resource could be in excess of 1000 tcf. Reliable economic reserve figures for shale gas are not available, largely because there has been little or no exploration or drilling in most basins.

Given the potential size of the resource and implication of that resource to the future energy mix in Australia, there clearly is a need for governments, working in consultation with the private sector, to refine these resource estimates using all available information. Exploration by the private sector will then be required to turn the prospective resource estimates for shale oil (and shale gas) into contingent resources and ultimately into proved reserves. At the present time there is projected to be of the order of $500 million spent on unconventional gas exploration (much of that shale gas) in the next 1-2 years in the Cooper Basin alone. This gives an indication of just how seriously industry is taking up the challenge of shale gas.

Current Australian Developments

In Australia, very few shale gas wells are in or nearing production: three recent examples are (i) the Santos "Moomba–191" vertical well in the Cooper Basin, (Santos, 19 Oct 2012) and (ii) the Beach Energy Encounter-1 well, (Beach Energy, ASX, 10 July 2012) and (iii) Beach Energy Moonta-1 well (Beach Energy, 18 Jan 2013) also in the Cooper Basin. It has been noted in public shareholder documents that the Moomba-191 well has three hydraulically fractured sections (one in production, two currently being tested) and had an initial gas production of 84.9 mcm/d (3,000 Mscf/d)*. The well has been in production for six months (to March 2013) and over that time the production declined to around 65 mcm/d (2,300 Mscf/d). Beach Energy reported that the Encounter-1 well had 6 fracture stimulation stages and flowed at a maximum rate of 59.4 mcm/d (2,100 Mscf/d). Beach Energy has also recently reported a maximum flow of 73.6 mcm/d (2,600 Mscf/d) for its Moonta-1 well, with a current flowrate of 45.3 mcm/d (1600 Mscf/d) through a 1.5 inch choke (Beach Energy, 18 Jan 2013). To illustrate the point that there is already an active shale gas industry in Australia, work programs for the Cooper-Eromanga Basin with a total value of approximately $500 million have been announced for completion over the next 1-2 years in unconventional gas, with the focus on shale gas.

*mcm/d, million cubic metres per day. Mscf/d, one thousand standard cubic feet per day

4

Technology and engineering

Overview

Technologies for the extraction of unconventional shale gas have been extensively developed in the United States over the last decade. The technologies involve deep horizontal drilling and multiple-stage hydraulic fracturing, together with associated real-time sensing to monitor and guide the drilling and fracturing process. These methods have proved to be an economic game-changer in the United States through cost reduction. In this chapter of the report, these technologies are first reviewed and then assessed in the Australian context. A list of some 60 technical references for both hydraulic fracturing and shale gas technology broadly has been compiled by Geoscience Australia, and this compendium has informed this Review. A key reference is that of King (2012), in which detailed information is provided and which is summarised here. A recent review of hydraulic fracturing by the UK Royal Society and Royal Academy of Engineering (2012) has also provided important detail. In this review, the technologies and associated issues are taken in chronological order for the development of a drilling site.

A number of key issues for shale gas extraction in Australia are identified. Geological differences between Australian and United States shales are centrally important, in particular the deep *in-situ* stress regime, which influences how the shales may fracture. The major technical advance in the United States has been the combination of a number of deep horizontal wells from a single pad, each with multiple fracture stages targeting specifically shale strata. Horizontal shale gas wells require a deep *in-situ* stress regime that will sustain a significant transverse vertical fracture component at the many fracture stages along the lateral length of the horizontal well. Fracturing experience from vertical wells in the Cooper Basin has indicated that the minimum horizontal stress at some shale target depths might approach or in some cases exceed the vertical overburden stress, generating the potential for fractures to be oriented in the horizontal plane at some locations (Pitkin, *et al.*, 2012). Such 'compressive stress' situations contrast with the generalised US 'extensional stress' regime. Whilst this will not be the case for all Australian basins, or throughout a particular basin, the economic extraction of shale gas is optimised by horizontal wells and knowledge gained from the planned development of a number of horizontal shale wells by industry in the Cooper Basin in the near future will considerably clarify the situation. In addition to shale targets, overlying and underlying rock formations in some Australian basins such as the Cooper Basin importantly contain tight gas in deep sandstones, and deep coal seam gas, all of which similarly require hydraulic fracturing for extraction. This continuous vertical column of gas-bearing strata, of mixed lithology, can be accessed by hydraulic fracturing at different depths from the same vertical well bore. Such an approach to target a broader section of deep unconventional gas in reservoir rocks of higher permeability than shale, but which still require hydraulic fracturing, is compatible with the drilling of a number of wells, with near-vertical sections at depth, from a single drilling pad.

In important Australian basins such as the Cooper Basin, shale gas wells will pass through the sequence of deep aquifers of the Great Artesian Basin to access shale and other gas targets in close, underlying proximity. Engineering best-practice with regard to well integrity at depth and the use of sensing technology to accurately and closely monitor the hydraulic fracturing process, particularly any extended upward vertical growth of fractures due to intersection of local transmissive faults, is available to minimise the risk to this important water resource. In certain geothermal 'hotspot' regions in Australian basins the subsurface temperature regime will require adaptation of sensor technology. There is also the opportunity to use water from deep saline aquifers in arid regions of Australia for the hydraulic fracturing fluid, within an overall aquifer management plan. The use of saline aquifers for this purpose is current practice in the United States.

The essential technical details of the successful, proven United States-developed technology for shale gas extraction otherwise largely carry over to Australia, spanning the pre-development baseline survey stage, through well drilling and hydraulic fracturing to production, including the use of technology for risk mitigation.

Graphics illustrating key technology issues for shale gas extraction (US and Australia) are provided at the end of this chapter.

Well Site Construction

It is important before any land modification occurs that baseline environmental measurements are carried out. This is particularly true for ambient atmospheric methane measurement. This is considered in detail in Chapter 12.

Site construction involves levelling of the site, structures for erosion control, excavation of fenced pits with special impervious liners to hold drilling fluids and cuttings, and access roads for the transportation of equipment to the site. Once the well (or multiple wells from the pad) is drilled, the drilling rig is removed and the site prepared for well stimulation, by hydraulic fracturing. Equipment includes fracture fluid storage tanks, sand storage units, chemical trucks, blending equipment and water pumping equipment installed on a number of trucks (each with a large pump). The hydraulic fracturing operation is

Figure 4.1: Well drilling in Australia

Source: Santos 2013

Figure 4.2: Well stimulation by hydraulic fracturing in Australia

1. Relief / Flowback lines
2. Backpressure pump and water supply
3. 15k psi fracture stimulation wellhead
4. Pump units
5. Proppant storage
6. High pressure pump lines
7. Diesel fuel storage
8. Blenders
9. Control vans
10. Water supply
11. Water tanks
12. Electric wireline unit
13. Chemicals and additives
14. Gel hydration blender

Source: Santos 2013

controlled by a data management van (Fracfocus, 2012). Figures 4.1 and 4.2 show these two stages of the operation in Australia.

Well Drilling and Completion

A shale gas well is drilled in stages of decreasing diameter and increasing depth. Well drilling and completion is typically of several weeks duration, and involves a sequential process of drilling, insertion of steel casing strings, cementing, testing and establishing connection to the deep shale reservoir (well completion), which is then fractured (see 'Hydraulic Fracturing'). Two breakout boxes (Horizontal Drilling I, II) provide information on the key technical features of the drilling process. These include the initial vertical

and subsequent horizontal drilling stages, engineering of the well casings, well completion and integrity testing (throughout the process). To give a sense of scale, shale gas wells in the United States have a vertical well section to a depth on average of approximately 2 km, curving on a radius of approximately 500 m to a horizontal well section that extends out laterally 1-2 km (and in extreme cases beyond 3 km) within the deep shale layer of thickness 15 to 150 m. The steel production casing diameter depends on the well design, but is around 18 cm.

It is important to note that unlike the situation for conventional gas, where a gas field can be exploited by a few wells involving a one-off, up-front capital investment, exploitation of a shale gas field can require thousands of wells drilled

over a continuing timescale due to the nature of the gas production decline curve for a single shale gas well – see Chapter 6 of this report which deals with the economics of shale gas. This large well number has environmental impact that requires governance, which is discussed in Chapters 7, 8, 10 and 12.

Hydraulic Fracturing

Hydraulic fracturing has been a commercial process in the oil and gas industry since 1947 and the Society of Petroleum Engineers (SPE) estimate that 2.5 million hydraulic fractures have been undertaken worldwide, with over 1 million in the United States. Tens of thousands of horizontal wells have been drilled over the past 60 years. The technical literature on horizontal wells and hydraulic fracturing adapted to shale is extensive, covering 30 years of development, with over 550 papers on shale hydraulic fracturing and 3000 papers on aspects of horizontal wells. Recent reviews on hydraulic fracturing have also been published (King, 2010d; King, 2012). In Australia, drilling for hydrocarbons has over a 50-year history and hydraulic fracturing has for example been previously carried out in 70 wells in the Cooper Basin (Report to this Review by Sinclair Knight Merz, 2013). Most recently in Australia, 50 wells targeting shale and tight gas have been drilled, but less than 15 wells have been stimulated by hydraulic fracturing (Santos Limited, 2012a).

United States Benchmark: Shale Gas Well – Horizontal Drilling II

Well Drilling – Horizontal Drilling: In horizontal drilling, the well is first drilled vertically to a kick-off point (KOP) ~150 m above the targeted gas-containing strata, at a depth (in the US) of typically 2 km. At the KOP, the standard drill bit can be replaced by a downhole drilling motor equipped with measurement-while-drilling instruments. These can include inertial guidance systems and/or gamma and neutron logging tools for geo-steering. The ~500 m long curvature of the well to horizontal and the horizontal (lateral) section is drilled in ~10 m sections. Each section of casing weighs ~230 kg and for deep, long horizontal wells the complete drilling assembly can approach 90 tonnes in weight. 'Horizontal' wells can be flat (90^0 to the vertical), toe-up (end or toe of the lateral higher than the heel), or toe-down. The compass direction of the lateral is determined by the *in-situ* underground stress regime (and to achieve transverse vertical fracture planes is in the direction of least horizontal stress when the maximum principal stress is in the vertical direction). A typical range of length for the lateral is ~600 m - ~1800 m, with extremes to ~3600 m. In horizontal wells, multi-stage hydraulic fracturing (10 - 40 stages) is achieved using isolation plugs lowered into the well bore, in ~110 m sections along the length of the horizontal casing. These isolation plugs are subsequently drilled out.

Well Completion: After drilling the well and establishing the casings, the drill rig is removed. To connect the interior of the final casing to the deep shale reservoir (well completion), a perforating gun configured with electrically-triggered shaped charges is lowered by wireline into the horizontal shale-gas-containing zone of the production casing. The explosive charges generate a jet that cuts through the casing and its cement seal at this point into the reservoir (several 10s of cm penetration) to create holes through the casing and into the rock formation.

Well Integrity – Test: The innermost steel casing – the production casing – is used to deliver the fracture fluid, as well as the flowback fluid (produced water) and gas. At the surface, a blow-out preventer (BOP) is connected to the casing to control pressure while drilling. When the BOP closes, the well casing and cement are vulnerable to failure, and proper design is important to maintain subsurface well integrity. A well integrity test is carried out after each casing string has been cemented by pressurising the well bore with water. A pressure of ~700 atmospheres (atm) (~70 megapascals (MPa)) for hold times of 10 minutes during the test is typical, with the actual details dependent on casing and well design. If some hydraulic fracturing pressures exceed this, higher pressure tests are required. Pressure monitoring in the annulus region between casings is important to identify potential leaks.

Well Integrity – Cement Seals: The cement seals are critically important to prevent aquifer contamination, and as best-practice (see American Petroleum Institute guidance document HF1, 2009) a cement bond log (CBL) is employed to test the bond strength of the cement to the pipe and to the formation wall for each cemented string. The CBL runs inside the casing and is an acoustic device that transmits a sound signal and records the amplitude of the arrival signal, which is sensitive to the quality of the seal. Cement is a long-lived seal, with examples of 40 year-old cemented wells exhibiting good isolation under pressure testing. Centralisation of the casing strings, displacing all mud prior to cementing, achieving sufficient cement height and avoiding gas migration through the cement as it sets, are some important details to be addressed. Special additives to the cement protect against gas migration, high temperatures, mineral acids and other factors. Non-toxic cementing additives based on cellulose have been developed and applied.

Summary from details in G.E. King, SPE 152596 (King, 2012); API Guidance Document HF1, 2009 (Energy API, 2009) and other references. Video animations of the processes involved are available from Marathon Oil Corp. (2012), Apache Corp (2012), and Western Australia Onshore Gas (AWE, 2012) (links provided at References).

The need for stimulation of gas shales derives from their low permeability, which is a measure of the flow of fluids through the rock. Whereas sandstones for conventional gas and oil producing reservoirs have permeabilities in the range 0.5 to 20 millidarcies (mD), gas shales are in the range 0.000001 to 0.001 mD. Not all shales produce gas, even with hydraulic fracturing, and gas shales differ from high-clay-content shales of even lower permeability which serve as natural seals. In contrast, tight gas is natural gas trapped in low permeability (0.001-0.1 mD) and low porosity reservoir sandstones and limestones. Hydraulic fracturing is also required for stimulation of tight sands. Importantly, these deep unconventional gas reservoirs can also contain natural gas liquids (NGLs – see Chapters 5 and 6). Associated NGLs are more difficult

to extract than shale gas and can require an increasing number of hydraulic fracturing stages (Bernstein Research, 2011).

Key details of the hydraulic fracture process are summarised in the breakout box (Multi-stage Hydraulic Fracturing). The process involves pumping, at controlled high pressure, a hydraulic fracturing fluid mixture of mostly water (99.5-99.9% by volume) and sand or ceramic particles (proppant), plus an amount of chemicals (0.1-0.5%), into the deep underground shale reservoir layer. This induces fractures in the reservoir that are subsequently kept open by the proppant to release the gas. The gas flows back to the wellhead via the fracture network pathway connection to the (perforated) steel production casing. Multi-stage hydraulic fracturing provides well contact with an enormous shale reservoir area, enhancing shale gas extraction to economic levels. When production begins after completion, water and then gas flows – see breakout box (Flowback and Gas Flow). From 15-50% of the

hydraulic fracturing fluid is recovered (during flowback and as produced waters), and is either recycled for other hydraulic fracturing operations, or disposed of in accordance with regulations.

Chemicals used in Hydraulic Fracturing – Technical

A typical hydraulic fracturing fluid includes between three and twelve additive chemicals depending on the characteristics of the water and the shale being fractured. Each component serves a specific, engineered purpose. The United States Department of Energy has published a table of additive type, main chemical compounds and common use for hydraulic fracturing (USDOE, 2009), shown in Table 4.1. In addition, some service companies have disclosed the nature of hydraulic fracturing fluids – see for example Halliburton's disclosure for the United States, Europe and Australia (Halliburton, 2013). During

Table 4.1: Hydraulic fracturing fluid additives

Additive Type	Main Compound(s)	Purpose	Common Use of Main Compound
Diluted Acid (15%)	Hydrochloric acid or muriatic acid	Help dissolve minerals and initiate cracks in the rock	Swimming pool chemical and cleaner
Biocide	Glutaraldehyde	Eliminates bacteria in the water that produce corrosive byproducts	Disinfectant; sterilize medical and dental equipment
Breaker	Ammonium persulfate	Allows a delayed break down of the gel polymer chains	Bleaching agent in detergent and hair cosmetics, manufacture of household plastics
Corrosion inhibitor	N, n-dimethyl formamide	Prevents the corrosion of the pipe	Used in pharmaceuticals, Acrylic fibers, plastics
Crosslinker	Borate salts	Maintains fluid viscosity as temperature increases	Laundry detergents, hand soaps, and cosmetics
Friction reducer	Polyacrylamide	Minimizes friction between the fluid and the pipe	Water treatment, soil conditioner
	Mineral oil		Make up remover, laxatives, candy
Gel	Guar gum or hydroxyethyl	Thickens the water in order to suspend the sand	Cosmetics, toothpaste, sauces, baked goods, ice cream
Iron control	Citric acid	Prevents precipitation of metal oxides	Food additive, flavouring in food and beverages; lemon juice ~7% Citric Acid
KCl	Potassium chloride	Creates a brine carrier fluid	Low sodium table salt substitute
Oxygen Scavenger	Ammonium bisulfite	Removes oxygen from the water to protect the pipe from corrosion	Cosmetics, food and beverage processing, water treatment
pH Adjusting Agent	Sodium or potassium carbonate	Maintains the effectiveness of other components, such as crosslinkers	Washing soda, detergents, soap, water softener, glass and ceramics
Proppant	Silica, quartz sand	Allows the fractures to remain open so the gas can escape	Drinking water filtration, play sand, concrete, brick mortar
Scale inhibitor	Ethylene glycol	Prevents scale deposits in the pipe	Automotive antifreeze, household cleansers, and de-icing agent
Surfactant	Isopropanol	Used to increase the viscosity of the fracture fluid	Glass cleaner, antiperspirant, and hair color

Note: The specific compounds used in a given hydraulic fracturing operation will vary depending on company preference, source water quality and site-specific characteristics of the target formation. The compounds shown in Table 4.1 are representative of the major compounds used in hydraulic fracturing of gas shales.

Source: US Department of Energy, Office of Fossil Fuel and National Technology Laboratory (April 2009). Modern Shale Gas Development in the United States: A Primer (p63) (USDOE, 2009).

US Benchmark: Shale Gas Well – Stimulation by (Multi-stage) Hydraulic Fracturing

Hydraulic Fracturing Equipment Spread: Once the well is drilled and completed, the site is prepared for hydraulic fracture stimulation (HFS). This consists of pumping a mixture of mostly water (99.5-99.9% by volume) and sand (proppant), plus a small amount (0.1-0.5%) of chemicals, under controlled (high pressure) conditions into the deep underground shale reservoir formations. The chemicals are first mixed into the fluid via a chemical addition trailer and sand (or ceramic particles) is then added via a blender before going to the high pressure pumps and down the well. Pumping of a fracture stage may last between 20 minutes to 4 hours, depending on the design.

Hydraulic Fracturing Design: The aim is to design a stimulation that will stay in the "pay zone", develop maximum producing formation contact and achieve maximum flow of hydrocarbons and minimum flow of produced water. The hydraulic fracturing fluid design specifies volume, rate and other factors to achieve the targeted fracture height, width, length and complexity.

Hydraulic Fracturing Fluid: The chemicals in the hydraulic fracturing fluid reduce fluid pumping friction, improve the stimulation performance and stop the formation of bacteria. Safe transport, storage and handling of these chemicals is important, and involves the use of collision-proof, double-walled containers, container mats under hydraulic fracturing fluid line connections, portable tank containment berms, and tank monitoring. Whilst most fracture treatments in shales are water with a friction reducer ("slickwater") plus chemicals, hybrid hydraulic fracturing (mixtures and separate stages) is becoming more common, in which slickwater is first used, followed by gels and cross-linked gels which thicken the water in order to suspend the sand and maintain fluid viscosity as the temperature increases.

Fluid Injection: The hydraulic fracturing fluid is injected into the well bore by an array of trucks fitted with high pressure pumps, at pressures ~50 MPa or greater. The hydraulic fracturing fluid flows out of the casing perforations into the shale formation, creating fractures in the reservoir rock. Sand (or ceramic – for example spherical particles of sintered bauxite) proppant remains in the main hydraulic fractures and keeps them open, allowing gas to flow to the well bore. Typically a fine mesh proppant is first used, followed by increased mesh sizes to prop larger fractures closer to the well bore. Proppant strength is selected to match the anticipated tectonic stresses. As a first approximation the fracture fluid pumping pressure depends on the value of the *in-situ* minimum principal stress. The next largest factor is the fluid friction in the well system, including flow through the perforations and into the first few metres of fracture.

Scale: Some numbers are helpful to get a sense of scale for hydraulic fracturing: for a stimulation requiring ~15 million litres of water (roughly the average fresh water volume for fracturing per US shale well), the amount of chemicals required (using the high-end percentage of 0.5%) is ~75,000 litres (2 road-tanker loads), and the amount of sand (proppant) required is of order 1 million kg (1000 tonne).

Fracture Growth: The effective *vertical* fracture growth in the United States shales, predicted by computer models and confirmed by microseismic and other monitoring is cited as mostly extending up to a maximum of 90 m from the well (King, 2012). Vertical fracture growth in most formations is effectively limited by barriers (rock layers of different structure, texture and strength in the sedimentary sequence) and loss of fluid to the rock (increasing contact area and invasion of natural fractures). There is also a stress-induced limit on upward growth. A detailed study (Fisher & Warpinski, 2011) has compiled data on the limits of hydraulic fracture height growth collected on thousands of hydraulic fracture treatments from 2001 to 2010, sorted by well depth, on four of the most active US shale plays (Barnett, Woodford, Marcellus and Eagle Ford), from microseismic, tiltmeter and other measurements. The most significant fracture height growth occurs in the deepest wells in a given reservoir. The data is largely consistent with the 90 m maximum upward extent cited by King (2012), however in circumstances where a transmissive fault is intersected, it can result in limited additional height growth, easily seen as spikes in the microseismic data, and in isolated cases with large spikes signifying growth up to 300 m. Planar vertical fractures can extend *laterally* 100m or more away from the wellbore, and the formation contact area of hydraulic fracturing fluid in a pay zone can approach 100,000 m^2 within 100 m of the wellbore.

Summary from details in G.E. King, SPE 152596 (King, 2012), and other references. See also Chesapeake Energy hydraulic fracturing animation (Chesapeake Energy, 2012a) and Schlumberger hydraulic fracturing video (Schlumberger, 2010)(links provided at References).

Flowback and Gas Flow

Flowback and Produced Water After Hydraulic Fracturing: When production begins, water and then gas flows. Around 15-50% of the hydraulic fracturing fluid is recovered (during flowback and as produced waters), and this is either recycled for other hydraulic fracturing operations, or disposed of in accordance with regulations. Flowback recovery rates can be 500-1000 litres per minute for a few hours, dropping to 160,000 litres per day within 24 hours and then quickly decreasing over several days to 50,000 litres/day. This is followed by a gradual decrease to 500 litres/day within a few weeks. It is cited that hydraulic fracturing fluid left behind poses little or no environmental risk since it is trapped at great depth and cannot migrate from the formation at greater than parts per million level.

Gas Flow: First gas may occur from 2 days to 20 days after hydraulic fracturing, depending on details such as shale permeability, back pressure and flowback control. The rate of water recovery drops significantly with gas flow, which makes it practical to initially flow produced water directly to tanks, and subsequently with a gas-liquid separator with the onset of gas flow. With evidence that absorption of water from the fracture fluid by mineral structures in the shale reservoir can act as a proppant for small fractures due to their enlargement (natural fractures open at 50 to 60% of rock fracture pressure but are difficult to prop), recent procedures include shutting wells for extended times after hydraulic fracturing and before flowback to maximise production returns.

Summary from details in G.E. King, SPE 152596 (King, 2012) *and other references. See also Chesapeake Energy hydraulic fracturing animation* (Chesapeake Energy Corporation, 2012) *and Schlumberger hydraulic fracturing video* (Schlumberger, 2010) *(links provided at References).*

multi-stage hydraulic fracturing, a series of different volumes of hydraulic fracturing fluids are injected with specific concentrations of proppant and other additives.

The chemicals used during hydraulic fracturing, although at very low concentration (by volume) in the hydraulic fracturing water (0.1 to 0.5%), are causing shale gas developers to adopt the following actions:

- Revealing what chemicals are used in fracture stimulation treatments,

- Pointing out that those chemical are at very low concentrations,

- Communicating other areas where the public comes into contact with the same chemicals: for example the 'gel' used in fracture stimulation treatments is also found in cosmetics,

- Removing/reformulating chemicals where needed and where possible: for example some fracture stimulation contractors can use UV light instead of a biocide to remove unwanted bacteria.

Water Management during Hydraulic Fracturing and Use of Brackish/Saline Water

The composition of produced water from a hydraulic fracturing stimulation varies from that of the initial fracture fluid at the start of flowback, to water dominated by the salt level of the shale near the end of clean-up, together with ions, compounds and contaminants reflective of the deep sedimentary deposition history. It can contain ions such as barium, strontium and bromine, and may have low concentrations of heavy metals and naturally occurring radioactive materials (NORM), such as isotopes of uranium, thorium and potassium or their decay products such as radium and radon that have been temporarily concentrated. It is cited that radioactivity levels of ions in well fluids are usually low and do not usually encroach US EPA thresholds, unless they are concentrated by formation of mineral scale or intentional trapping mechanisms. The flowback constituents dictate the level of care required and what treatments are required for fluid disposal or re-use (King, 2012).

Case Study of the use of Saline Water for Hydraulic Fracturing

One striking example of the application of saline water for hydraulic fracturing is Apache Corporation's British Columbia shale gas pad developments (King, 2012). In 2010, from a 2.4 ha pad, 16 horizontal wells were completed to recover gas from 1000 ha, requiring 46 M litre of freshwater per well (taken from local lakes) for a total of 274 fracture stages. In the 2011 development of a new pad, using 12 wells with a total of 154 fracture stages to recover gas from 2000 ha, the previous freshwater sources were replaced with high-Cl⁻, sour (H_2S) brine from a deep salt-water formation, located 600 m above the shale formation at 2440 m, in a 'closed-loop' hydraulic fracturing system – which minimised water use, minimised water storage (less than 5% of the job volume) and waste transport and reduced the need for many chemicals. The 140 F (60 C) temperature of the extracted water made heating unnecessary during winter operations and reduced air emissions. The brine was supplied at a high rate to a treating facility for sweetening and thence to the hydraulic fracturing spread for pumping. Flowback water was cleaned and re-injected. This advance has been made possible by more compatible chemical additives, in particular friction reducer chemicals that work in up to 70,000 ppm salinity levels.

The cost of processing and re-using produced water for hydraulic fracturing is being re-evaluated by the industry. Treatment of produced water to remove salt, suspended solids, specific ions, naturally occurring radioactive materials (NORMs), toxic chemicals and oil, and for bacterial control, involves a wide range of options, such as reverse osmosis and micro-, nano-, or ultra-filtration, similar to processes used to treat raw fresh water sources for drinking water (King, 2012). Regulated disposal of produced water is primarily through re-injection into (conventional) oil and gas producing pay zones for pressure maintenance, water flooding or other enhanced oil and gas recovery operations, with deep well disposal the secondary method.

Most United States shales in shale gas basins are of marine origin and have a salinity near that of sea water (*viz.* 35,000 ppm or 3.5%, predominantly sodium chloride). Whilst a freshwater supply is needed for drilling and cementing, the need for freshwater can be significantly reduced by using salt-water-based hydraulic fracturing fluids that are roughly matched to the reservoir salinity. Broadly, the water volume required for multi-stage hydraulic fracturing of United States horizontal wells is ten times (or more) the volume needed for drilling. A case study for the use of saline water for hydraulic fracturing, extracted from deep aquifers that overlay the shale targets, is described in a breakout box. This is particularly important in the Australian context, where significant shale resources occur in remote, arid areas as described in Chapter 3, and discussed in detail in Chapter 8 in relation to shale reservoirs in the Cooper Basin and overlying deep aquifers of the Great Artesian Basin.

Technical Risk and Risk Mitigation via Sensing Technology for Hydraulic fracturing in US Shale Gas Wells

A detailed discussion of risk for hydraulic fracturing in United States shale gas wells (King, 2012, pp. 55-65), describes a risk matrix (consequence *vs.* probability of occurrence) for some 20 key identified risk scenarios associated with hydraulic fracturing. The risk analysis is shown for the worst-case risk with normal probability and *without* the application of (mitigating) technology in the first few wells in an area and, by contrast, where technology *is* used at the appropriate stage and time of well development. The comparison highlights that technology is a powerful tool in making well selection, materials transport, fluid storage, well construction, hydraulic fracturing and clean-up operations safer.

Of the twenty key risks identified by King, nine are related to spills, both in road transport and at the well site (storage and operations). There are ten risks related to various aspects of

the hydraulic fracturing process and one risk related to emissions. The risks considered (worst cases and best cases are discussed in the paper for each) and their worst-case probability of occurrence [frequency – that is, 1 occurrence in 'x' fracture stimulations] are summarised in Table 4.2. As a summary, the key risks relate to on-site spills and well integrity issues induced by the hydraulic fracturing process, with the highest frequency risk being emissions of methane. Most recently a United States report by Resources for the Future (RFF) has looked in detail at environmental risks of shale gas development involving an extensive survey of expert opinion (Krupnick, *et al*., 2013).

Faults can connect deep shale reservoirs to aquifers and the intersection of faults by high pressure fluid from either hydraulic fracturing, or the disposal of large volumes of produced water from shale gas plays via deep injection in wastewater wells requires caution with regard to aquifer contamination and induced seismicity, respectively. The speed and vertical extent of fluid movement along a fault is an area of research. This subject is dealt with in detail in Chapters 8 and 9 of this report, which address water and seismicity issues. The issue of hydraulic fracturing and faults in the context of risk (aquifer contamination, seismicity) is dealt with in detail by Fisher and Warpinski (2011) for the United States shale gas plays.

Sensing technologies are important for controlling and monitoring the hydraulic fracturing process in real-time, particularly with regard to technical risk mitigation, and are summarised in the accompanying breakout box. From a technical perspective, mitigation of the risk from hydraulic fracturing involves identification and characterisation of local fault structures by 3D seismic measurement, avoiding fracture stimulation in the vicinity of active faults, and shutting down the fracture stimulation if unwanted vertical growth of fractures is observed by (real-time) microseismic measurement (Report to this Review by Cooke, 2013). Tiltmeter and downhole pressure measurements of (real-time) fracture propagation are also important. The United Kingdom study of hydraulic fracturing (The Royal Society and the Royal Academy of Engineering, 2012) discusses a 'cease (fracturing) operation' trigger at a threshold-measured seismicity, with separate reports recommending thresholds of 1.7 M_L and a more precautionary value of 0.5 M_L (see Chapter 9). Well integrity is also a key risk issue, particularly the integrity of cement seals, and pressure sensors placed in the annulus region between casing strings are used to detect leakage from the production casing.

The breakout box gives brief details of the sensing technologies employed, including microseismic, tiltmeter and pressure sensors,

Table 4.2: Key risks for hydraulic fracturing and worst case frequency

# 1	Spill (20,600 litres) of a transport load of water without chemicals [1 in 50,000].
# 2	Spill (1,890 litres) of concentrated liquid biocide or inhibitor [1 in 4.5 million].
# 3	Spill (227 kg) of dry additive [1 in 4.5 million].
# 4	Spill (1,135 litres) of diesel from ruptured saddle tank on truck (road wreck) [1 in 5100].
# 5	Spill (13,250 litres) of fuel from standard field location refueler (road wreck) [1 in 1 million].
# 6	Spill (80,000 litres) of well-site water (salt/fresh) storage tank – no additives [1 in 1000].
# 7	Spill (190 litres) of water treated for bacteria control [1 in 10,000].
# 8	Spill (190 litres) of diesel while refuelling pumpers [1 in 10,000].
# 9	Spill (80,000 litres) of stored frack water backflow containing chemicals [1 in 1000].
# 10	Frack ruptures surface casing at exact depth of fresh water sand [1 in 100,000].
# 11	Frack water cooling pulls tubing out of packer, frac fluid in sealed annulus [1 in 1000].
# 12	Frack opens mud channel in cement on well less than 2000 feet deep [1 in 1000].
# 13	Frack opens mud channel in cement on well greater than 2000 feet deep [1 in 1000].
# 14	Frack intersects another frac or wellbore in a producing well [1 in 10,000].
# 15	Frack intersects an abandoned wellbore [1 in 500,000].
# 16	Frack to surface through the rock strata (well less than 2000 feet deep) [1 in 200,000].
# 17	Frack to surface through the rock strata (well greater than 2000 feet deep) [no cases].
# 18	'Felt' earthquake resulting from hydraulic fracturing [no cases in US].
# 19	Frack changes output of a natural seep at surface [1 in 1 million].
# 20	Emissions of methane, CO_2, NO_X SO_X… [high frequency].

Adapted and tabulated from information in King, 2012.

temperature and flow logging, tracers and proppant tagging, fibre-optics and photography, and 3D seismic methods. This technology provides the tools to accurately monitor, in real-time, the subsurface propagation of hydraulically induced fractures.

Advanced Technologies

There are a number of advanced technical developments for shale gas extraction referred to in the literature. In summary:

1. **Proppant:** Proprietary fibres have been developed as an advanced proppant to replace sand, to provide more optimal gas flow from the fractured shale

Sensing Technology for Monitoring Hydraulic Fracturing

Microseismic Sensors: The key measurement during hydraulic fracturing is fracture growth, both in orientation and extent. This is required in real-time (< 5 minute time delay). Fracturing fluid injection causes shear slip along natural fractures in the reservoir and the surrounding rock, and this produces a microseismic signal that can be measured by a long array (60-120 m) of accelerometers/geophones located in an offset monitoring well, situated approximately 100 m or more away at comparable depth. In essence, this technique triangulates the location of sounds made by rock breaking during shear fracturing. Accuracies of 15 m are cited, using one to three listening arrays (Schlumberger, 2006; Halliburton, 2007). In actual operations, microseismic measurement may only be used if an appropriate (deep) offset well is available. The sensors and insertion tools are generally designed for temperatures up to 175 C (~350 F), and between 175-200 C (~350-400 F) is a temperature range where specialist suppliers are required. Microseismic measurement can be problematic above 200 C (~400 F) (Santos Limited, 2013).

Tiltmeters: The opening of a fracture at reservoir depth causes small displacements (rock deformation and tilt) that can be sensed (with resolution better than one nanoradian) by an array of tiltmeters either located in shallow (~10 m) offset wells at the site surface, or more sensitively in a deep offset well at comparable depth to the fracturing events, providing information on fracture orientation and direction (azimuth) (Schlumberger, 2006). Tiltmeter resolution can be better than 1 nanoradian, although background noise and drift can be problematic in certain locations (Pitkin, *et al*., 2012).

Pressure Sensors: Downhole pressures provide an indirect measurement of fracture height, showing characteristic features that correlate with fracture initiation, propagation, height growth (or lack of height growth), containment and closure. Pressure sensors are connected to the production casing, as well as the outer casings to monitor well integrity.

Temperature and Flow Logging: After a hydraulic fracturing operation, logs of temperature and flow along the well provide information correlated with fracture location and hence growth (and also fracture height for vertical wells).

Proppant Tagging: Radioactive isotopes tagged to the proppant can be subsequently analysed to locate where different stages of proppant went, and hence the fracture location.

Chemical Tracers: can be added to the hydraulic fracturing fluid to improve understanding of fracture fluid loss and flowback efficiency.

Temperature Measurement: Shale formations are at higher temperatures than hydraulic fracturing fluid at the surface. Cooling due to injected fluids can be detected to provide data on hydraulic fracturing performance.

Fibre-optic Sensors: Measuring temperature, pressure and sound provide real-time information on fracture location in a well. Fibre-optic sensors are particularly useful for downhole measurements of high pressure/high temperature conditions, beyond the limits of electronic gauges (Pitkin, *et al*., 2012).

Photography: Downhole, side-looking cameras have been developed to provide images of fracture growth. They are limited to low pressure and clear fluid regimes.

3D Seismic: Using a seismic source and a grid of geophones on the surface, a 3D seismic survey can accurately image reflected seismic waves utilising multiple points of observation, to provide a representative image of a volume of subsurface geologic features and formations via a computer-aided reconstruction. Importantly this can map the location of aquifers and pre-existing fault risks to be avoided by fracture stimulation (Resolution Resources International, 2009).

(Schlumberger, 2012). This development is referred to as the 'HiWAY Flow-Channel Hydraulic Fracturing System'. HiWAY hydraulic fracturing creates open pathways inside the fracture, enabling hydrocarbons to flow through stable channels rather than the proppant. This optimises connectivity between the reservoir and the wellbore.

2. **Cement Seals**: Sliding sleeves and mechanical isolation devices have been developed to replace cement seals (Baker Hughes Inc, 2010; Marathon Oil Corp., 2012). This development is referred to as the 'Frack Point Openhole Fracture Completion System'. This multi-stage hydraulic fracturing system uses ball-activated fracturing sleeves.

3. **Fracturing, Drilling**: Alternative methods of fracturing shale rock, including use of electrical pulses, waterless fracturing (including gels, and carbon dioxide and nitrogen gas foams), automation, and smaller drill rigs have been reported (Royal Dutch Shell, 2012). A non-hydraulic fracturing method involving the use of exothermic heat from metal-oxide reactions has been announced by a Texas company (Chimera Energy Corporation, 2012). Most recently, Halliburton has announced a new, non-toxic fracturing fluid ('Clean Stim') that contains safe food-industry ingredients (IEAGHG, 2013).

4. **Alternative Water Sources**: As mentioned previously, the use of saline water for hydraulic fracturing is being developed, drawing on information from offshore hydraulic fracturing.

5. **New Chemicals**: Chemical rating systems have been developed that 'score' the chemical mix for environmental, toxicological and physical hazards (Jordan, *et al*., 2010). This has led to the replacement of chemicals by mechanical options and the utilisation of food grade chemicals, biodegradable biocides, and the use of lower volumes of chemicals.

Australia: Technical Differences with the United States impacting Hydraulic Fracturing

Mechanical properties of the shales and *in-situ* tectonic stress regimes are important factors for well stimulation by hydraulic fracturing. North American shale plays are generally in extensional stress regimes whereas Australian shales in some basins experience higher compressive tectonic stress. This phenomenon is shown in world and Australian stress maps

Australia: In-Situ Stress and Hydraulic Fracturing

'In-situ stress will play a critical role in determining how to drill production wells. The North American shale gas practice has evolved around drilling long horizontal wells and then placing 10 to 40 hydraulic fractures transverse to the wellbore to achieve the stimulation effect needed to produce the gas at economic rates. The gas shales in North America are in 'relaxed' basins where the minimum stress is one of the horizontal stresses. This stress state results in vertical hydraulic fractures, which require horizontal wells in order to place a number of fractures along one well. Australian gas shales can be expected to be subject to higher horizontal stresses and some may even be in a situation where the vertical stress is the minimum stress. In that case, hydraulic fractures will grow with a horizontal orientation, which requires near vertical wells for effective production. However, horizontal hydraulic fractures are parallel to bedding in the reservoir and may not provide effective stimulation because low permeability layers in the reservoir may act as barriers to gas movement. If a network of subvertical natural fractures exist in such reservoirs and can be stimulated during the fracturing treatment, horizontal hydraulic fractures may prove to be highly effective. Research required to support the Australian shale gas industry centres around characterising the stress state and natural fracture system and developing methods to predict the stimulation effect arising from the interaction of the hydraulic fracture with the natural fractures.'

Extract from CSIRO (2012f).

(Heidbach, *et al.*, 2009; Australian School of Petroleum, 2012). The differing stress regimes have significant implications for hydraulic fracturing characteristics in the two regions, since fractures propagate perpendicularly to the direction of least principal stress, following the direction of maximum principal stress (Fisher & Warpinski, 2011). This issue, and its implications for the fracturing of Australian shales, has been highlighted in the submission to this Review from CSIRO (CSIRO, 2012f), as outlined in the accompanying breakout box. In summary, the CSIRO submission's key point is that whilst the US extensional stress regime is compatible with multi-stage transverse vertical fracturing from deep horizontal wells, Australian gas shales can be subject to higher horizontal stresses, which in certain situations can lead to hydraulic fractures with significant horizontal orientation components.

Australian shale gas activity to date is characterised by vertical wells with a complexity of horizontal/vertical fracturing components, with some reports of hydraulic fractures from vertical wells initiating vertically and twisting to horizontal due to the *in-situ* stress regime. Additionally, in the Cooper Basin, the large horizontal stress causes significant variation in the fracture gradients (over 100 km length scale) that follow structural trends and reservoir quality.

Horizontal shale gas wells require a deep *in-situ* regime that will sustain a significant vertical fracture component (at the many fracture stages along the 1-3 km lateral length of the horizontal well – see Figure 4.3). Fracturing experience from vertical wells in the Cooper Basin has been recently discussed by Pitkin *et al.* (2012), in relation to the Roseneath shale, Epsilon formation, Murteree shale (REM) targets and two vertical wells separated by 25 km, Holdfast-1 and Encounter-1, drilled and hydraulically fractured specifically to examine fracture orientation. In this work it is stated that *'General fracturing experience in the Cooper Basin has indicated that the magnitude of the minimum horizontal stress*

gradient increases with depth due to an increase in tectonic strain. Therefore due to the increased target depth and overpressure…..the minimum horizontal stress in the REM at Holdfast-1 and Encounter-1 was expected to approach the vertical overburden stress, thereby generating potential for induced fractures to be oriented in the horizontal plane. In this eventuality, vertical wells (not horizontal wells) may be the optimal well configuration to maximise reservoir contact and drainage'.

Fracture orientation results for Holdfast-1 and Encounter-1, measured by an array of 44 tiltmeters randomly positioned within a radius of 2.5 km of the well bore (at each well), indicated the required predominantly vertical fracture growth for one well, whilst horizontal volumetric fracture components above 50% were measured for two intervals in the second well (Pitkin, *et al.*, 2012). In short, for Holdfast-1 '*all mapped stages indicated predominantly vertical fracture growth with a maximum of 25% horizontal component observed'*, whereas '*The horizontal volumetric component at Encounter-1 was in the range of 26 to 53%, indicating possible twisting of fractures…Two of the intervals in particular, the Murteree Shale and the middle Epsilon Formation showed horizontal volumetric components above 50%'.*

A number of horizontal shale wells will be developed by industry in the Cooper Basin in the near future and this will considerably clarify the situation.

Differences in the organic matter and minerals present in US and Australian shales, due to the differing depositional environments (United States – marine conditions; Australia – marine, lacustrine or deltaic), can also affect the tendency of the shale to fracture and in turn the amount of gas produced. Further, Australian shales cover a wide range of geological time (Proterozoic to Cretaceous), which differs from the United States shales (mainly Devonian to Carboniferous), and have different thermal regimes – which will also affect gas productivities. (Submission to this Review by Geoscience Australia, 2012; and CSIRO, 2012f.)

Australia: Technical Issues in Current Development of Deep Unconventional Gas

Due to the early exploratory status of Australian shale gas development, technical detail is limited. One source of publicly available information is environmental impact reports (EIRs) lodged in relation to fracture simulations for shale and tight gas targets in the Australian sedimentary basins. Another source is State government regulatory documents and roadmaps for shale gas which contain technical information, and presentations by exploration companies (DMITRE, SA, 2012); Industry presentations, SPE Symposium on Australian Shale Gas, Sydney, 2012). Developments in the Cooper Basin are representative of the key technical detail (with similar issues reported for the North Perth Basin).

The technical differences between the situation in the United States and Australia were discussed at a recent Society of Petroleum Engineers (SPE) Symposium held in Australia in 2012 (SPE, 2012). This symposium noted that compressive stresses are very high in the Cooper Basin and this can lead to significant (non-optimal) longitudinal horizontal fracture components at some locations. Experience with hydraulic fracturing of coal seam gas wells in Australia is of complex fractures with both vertical and horizontal components. This situation has already been experienced for Australian shale gas wells.

The symposium further noted that the whole of the Permian section of the SW Cooper Basin is prospective for deep unconventional gas, involving shale, tight sand and coal strata within the same well bore at various depths. This mixed lithology was described as a 'continuous' vertical gas play, for which hydraulic fracturing is the enabling technology. An 'egalitarian' completion strategy was cited in which all reservoirs in the vertical column have an equal opportunity to contribute to production. It was also suggested that there may be mixtures of both conventional and unconventional plays in Australia as a function of depth and lithology. The symposium provided technical detail of hydraulic fracturing (at multiple depths) in vertical, deep unconventional gas wells in the basin. Ultimately large tracts of the basin could be drilled with closely spaced vertical wells, initially with a focus on tight sandstone reservoirs but eventually on the mixed lithology resource. Further details may also be found in public reports of Australian petroleum companies (Beach Energy, 2012a; Campbell, 2009; Santos Limited, 2012b).

Comparison with Coal Seam Gas Technologies

CSG is primarily extracted from coal seams at depths from 250 to 1000 m. Up to 750 m depth, coal rank and gas content per tonne of *in-situ* coal increase; at greater depths, coal permeability decreases thus lowering gas extraction rates.

Coal seam gas is sorbed in organic matter, and held there from the hydrostatic water pressure exerted on the coal seam by the water table. When this water pressure is removed by pumping down the water table, the gas is released.

Most of the CSG production to date in Australia, particularly in Queensland, has been produced from drill holes without the need for stimulation (involving hydraulic fracturing of the coal seam). This is the reverse situation to that in the United States with CSG. However as CSG wells get deeper, or are located in less permeable coal seams, the need for fracturing will probably increase.

Shale gas in Australia is generally located at depths in excess of 3000 m, which is considerably deeper than CSG resources. Shale gas, as distinct to CSG, is tightly held within the shale, which is of orders of magnitude less permeable and less porous than coal and hence has to be extensively hydraulically fractured to release the methane.

Initial commercial production of CSG at Moura mine in Queensland in 1995/96 involved the use of hydraulic fracturing of the coal seam from vertically drilled holes and applying technology from the United States Alabama/Black Warrior Basin. This proved unsuccessful because of the different geological ground stress regimes between the two locations. In Eastern Australia the principal stresses are horizontal and 2 to 3 times the vertical stress, whereas in the United

States both stresses are approximately equal. The initial gas production from the wells at Moura was in line with forecast, but declined rapidly and the wells were ultimately abandoned.

Initial CSG developments in Queensland, particularly in the Bowen Basin, focused on gas production from drilled holes (both vertical and deviated) with minimal hydraulic fracturing. However, much of the more recent CSG developments have been centred around 'sweet zones' where the anticlinal nature of the underlying formation has favoured large and spontaneous gas flows with minimum stimulation. These zones have realised daily flows in excess of 1.0 mcm/d. However, current CSG developers (Santos and Origin) have indicated that the current level of hydraulic fracturing may well rise from the current 10% to upwards of 40%, particularly in areas of low coal permeability (Institute for Sustainable Futures, UTS, 2011).

The AGL Camden project is the only major commercial CSG project in New South Wales. This project adopted a drill hole pattern of 104 vertical wells (all hydraulically fractured) and 20 horizontal wells (not hydraulically fractured).

Coal Seam Gas Extraction

In CSG extraction, holes are drilled parallel to the dip of the coal seam and in so doing cut through the coal cleats, thus enabling release of gas once the water pressure within the seam has reduced by pumping. This release in pressure enables desorption of gas from the coal. These CSG extraction holes were initially drilled down-dip into the 'high walls' of existing exposed open cut coal seams. The technology has now been extended to drill such holes from the surface, either through long radius (deviated) drill holes (LRD) or through a fan-like series of holes from a central vertical well, termed tight radius drilling (TRD).

Present CSG production wells in Australia (other than those producing in so called 'sweet zones') have been predominantly deviated holes approximately 15 cm in diameter drilled from the surface and penetrating in excess of a kilometre within the target coal seam.

Using Australian-developed technology on guidance of the drill penetrating the coal seam hundreds of metres below the surface, it became possible to intersect another drilled vertical water wellhole, usually in the 15-20 cm diameter range. As a result, the vertical hole is available to house a pump to reduce the water pressure on the coal seam. The gas then continuously desorbs from the coal seam and flows to the surface through the deviated drill hole, where it is collected for processing and distribution.

Because the flow of gas is unlike conventional gas reservoirs which release gas at very high pressures, CSG simply rises to the surface at atmospheric pressure, is collected, and then fed at low pressure to the treatment plant prior to compression into a high pressure transmission pipeline.

The quantity of water extracted from these CSG Wells, particularly in early development (produced water) is widely variable, and is generally orders of magnitude higher than that resulting from shale gas extraction.

If hydraulic fracturing is technically necessary to activate a particular (low permeability) coal seam, then it is a much easier process than shale gas hydraulic fracturing. In the CSG case a vertical hole is drilled, involving a steel cased bore lining to the top of the target seam. The drilling is continued through the coal seam (there is no steel case lining within the coal seam) and then terminated just below the bottom of the seam. The wellhead is then sealed off with controlling valves prior to hydraulic fracturing. Whilst proppants and chemicals (viscosity controlling fluids) are used in the hydraulic fracturing of coal seams, they are used at a significantly lower level than those used in shale gas hydraulic fracturing.

Conclusion

In summary, with regard to hydraulic fracturing it is not yet clear as to the extent to which the US techno-economic success resulting from the optimal combination of horizontal drilling of deep shale reservoirs and multi-stage transverse vertical fracturing will translate directly to Australian shales. A horizontal shale well has just been drilled but not yet fractured in Australia (hydraulic fracturing planned for 2013), but from fracturing results in vertical wells this is a complex issue. A number of horizontal shale wells in the Cooper Basin are planned over the next 18 months and this will considerably add to the knowledge base to better assess the Australian situation. There is additionally the potentially 'counter-balancing' factor that the Australian mixed lithology for its deep unconventional resources in particular basins, that include tight gas, constitutes a 'continuous' gas play that can be accessed by hydraulic fracturing stages at different depths in a single well. This additional approach is compatible with drilling a number of wells with near-vertical sections at depth, from a single pad.

Deep aquifers are also an important consideration in Australia. The Great Artesian Basin (GAB) extends beneath much of the arid interior of Queensland, New South Wales, South Australia and the Northern Territory. The deepest aquifer, the Hutton Sandstone, extends to a depth approaching 3000 m in the Cooper Basin region, 300-800 m above the shale/tight sand reservoirs that constitute the unconventional gas targets. There are two important technical issues that this raises: (i) ensuring well integrity at depth and (ii) monitoring to ensure that there is no long distance vertical growth of hydraulic fracturing. This subject is discussed in detail in Chapter 8 of this report.

Figure 4.3 US benchmark – Horizontal drilling, multi-stage hydraulic fracturing

1 WELL DRILLING

Drilling Rig

Well Head
Wire Line Unit

Cement Seals
Steel Casings

AQUIFER

SALT WATER

PRODUCTION ZONE

Production Casing

Casing Strings
NOT TO SCALE

3 HYDRAULIC FRACTURE STIMULATION

Chemical Truck
Fracture Fluid Storage Tanks
Hydration Unit
Blending Equipment
Manifold
Sand Storage Units

Water Storage Empoundment

High Pressure Pump Trucks

Treatment Monitoring Van

Schematic Only
Not to Scale

AQUIFER

SALT WATER ZONE

2000–3000m

PRODUCTION ZONE

Fracture Stages

600 – 1800+ m

2 WELL COMPLETION

Perforation Gun

Shaped Explosive Charge Perforation

Steel Casing

Plug

Cement

4 GENERALISED STRESS REGIME
United States:
Transverse Vertical Fracture

Sources: Adapted from multiple sources. See caption for attribution
Design/Illustration: CampbellBarnett Design Partners, Sydney

Sources: Adapted from (1) US Department of Energy, 'Modern Shale Gas Production in the United States', April 2009, p.52; (2,3) Ingenia Issue 52, 'Shale Gas', September 2012, Hydraulic Fracturing Graphic (Graphic News), p.16; (2) Chesapeake Energy Hydraulic Fracturing Animation (youtube) – see references for link; (4) API Guidance Document HF1, 'Hydraulic Fracturing Operations', October 2009, p.17.

Figure 4.3 illustrates the three steps involved in bringing a deep US shale gas well into production. Note that the diagram is schematic, and the surface features (trucks, drilling rigs, tanks, etc.) and distances subsurface are NOT drawn to scale. Note also that the blue bands, representing aquifers, are in fact permeable sandstone rock layers containing water in the microscopic pore spaces in the rock.

The first step involves drilling the vertical and horizontal sections of the well and establishing the steel casing strings and cement seals that isolate the well from freshwater and saltwater aquifers, after which the drill rig is removed and hydraulic fracturing infrastructure is set up (1).

The second step is termed 'well completion' (2) and involves providing a connecting pathway between the horizontal well bore and the shale reservoir. This is achieved by lowering a perforating gun by wire-line down the well bore into the production zone in the shale. The gun contains electrically triggered explosive charges, which punch through the steel casing of the well and its surrounding cement seal, creating perforations into the shale strata. These perforations are relatively small, and protrude a few tens of centimetres into the shale.

Once the well is 'completed', stimulation of gas flow from the shale reservoir is achieved by hydraulic fracturing. This involves injecting fracturing liquid (mainly water) down the well at high pressure (3). This fluid enters the shale strata through the previously engineered perforations in the well bore, initiating fractures in the shale which propagate in planes transverse to the horizontal well. The fracturing fluid is mainly water, plus a small percentage of chemicals and sand or ceramic.

Sand or ceramic particles in the fracturing fluid ('proppant') hold the fractures open when the high pressure injection is completed. This stimulates gas flow from the shale strata into the well bore and up to the wellhead at the surface. Initially the fracturing fluid is returned to the surface ('flowback water'), followed by a mixture of liquid and gas, and finally gas flow. Around 15-50% of the fracturing fluid is recovered, which can be re-cycled for re-use or disposed of in accordance with regulations.

Well completion and hydraulic fracturing is completed in stages, via the use of stage isolation plugs, which are subsequently drilled out to allow all stages to contribute to the gas flow.

The fracturing infrastructure spread at the well site involves fracture fluid storage tanks, sand and chemical storage units, and blending equipment to mix the fracturing fluid components. The fracture fluid enters a manifold connected to a number of truck-mounted high pressure pumps, which act in combination to pump the fluid down the well bore at high pressure.

Detail: The generalised deep *in-situ*, 'extensional' stress regime for United States shales is shown (4), for which the maximum principal stress is in the vertical direction. Fractures propagate perpendicularly to the direction of least principal stress, following the direction of maximum principal stress (Energy API, 2009). In the cube (4), arrow sizes indicate schematically the magnitude of the stress components (vertical stress is maximum). This leads to hydraulic fracturing in transverse vertical planes (shown in dark yellow) for horizontal wells drilled in the direction of least horizontal stress, as shown. By drilling long, horizontal wells it is possible to engineer multiple vertical fracture planes, providing large contact area with the shale reservoir and this leads to economic production from a single well.

Figure 4.4 Aquifer/seismicity issues and sensing technology

1 WELL INTEGRITY, FAULTS

Schematic Only
Not to Scale

Shallow Aquifer
Tiltmeter

Impermeable Layer

Deep Aquifer

Impermeable Layer

2000–3000m

Pre-existing Fault
(schematic)

Gas Bearing
Formation

Induced
Seismicity

Deep
Monitoring
Well

Tiltmeter
Surface
Deformation
Sensor

AQUIFER

SALT WATER ZONE

Microseismic
Sensor Array

Seismic
Signal

PRODUCTION ZONE

Fracture
Initiation

Fracture
Breakdown

Fracture
Propagation

Fracture
Closure

Bottomhole Pressure

Fluid Injection Rate

~ 0.5 – 4 hours

Time

Pressure
Sensor
(Casing
Annulus)

Methane

Pressure
Sensor
(Production
Casing)

2 PRESSURE SENSING

Solar
Panel

4"
Inner
Pipe

Tiltmeter
Cement

Sand

5–40ft

Vertical Fracture Extent

Well

~100m

Fracture Stages

0

1000

2000

Depth (m)

US Marcellus Shale

Fracture Stages

3 TILTMETER

4 MICROSEISMIC DATA

Figure 4.4 illustrates two key subsurface risk issues for shale gas wells, namely potential aquifer contamination and induced seismicity, and sensing technology deployed to minimise these risks (1). (See Chapters 8 and 9 for a full discussion). Note that the diagram is schematic, and the surface features (trucks, sensors, etc.) and distances subsurface are NOT drawn to scale. Note also that the blue bands, representing aquifers, are in fact permeable sandstone rock layers containing water in the microscopic pore spaces in the rock. The small red arrows in (1) represent the desired movement of gas in the hydraulic fracture process.

The first risk issue relates to well integrity, namely ensuring that the jointed steel casings of the well, and their surrounding cement seals, maintain isolation between the hydraulic fracturing fluid and subsequent gas flow in the well bore, and both freshwater and saltwater aquifers through which the well is drilled. This is to avoid potential aquifer contamination, shown schematically by the white arrows in the shaded blue regions (1).

The second risk issue relates to the potential intersection of a pre-existing fault by a fracture stage, which could lead to low-magnitude induced seismicity arising from release of energy by the fault caused by the high pressure fracturing fluid entering the fault structure, depending on the nature of the fault. Red concentric circles at a point along the horizontal well represent this potential induced seismicity. There could also be an issue with regard to upward transport of fracturing fluid along the fault, shown schematically in (1), if there are deep overlying aquifers in close proximity and the fluid pressure is high enough.

To help mitigate these risks, real-time sensing technology is used to monitor well integrity and the hydraulic fracturing process.

One component of the mitigating sensing technology is the use of pressure sensors (1), (2). Sensors located in the low-pressure cemented annular region between steel casing strings of the well that provide isolation from aquifers detect breakdown in well integrity through measurement of changes in casing pressure.

Pressure sensors inside the production casing measure the pressure in the well bore during hydraulic fracturing, which has a characteristic signature associated with 'normal' fracture initiation, breakdown and propagation. This 'pressure signature' is shown as a graph in the diagram (2). Intersection of a fault perturbs this signature, alerting operators to take mitigating action.

A second method is to use acoustic sensors. An array of acoustic sensors located in a deep offset monitoring well detects the location of sounds made by rock breaking in the hydraulic fracturing process through triangulation of the acoustic signals reaching sensors in the array. This provides real-time measurement of fracture growth with accuracies around 15 metres. This acoustic signal, represented schematically by red curved lines in (1), is sensitive to induced seismicity and can be used to provide a 'cease operation' trigger if signal above a threshold level is recorded.

Shallow tiltmeters, a sophisticated version of a spirit level, are also used (1), (3). The tiltmeters, shown in cross-section, detect the real-time deformation at the surface caused by the opening of fractures at depth, and serve a similar purpose to the microseismic array, providing information on fracture orientation and azimuth. Abnormal pressures, tiltmeter signals and microseismic signals can be used as triggers for cease operation.

Detail: Microseismic sensors (4) are used to monitor the vertical extent of fracture growth, and indicative data are shown as a graph in cross-section for a compilation of a number of US shales over several fracture stages (Schlumberger, 2012). For US shales the upward vertical extent is mostly 90 m or less (King, 2012), although additional height growth can occur where a transmissive fault is intersected – see Hydraulic Fracturing text box. A second graph shows microseismic data (from many thousands of hydraulic fracturing events) for horizontal drilling and multi-stage hydraulic fracturing of the US Marcellus shale (Fisher & Warpinski, 2011). This plots the vertical extent of fracture tip growth upwards and downwards (red spikes) contrasted with the depth of overlying water sources (blue spikes). Note that the separation distance between the two is very large. Larger (upward) red spikes correspond to hydraulic fractures intersecting small faults.

Figure 4.5 Australia: Cooper Basin – In-situ stress regime, deep aquifers, mixed lithology

1 DEEP UNCONVENTIONAL GAS WELLS: SCHEMATIC

Vertical Well   Horizontal Well   Rock Unit

Lake Eyre Basin
Eromanga Basin
Cooper Basin

Depth (m)
1000
2000
3000

Cement
Steel Casing
Cement
Steel Casing
Cement
Steel Casing

Great Artesian Basin Deep Aquifers

Low Permeability Layer

Lake Eyre Basin
Winton Formation
Mackunda Formation
Allaru Formation
Wallumbilla Formation
Cadna-owie Formation
Murta Formation
Namur Sandstone
Westbourne Formation
Adori Sandstone
Birkhead Formation
Hutton Sandstone
Nappamerri Group
Toolachee Formation
Daralingie Formation
Roseneath Shale
Epsilon Formation
Murteree Shale
Patchawarra Formation
Tirrawarra Sandstone
Merrimelia Formation
Basement

G A B

300-800m Separation

R E M

2 MIXED LITHOLOGY
Permian Target

PERMIAN
WET GAS TARGET INTERVAL

Toolachee Formation
Daralingie Formation
R E M
Patchawarra Formation
~1000m
Tirrawarra Sandstone
Merrimelia Formation

Sandstone   Shale
Conglomerate   Coal

3 DEEP AQUIFERS
3D Seismic Data

2500m

Surface

Deep GAB Aquifer Band

300-800m Separation

R

Big Lake Fault

4 GENERALISED STRESS REGIME
Longitudinal Horizontal Fracture

GAB Aquifers

NOT TO SCALE

Cadna-owie Formation
Hutton Sandstone
Approximate Roseneath Shale

Cooper Basin

There are important geological differences between Australian and United States shales that may require a tailored approach to application of the benchmark horizontal drilling, multi-stage vertical fracturing strategy successfully proven in the United States. In particular there are differences in the geological stress regime for some Australian basins, which determine how the shales fracture.

Figure 4.5 shows rock strata in the Cooper Basin (1), (2), (3), and identifies the deep Roseneath, Epsilon and Murteree (REM) shale targets (1), (2), and overlying deep aquifers of the Great Artesian Basin (GAB) (1), (3). Note that the diagram is schematic and the lateral features and distances shown subsurface are NOT drawn to scale. Note also that the blue bands (1), (3), (4), representing aquifers, are in fact permeable sandstone rock layers containing water in the microscopic pore spaces in the rock.

In addition to the REM shale targets, overlying and underlying rock formations importantly contain tight gas in sandstones, and deep coal seam gas, all of which require hydraulic fracturing for extraction (2). This continuous vertical column of gas-bearing strata (called a 'mixed lithology') can be accessed by hydraulic fracturing at different depths from the same vertical well bore, as shown schematically (1). This approach is compatible with the drilling of a number of wells, with near-vertical sections at depth, from a single drilling pad.

Also shown schematically is a pair of US-type horizontal wells (as in Figure 4.3) from the same pad specifically targeting the REM shale layers (1). Horizontal shale gas wells require a deep *in-situ* stress regime that will sustain a significant vertical fracture component (at the many fracture stages along the 1-3 km lateral length of the horizontal well – as shown in Figure 4.3). Fracturing experience from vertical wells in the Cooper Basin has indicated that the minimum horizontal stress at REM target depths might approach or

in some cases exceed the vertical overburden stress, generating the potential for fractures to be oriented in the horizontal plane at some locations (Pitkin, *et al*., 2012). This 'compressive stress' situation is shown schematically (4), where the horizontal fracture plane is shown in dark yellow. Two vertical wells, separated by 25 km in the Cooper Basin, drilled and hydraulically fractured specifically to evaluate this issue via fracture orientation measurement by tiltmeter arrays, indicated the required predominantly vertical fracture growth for one well, whilst horizontal volumetric fracture components above 50% were measured for two intervals in the second well (Pitkin, *et al*., 2012). A number of horizontal shale wells will be developed by industry in the Cooper Basin in the near future and this will considerably clarify the situation.

The deepest Great Artesian Basin (GAB) aquifer, the Hutton sandstone, is vertically separated from the Roseneath shale by 300-800 m (as shown in (1), (3)). This relatively close proximity of deep GAB aquifers to the deep unconventional gas targets requires excellent well integrity at depth and best-practice monitoring of hydraulic fracturing to ensure isolation, particularly if local transmissive fault structures are present. Some of the techniques for sensing and monitoring of the hydraulic fracturing process are shown schematically in Figure 4.4. The Cooper Basin is a geothermal hotspot, with temperatures at reservoir depth above 200 C (~400 F), which can however be problematic for microseismic sensors in deep offset wells (Santos Limited, 2013).

Detail: A 3D seismic data image (Cooke, 2013) of the subsurface geological structure is also shown (3). The separation of the deep GAB aquifer band and the Roseneath shale strata can be seen, together with the location of a known fault structure (the 'Big Lake Fault'). A cross sectional view (east-west) of the GAB deep aquifers (not to scale) is also shown for reference.

5 | Infrastructure considerations

The development of a shale gas industry in Australia will mean the drilling of thousands of wells in remote areas of the country. This gas must then be piped to a market, or processed to other 'value-add' products such as liquid fuels. Of great importance is the relative cost of providing this infrastructure to remote regions, relative to the current experience, both with coal seam gas in Australia and shale gas in the United States.

Drilling Rigs

The number of drilling rigs required is a function of the drilling rig productivity, estimates of which can range from 6 to 40 days per well. Timing for well completion and hydraulic fracturing are also important; these can range from 7 to 20 days (DMITRE, SA, 2012; Report to this Review by Sinclair Knight Merz, 2013). The total time required for a well to commence production can therefore be between 13 and 60 days. Based on these numbers, one drilling rig will produce between 11 and 18 wells per year.

Table 5.1: Indicative schedule for rigs and units required for a 6 tcf (0.17 tcm) development of unconventional gas in the Cooper Basin

	Year 1	Year 2	Year 3	Years 4 – 14
Drilling Rigs	3	5	9	15
Workover* Rigs	1	1	2	3
Fracture Stimulation Crews	1	2	3	5

*A "workover" is a re-stimulation of an existing well to encourage greater gas flows.
Source: DMITRE, SA, 2012.

Figure 5.1: Availability of drilling rigs in the United States (a) and the Fourth District (b) (where unconventional gas is dominant over conventional supplies)
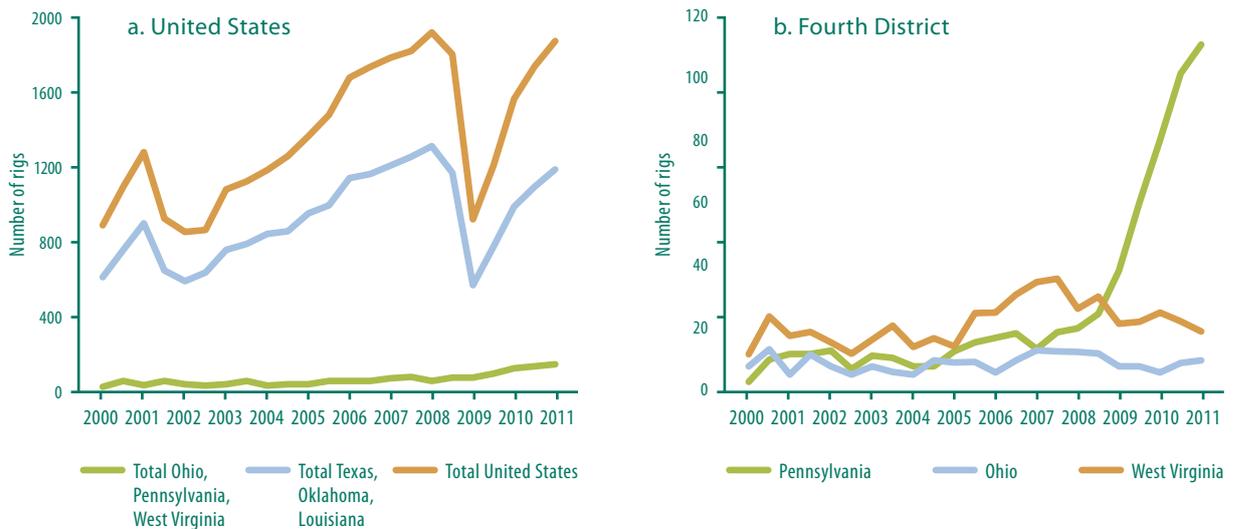
Source: Sadowski and Jacobson, 2011.

The South Australian "*Roadmap for Unconventional Gas Projects in South Australia*" identifies the infrastructure for the drilling operation that would be needed for a 6 tcf (0.17 tcm) development of unconventional gas in the Cooper Basin, as shown in Table 5.1.

For early shale projects in Australia, some inefficiency will most likely have to be accepted. SKM (Report to this Review by Sinclair Knight Merz, 2013) estimate that for a smaller project over 20 years, producing 50 PJ per year or around 1.4 tcf (0.04 tcm) in total, five drilling rigs, one completion rig and two hydraulic fracturing rigs would be needed. Given that there is the potential for 85 tcf (2.4 tcm) of sales gas from the Cooper Basin alone (US Energy Information Administration, 2011) and potentially 650 tcf (18 tcm) (DMITRE, SA, 2012) throughout Australia, a significant shale gas industry would require at least two or three times the infrastructure presented in Table 5.1, and possibly up to 20 times these requirements as it develops. This

could mean up to 300 drilling rigs in operation at any one time in Australia.

The availability of such drilling rigs and experienced frack crews is currently very limited, with only two rigs in Australia capable of doing the required work (Bernstein Research, 2011). The drilling technology developed in Australia for CSG (coil tubing rigs) is not applicable to the deeper shale gas wells, which require more traditional jointed pipe rigs. Consequently, synergies between shale and CSG drilling are unlikely. Hybrid rigs, that use coil to a set depth then drill to full depth with jointed pipe, are emerging in the United States (Report to this Review by Sinclair Knight Merz, 2013) and these may offer greater flexibility in Australia.

The limited availability of drilling rigs is contrary to the United States experience, where a very important driver for shale gas developments has been access to substantial and inexpensive drilling capacity as conventional gas production

on land declined sharply (Asche, *et al.*, 2012). In the United States, over 1800 rigs were in active use in 2008 (Sadowski & Jacobson, 2011). These data are shown in Figure 5.1.

The current practice in CSG in Queensland is for most large pieces of equipment to be imported from overseas (Report to this Review by Sinclair Knight Merz, 2013). At times, equipment is in high demand and there are waiting lists and long lead times that may lead to construction delays. Further, the access to spare parts is limited and this can significantly delay production at any point, leading to cost blowouts. A further constraint is the movement of these rigs into position, since the larger rigs must be carefully designed to fit local size limits.

Surface Infrastructure

The surface infrastructure and the surface footprint of the shale gas operation depend significantly upon whether vertical or horizontal wells are drilled. As an example, the surface infrastructure associated with the development of a 1000 ha shale play (around 56 PJ or 1.4 bcm) would range from (King, 2010d):

- 64 vertical wells on individual pads of 0.8 hectare each, using 50 hectares of land in total, about 40 kilometres of roads, 40 kilometres of pipelines, plus 4 to 8 facility pads to effectively capture the gas reserves.

    to:

- 16 horizontal wells from 1 pad of 2.5 hectares, with 3 kilometres of roads, 3 kilometres of pipeline and one facility on the same pad as the wells.

For a pad with 6 wells the underlying resource area covered is 2.25 km^2, with roads and gathering pipelines of 1.5 km; and recovering 13 PJ over 40 years (Report to this Review by Sinclair Knight Merz, 2013).

The well pads have facilities for storing water and proppants required for drilling, as well as storage for produced water; gas treatment and compression facilities including filtration, compression, cooling and dehydration process items; and power supply networks (above and below ground) (Report to this Review by Eco Logical Australia, 2013).

Broader field infrastructure will include access roads and tracks, storage warehouses, workers accommodation camps, offices and telecommunications (DMITRE, SA, 2012; Submission to this Review by Beach Energy, 2012b).

The wells are connected by low pressure High Density Polyethylene (HDPE) pipe to a processing plant. Up to 200 wells can be connected in this manner to a single processing facility (Report to this Review by Sinclair Knight Merz, 2013).

Gas Processing Plant

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 70 PJ per annum and about 15 km apart. This contrasts with Cooper Basin conventional gas processing which takes place at Moomba and Ballera, and which are 180 km apart.

Due to the broader range of gas composition, the processing facility is more 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 (Report to this Review by Sinclair Knight Merz, 2013). A schematic of such a natural gas processing plant illustrating the various components is presented in Figure 5.2.

Given this greater complexity, it is more likely that for shale gas, larger scale processing facilities will be constructed. As an example, the conventional gas processing plant at Moomba has a capacity to process up to 430 PJ per day of methane and occupies around 40 hectares of land within the Moomba township. It currently processes gas from 440 wells, which feed into 13 individual gas satellite facilities, which are connected to the plant through 9 separate trunklines. Similarly, oil

Figure 5.2: The possible unit operations involved in a shale gas processing facility

*Optional Step, depending upon the source and type of gas stream.

Adapted from: US Energy Information Administration, 2006.
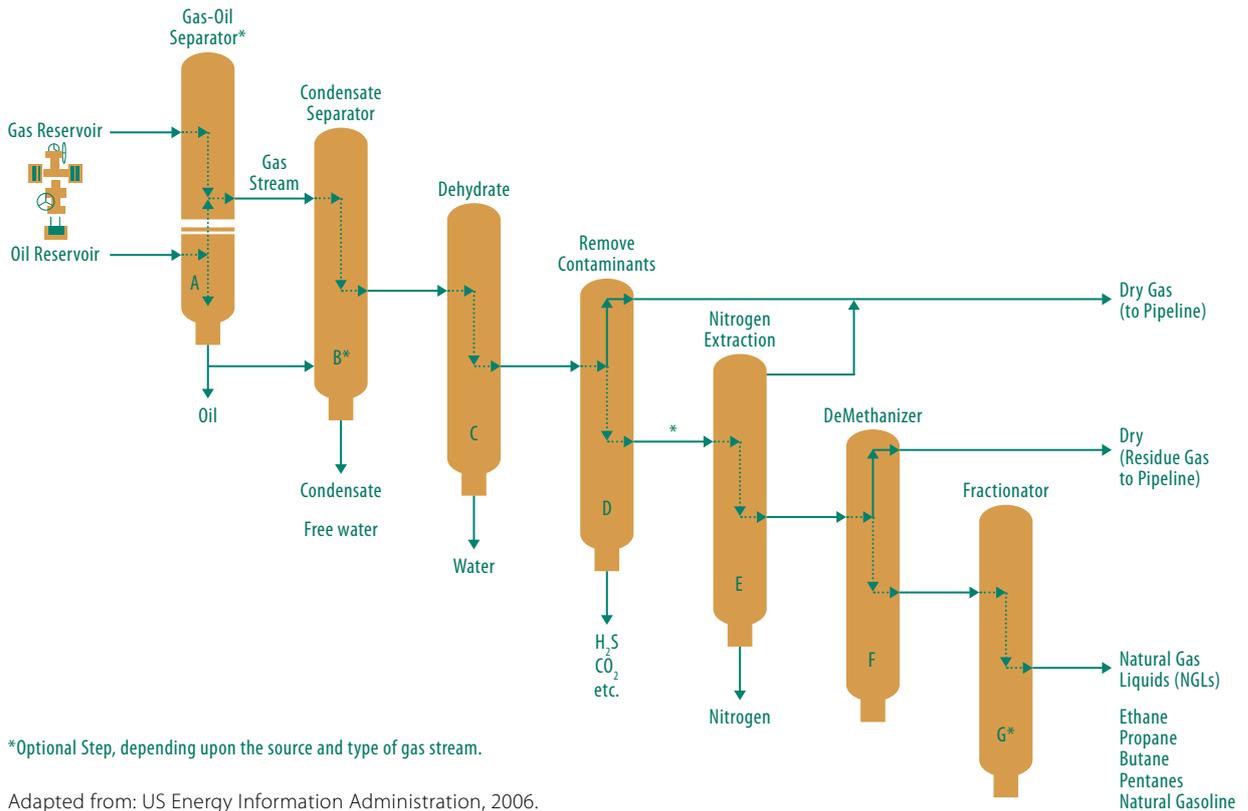
Natural Gas Processing

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

- **Gas-oil separator:** multi-stage gravitational separation of light and heavy hydrocarbons (oil = C12+)
- **Condensate separator:** mechanical separation of condensates (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 absorption. 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 of methane from heavier gas components and lighter liquids
- **Fractionator:** separates Natural Gas Liquids (NGLs) using their different boiling points.

from 120 wells is directed into the plant from 10 oil satellite facilities. The plant itself separates ethane, propane and butane, condensate and oil. Carbon dioxide is also removed from the gas (Santos Limited, 2001). It also separates carbon dioxide from the other gases. The plant could be upgraded or expanded to process greater volumes of sales gas to markets, should a shale gas industry be developed in the Cooper Basin (DMITRE, SA, 2012). The time scale of investment is indicated by the fact that to replace the existing Moomba Gas Plant would cost of the order of $5 billion.

Compression

The processed gas must then be compressed up to pipeline pressure, which is up to 15MPa 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. For 50PJ of gas, around 10 to 15 MW of compression capacity is required (Report to this Review by Sinclair Knight Merz, 2013).

Other Infrastructure

While some shale gas might be for domestic use, it is likely that some will be exported as LNG, which may require the development of additional LNG processing plants, most likely located at a coastal site. The need for increased port and shipping facilities will also require consideration.

Access to sufficient water supplies may become an issue. While it is possible to use saline water, around 4 to 22 Ml per well is required, depending on the number of fracks (US Groundwater Protection Council & All Consulting, 2009; Reports to this Review by Sinclair Knight Merz, 2013, Eco Logical Australia, 2013, and Frogtech, 2013). Based on initial drilling activities within Australia, a single frack requires approximately 500,000 litres (0.5Ml) of water, (which is equivalent to the capacity of around 15 truckloads) and there can be 10 to 20 fracks per well. This initial input is significantly greater than that required for coal seam gas, which is of the order 0.2Ml per well (US EPA, 2004). This may require water supply pipelines to be built alongside gas pipelines or groundwater extraction infrastructure to be developed.

Pipeline and Major Road Infrastructure

Piping is required to deliver both gas and any natural gas liquids to markets and roads are required to supply equipment, proppants and, potentially, water. In addition to upgrades of roads or rail lines, dirt airstrips may need to be sealed to provide all weather and night access to increase availability of appropriate medical care and other support in a high work load environment (DMITRE, SA, 2012; Submission to this Review by Beach Energy, 2012b).

Again, contrary to the United States situation when the shale gas industry developed, the piping infrastructure in Australia is limited (Figure 5.3) (DMITRE, SA, 2012). This lack of gas transportation infrastructure restricts the development of local industries to make use of the gas as it comes on stream. However, there may be opportunities to utilise the road, rail, human resources and water infrastructure that will be required to also develop and assist other local industries and community amenity.

The Cooper Basin is relatively well resourced, with existing gas, ethane and liquid lines to relevant east coast markets. This means that it will probably be the most readily developed (Report for this Review by AWT International, 2013) '*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*' (Report to this Review by Sinclair Knight Merz, 2013).

'*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 industry developments for example, could make sealing economically attractive compared to the increased cost of maintenance of unsealed roads.*' (Report to this Review by Sinclair Knight Merz, 2013).

The Perth and Otway basins are also well placed for relatively rapid development, due to the presence of existing demand markets and transportation infrastructure that either has incremental capacity or that can be readily expanded (Report to this Review by Sinclair Knight Merz, 2013).

Figure 5.3: Maps of Australian (a) and United States (b) to illustrate the differences in the density of existing oil and gas infrastructure between the two countries

a. Existing oil and gas infrastructure, Australia

Gas pipeline, existing
Gas pipeline, proposed
Oil-liquids pipeline
Ethane pipeline

Refinery
IPG plant
Gas and oil treatment plant
Gas treatment plant

b. Existing oil and gas infrastructure, United States

Interstate pipelines
Intrastate pipelines
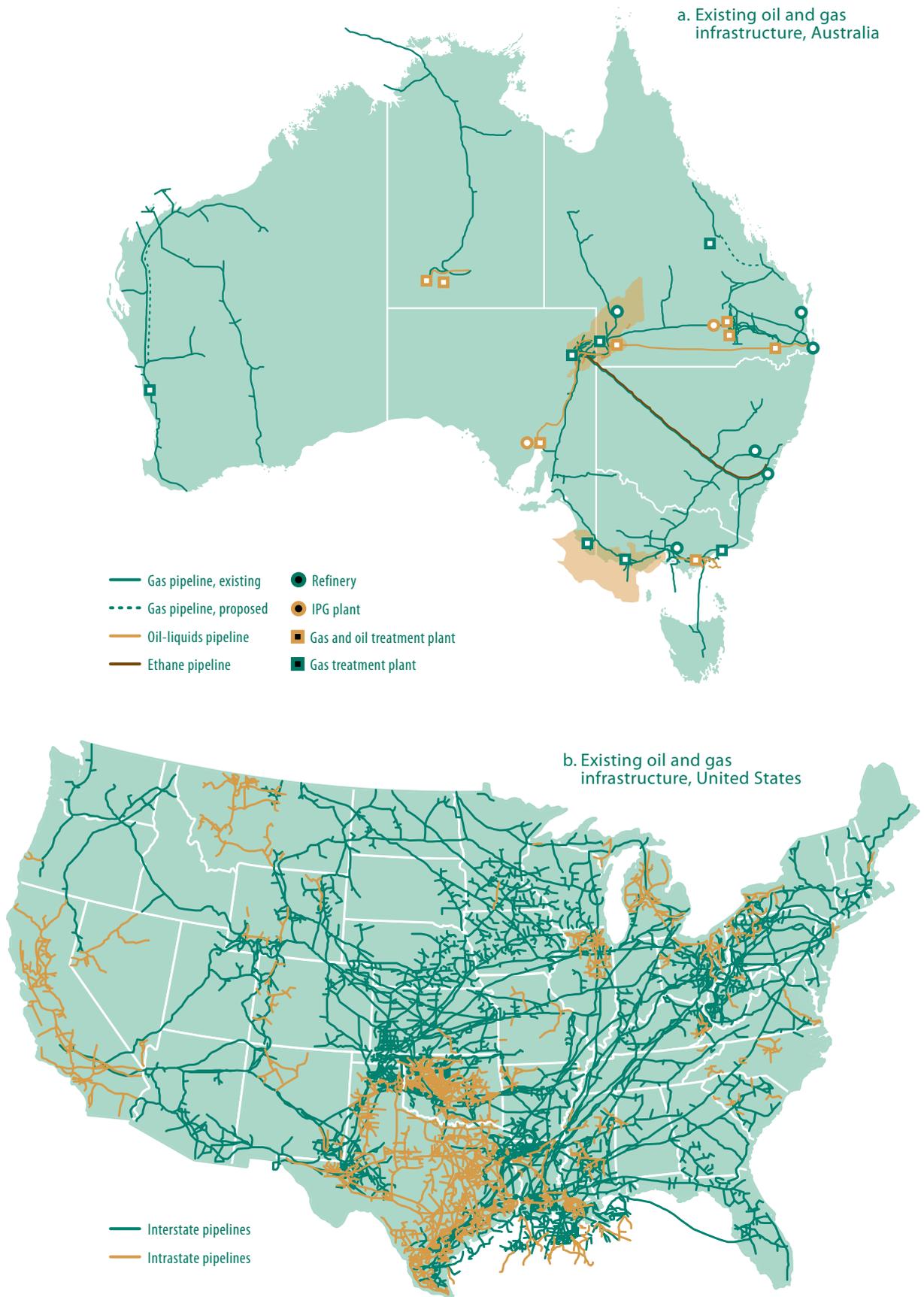
Adapted from: DMITRE, SA, 2012; US Energy Information Administration (EIA, 2011b).

The McArthur Basin is serviced with a gas pipeline to Darwin. Any production of natural gas liquids would initially be trucked to Darwin via the Carpentaria Highway. *'Each truck would carry approximately 200bbl of oil [30,000 litres], so production of 1,000 bbl/day [160,000 litres/day] would mean 5 truck loads/day and 10,000 bbl/day [1.6Ml/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'* (Report to this Review by Sinclair Knight Merz, 2013).

The Betaloo sub-Basin is also serviced with a gas pipeline to the coast at Darwin. However, the current pipeline is too small to be of any significant use for the transport of gas and trucking and rail appear to be the first option to transport products (CSIRO, 2012a). A rail line runs parallel to the Stuart Highway, which is adjacent to the prospective field (Ryder Scott , 2010).

Pipeline infrastructure into the Canning Basin is currently non-existent. However, the planned Great Northern Pipeline from the Canning Basin (Valhalla) to the coast (Karratha) will provide a pathway to WA domestic markets. A recent ministerial statement indicates that the pipeline will also 'make available for sale related products such as ethane, propane, butane and condensate, for the possible manufacture of chemicals or use as transport fuel' (Barnett, 2012). However, it is unclear how these products would be transported without duplicate pipelines being installed.

New transmission pipelines have significant economies of scale and production in areas like the Canning Basin will need to reach a minimum scale for the pipeline to be economic (MMA, 2009). SKM (Report to this Review by Sinclair Knight Merz, 2013) estimates that for Canning Basin gas to reach existing WA markets this threshold is of the order of 50 PJ per annum. *'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.' SKM (Report to this Review by Sinclair Knight Merz, 2013) note that there is one CNG and two LNG trucking operations in WA at present, mostly supplying gas to remote power stations.

The road network in the Canning is also limited and existing roads would need to be upgraded to suit heavier wider vehicles such as B-doubles and -triples carrying large items of plant. Development in this area would require *'air infrastructure suitable for 10-seater aircraft rather than the 6-7 seater aircraft typical of current outback services, together with greater availability during the wet season. Gas companies have proved willing to fund these improvements when they are critical to their operations'* (Report to this Review by Sinclair Knight Merz, 2013).

Similarly, the major challenge for any energy project in the Galilee Basin will be the significant investment required in infrastructure to access markets.

Labour Force Requirements

In the United States, employment in the entire unconventional upstream sector accounted for more than 1.7 million jobs in 2012 and could account for almost 3 million jobs by the end of the decade (Larson, *et al*., 2012). Of this growth, around 20% is direct employment, with the remainder indirect or induced employment. This corresponds to 1.5% of the total US workforce in the near term and 2% in the longer term (2020-2025).

Within Australia, a 50 PJ project is likely to require a direct labour workforce of 450 construction staff (see Table 5.2) and an operational staff of 75 (Report to this Review by Sinclair Knight Merz, 2013). Labour would also be needed for construction of roads, accommodation and transmission pipelines.

It should be noted that as the lifetime of any particular well is short, the construction and drilling workforce is not transitory, but persists over the lifetime of the project. Drilling and fracking crews move from one well to the next, with wells successively drilled on a continuing basis over many years.

Table 5.2: Shale production labour requirements for a 50PJ development

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

Source: Report to this Review by Sinclair Knight Merz, 2013.

Table 5.3: The proportion of graduates still looking for work four months after completion of their degree and its relationship to the skills crisis

Profession	% of Graduates Seeking Full time Employment following completion of their degree in 2011[23]	DEEWR Skills Shortage Status 2011-12	Expected Employment Growth to 2016-17
Mining Engineering	6.1	National Shortage	23.5
Surveyor	7.0	National Shortage	10.4
Civil Engineering	9.5	National Shortage	14.8
Mechanical Engineering	11.6	National Shortage	9.3
Electrical Engineering	12.0	National Shortage	10.4
Geology	16.3	National Shortage	12.1
Chemical Engineering	22.5	Recruitment difficulty	15.4
Average across all graduates	23.9		7.2

Source: Department of Education, Employment and Workplace Relations (DEEWR, 2012a; DEEWR, 2012b).

Access to such a workforce, appropriately skilled, at a local level may be limited. In some cases, workers could transfer from Queensland CSG projects when the rate of CSG development there slows. However, the Roundtable for Unconventional Gas Projects in South Australia ranked as 2nd of 125 recommendations the need to '*Manage the risk of a shortage of skills and people. Better training facilities and education programs for skilled trades people, para–professionals and professionals*' (DMITRE, SA, 2012). It will be important for shale gas producers to contribute to these training programs so that local communities do not suffer a loss of amenity as local tradespeople and professionals are diverted to service the new industry.

Addressing this skills shortage may not come just through traditional education routes. Specifically, while there are national skills shortages in many engineering disciplines and in geology, there are still many graduate engineers and graduate geologists looking for work (Table 5.3). Thus, for example, the Department of Education Employment and Workplace Relations (DEEWR, 2012a) indicates a national shortage of geologists, even though Graduate Careers Australia shows that 16.5% of new geology graduates were still looking for work four months after completing their degree (Grad Stats, 2012).

This data may partly reflect the reluctance of graduates to move to remote areas to secure employment. However, this view is disputed and it has been argued that '*during the resources boom, the deviation in regional unemployment rates has narrowed as the national unemployment rate has fallen*' (Gruen, *et al*., 2012).

Of more relevance may be the lack of appropriate on-the-job experience of these graduates. The skills shortage appears to be mainly for people with relevant experience of at least three years on the job; preferably with 5-10 years of experience. Hence, it may be better to direct resources towards providing more on-the-job training, vacation studentships and local work experience for young graduates, rather than formal education.

The skilled workers required will include plumbers, pipefitters and steamfitters, cement masons and concrete finishers, industrial

Table 5.4: A selection of trades identified by DEEWR as at a National skills shortage and their predicted employment growth (where known) to 2016-17

Trades identified as at a National Skills Shortage Status	Employment Growth to 2016-17
Airconditioning and Refrigeration Mechanic	9.9
Electrician (General)	17.1
Plumber	15.4
Electrical Engineering Draftspersons and Technicians	6.2
Civil Engineering Draftspersons and Technicians	6.2
Construction Estimator	
Mine Deputy	

Source: Department of Education, Employment and Workplace Relations (DEEWR, 2012a; DEEWR, 2012b).

Table 5.5: Examples of equipment imported from overseas for the CSG Industry in Queensland

Item	Project	Source	Country
Drilling Rigs	APLNG	Savannah 406	Canada
Drilling Rigs	GLNG	Saxon	Canada
Gas Processing	APLNG	Offsite fabricated/ pre-assembled Modules	Thailand
Compressors	APLNG		Germany
Pipeline	APLNG	Metal One	Japan
Desalination Membranes			USA

Source: Report to this Review by Sinclair Knight Merz, 2013.

machinery mechanics, fracture stimulation crews and petroleum pump operators (Larson, *et al*., 2012). Semi-skilled workers will include welders, inspectors and testers. There are also clear national skills shortages in some of these areas, with some relevant trades listed in Table 5.4.

Many workers will be fly in/fly out (FIFO); which in turn adds to costs in comparison to the United States base case. This is particularly true for the Cooper and Canning Basins. The Federal Government House of Representatives Standing Committee on Regional Australia has recently tabled a report on an inquiry into FIFO workforce practices (House of Representatives, 2013) and this report gives a perspective on the social issues associated with this approach. It is claimed that FIFO employment has been associated with negative impacts on employees, including elevated risks of high stress levels, depression, alcohol abuse, recreational drug use and relationship breakdowns (Deloitte Access Economics, 2012). It is also claimed that local social infrastructure can be disrupted by increases in rental prices and housing shortages; reduced access to regional health services; high costs of labor and difficulties retaining labour, given the salaries paid to FIFO workers. On the

other hand, higher wages and increased demand for rental properties have positive flow-on effects to local businesses.

Indirect Employment

It is unclear what the growth in indirect and induced employment within Australia is likely to be, given that '*much of the key capital equipment is manufactured by a small number of major international suppliers, often using proprietary technologies. This includes gas platforms, modularised components and liquefaction facilities. For example, of the eight LNG facilities being constructed at present, four are using Bechtel LNG trains. Other components which may be manufactured in Australia in certain form and specification may not be made to the technical requirements of projects. For instance, many of the current gas projects underway are being configured with large diameter high grade 42 inch pipeline systems which are not made in Australia. Other equipment such as fabricated steel structures which can be made in Australia may not be available at the scale required by project developers'* (Deloitte Access Economics, 2012). This issue is illustrated by Table 5.5 for the CSG industry.

Australian drilling manufacturers appear to *'offer products suitable only for mining [core] 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 imported 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, [and probably higher]. Local manufacture is possible but failure of local industry to take up the CSG opportunity suggests there are significant economic [and skill] barriers to be overcome'* (Report to this Review by Sinclair Knight Merz, 2013).

As reported by Sinclair Knight Merz (2013), *'Australian companies have operated in all [of these equipment] sectors except compression.'* However, most recent CSG processing plant is imported in a high state of completion, with recent plant designed to require only one weld for installation. *'The limited domestic gas market and the small number of items required have until now prevented a competitive [rig manufacturing] 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 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'* (Report to this Review by Sinclair Knight Merz, 2013).

Nearly 50% of the revenues generated from unconventional gas production is spent on construction, fabricated metals, and heavy equipment suppliers (Larson, *et al.*, 2012). This could mean that a significant component of any revenue generated in Australia will be spent overseas. Again, this is different to the American situation where the majority of the technology, tools, and knowhow are home-grown (Larson, *et al.*, 2012). There may be benefits to the Australian economy if a higher proportion of local content was achievable and the government has recently taken steps in this direction. Under the proposed Plan for Australian jobs, any project in Australia worth $500 million or more must include an

Australian Industry Participation Plan outlining how local companies will get a fair chance of winning work (DIISRTE, 2013). However, care needs to be exercised in how such an approach is implemented to ensure that the Australian industry does not become uncompetitive.

Corporate Environment

The remote location and the current status of the Australian gas market means that development is more likely to be by larger corporations. About 80% of total gas reserves within Australia are in the hands of 10 companies, and there are less than 35 companies in the total market (Dow Chemical Australia Ltd, 2012a). This is significantly different to the United States scene where there are around 6400 producers, with the top 10 companies representing only 32% of the market. The rapid expansion of the American shale gas industry is partly attributed to this dynamic market:

> *'Nimble independent exploration and production companies…exploited lower cost structures and technology to yield profitable results. Adding to the independents' ability to achieve success is a characteristically decentralised corporate structure that enabled quick, in-the-field decision making in crucial areas'* (Carr, *et al.*, 2009). *'An efficient engineering and fast-response procurement and construction chain will be more crucial for life-cycle-cost minimisation than it is for conventional gas production'* (Guarnone, *et al.*, 2012).

In their Report to this Review, SKM (2013) have noted: The organisational structures required for success in shale gas operations include:

a. *'Development and deployment of a manufacturing approach i.e. repeated application…and designs rather than development of bespoke designs for each well*

b. *Application of continuous improvement to technology and organisation*

c. *Staff/contractor acquisition and retention*

d. *Inclusion of social engagement in the business process'*

Rapid drilling, standardisation of facilities and managing the 'production line' are critical to success (Report to this Review by Sinclair Knight Merz, 2013).

Pipeline infrastructure in Australia is similarly dominated by a small number of large operators (4 relative to 160 in the United States) (Dow Chemical Australia Ltd, 2012b). Australia also has a smaller and less competitive services sector. Indeed, the three major oilfield service companies operating in Australia, Halliburton, Baker Hughes and Schlumberger, are not local but international. 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. In the iron ore and LNG sectors this dominance by a small number of companies may in part be responsible for cost blow-outs and delays (Report to this Review by Sinclair Knight Merz, 2013).

The smaller producer group; the less competitive services sector; the skills shortage; coupled with the needs of a FIFO workforce; and the importation of a large range of equipment means that the cost of production will be significantly higher than in the United States. As an example,

Australian LNG projects under construction are now 80% more capital intensive than those already in operation, with much of this increase blamed on the cost of labour (Knox, 2013).

However, the small number of major gas producers and service companies may mean that regulatory standards, including safety and environmental controls, will be more readily communicated, perhaps leading to less dangerous situations and fewer health, safety and environmental issues. Further, the use of oilfield service companies with years of shale gas experience in the United States will facilitate more rapid learning in the Australian environment.

Concluding Remarks

Much of the prospective shale gas resource in Australia is within remote regions, serviced with poor infrastructure and a limited workforce. The lack of road and pipeline infrastructure in such regions will slow the development of a shale gas industry and also limit access to markets for use of the gas produced. Conversely, any infrastructure that is developed within these remote regions might be used to assist other local industries and the rural economy.

The Cooper Basin stands out as the one region where infrastructure already exists. Access to pipelines for gas, ethane and oil, and a large gas processing plant, means that any development of shale gas is likely to occur here first.

The provision of sufficient quantities of water (either saline or fresh) may be problematic in all regions, due to the very large quantities required per well. This may require additional pipeline infrastructure or groundwater extraction capability. The reader is directed to Chapter 8 for a further discussion of these issues.

The development of a shale gas industry in Australia will rely heavily on imported equipment and skills. Australia does not have sufficient local demand or the skill sets to manufacture much of the necessary equipment, including pipelines, compressors and gas processing plant and so the revenue associated with the development of this infrastructure will be lost overseas. Drilling rigs will need to be imported and the importation process may further delay the development of the industry.

However, Australian labour will be used for direct employment in construction, drilling and operating the shale gas facilities. Given the remote nature of the resource, much of this workforce will be fly in/fly out. Skills will be transferable from the CSG industry but there is likely to remain a shortfall and industry will need to work with education and training providers to ensure that both formal training and on-the-job experience is provided to address this shortfall.

Overall, the remote location, the limited skilled workforce, the less nimble corporate environment and the need for importation of a large range of equipment will mean that the cost of production will be high and in some cases, could outweigh the benefits of development.

6

Financial analysis of shale gas in Australia

Gas Supply and Demand Economics in Australia

There are 392 tcf (11.1 tcm) of total identified gas resources in Australia – of which 34.6% is economic demonstrated reserves (EDR) – and 27.85 tcf (788.6 bcm) of proven reserves (Central Intelligence Agency, 2013).

Coal accounts for three-quarters of total energy produced in Australia and its growing share over the past decades suggests that it will continue to dominate the market for some time to come, although natural gas production is growing at a faster rate (Figure 6.1). Crude oil production has shrunk and is expected to continue to decline. Because gas-fired generation is a mature technology, gas production will remain significant until producing cleaner energy becomes more cost effective, around 2030.

Gas production in Australia has more than tripled since 1973, and increased by about 50% over the past decade. Once new projects currently under construction or planned are in full operation, Australia's LNG export capacity is expected to more than triple, from 24 to 80 million tonnes annually (Bureau of

Figure 6.1: Share of natural gas in primary energy production in Australia (percentage)
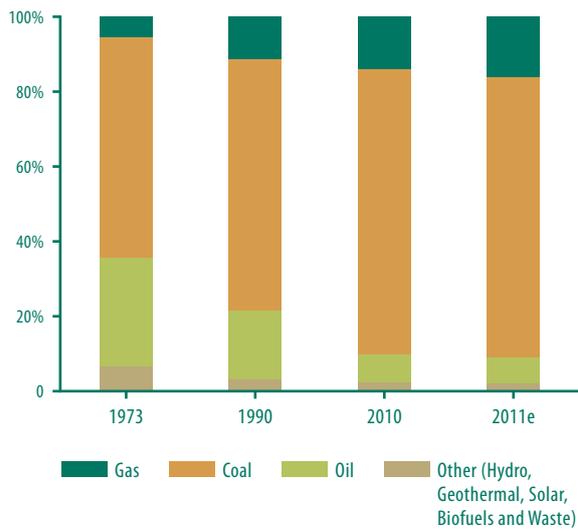
Source: International Energy Agency and Organisation for Economic Co-operation and Development (IEA, 2012b; OECD Energy, 2012).

Resources and Energy Economics, 2012b). These projects could potentially make Australia the world's second-largest exporter of LNG by 2015, and overtake Qatar to become the largest exporter by 2021 (Department of Resources, Energy and Tourism, 2012).

Production is expected to increase almost threefold from current levels to 2050, at an average annual growth rate of 2.9%. Production will grow faster between 2013 and 2035, mainly because of rapid development in north-western Australia and the contribution of new CSG projects in eastern Australia.

Domestic primary energy demand has increased almost fourfold over the period 1973-2011. Oil and coal have become less important, although together they account for more than two-thirds of the total domestic primary energy consumption. Coal's share of consumption has been steady since 1973, ranging between 35 and 40% of the total energy consumption. Over the past decade, gas consumption has increased by 4% per year. In 2009-10, gas constituted 23% of primary energy consumption and 15% of electricity generation (Geoscience Australia and BREE, 2012). Major consumers of gas are the manufacturing, electricity generation and mining sectors (Figure 6.2).

Investment in gas-fired power generation and policies encouraging the use of gas – such as carbon pricing or measures to increase the competitiveness of gas-fired electricity relative to coal-fired electricity without carbon capture and storage (CCS) – are expected to maintain its growth over the next decade.

Future Gas Price Evolution in Australia

LNG imports in the Asia-Pacific account for almost two-thirds of global LNG trade, and the largest importers in the region are Japan, Korea, China, Chinese Taipei and India. Imports into all of these countries are expected to continue to rise, due to an increase in domestic consumption that outpaces production. In 2011, imports from Japan and Korea were up 20 and 12% respectively, and in 2012 China's imports were expected to increase 30% (Bureau of Resources and Energy Economics, 2012d).

Australia's geographical advantage in supplying these markets is likely to lead to its share of global LNG exports increasing significantly over the next two decades. Australia's LNG exports accounted for 8% of global LNG exports in 2011, representing 19Mt (Bureau of Resources and Energy Economics, 2012d).

Figure 6.2: Sectoral consumption of gas in Australia, 2009-10
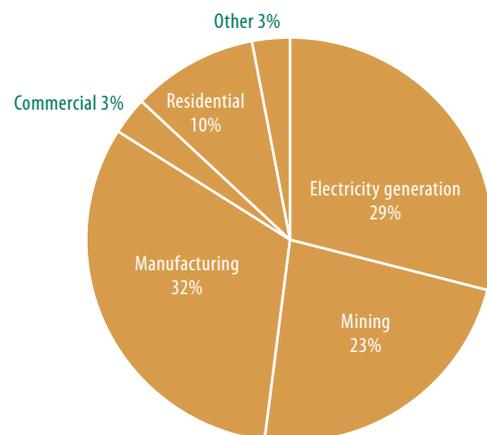
Source: Bureau of Resources and Energy Economics (BREE, 2012d).

There are three gas markets in Australia – the Eastern, Western, and Northern gas markets – separated because of the distance between gas reserves and consumption centres (Bureau of Resources and Energy Economics, 2012d).

Domestically, gas prices are expected to increase along with the demand for both consumption and exports, as well as rising supply costs. Low priced domestic long-term contracts in the eastern market either expired during the past five years or will expire in the next five years. At just above $US3.80/GJ in 2010, the average wholesale gas price in Australia is low compared to other countries, for instance Japan and Korea where the average wholesale price was $US11.40/GJ (Bureau of Resources and Energy Economics, 2012d). However, retail gas prices have increased in recent years in Australia, and are expected to continue to rise. Existing long-term contracts have a price around $3.5-$4/GJ in the eastern markets and will be renegotiated from 2018, in a market exposed to global gas prices (Australian Energy Regulator, 2012). As these contracts continue to come to an end, there is more uncertainty in eastern gas markets and upward pressure on the wholesale domestic gas price.

As an example, a report commissioned by APPEA in 2012 suggested that a 'freeze' on CSG developments in NSW could lead to wholesale gas prices between 20 and 25% higher in NSW, Victoria, South Australia and Tasmania; and 8 to 9% higher in Queensland by 2030. With LNG exports from Gladstone expected to commence in 2014-15, wholesale gas prices in eastern states are expected to converge toward an export netback price (i.e. export prices minus processing and shipping costs) over time. This observation is consistent with the proposition that future wholesale prices of gas will trend higher in Australia in the longer term.

Since 2006, the Western Australian Government has applied a formal Domestic Gas Reservation Policy (Deloitte Access Economics, 2012). Under this state policy, project developers are required to reserve up to 15% of production for domestic supply to local energy markets. It has been suggested that an Australia-wide domestic gas reservation policy could alleviate pressure on domestic gas prices. However, such a reservation policy would amount to a significant intervention in the energy market and there is no evidence to suggest that reserving gas for use within Australia will generate greater net economic benefits than selling that gas on export markets. In a submission to the EWG by Dow Chemicals, it was suggested that an alternative approach could be for governments to work with industry to establish the necessary infrastructure and that this would serve to hold down domestic gas prices. A recent report commissioned by the US Department of Energy showed that the United States would gain net economic benefits from allowing LNG exports. For every one of the market scenarios examined, net economic benefits increased as the level of LNG exports increased: 'Benefits that come from export expansion more than outweigh the losses from reduced capital and wage income to US consumers, and hence LNG exports have net economic benefits in spite of higher domestic natural gas prices' (Montgomery, et al., 2012).

Projected gas prices to 2030 by Australian region are shown in Table 6.1. These prices can be used to provide some guidance on whether prospective shale gas projects are likely to be competitive in Australia.

Table 6.1: Projected gas prices in Australian regions to 2030 (2012-13 $/GJ)

Year	SQLD	NQLD	NSW	VIC	SA	TAS	NT	SWIS	NWIS
2012	6.8	6.4	6.4	5.4	6.4	5.8	11.0	11.7	10.6
2020	9.4	9.3	8.6	7.7	8.7	8.2	11.0	13.9	12.9
2030	11.9	12.0	11.7	11.0	11.8	11.5	11.0	12.3	11.3

Source: ACIL Tasman, 2012a and Bureau of Resources and Energy Economics, 2012d, p. 61.

Coal Seam Gas

Since the first commercial production in Australia of CSG at Moura Coal Mine (Bowen Basin) in Central Queensland in 1995-96, with an installed production capacity of 6 PJ/a *(8 bcf/a)*[5], the Industry has steadily progressed in its development in that State until by 2010-11 production had reached 234 PJpa (Department of Employment Development and Innovation, 2012) representing some 30% of Australian East Coast gas consumption (ACIL Tasman, 2011) and 79% of Queensland production.

In terms of Queensland 2P reserves[6], as at June 2011 these stood at 33,000PJ, (Department of Employment Development and Innovation, 2012) with possible or inferred reserves being considerably higher, and certain to increase because of the current vigorous exploration program under way in both the Bowen and Surat Basins. For comparison the estimated conventional gas reserves for Eastern Australia are around 8,000PJ (Institute for Sustainable Futures, UTS, 2011).

In comparison, CSG 2P reserves in NSW at 2010 stood at 2466 PJ with annual domestic production being 6PJ from the AGL Camden Project (Institute for Sustainable Futures, UTS, 2011).

Most of this CSG, especially in Queensland, has already been on-sold to overseas markets, principally in Asia, as LNG exports from the port of Gladstone (Cooke, 2012). This product is referred to as CSG-LNG. To date, firm commitments have been made and construction commenced on three separate LNG plants on Curtis Island in Gladstone, each essentially consisting of two production trains each of a nominal capacity of 4 million tonnes per annum (Mtpa), or a total export capacity of 24 Mtpa.

To illustrate the magnitude of this CSG production and to put it into proper perspective, an annual CSG production rate of 1440 *PJ* will be required. This is compared with a current annual Australian domestic East Coast natural gas consumption of 750 *PJ* (ACIL Tasman, 2012b).

In addition, there is one further potential development for Curtis Island comparable in size to the three plants already under construction, which would lift exports to 32 Mtpa of LNG, with CSG-LNG annual requirements rising to 1920 PJ (Queensland Department of Industry, 2012).

When comparison of 2P reserves is made with annual consumption of natural gas and LNG exports, it is clear that there is a significant possible constraint on the availability of CSG for domestic consumption. This is also exacerbated by decreasing gas reserves from conventional gas available from Bass Strait and the Cooper Basin. As mentioned, this has led to the conclusion that real gas prices will increase in the future in eastern Australia (ACIL Tasman, 2012b). In turn, this could result in less gas use (and more coal use) for electricity generation, leading to higher CO_2 emissions than might otherwise have occurred.

Further Processing Options in Australia

Cheaper and more accessible gas may assist in the growth of other industries. The markets for shale gas are the same as the markets for conventional gas and CSG. Table 6.2 provides an indication of market values (including scale) and key determining factors.

As a specific example, there are at least five companies developing plans for direct reduced iron plants in the United States (Bloomberg, 2013). These plants, if developed, will make use of cheap shale gas to reduce iron oxide to direct reduced iron for use in steel making. These companies include Bluescope Steel, which is assessing the development of a $300M direct reduced iron production facility in Ohio (Chambers, 2013). However, Direct Reduced Iron (DRI) manufacture is capital intensive and requires relatively low gas prices to be economically competitive (Burgess, 2013, pers. comm.). Such DRI developments, if economic, would imply a turnaround for the United States steel industry, which has been losing ground due to competition from China (Bloomberg, 2013).

Such 'value adding' projects are most likely to take place in locations where existing processing takes

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5 1 Peta Joule (PJ) is equal to 1.35 billion cubic feet (bcf) of natural gas.
6 2P reserves means the sum of Proven and Possible reserves.

Table 6.2: 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

*At the source gas plant, net of transmission costs
Source: Report to this Review by Sinclair Knight Merz, 2013; SKM estimates.

Table 6.3: Potential market locations for Canning and Cooper Basin shale gas

Market	Canning Basin	Cooper Basin
Generation	Kimberley, Pilbara, SWIS*	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

*South West Integrated System (Electricity)
Source: Report to this Review by Sinclair Knight Merz, 2013.

place or where there are proposals for other gas to be processed, and in port locations for export products. Specific examples for the Canning and Cooper Basins are provided in Table 6.3 (Report to this Review by Sinclair Knight Merz, 2013).

On the other hand, a shale gas boom might lead to an appreciation of the real exchange rate and a consequent fall in the competitiveness of other market sectors. This effect is often referred to as 'Dutch Disease' in reference to the adverse impact of North Sea oil revenues on the size of the Dutch manufacturing sector in the 1970s (Deloitte Access Economics, 2012).

Ethane and Natural Gas Liquids

There is a clear market for shale oil and condensate for the transport market and as already indicated, such liquids will often drive the economics of shale production. The overwhelming majority of propane and butane gases are also likely to be removed from wellhead gas and marketed separately as liquefied petroleum gas (LPG) for transport and heating markets. The price of these hydrocarbons will be fixed by the global oil price and will remain largely independent of gas price movements. Extraction of these natural gas liquids could provide a further 'value add' to Australia through increased employment, investment and international competitiveness.

The market demand and value add opportunities arising from the large quantities of ethane that might be produced from shale gas are less clear. In the United States, increases in ethane and propane supply have led to an expansion of the petrochemicals industry. Steam cracking of these species forms ethylene and propylene. These high volume chemical intermediates are used to form a wide range of plastics, detergents and surfactants (American Chemistry Council, 2011). For example, Dow is investing $4 billion in new facilities in the United States (Liveris,

2012; Bloomberg, 2012) due to the availability of a well-priced ethane feedstock. The interest in establishing similar facilities in Australia would be to grow export markets for plastics and chemicals into Asia. Dow Chemicals suggest that such new manufacturing opportunities could provide on average an eight-times value add across the entire economy (Liveris, 2012).

DEEWR has indicated that employment growth in manufacturing in Australia is expected to decline by 9% over the next five years (DEEWR, 2012b). Basic chemical and chemical product manufacturing is in decline with a total fall of 6% predicted by 2016-17. Also of relevance is the employment in polymer product and rubber product manufacturing, which might gain from the growth of a new ethylene industry. The decline in these employment markets is expected to be 17% over the next five years. A new ethylene-based chemical industry might assist in mitigating this decline. However, total employment in these two sectors is currently only 73,700 people, so the change in total direct employment outcomes is not likely to be great.

Two ethylene production facilities currently exist in Australia, one in Botany in Sydney, supplied with ethane from the Cooper Basin and the other in Altona, Melbourne, supplied with ethane from the Bass Basin. Between them, these two plants produce 360,000 tonnes per annum of ethylene, as well as propylene, pygas and quench oil (Qenos, 2012). A recent announcement indicates that the Altona plant will soon undergo an expansion valued at $195M to increase its capacity by 20% (Qenos, 2010). This would bring total Australian production to around 400,000 tonnes per annum (0.9 billion lbs). However, both plants are still small and ageing, relative to the latest international scale and modernity. The new Texas ethylene facility planned by Dow Chemicals in the US will produce three times the total Australian output at 1.5 million tonnes per annum (Bloomberg, 2012).

If ethane prices are too low, or the volumes present are too trivial to warrant extraction and a separate pipeline, then this component is not extracted, but sold within the natural gas for its energy content. A recent report suggested that

only 8% of the ethane produced in the United States is converted to petrochemicals with the remainder sold into the gas stream (Bernstein Research, 2011). A similar situation occurs in Australia, where the ethane can be sold within LNG at relatively high prices, reducing the incentive to separate it for chemicals production (Table 6.4). In recent times, the global price of these NGLs has fallen, reflecting the lower price of shale gas (Ernst and Young, 2012b), but reducing further the incentives for separation. Ethane realised 50% of the price of Brent crude in January 2010 (Bernstein Research, 2011) but this was down to 34% in late 2011. Prices fell further in 2012, with the average spot price 10.6 US cents/litre (40 US cents/gal), relative to 20 US cents/litre (77 US cents/gal) in 2011 (ICIS Chemical Business, 2013).

Conversely, 50% of the ethane is extracted from Canadian gas, presumably due to royalty credits to encourage increased extraction and consumption of ethane, and controls on its export (Dow Chemical Australia Ltd, 2012a).

Table 6.4: The percentage of available ethane extracted from natural gas supplies

Location	% of Ethane Extracted
Australia	1
USA	8
Canada	50

Source: Bernstein Research, 2011 and Dow Chemical Australia Ltd, 2012a.

Financial analysis of shale gas extraction – United States Example

The extraction of shale gas from tight geological structures involves new technologies such as horizontal drilling and hydraulic fracturing. These include deep and directional (e.g. horizontal) drilling to access the shale formations, as well as shale hydraulic fracturing adjacent to the borehole to increase permeability. It has been found in the United States that the production from any given well is relatively uncertain, although investment in a multiplicity of wells provides a geologically suitable field with an

aggregated gas flow that is reasonably certain over time. A financial model for shale gas should therefore be probabilistic in nature at the individual well level, but aggregate the well gas flows over the field to give a probabilistic range in gas prices required for the overall investment to be financially viable.

The production of liquids from a shale gas field also influences the economics of shale gas extraction. This is because the price of liquid petroleum products is higher in the United States than that for gas. The financial model presented here does not include liquids production.

In terms of financial effect, as wells are drilled in a shale gas field there is a probability distribution in the initial gas production from each well. Moreover, the well gas production declines rapidly after operation commences, and this decline varies within and between fields (MIT, 2011a; Jacoby, et al., 2012). The revenue stream from a shale gas field each year is thus the consolidated gas production from these wells, times the gas price. The capital cost each year comprises the cost of drilling and hydraulic fracturing of the wells and any up-front land lease costs prior to the drilling. Shale gas is different to a conventional investment, since the capital cost are ongoing as more wells are drilled over the life of the investment.

The financial model developed in the present report (see Appendix 3) calculates the gas price required to ensure that an investment in shale gas earns at least the cost of capital. It is a probabilistic calculation, which means that several of the important variables are represented as probability distributions. These include:

- The parameters for the gas well decline rate over time;

- The probability distributions of the initial decline rates for a gas field;

- The development and completion costs, and leasing costs, of gas wells; and

- Operating costs.

Appendix 3 gives details on the methodology for the financial calculations, as well as a flowchart and explanation of the methodology. The overall

calculation is iterative in order to build the probability distribution of the required gas price to make the shale gas investment viable for the owners of the shale gas extraction company. Detail is also given in the Appendix on the fiscal regimes of the United States and Australia employed in the model.

Results of the United States Financial Analysis

A report from Massachusetts Institute of Technology (MIT, 2011a) has described aspects of the economic modelling of shale gas extraction. An appendix to this MIT report provides further detail on the assumptions made. For the purposes of comparison in the present study, the MIT data were used together with the initial production distribution and production decline curves (described) to model the required gas prices in the United States. The assumptions made in the MIT report are also summarised in Appendix 3 while the breakout box shows some details of the present cost components of shale gas extraction in the United States, taken from the MIT study.

The calculated gas prices from the model outlined in Appendix 3 using the data shown in the breakout box and the United States fiscal regime, are compared with the prices from the MIT study (using the parameters given in the appendix) in Table 6.5.

As can be seen from Table 6.5, most of the gas price predictions from the present model agree reasonably with the MIT study. The main exception is the Haynesville field, where the present study predicts a lower required gas price than the MIT work. O'Sullivan (O'Sullivan, 2012, pers. comm.) from MIT has confirmed that this is due to faster decline rates from this field than assumed here and given in Appendix 3. Further comparisons with a published United States shale gas cost curve are given in this appendix, where it is shown that the two lowest cost producers studied here (Marcellus and Haynesville) and the two highest cost producers (Barnett and Woodford) have been successfully predicted by the present financial model.

Costs of Shale Gas Extraction in the United States

The following tables give an indication of the costs of drilling and completion, land leasing costs and operating costs for shale gas extraction in the United States. The values are taken from the 2011 MIT study on shale gas economics (MIT, 2011a; MIT, 2011b).

MIT estimates for lease costs ($/ha) and operating and maintenance costs ($/GJ) from the MIT study are given by Table 2.

MIT estimates of well drilling and completion costs for various fields in the United States

$ Million	Low	Mid	High
Barnett	3.0	3.5	4.0
Fayetteville	3.0	3.5	4.0
Haynesville	6.5	7.5	8.5
Marcellus	3.5	4.0	4.5
Woodford	4.5	5.0	5.5

Source: MIT, 2011a and MIT, 2011b.

MIT estimates of lease and operating costs for all fields

Item	Low	Mid	High
Lease ($/ha)	6,172	12,346	24,690
Opex ($/GJ)	0.527	0.79	1.06

Source: MIT, 2011a and MIT, 2011b.

Table 6.5: Comparison between MIT "required gas price" (RGP) and those calculated in the present work for a variety of shale gas fields in the United States

Field	MIT	MIT	THIS WORK
	IP Rate (mcm/day)	RGP ($/GJ)	RGP ($/GJ)
Barnett	52.1	$6.19	$5.96
Fayetteville	59.2	$5.24	$5.24
Haynesville	223.2	$4.85	$3.05
Marcellus	99.1	$3.81	$3.73
Woodford	71.7	$6.01	$5.34

Source: MIT, 2011a.

It is clear from the present analysis of shale gas costs in the United States that the important parameters that control the required gas price for financial viability are:

- The capital costs of well drilling and completion in the field, including land and infrastructure costs,

- The initial production rate of wells in the field, and the probability distribution of this parameter,

- Royalties and taxes, as well as the fiscal regime and investment incentives of the location in question, and;

- Any credits from co-produced liquids while there is a price differential between gas and liquids.

These parameters vary with geological conditions, land costs, drilling and completion costs, infrastructure required, nature of the hydraulic fracturing strategy, shale gas field location and state fiscal regime, supply-demand conditions, and so on. They will be site and field specific and could be significantly different in Australia compared to the United States.

Financial analysis of shale gas extraction – Australia

The significant differences between the fiscal regimes in the United States and Australia are explained in detail in Appendix 3. In addition to the fiscal regimes, there are other factors that could change the economics of shale gas extraction in Australia:

- Australian land acquisition (or lease) costs are likely to be lower than those in the United States, especially in remote regions.

- Australian drilling and completion costs are likely to be higher than in the United States, due to remoteness and higher costs generally in Australia. This also applies to Australian operating costs.

- The costs associated with infrastructure (electrical power, fuel, pipelines, other transportation) are likely to be higher in Australia than in the United States.

- The economic and financial context of fossil fuel developments could change because of broader changes in climate policy.

The key operational parameters – (i) initial gas production from shale gas wells, (ii) the probability distribution of initial gas production rates, and (iii) the decline rates of Australian wells in different locations, are still essentially unknown. This is because very few wells have been recently drilled in Australia and the data are not yet available.

Effect of Fiscal Regime

In order to evaluate the influence of the two different fiscal regimes, the shale gas well production data and drilling and completion costs for two fields from the United States was simulated as if those wells were subject to Australian taxes. The two fields in question were the Barnett and the Marcellus. The Australian fiscal regime was applied to these wells, with landowner costs the same as in the United States and treated as capital. In this way, the two fiscal regimes could be directly compared.

It has been found that the two fiscal regimes, although different in detail, give similar results for

required gas price for financial viability in the two countries (see Appendix 3).

Australian Cost Data

Information on capital costs of well drilling and completion in Australia were discussed recently as part of the study (Cruickshank, 2013, pers. comm.; Pepicelli, 2012, pers. comm.). The following points summarise these discussions:

- Costs of offshore drilling and completion in Australia are "3 to 4 times" those in the United States (Santos Limited, 2012a), and onshore could be more than two times. For the average price of a US well of around $5M (MIT, 2011a), this would indicate a cost of over $10M in Australia.

- A 3km deep vertical well in the Cooper Basin would cost $11-12M for drilling and completion with up to 6 hydraulic fracturing stages, as a "rough" estimate (Pepicelli, 2012, pers. comm.).

Clearly, more information is required on this important capital cost parameter. However, for the purposes of this preliminary analysis a base-case a conservative capital cost for drilling and completion of $12M has been assumed.

Base Case Financial Analysis for Australia

The base case assumptions for "price of gas required" at the wellhead used for Australia are:

- Drilling and completion cost: $12M per well.

- Initial production (IP) rate: mean = 85mcm/d (3,000 Mscf/d), as a log-normal distribution[7] with a standard deviation of 62 mcm/d (2,200 Mscf/d) (similar to the Santos Moomba-191 well).

- Well decline rate: Average of US rates.

- Operating cost: $1.05 per GJ.

Under these assumptions, the base case "price of gas required" in Australia was calculated by the present financial model as $7.37/MMBtu,

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[7] Log-normal is the probability distribution of a random variable whose logarithm is normally distributed.

with a range (standard deviation) from $5.31 to $8.65. This value is close to that reported by Santos as "$6 to $9 per GJ" for the Cooper Basin (Cruickshank, 2013, pers. comm.).

Sensitivities of the "price of gas required" have been carried out for:

- Capital cost
- Initial well production (IP)
- Well gas production decline
- Operating costs

The results of this sensitivity analysis are shown in Appendix 3. The results show high sensitivity to capital costs, initial production (IP) of the well, and well gas production decline. The results are less sensitive to operating costs.

Importance of Capital Intensity

It was found that the capital intensity in terms of (*drilling and completion costs*) divided by (*initial gas production rate*) gives a reasonable correlation with the "required gas price". The results from the United States analysis and the sensitivity analysis for Australia have been plotted together in terms of this 'capital intensity' in Figure 6.3.

Figure 6.3 shows that, owing to present higher estimated capital costs, the capital intensity in Australia appears to be higher than in the

Figure 6.3: Required gas price plotted as a function of capital intensity
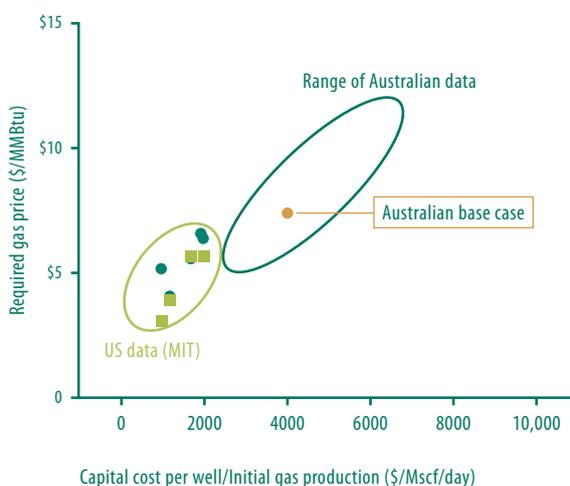
The United States data and the Australian base case are highlighted on the diagram. The orange circle represents sensitivity variations on the Australian base case capital costs (see Appendix 3).

United States and this leads to a predicted higher "required gas price" at the wellhead. For Australian shale gas prices to be competitive with those in the United States this capital intensity will need to be reduced through technology learning over time, assuming that shale in Australia behaves similarly to that in the United States in terms of the gas initial production and gas production decline rates. These effects are still to be evaluated in Australia through the drilling of more shale gas wells and the gathering of further well production information.

Conclusions from the shale gas financial analysis of this study

The model that has been developed by the present study has predicted required gas prices that agree reasonably with published data from the United States. These predicted gas prices are in the range $3.00 to $6.20/GJ.

It is clear from the work undertaken so far that the important parameters that control the required gas price are:

- The capital costs of well drilling and completion in the field, including land and infrastructure costs,
- The initial production rate of wells in the field, and the probability distribution of this parameter,
- The levels of royalties and taxes, as well as the fiscal regime and investment incentives of the location in question, and:
- Any credits from co-produced liquids while there is a price differential between gas and liquids.

These parameters vary with geological conditions, land costs, drilling and completion costs, infrastructure required, nature of the hydraulic fracturing strategy, shale gas field location and state fiscal regime, supply-demand conditions, and so on.

The Australian fiscal regime, with state royalties and an onshore petroleum resource rent tax, produces much the same "required gas price" when data from US shale gas fields is input to the financial model.

Costs for shale gas extraction in Australia have been stated to be higher than the United States. It has been indicated that a 3km deep vertical well in South Australia would cost $11-12M for drilling and completion (Pepicelli, 2012, pers. comm.), compared with $3.5M to $5M in the United States. Santos (Cruickshank, 2013, pers. comm.) has stated that capital costs for drilling and completion are "3 to 4 times" United States costs.

One producing well in Australia – Santos' Moomba-191 well – had an initial production rate (IP) of 85 mcm/d (3,000 Mscf/d), which is in the mid-range for wells in the United States. After 12 weeks production this rate had fallen to 71 mcm/d (2,500 Mscf/d), which aligns with average decline rates in United States wells (Santos Limited, 2012c). A second well – Beach Energy's Encounter-1 well – had a maximum production rate of 59 mcm/d (2,100 Mscf/d) (Beach Energy, 2012a). However, it is too early to determine whether these wells will continue to show the decline characteristics of US wells, or what the probability distribution of the initial production rates will be in these or other fields in Australia. These will be revealed over time as more shale gas wells are drilled in Australia.

Assuming that an initial gas production of 85 mcm/d (3,000 Mscf/d) is typical of shale gas wells in Australia, and that well drilling costs are $12M per well, the present financial model has predicted a range in "required gas prices" at the wellhead from approximately $5.30 to $8.65/GJ, with a mean gas price of approximately $7.10/GJ. These values agree well with required prices publicly quoted by Santos of $6 to $9/GJ.

Sensitivity analysis has shown that the most important parameters that influence the "required gas price" are (i) the capital costs of drilling and completion and (ii) the initial gas production rates from shale gas wells (the IP rate). A reasonable correlation has been obtained in this study between a "capital intensity" factor, calculated by dividing the capital costs by the IP rate, and the "required gas price". The base case Australian assumptions yield higher capital intensity than the United States. If this is validated, the capital intensity needs to be reduced here by extensive "learning-through-doing" if Australian shale gas prices are to match those currently found in the United States. Clearly, Australia is early on the shale gas learning curve.

Conclusions

Domestically, gas prices are expected to increase along with the demand for both consumption and exports, and rising supply costs. Low priced domestic long-term contracts in the eastern market either expired in the past five years or will expire in the next five years. Existing long-term contracts have a price around $3.5-$4/GJ in the eastern markets and will be renegotiated from 2018, in a market exposed to global gas prices. As these contracts continue to come to an end, there is more uncertainty in eastern gas markets and upward pressure on the wholesale domestic gas price. With LNG exports from Gladstone expected to commence in 2014-15, wholesale gas prices in eastern states are expected to converge toward an export netback price (i.e. export prices minus processing and shipping costs over time). The existence of domestic gas prices at levels around expected export netback prices would be sufficient to encourage the development of shale gas resources located near existing infrastructure. Higher prices and/ or liquids credits would probably be required to justify the development of more remote shale gas resources in Australia.

7 | Landscape and biodiversity

Humans already impact significantly on the landscape and our needs of land for settlement as well as for supplying energy, water, food, fibre and minerals compete fundamentally with the maintenance of biodiversity that underpins the ecological functioning of the landscape itself upon which we also ultimately depend. The production of shale gas in Australia will add to these demands and pressures on the landscape.

Based on the shale gas experience in the United States and the Australian experience with CSG, a shale gas industry in Australia can be expected to add its own impacts on biodiversity: vegetation, flora and fauna species, soils and local water supplies for ecosystems. Additionally, in relatively populous regions, shale gas operations' effects on landscape will inevitably impact on people and other industries.

Using our knowledge of Australian landscape processes, together with specific landscape, geological and hydrological data, it is possible to work out where we can extract resources such as shale gas in a manner and in locations that do not compromise agriculture, water resources, alternative land uses, and landscape function (O'Neill, *et al*., 1997; Tongway, 2005; Eco Logical Australia,

2011; Eco Logical Australia, 2012). Landscape ecology, land use and water resources are all components of a highly connected and complex landscape system and it is important to take account of the *cumulative* impacts on this connected complex landscape that are of critical importance (New York City Department of Environmental Protection, 2009, p. 29). Planning tools are now being developed to assess cumulative risk (Shoemaker, 1994; Eco Logical Australia, 2012) and these, along with older risk assessment tools, appear to provide a means to manage multiple land use pressures and protect biodiversity and landscape function.

Shale gas production in Australia needs to be seen as a new land use development pressure — one more in a long series of land use pressures that have been applied to the landscape. Shale gas production is no different from any other development of the landscape and like most other land uses, it poses some risks to the condition of the water, soil, vegetation and biodiversity, and has the potential to impact on the capacity of natural resources to supply human, as well as ecological needs into the future. It is important to see shale gas field operations in this context, while planning and legislating for the industry's specific features.

It is necessary to distinguish between *hazard* and *risk*. The potential consequences of a possible impact on the environment is a hazard, whereas *risk* not only includes *consequences*, but the *likelihood* of an event occurring. In most of this discussion there is a focus on environmental hazards and possible consequences, which may or may not be likely to occur. This chapter first outlines general landscape and ecological characteristics of Australian sedimentary basins where there are shale gas resources, and then outlines potential consequences for landscape and biodiversity that are already known to follow any type of land use development, including shale gas production – both in relatively un-peopled rangeland regions and in relatively populated non-rangelands. Finally, the section discusses the risk and potential consequences of adding shale gas production to the land use in those areas.

Landscapes of Prospective Shale Gas Basins – Ecological Characterisation

Areas in Australia prospective for shale gas occur in arid and semi-arid landscapes and could also coincide with a number of temperate and sub-tropical landscapes. An interim biogeographic regionalisation (Thackway & Cresswell, 1995) reviewed by Environment Australia (Environment Australia, 2000) may be used as the basis for a broad ecological characterisation of parts of Australia from which shale gas may be produced. Appendix 4 lists 25 bioregions that may be affected, and broadly describes their diagnostic characteristics and some specific values. The locations and extents of the shale gas basins are shown in Table 3.4 and Figure 3.7.

Australia's Shale gas resources are mostly located in the deep sedimentary basins of the remote inland areas of Western Australia, Queensland, South Australia and the Northern Territory. As pointed out by Eco Logical Australia (2013), these regions support contiguous expanses of relatively intact arid and semi-arid native vegetation. However, some urbanised or agricultural regions, where native vegetation is less likely to be intact, within temperate and sub-tropical areas, such as the Sydney (NSW), Otway (Victoria), Perth (WA) and Maryborough (Qld) Basins' also have shale gas resources.

The Australian rangeland landscapes that contain prospective shale gas resources (for more detail see Appendix 4) coincide with vast and remote parts of Australia's inland that support contiguous and extensive areas of arid and semi-arid vegetation and are managed by pastoralists and indigenous people. These rangeland landscapes (Woinarski, *et al*., 2000) have the following characteristics:

- Are located in regions most of which have an average annual rainfall of 400 mm or less (except near the north coast of WA), but experience highly variable rainfall and sporadic flood events. Most river channels are ephemeral and 'permanent' water is scarce or confined to waterholes between rains and floods (e.g. Kerezsy, 2011).

- Are underlain by sedimentary basins, which typically have major groundwater resources to great depths (Geoscience Australia, 2012).

- Carry a rich biota of native plants and animals, including endemics, and threatened species ranging from a few in some bioregions of the Carnarvon and Canning Basins (WA), to 30–40 (e.g. Great Sandy Desert (Canning Basin) and the Amadeus Basin (NT)), and several threatened ecological communities.

- Have cattle grazing (and to a lesser extent, sheep grazing) as their main land use across semi-arid tropical, sub-tropical and temperate regions. That grazing pressure combines with the grazing pressure imposed by macropods—mainly kangaroos—and feral herbivores such as rabbits, goats, camels and pigs. The result is a total grazing pressure that can be detrimental to sensitive native flora, including perennial grasses, particularly during dry periods and in association with over-frequent burning.

- Have significant invasions by populations of feral animals and pest plants, which have adversely impacted (and continue to impact) native fauna as well as flora.

- Support a growing tourist industry in some regions, particularly those associated with scenically spectacular and beautiful landscapes (e.g. MacDonnell Ranges in the Amadeus Basin).

- Have biodiversity and ecosystem values which are generally not well represented in formal conservation reserves, yet the loss of native fauna is a significant issue across the semi-arid tropics (Woinarski, *et al.*, 2000).

The Maryborough, Galilee, Bowen, Otway, Perth and Sydney Basins differ from the rangeland sedimentary basins in that they tend to have higher annual rainfall and more frequent floods. The regions are rich in biodiversity with endemic and threatened species and ecological communities, as outlined in Appendix 4. There is often significant human population (e.g. the Sydney area is in the Sydney Basin; SE Queensland's major centres are in the Maryborough Basin; the Perth region is in the

Perth Basin) with ongoing pressures from urban expansion and agricultural development, as well as mining. Large parts of these landscapes have been subject to major episodes of land clearing and consequent fragmentation and disturbance (DEST, 1995).

Potential and Known Consequences of Land Use Development

In most prospective shale gas basins, gas production will be an additional land use, adding to any or all of the other uses including urban development; extensive, irrigated or intensive production of food and fibre; energy production; water storage; roads, railways and pipelines; tourism; mining; manufacturing industry; production forestry; as well as conservation. Shale gas operations may have far less consequences than the impacts and degradation already experienced as a result of agricultural and urban development over the past two centuries in Australia including fragmentation, habitat loss and impaired ecological function in terrestrial and aquatic ecosystems.

There is already information (Nelson, *et al.*, 2006; State of the Environment, 2011; Riitters, *et al.*, 2012) about the kinds of impacts that can occur in Australia with these land uses, and legislation and planning is in place which seeks to repair or prevent them. Cumulative impacts can be expected to emerge, on water resources and land capability, as yet more land uses are added in particular areas: e.g. mining and peri-urban development added to agriculture or water storage areas.

These are known consequences of land use development in Australia (State of the Environment, 2011; Riitters, *et al.*, 2012) on environment and landscape including amenity:

- habitat destruction and fragmentation by partial or complete clearing of vegetation, and consequent effects on biodiversity of local fauna and flora, including added threats to threatened species (Cushman, 2006),

- impacts on landscape function and on competing current and future land uses such

as grazing, cropping, forestry, conservation, national heritage and traditional land uses,

- impacts on drainage lines, flow regimes, volumes of surface waters and groundwater systems from water extraction and disposal, and new infrastructure, with implications for terrestrial and groundwater-dependent ecosystems,

- contamination of water quality (surface and groundwater) with sediments, microorganisms and chemicals, and effects on water temperature and dissolved oxygen as a result of agriculture, forestry and other industries and human living practices, with implications for aquatic ecosystems and human activities,

- contamination of air, soils and vegetation, including release of stored carbon, with consequent damage to terrestrial and aquatic ecosystems,

- cultural amenity of indigenous peoples,

- impacts on community amenity through traffic, dust, noise and light pollution.

Detailed US studies have also considered these same environmental issues (USEPA, 2011; USDOE, 2009; USEPA, 2008; New York State Department of Environmental Conservation, 2009; New York State Department of Environmental Conservation, 2009a; Smith, 2012; Australian National University, 2012) when preparing environmental impact assessment associated with shale gas industry developments. As the shale gas industry in Australia is at an early stage of development, it is possible to plan ways to minimise further impacts, based on experiences in the United States (e.g. New York State Department of Environmental Conservation, 2011).

Shale gas developments in the US are considered there as an additional and accumulating threat to native vegetation, biodiversity and threatened species (New York City Department of Environmental Protection, 2009; Slonecker, et al., 2012a; Slonecker, et al., 2012b). In Australia, development of the infrastructure associated with shale gas projects can be expected to impact through direct clearing of bushland, fragmentation of patches of native vegetation, fauna mortality, spread of invasive species and increased fire risk. Extracting groundwater or perturbation of groundwater pressure gradients could change the hydrology of wetlands (including Ramsar wetlands) and other groundwater-dependent ecosystems (Hatton & Evans, 1998; National Water Commission, 2012) particularly in arid regions. These potential consequences are now discussed individually.

Consequences of habitat destruction and fragmentation resulting from land use development

Numerous scientific studies have reviewed the impacts of fragmentation of bushland on native fauna (Wiens, 1985; Forman & Gordon, 1986; Franklin & Forman, 1987; Saunders, et al., 1991; Ries, et al., 2004; Cushman, 2006; Fischer & Lindenmayer, 2007). Fragmentation of a landscape that has already received extensive clearing can have very large impacts on biodiversity and landscape function (Hansen & Clevenger, 2005; Fischer & Lindenmayer, 2007). This cumulative impact has a crucial importance, and requires careful consideration and attention (Shoemaker, 1994; New York City Department of Environmental Protection, 2009).

The removal of native vegetation, resulting in negative and potentially irreversible environmental impacts, has been asserted within a large volume of literature, to be related to various land use activities including agriculture, mining, urbanisation and recreation (e.g. Nelson, et al., 2006; State of the Environment, 2011; Riitters, et al., 2012). The large scale, permanent loss of vegetation has been demonstrated to result in land degradation (Standish, et al., 2006), declining biodiversity (Wiens, 1985; Johnson, et al., 2007; Saunders, et al., 1991; Robinson, et al., 1995) and release of meaningful volumes of carbon dioxide (Intergovernmental Panel on Climate Change, 2007a; Intergovernmental Panel on Climate Change, 2007b).

In relation to species, the local removal of native vegetation as a consequence of the various land use activities may result in:

- potential loss of flora, including some species listed as a Matter of National Environmental Significance (MNES)

- potential loss of some fauna species listed as a MNES, or their preferred habitat.

There may be flexibility with regard to the exact location of infrastructure, which could mitigate the loss of threatened species habitat at the project level, but cumulative impacts can be more intractable (New York City Department of Environmental Protection, 2009; Eco Logical Australia, 2013).

Meta-population biology theory asserts that numerous, small physically isolated populations can collectively function as a larger resilient population, if the level of connectedness that links them facilitates dispersal of individuals among populations (Brown & Kodric-Brown, 1977; Harrison, 1991). Dispersal is a critical ecological process for maintaining genetic diversity, rescuing declining populations, and re-establishing populations that have been completely wiped out (Calabrese & Fagan, 2004). Meta-population dynamics can allow entire networks of at risk populations to persist through the sufficient movement of individuals (Hanski & Gilpin, 1991). The connectivity of remaining fragments linked by dispersal become increasingly important as human activity reduces areas of natural habitat (Calabrese & Fagan, 2004).

Small sub-populations, which are not viable in their own right and where isolation prevents dispersal, can be vulnerable to a combination of stochastic and human impacts resulting in a rate of local extinction that exceeds the rate of re-colonisation (Lambeck, 1997). Empirical observe that population size is the main determining factor in extinction probabilities which is often approximated by patch area. Therefore, connectivity to existing local populations is the determining factor of the colonisation probability of an empty habitat patch (Robinson, *et al.*, 1995; Moilanen & Nieminen, 2002; Eco Logical Australia, 2013).

Eco Logical Australia (2013) point out that *'an intactness index can be generated across any landscape in a geographic information system (GIS) by mapping all extant native vegetation patches and all existing infrastructure easements (road, rail and powerlines) and other non-vegetated areas as a raster layer, (O'Neill, et al., 1997). The more the landscape has been cleared and the greater the*

number of remnant patches created, the greater the relative loss of intactness in the landscape'. O'Neill *et al.*, (1997) and others (e.g. Wiens, 1985; Wiens & Milne, 1989; Saunders, *et al.*, 1991) have shown that loss of intactness can explain ecological response; although it must be appreciated that an intactness index is but one of a number of measures which can be used to characterise habitat fragmentation. The proportion of remaining native vegetation and its patchiness (number of patches per unit of area) are influencing factors on the intactness or 'naturalness' of the landscape. A continuum of native vegetation, with little to no degree of roadways or modification and therefore high connectivity is characteristic of intact landscapes, including within arid and semi-arid regions (Kareiva, 1986; McIntyre & Hobbs, 1999; Eco Logical Australia, 2013). Through the bisection of contiguous areas of native vegetation, infrastructure and roads can act as vectors for invasive species and result in various edge effects. Therefore, intactness, while reasonable, is not an absolute measure of landscape function (Forman, *et al.*, 2003; Hulme, 2009; Spellerberg, 1998; Trombulak & Frissell, 2000; Eco Logical Australia, 2013).

Within a bioregional context, the creation of new roads into intact areas can facilitate the establishment of invasive fauna species into remote areas (Andrews, 1990; Brown, *et al.*, 2006; Mahan, *et al.*, 1998), including invertebrates, which can significantly disrupt ecological systems (Lach & Thomas, 2008; Eco Logical Australia, 2013). New road creation can also introduce weeds along the roadside and beyond (via vehicles and fauna) (Bergquist, *et al.*, 2007; Davies & Sheley, 2007; Gelbard & Belnap, 2003; Hansen & Clevenger, 2005).

Depending on the volume of use, road and infrastructure corridors can increase animal deaths, both of livestock and of native fauna. Substantial literature is available (e.g. Jones, 2000) on wildlife mortality associated with vehicular traffic (henceforth referred to as 'road kill' and see breakout box 'Road Kill in Australia') both in Australia and overseas. However, much of the literature is not specifically about unconventional gas project areas but refers to regular traffic flow (Eco Logical Australia, 2013).

Fragmentation also results in two other primary effects:

- alteration of the microclimate within and surrounding the remnant
- isolation of each area from other remnant patches in the surrounding landscape

Therefore, a fragmented landscape will experience biogeographic changes as well as changes in the physical environment. Physical changes include fluxes across the landscape such as fluxes of radiation, wind, and water all of which important effects on native vegetation remnants (Saunders, *et al*., 1991; Ries, *et al*., 2004; Fischer & Lindenmayer, 2007; Eco Logical Australia, 2013).

Fragmentation and shale gas operations

In Australia, shale gas resources underlie large land areas, and the number of wells required to access the resource is likely to be large. Existing operations in some US gas fields have a well density of one well per 13 km^2 after 6 years, increasing to one well per 0.8 km^2 after 13 years of development (Eco Logical Australia, 2013). These wells are usually connected by a network of roads, pipelines, compressor stations and often large industrial sites to accommodate gas processing plants to service the gas field operations. In establishing the well pads, associated infrastructure and particularly gas processing plants, vegetation is inevitably partially or fully cleared.

The revised Environmental Impact Assessment (EIS) conducted by the New York State Department of Environmental Conservation (New York State Department of Environmental Conservation, 2011) over Marcellus Shale Reserves observed that because most shale gas development would consist of several wells on a multi-well pad, more than one well would be serviced by a single access road instead of one well per access road as was typically the case when the 1992 EIS was prepared. Therefore, in areas developed by horizontal drilling using multi-well pads, it is expected that fewer access roads would be constructed. This method provides the most flexibility to avoid environmentally sensitive locations within the area to be developed.

With respect to overall land disturbance from a horizontal drilling, there would be a larger surface area used for an individual multi-well pad. This would be more than offset, however, by the fewer well pads required within a given area and the need for only a single access road and gas gathering system to service multiple wells on a single pad. Overall, there clearly is a smaller total area of land disturbance associated with horizontal wells for shale gas development than that for vertical wells.

In some US gas fields there can be up to 2 to 4 well pads per km^2 (Broderick, *et al*., 2011; New York City Department of Environmental Protection, 2009). Well pads within shale gas networks average 1.5 – 2.0 ha in size during the drilling and hydraulic fracturing phase, but pads of over 2.0 ha are possible. Following part reclamation, production pad size in the USA is likely to average 0.4 – 1.2 ha. The size of the well pad is determined by the space required to accommodate equipment for hydraulic fracturing, the larger equipment required for horizontal drilling and space for fluid storage. Shale gas developments also require service roads, which may total thousands of kilometres depending on the gas field size, location and existing road infrastructure. Roads are generally 4-6 m wide, and can accommodate or be co-located with any associated infrastructure (monitoring, communications and pipelines). In addition processing plants could occupy areas in excess of 50 ha (Eco Logical Australia, 2013).

While there will be differences between shale gas fields (see Slonecker, *et al*., 2012a, p. 3; Slonecker, *et al*., 2012b for US example) and CSG fields, the scale of landscape fragmentation as shown in Figure 7.1 illustrates the nature of the habitat fragmentation issue. The average density within CSG developments (Eco Logical Australia, 2012) is approximately 1.1 well pads (and 1.6 km of road) per km^2 of land compared to up to 3 – 4 well pads per km^2 of US shale gas fields. Shale gas fields require wells to be constantly increased over the life of the gas field in contrast to CSG where the well field is generally established initially and maintained in place through the life of the gas field.

Figure 7.1: Aerial photograph showing the interconnected network of roads and other infrastructure in a CSG field near Dalby State Forest, Southern Queensland

6.8 km

Source: Eco Logical Australia, 2013.

In Australia the shale gas infrastructure will vary with the geology and the topography. It is salutary to recognise that the projected impacts on vegetation and habitat from shale gas production in Australia are likely to be smaller than the historical impacts of land clearing for agriculture or urban development. However further loss on an already highly fragmented vegetation cover or reserves for such landscapes can be a significant threatening process. Further loss of native vegetation is the subject of regulation and legislation in all states (e.g. NSW Government Department of Environment and Heritage, 2013). This legislation was implemented to bring under control the threatening processes associated with land clearing.

Establishing a fully operational shale gas network within a contiguous landscape would generally decrease intactness from 1.0 (or near 1.0) to less than 0.7. Within a variegated landscape,

intactness would generally be reduced from 0.7 to 0.5. Under both scenarios, the long-term viability of some species is likely to be compromised due to the combined effects of increasing fragmentation, increased magnitude of edge effects, the possible proliferation of exotic species, noise and vehicle traffic. Overall impacts, such as any species impacted, extent of any loss and degree of impact will vary depending on the landscape context, history of disturbance and mitigation measures in place (Eco Logical Australia, 2013).

As discussed previously, much of Australia's potential shale gas development is likely to be in arid and semi-arid landscapes comprising large areas with reasonable cover of contiguous sparse native vegetation. While past clearing has been limited, the structure and function of these vast mosaics have been modified to some extent by other disturbance factors such as grazing, fire and invasive species (and there are many areas which have suffered severe land degradation including catastrophic decline in many rangeland areas of terrestrial mammal fauna) (Woinarski, *et al*., 2000; Eco Logical Australia, 2013). Nevertheless, the high level of intactness and vast size, has imbued in these landscapes a level of resilience resulting in the survival of the majority of native inland species populations (Eco Logical Australia, 2013).

While there may be flexibility when determining the exact location of wells and associated infrastructure to minimise the loss of habitat of threatened species, experiences in the USA, have shown that cumulative impacts can be more intractable (New York City Department of Environmental Protection, 2009).

Over the life of a mine, the level of vehicular access to each well pad may be considerable. A USA based study referred to by Broderick *et al.* (2011), estimated that total truck visits to a six well pad, for activities such as clearing, construction, drilling, hydraulic fracturing, flowback water removal and well completion can range from 4,300 up to 6,600 (Eco Logical Australia, 2013).

A field visit by members of the EWG to a multi-well pad suggested that in Australia, this estimate of truck visits is likely to be too high. Nonetheless, *'light vehicle visits associated with project management, safety inspections, internal and external audits, equipment maintenance, environmental*

Road Kill in Australia

- affects a wide diversity of fauna species (Clevenger, et al., 2003; Dodd, et al., 2004; Hobday & Minstrell, 2008; Taylor & Goldingay, 2004);
- can reduce the persistence of local fauna populations and result in local extinctions (Bennett, 1991; Clevenger, et al., 2001; Fahrig, et al., 1995; Forman & Alexander, 1998; Gibbs & Shriver, 2002; Jones, 2000; Magnus, et al., 2004), including populations of threatened fauna species (Dique, et al., 2003);
- may be more pronounced in particular seasons, especially in relation to breeding and dispersal (Clevenger, et al., 2003; Dodd, et al., 2004; Hobday & Minstrell, 2008; Taylor & Goldingay, 2004) during periods of drought (Ramp & Croft, 2002);
- is more acute in areas of high animal density (Dique, et al., 2003) and on roads that are close to wetlands and ponds (Forman & Alexander, 1998);
- often occurs at fauna 'black spots' (Case, 1978; Clevenger, et al., 2001; Clevenger, et al., 2003; Hobday & Minstrell, 2008; Magnus, et al., 2004), possibly relating to resource availability such as succulent grass or water (Jones, 2000; Magnus, et al., 2004; Smith-Patten & Patten, 2008), areas of tree cover within fragmented landscapes (Bennett, 1991; Clevenger, et al., 2003; Hubbard, et al., 2000; Taylor & Goldingay, 2004) and the configuration of roads (Clevenger, et al., 2003; Jones, 2000);
- increases in number when vehicles travel faster (Andrews, 1990; Clevenger, et al., 2003; Forman & Alexander, 1998; Hobday & Minstrell, 2008; Jones, 2000; Trombulak & Frissell, 2000);
- increases in number as traffic volume increases (Dique, et al., 2003; Forman & Alexander, 1998; Hubbard, et al., 2000; Jaeger & Fahrig, 2004; Trombulak & Frissell, 2000), and is influenced by traffic pulses (Trombulak & Frissell, 2000);
- most commonly occurs at night (Dique, et al., 2003; Magnus, et al., 2004) or in early morning and late afternoon (Hubbard, et al., 2000);
- can cause substantial damage to vehicles and may result in injury or death of occupants (Hobday & Minstrell, 2008; Gibson, 2008; Magnus, et al., 2004; Magnus, 2006; Ramp & Croft, 2002); and
- can be reduced through appropriate mitigation (Clevenger, et al., 2001; Dodd, et al., 2004; Jaeger & Fahrig, 2004; Jones, 2000; Magnus, et al., 2004).

Source: Eco Logical Australia (2013).

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surveys, site monitoring, and cleaning will also be substantial' (Eco Logical Australia, 2013). It is likely that native fauna mortality will occur in Australia in and around shale gas well pads. A breakout box documents trends in road kill in Australia in all environments, including on urban fringes, with dense traffic; it is important to stress that it does not relate specifically to shale gas operations.

Contamination and related impacts

Land use development has a history of contaminating natural resources. Human activities inevitably generate wastes, spills, deliberate disposals, leakages, erosion, noise, light, all of which have the potential to contaminate soil, air, water resources and the environment in general, for humans and ecosystems. Levels of contamination or pollution and outcomes of amelioration are regularly reported by the state and Commonwealth governments and the COAG Standing Council on Environment & Water (incorporating the National Environment Protection Council)[8]. Environment protection agencies or authorities exist in most jurisdictions to monitor compliance with government regulations on contamination or pollution.

As a result of land use development, surface waters carry large loads of sediment through much of the farmed zones of eastern and south-western Australia – perhaps as much as 10 times the loads before European settlement (Harris,

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8   www.nepc.gov.au

2006; Norris, *et al*., 2001). Sediment in streams reduces the range of insect larvae that can live in them, which in turn depletes the diversity of insects for pollination, vegetation and soil organic matter turnover, dung management, and other ecosystem roles. Apart from agricultural, forestry and urban activities, sources of sediment include gravel roads, especially those that are well travelled.

Contamination in relation specifically to shale gas operations

Adding a new land use, such as shale gas production, adds further potential for contamination of the landscape and environment. US experience, as outlined by Eco Logical Australia (2013) and others (Broderick, *et al*., 2011; New York State Department of Environmental Conservation, 2011; USEPA, 2008; USEPA, 2011; USDOE, 2009; New York State Department of Environmental Conservation, 2009; New York State Department of Environmental Conservation, 2009a; New York City Department of Environmental Protection, 2009; Society for Conservation Biology, 2013); suggests the following possible contamination impacts:

- impacts to aquatic ecosystems from contamination of land and surface water, and potentially groundwater via surface route, arising from:
  - spillage of hydraulic fracturing additives
  - spillage/tank rupture/storm water overflow from liquid waste storage, lagoons/ pits containing cuttings/drilling mud or flowback fluid.

- impacts to groundwater dependent ecosystems (Richardson, *et al*., 2011) and subsurface fauna as a result of contamination of groundwater by hydraulic fracturing fluids or mobilised contaminants arising from:
  - wellbore/casing failure
  - subsurface migration.

- loss of vegetation, habitat and landscape function from:
  - drill rig and well pads,
  - storage ponds or tanks
  - access roads.

- ongoing impacts arising during construction and pre-production:
  - noise (Blickley, *et al*., 2012), light pollution during well drilling/completion (Moran, 2013), local traffic impacts.

- emissions to air, of methane and volatile compounds from drilling, hydraulic fracturing, high pressure compressors, etc.

- new access roads and infrastructure are liable to be subject to erosion, adding dust and sediment movement to existing levels in that area.

Noise (Blickley, *et al*., 2012) and light pollution (Moran, 2013), as well as traffic movement, will also contribute to loss of intactness in the landscape. In the USA, Broderick *et al*, (2011) have estimated that over the lifetime of a project, noisy surface activity associated with each well pad will occur on 800 - 2,500 days. Drilling is likely to produce the single greatest noise (24 hours continuous noise for 8 - 12 months, for a well pad containing 10 horizontal wells) (Eco Logical Australia, 2013). However, drilling time can vary considerably depending on depth and sedimentary strata encountered and this US experience may not apply to Australian operations.

Prior experience during mining and other activities has established that retention ponds storing flowback fluids or freshwater may attract wildlife (Hein, 2012; Ramirez, 2009; Eco Logical Australia, 2013). While quantitative studies do not appear to have been conducted in relation to unconventional gas operations, fauna deaths in treatment dams are not likely to be significant, and should be put in context of the loss of native wildlife in and around rural farm dams as a result of poisoning by algal blooms (Yiasoumi, *et al*., 2009) or from dam inundation and failure (Department of Sustainability and Environment, 2007). Eco Logical Australia (2013) have highlighted that notwithstanding this relatively low risk, '*measures to reduce fauna deaths include exclusion fencing around containment ponds, exclusion netting above the surface of dams, and absence of lighting around ponds that might attract insectivorous fauna species*'.

Use of water for drilling activities and camps to some extent modifies the resource available

for environmental and other uses. The impacts may be relatively large in terms of the water resources available (see Table 8.2), and are likely to differ between rangeland shale gas wells and those in more populated areas where water use is already under considerable competition and needs to be licensed.

Wildfire

In relation to potential wildfire, distributed access and equipment may be beneficial in terms of controlling fires. Severe or 'catastrophic' wildfire can threaten life and property, and results in wide-scale death of native fauna and flora. Wildfire can also result in changes to the state or type of native vegetation, to an extent whereby species may have problems recolonising an area. The risk of uncontrolled wildfire from a gas project site as a result of an accident or act of arson is low because of the high degree of supervision of all operations in the vicinity of gas wells; and the network of roads developed for the shale gas project will provide access to fight the fire. In addition it would be reasonable to expect that emergency response measures will be developed on shale gas fields in order to contain fires effectively and quickly, so that potential for wide scale devastation is low (Eco Logical Australia, 2013).

Human amenity: Land access and multiple land use planning

Experience with production of unconventional gas in Queensland and NSW has shown that access roads and well networks can compromise the landscape for productive agricultural and pastoralist activities (see Figure 7.2), and for indigenous land use, as well as for its habitat values and scenic and aural qualities. The US experience with shale gas production indicates that without measures being taken prior to the development of the industry in Australia, similar land use tensions are possible. Shale gas developments will often be in landscapes where indigenous ownership and management of

land will be significant. The principle underlying the administration of Aboriginal land is that the traditional Aboriginal owners of each parcel of land have the sole right to make decisions as to land use. The provisions of the *Native Title Act* (1993) and various State and Territory *Aboriginal Land Rights Acts* can be complex and resolving a just social process will be an issue of importance in managing land access and building multiple land use mosaic across the landscape. This issue is discussed in greater detail in Chapter 11.

The development and operation of shale projects will require a large number of wells, rigs and collection and transmission pipeline networks. Projects will need to minimise competition for land, water and infrastructure with other resource development projects, agricultural uses and communities. At the same time, shale gas developments have the potential to provide new roads and other infrastructure in areas of inland Australia that are currently poorly served. The potential also exists for the industry to provide access to deep groundwater in areas where access to useable groundwater is currently limited. In other words there is the opportunity for positive outcomes that may counterbalance some of the adverse impacts.

Legislation has been introduced in Queensland for mining exploration and development, to protect the State's strategic cropping land (Queensland Department of Environment and Resource Management, 2012). In NSW a similar

Figure 7.2: Productive farmland in northern NSW surrounding a CSG exploration and testing development

Source: Williams *et al.*, 2012, p37.

approach has been adopted. The aim is to strike a balance between the competing interests of the agriculture, mineral resources and urban development industries. In Queensland, projects such as open cut mining, CSG, underground coal gasification, long-wall/underground mining, urban development and industrial development will all be assessed under the laws. The NSW Government's Strategic Regional Land Use Plans will seek to identify criteria for strategic agricultural land and define appropriate protection requirements under a risk management framework (NSW DoPI, 2011; NSW DoPI, 2012; NSW EPA, 2012). The regional plans will identify the most appropriate land use, whether mining, agriculture, CSG extraction, conservation or urban development or a mixture of these activities. The regional plans will involve community consultation to ensure issues are clearly identified and considered in the land-use planning process. Priority plans are being prepared for the Upper Hunter and Gunnedah regions.

Approaches like those in Queensland and NSW may be appropriate for shale gas and other unconventional gas developments in some areas. This will require industry to work with local government, the regional natural resource management bodies and landholders including traditional Aboriginal landholders to ensure that infrastructure is planned and developed in a manner that reduces surface impacts, minimises inconvenience and adds value to local infrastructure.

Risk assessment of potential consequences from shale gas and other land use developments

It is possible for there to be a balanced co-existence of distributed forms of mining (used for unconventional gases) and other forms of food and fibre production. It will require careful management. For this reason, good bioregional planning and cumulative risk assessment are absolutely fundamental matters that require priority attention.

Risk assessment methods and tools have already been developed (Bain, *et al*., 1986; LaGory, *et al*., 1993) for use in catchments where there are multiple land uses. Examples include LUCRA, the Land Use Conflict Risk Assessment (NSW Department of Primary Industries, 2011), methods applied in the Alligator Rivers Region of NT (which encompasses mining, indigenous values and conservation; SEWPaC, 2011), and the land use impact model developed in Victoria (MacNeill, *et al*., 2006). The Namoi Catchment Management Authority (NSW) also has built on the Catchment Action Planning process and regional land-use planning and developed methods for making *cumulative* analysis of multiple industry development (Eco Logical Australia, 2011; Eco Logical Australia, 2012).

Other approaches also in development may help resolve potential conflicts. These include cumulative risk assessment and strategic land use planning and policies such as the proposed Multiple Land Use Framework developed by the Land Access Working Group under the Standing Council on Energy and Resources[9].

The approach outlined for conduct of cumulative risk assessment within a regional land use planning framework, is not only necessary for landscape biodiversity and land use issues but is central to the whole-of-system examination of hydrology and water resources. These are the subject of further discussion in Chapter 8.

Ecological Risk Assessments

Preliminary risk assessments have been conducted for potential ecological, hydrological impacts by consultants engaged for this study (Eco Logical Australia, 2013). Six major impacts were examined in their work:

1. Removal of native vegetation;
2. Landscape fragmentation and loss of intactness;
3. Increased incidence of bushfire;
4. Reduction in surface water;
5. Contamination of surface water; and
6. Impacts to groundwater ecology.

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9   www.scer.gov.au/workstreams/land-access

Table 7.1: Major ecological risks identified for shale gas development in Australia, and their mitigation

	Risk Assessment	Risk Mitigation Measures
Removal of native vegetation	Moderate	Avoidance of sensitive areas; establishment of offsets; land site rehabilitation; implementation of biodiversity management plans, including strategic buffers around rivers, streams, wetlands, and other sensitive areas (Arthur *et al.,* 2010)
Landscape fragmentation and road mortality	High	Co-location of pipelines; full utilisation of established roads and tracks; minimisation of road length and maximisation of contiguous vegetation; reclamation of temporary service tracks; feral animal and noxious plant control; speed limits and dawn/dusk driving curfews; strategic over- and under-passes to facilitate movement of fauna.
Bushfire	Low	Fire emergency response protocols in place; establishment of fire breaks.

Source: Eco Logical Australia, 2011; Eco Logical Australia, 2012; Submission to this Review by Eco Logical Australia, 2013.

Most of these potential consequences have been considered within Chapter 7; the hydrological risks are considered in Chapter 8. Seismic risks are considered in Chapter 9.

The risks were analysed according to Australian Standards (AS/NZ ISO 31:000:2009), taking into account the likelihood of the impact and its consequences. The compendium of consultancy reports (Eco Logical Australia, 2011; Eco Logical Australia, 2012) gives details of this analysis, including judgements about the components of the risk. Further details on environmental risks, and their analysis, may be found in the Eco Logical Australia Report to this Review (Eco Logical Australia, 2013).

Table 7.1[10] summarises the major ecological risks identified for shale gas development in Australia and suggests methods for their mitigation (Eco Logical Australia, 2011; Eco Logical Australia, 2012).

Conclusions

The majority of Australia's shale gas resources occur in large sedimentary basins spanning vast inland areas, parts of which support contiguous expanses of relatively intact native arid and semi-arid vegetation. Shale gas resources also occur in some temperate and sub-tropical parts of Australia that are in part urbanised, or developed for agriculture.

The shale gas industry has the potential to impact on natural assets and the long-term function and value of vital renewable natural resource assets and ecosystem services. However the industry also has the opportunity to work with communities and regulators to minimise those potential impacts and maximise the prospect of positive outcomes.

From US experience and experience to date in unconventional gas developments in Australia, there is good evidence (e.g. New York State Department of Environmental Conservation, 2011) that habitat fragmentation and some degree of environmental contamination will be an unavoidable result of shale gas expansion. Alongside the previously described risks to local fauna and flora and landscape function (e.g. loss of intactness, influx of foreign species, increased noise, increased roadkill, and edge effects), there is some risk of contamination to terrestrial and riparian ecosystems from chemical spills (Eco Logical Australia, 2013). While some of these impacts are responsive to specific mitigation most of the impacts on biodiversity cannot be readily mitigated and will result in unavoidable loss. Clearly no loss in biodiversity under shale gas development is not possible but experience with the Native Vegetation Act (NSW Government Department of Environment and Heritage, 2013) in NSW shows that a policy of no net loss in biodiversity is a possible mechanism in which establishing and monitoring biodiversity offsets has shown some promise. It would appear that this may also be a worthwhile tool for the shale gas industry to achieve no net biodiversity loss. While spills

10 Table 7.1 has been taken directly from the ELA consultancy report for this study (2013) and other ELA consultancy reports (Eco Logical Australia, 2011; Eco Logical Australia, 2012) with permission.

are an issue that require specific mitigation, the industry already has in place rigorous procedures for minimising spills. If despite everything, a spill was to occur, there are well-defined procedures for remediation and for reporting the quantities of chemicals used and the number of impoundment ponds and holding tanks required.

Land access and land use issues similar to those encountered with CSG developments are liable to accompany development of shale gas resources, perhaps more intensely in non-rangeland regions where there is already considerable agriculture, mining and urbanisation. Projects will be competing for land and water and infrastructure resources. In remote locations where shale gas development is anticipated, potential issues with access to land may conflict with Indigenous land use and management and need to be resolved.

Shale gas production will add to other land use pressures and the landscape and biodiversity will benefit from strategic land use planning and environmental assessment, to avoid risk in critical sensitive habitats, and specific mitigation to manage risk in other circumstances. While the impacts of shale gas extraction on environmental assets may be limited at a project by project basis, the collective impacts of multiple operations across a catchment or landscape could be significant, and must be carefully managed as the industry expands, in order to minimise the risk of significant adverse effects arising from landscape fragmentation (DEST, 1995) and

water and land contamination. A possible way to address this issue may be to explore robust strategic regional planning, including the use of the principles of 'integrated catchment (or watershed) management' to create a mosaic of appropriate land uses, in order to prepare for an orderly expansion of the exploration and development of shale gas in ways that will not compromise landscape environmental function.

The approaches taken by State and Commonwealth governments to CSG may provide added protection for biodiversity and the environment, water resources for food and fibre production and land uses of indigenous peoples. Current approaches may also allow shale gas developments to co-exist with conservation, Indigenous land use, agriculture including pastoral activities and food production. This may need to include 'no go' zones for shale gas development but the aim must be to promote 'balanced co-existence' that includes environmental protection.

It appears possible for unconventional gas development to be able to work within a framework of legislative and regulatory processes for multiple land use based around well-resourced regional strategic biophysical planning and cumulative risk assessment, given that cumulative landscape risk analysis tools and reliable data are now becoming available. These tools and the social process involved in their use will be constrained by biophysical and geophysical knowledge and spatial data

availability and therefore it is important that steps are taken to address any knowledge gaps.

Shale gas production is no different from any other development of our landscapes and like them, it poses risks to the condition of the water, soil, vegetation and biodiversity, and has the potential to reduce the capacity of our natural resources to supply human, as well as ecological needs. It also has the capacity to provide economic and social development in areas which currently lack many services and where jobs are limited.

The way forward will be to recognise that a whole-of-system framework is essential, to deal with the strong interacting impacts of multiple land uses, including gas development, on the long-term need to retain landscape functionality – that is the integrity of hydrological and ecological processes on which humans depend.

As a strategic framework it is feasible (Eco Logical Australia, 2011; Eco Logical Australia, 2012; New York City Department of Environmental Protection, 2009; Shoemaker, 1994) to build at the bioregional level a set of cumulative risk assessment methods (e.g. Gordon, *et al*., 2009) that according to Eco Logical Australia (2013) '*seeks to avoid, mitigate and offset potential impacts prior to shale gas approvals. This framework would act to provide an over-arching level of mitigation to address major landscape issues and be underpinned by agreed and scientifically robust thresholds and targets*

transferable to project-by-project measures. The strategic environmental assessment process available in the EPBC Act [Commonwealth of Australia, 2012] would appear well suited for such a purpose and provide companies with regulatory certainty and align natural resource management (NRM) goals for catchments, and embrace other landscape initiatives such as the National Reserve System (NRMM, 2009) and the National Wildlife Corridors Plan (SEWPaC, 2012)'. There is progress in part in the development of CSG-Draft-National-Harmonised-Regulatory-Framework (SCER, 2012) and it would seem that such frameworks could be further developed to incorporate shale gas production. The assessment for shale gas risks can be incorporated into the existing Bioregional Assessment Process underway between the states and Commonwealth.

This approach may offer industry, community and government a mechanism within the existing approvals framework to operate in tandem with standard industry mitigation measures to protect ecological values together with the existing Bioregional Assessment Process underway between the states and Commonwealth (Eco Logical Australia, 2013). Understanding and managing the risks associated with resource extraction will help to ensure that Australia can make the best use of its resources, including its shale gas resources while minimising adverse environmental impacts.

8

Water resources and aquatic ecosystems

There is evidence of a consensus among experts from government agencies, industry, academia, and environmental organisations, about potential consequences for water resources, which need to be avoided, managed and mitigated against, in shale gas development (Smith, 2012; Australian National University, 2012; Krupnick, *et al.*, 2013; Society for Conservation Biology, 2013). These studies found that, despite significant public and regulatory concerns about groundwater risks, risk of impacts on surface waters from shale gas projects was the dominant concern among the experts.

Put simply the potential impacts of shale gas production on water resources arises from what water is extracted from the water resource and what is discharged along with contaminants into streams and groundwater aquifers. Therefore water management to minimise both extraction from, and disposal to the surface and groundwater resource, is important to the development of shale gas production so as to minimise its impact on the environment.

Surface water and groundwater are connected components of the one hydrological system. The traditional separation of surface and groundwater can be convenient, but often fails to recognise that surface and groundwater are components of the same hydrological system (Sinclair Knight Merz, 2012; Barlow & Leake, 2012). River discharge to groundwater and groundwater discharge to rivers and streams is always occurring and such flows reverse direction in time and space over the catchment and life of the streams and aquifer. This is particularly so in shallow groundwater and alluvial river systems so common in the Australian arid and semi-arid landscapes (English, *et al*., 2012) where there are large areas with prospects for shale gas development.

Further if drilling and hydraulic fracturing operations intersect aquifers and aquatards, this may cause mixing of water and contaminants and change aquifer water quality and aquifer discharge and recharge flow regimes (Osborn, *et al*., 2011; Warner, *et al*., 2012).

Water Extractions from Streams and Groundwater Aquifers

Managing water in a sustainable manner is an important issue facing the shale gas industry in Australia. There are at least four components of water management for shale gas production that need to be considered (New York State Department of Environmental Conservation, 2009; New York State Department of Environmental Conservation, 2009a):

- the source of water to be used in hydraulic fracturing,

- how to avoid over-extraction of potable water from aquifers and how to protect them from contaminants,

- re-use and disposal of any 'produced' water that emerges from the well during drilling, and

- avoiding aquifer interference and perturbation of groundwater flow.

As noted in Chapter 4, the primary component of the hydraulic fracturing process is water. The actual volumes required for the hydraulic fracturing process depends on local geological conditions such as depth to shale strata, porosity, length and number of horizontal strings and existing fractures. It can vary both within and between geological basins (Nicot & Scanlon, 2012).

In the United States, depending on location and price, fracking water comes from both surface and groundwater sources. Table 8.1 shows the median volume of water used for hydraulic fracturing each well in the United States.

Table 8.1: Median volume of water used per shale gas well in the United States

Shale Gas Play	Volume of water used (Ml)
Barnett, Texas	10.6
Haynesville, Texas	21.5
Eagleford, Texas	16.5
Marcellus, PA	17.1

Source: Nicot & Scanlon, 2012 and Beauduy, 2011.

Cumulative impacts assessment data has been assembled for the Impact Assessment of Natural Gas Production in the New York City Water Supply Watershed compiled by the New York City Department of Environmental Protection (New York City Department of Environmental Protection, 2009) as the Final Impact Assessment Report. Table 8.2 provides estimates of water requirements for shale gas development to give a scale to the cumulative water consumption, flowback volumes and produced water for a major shale gas field.

Based on this data the volumes of water required for a single hydraulic fracking for the life of a major gas field (3,000 wells) is of the order of 45,600 ML (45.6 GL) which while a large amount of water, is modest when set against consumption in irrigated agriculture (Chartres & Williams, 2006).

Table 8.2: Summary of individual and cumulative impact estimates for impact assessment of natural gas production in the New York City water supply watershed

Parameter (unit) Estimate (source)	Quantity for One Well (range)	Annual Well Development (Quantity/Year)		Full Build-out (Total Quantity)	
		Low	High	Low	High
Developable area (Km)^2				1,300	2,600
Percent Total Watershed Area *Total Watershed Area is 4121(Km)^2*				32%	63%
Number of Wells *Assume 2.3 wells/(Km)^2*	1	20	500	3,000	6,000
Water Consumption (ML) *Industry and SGEIS (2009)*	15.2 *11.4 to 30.4*	304	7,600	45,600	91,200
Flowback (ML) *10% to 70% of fracture fluid Assume 50%*	7.6 *1.52 to 10.64*	152	3,800	22,800	45,600
Produced Water (ML) *Industry and SGEIS (2009)*	0.28 *0.057 to 0.57*	5.7	142.5	855	1,710

Source: New York City Department of Environmental Protection, 2009.

Shale Gas and the Australian Hydrogeological Environment

Because shale gas production in Australia is in its infancy, the average volume of water needed to hydraulically fracture Australian shales is not yet known. The volume of water required to hydraulically fracture shale gas strata can be an order of magnitude larger than that of coal seam gas due to greater depths and different geo-mechanical properties of coal and shale (Golder Associates, 2010; New York City Department of Environmental Protection, 2009) as summarised in Table 8.2. Conversely, the volume of produced water is orders of magnitude less than the amount produced over the life of a CSG project. The information available to the Expert Working Group leads us to conclude that while extraction of water for shale gas operations will be a significant issue for shale gas operations, these operations will not be faced with the disposal and subsequent replacement of large volumes of produced water, as is the case in CSG operations.

Most of the shale gas resources in Australia are located either wholly or partly within the arid and semi-arid zone. Groundwater systems, as characterised by English *et al.* (2012), will often be the sole water resource available to energy companies, unless it is imported from elsewhere. In Australia generally, natural groundwater recharge rates are low and particularly so in many

of the regions with shale gas resources (English, *et al.*, 2012; Sinclair Knight Merz, 2012). The extraction of water for shale gas operations may have significant impacts on local groundwater systems and therefore should be managed within National Water Initiative Principles (National Water Commission, 2003). The use of recycled water or waterless methods of hydraulic fracturing will assist to reduce the volume of water needed for hydraulic fracturing. However, there will be a disposal problem of salt and other components in resultant brines and this will be considered later.

Points to Consider in Relation to Surface Streams and Groundwater

Existing land use developments and activities in Australia tend to affect local water resources (Nevill, *et al.*, 2010). Shale gas production is likely to add to these consequences, which may include effects of:

- abstraction of water on stream flow;
- shallow groundwater abstraction on dependent ecosystems and stream flow;
- roads on surface water flow that is essential for vegetation;
- contamination of water resources (surface or groundwater); and

- using streams as drains to dispose of surplus water, which affects flow regimes and the stream ecology.

Flow Regimes in Surface Streams

In high rainfall regions, shale gas operators may be able to access permanent river water or domestic/agricultural storage, for use in hydraulic fracturing or related activities. As pointed out by Eco Logical Australia (2013) *'in drier regions where surface flow is unreliable, opportunistic water abstraction and on site retention may be possible following good rains'… 'Pumping from groundwater may be possible in some areas, and this may have implications for surface flow if local groundwater is* a source of discharge to surface flow. While part of the water demand may also be achieved through water recycling, an alternative supply option for large operations will be piping or transportation of water from an external source, to each well pad for the time in which drilling and hydraulic fracturing take place.' Impacts of reduced water flows and of changed flow regimes on aquatic ecosystem health as a result of direct abstraction or because of reduction of groundwater discharge, are well known; Eco Logical Australia (2013) and references therein: Brookes *et al.* (2009), Bunn and Arthington (2002), Bunn *et al.* (1999), NSW Department of Environment and Climate Change (2009), Gawne *et al.* (2007), McKay and King (2006), and Read and Brooks (2000) (see breakout box).

Impact of reduced aquatic system water flows

Since natural flows determine physical riparian and floodplain habitat, reduced flows:
- simplify geomorphology, minimise morphological structure complexity and lead to a more homogenous habitat,
- reduce and alter habitat complexity,
- reduce habitat accessibility e.g. fish movement,
- reduce food availability and limit food sources, through:
    - reduction in the distribution of allochthonous carbon (logs, leaves, dissolved organic carbon) for temperate/tropical ecosystem,
    - altered autochthonous inputs from phytoplankton, periphyton and macrophyte productivity,
    - increased competition between native and invasive species for limited resources,
- degrade surface water quality via:
    - increase in nutrient concentrations (nitrogen and phosphorus), leading to higher probability of algal blooms,
    - increased levels of salinity in streams with decreasing water levels, and increased salt loads in soils that impacts riparian vegetation.

Aquatic organisms have life strategies that are evolved to natural flow conditions, so that reduced flows also:
- impact flow dependent species e.g. ribbon weed (Georges, *et al.*, 2003),
- alter critical ecological processes such as trigger breeding cues for birds and fish, where the long term impact may be reduced species diversity (Bunn & Arthington, 2002),
- reduce water available for groundwater dependent ecosystems (GDEs).

Natural flow patterns maintain longitudinal and lateral connectivity in aquatic ecosystems, thus reduced flows:
- restrict connectivity between major habitats (river, wetlands, floodplain, estuaries);
- change the ecological character of habitats – increase in salinity concentrations and nutrient loads, reduce native macrophyte distribution and habitat availability, increase distribution of invasive plants, decline wetland dependent communities (e.g. waterbirds) and increase acidification of soils (NSW Department of Environment and Climate Change, 2009); and
- fragment floodplains and limit riparian vegetation recruitment.

The success of invasive species is often facilitated by altered flow regimes.

Source: Eco Logical Australia (2013).

Many Australian streams in developed areas are already in poor ecosystem health. Abstraction of water for shale gas production will place additional or cumulative pressure on these eco-hydrological systems. In examples provided by Eco Logical Australia (2013), the impacts of water extraction may:

- *'be compounded when associated with the effects of river regulation and other water extraction activities (irrigation), extreme and prolonged drought conditions, climate change and water pollution* (NSW Department of Environment and Climate Change, 2009), *and*

- cause increased pressure on species/ ecological communities that are already threatened in the landscape'.

Sheet flow

In arid and semi-arid zones in Australia many vegetation formations rely on a water movement known as sheet flow for adequate moisture absorption to support growth. (Tongway & Smith, 1989). Sheet flow occurs in a broad, sheet-like film, typically over a very gentle downhill slope over relatively smooth rock and soil surfaces and does not concentrate into channels larger than rills (Miller, *et al*., 2002; Eco Logical Australia, 2013). Sheet flow is a typically low volume water movement representing low velocity water dispersal and thus low energy and low potential

for erosion (Ludwig, *et al*., 1997; Tongway, 2005; Eco Logical Australia, 2013).

Shale gas developments and their associated linear infrastructure have the potential to intercept and divert sheet flow. As highlighted by Eco Logical Australia (2013), roads that require raised embankments, sections of cut and fill, and water diversion works such as culverts and spillways, all have potential consequences for sheet flow, including:

- water ponding upslope of infrastructure

- reduced sheet flow (water starving) downslope of infrastructure

- concentrated water flow through diversion infrastructure, with potential to cause erosion and subsequent deposition; and

- channel formation.

The most widely recognised sheet flow dependent vegetation (SFDV) (Ludwig & Tongway, 1995; Ludwig, *et al*., 2005) in Australia is Mulga (*Acacia aneura*) woodland (Morton, *et al*., 1995; Woinarski, *et al*., 2000), an important component of vegetation in semi-arid or arid regions. Mulga is well adapted to arid conditions as it possesses thick-skinned, leaf-like 'phylodes' that are adapted to minimise sun exposure and moisture loss. The species is able to grow in poor soils through a symbiotic relationship of nutrient fixing bacteria, *Rhizobium* around its root system.

Table 8.3: Summary of impacts of linear infrastructure on sheet flow dependent vegetation (SFDV)

Impact on sheet flow	Location	Impact on sheet flow dependent vegetation	Timescale
Water Ponding	Upslope of infrastructure	Excess water leading to change in SFDV • Increased growth and recruitment with increased water • Decreased growth and recruitment with increased water • Invasion of exotic and native plants (weeds) in altered environment	Short to long-term (months to decades)
Water Starving	Down slope of infrastructure	Reduced water leading to decreased growth and recruitment	Long-term (years to decades)
Erosion	Down slope of infrastructure, below culverts	Concentrated flow leading to erosion	Short to medium-term (months to years) following large rainfall events
Deposition	Down slope of infrastructure, below culverts	Erosion and transport of sediment leading to deposition	Short to medium-term (months to years) following large rainfall events
Channel formation	Down slope of infrastructure, below culverts	Concentrated flow leading to erosion and channel formation	Short to medium-term (months to years) following large rainfall events

Source: Eco Logical Australia, 2012.

Mulga is very slow growing and lives for up to 200 years. It is important in arid ecosystems for nutrient capture and slowing down surface run off and localised hydrological regimes (Dunkerley, 2001). Road construction for shale gas exploration and extraction has the potential to impact the Mulga community, and possibly other SFDVs, by disrupting sheet flow through interception, concentration and pooling (Reid, *et al*., 1999; Eco Logical Australia, 2013).

Flow Regimes in Groundwater Aquifers

Groundwater dependent ecosystems (National Water Commission, 2012) rely either wholly or partially on groundwater to maintain their species composition and natural ecological processes (Hatton & Evans, 1998; Sinclair Knight Merz, 2012; National Water Commission, 2012). Human activities, such as leaving bores flowing, or over extraction, can affect the groundwater supply to such ecosystems, which include deep rooted vegetation[11], wetlands, cave ecosystems

and mound springs fed by artesian groundwater. Groundwater is also often the source of the baseflow that maintains streams and rivers in the absence of runoff (Sinclair Knight Merz, 2012; Barlow & Leake, 2012). Groundwater is used for agriculture and for domestic and town water. Cumulative impacts on groundwater aquifers, such as over extraction, could affect all the described uses (e.g. Nevill, *et al*., 2010) and will need to be considered if shale gas production uses groundwater in its operations.

Groundwater dependent ecosystems, such as the important Artesian springs fed by the Great Artesian Basin (GAB) (Figure 8.1) could be impacted by shale gas operations in the Cooper and Galilee Basins. Artesian springs support unique and highly restricted vegetation formations of ecological significance (Fensham & Fairfax, 2003), including endemic invertebrate communities (Fensham, *et al*., 2007; Ponder, 2004). Artesian springs are listed under the Commonwealth *Environmental Protection and Biodiversity Conservation Act 1999* (Commonwealth of Australia, 1999) as '*The community of native species dependent on natural discharge of groundwater from the Great Artesian Basin*' (Eco Logical Australia, 2013).

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11 Ecosystems in which the root zone (deep or shallow) is connected to the water table.

Figure 8.1: Australian Great Artesian Basin (GAB)
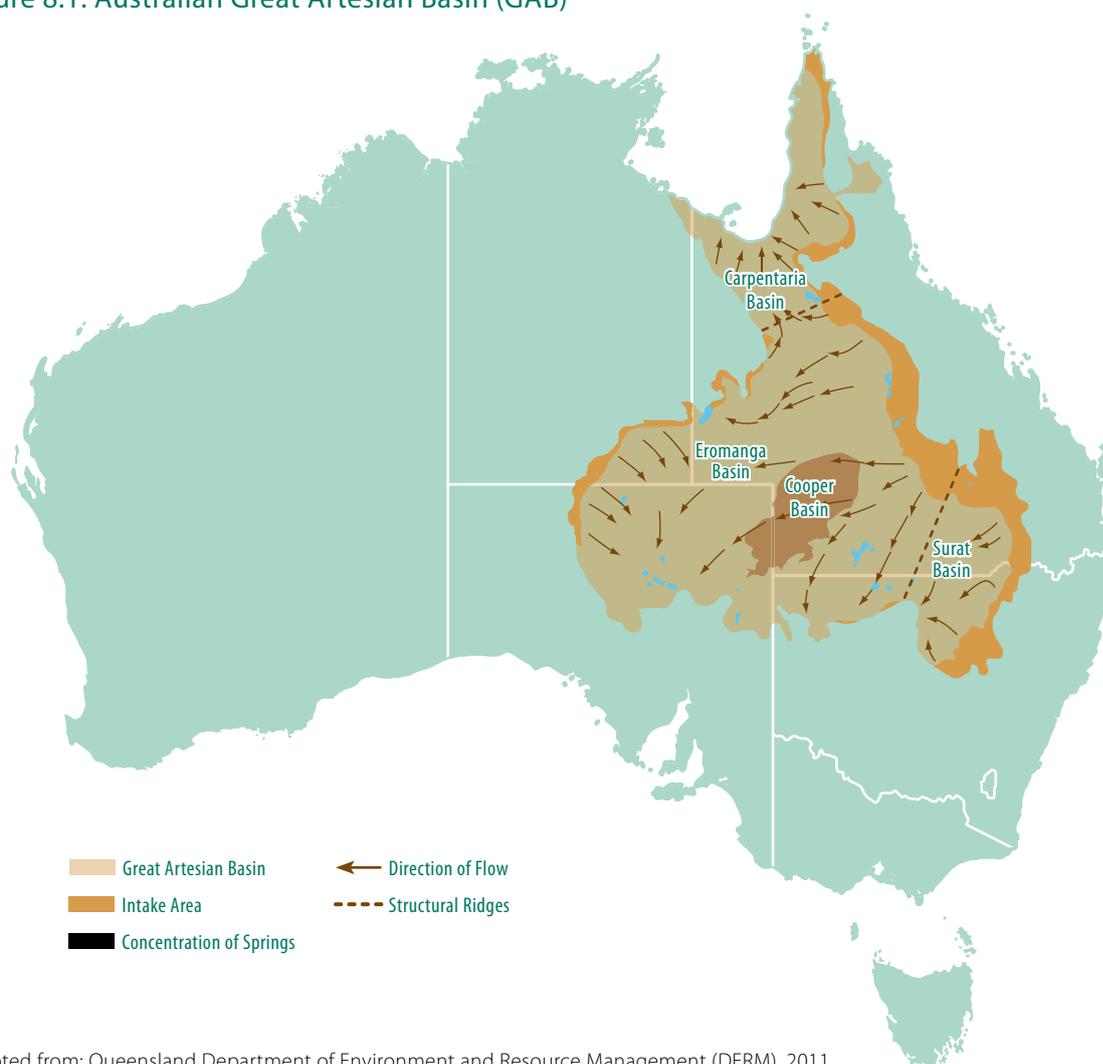
Adapted from: Queensland Department of Environment and Resource Management (DERM), 2011.

Another potential consequence of shale gas extraction on groundwater aquifers and connected spring ecosystems is unintended pollution, that can intersect wetland GDEs, derived from groundwater or uncontained flowback. The GAB is a confined aquifer system with water up to 1 million years old (Fensham, *et al*., 2007) isolated from human-induced pollution (Eco Logical Australia, 2013). Any increase in contamination as a result of shale gas developments could impact on mound spring communities. Based on the US experience, uncontained flowback of spent hydraulic fracturing fluid might also impact on wetland GDEs and other aquatic ecosystems (Michaels, *et al*., 2010; Eco Logical Australia, 2013). The Great Artesian Basin is considered in further detail and is the subject of a comprehensive assessment of recharge and groundwater flow pathways and mechanisms by CSIRO (Smerdon, *et al*., 2012). These new insights and information on GAB function and characterisation could be a valuable knowledge set in planning for sustainable management of shale gas development.

Water Discharges and Releases to Surface Streams and Groundwater Aquifers

Environmental issues identified with produced water management can range from potential harm to aquatic life and crops, to streambed erosion from produced water discharges (USEPA, 2008; Entrekin, *et al*., 2011; National Energy Technology Laboratory, 2009; Eco Logical Australia, 2013). While discharge of produced water to streams is unlikely to occur from shale gas operations in Australia, any rare discharges should be conditioned so that environmental values and water quality objectives, including

water quality to meet public health objectives, are protected. In such circumstances discharges to ephemeral streams should be pulsed to avoid flows in naturally dry periods. Inappropriate disposal of even high quality treated water to ephemeral streams in arid regions may have serious ecological impacts (Levick, *et al.*, 2008; Smythe-McGuinness, *et al.*, 2012).

Great care is required for the storage, both on-site and offsite, of chemicals used for hydraulic fracturing, and impoundment and treatment of flowback waste water. Spills could impact the surrounding ecosystem and result in the dieback or death of vegetation or contamination of riparian areas. Broderick *et al.* (2011) summarise that adverse ecological impact may result from the various risks associated with handling and storage

of toxic materials (see breakout box) (Eco Logical Australia, 2013). Details of the chemicals used in hydraulic fracturing are given in Chapter 4.

Surface ecosystems may also be impacted by well failure including blowouts, involving the sudden and unplanned escape of poor quality water and/or methane gas to the surface (Michaels, *et al.*, 2010). Rana (2008) reports that in the United States, on average, 7 out of every 1,000 exploratory shale gas wells result in a blowout, with a major blowout that results in intense and prolonged hydrocarbon release averaging about 1 in 10,000 wells. Routine spills that occur during drilling operations can be controlled effectively (in hours or days) by closing the well with the help of blowout preventers and by altering the density of the drilling fluid (Eco Logical Australia, 2013).

Contamination of Aquatic Systems

Eco Logical Australia (2013) summarise the potential incidents that can lead to the contamination of aquatic systems as including:

- spillage, overflow, water ingress or leaching from cutting/mud pits owing to:
  - limited storage capacity;
  - operator error;
  - storm water or flood water ingress; or
  - poor construction or failure of pit liner;
- spillage of concentrated hydraulic fracturing fluids during transfer and final mixing operation (with water) that occurs onsite owing to:
  - pipework failure;
  - operator error;
- spillage of flowback fluid during transfer to storage owing to:
  - pipework or well failure during the operation;
  - insufficient storage capability and overflow;
  - operator error;
- loss of containment of stored flowback fluid owing to:
  - tank rupture;
  - overfilling of lagoons due to operator error or limited storage capacity;
  - water ingress from storm water or floods;
  - poor construction or failure of liner;

  spillage of flowback fluid during transfer from storage to tankers for transport owing to:
  - pipework failure; or
  - operator error
- spillage of flowback fluid during transport to wastewater treatment works.

Source: Eco Logical Australia (2013) and references there in: Broderick, et al., 2011; New York State Department of Environmental Conservation, 2011; New York City Department of Environmental Protection, 2009.

The gas industry is very conscious of the need to take all precautions to avoid a major incident such as a blowout and there have been very few such events in Australia over the past 50 years. The risk of a shale gas blowout in Australia is low.

Contamination of water resources is always possible when there are spills or leakage of chemicals or wastewaters, whether from agriculture or urban/peri-urban areas or industry including shale gas production. With shale gas production, the water used for hydraulic fracturing, and impounded flowback wastewater could be detrimental to surrounding ecosystems, and humans. Broderick *et al*. (2011) summarise the various risks associated with handling and storage of toxic materials related to shale gas production that may result in an adverse ecological impact (see breakout box) (Eco Logical Australia, 2013). Details of the types of chemicals used in hydraulic fracturing for shale gas extraction are given in Chapter 4. The storage, treatment, transport and disposal of liquids including wastewater and saline water are matters for regulation and care, in all industries, including the gas industry, to minimise environmental damage (National Energy Technology Laboratory, 2009).

In the United States groundwater contamination by methane, after hydraulic fracturing at shallow depths of several hundred metres in conventional gas wells, has been noted (Osborn, *et al*., 2011; DiGiulio, *et al*., 2011). But as pointed out by Frogtech (2013) methane occurs naturally in groundwater due to either slow migration from deeper gas-bearing strata or from microbial activity. Indeed, the Moomba gas field in South Australia was identified in part as a result of the presence of gas shows in the Great Artesian Basin aquifers (Cotton, *et al*., 2006; Frogtech, 2013). The source of the methane can be determined by analysing the isotopic signature of the gas, different isotopes of carbon indicating different gas sources (Osborn, *et al*., 2011). The naturally occurring biogeochemical processes and pathways of methane presence in groundwater and any emissions to atmosphere is not well understood although there are techniques and studies (Aravena & Wassenaar, 1993; Aravena, *et al*., 2003) which are clarifying the issue. It is an

area of study that would benefit from further work. The fugitive emissions of methane during shale gas production is discussed in Chapter 10 and the need for robust baselines studies and improved monitoring of methane emissions and sources is raised in Chapters 12 and 13.

Shales typically have low permeability and will act as aquitards or aquicludes, which limit vertical groundwater flow. However, transmissive faults, fractures, and lithological heterogeneities in the shale and overlying and underlying units can act as groundwater pathways (Myers, 2012; Frogtech, 2013). Because of the low permeability and the depth of gas-bearing shale resources (1,000-3,000m) there is little or no connection between deep brines associated with shales and shallower drinking water. However, as pointed out by Frogtech (2013) Warner *et al*. (2012), '*found evidence of natural mixing of brines and shallow groundwater through advective flow via faults and fractures*'.

Most Australian sedimentary basins have multiple users that can affect natural groundwater flows. These include mining, conventional oil and gas, CSG, agriculture and waste disposal. The cumulative effect of these multiple users is not understood and is rarely modelled or strategically examined. Greater than 95% of groundwater bores in Australia are less than 200m deep (Frogtech, 2009; Report to this Review by Frogtech, 2013). Shale gas is likely to be found at very much greater depths than this (2,000 to 3,000m), and groundwater systems will be difficult to characterise at that depth. Relationships between deep aquifers, faults, fractures, and over- and under-lying gas shales (or coal) are poorly understood, as are permeability, porosity and groundwater quality and flow direction (Frogtech, 2009).

Disposal of Hydraulic Fracturing Water

Water injected during shale gas fracture stimulation is back-flowed from the fractures into the well before gas production begins. This water may have a high salt content and contain dissolved methane, as well as chemicals dissolved from the geological strata, including naturally occurring radioactive materials (NORM)

(King, 2012). It also contains the chemicals added to assist in the process of fracturing (see Chapter 4 for details). There is evidence from the United States, that inappropriate disposal of fracking fluids can have significant negative environmental consequences (Adams, 2011). In Australia Batley and Kookana (2012) have suggested a lack of understanding in environmental chemistry with respect to CSG hydraulic fracturing in Australia and of the potential hazards the fate of hydraulic fracturing and produced water chemical may present to the environment. In the United States regulations are now in place mandating re-use of this water for hydraulic fracturing, and this may be appropriate for Australia. As pointed out by Frogtech (2013), approximately 30-70% of the hydraulic fracturing fluid injected is recovered although there is a wider range of values reported in the literature (New York City Department of Environmental Protection, 2009, p. 30). The remainder is trapped within macro-pores, micro-pores and fractures within the shale (USDOE, 2009; New York City Department of Environmental Protection, 2009). US experience shows that the key concerns in the responsible management of the recovered fluid are (USEPA, 2011; Frogtech, 2013):

- Unregulated release to surface and groundwater resources;

- Leakage from on-site storage ponds;

- Improper pit construction, maintenance and decommissioning;

- Disposal of large volumes of brine;

- Incomplete treatment;

- Spills on-site; and

- Wastewater treatment accidents.

Policies to manage co-produced water during CSG production have been developed in Queensland (Queensland Department of Environment and Heritage Protection, 2012) and NSW (NSW DoPI, 2011; NSW DoPI, 2012; NSW EPA, 2012). While shale gas production produces far less water than CSG production, it is generally of a poorer quality and therefore some of the re-use and recycle options such as irrigation, stock water, aquaculture and industrial uses are probably not suitable (RPS Australia East Pty Ltd, 2011). Therefore there will be a dependence on suitable hydrogeological conditions which would facilitate re-injection or its safe storage and re-use for further hydraulic fracturing.

Integration of Shale Gas Water Management with Principles Arising from the National Water Initiative

As already mentioned, the volume of water required to hydraulically fracture shale gas strata can be more than that required for hydraulic fracturing associated with CSG (New York City Department of Environmental Protection, 2009; CSIRO, 2012d) depending on the depth and extent of horizontal drilling. Conversely, the volume of produced water in shale gas operations is orders of magnitude less than the amount produced during CSG dewatering operations (New York City Department of Environmental Protection, 2009, p. 30; Williams, *et al.*, 2012; CSIRO, 2012e). It follows therefore that while extraction of water for shale gas operations from surface waters or aquifers will be significant, only a proportion of this water (flowback) needs to be stored at the land surface for re-use, or appropriately discharged to surface waters or re-injected into suitable geological strata.

Nevertheless, during the early stages of shale gas operations, large quantities of water, including saline water, will need to be extracted from surface and/or groundwater resources. The extraction and subsequent disposal will need to be managed within regulatory processes. These processes include water entitlements compliant with the National Water Initiative (National Water Commission, 2003), and aquifer management plans, and are necessary in order to minimise changes to flow regimes in streams and water levels in groundwater aquifers, and the potential for contamination of both types of water resource.

In implementing the NWI, most States and Territories have established limits to diversions, often referred to as "sustainable diversion limits", and water is allocated to extractive users by

governments within these limits. The allocation, entitlement, and use of surface and groundwater resources are matters of national interest and are covered by the Council of Australian Governments (COAG) *Water Reform Framework* and the *National Water Initiative*. Under these arrangements Federal and State governments made commitments to prepare water plans with provision for the environment; deal with over-allocated or stressed water systems; introduce registers of water rights and standards for water accounting; expand the trade in water; improve pricing for water storage and delivery and meet and manage urban water demands. If water entitlement allocation and management for shale gas operations is to be done according to the NWI then water resources in all aquifers (fresh, brackish or saline) within the shale gas basin, will need to be addressed in a systematic manner. It cannot be assumed an aquifer is an unallocated resource in States where the NWI has been implemented.

Clause 34 of the *National Water Initiative's* intergovernmental agreement provides for a possible exemption for mining where the parties agree that there may be special circumstances facing the minerals and petroleum sectors that will need to be addressed by policies and measures beyond the scope of the Agreement. In this context, the States, Territories and Commonwealth indicated that specific project proposals would be assessed according to environmental, economic and social considerations, and that factors specific to resource development projects, such as isolation, relatively short project duration, water quality issues, and obligations to remediate and offset impacts, might require management arrangements outside the scope of the NWI Agreement.

In 2012 and 2013 the National Water Commission (NWC) noted that CSG developments are often not well integrated with state and territory water planning and management arrangements. The NWC recommended a number of principles be applied by state and territory jurisdictions to manage the cumulative impacts of CSG water in a more NWI consistent manner namely:

- The interception of water by CSG extraction should be licensed to ensure it is integrated into water sharing processes from their inception.

- Project approvals should be transparent, including clear and public articulation of predicted environmental, social and economic risks along with conditions implemented to manage the risks.

- Adequate monitoring, including baseline assessment of surface and groundwater systems, should be undertaken to provide a benchmark for assessing cumulative impacts on other water users and water-dependent ecosystems.

- Jurisdictions should work to achieve consistent approaches to managing the cumulative impacts of CSG extraction. Such arrangements should consider and account for the water impacts of CSG activities in water budgets and manage those impacts under regulatory arrangements that are part of, or consistent with, statutory water plans and the National Water Initiative.

- Potential options to minimise the cumulative impacts of extraction on the water balance should be pursued as a first priority. These options include aquifer reinjection, where water quality impacts are acceptable, and groundwater trading or direct substitution for other water use.

- If discharges to surface waters are unavoidable, discharges should be conditioned so that environmental values and water quality objectives, including water quality to meet public health objectives, are protected. In such circumstances discharges to ephemeral streams should be pulsed to avoid flows in naturally dry periods.

- Jurisdictions should undertake water and land-use change planning and management processes in an integrated way to ensure that water planning implications of projects are addressed prior to final development approval.

- Clear accountabilities should be identified for any short- or long-term cumulative impacts from CSG processes, clarifying which organisations are

responsible for managing and rectifying or compensating for any impacts.

- The full costs, including externalities, of any environmental, social and economic water impacts and their management should be borne by the CSG companies. This includes, if not already in place, mechanisms such as bonds and sureties that deal with uncertainty and the timeframes associated with potential impacts. Given that these timeframes may extend for 100 or more years, current systems need to be re-evaluated.

- A precautionary and adaptive approach to managing and planning for CSG activities is essential to enable improved management in response to evolving understanding of current uncertainties. This includes impacts such as long-term reductions in adjacent aquifer pressures and levels, and impacts on environmental assets that are not adequately protected by current 'make good' mechanisms.

- Water produced as a by-product of CSG extraction, that is made fit for purpose for use by other industries or the environment, should be included in NWI-compliant water planning and management processes. This will enable CSG producers to manage this resource in accordance with the principles of the National Water Initiative.

The use of Clause 34 of the NWI is only intended for exceptional circumstances. Where Clause 34 of the NWI is used, a clear and transparent explanation of why it was used, rather than complying with the normal water planning and management regime, is required.

The National Water Commission's position is that NWI-consistent water access entitlements should be made available to the CSG industry. It would seem appropriate for measures similar to those for CSG to be available to operators of shale gas developments wherever possible. It should be noted that over the life of the shale gas field, the total amount of groundwater abstracted is very much less than that abstracted as part of CSG production.

Figure 8.2: A 3-dimensional illustration of a slice through geological basins, including the Eromanga Basin that hosts the Great Artesian Basin (GAB)
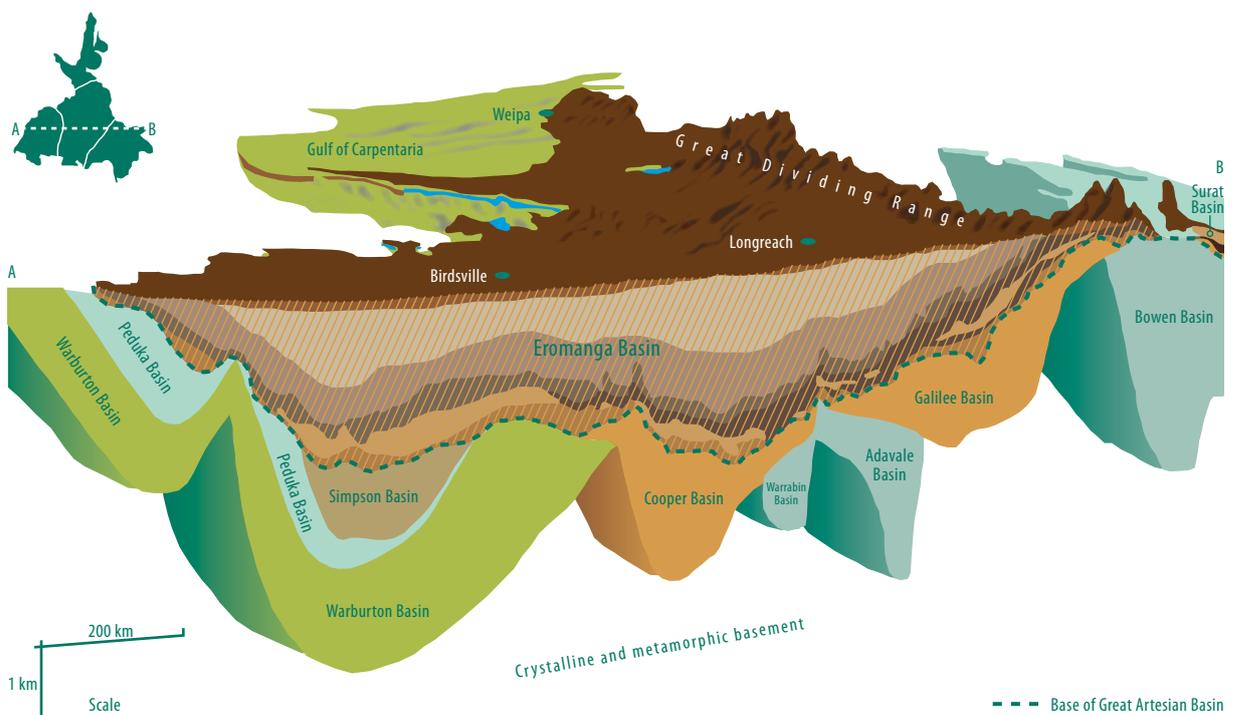
This diagram shows aquifer layers of the GAB and underlying geological basins. Because the GAB is a groundwater entity, some of the GAB aquifers may be in contact with groundwater in underlying basins.

Source: Smerdon, *et al.*, 2012.

Potential Impacts of Shale Gas Operations on Groundwater Aquifers

Australia: Deep Aquifers – Great Artesian Basin (GAB)

The Great Artesian Basin (GAB) extends beneath much of the arid interior of Queensland, New South Wales, South Australia and the Northern Territory, to depths of up to 3,000 metres, underlying an area of 1.7 million square kilometres and estimated to store 65,000 Gigalitres of water. It encompasses several geological basins ranging in age from 200 to 65 million years (Jurassic - Cretaceous). These geological basins sit on top of deeper, older geological basins (Figure 8.2) and, in turn, have newer surface drainage divisions such as the Lake Eyre and Murray-Darling river basins situated on top of them (Smerdon, *et al.*, 2012).

In cross-section there are six key GAB aquifers, with an average thickness of 150-200 metres, predominantly sandstones recharged by rainfall and streamflow infiltrating into the exposed sandstones on the eastern edge of the Basin. The water in these aquifers is old (~ 1 million years). Figure 8.3 shows in simplified form a cross section of the stratigraphy of the Cooper basin within the GAB.

The deepest aquifer in the GAB, the Hutton Sandstone, extends to a depth approaching 3,000 metres in the Cooper Basin region, approximately 300 - 800 metres above Permian shale/tight sand reservoirs that constitute the unconventional gas (Gravestock, *et al.*, 1998; Santos Limited, 2012c; Reports to this Review by Cooke, 2013, and Frogtech, 2013). It should be noted that conventional wells in the Cooper Basin have extracted oil and gas from deep GAB strata for many years without incident (Cooke, 2013).

There are two important technical issues that require consideration: (i) well integrity at depth and (ii) monitoring the vertical extent of hydraulic fracturing. Whilst most of the technical reviews of multiple barrier well construction and cement seals focus on well integrity from fresh water aquifers close to the surface (down

Figure 8.3: Schematic diagram of the stratigraphy showing aquifers and shale gas sources in the Cooper Basin within the Great Artesian Basin along with both shale gas and conventional natural gas wells
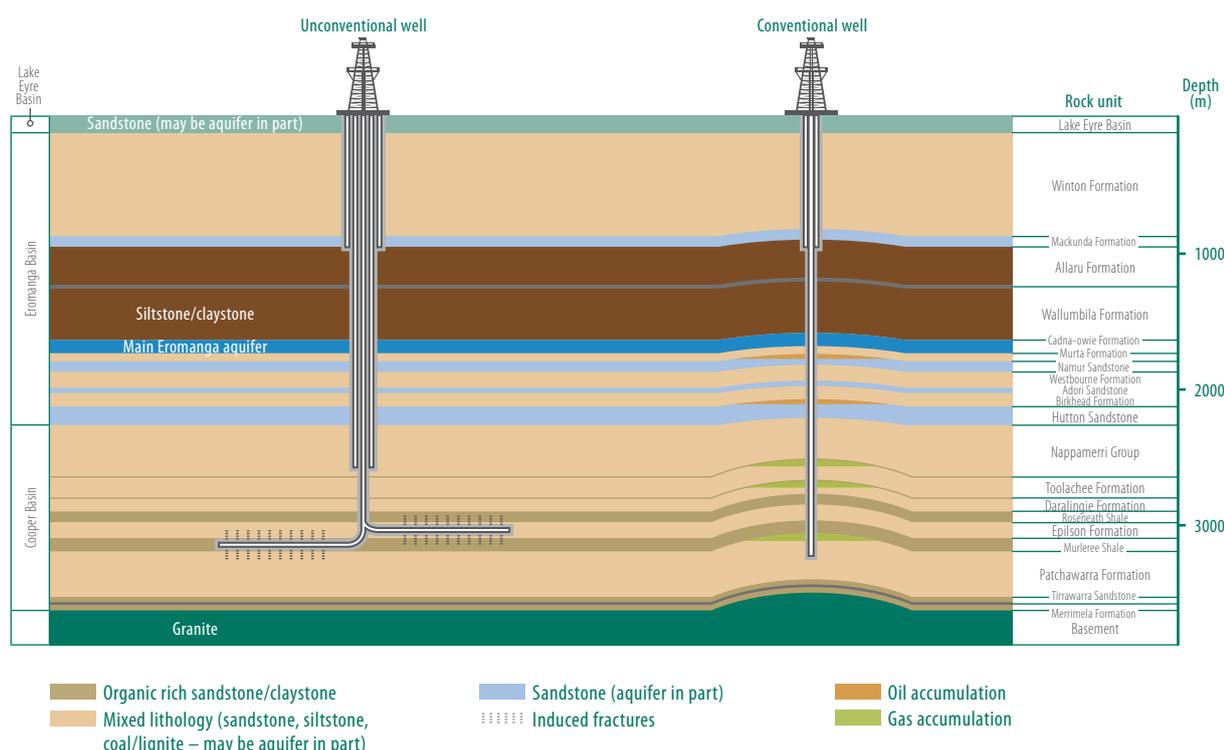
Source: DMITRE, 2013.

to say 300 metres), drilling in the Cooper Basin for example will pass through the major GAB aquifers at depths far below this, which will require well integrity *at* depth (down to 3,000 m and more). There may also be a risk of propagating fractures towards the aquifers of the GAB along pre-existing faults (Report to this Review Cooke, 2013) though it is difficult to propagate a fracture further than a few tens of metres, other than where a transmissive fault is intersected. Minimising this possibility involves using high resolution 3D seismic to map locations where fault risks may exist (and avoiding these locations), using microseismic sensing to map the real-time vertical growth of fracture stimulation treatments (though this is not presently possible in 'hot' basins such as the Cooper Basin, where often the best indicator of the progress of hydraulic fracturing is downhole pressure (Santos Limited, 2013)), and stopping hydraulic fracturing if unwarranted fracture growth is observed. The risk can be further mitigated by conducting geomechanical modelling to predict the susceptibility of different fault orientations to transmit fluids (Report to this Review Cooke, 2013).

Using saline water from deep GAB aquifers for hydraulic fracturing would require an overall aquifer management plan and entitlement assignment in line with NWI principles involving allocations from the GAB. This water is generally used for watering livestock, but due to high levels of total dissolved solids (such as Na-Cl-SO$_4$ and Na-Ca-Cl-SO$_4$ ions) it is not suitable for irrigation. The South Australian GAB water allocation policy is based on groundwater pressure and relates to the impact on the potentiometric surface: '*Water shall not be allocated where the taking and use of water shall cause, or be likely to cause, a cumulative drawdown in excess of 1 metre on the potentiometric surface…*', although there are exceptions to this principle (based on a satisfactory Environmental Impact Report (EIR)). More generally, the GAB is managed by multiple legislative arrangements specific to GAB States, and a GAB coordinating committee is responsible for coordination between the jurisdictions involved, within a GAB strategic plan.

Groundwater Contamination

Human induced changes to conditions within a sedimentary basin, such as from extraction of water from groundwater, land use changes, mines, CCS, hydraulic fracturing and production from oil and gas wells, occur much more rapidly than natural processes. The resulting changes are from a quasi-equilibrium or steady state conditions into transient conditions (Frogtech, 2013). In their natural state, geo-fluids (water, oil, gas, CO$_2$ etc.) in a sedimentary basin are in "quasi-equilibrium". In a report to the Review, Frogtech indicate that *'changes to the environment such as reduced groundwater recharge, uplift, erosion or changes in stress directions will generally happen slowly enough (although not always) for the geofluids system to adjust so that quasi-equilibrium is maintained'*. After the perturbations involved in gas extraction (and often over long periods of time) a new steady state condition will be reached. However, the resultant changes in flow conditions in the basin can lead to reduced groundwater and surface water availability, migration of contaminants and/or ground subsidence etc. (Freeze & Cherry, 1979). For example, immediately after conventional gas production, groundwater flow direction will be towards the reservoir as the decrease in pressure that occurred during oil and gas production is re-established. Over time, steady state groundwater conditions will gradually return and upward advective diffusion within the basin can be expected to be re-established. If preferential pathways (e.g. faults) are stimulated from the hydraulic fracturing process, travel time for contaminants to reach the surface can be reduced by 1-2 orders of magnitude (Myers, 2012; Frogtech, 2013).

Frogtech (2009; 2013) indicate that *'managing the effects of changes in steady state conditions necessitates understanding the controls on the movement of geofluids in a basin such as permeability, porosity, thickness, geometry, location and type of fractures and faults, lithology, heatflow, tectonic history etc. that make up the tectono-stratigraphic framework'*.

Figure 8.4: Barnett shale measured fracture heights sorted by depth and compared to the depths of aquifers
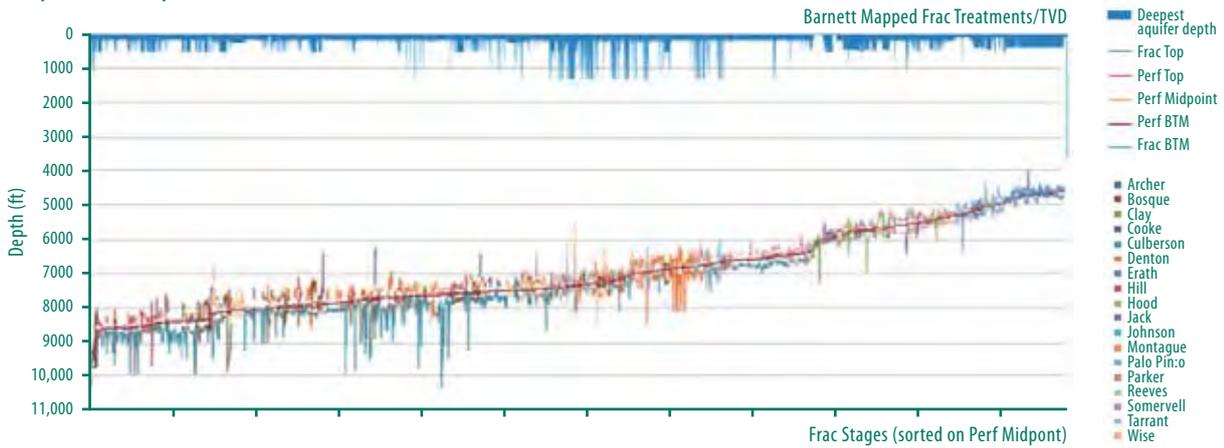
Source: Fisher & Warpinski, 2011.

Figure 8.5: East-West seismic line in the Cooper Basin
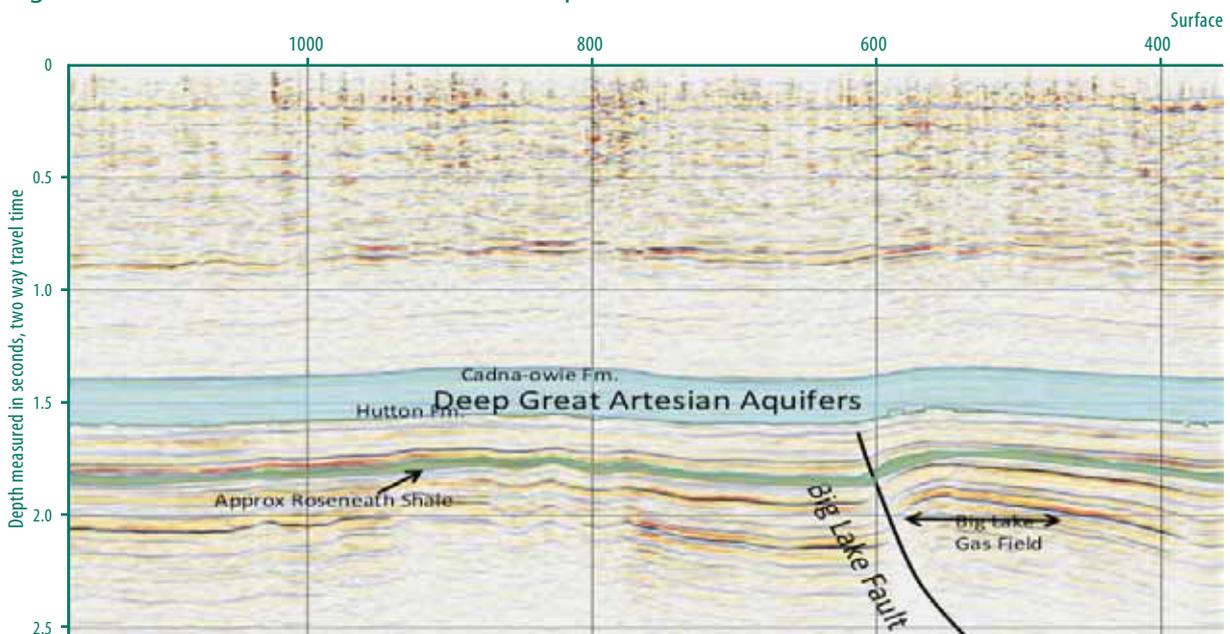
Source: Cooke, 2013.
Original seismic data available from DMITRE.

Figure 8.4 compares the depth of fracture stimulation treatments for the Barnett Shale to the vertical extent of the created fractures and the distance to surface water supplies in the United States. Because of the large vertical separation between the hydraulic fracturing and the groundwater, the risk of contamination during fracture stimulation treatments is low.

The depths between shale gas strata and surface water supplies in the Cooper Basin (where shale gas development has commenced) are illustrated in Figure 8.3 (DMITRE, SA, 2012). In the case of the GAB, (see Figure 8.3) there is a 3,000 m separation between the surface water (Lake Eyre Basin, in yellow at the top of the figure) and the fracture stimulation target (Roseneath and Murteree shales) – a distance greater than in the Barnett Shale United States example. However, Figure 8.3 also shows that the shale gas reservoirs are closer to the aquifers of the Great Artesian Basin (the Cadna-owie to Hutton Formations shown in light and dark blue) with a vertical separation of approximately 1,000 m (Cooke, 2013). Davis and Robinson (2012) cites a maximum fracture height of 588 m for a hydraulic fracture that extended into a pre-existing fault.

Figure 8.5 shows an east-west seismic line in the Cooper Basin and illustrates shale layers and a large fault (the Big Lake Fault), which could act as a conduit for deep fluids. An Australian gas development could seek to utilise 3D seismic imaging to map locations where major faults exist, to avoid fracture stimulation in these zones. However, in most instances the seismic image has insufficient resolution to detect small to medium faults, which might also be important conduits and would represent a risk in terms of groundwater contamination. In a report to the Review, Dennis Cooke (2013) indicates that useful mitigation procedures could include geomechanical modelling to predict the susceptibility of different fault orientations to conduct fluids and real time microseismic mapping to reveal fracture growth kinetics.

Most states and territories have policies regarding aquifer interference (NSW DoPI, 2011; NSW DoPI, 2012; NSW EPA, 2012). Under the NSW *Water Management Act 2000*, aquifer interference includes (NSW Government, 2013):

- Penetration of an aquifer;

- Interference of water in aquifer;

- Obstruction of water in an aquifer;

- Taking water from an aquifer in the course of carrying out mining or any activity prescribed by the regulations;

- Disposal of water taken from an aquifer in the course of carrying out mining or any activity prescribed by the regulations.

Under these guidelines aquifer interference could occur as a result of shale gas production and would be potentially managed as part of an environmental impact statement (EIS) process, through the use of groundwater models that help predict the effects of a particular action on surrounding aquifers (Queensland Department of Environment and Heritage Protection, 2012). However, as pointed out by Frogtech (2013) *'even the best groundwater model is an imperfect conceptualisation of groundwater movement and subsurface geology. Typically, the deeper the aquifer/resource is within a basin, the less the amount of information is available. As a result groundwater modellers often resort to the use of*

generalised data that may or may not accurately represent conditions at depth. As more and more users compete for the resources within a basin, managing and understanding the causes and effects of aquifer interference will become ever more important'. Balancing the needs of competing users, including shale gas operators, will necessitate that groundwater models be constructed as realistically as possible through the collaboration of hydrogeologists, basin modellers, stratigraphers, structural geologists and geophysicists (Frogtech, 2013).

Shale Gas Well Failure and Leakage

As pointed out by Eco Logical Australia (2013), groundwater may be at risk from well failure such as radial leaks (movement of contaminants through casing into rock formation) or annular leaks (vertical movement of contaminants between casings, or between casing and rock formation).

However as Eco Logical Australia further indicate in their report to the Review, '*casing failure is more common as cement is known to shrink over time, causing hairline cracks in the well casing which can result in annular or radial leakage (The Royal Society and the Royal Academy of Engineering, 2012)'*. The short- and long-term effects of repeated hydraulic fracturing on well components such as cement casing, are currently not well understood (USEPA, 2011; Cohen, *et al.*, 2012), and therefore continuous monitoring of well components over the lifetime of the project may be appropriate to minimise risk of well failure (Eco Logical Australia, 2013).

Groundwater may be at risk from fluid leak-off, if methane gas migrates from the shale rock to surrounding aquifers following hydraulic fracturing. Aquifer gasification due to shale gas development has been suggested as a potential cause of elevated seismic activity (KPMG, 2011; Eco Logical Australia, 2013). Community concerns surrounding groundwater contamination due to possible wellbore failure, land subsidence or seismic activity have led to moratoria on hydraulic fracturing for shale gas extraction in parts of the United States and in other countries such as Bulgaria, France and South Africa (The Royal Society and the Royal Academy of Engineering, 2012), though there is no evidence

that these problems are widespread or common (Eco Logical Australia, 2013).

Well failure has the potential to cause water and soil contamination with possible consequences to environment and human health. King (2009) suggests that in the US, '*well construction problems are reasonably rare, with about usually 1 to 5% of initial completions requiring a workover to repair before the well will pass the tests required to drill deeper'*. Best practice guidelines for hydraulic fracturing operations and well construction and integrity are set down in the API Guidance Document HF1 (2009). Well construction is subject to various statutes and regulations in the US, at the State level. The UK Royal Society Report (2012, p. 26), states, for North American oil and gas wells, that '*fewer than 0.5% of those constructed since 2000 according to stricter standards were found to be leaky (Watson & Bachu, 2009)'* whereas '*several percent of older oil and gas wells leaked'*. Studies in North America have used well data to identify key factors affecting leakage, especially the number of casings and the extent to which these casings were cemented. Some of the leaky wells in a Canadian study had only a single casing or were left uncased except in the section from the surface casing down to just below the aquifer (Watson & Bachu, 2009). Others had not been cemented at all or the cementation had not reached the required depth and Watson and Bachu (2009) concluded *that 'The majority of leakage occurrence is because of time-independent mechanical factors controlled during wellbore drilling, construction, or abandonment-mainly cementing'*. They further concluded that leakage is influenced by the regulatory environment, oil price and technology at the time of construction.

There appear to be few other studies on which to base the statistical rate of well failure bearing in mind the definition of failure requires careful specification. To alleviate public concern with well leakage and loss of integrity, which is significant, (Nikiforuk, 2013) the auditing of well performance with respect to failure will be important.

Even with a failure rate as low as 0.5% (The Royal Society and the Royal Academy of Engineering, 2012, p. 26), with large shale gas fields and many of them, well numbers in excess of 10,000 are

feasible in Australia and this could mean 50 "failed" wells. However this does not necessarily imply major environmental or other consequence as well failure may involve for example low leakage rates of fluid, which can be readily remediated. At the moment there appears to be a lack of comprehensive data and analysis on the matter upon which a judgement can be formulated or even an agreed definition of what constitutes a "failed" well.

Shale Gas Well Abandonment Issues

Abandonment of wells involves cementing and capping to ensure they are not a threat to water systems or lead to gas emissions. This issue is addressed in the UK report on hydraulic fracturing (The Royal Society and the Royal Academy of Engineering, 2012) where it is noted that abandonment requirements and an abandonment plan be considered in the original well design, and should be subject to regulation. While no subsequent monitoring is currently required, it is recommended in the UK report that on-going monitoring arrangements should be developed for both surface gas monitoring and aquifer sampling, every few years. Operators are responsible for wells once abandoned, with liability to remediate ineffective abandonment operations. The establishment of a common liability fund is discussed to cover the situation where the operator can no longer be identified. The very long-term integrity of a cemented and plugged abandoned well (beyond 50 years) is a topic where more information will be essential. Cement and steel do not have the very long-term integrity of geological materials. If shale gas fields develop to the size and extent in Australia as in the United States, there will be a legacy of abandoned gas wells, which will need to retain integrity if we seek to avoid connections across stratigraphy over many thousands of metres, including confined aquifers and strata of water-bearing material with very different chemistry. The integrity of strata containing waters from re-injection of flowback and other wastewaters will also be compromised if well integrity is not maintained. Technology has been developed for assessing well integrity (Duguid & Tombari, 2007) and monitoring regulated gas storage

Table 8.4: Major hydrological risks identified for shale gas development in Australia, and their mitigation

	Risk Assessment	Risk Mitigation Measures
Surface water flow	Moderate	Abstraction of surface water only during peak flow periods; metered abstraction of groundwater; total volume based on extractability limits, whole of system requirements and requirements of other water users.
Water and land contamination	High	Avoidance of sensitive areas; application of best-practice design, construction, operation and maintenance principles.
Groundwater ecology	Moderate	Best practice design, construction, operation, monitoring and maintenance of well bores; rigorous and precise following of standard procedures for hydraulic fracturing operations; risk minimisation procedures to prevent well "blowout"; ongoing inspection and monitoring of decommissioned wells; groundwater monitoring at all stages of the development including pre-development; avoidance of areas that contain underground caves, feed groundwater springs, or sub-surface fauna.

Source: Eco Logical Australia, 2011; Eco Logical Australia, 2012; Submission to this Review by Eco Logical Australia, 2013.

reservoirs, and for identifying old, abandoned well locations. These technologies include remote sensing (magnetic, infra-red), satellite surveys and ground-penetrating radar.

Given all of this, the long-term management of abandoned gas wells so as to protect cross-contamination of waters and soils along with gas emissions to the atmosphere is a matter that requires careful attention in terms of regulation and governance as well as perhaps an opportunity to develop technological solutions. It certainly is a matter of increasing concern in the USA (Kenarov, 2013) and there is a need to formulate governance and regulation and develop leading industry practice.

Hydrological and Ecological Risk Assessments

As outlined in Chapter 7, preliminary risk assessments have been conducted for ecological and hydro-geological impacts by consultants engaged for this study (Eco Logical Australia, 2012), who examined three potential major impacts:

- Reduction in surface water

- Contamination of surface water

- Impacts on groundwater ecology

The risks were analysed according to Australian Standards (AS/NZ ISO 31:000:2009), taking into account the likelihood of the impact and its consequences. The compendium of consultancy reports (Eco Logical Australia, 2011; Eco Logical

Australia, 2012) gives details of this analysis, including judgements about the components of the risk. Further details on environmental risks and their analysis are provided in the report to the Review by Eco Logical Australia, 2013.

Table 8.4[12] summarises the major hydrological risks identified for shale gas development in Australia and methods for their mitigation by the consultancies (Eco Logical Australia, 2011; Eco Logical Australia, 2012).

Conclusions

Risks arising from shale gas development are associated with water extraction and use for hydraulic fracturing and drilling, handling and disposal of produced contaminated water, protection of potable aquifers, well integrity and feasibility of well integrity for an indefinite period following decommissioning of the gas field.

A large number of shale gas wells could be drilled in Australia and each hydraulic fracture would use approximately 100,000 litres of fresh to brackish water. Because most shale gas basins are located in semi-arid to arid Australia, most of this water will need to come from either groundwater, be imported from elsewhere, sourced from recycled water or

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12   Table 8.4 has been taken directly from the ELA consultancy report for this study (2013) and other ELA consultancy reports (Eco Logical Australia, 2011; Eco Logical Australia, 2012), with permission.

come from non-water-based fluids. The impact of water extraction and its availability on scarce local resources will be an issue to be carefully examined within the National Water Initiative principles and particularly in terms of cumulative impacts on the regional groundwater systems.

The volume of water required to hydraulically fracture shale gas strata can be an order of magnitude larger than that used in hydraulic fracturing for coal seam gas. Conversely, the volume of produced water in shale gas operations is orders of magnitude less than the amount produced during CSG operations. The information available to the Expert Working Group leads it to conclude that while extraction of water for shale gas operations will be significant the shale gas operations will not be faced with the disposal and subsequent replacement of the large volumes of water

produced during CSG operations. Nevertheless during the early stages of shale gas operations, large quantities of water (including saline water) will need to be extracted from surface and/or groundwater resources. The extraction and subsequent disposal will need to be managed within regulatory processes including (in most circumstances) NWI-compliant water entitlements and aquifer management plans, in order to minimise changes to flow regimes and the potential for contamination of aquifers.

Under normal conditions, risks of consequences from shale gas production to groundwater ecology and groundwater dependent ecosystems are low to moderate, although uncertainty about groundwater impacts is high largely because of lack of detailed information on deep stratigraphy, faults, discontinuities, stress distribution and lack of understanding of deep hydrogeological

processes. Most gas wells can be expected to pass through aquifers ranging from freshwater to saline and at depths ranging from very near surface (tens of metres) to deep (hundreds to thousands of metres), and are subject to well integrity regulation. In important Australian basins such as the Cooper-Eromanga Basin, in addition to surface aquifers, shale gas wells (like conventional gas wells) pass through deep aquifers of the Great Artesian Basin. To minimise the risk to this vital groundwater resource, best practice should be adopted in both well integrity and the use of sensing technology to monitor the hydraulic fracturing process, particularly when there is any potential for extended vertical growth of fractures.

Produced water is often highly saline (greater than 100,000mg/l) in a mix of recovered hydraulic fracturing fluid and connate water from the shale.

When this water reaches the surface it must be stored, treated and disposed of properly to avoid damage to the environment, people and water supplies. The Expert Working Group considers that the gas industry takes great care to avoid spillage, but whilst unlikely, contamination of terrestrial and riverine ecosystems may accidently occur from spills associated with chemicals used during the early stages of production; the use of impoundment ponds and holding tanks; and the volume of traffic needed to service operations. These risks can be minimised through a code of best practice. The petroleum industry has experience in managing issues like these and remediating them. In the relatively new shale gas industry in Australia, it will be important to have best practice management procedures in place.

9 | Induced seismicity

One of the potential consequences of shale gas production that has received attention recently has been induced seismicity. It is well known that a range of human activities such as the building of dams and deep disposal of fluids can result in induced seismic events. Examples of this phenomenon include seismic events associated with the Rocky Mountain Arsenal well in the mid-1960s following deep injection of fluids, and the more recent Basel earthquakes following injection of water as part of a geothermal project.

The vast majority of induced seismic events are small and non-damaging (generally much too small to be detected by humans) and of limited vertical and lateral extent. Since the largest induced seismic event can actually occur after injection has stopped (for example, the Basel incident), a conservative approach to risk management is appropriate. A summary of the science of induced seismicity has been presented by Maxwell and Fehler (2012) and the general topic of hydraulic fracturing and induced seismicity has been thoroughly studied by the US National Academy of Sciences (US NAS, 2012).

Induced Seismicity and Shale Gas Operations

The issue of induced seismicity associated with shale gas operations falls into two categories. The first relates to seismicity induced by the hydraulic fracturing process itself, and the second is seismicity induced by the disposal of fluids (such as produced water from shale gas plays) by deep injection (deeper than several km) into wastewater wells. In short, in shale gas operations in North America and Europe there have been only a few isolated incidents, of low magnitude seismicity, associated with hydraulic fracturing itself. Similarly, in Australia, there have been no reported incidents of induced seismicity associated with hydraulic fracturing, either in coal seam gas or tight gas operations. However in the United States there have been a number of incidents correlated with the disposal of significant volumes of water from shale gas wells by injection at depth at wastewater sites. These induced events can be in the range of magnitude 3 M_L and 4 M_L (US NAS, 2012).

A number of reports and presentations have concluded that seismicity associated with deep hydraulic fracturing of shales does not present a significant problem. For example the United Kingdom Royal Society/Royal Academy of Engineering report *'Shale Gas Extraction in the UK'* (The Royal Society and the Royal Academy of Engineering, 2012) states: '*There is an emerging consensus that the magnitude of seismicity induced by hydraulic fracturing would be no greater than 3 M_L (felt by few people and resulting in negligible, if any, surface impacts).*' In a United States 'State of the Science' presentation on this subject, and by the National Academy of Sciences (US NAS, 2012), a similar conclusion is reached, namely that *'hydrofracking, by itself, rarely triggers earthquakes large enough to be a safety concern'* (Leith, 2012) and '*the process of hydraulic fracturing a well as presently implemented for shale gas recovery does not pose a high risk for inducing felt seismic events*' (US NAS, 2012).

However, notwithstanding this conclusion with regard to hydraulic fracturing itself, Leith (2012) cites that earthquakes of magnitude greater than or equal to 3 in the US mid-continent (with a number at magnitude 4 M_L) have risen from 21 per year for the period 1970 to 2000, to 31 per year for the period 2000 to 2008, and to 151 per year for the period since 2008. It is explained that this increase is not the result of hydraulic fracturing but the deep disposal of large volumes of produced water from shale gas wells. Over time, the large volumes of fluid in disposal wells can allow greater pressures to build up. For large injected volumes the fluid can potentially flow along nearby fault structures (if present) and the subsequent stress relief can trigger small earthquakes.

Mitigation of Induced Seismicity Risk from Shale Gas Operations

Leith (2012) concludes that seismicity induced as a result of produced water disposal by deep injection can be managed, by altering the injection practices to control the risk. A related discussion regarding mitigation of the risk associated with disposal of produced waters, to avoid seismicity, is given in the United Kingdom report (The Royal Society and the Royal Academy of Engineering, 2012). A short summary of mitigation steps is:

- characterise stresses and identify faults by seismic imaging,

- minimise pressure changes at depth by reducing the volumes of fluid to be disposed,

- construct more disposal wells into which smaller volumes of fluid are to be injected, and

- select highly permeable rock formations that both accommodate larger volumes of fluid and deform plastically, thereby storing less amounts of energy.

In addition, the US Department of Energy (DoE) protocol for addressing induced seismicity associated with enhanced geothermal systems (Majer, *et al.*, 2012) together with the US DoE draft best practice manual provide useful guidance.

Whilst only isolated incidents of low-magnitude induced seismicity have been reported for

hydraulic fracturing, it is nevertheless important to also mitigate this risk. The mechanism for the triggering of seismicity is similar to the produced water disposal scenario, namely intersection of a critically stressed fault by the fracturing fluid (under high pressure with hydraulic fracturing, but of smaller volume relative to produced water disposal). In an important review of hydraulic fracturing (King, 2012) it is commented: *'Recognition that a frac has entered a fault by microseismic or pressure response is a decision point. Continued injection into a fault of significant size may not be beneficial to production and can, in rare cases, be potentially problematic on a number of levels if very large volumes are injected. Small faults do not appear to be a problem and may hold significant gas reserves, however, more knowledge is needed about local geology.'*

Intersection of small faults leads to enhanced spikes in the microseismic signal monitoring the vertical extent of fracture growth, which are generally not significantly greater than the signature from the fracturing itself. (See for example extensive microseismic data compilations for fracturing of US shales (Fisher & Warpinski, 2011).

It is important to determine, if possible, the location of faults and the nature of the stress field before undertaking hydraulic fracturing. At the same time it is important to recognise that most faults are not active or transmissive and the presence of an old fault does not necessarily constitute a potential problem. It is necessary that a site is well characterised before a hydraulic fracturing operation gets underway and for there to be ongoing microseismic monitoring of the site.

Seismic risk associated with the intersection of faults by hydraulic fracturing is mitigated by appropriate best practice, namely mapping local fault structures with 3D seismic (and avoiding them); near-real-time monitoring of the fracturing by microseismic (and pressure) sensing (described in Chapter 4); and a plan to cease operation if fracturing impinges on fault structures resulting in prescribed threshold levels in the microseismic signal, so-called 'cease operation' trigger levels.

Induced Seismicity and Well Integrity

In addition to considerations of damage at the surface from induced seismicity, it is also important to consider damage to well integrity. In the UK incident described in the Breakout Box, the magnitude 2.3 event caused deformation of the well casing at depth (The Royal Society and the Royal Academy of Engineering, 2012). Risk mitigation recommended in relation to this incident includes repeat pressure tests

A United Kingdom Incident of Induced Seismicity related to Hydraulic-Fracturing

An incident of hydraulic-fracturing-induced seismicity (intersection of fracturing/significant fault) has occurred in the United Kingdom (Cuadrilla's shale gas site in Lancashire in mid-2011). This incident is discussed in some detail in the UK report on hydraulic fracturing (The Royal Society and the Royal Academy of Engineering, 2012), summarised here. In both Cuadrilla's commissioned seismicity reports and an independent report into the incident, the generation of a magnitude 2.3 event (2.3 M_L) in April 2011 and a magnitude 1.5 event (1.5 M_L) in May 2011 following renewed fracturing of the same well, is ascribed to an existing (but previously unidentified) pre-stressed fault that was induced to fail (slip), either by being directly intersected by the fracturing or (if the fault was distant) by pressure change caused by the nearby fracturing. The energy release was several orders of magnitude greater than the microseismic energy associated with routine hydraulic fracturing. A Cuadrilla-commissioned report subsequently recommended a cease-operation trigger of 1.7 M_L and a later independent report gave a more precautionary trigger of 0.5 M_L. It is also noted that, due to the slow movement of fluids through faults, both seismic events occurred 10 hours after injection of fluid, indicating potential limitations with regard to the responsiveness of seismic triggers. This incident also needs to be kept in balance with regard to the 1 million fracture operations in the United States since 1950.

and cement bond logs (see Chapter 4) being reviewed by an independent well examiner, with results submitted to the regulatory authority.

Overall, the United Kingdom review of hydraulic fracturing (The Royal Society and the Royal Academy of Engineering, 2012), concluded that '*The health, safety and environmental risks associated with hydraulic fracturing…as a means to extract shale gas can be managed effectively in the UK as long as operational best practices are implemented and enforced through regulation*'. Microseismic monitoring of shale gas operations will not provide the location or transmissibility of all fractures, or indicate the probability of induced seismicity being felt at the surface. The UK report recommended that seismic monitoring be carried out before, during and after shale gas operations are undertaken. It also suggested that '*the risk of seismicity induced by hydraulic fracturing can be reduced by traffic light monitoring systems that use real-time seismic monitoring so that operators can respond promptly*'.

Normal Microseismic Events from the Hydraulic Fracturing Process

In standard hydraulic fracturing operations, the engineered initiation and propagation of fractures in shale layers generates a microseismic signal that is monitored either by an array of geophones/accelerometers or by tiltmeters (Chapter 4) or indirectly by monitoring of the bottom hole pressure. As pointed out by Wong *et al.* (2013):

> '*The stimulation of these natural fractures is often inferred from microseismic events. Generally, shale formations do not have naturally conductive fractures. If natural fractures are present they are normally filled with calcite or other minerals. Stimulating these natural fractures requires the fractures to open up in a shearing mode, which means firstly they should be oriented in favourable positions with respect to in-situ stress direction for them to be sheared and secondly, the stress regime on these fractures should be near a 'critical' state so that*

> *any stress perturbation from injection would 'push them over' and cause them to shear'.*

It is reasonably well understood when microseismic events are likely to occur as a result of hydraulic fracturing and there is some capability to model the resulting fracture patterns. Importantly with regard to fracturing of shales, it is discussed in the United Kingdom report (The Royal Society and the Royal Academy of Engineering, 2012) that:

> '*The properties of shale provide natural constraints on the magnitude of seismicity induced by hydraulic fracturing. Different materials require different energy to break. Shale is relatively weak. Stronger rocks will generally allow more energy to build up before they break, generating seismic events of larger magnitude*'.

Microseismic data are useful to a shale gas operator because they give an indication of where fractures are being induced along the wellbore, and they form the basis of a simple but essential 'traffic light' system for managing risks associated with hydraulic fracturing as outlined and described in the breakout box, 'Risk Mitigation Strategies for Induced Seismicity'.

Induced Seismicity: Australian Context

The Australian continent has a low level of seismic activity, but with occasional damaging earthquakes. In a report to the Review, Frogtech (2013) state that '*Reports of anthropogenic-induced seismicity in Australia have largely been documented around geothermal power development and also the construction of dams and reservoirs*', and that '*Fracking is currently occurring in the CSG industry in Australia with no reports of induced seismicity*'. Geothermal power development in Australia also involves hydraulic fracturing, at greater depth than shale gas operations and in stronger rock structures. Hydraulic fracturing experiments by Geodynamics Ltd, associated with three geothermal wells drilled in the Cooper Basin, have provided an induced seismicity data set for this related activity. Frogtech (2013) notes

Risk Mitigation Strategies for Induced Seismicity

To minimise the risks associated with induced seismicity the following suggestions have been proposed (Report to this Review by Frogtech, 2013):

'1. Develop the necessary scientific background on seismicity and structural geology, preferably led by an independent publically funded agency. Such activities could include:

   • Mapping and characterising stresses, faults including orientations and strike slip tendencies,

   • Mapping the direction of bedding planes within shales,

   • Building ground motion prediction models for affected regions, and:

   • Establishing a traffic light control system for responding to an instance of induced seismicity. Components of a traffic light control system include monitoring seismicity before, during and after fracturing and establishing action protocols in advance.

2. Developing an appropriate Australian model for seismicity. Until such a model is developed, Australia adopts world best practice trigger levels to manage seismicity caused by fracturing and fluid injection.

3. Developing the ability to alter plans on-the-fly, such as changes to injection rates.

4. Make transparent documentation and communication to the public and to regulatory agencies a priority. Communication, transparency and meeting community expectation will help to build community consent to operate. Suggested activities include:

   • Publicising the processes and techniques to be employed in area.

   • Publicising action protocols and risk reduction plan in the event seismic trigger values are reached.

   • Reporting seismic incidents related to well construction, operation and abandonment.

   • Explaining the goals and expectations of the project.

5. Develop a checklist to determine if fracturing and fluid injection might cause seismicity such as developed by (US NAS, 2012). Example checklist questions include:

   • Are large earthquakes (say M_L>4) known in the region?

   • Are earthquakes known near the fracturing site?

   • Is the rate of activity near the fracturing site high?

   • Are faults mapped within 20 km of the site?

   • Are these faults active?

   • Is the site near tectonically active features?

   • Do stress measurements in the region suggest rock is close to failure?

   • Are proposed fracturing practices sufficient for failure?

   • If fracturing has been ongoing at the site, is it correlated with earthquakes?

   • Are nearby fracturing wells associated with earthquakes?

6. Develop a set of best practice fracturing methods such as minimising pressure changes at depth.'

The suggestions by Frogtech (2013) to manage induced seismic activity are cited as being based on world experience of fracturing for shale gas and suggestions for lowering risk, from Davies et al. (2012), Green et al. (2012), NAS (US NAS, 2012), UK Royal Society and Royal Academy of Engineering (2012), and Holland (2011).

that '*Australia also has a higher than world average occurrence of dams and reservoir-induced earthquakes. Large reservoirs may trigger seismicity either by the weight of the water changing the underlying stress fields or increasing groundwater pore pressure which lowers the stress threshold required for earthquake activity. Induced seismicity has been reported at several Australian reservoirs, e.g. at the Talbingo, Thomson, Pindari, Eucumbene, Warragamba, Gordon and Argyle Dams'*. Hydraulic fracturing has been carried out in the Cooper, Canning and Perth Basins for deep shale gas and tight gas, but a comprehensive knowledge base on seismic activity has yet to be developed.

The national seismic network is operated by Geoscience Australia, but in most areas does not provide a record of small seismic events of the type that might result from hydraulic fracturing (magnitude 3 and below). Therefore there may be a need to enhance the national seismic network, though it would be unrealistic to expect a national network to provide the baseline for all potential shale gas developments, given that many of them may take place in quite remote areas and it will be up to the operators to establish seismic baselines. This would pose a practical difficulty if the operator were expected to have a long-term seismic baseline prior to any hydraulic fracturing operations. It is often the case (because of coincidences in space and time) that an induced seismic event can be clearly identified and microseismic monitoring is now common, if not routine, in operations involving injection of fluids into the deep subsurface, whether for shale gas, tight gas or geothermal operations. The hardware cost of a small seismic array for a site is modest, but the expertise to operate the array and process and interpret the data is the real expense.

Conclusions

Induced seismicity from hydraulic fracturing itself does not pose a high safety risk. However the disposal of large volumes of produced water from shale gas wells by deep injection has been correlated with an increased number of magnitude 3 and 4 seismic events in the United States. This risk can be managed by adopting a range of mitigation steps. These include better knowledge of fault structures close to disposal sites, and control of volume and pressure of produced water re-injection. Notwithstanding the low risk presented by hydraulic fracturing itself, adoption of a traffic light monitoring system that uses real-time seismic monitoring, so that operators can respond promptly, including cease-operation threshold trigger levels, will further mitigate this risk. Transparent communication and documentation, both to the public and regulatory authorities, is essential to meet community expectations. There may be a need to enhance the Australian national seismic network operated by Geoscience Australia in prioritised locations.

10 | Greenhouse gas emissions

In this section of the report, Greenhouse Gas Emissions from the development and production phases of shale gas extraction are specifically discussed. These emissions from shale gas development and production arise from a number of potential sources:

- Emissions of methane during pre-production operations associated with well completion,

- Emissions of methane during gas production operations,

- Carbon dioxide vented from gas sweetening operations,

- Carbon dioxide emissions from fuels and energy used during operations,

- Carbon dioxide from flaring of gas during operations,

- Carbon dioxide emissions from fuels and energy used during compression and pipelining of the gas to markets,

- On a life-cycle basis, the carbon dioxide emitted during combustion of the fuel, including for electricity generation.

Methane has a much greater global warming potential (GWP[13]) than carbon dioxide. The Australian Government has decided to adopt a GWP of 25 for methane (increased from a previous GWP of 21), applicable for a 100-year timeframe (DCCEE, 2010). This is consistent with an agreement at the United Nations Framework Convention on Climate Change meeting in November-December 2011 in Durban, South Africa, to adopt updated GWPs as published in the Intergovernmental Panel on Climate Change's (IPCC) 2007 (Intergovernmental Panel on Climate Change, 2007b) fourth assessment report (AR4) from 2015 onwards (reporting emissions for the 2013 inventory year). It should be noted that the 2007 IPCC report also presents an alternative value of 72, based on a 20-year timeframe, but this has not been adopted by the Australian Government.

For the purposes of this report a methane GWP = 25 has been assumed, and all results reported use this factor. This represents a 100-year timeframe for methane in the atmosphere.

There is no consideration here of methane migration underground, as this does not necessarily escape to the atmosphere. The environmental issues from such migration are considered elsewhere in this report.

Figure 10.1 shows an approximate proportional estimate of these emissions (Jiang, *et al*., 2011) for the United States Marcellus shale gas field.

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13 GWPs are used to convert masses of different greenhouse gases into a single carbon dioxide-equivalent metric (CO_2-e). In broad terms, multiplying a mass of a particular gas by its GWP gives the mass of carbon dioxide emissions that would produce the same warming effect over a defined period.

Pre-production emissions

The extraction of energy from any resource (including conventional gas sources, wind turbines and other energy-related structures) involves emissions from energy consumption during construction and the initial set-up phase. For shale gas, these emissions include combustion of fossil fuels to drive the engines of the drills, pumps and compressors etc. required to extract natural gas on-site, and to transport equipment, resources and waste on and off the well site. Broderick *et al*. (2011) have estimated that the CO_2e emissions associated with these processes account for 0.14 to 1.63 g CO_2e/MJ. Jiang *et al*. (2011) noted that the emissions from the preparation of the well pad, including vegetation clearing, the CO_2 emissions from the drilling energy, the trucking of water to site and the disposal of produced water are 0.7 g CO_2e/MJ. For the purposes of this report it is assumed that the pre-production emissions are 0.7 g CO_2e/MJ.

Flowback Emissions

Pre-production emissions are also those generated during well completions and well workovers. There is a significant flowback of methane from the well during these steps. Estimates of the amount of methane generated vary from 138 to 4620 tonnes of methane for each completion (see Appendix 2). The impact of these emissions can be reduced by capturing the gas for sale or for reinjection; this is referred to as a "green completion". Indeed, some US States mandate that such gas may not be intentionally

Venting, Leakage and Flaring

The Climate and Clean Air Coalition, working under the auspices of the United Nations Environmental Programme (UNEP) has estimated (CCAC, 2013) '*that over 8 percent of total worldwide natural gas production is lost annually to venting, leakage, and flaring. In addition to U.S. $27 to $63 billion in energy and economic losses, these activities result in nearly two gigatonnes of CO_2 equivalent of greenhouse gas emissions per year, over 80 percent of which are methane emissions – making oil and gas operations the second-largest source of global anthropogenic methane emissions behind agriculture*'.

Figure 10.1: GHG emissions through the life cycle of Marcellus shale gas
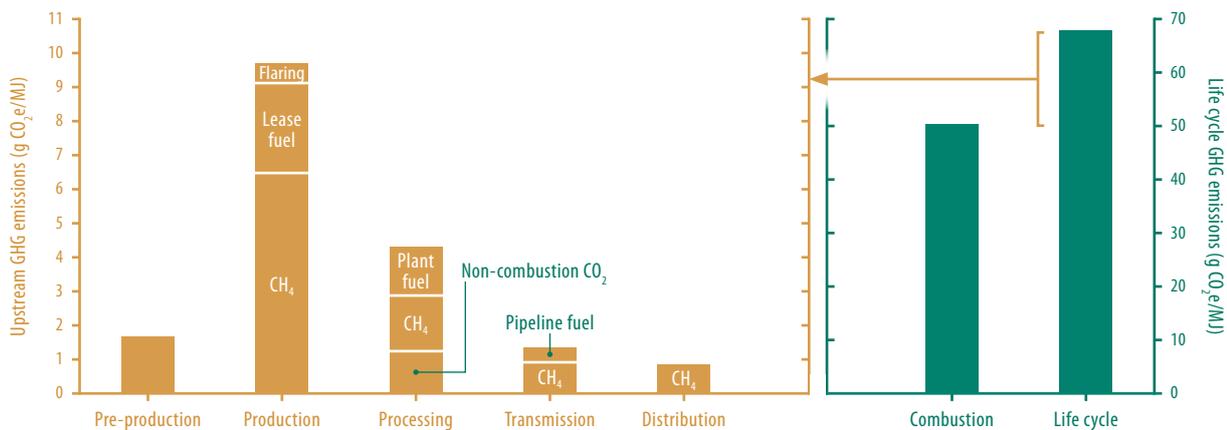
No carbon capture is included after combustion of the gas in use; note the different scales of the left and right hand sides of the diagram.

Source: Jiang *et al.*, Life cycle greenhouse gas emissions of Marcellus shale gas, Environmental Research Letters, volume 6,034014, 5 August 2011. © IOP Publishing Ltd. Published under a CC BY-NC-SA licence.

vented, and "Reduced Emissions Completion[14]" permit schemes are in operation in some areas. Alternatively, the emissions can be burnt on site, in a process referred to as "flaring". Since carbon dioxide has a much lower global warming potential than methane, this substantially reduces the total impact on climate change. However, flaring can also release black carbon (CCAC, 2013), volatile organic carbon and nitrous oxides, all of which could potentially be harmful to human health.

Estimates of the percentage of total emissions that are currently captured and flared in the United States vary widely, with Howarth *et al*. (2011) arguing that very little of this mitigation activity occurs. These authors assume that 100%

of the methane is vented. Conversely, O'Sullivan and Paltsev (2012) argue that a more realistic case is where 70% of potential emissions are captured, 15% are vented and 15% are flared. They refer to this as 'USA Current Field Practice' (see Table 10.1). For a discussion on differences between Howarth *et al*. and O'Sullivan and Paltsev for estimates of the both the quantity of methane associated with flowback and subsequent emissions, refer to Appendix 2.

As noted in Appendix 2, the results of O'Sullivan and Paltsev are the mean values[15] for each of the shale gas formations considered, whereas these authors state that the high result for Howarth *et al*. is from an unrepresentative high-flow Haynesville well.

Jiang *et al*. (2011) assumes a base case of 76% flaring and 24% venting. They estimate

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14 Reduced emissions completions (REC) for unconventional wells, are where all flowback from fracturing operations is directed into equipment that separates and handles gas. As soon as possible, the gas must be directed to pipelines for sales and use. Gas that cannot be captured for sales should be flared.

15 The ratio of the P80 to P20 values for the O'Sullivan and Paltsev data sets for each well is over a factor of three.

Fugitive Emissions of Methane from Coal Seam Gas

Fundamentally, very little is known about fugitive GHG emissions in the form of methane from CSG production, with few recorded measurements.

However there are reasons to believe that it should be considerably lower than for shale gas (or even conventional gas) at the wellhead, given the somewhat simpler extraction and treatment processes involved with CSG.

In the case of shale gas, the nature of the flowback of large volumes of hydraulic fracturing fluid containing high concentrations of liberated gas (owing to the high initial production rates of shale gas wells) leads to liberation of considerable amounts of fugitive methane gas.

Conversely, CSG wells for their part are slow to come on stream whilst the water pressure is reduced by pumping. Likewise, the gas comes to the surface at atmospheric pressure and is easily handled. In most cases it is of "pipeline quality" and, apart from drying, requires minimal treatment.

Underground coal mining world-wide also releases large volumes of methane to the atmosphere of the order of 3 to 5 cubic metres per mined tonne.

Table 10.1: Summary of the range of methane returned during flowback, and total GHG emissions, GWP=25

Assumptions	Methane, Percent of lifetime production	Total GHG emissions[*], g CO_2e/MJ (of natural gas in production), using a GWP of Methane = 25	Reference
100% Venting	1.1 – 3.2%	5.0 – 14.6	Howarth[**] et al. (2011)
100% Venting	0.52 – 0.99%	2.4 – 4.5	O'Sullivan and Paltsev (2012)
70% Capture, 15% flaring, 15% venting		0.6 – 1.1	O'Sullivan and Paltsev (2012)

*These values have been derived from the results presented in the quoted references.

**Howarth et al. (2011) notes that an allowance should be made for methane that is emitted during the drill out phase. It is estimated that that this is 0.33% of the total life-time production of wells. This has not been included in the results for Howarth above.

Source: Howarth, et al., 2011 and O'Sullivan & Paltsev, 2012.

that the emissions for well completion are 1.15 g CO_2e/MJ with a standard deviation of 1.8 g CO_2e/MJ; these values are broadly consistent with the O'Sullivan and Paltsev (2012) numbers in Table 10.1 for the flowback stage under the green completion scheme.

The United States Environmental Protection Agency (EPA, 2012) has recently issued a set of comprehensive regulatory standards for the oil and gas industry requiring the reduction of emissions of volatile organic compounds, air toxics and methane from sources in the industry, including the hydraulic fracturing of horizontal natural gas wells. Should shale gas exploration and exploitation continue to develop in Australia, it would be prudent to require similar management practices around both green completions and

flaring to minimise this potentially substantial source of emissions with a robust compliance and monitoring regime. A recent study by McKinsey and Co. suggests that methane abatement in the oil and gas sector provides some of the lowest cost global methane mitigation opportunities, with many of the costs negative due to the value of captured gas, and typically costing well under $20 ton/$CO_2$e, (CWF & ECF, 2011).

A further option may be to convert the gas to diesel at the wellhead using gas-to-liquids processes (GTL) (Loring, 2010). There is a developing commerciality around small-scale GTL, driven by a similar need to eliminate flaring in offshore oil and gas rigs. Recent developments in microchannel technology enable the Fischer-Tropsch reaction to proceed

10 to 1000 times faster than in conventional systems and this enables smaller, more efficient GTL plants to be constructed (McDaniel, 2012). An example is the collaboration between Compact GTL (UK) and Petrobras in Brazil that has led to the world's first commercial small-scale GTL facility (McDaniel, 2012).

Production, Processing, Transmission and Distribution

Once the well is commissioned and in production, emissions are comparable to those of conventional gas production (Jiang, et al., 2011). The GHG emissions from these life cycle stages consist of vented methane (gas release during operation), fugitive methane (unintentional leaks) and CO_2 emissions from the processing plants and from fuel consumption. The US Environmental Protection Agency (US EPA) has recently released emission standards to reduce some of these emissions, including those associated with equipment, such as pneumatic controllers, compressors and storage vessels (EPA, 2012). Estimates of these emissions as presented by Venkatesh et al., (2011) are summarised in Table 10.2.

Table 10.2: Emissions during production and processing of natural gas from conventional and unconventional sources

Process	GHG Emissions (g CO_2e/MJ of NG in Production) using a GWP of Methane = 25)	Derived ratio of methane released to total life-time production Percent[*]
Production	9.7	2.1%
Processing	4.3	0.9%
Transmission	1.4	0.3%
Distribution	0.8	0.2%
Sum of Above	16.2	3.5%

[*]These results have been derived from the "Emissions" data given in the second column in this Table.

Source: Venkatesh et al., 2011.

Based on data for conventional gas wells, Howarth et al. (2011) accounts for emissions from venting and equipment leaks at site, liquid unloading, gas processing, transport, storage and distribution. These authors quote values of between 1.7 to 6.0% of the total lifetime production of the well (see Appendix 2). This data is consistent with the result of 3.5% derived from Venkatesh et al. (2011).

Addition of the emissions from pre-production (0.52 to 3.2%), production, processing and transmission (3.3%) suggest total 'on-site' emissions of up to 6.5% of the total methane extracted. However, measurements of air quality at a shale gas site have produced values apparently in excess of this value. Tollefson (2013) reports that air sampling in the Uinta Basin of Utah in the United States indicated that about 9% of gas production was being lost to the atmosphere. It is understood that this work was conducted over both oil and natural gas fields and that the results may indicate cumulative emissions from fracturing, gathering and compression, through to processing and transmission. In Australia very limited measurements have been undertaken of methane levels in the gas fields of independent gas extraction operations. Without a proper understanding of the methane emissions prior to drilling, it is impossible to understand the true nature of the emissions generated by drilling through an air sampling technique.

The emissions for processing include the venting of CO_2 captured during natural gas sweetening (or acid gas removal). Venkatesh et al. (2011) estimated this venting to be 1.2 g CO_2e/MJ, which is equivalent to a gas stream of around 2.5% CO_2. However, the CO_2 content of the gas produced from the well can be higher. In a limited analysis of six gas formations in the United States, Bullin & Krouskop (2008) noted that the CO_2 levels vary from 0.1 to 9.0 vol%. It was also noted that this can increase to over 30% in some cases during the later productive life of some fields. In the Australian context, it has been noted by the EIA (US EIA, 2011a) that:

'High levels of carbon dioxide are common in the Cooper Basin. Gas produced from tight sandstones in the Epsilon Formation (central portion of the "REM" [Rosemead,

Epsilon and Murteree] sequence) contains elevated CO_2, typically ranging from 8% to 24% (average 15%). Gas produced from the Patchawarra sandstone contains even higher levels of CO_2 (8-40%)'.

If the CO_2 content increases to 15 vol%, as might occur in the Cooper Basin, the processing emissions can increase to 9.3 g CO_2/MJ of natural gas. Indeed, the Climate Institute (Kember, 2012) provides an estimate of 17 g CO_2/MJ for processing of conventional gas in this basin. This estimate is based on current CO_2 levels in Cooper Basin gas of around 24 vol%.

These potentially high emissions during the processing stage could be reduced through carbon capture and storage technology (CCS). As the CO_2 is already 'captured' during the natural gas sweetening operation, and the only costs relate to transport and geological storage, the overall cost of CCS at a gas field is significantly reduced relative to power station flue gas-based CCS. However it should be noted that the application of CCS to gas fired power generation is at least as costly as for coal-fired power generation (see later).

Total GHG Emissions

A summary of the data and analysis is given in Table 10.3, where estimates of the total methane emissions over the lifecycle of a well are provided.

Given that the combustion of natural gas results in emissions of around 57 g CO_2/MJ then the CO_2e emissions given in the Table 10.3 are between 16 to 51% of the emissions produced during the final combustion of the methane.

Jiang *et al*. (2011) estimates total emissions at 18 g CO_2e/MJ (see Figure 10.1), which is again consistent with the data in Table 10.3. A report by Worley Parsons (Hardisty, *et al*., 2012) quotes a rate of 17 g CO_2e/MJ for Australian CSG based on the export of LNG to China. The results of Hardisty (some of which are given in Table 10.5) include an emissions component for shipping the energy resource and its transport and use in China; also included in the case of gas are the emissions from the LNG train.

It is useful to compare the mean emissions presented in Table 10.3 with those of the 100% venting case using the results of Howarth *et al*. for well completion. This comparison is shown in Table 10.4.

Table 10.3: Total GHG emissions for the USA current field practice case*, g CO_2e/MJ

	GHG Emissions g CO_2e/MJ of NG in Production (GWP of Methane = 25)
Preproduction, excluding well completion	0.7
Well completion	0.6 to 1.1
Production, Processing, Transport and Distribution	7.8 to 27.3
Total	9.1 to 29.1
CO_2e emissions as % of CO_2 from methane combustion	16 to 51%

*The term "Current Field Practice " is adopted by O'Sullivan et al. to nominally represent 70% capture, 15% venting and 15% flaring for well completion. Note that the estimates for "Preproduction (excluding flowback)", "Well Drill-out" and "Production, Processing, Transport and Distribution" are the same for both cases considered; namely 100% Venting and "Current Field Practice".

Table 10.4 Mean GHG emissions, g CO_2e/MJ, from Table 10.3

	Mean GHG Emissions, g CO_2e/MJ of NG in Production		Ratio 100% venting case to "Current field practice" case
	100% Venting	Current field practice	
Well completion	9.8	0.9	11.5
Total emissions prior to combustion	27.9	19.1	1.5
Combustion emissions	57	57	1.0
Total emissions, including combustion	92.7	77.0	1.2

While the ratio of emissions for 100% venting compared to the "current field practice" case is over 11 times at well completion, the total emissions after combustion are only 20% higher. This demonstrates that the total emissions, including combustion, have relatively limited sensitivity to very substantial differences in emissions at well completion.

Howarth *et al*. (2011) also presented results for the total emissions including combustion (using a GWP factor applicable to a 100-year timeframe). These authors noted that the life cycle GHG footprint for shale gas is 14% to 19% greater than that for conventional gas and ranges from 18% lower to 15% greater than for coal combustion. As noted previously, the Howarth *et al*. results are applicable to a 100% venting case for shale gas. However, it is highly unlikely that a 100% venting case will occur in Australia because of industry practice and/ or regulation, as well as the cost of a carbon price.

Total lifecycle GHG emissions during electric power generation – estimates from the literature

The emissions arising from the combustion of natural gas for electricity generation generally outweigh the emissions from the gas development and production process (see Figure 10.1). Table 10.5 shows a summary of some of the literature on the total lifecycle emissions from pre-production, production, processing, final combustion and electricity generation.

As shown in Table 10.5, the total LCA emissions show a range from 0.49 to 0.62 tonne CO_2e/MWh for shale gas for electricity generated from a combined cycle gas turbine. This compares with estimates for conventional gas of 0.44 to 0.53 tonne CO_2e/MWh and 0.58 to 1.56 tonne CO_2e/MWh for black coal generation, with the low end of this range occurring with new highly efficient ultra-supercritical black coal generating facilities.

Hultman *et al*. (2001) noted that although there are uncertainties in emissions from the hydraulic fracturing process, the greenhouse footprint of shale gas and other unconventional gas resources appears to be 11% higher than that of conventional gas for electricity generation, and the total emissions for shale gas are some 62% of the CO_{2e} emissions associated with the combustion of coal for electricity generation. The authors also noted that better data collection and improved technology could substantially lower the estimates of emissions from a standard unconventional gas well, which would reduce (possibly substantially) the difference in GHG emissions between unconventional and conventional gas. Hultman *et al*. adopt the position that well completion comprises 15% flaring and 85% venting and notes that this is consistent the US EPA's estimate for flaring.

When comparing GHG results from different authors and for different generation technologies it is important to note that considerable distortions can arise if the results of the various LCA studies are not conducted with the same rigour and on the same basis.

Table 10.5: Total life cycle emissions for electricity generation (tonne CO_2e/MWh)

Fuel	Generation	CO_2e Emissions (tonne CO_2e/MWh)	Reference
Coal	34 to 39% efficiency	0.83 – 0.95	(Hultman, *et al.,* 2011)
Black Coal	Ultra- supercritical to subcritical	0.58 – 1.56	(Hardisty *et al.,* 2012)
Shale Gas	CCGT	0.49	(Jiang, *et al.,* 2011)*
Shale Gas	CCGT	0.53 – 0.62	(Hultman, *et al.,* 2011)
Coal Seam Gas	CCGT & OCGT	0.49 – 0.84	(Hardisty *et al.,* 2011)
Conventional Gas	CCGT	0.44 – 0.52	(Venkatesh, *et al.,* 2011)
Conventional Gas	CCGT	0.48 – 0.53	(Hultman, *et al.,* 2011)
Conventional Gas	CCGT & OCGT	0.39 – 0.7	(Hardisty *et al.,* 2011)
LNG	CCGT	0.47 – 0.56	(Venkatesh, *et al.,* 2011)
LNG	CCGT & OCGT	0.39 – 0.70	(Hardisty *et al.,* 2012)

OCGT = Open cycle gas turbine, CCGT= Combined Cycle Gas Turbine.

*Assuming a combined cycle gas turbine plant efficiency of 50% (Jiang *et al.*, 2011).

Source: Hultman, *et al.*, 2001, Jiang, *et al.*, 2011, Venkatesh, *et al.*, 2011, and Hardisty, *et al.*, 2012.

As noted in a submission to the Expert Working Group (Sandiford & Rawlings, 2013), and discussed previously, Howarth *et al*. (2011) presents data that indicates that the LCA emissions from gas combustion are higher than those for coal. However, importantly, this result is for combustion of the fuel (heat generation) and <u>not</u> for electricity generation. Coal-fired electricity generation is between 33 and 43% efficient, whereas gas-fired electricity generation is between 39 and 53% efficient (Hardisty, *et al*., 2012). The generally higher efficiency of gas-fired electricity generation plant means that the total emissions from gas-fired electricity are less likely to reach those of coal-fired generation.

In a recent paper, Cathles *et al*. (2012) make a similar case, arguing that the Howarth *et al*. analysis is seriously flawed since they '*significantly overestimate the fugitive emissions… undervalue the contribution of "green technologies"…base their comparison…on heat rather than electricity generation…[and adopted a] short residence time of methane in the atmosphere*'. Cathles *et al*. observed that using more reasonable leakage rates and other bases of comparison, shale gas used in electricity generation has a GHG footprint that is half and perhaps a third that of coal. This is consistent with the present analysis. Subsequently, Howarth *et al*. (2012) rejected the criticisms by Cathles *et al*.

Wigley (2011) similarly argued that emissions from gas combustion are higher than those for coal. His analysis calculated the impact of emissions directly through a climate model rather than using global warming potentials, so is more difficult to compare with other results. However, it appears that the differences between Wigley (2011) and the results presented here are due to considerations of the reduction in sulphur dioxide and black carbon aerosols as coal production falls. As these aerosols themselves act to mitigate against warming, removing them from the atmosphere ultimately causes temperatures to rise. Given Australian coals are low in sulphur content, this argument may not apply to the Australian situation. Wigley noted that his results are very sensitive to the assumed leakage rates for methane.

Based on the results derived from various LCA studies, Figure 10.2 gives an indication of the quantities of GHG emitted for electricity generation for various technologies (including shale gas that use green completion schemes). Renewable energy sources produce no GHG during electricity generation, and the greenhouse gas emissions result from fuel use for construction and ancillary purposes, and embedded emissions in infrastructure and consumables. There are significantly higher GHG associated with fossil fuels compared to renewables and nuclear energy.

Figure 10.2: The range of life cycle emissions for electricity generation (tonne CO_2e/MWh) from a range of energy sources
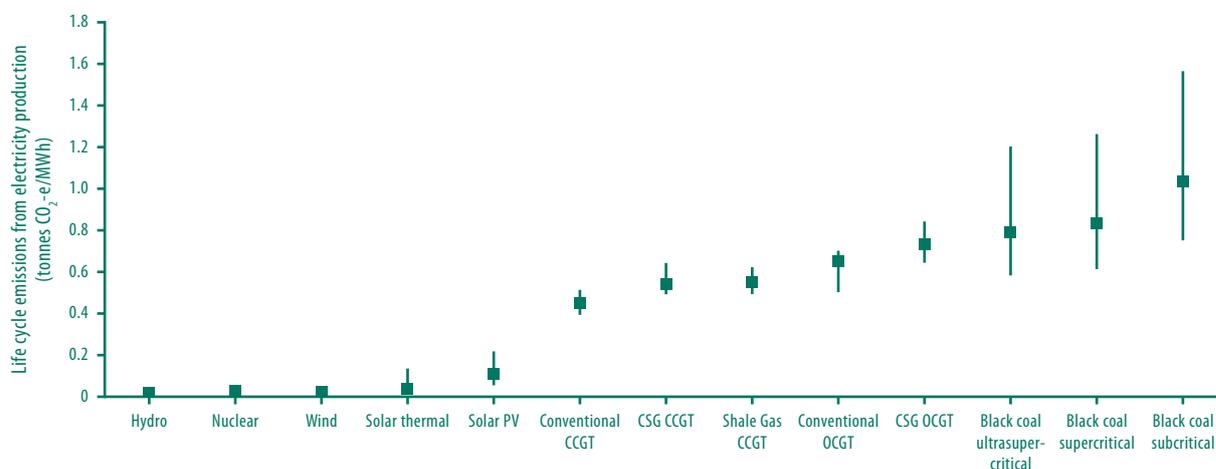
OCGT = Open cycle gas turbine, CCGT= Combined Cycle Gas Turbine.
The data is taken from Hardisty *et al*., (Hardisty, *et al*., 2012); with the exception of shale gas, where the estimate is based on the data in Table 10.5.

An analysis of Figure 10.2 suggests that:

- On average, a shale gas- fuelled, baseload combined cycle gas turbine (CCGT) plant will produce 23% more life cycle GHG emissions per MWh, when compared with a conventional gas-fuelled CCGT, and will produce life cycle GHG emissions per MWh that are 53%, 66% and 69% of the emissions produced from coal combusted in a subcritical, supercritical or ultra-supercritical pulverised coal plants respectively. However, it should be noted that gas-fired electricity generation will generally replace existing coal-fired boilers that are less efficient subcritical facilities and hence the comparison with this type of boiler is most relevant to the present analysis.

- On average a shale gas-fuelled open cycle gas turbine (OCGT) plant will produce 12% more life cycle GHG emissions per MWh, when compared with a conventional gas-fuelled OCGT, and will produce life cycle GHG emissions per MWh that are 71%, 88% and 93% of the emissions produced from coal combusted in a subcritical, supercritical or ultra-supercritical pulverised coal plant, respectively. However this comparison is less relevant for coal since OCGT is seldom used for baseload generation but rather is employed at low capacity factor for supply-demand peaking duty.

- Sensitivity bands for emission uncertainties for electricity generated reveal that there are relatively few cases, with low probability, where coal is less GHG intensive than the worst shale gas CCGT cases.

As part of this Review, calculations have been undertaken to estimate the quantum of GHG emissions savings that may result from the penetration of gas into the Australian electricity generation market in 2030 under various scenarios. The results of these calculations are presented at the end of this section.

Reported emissions

The US EPA has recently started to release the results of its GHG reporting program. Operators are required to report emissions from well sites (above a certain size) and these results are helping to provide more insights regarding volumes and durations for capture, venting and flaring of emissions. It is understood that the US Environmental Defence Fund and the University of Texas are currently conducting an empirical study of emissions in order to assist with updating emission factors.

Under the *Australian National Greenhouse Gas Accounts,* data is reported on venting, flaring and fugitive emissions for oil and natural gas. This is done at an aggregate industry level and not a company level; the reason advanced is that there are confidentially issues attached to the small size of the industry in Australia. Methods for estimating fugitive emissions by companies are specified by the *National Greenhouse and Energy Reporting (Measurement) Determination 2008* (NGER Determination). The NGER Determination methods currently do not differentiate between conventional and unconventional gas production; that is, the same methods are used for natural gas, CSG and shale gas activities. Using an evidence-based approach, consideration should be given to differentiate the emissions arising from conventional and unconventional gas sources in Australia.

As noted previously, it is important that reliable measurements are taken on GHG emissions for shale gas operations under Australian conditions. It is appropriate to note that as an example, the University College London and the University of Adelaide have recently prepared a joint proposal to develop cost-effective remote sensing and ground truth technologies to detect fugitive GHG emissions. This is an example of a relevant development arising under the Roadmap for Unconventional Gas Projects in South Australia.

Relevant coal seam gas initiatives

The Department of Industry, Innovation, Climate Change, Science and Tertiary Education (formerly Department of Climate Change and Energy Efficiency, DCCEE) initiated a public consultation process in April 2012 on CSG fugitive emission estimation. The Department plans to release a Technical Discussion Paper on CSG regarding the enhanced estimation and reporting of fugitive greenhouse gas emissions under the NGER Measurement Determination in the near future.

In addition, the Department is collaborating with CSIRO Division of Energy Technology (Advanced Coal Technology) on a joint project to provide data based on field measurements, and modelling of methane emissions from a sample of CSG production facilities in Queensland and New South Wales. Research findings are expected to be available by December 2013. The primary aims of the project are to make measurements at selected CSG operations to quantify fugitive emission fluxes from various parts of the production process and develop wide-field atmospheric methodology as a top-down method for monitoring and quantifying methane fluxes from CSG production facilities. These initiatives will also have relevance to shale gas.

Greenhouse gas emissions in Australia from electric power generation using gas

This section provides estimates of the quantum of LCA GHG emissions savings that may result from the penetration of gas into the Australian electricity generation market in 2030. To gain some understanding of the possible penetration of gas into the Australian market, it is appropriate to firstly consider the relative costs of different electricity generating technologies. The Bureau of Resource and Energy Economics (BREE) have forecast in their recent analysis of new electrical power generating technologies that the price of domestic gas is likely to rise in real terms (Bureau of Resources and Energy Economics, 2012a). For example, by 2030 the price of gas is forecast by

BREE to climb from $6.36 to $11.71/GJ in NSW (real). At this price, shale gas is expected to be economic for domestic power generation with efficient Combined Cycle Gas Turbine (CCGT) units (Chapter 6). In any future scenario of gas-fired power generation in Australia, the gas source could be from conventional gas, coal seam gas, tight gas or shale gas, depending on the relative price and supply.

The BREE study (Bureau of Resources and Energy Economics, 2012a) also calculated the Levelised Cost of Electricity (LCOE) for new power generating technologies, including CCGT. By 2030, the BREE analysis shows that CCGT is a mid-range cost power generating option, even with a carbon price of $50/t CO_2e (increasing at 5% per year) and the $11.71/GJ gas price. Table 10.6 shows the real LCOE value for the lowest cost six technologies in 2030 predicted by BREE: these relativities also broadly agree with a previous study by the Australian Academy of Technological Sciences and Engineering (ATSE, 2010).

Table 10.6: Levelised cost of electricity for power generating options in 2030

Technology	LCOE ($/MWh), Real
On-shore wind	$95
Nuclear (GW scale)	$100
Solar PV (small scale, non-tracking	$115
CCGT (NSW)	$135
Black Coal SC (NSW)	$160
Geothermal (saline aquifer)	$160

Source: Bureau of Resources and Energy Economics, 2012a.

Because of the intermittency and low capacity factors for solar and wind energy sources, it is assumed that gas CCGT will be required for baseload generation unless there is a breakthrough in energy storage technologies, or nuclear energy is allowed in Australia. Higher cost, lower efficiency Open Cycle Gas Turbines (OCGT) would be used for peaking or when renewable energy electricity production is low (for example if there is no wind or it is cloudy).

In Australia, gas currently provides about 20% of electricity production (Bureau of Resources and Energy Economics, 2012b). This amounts to approximately 40 terawatt-hours (TWh) per

year. Coal provides about 70% of electricity production, amounting to 130 TWh (black coal 48%, brown coal 21%). Renewables provides about 10%, amounting to 20 TWh. Total electricity generation is approximately 190 TWh/year at present. With a 1.5% per year increase in electricity demand to 2030, the supply at that time could amount to 250 TWh/year, with a very significant increase in the use of gas (Bureau of Resources and Energy Economics, 2012b). In 2030, the Energy White Paper projected technology mix is: black coal 30%, gas 30%, and renewables 40%, with no brown coal (Department of Resources, Energy and Tourism, 2011a).

Calculations have been carried out as part of the present Review to estimate the GHG emissions now and in 2030, based on the Energy White Paper (Scenario 1) at that time (Department of Resources, Energy and Tourism, 2011a). The analysis has also been extended here to include a second scenario with no coal-based generation in Australia (50% gas and 50% renewables Scenario 2). These calculations take the present emissions from coal- and gas- fired energy in Australia and calculate a 2012 base case emissions. They then calculate the emissions in the Energy White Paper (2012) for the energy supply forecast in 2030. These include increased use of gas-fired technology, improved emissions from CCGT and OCGT gas turbine technologies through learning, plus the fugitive emissions discussed in this chapter of the report from shale gas well completion and production. In the analysis that follows, it has been assumed that all the gas being used to generate electricity comes from shale gas. This is an unrealistic assumption, as it will depend on supply and demand of natural gas from different sources in Australia in the future. However, because shale gas has the highest fugitive emissions from the flowback operation (described previously), this is a conservative assumption in terms of CO_2e emissions since other gas sources will have a slightly lower life-cycle GHG profile.

The calculations involve the probabilistic modelling of the emissions from gas-fired generation, plus the fugitive emissions in CO_2

equivalent from the extraction and production of gas (as outlined earlier in this chapter). This analysis gives a range of CO_2e emissions in Australia from the use of gas for electricity generation in the future when higher domestic gas prices could support the use of shale gas in electricity generation. Further details on the analysis and the calculations may be found in Appendix 2 of this report.

Emission components of the CO_2e emissions from the combustion of gas over the life cycle of electrical energy generation are shown in Table 10.7. It should be noted that in this Table these emissions are mean values and that a probabilistic analysis has been carried out on each of these parameters with a range from the lowest to the highest values from the literature discussed previously, to yield a probabilistic range for the total gas-fired emissions.

Table 10.7: Components of gas-fired power generation in 2030 for shale gas (50% OCGT and 50% CCGT)

Component	Emissions (t CO_2e/MWh)
Pre-production	0.006
Flowback completion	0.007
Gas production	0.132
Gas firing for power	0.417
Total gas fired power generation	0.562

If all the shale gas flowback completion were undertaken with 100% gas venting, there would be a small increase in flowback emissions from 0.007 t CO_2e/MWh to 0.030 t CO_2e/MWh, giving a slightly higher total life cycle rate of 0.585 t CO_2e/MWh.

The results in Table 10.7 are applicable to a nominal 2.5 vol% of CO_2 in the gas stream being vented during processing. If the CO_2 levels in the gas extracted from the wells increases from 2.5 vol% to 24 vol%, similar to current conventional gas from the Cooper Basin, and if this CO_2 is vented, the LCA GHG emissions for electricity production can be increased from 0.56 t CO_2e/MWh up to 0.65 t CO_2e/MWh.

The results of the CO_2e emissions reduction analysis in 2030 are shown in Table 10.8 for a 10% venting, 90% flaring case, which is more likely in Australia owing to future regulations or costs associated with a CO_2e price then. As shown in the Table, there is considerable uncertainty (range) regarding these emission reductions, depending mainly on the emissions from the gas turbine type employed and the generation fleet mix assumed. The calculated emission reductions in Table 10.8 are derived from a base case of 197 Mt CO_2e per year in 2012 using the current fleet mix and technology specific emission rates and the results presented in Table 10.7.

Table 10.8: CO_2e emissions reduction in 2030 from increased use of gas and renewables in the power generation technology mix for 10% venting and 90% flaring during flowback completion (100% shale gas is assumed as the gas for electricity generation for both scenarios)

Parameter	SCENARIO 1 Energy White Paper Technology Mix	SCENARIO 2 50% gas 50% renewables
Emissions reduction relative to 2012	Mean = 54 Mtpa	Mean = 103 Mtpa
	Range = 26 Mtpa to 82 Mtpa	Range = 79 Mtpa to 126 Mtpa

As shown in Table 10.8, substantial GHG emissions reductions would be possible if gas was used to provide baseload and peak electrical power generation in Australia under scenarios of higher intermittent renewables energy and gas use. The mean range of emission reductions from 54 Mtpa to 103 Mtpa in Table 10.8 represents savings of 27% to 52% from the base case of 197 Mt CO_2e per year in 2012. Conventional gas would also provide similar (slightly greater) emissions reductions than these, since the component of flowback fugitive emissions would be absent in this case. It is important to note that in this analysis no account has been made of the relative costs of these scenarios, or the competitiveness of shale gas relative to other gas sources in 2030.

The results in Table 10.8 are applicable to a nominal 2.5 vol% of CO_2 in the gas stream being vented during processing. For a worst case of 24 vol% of CO_2 in wellhead gas and with this CO_2 subsequently vented, the Scenario 1 value in Table 10.8 for the CO_2 mean emission reductions would fall to 46 Mtpa, and the Scenario 2 mean value would fall to 88 Mtpa.

Kyoto Protocol

The Government signed up to a second commitment period under the Kyoto Protocol at the United Nations Framework Convention on Climate Change (UNFCCC) Conference of the Parties, Meeting 18 (COP 18) in Doha in December 2012.

The first commitment period ended on 31 December 2012. The second commitment period of the Kyoto Protocol commenced on 1 January 2013 and will end in 2020.

Australia has nominated a provisional Quantified Emissions Limitation or Reduction Objectives (QELRO) of 99.5% of 1990 levels over the eight-year commitment period.

Australia's provisional QELRO of 99.5% is consistent with the unconditional commitment to reduce emissions by 5% below 2000 levels in 2020. The option later to move up within the full target range of 5 to 15, or 25%, below 2000 levels in 2020, remains if Australia's target conditions relating to the extent of global action are met.

Source: DCCEE, 2012.

Conclusions

Like all other natural gas activities, the production, processing, transport and distribution of shale gas results in greenhouse gas (GHG) emissions. In addition, shale gas can also generate emissions associated with the hydraulic fracturing and well completion processes, particularly during the flowback stage prior to gas production. The magnitude of the emissions is not known with great accuracy and published results normally include wide uncertainty bands. Initiatives have commenced in Australia to collect greenhouse gas data for CSG but all of the available data for shale gas is from overseas, and its applicability to Australia is not clear. The Expert Working Group considers there is a need to collect data applicable to Australian conditions, monitor emissions and have strategies to mitigate risks.

Emissions, particularly during the flowback stage, can be ameliorated by the implementation of best practice strategies such as the use of so-called "green completions", including the adoption of emission capture and/or flaring rather than venting. The Expert Working Group considers it would be feasible to implement the technology in Australia.

Under the *Australian National Greenhouse Gas Accounts,* aggregated data is reported on venting, flaring and fugitive emissions for oil and natural gas. Methods for estimating fugitive emissions by companies are specified by the *National Greenhouse and Energy Reporting (Measurement) Determination 2008* (NGER Determination). The NGER Determination methods currently do not differentiate between conventional and unconventional gas production. The Expert Working Group believes that an evidence-based approach should be taken to differentiate the emissions arising from conventional and the various types of unconventional gas sources, and that more detailed results should be made publicly available

In general terms the GHG emissions associated with combustion of natural gas to generate energy are greater than emissions occurring during production processing, transport and distribution, and these in turn are greater than those emissions generated during the flowback stage and the pre-production stage. Total lifecycle analysis (LCA) emissions have limited sensitivity to very substantial differences in emissions at well completion.

There are uncertainties in estimating the total lifecycle GHG footprint of electric power generating technologies. These uncertainties are quantified for a number of technologies in this report. The implications for the mean total lifecycle greenhouse gas (GHG) footprint of shale gas when used for electricity production (and green completion schemes for flowback are implemented) are: that the mean emissions will be approximately 10 to 20% higher than that of conventional gas; higher efficiency combined-cycle gas turbines will have approximately half to three quarters the emissions of black coal; and open-cycle gas turbines will have approximately 70 to 90% the emissions of black coal. Even in the unrealistic case of 100% venting of all the flowback gases, the mean total lifecycle GHG emissions for electricity production will be some 20% higher than for the equivalent case when using green completion schemes. Based on an analysis of uncertainty, there is a low chance that the performance of some combined cycle gas turbines using shale gas in the future will have larger emissions than higher efficiency black coal sub-critical generators.

Government projections indicate that gas may grow to 30% of the technology mix by 2030. Based on gas supplying either 30% or 50% of electricity generation in 2030, analysis indicates that this could lead to reductions of either

54 or 103 M tonne CO_2 per annum, or 27% or 52% respectively in terms of the current GHG emissions for electricity production. These are mean value estimates (from distributions of uncertainty) and are applicable to low values of CO_2 in the gas stream being vented to atmosphere during processing. The large amount of gas required for this to occur could be provided, in part, by shale gas.

Given that Australia has obligations under the second commitment period of the Kyoto Protocol (to achieve GHG emissions of 99.5 precent of 1990 levels by 2020 or the option to move up to a 25% reduction on 2000 levels by 2020), the Expert Working Group believes that deployment of higher efficiency gas turbines (and in the case of shale gas the use of green completion technologies) have the potential to make a substantial contribution to the achievement of Australia's GHG obligations over this timeframe.

Some conventional gas fields have high CO_2 content and shale gas in the same sedimentary basins may also have high CO_2 levels, which would need to be removed from the gas before it is put into the pipeline. Carbon capture and storage (CCS) is the only technology available for decreasing CO_2 emissions from major point sources and application of CCS to high CO_2 shale gas may be appropriate in the future.

11 | Community

Community Amenity and Opportunity

The CSG experience

To date, little academic research has been published on the social and economic impacts of the rapid growth of the CSG industry in areas like Queensland's Surat Basin. This reflects the recency of these developments. However, there is extensive anecdotal and statistical evidence (e.g. government population estimates, data on housing values and availability) to indicate that these impacts have been substantial. Some of these impacts have been perceived positively by affected communities, but others have been viewed in predominantly negative terms. The projected growth in CSG production in the next few years to support the East Coast LNG industry is likely to add to these pressures. Potential impacts associated with large-scale CSG development that have been identified in social impact assessments undertaken by project proponents include:

- Population growth and a changed demographic profile
- Increased employment and business opportunities at the local level

- Local labour market shortages

- Land use conflicts

- Landowner concerns about property values

- Perceived changes to community values and lifestyle (welcome and unwelcome)

- Pressure on community infrastructure and services (but partly counterbalanced by significant levels of social investment from CSG companies)

- Reduced housing and accommodation availability and affordability, at least in the early stages of development

- Increased traffic on local roads

- Concerns about community health, safety and wellbeing

Similar impacts have also been identified in the now substantial body of research literature on the social impacts of mining in regional Australia (see for example: Ivanova, *et al*., 2007; Rolfe, *et al*., 2007; Haslam McKenzie, *et al*., 2008; Solomon, *et al*., 2008; Lockie, *et al*., 2009; Franks, *et al*., 2010; Carrington & Pereira, M, 2011; Hajkowicz, *et al*., 2011; Tonts, 2011).

In Queensland, and to a lesser extent in New South Wales (where development is not as advanced) governments and companies have sought to address these issues in a range of ways, including by: requiring companies to undertake comprehensive social impact assessments and implement approved Social Impact Management Plans (SIMPs) quarantining some forms of agricultural land from development (e.g. the Queensland Strategic Cropping Land Act), adopting local employment and business development initiatives, undertaking regional planning exercises (e.g. the Surat Basin Resource Town Housing Affordability Strategy) setting up new governance arrangements (e.g. the Queensland Gasfields Commission) and providing additional government funding (Queensland Royalties for the Regions scheme). It is still too early to tell whether these initiatives have been effective, but they do represent a serious effort to manage the social impacts of rapid growth, albeit after the event in some instances.

Application to shale gas

While there are valuable lessons to be drawn from the CSG experience, caution must be exercised in extrapolating to the shale gas sector. The magnitude of social and economic impacts associated with resource projects will vary significantly depending on where the development in question is located, the speed and scale at which it occurs, its duration and how it is configured. For instance, the size of the economic multiplier in a local or regional area will be determined by factors such as the size and degree of diversification of the local economy, whether a FIFO or residential model is used, and the extent to which project operators purchase inputs from the local or regional economy.

Contextual factors will also influence whether impacts are experienced negatively or positively by those living in the vicinity of gasfield developments. For example, small communities with a declining population may welcome an influx of new people, and the local economy may benefit from increased employment and business opportunities. On the other hand, communities with stable or growing populations and a pre-existing strong economic base may be more concerned about issues such as local labour shortages, increased traffic and distortion of the local housing market.

As already discussed in this report, many of the prospective areas for shale gas development currently identified in Australia are in relatively remote and sparsely settled parts of the country. Possible implications of this include:

- amenity issues, such as dust, noise and light may be less of a concern as there will be fewer people living in close proximity to drilling operations

- there might also be fewer conflicts over competing land usage, although this may be counter-balanced by the fact that these developments will be more likely to occur on Aboriginal land

- particularly in the short term, there are likely to be fewer opportunities to source labour from the local area

- there could be fewer opportunities for economic diversification; there is likely to be a greater reliance on fly-in fly-out operations and camps, with commensurately smaller flow-on benefits to local businesses

- local governments (which are small and typically under-resourced) are likely to struggle with meeting the planning and infrastructure requirements

Maximising the benefits for regions

Regardless of where development occurs, a key focus should be on ensuring that there are long-term, broadly dispersed benefits for the affected regions. The following points are salient in this regard.

- Information sharing, communication and transparency are critical for enabling good governance and change management at the community level. Information is also critical for effective on-going management of regional opportunities from the energy boom. Information is crucial for being able to plan, to make policy decisions and to evaluate past policies

- Economic diversification leveraged off the energy boom is the best way of contributing to the long-term wellbeing of the region. The evidence in the literature indicates that economic development based on mining industries alone over the long term will not enable sustained economic growth. However, it must also be acknowledged that remote regions with few comparative advantages will struggle to realise the benefits of diversification

- As the CSG experience has demonstrated, large-scale development is likely to place significant pressure on the hard and soft infrastructure of affected regions. This includes road networks, public transport, utilities, education, health-care, police and community services and the local housing stock. A planned approach to regional development can reduce these impacts and enhance community liveability in the process. For this to occur there needs to be effective local coordination and access to timely information about the scale and timing of proposed developments (Williams, *et al.*, 2012)

Stakeholder Engagement and Communication

Given the experience of the United States and the controversy that has been associated with the rapid expansion of the coal seam gas industry in Australia, any proposal to undertake large-scale shale gas extraction is likely to generate a high level of public interest and debate. CSG development in Australia has been the focal point of substantial community opposition and

Infrastructure contributions

Since the 1970s, coal mining companies in both NSW and Queensland have had to make significant capital and on-going cost contributions to local communities for their presence. These contributions extended to both local and State governments to extend and maintain major regional roads. Similar contributions may be required in both CSG and Shale Gas developments, notwithstanding the fact that that gas fields and associated wells are widely dispersed when compared with coal mines and there is less need to accommodate a significant number of operating personnel in local towns.

Recently the Queensland Government has established a "Royalties for the Regions" Program to address local concerns about the pressure of resource development, including expansion of the CSG industry, on local infrastructure. This program provides for $495 million to be invested over a four-year period starting from 2012, in new and improved community infrastructure, roads and floodplain security projects in resource regions. In future years there will be an on-going commitment of $200 million each year.

disquiet, which has weakened the industry's social licence to operate (SLO). This opposition has been manifested in:

- numerous media stories highlighting the negative environmental and social impacts of CSG development

- organised resistance by landowners to entry on their properties ('Lock the Gate' campaign)

- well-organised information campaigns using social media

- direct action by protestors, including the blockading of drilling sites

- political lobbying by various groups to restrict or ban CSG exploration and extraction

- the emergence of hitherto unseen political alliances between environmentalists and farmers

As noted, governments have responded to these pressures by imposing stricter regulatory requirements on the sector and, in some instances, quarantining land from development. These interventions have addressed some community concerns but have also added to project delays and costs. In addition, the industry's reputation has been damaged and some State governments have experienced a political backlash for their handling of these issues.

While the remoteness factor may eliminate or alleviate some of the potential sources of conflict, particularly around competing land use, the stakeholders for shale gas are not just those living in the vicinity of proposed developments, but include groups who have broader concerns about issues such as protecting the Great Artesian Basin, reducing greenhouse emissions and Australia's dependence on a carbon-intensive economy, and protecting natural areas.

Based on the experience with CSG, possible points of contention around shale gas include the following (Report to this Review by Kuch, *et al*., 2013, pp. 6-7).

- Government rules and industry practices
  - Uncertainty in the timing, location and scale of required surface activities

  - Loss of privacy and control of property access
  - Loss of control over activities that may alter the financial or other perceived value of the property
  - Compensation

- Regional Socio-economic issues
  - Pressure on local housing: crowding out of local service sector workers
  - Local labour shortages
  - Friction between local lifestyle amenity and resource exploitation
  - Social contentions about links to land

- Local environmental and/or safety concerns
  - Water resource interference
  - Aquifer contamination risk
  - Salinity management
  - Gas leakage/flaring and fire hazard
  - Clearance of vegetation for roads, pads and pipelines
  - Soil compaction and alteration of drainage patterns
  - Noise and visual amenity
  - Increased traffic and road safety risks

- Wider environmental and/or safety concerns
  - Greenhouse gas emissions – fugitive and combustion related
  - Investment diversion from renewable energy generation capacity

As discussed in more detail at the end of this section, there may also be points of contention with Indigenous communities who are the traditional owners of the land on which exploration and extraction is planned or which will be crossed by pipelines (Limerick, *et al*., 2012). These issues include:

- Demonstrating respect for traditional owners and Indigenous culture

- Landscape and environmental disturbance

- Protection of cultural heritage

- Equitable access to economic opportunities arising from resource development

Building a social licence for shale gas

What is a social licence?

The concept of 'social license to operate' (SLO) first emerged at World Bank convened meetings about mineral projects in developing countries in the late 1990s in response to campaigns from newly mobile, networked and professional environmental organisations that publicised chemical spills, dam failures and conflicts. The language of SLO is now widely used in the resources industry and, increasingly, other sectors, although it has so far received only limited attention in the academic research literature (Gunningham, *et al.*, 2004; Nelson, 2006; Thomson & Boutilier, 2011; Lacey, *et al.*, 2012; Owen & Kemp, 2013).

Central to the SLO concept is the proposition that successful resource developments require not only the formal approval of government, but the broad acceptance of local communities and other key stakeholders who can impact on project profitability. Without this acceptance, projects are likely to experience disruption and delays and, in some cases, may not proceed at all. Companies associated with unpopular projects risk significant reputational damage and may find it more difficult to obtain access to other resources in the future. Furthermore, as the experience of CSG has shown, where there is significant stakeholder dissatisfaction governments are likely to respond by imposing more onerous regulatory requirements on the sector, and may even block some developments altogether.

Securing and retaining a social licence

There is a body of practice-based knowledge about what companies and industries need to do in order to establish and maintain a SLO (Thomson & Boutilier, 2011; Zandvliet & Anderson, 2009). Drawing on this work, and the experience to date of the CSG sector and mining industry in Australia, four key requirements must be met to secure a broad-based social licence for large-scale shale gas development:

1. Industry and government need to be able to provide a *reasonable level of assurance* that gas extraction can be undertaken without causing any long term environmental harm. This includes being able to demonstrate that: (a) aquifers will not be depleted or contaminated; (b) surface water availability and quality will not be impacted to the extent that it cause detriment to other users or the environment more broadly; (c) harmful emissions will be controlled; and (d) ecologically important landscapes will not be destroyed or damaged. Actions required to provide this level of confidence are discussed elsewhere in this report.

2. Local communities and the broader society will need to be *receptive* to the message that gas extraction can be done responsibly and without causing environmental harm. This is the critical element of *trust*. If influential stakeholders do not accept the science, have a deeply held belief that gas companies are irresponsible, and/or do not trust government to

Social Licence to Operate – some key points

SLO goes beyond regulatory approval and consent conditions to incorporate wider publics who can affect the profitability of a project.

1. A SLO does not indicate universal agreement, but could exist along a continuum of approval, acceptance and support from various publics.

2. any separation between the immediate community surrounding a project and a wider set of stakeholders and publics is fragile.

Source: Lacey, *et al.*, 2012.

exercise effective regulatory control, it does not really matter what the 'reality' is of the industry's performance.

3. Individuals and communities who are potentially exposed to adverse social and economic impacts from projects will need assurance that these concerns will be *recognised and addressed* in a timely way. As the rapid growth of the CSG industry in Queensland has shown, projects can bring with them a range of other impacts apart from environmental ones. These include increased traffic, damage to roads, more pressure on services, landscape and lifestyle changes, housing shortages, local price inflation, disruption to farming practices, a perceived loss of control, and concerns about impacts on land values. A failure to respond to these concerns will add to distrust of companies and government and creates fertile ground for building 'coalitions of opposition' to projects.

4. People living in and near areas where gas is to be extracted will generally be more be supportive of development if they see evidence of *net benefits*, and not just an absence of environmental harm or the minimisation of adverse social impacts. Even if a project can be shown to be environmentally safe, it will not necessarily be welcomed by a community; understandably, communities also want to know if and how they will be better off as a result of a project going ahead. Resource extraction activities create wealth but usually not in an evenly distributed way, so it is important to build a broader value proposition.

Communication and engagement

Communication and engagement are critical mechanisms for building and maintaining a SLO. Undertaking rigorous scientific research on issues such as the impacts of hydraulic fracturing and fugitive emissions will be of limited value from a SLO perspective unless this information can be effectively communicated to a wider, non-expert audience, and seen as credible. This depends, to a large extent, on the source of that information being trusted.

Communication also has to be approached as a two-way activity. It is not just about informing and explaining; it is also about listening, engaging in dialogue and responding. If companies and governments are not attuned to community and stakeholder concerns they will miss key information signals and will be perceived as unresponsive and uncaring. This, in turn, will undermine public trust in the process.

To summarise, the desired outcome is that:

a. Communities and other stakeholders have an *informed understanding* of the technologies of shale gas production and the associated risks, impacts and potential benefits; they are also informed about the management and regulatory processes that are used to manage these risks;

b. proponents and regulators of these technologies likewise have an informed understanding of, and *demonstrate respect for*, the concerns and perspectives of various stakeholders; and

c. different parties are able to engage in *constructive dialogue* with each other and work towards agreed outcomes, or at least an accommodation of differences.

Obstacles to effective communication and engagement

Diversity of participants and viewpoints

Some issues have only a small 'interested public', who are relatively homogenous in their values and knowledge base. However, complex and controversial issues such as CSG and other forms of unconventional gas extraction attract a broad diversity of stakeholders, with different values, interests and levels of knowledge. Interested parties include not only people from the areas

where development is likely to occur, but those living anywhere in Australia (and even beyond) who are concerned about issues such as climate change, energy security, pollution and potential impacts on landscapes and biodiversity values. To state the obvious, what may be an effective means of communicating and engaging with one group will not necessarily work with another. For example, face-to-face meetings are a reasonable option for engaging with local landholders and small communities, but are not feasible for large, urban-based, publics. Even where direct contact is feasible, it will need to take a different form depending on which group is involved; for example, ways of engaging with farmers and local businesses may be quite inappropriate for traditional Aboriginal communities.

Value conflicts

The debate about CSG and unconventional gas is not just a dispute over how to interpret the data or what the science means. Many people who are opposed to development of these resources operate from different value frameworks, which prioritise things such as the preservation of rural landscapes and lifestyles, biodiversity protection, and strong action to address human-induced climate change. These groups are unlikely to be persuaded to change their position in response to scientific evidence that 'fracking' can be done safely. Conversely, many of those who support the expansion of the unconventional gas sector have an equally strong value position that economic development should be prioritised and are unlikely be dissuaded by a lack of scientific certainty.

Not surprisingly, where people are not 'on the same page', it is much more difficult to find common ground. There is also a greater risk of communication mismatch if people are proceeding from different value positions. An example is where a company responds to a resident who is concerned about the visual impact of a development by offering them financial compensation, whereas what really matters to that person is their emotional connection to the land.

Information overload

In the modern world, where people are deluged with – and can also readily access – large amounts of information from a diversity of sources, it is increasingly difficult to get a message through. Faced with conflicting messages and masses of data, individuals tend to resort to 'trusted sources' and 'gut feel', rather than taking time to absorb new information.

Declining levels of trust

There is substantial evidence that levels of trust in political institutions and processes have diminished over the last two to three decades. Government is no longer seen as an independent arbiter.

> *'Communities are no longer satisfied to leave all the decisions to their elected representatives because they no longer trust them to look after their interests…. On the flip side, some elected representatives are equally frustrated about how they are expected merely to rubber stamp decisions made by appointed executives or bureaucrats'* (Twyford, *et al.*, 2012, p. 32).

Values Matter

We often hear the call for "best science" to be used in resolving controversial issues, such as those surrounding the competing water needs of irrigators, farmers and the environment in Eastern Australia's Murray Darling Basin. Or the question of whether fracturing technology used for mining coal seam gas will damage aquifer water quality, thus inflicting serious unintended consequences on the environment. It is our view that these complex issues are fundamentally value dilemmas masquerading as scientific questions, and that attention to the science alone will never generate sufficient trust or agreement between the parties so that they can create implementable solutions together (Twyford, *et al.*, 2012, p. 44).

There are also low levels of trust towards multi-national corporations and big business, especially relative to environmental NGOs (Terwel, *et al*., 2011). This means that information coming from these sources is likely to viewed sceptically by many in society.

Uncertainty

A further challenge is that the research relating to the environmental impacts of unconventional gas extraction is not definitive now and is unlikely to be so in the future. The dynamics of gas capital investment mean that management has been adaptive, and 'science' emerged from real-world experimentation. The extent of fugitive emissions, and the composition and impacts of hydraulic fracturing fluids, are under active experimentation, discussion and debate. As a consequence, the management of risk and uncertainty are likely to be permanent features of unconventional gas activity. Communicating information about risks is inherently more challenging, particularly as this knowledge is dynamic (Report to this Review by Kuch, *et al*., 2013).

Developing a response

There is ample scope to learn from past mistakes and to take a proactive, rather than reactive, approach to addressing the communication and engagement challenges around shale gas. Some suggested approaches are discussed, under three headings:

1. Building confidence in the science and technology of shale gas extraction

2. Engaging at the regional and local level

3. Developing one or more 'strategic narratives'.

1. Building confidence in the science and technology of shale gas extraction

Communicating scientific and technical knowledge is not simply a matter of how this information is packaged. Preparing easy-to-read fact sheets, visual displays, DVDs, etc. can all help with the translation of technical information, but

as indicated, whether people choose to accept this information as valid will depend, to a large extent, on whether they trust the source (on the general issue of dealing with trust deficits see Terwel, *et al*., 2011).

A fairly common government response in Australia, as elsewhere, has been to establish independent expert groups to act as a source of authoritative advice on controversial issues. A recent example is the federal Environment Minister's announcement late in 2012 of the formation of an Independent Expert Scientific Committee to advise on Coal Seam Gas and Large Coal Mining and to review proposed developments and their potential impact on water resources when referred by the Commonwealth and state regulators.

Expert committees can play a valuable role, but do not provide the full answer. Making it a condition of membership that a person be a recognised technical 'expert' can actually limit the opportunities for a broader dialogue between different viewpoints. Experts often work from similar paradigms and tend to defer to each other on matters within each person's area of expertise. Rules of confidentiality can also inhibit transparency and may inadvertently reduce public confidence in the process. Moreover, public engagement often takes the form of receipt of submissions and formal hearings rather than genuine dialogue.

A number of commentators have argued in favour of more open deliberative forums that aim to represent a variety of viewpoints and interests, and seek to build trust between different stakeholders. Some elements of this approach can be seen in the recently created Queensland Gasfields Commission. This organisation comprises six Commissioners representing landholder, community and business, local government and infrastructure, industry, water and science interests. It is envisaged that the Commission will also have a strong outreach role. It is early days for the Commission, but it could potentially provide a model that could be replicated in other regions, where there is the prospect of large-scale unconventional gas development.

The issue of research independence

Consultations with representatives of environmental organisations as part of the present study revealed that, based on their experience with the CSG industry, they had significant concerns about the potential for government research organisations to be compromised if their activities were wholly or partly funded by gas companies. This was seen by the NGOs as reducing public confidence in the validity of any research emanating from these organisations. It is unlikely that all research and surveys relating to the impacts of gas production will be funded from public sources and, without corporate support, the research often would not be undertaken. Moreover, companies, for the most part, are eager to use good scientific research to better manage the impact of their exploration and production. However there is clearly a perception problem regarding the funding of research and surveys by gas companies and it is likely the same issue will arise in the case of shale gas.

Concerns about independence can be addressed, at least in part, by having guidelines for the use of industry funding (e.g. 'right to publish' clauses, peer review requirements) and by being transparent about funding arrangements and the process whereby projects are selected and reports signed-off. In addition governments may wish to increase their funding of key areas of research that are of particular concern to stakeholders and where there is obvious market failure.

A 'bottom up' approach to building community confidence and knowledge is to involve local people in monitoring and interpreting data, where it is practical to do so.

For example, demonstrating the veracity of a monitoring technology such as a seismic readout builds trust between project proponents of a Carbon Capture and Storage (CCS) activity and local landholders. Farmers may not necessarily support CCS, but trust can be developed around specific demonstrations of technological competence (Report to this Review by Kuch, *et al.*, 2013, p. 22).

Similarly, participatory water monitoring has been used in the mining industry on a number of occasions as a means of alleviating community concerns about impacts of mining activity on water quality and availability (Compliance Advisor Ombudsman, 2008).

2. Engaging at the regional and local level

Landholders and regional and local communities are key stakeholders for the unconventional gas industry. If there is strong local support for the industry, it will be more difficult for opponents and critics from outside the region to gain traction. Conversely, if local people feel poorly treated and have unresolved concerns, they will be more open to entering into formal or informal alliances with groups who are opposed to the exploitation of unconventional gas resources. How well government and companies engage with and respond to local stakeholders will therefore help to determine whether the industry is able to secure and maintain a broader social licence. Some practical measures that can be adopted are as follows:

- Ensure that front line personnel (land access, drillers, etc.) are trained in the basics of communication and dialogue, and understand the importance of behaving as a 'good neighbour'. Unthinking acts such as rudeness, entering properties without first seeking permission, leaving gates on a property open, not stopping to assist someone who has broken down, not consulting landowners on the siting of wells, and so on, can create an atmosphere of ill-will and mistrust. In rural communities in particular, stories of poor behavior travel quickly and can easily be amplified. This was a major focus of the 2012 report of the Queensland Land Access Review.

- Formulate codes of practice around land access, management of water, vegetation protection, management of chemicals and so on, and require developers to commit to these. (This approach is already being used in Queensland and New South Wales.)

- Provide fair and prompt compensation to landowners where they have suffered economic or other disadvantage as a result of development (Land Access Review Panel, 2012).

- Require companies to set up grievance mechanisms to enable people who have complaints or concerns to have those matters heard and responded to. These mechanisms should allow for matters that cannot be satisfactorily resolved by the company to be referred to a respected third party (International Council on Mining and Metals, 2009).

- Establish local and regional consultative mechanisms. This approach has been used widely in Queensland, where proponents have been required as a condition of their licence to establish community consultative committees. The new Gasfields Commission is also charged with establishing a Gasfields Community Council 'for the purpose of assisting the commission to identify issues affecting the coexistence of landholders, regional communities and the onshore gas industry in Queensland'. Consultative committees often do not deliver what is hoped for them, but there is a growing body of knowledge about 'what works and what doesn't' in their design and operation. When they are working well, such committees not only provide a useful forum for information exchange, but can help in building trust between different parties (Franks, et al., 2012).

3. Developing a strategic narrative

While the local level is important, there will also be a range of other stakeholders around the country who will want to have their voices heard on decisions about whether, and under what conditions, large-scale development of shale gas resources should proceed. Engaging with these groups will be challenging, because of their size and geographical dispersion and diversity of interests.

Kuch *et al.* argue that, in the case of CSG, there is currently 'little in the way of a strategic narrative that underpins and justifies exploitation of resources beyond its dollar value contribution to State and Federal budgets' (Report to this Review by Kuch, *et al.*, 2013, p. 9). They note that efforts have been made to develop a 'regional development' and 'jobs' narrative, but these have gained only limited traction to date.

As argued by Kuch *et al.,* for many landowners, and others living in areas where large-scale CSG exploitation is under way, or proposed, CSG development is still predominantly perceived as a high risk, low reward option and as something over which local people have little control. Many others living outside of impacted areas are concerned about potential impacts on water and greenhouse gas emissions, and likewise do not see themselves as economic beneficiaries. Developing one or more 'narratives' that link to more than dollar value will help to build a broad-based social licence and positively position unconventional gas projects in the future energy mix.

The content of any such narrative should be the outcome of a *dialogue* between stakeholders, government and industry, rather than being predetermined and then marketed. However, possible themes include:

- the potential to leverage off industry technology, infrastructure and know-how to enhance the reliability of water supply and increase agricultural production and food security in farming areas;

- using unconventional gas development to facilitate the transition to a low carbon economy; and

- creating opportunities to kick-start development in remote areas of Australia and provide a point of economic engagement for the Indigenous people living in those regions.

From the perspective of Kuch *et al.,* the ideal outcome would be a single, overarching strategic narrative at the national level which links to one or more regional narratives. The Expert Working Group is sceptical about the ability to achieve this degree of national consensus, but sees value in a process that encourages a broader national

dialogue about how best to utilise the economic opportunities presented by unconventional gas to address other societal needs and priorities.

Kuch *et al.* (2013) also recommend establishing an independent collaborative learning forum for the shale gas sector. The forum would be independently chaired and comprise representatives from sectors such as government, the unconventional gas industry, the research community, Indigenous organisations, farming organisations, environmental groups, local government, other business sectors and community organisations. Its function would be to: (a) provide a safe space in which different actors could share their experiences and knowledge, and: (b) encourage forward-looking discussions about how to maximise the societal benefits of shale gas development. The forum would need a small secretariat and could further be supported with a social media outreach program. Access to high quality facilitation skills would also be critical. These processes could possibly be replicated at the regional level, by creating similar entities, or utilising existing structures such as consultative forums or bodies like the Queensland Gasfields Commission.

Engaging with Aboriginal People

Given that the most prospective Australian shale gas basins are located inland, in arid sparsely populated areas, it is likely that a significant amount of exploration and development will be on lands over which Native Title has either been recognised or is subject to a claim, pursuant to the *Native Title Act* 1993 or which are designated Aboriginal Lands under the *Aboriginal Land Rights (Northern Territory) Act* 1976. In addition, any gas pipelines will almost certainly cross traditional lands.

Australian legislation gives limited, but important, rights to the traditional owners of land on which resource development takes place, or is proposed. In the case of trust lands created by virtue of the *Aboriginal Land Rights (Northern Territory) Act*, Aboriginal owners have a right to consent to exploration activities on their land.

This is not an indefinite right to exercise a veto: the veto can be exercised only at the initial exploration stage and does not apply to the extraction stage; companies can apply again after five years; and there is an over-arching national interest clause (although it has never been invoked). However, the failure to secure consent would be a significant setback for any aspiring shale gas explorer.

The more common scenario is that the *Commonwealth Native Title Act* 1993 will apply, as this legislation has national applicability[16]. Under the Act, native title is deemed to have been extinguished if the land is under freehold title, but can be claimed over vacant Crown Land, other public lands such as state forests and reserves, lakes and inland waters, and some types of leases (such as pastoral leases). Most shale gas exploration leases are likely to include some land that is potentially subject to native title, even if this is only a small area.

Native title gives only limited rights to traditional owners. In particular, native title holders do not own the subsurface rights, do not have a right of exclusive use and have no right of veto over development. They do, however, have a legally recognised right to negotiate over future uses of that land. If the parties cannot reach agreement, the matter can be referred to a court for final resolution, but in practice the great majority of claims involving resource projects are settled by negotiation. The main reason for this is that the alternative – seeking a court determination – is slow, costly and uncertain for all parties.

Understanding the aspirations of Aboriginal people regarding resource development should be the starting point for any resource company seeking to enter into an agreement with Aboriginal people. Most groups aspire to create a better life through the material benefits of resource development on their land and access to employment and business

16 In situations where native title has not been confirmed, it is generally considered prudent to seek an agreement with the claimants, using the Indigenous Land Use (ILUA) provisions of the Act. This is a flexible process under which native title claimants and companies can reach a legally binding agreement on a wide range of matters, including approval of future activities and multiple projects.

opportunities, but they are also involved in a complex balancing exercise between conservation and development and between competing individual and group interests and perspectives (O'Faircheallaigh, 2008).

Respect and recognition are very important for Aboriginal groups as the original owners of the land. Aspirations around material benefits may include funding for cultural awareness programs, cultural centres, language preservation, rangers and cultural heritage protection. Environmental protection and management is also a key concern. For Aboriginal people, the environment is not only a source of water, food and shelter, but also has great cultural and spiritual significance. While environmental management did not feature in most agreements before the late 1990s, it is now common for agreements to acknowledge the importance of the land for Aboriginal people and to include provisions for them to participate in monitoring environmental management during a project (Limerick, *et al*., 2012, p. 93).

Shale gas extraction is a new technology, which will be unfamiliar to most Aboriginal people. One of the aims of a communication and engagement strategy, therefore, should be to ensure that, when Aboriginal parties enter into the negotiation process, they do so with an understanding of how extraction is undertaken, the potential environmental footprint and the risks involved. In the case of Aboriginal trust lands in the Northern Territory, where traditional owners have the right to withhold consent to exploration activities, this understanding is critical for making an informed decision about whether the activity should be allowed to proceed. Where the *Native Title Act* applies (and there is no right of veto), ensuring that the Aboriginal parties are properly informed will place the negotiations on a fairer footing and should enable the process to run more smoothly.

A best practice model of how to communicate information and build understanding is the process developed by the Central Land Council (CLC) to inform traditional owner groups in the Northern Territory

about uranium mining. In practical terms, the strategy comprised the following:

- The CLC worked in collaboration with the Northern Territory Mines and Energy Division and other groups to develop a series of seven two-metre high posters covering several themes related specifically to the environmental and social issues associated with uranium mining.

- Two large-scale community meetings were held over a whole day. Each meeting was advertised in advance and the rationale discussed with respective senior community members. These meetings were addressed by representatives from the Australian Uranium Association and the Australian Conservation Foundation in turn. The Radiation Officer from the Northern Territory Government's Minerals and Energy Division also presented information on the regulatory regime and safety.

- A site trip was then organised to the Ranger Uranium Mine, in collaboration with Energy Resources Australia Ltd (ERA). A DVD of the mine tour was also prepared, for viewing by those who were unable to attend.

Feedback on the process was positive, both from traditional owners themselves and the representatives of industry and the environmental movement who presented at the meetings (Stoll, *et al*., 2008). A modified version of this approach could potentially be utilised to inform Aboriginal groups about the issues and impacts associated with shale gas development and exploration. However, native title representative bodies and other organisations would need to be funded to undertake this work.

Being able to protect the rights and interests of Aboriginal people in relation to shale gas development also depends heavily on there being an effective regulatory regime in place. In the case of the Northern Territory, both the Northern and Central Land Councils expressed concern to the EWG about the current level of regulatory capacity in the Northern Territory and the weakness of legal frameworks. One of the issues highlighted by the Central Land Council

was the large number of 'speculative' exploration applications being received, which was stretching the resources of the Council and leading to a lot of frustration amongst traditional owners. The Council called for more front-end screening by the Northern Territory to ensure that only *bona fide* applications progressed through the system.

If these and other procedural issues can be resolved, there may be an opportunity, through the agreement making process, to use shale gas developments to help address the aspirations of Aboriginal people living in remote parts of Australia to build greater economic self-sufficiency. The high skill requirements of some jobs, and the socio-economic disadvantage experienced by many Aboriginal people, particularly those living in remote areas, will likely limit access to direct employment in the unconventional gas sector – at least in the shorter term. However, the experience of the mining industry has shown that a concerted investment in recruitment and training can deliver results (Tiplady & Barclay, 2007). Provided there is sufficient support and the commitment of the parties, there should also be significant opportunities for Aboriginal people to be engaged in land protection and rehabilitation activities associated with shale gas developments, as well as in support functions such as road construction, maintenance and camp operations.

Human Health

Potential Health Impacts of Unconventional Gas

Community responses to any new industry such as unconventional gas production will be heavily influenced by whether or not that industry is seen as posing a threat to human health and wellbeing. The Expert Working Group did not have the opportunity to consider any potential health issues arising from the shale gas industry. Nonetheless, there is literature that suggests this issue will require careful attention as part of policy and regulation; both for the potentially impacted community as well as operating staff

at the well site involved in production and processing. One issue for human health is the use of chemicals in the fracking operations, although many of these chemicals are benign (see Chapter 4). In a study of natural gas production (not specifically shale gas it should be noted) Colburn *et al.*, (2011) identified some 353 chemicals that could affect human health in a variety of ways. But at the same time it should be noted that the chemical and petroleum industries have a range of protocols in place for handling these and many other chemicals. Therefore the issue is perhaps less the potential of these chemicals to cause harm and more the level of confidence that we can have that they will be handled safely in accord with established protocols and management systems.

The American Public Health Association (American Public Health Association, 2012) has recently stated in their policy statement (2012) on *'The Environmental and Occupational Health Impacts of High-Volume Hydraulic Fracturing (HVHF) of Unconventional Gas Reserves'* that HVHF poses potential risks to public health and the environment, including groundwater and surface water contamination, climate change, air pollution, and worker health. Their position statement relates to the entire process surrounding HVHF, including site preparation, drilling and casing, well completion, production, transportation, storage and disposal of wastewater and chemicals, and site remediation. They claim that HVHF presents potential direct and indirect health challenges through changes in vehicular traffic and community dynamics, unequal distribution of economic benefits, demands on public services, health care system effects, and increased housing costs. Further the APHA state that '…*the public health perspective has been inadequately represented in policy processes related to HVHF. Policies that anticipate potential public health threats, require greater transparency, use a precautionary approach in the face of uncertainty, and provide for monitoring and adaptation as understanding of risks increases may significantly reduce the negative public health impacts of this approach to natural gas extraction*' (American Public Health Association, 2012).

In Australia it would be prudent that the learning and experience in health issues relating to United States shale gas production be taken into future considerations. However a recent report by the Queensland Department of Health (2013) (drawing on the findings of a Darling Downs Public Health Unit investigation conducted in 2012, along with independent medical assessment and scrutiny), concluded that there were no adverse health impacts resulting from natural coal seam gas operations near Tara in western Queensland.

A comprehensive study by Krzyzanowski, (2012) on environmental pathways of potential impacts to human health from oil and gas development in northeast British Columbia in Canada provides evidence of human health concerns and also sets out a very useful framework to consider the issues that may determine the risk of unconventional shale gas production on matters of human health.

In the case of air emission pathways, concerns are air-borne emissions of sulphur, carbon and nitrogen oxides, hazardous volatile organic compounds (VOC) (European Commission DG Environment, 10 Aug 2012, re-issued with minor corrections 11 Feb 2013), hydrogen sulphide, ozone, particulate matter and radiation. Air is an inevitable pathway through which people are exposed to contaminants. Additionally, air pollutants can be deposited on the surfaces of water, soil and crops. In the United States, there has been public concern about air pollution from activities associated with shale gas production. Debate between industry and academic research on the nature and levels of emission of benzene and other pollutants has focused on the very high density drilling for shale gas west of Dallas, Texas (Duncan, 2012). That example has given some indication of how emissions from processes associated with shale gas production can affect air quality. The air emissions are from diesel generators, compressors and the very high density traffic transporting waste material such as contaminated water and residue. It is unlikely that such high intensity of gas production will develop in Australia. Moreover, even with the described high intensity of production in parts of the United States, benzene measurements over

time at the Barnett gas field have shown that maximum benzene concentrations are at or, more likely, below long-term recommended levels.

In shale gas production the management of water, salt fracking fluids, and chemical contaminants is of utmost importance to minimise environmental impact, as discussed at length in Chapter 8, but it will be equally important to minimise impact on human health. The two pathways of water and soil are considered together rather than separately because the contamination of either can occur through the same mechanisms: accidental spills, purposeful disposal, or atmospheric deposition. Disposal or spillage to land for instance can percolate below the surface and enter groundwater; run off the surface as overland flow; or move (leach) through substrates as throughflow, potentially entering surface- or groundwater elsewhere. Contaminated soil can erode and enter waterways reducing surface quality. Once in the system, contaminants can travel throughout basins and throughout the hydrological cycle and accumulate in ecological food chains. However that same cycle also dilutes the level of contaminants, so that whilst the potential may be there, the reality is that the contaminant can also end up below detection limits.

Noise and visual amenity

Noise is emitted from shale gas operations, be it exploration (fracking activities and seismic operations), drilling, compression, maintenance, transport, emergency and other operations. Impacts on visual amenity can cause 'environmental distress' and affect tourism in some areas. However for most operations it is a requirement that effective sound suppression is undertaken.

As mentioned previously, Krzyzanowski (2012) found for the Canadian study in British Columbia that there were potential health impacts from upper stream oil and gas development. The extent to which this might apply to shale gas development in Australia is not known and it has to be recognised that the two countries have very different hydrological and

climatic regimes. Notwithstanding this, there are grounds for a careful examination of the issues the study raised. Krzyzanowski (2012) suggested that research must include long-term spatially representative monitoring of contaminants in the environment as well as spatial epidemiological analyses of potentially related health symptoms and any confounding lifestyle factors in local communities.

However, to date there has been little peer-reviewed literature on the nature or extent of these impacts. This dearth of research is due to the limited number of years shale gas operations have been in place and the absence of identified unique health indicators, latency of effects, limited baseline and monitoring data, low population densities in many affected areas, and, in some cases, industry practices and nondisclosure agreements that limit access to relevant information.

Individual drilling operations may not create air emissions that trigger regulation under existing environmental laws. However, the cumulative impacts of emissions may create public health threats for local communities or regions. Therefore, projections of aggregate emissions under expected extraction scenarios could be a more rational basis for regulation of individual sources. Overall density and projected development over time would need to be considered. Health Impact Assessment (HIA) such as that reported for Battlement Mesa Community in Garfield County, Colarado, USA (Witter, *et al*., 2008; Witter, *et al*., 2010) may be a useful way forward on this matter. It would seem wise in Australia for government, community and industry to understand both the benefits and the potential public health impacts arising from shale gas developments and develop an understanding of how those impacts might be avoided through best practice procedures.

Conclusions

While some sections of society will welcome the economic and other opportunities generated by the development of shale gas reserves, others are likely to be concerned about potentially adverse environmental, social and public health impacts, and sceptical about the purported benefits. It is very important that governments and industry address these concerns from the outset, by proactively engaging with affected and interested parties, building confidence in the science and technology and demonstrating a preparedness to adopt and enforce strong regulatory and internal controls. Failure to do so will weaken the sector's 'social licence to operate' and lead to more controversy, more delays and increased project costs. This chapter has identified a number of practical measures that can be taken to avoid these outcomes and, in particular, has highlighted the valuable lessons that can be drawn from the CSG experience in Australia.

12 Monitoring, governance and regulation

Monitoring the impact of operations is an inherent part of any resource activity, including oil and gas production. There have been few shale gas wells brought into production to date in Australia and there is no specific monitoring or regulatory regime for them at this time. However comprehensive monitoring regimes are in place for conventional and unconventional (CSG) gas operations and many features of those existing requirements will readily translate to shale gas production and related activities.

Given this range of existing mechanisms for regulating and monitoring gas, is it necessary to contemplate additional requirements for shale gas production? Should unconventional gas (shale gas, tight gas, CSG) and conventional gas all be regulated perhaps under the heading of 'onshore gas' as discussed earlier? There is obviously merit from the point of view of simplicity. However perhaps the genie is out of the bottle in the mind of the community, in that they are increasingly aware of "shale gas". At the same time, a shale gas industry in Australia is not starting out with a blank sheet of paper as far as regulations are concerned. Overall, existing

regulations for conventional gas production appear to have worked well, but at the same time, the level of community opposition to some CSG developments (Chapter 11) suggests that all is not well with some aspects of the current process. If a major shale gas industry is to fully develop in Australia, it is important that it does not generate the same level of community opposition as CSG. Part of the way to avoid this (other than by refusing to approve exploration for and production of shale gas) is through improved communication and having a value proposition that recognises that there will be impacts and risks associated with shale gas developments, but that the impacts will be acceptable compared to the benefits that will accrue to the community at the local, regional and national levels. Robust and transparent regulation underpinned by effective and credible monitoring is key to public acceptability.

The existing monitoring regime for onshore oil and gas production, largely administered by the states, is likely to be the preferred starting point for a shale gas industry in Australia. However there is likely to be federal involvement through agreement via COAG, or a wish to have national harmonisation of regulations, or responsibilities relating to the Murray-Darling Basin (Rural Affairs and Transport References Committee, 2011) (through the *Commonwealth Water Act* 2007). In addition, the federal government has national responsibilities arising as a consequence of its international responsibilities, for example through the *Environmental Protection and Biodiversity Conservation (EPBC) Act*, 1999. Also, the recent agreement to establish the Independent Expert Scientific Panel for CSG provides another example of how issues relating to environmental impact of unconventional gas (CSG) production are being addressed at the federal and state levels. A number of principles, which are directly applicable to existing conventional and unconventional gas relating to regulation, have been agreed by COAG and these are given in Table 12.1. Potentially relevant policies and guidelines that have been suggested (Submission to this Review by Flood, 2013 pers. comm.) are summarised in Table 12.2.

A realistic way forward with the future regulation of shale gas production is to add to existing onshore gas regulations rather than developing new regulations specifically for shale gas. Part of the benefit in such an approach is that it avoids the problem that might arise in some instances of defining whether gas production from a well is of shale gas or tight gas or coal seam gas or conventional gas, or a combination of these sources. However it is also likely that shale gas development, like other gas developments, will be governed by a large body of legislation (Table 12.2). For example, at the present time – in addition to various petroleum laws – separate legislation governs CSG activities in areas such as the environment, heritage, development, native

Table 12.1: COAG Principles of Best Practice Regulation

Establishing a case for action before addressing a problem;
A range of feasible policy options must be considered, including self-regulatory, co-regulatory and non-regulatory approaches, and their benefits and costs assessed;
Adopting the option that generates the greatest net benefit for the community;
In accordance with the Competition Principles Agreement, legislation should not restrict competition unless it can be demonstrated that: • The benefits of the restrictions to the community as a whole outweigh the costs, and   • The objectives of the regulation can only be achieved by restricting competition.
Providing effective guidance to relevant regulators and regulated parties in order to ensure that the policy intent and expected compliance requirements of the regulation are clear;
Ensuring that regulation remains relevant and effective over time;
Consulting effectively with affected key stakeholders at all stages of the regulatory cycle; and
Government action should be effective and proportional to the issue being addressed.

Source: COAG, 2008.

Table 12.2: Some indicative Commonwealth, States, and Local Government Regulations, Acts, Policies and Guidelines potentially covering shale gas

Commonwealth
- Environmental Protection and Biodiversity Conservation Act 1999
- Industrial Chemicals (Notification and Assessment) Act 1989
- National Greenhouse and Energy Reporting Act 2007
- Native Title Act 1993
- Water Act 2007

New South Wales	Queensland
• Aquifer Integrity Policy 2012 • *Environmental Planning and Assessment Act 1979* • *Forestry Act 1916* • *Native Vegetation Act 2003* • *National Parks and Wildlife Act 1974* • *Noxious Weeds Act 1993* • NSW Biodiversity Strategy 1999 • *Petroleum (Onshore) Act 1991* • Petroleum (Onshore) Regulations 2007 • *Pipelines Act 1967* • *Protection of the Environment Operations Act 1997* • *Rural Fires Act 1997* • State Environmental Protection Plans • State Environmental Planning Policies • Strategic Regional Land Use Policy 2012 • *Threatened Species Conservation Act 1995* • *Water Management Act 2000* • *Water Act 1912* • *Work Health and Safety Act 2011*	• *Aboriginal Cultural Heritage Act 2003* • *Environmental Protection Act 1994* • Environmental Protection Regulations 2008 • *Greentape Reduction Act 2012* • *Nature Conservation Act 1994* • Petroleum & Gas (Production & Safety) Act 2004 • State Development and Public Works Organisation Act 1971 • Strategic Cropping Land Act 2011 • Water Act 2000 • Work Health and Safety Act 2011
Victoria	**South Australia**
• *Aboriginal Heritage Act 2006* • *Environmental Protection Act 1970* • *Environmental Effects Act 1978* • *Pipelines Act 2005* • Pipelines Regulations 2007 • *Planning and Environmental Act 1987* • *Water Act 1989*	• *Development Act 1993* • *Environmental Protection Act 1993* • *Petroleum and Geothermal Energy Act 2000* • Petroleum and Geothermal Regulations 2010
Western Australia	**Northern Territory**
• *Environmental Protection Act 1986* • Environmental Impact Assessment Administrative Procedures 2010 • *Petroleum and Geothermal Energy Act 1967* • *Rights in Water and Irrigation Act 1914*	• *Environmental Assessment Act 1982* • *Petroleum Act 1984* • Petroleum Regulations 1994 • Pipelines Regulations 1994
Tasmania	**Local Government**
• Environmental Management and Pollution Control Act 1994 • Gas Pipelines Act 2000 • Land Use Planning and Approvals Act 1993 • Water Management Act 1999	• Council Local Environmental Plans • Natural Resource Management/Catchment Management Authority Regulations

Source: Professor Peter Flood, 2013 pers. comm.

title and land rights, and occupational health and safety. Whilst there would be benefits from the perspective of an exploration or production company in bringing all this legislation together, the legal and political complexities in doing this make it unlikely. Most of the current regulations for gas processing will be directly translatable to shale gas processing, although there are likely to be differences between the handling of CSG which is predominantly methane, whereas shale gas is likely to have a composition more

analogous to that of conventional gas, with varying quantities of higher hydrocarbons, sulphur compounds, inert gases and carbon dioxide that would need to be extracted and monitored. There are some unique features of shale gas production, which give rise to an expectation that appropriate monitoring will be in place before there is extensive shale gas development, to measure emissions to the air, surface water and groundwater that may pollute or in some other way adversely impact on the

natural or human environment. This may require regulation and monitoring over and above that already in place for the existing gas (including CSG) industry. This could include the need to monitor any potential physical consequence of the production process (such as induced seismicity) that may constitute a hazard to health or safety. This will provide assurance to the community. Equally importantly, it will help to provide industry with the confidence that it will continue to have the social licence to operate and also the certainty it requires before making the necessarily massive investments to take shale gas developments forward.

Before setting up a monitoring program it is important to be clear on the rationale for doing the monitoring in the first instance. For example is atmospheric methane to be measured for carbon accounting purposes or because it is seen as an air quality issue or a hazard, or is it to reassure the public or the regulator? In fact it can be all of these things, and information can have multiple uses, but the purpose and the risk need to be identified from the start (Jenkins, 2013).

It is necessary to identify what risk or risks are of concern, so that the monitoring can be targeted at identified risks and have a clear purpose, otherwise monitoring can be seen merely as a requirement to tick a regulatory box. It is also important to bear in mind the cost of monitoring. At the present time we do not know what the cost of a comprehensive monitoring program for a major shale gas field would be, but using the IPCC (2005) estimates for the cost of monitoring a CO_2 storage site, monitoring a shale gas site might cost in the range of 1-3% of the total capital and operation costs over the life of the field, This needs far more consideration, but obviously monitoring will be an added cost on shale gas production, which is often not taken into account. Preferably a model can be tested through monitoring of the shale gas field, thereby providing far greater insights into the processes that are operating in the surface or subsurface (Groat & Grimshaw, 2012).

Baseline surveys are a very important part of monitoring, for without a baseline how do we know that there has been any significant change

from the 'norm'? But we do not always know what "significant change" really means and we do not fully understand natural variability in many surface and subsurface systems. Therefore, having a testable model can be a valuable component of detection and avoidance of chemical pollution or induced seismicity or some other impact. Baseline monitoring needs to get underway before large-scale gas production commences and it needs to continue throughout the production phase. Monitoring should also continue after gas production has ceased because one the higher long term risks, in terms of contamination of an aquifer, is leakage from a poorly engineered abandoned well.

Pre-development and Baseline Surveys

It is important to conduct baseline surveys of sites where drilling is to be undertaken, especially in relation to groundwater. The key necessary technical measurements for base-line surveys in the context of well integrity and groundwater contamination have been addressed in Chapter 3 of the UK Royal Society and Royal Academy of Engineering report (2012), where a recommendation is made that operators should carry out site-specific monitoring of methane and other contaminants in groundwater before, during and after shale gas operations. In this United Kingdom study it is additionally recommended that the UK's environmental regulators work with the British Geological Survey to carry out comprehensive national baseline surveys of methane and other contaminants in groundwater. The US EPA Hydraulic Fracture Taskforce has established a Baseline Environmental Monitoring site in Washington County (Hammack, 2012). This green-field site will be developed over the next few years by (horizontal) drilling of two typical Marcellus field shale gas production wells. Comprehensive monitoring and documentation throughout this period involves six Federal and two State agencies. It would be valuable for Australia to have a similar experimental field site.

Measurement of natural background levels of methane in groundwater unrelated to shale gas extraction to establish a baseline is important to remove ambiguity. In the near-surface area, methane is produced as a by-product from decay reactions of organic materials by micro-organisms. This biogenic methane is distinct from thermogenic methane formed deep within the earth from high temperature degradation of organic materials laid down with sediments. Whilst biogenic and thermogenic methane differ in their carbon isotope ratio (C^{12}/ C^{13}), these ratios cannot be reliably used to indicate a gas well leak, since migration of deep methane to the surface may occur through natural seeps unrelated to drilling. Testing of water wells in the United States before drilling has shown wide variation in methane content depending on local geology, with for example variation of 11% of water wells tested in West Virginia and 85% of water wells tested in Pennsylvania and New York State showing measurable methane content (King, 2012).

The Alberta Energy Resources Conservation Board (Energy Resources Conservation Board, 2012) has recently proposed a new framework for regulation of unconventional oil and gas in Alberta in recognition of the fact that unconventional resources extend over large areas and require a high concentration of infrastructure to make production economically viable. It has proposed two principles "*Risk-based regulation – regulatory responses that are proportional to the level of risk posed by energy development*" and "*Play-focused regulation – regulatory solutions that are tailored to an entire 'play' to achieve specific environmental economic and social outcomes*". For the most part the approach adopted in Australia has been the risk-based regulatory approach. However it would be appropriate to consider the play–focused approach as an alternative as it may provide a better basis for handling shale gas developments covering broad areas of onshore Australia, where there may be large-scale cumulative impacts from multiple wells. Monitoring may need to be conducted over a region rather than at a site.

Water Monitoring

For groundwater and surface water, a variety of chemicals are currently measured routinely by the oil and gas industry. As noted in Chapter 4, the composition of produced water from a hydraulic fracturing stimulation varies from that of the initial fracture fluid at the start of flowback, to water dominated by the salt level of the shale near the end of clean-up, together with ions, compounds and contaminants reflective of the deep sedimentary deposition history.

The United States Department of Energy (USDoE) has published a table of additive type, main chemical compounds and common use for hydraulic fracturing (Ground Water Protection Council, 2009). In addition, service companies have disclosed the nature of hydraulic fracturing fluids for the United States, Europe and Australia (Halliburton, 2013). Explanatory animations of the hydraulic fracturing process have also been published (Chesapeake Energy Corporation, 2012; Schlumberger, 2013).

It is important to recognise that ground waters and surface waters can contain natural contaminants, such as metals and hydrocarbons. Therefore it is important to have a baseline survey to determine natural levels of contamination and also natural variability. Given the speed with which some developments occur in the petroleum industry, this is not always done. Romanak *et al.* (2012; 2013) has developed the concept of vadose zone characterisation for monitoring carbon dioxide where there is not an adequate baseline available. This involves:

> *'a one-time assessment of spatial chemical variability pre-injection, rather than repeated background measurements. In addition, we suggest that a monitoring approach not requiring prolonged background measurements is most efficient as a response tool targeted to specific events and areas of concern thereby simplifying vadose zone monitoring without sacrificing accuracy'* (Romanak, *et al.*, 2013).

It is unclear at this stage whether this approach can be extended to the type of monitoring likely to be needed for shale gas, but it warrants

consideration, as it is likely that at least initially, the absence of adequate chemical baselines may be an issue for regulators.

Water issues in shale gas extraction have been previously considered in this report. A large amount of water is needed initially for the development of shale gas. Water is used for drilling, where it is mixed with clays to form drilling mud. This mud is used to cool and lubricate the drill-bit, provide well-bore stability and also carry rock cuttings to the surface. Water is also used in significant volumes in hydraulic fracturing. In addition to water and sand, other chemicals are added to the fluid to improve hydraulic fracturing efficiency (see Chapter 4, Table 4.1). Millions of litres of fluid may be required to hydraulically fracture a well. A typical hydraulic fracturing fluid is more than 99% water and sand. The other part is made up of a number of additives, which may vary depending on the particular well and operator (EPA, 2011; Myers, 2012). Under most jurisdictions, there is now a need to provide full disclosure of the chemicals used in hydraulic fracturing fluids and there is obviously great merit in implementing full disclosure in Australia, in order that the community and the regulators can have confidence in the industry.

Groundwater can potentially be contaminated by a range of natural chemicals derived from deeper shale intervals, including BTEX (benzene, toluene, ethyl benzene and xylene) natural radioactivity and heavy metals. It is important to assess which of these might constitute the highest risk, given that the shales may be separated by hundreds of metres of rock from the aquifer. In its review of hydraulic fracturing the Royal Society concluded that hydraulic fracturing of deep shales is unlikely to result in contamination of shallow aquifers. (The Royal Society and the Royal Academy of Engineering, 2012). A greater risk may arise from leaking wells, which can be a source of serious contamination if remedial action is not taken. Therefore ensuring that best practice is implemented in well completions followed by careful monitoring of wells during and after production is important (Watson & Bachu, 2009). Groundwater extraction for use in hydraulic fracturing operations can impact on a fresh water

aquifer through drawdown of the water table. Sampling of deep aquifers can be expensive and difficult and analysis for some chemicals can be costly. An important question is: does the lack of detection of a chemical mean it is not present, or is it merely below the limit of detection? An effective monitoring regime for groundwater will be important to a shale gas industry and very important to the community, which will be looking to industry and particularly the regulators for reassurance that its water supply will not be contaminated or diminished.

Surface water contamination can result from accidental discharge, or from the handling of extracted subsurface brines, or from poor site procedures. Again it is important that monitoring, including baseline monitoring, is part of the regulatory process, but there is a need for a more reactive approach here too if an incident is reported, when very focused monitoring for an extended period of time may become necessary. It is important to monitor not only for potential contamination but also for the impact of any contamination on plant and animal communities. Protocols have been put in place in many jurisdictions (usually under the aegis of the EPA or equivalent) for doing this for a range of industrial and extractive activities. Far more problematic and perhaps more controversial, is monitoring of human impacts (Social Justice Initiative, 2013) (see Chapter 11). This is usually handled through OH&S procedures in the case of people working in the industry, but a primary aim of any monitoring program (and of regulations) is to ensure that there is early warning of a pollution incident, well before it is likely to jeopardise human health in any way. However it is unclear whether a program to monitor human health would serve to allay any concerns or whether it would unduly alarm people. This issue requires further consideration

Methane and Hydrocarbon Monitoring

Dissolved methane can be difficult to detect in aquifers although higher-order hydrocarbons that may accompany methane are more readily detectable and may provide an early warning of

potential problems. These are also more likely to be carcinogenic and are therefore important to monitor in their own right. Overall a monitoring programme for shale gas would be expected to be looking for relatively low concentrations of methane, but atmospheric monitoring will be important. The background concentration of methane in the atmosphere is low (approximately 2ppb) and measurements at the parts per billion level are not easy. However, there are many areas in Australia, including the Great Artesian Basin, that are naturally high in methane and it is important that these are documented prior to shale gas developments.

Leakage of methane as a fugitive emission during shale gas operations is a matter under very active discussion (Nikiforuk, 2013)(Chapter 10). The United States EPA has a long record of being concerned about the level of fugitive emissions from the gas industry (US Environmental Protection Agency, 2011). The rapid growth in shale gas production has prompted further concern and controversy.

A need for accurate monitoring of methane is likely to be incorporated into shale gas projects. Jenkins (2012, pers. comm.) reports that instruments are available now to measure real-time methane concentrations with sufficient accuracy and precision, at modest cost. More expensive instrumentation for measuring isotopes such as $^{13}CH_4$ can be used to give insight into the origin of the methane. The spatial density of sensors that would be required is a strong function of the level of leakage to atmosphere that one wishes to detect. Atmospheric monitoring at all wellheads (Humphries et al., 2012) may be impractically expensive if wells are numerous. Other options might include arrays of sensors that monitor whole gas fields (scales of km) to narrow down large leaks to particular areas. In general it is much easier to detect point sources than large, spatially diffuse sources.

For focusing on leaks on surface equipment (piping, tanks, etc.) several infrared cameras are available that use the strong infrared absorption lines of methane to create images of the

Baseline atmospheric greenhouse gas monitoring and measurement of fugitive methane emissions

An atmospheric greenhouse gas monitoring station ("Arcturus") began operation in the northern Bowen Basin in July 2010 near Emerald, Queensland. The station is part of a collaborative project between Geoscience Australia (GA) and CSIRO Marine and Atmospheric Research (CMAR) to establish and remotely operate a high precision atmospheric monitoring facility for measurement of baseline greenhouse gases. The primary purpose of the station was to field test newly developed greenhouse gas monitoring technology and demonstrate best practice for regional baseline atmospheric monitoring appropriate for geological storage of carbon dioxide. In addition to carbon dioxide, atmospheric methane concentrations are continuously measured at Arcturus and these measurements presently form the most complete atmospheric methane baseline dataset for inland Australia.

The methane record at Arcturus in combination with atmospheric models (e.g. TAPM) is being used to evaluate techniques for quantifying the major sources of methane emissions in the region. The Arcturus site and environs

Arcturus baseline atmospheric monitoring station and nearby coal mines and producing gas fields

Bowen Basin

Operating coal mine
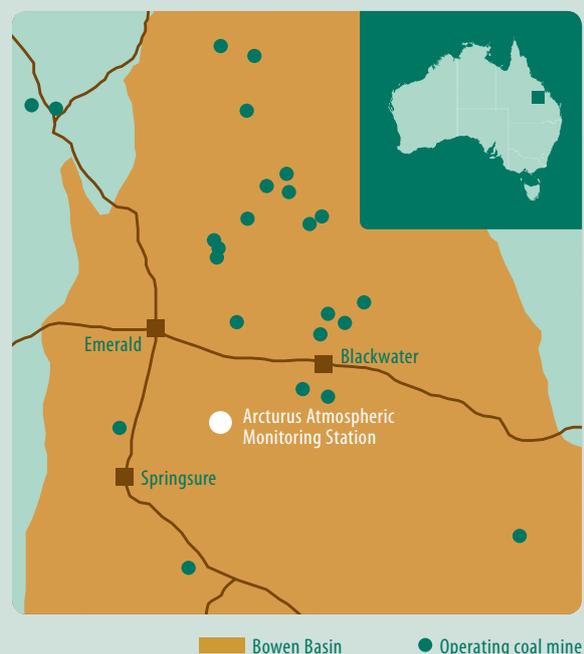
escaping plumes. The method is not quantitative but is valuable for locating leaks.

As pointed out by Jenkins and also Sandiford in their submissions to this Review, atmospheric monitoring is a well-established technique on scales from global to local, with a wide variety of compounds able to be routinely measured (Leuning, *et al.*, 2008; Loh, *et al.*, 2011). However, the interpretation of concentration measurements in the atmosphere requires detailed models of dispersion predicting the mixing and spreading out of a plume as it blows away from a source. It is possible to back-track to a source and quantify its position and magnitude, but this requires considerable expertise and computing power and would be difficult to undertake as part of a routine and cost effective monitoring program. For trace contaminants in the air such as BTEX, samples can be taken with automatic flask-sampling apparatus and measured off-line in the laboratory, but this is expensive and by no means a routine monitoring exercise in most field situations.

Induced Seismicity

Although there is ample evidence in Australia of induced seismic activity associated with large dams, mining operations and geothermal operations, there is no seismic risk data for gas-related activity in Australia, including hydraulic fracturing operations. Overseas evidence suggests that low-magnitude induced seismicity can be generated by the disposal of produced water from shale gas operations (Frolich, *et al.*, 2011; Zoback, 2012), where a significant produced water volume from a large number of wells is re-injected at high pressure into the deep subsurface at or near a critically-stressed fault (Baig, *et al.*, 2012; US NAS, 2012; Majer, *et al.*, 2007). Best practice mitigation involves better knowledge of fault structures close to disposal sites, and control of volume and pressure of produced water re-injection (Rutqvist, *et al.*, 2007).

Overseas evidence from extensive shale gas operations has documented just a few cases where the hydraulic fracturing process itself

are representative of the activities and ecology of Queensland's Central Highlands and the greenhouse gas signals are likely to be influenced by agriculture, coal and gas activities. Modelling suggests that fugitive methane emissions from coal mines in the region make a significant contribution to the methane signal detected at Arcturus. Current gas production in the region is small and simulated fugitive emissions from nearby producing fields appear to make a minor contribution to the signal at Arcturus.

Arcturus provides a template for future remotely operated atmospheric greenhouse gas baseline stations. If a similar atmospheric baseline station were located near a large producing gas field, it is anticipated that, should significant fugitive emissions from the field occur, these could be detected and quantified using the same modelling techniques. Arcturus (designated ARA) is a World Meteorological Organisation (WMO) regional Global Atmospheric Watch (GAW) station; Terrestrial Ecosystem Research Network (TERN) is a contributor.

Source: Geoscience Australia

Atmospheric methane measurements for Arcturus, Qld, North Bowen Basin
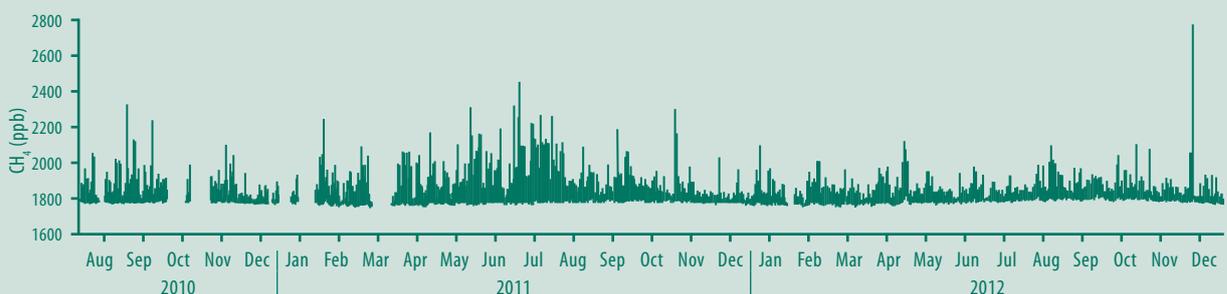
results in induced seismicity (de Pater & Baisch, 2011; Bachmann, *et al*., 2011). These events, which have been of low magnitude, have been linked to the intersection of active fault structures by hydraulic fractures (Lisle & Srivastava, 2004). Best practice mitigation involves the identification and characterisation of local fault structures, avoiding fracture stimulation in the vicinity of active faults, real-time monitoring and control of fracture growth through available sensing technologies and the establishment of 'cease-operation' triggers based on prescribed measured seismicity levels (DoE, 2012; Majer, *et al*., 2012).

As pointed out by Sandiford in his submission to this Review, the establishment of site, local and regional monitoring of seismicity at a greater resolution than is currently the case in Australia (including a database of fault structures and stress tectonics in prospective locations to better predict seismic risk), would be a valuable national asset in relation to further mitigating potential induced seismicity.

Shale Gas Well Abandonment Issues

There are existing monitoring and regulatory issues relating to abandoned wells that will apply to shale gas wells. However, because of the special factors:

1. their spatial density

2. production continues for many years

3. they involve hydraulic fracturing and,

4. in many areas they will penetrate deep aquifers

there may be a need for existing regulations to be modified and perhaps additional ones developed.

Abandonment of a well involves cementing and capping to ensure it is not a threat to water systems or likely to lead to gas emissions (Energy API, 2009; Schoenmakers, 2009). This issue is addressed in the United Kingdom report on hydraulic fracturing (The Royal Society and the Royal Academy of Engineering, 2012). It is noted that abandonment requirements and an abandonment plan are considered

in the original well design, and are subject to regulation. Whilst subsequent monitoring is currently not required, it is recommended in the UK report that on-going monitoring arrangements should be developed for both ground gas monitoring and aquifer sampling, every few years. Operators are responsible for wells once abandoned, with liability to remediate ineffective abandonment operations. The establishment of a common liability fund is discussed in the UK report to cover the situation where the operator can no longer be identified. In Alberta, the Provincial Government has established an 'Orphan Well' fund based on a well levy which can be used to remediate any wells where the operator has ceased to exist or cannot be traced. The (very) long-term integrity of a cemented and plugged abandoned well (beyond 50 years) is an area where more technical information would be useful. In all, the long-term issues, particularly those relating to abandoned wells need to be carefully considered within the existing regulatory framework, given the nature of a shale gas industry.

It should also be noted that the development of a shale gas industry in Australia will lead to an unprecedented opportunity to obtain reliable subsurface information on sedimentary basins that would be relevant not only to a shale gas industry but also to a range of other basin resources, most notably groundwater. It is very important that government works with industry to ensure that as part of the regulatory process, this new data source is fully captured and curated. There are various ways that this can be done. For example, some years ago the Federal Government operated a scheme under which it contributed to the extra cost of deepening a well or coring or extra logging over and above what the operator was required to do or would have normally done. This resulted in a massive inflow of new data to Geoscience Australia that is still an extremely valuable knowledge base for Australia's subsurface. A shale gas industry could result in the same knowledge legacy if the right measures are put in place. It is also important that the opportunity is taken to engage the research community in the use and interpretation of this new data source.

Conclusions

The evidence suggests that, provided appropriate monitoring programs are undertaken and a robust and transparent regulatory regime put in place (and enforced), there will be a low risk that shale gas production will result in contamination of aquifers, surface waters or the air, or that damaging induced seismicity will occur. In addition to being able to provide reassurance to the community that the risk is "low", it is also important the community has confidence that this is indeed the case. If, despite everything a problem occurs, the community needs to be confident that there is sufficient resilience in the system that operations will stop before a small problem becomes a major problem, and that remedial steps can and will be taken. It may be appropriate to consider application of a so-called 'play-based' approach to regulation and monitoring of shale gas, perhaps in addition to the current risk-based approach. Given that shale gas developments are likely to occur throughout a number of basins and are likely to cross state boundaries, it is also necessary for the state and federal governments to seek to harmonise regulations, for inconsistent regulations could result in ineffective management of shale gas developments and a loss of community support.

13 Knowledge needs

It is apparent from this Review that a great deal of information exists on matters relating to shale gas and to unconventional gas more generally. Much of the information relates to North America because of its position as a 'first mover' in shale gas, but there are significant geological, logistic, environmental and economic differences between Australia and the United States which call into question the extent to which we can always draw parallels, particularly if relevant information is not yet available in Australia. This matters greatly in terms of addressing the resilience of the natural system to change resulting from a shale gas industry.

There is no evidence of major technology gaps relating to shale gas production, that would constitute clear grounds for delaying the development of a shale gas industry in Australia. Conversely there are large areas of Australia where we have an inadequate understanding of surface and subsurface physical, chemical and biological processes. In order that the industry and the community can move forward, confident in the knowledge that adequate response systems are in place with regard to risk and risk mitigation, it is necessary to
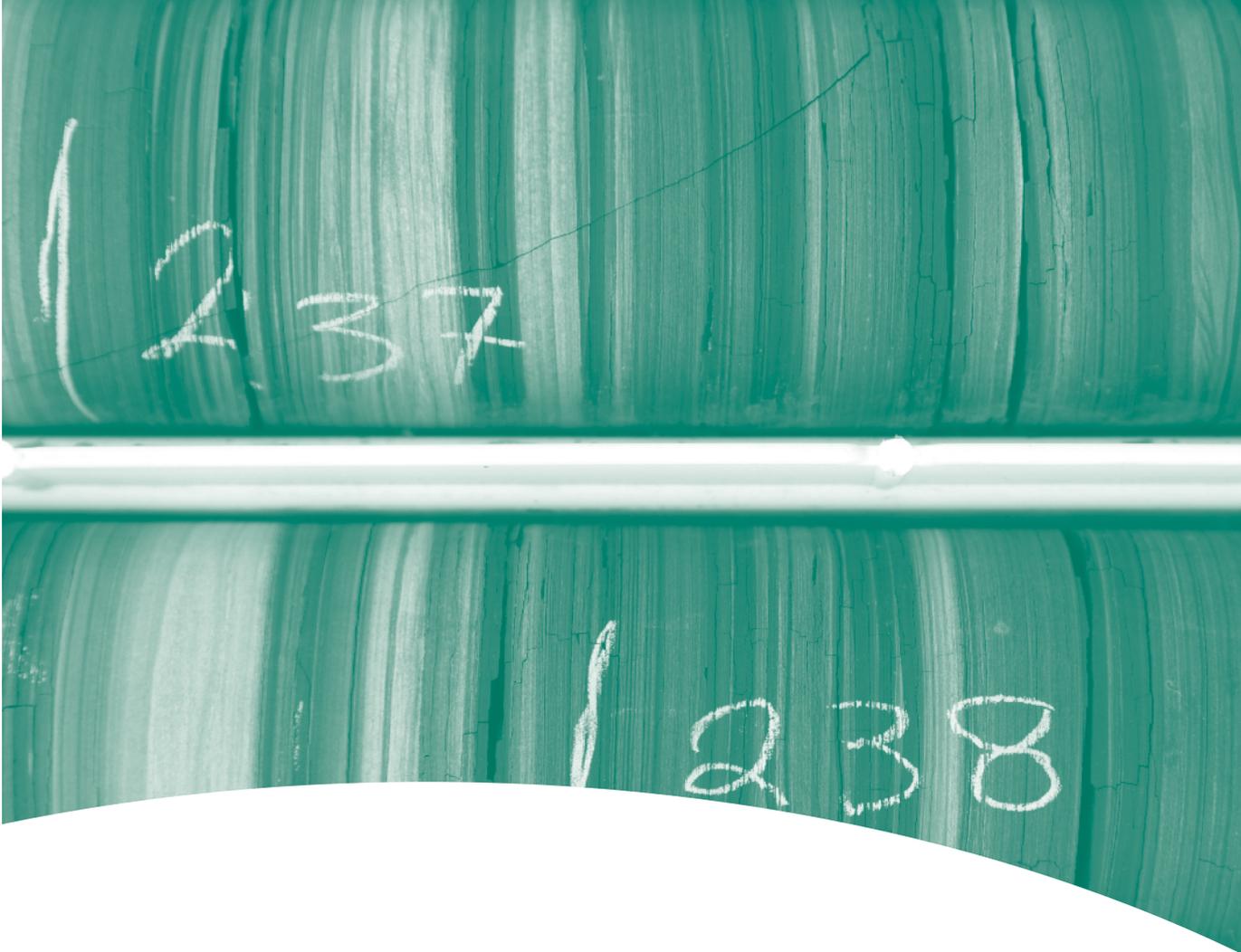
ensure that the environmental impact of the industry is readily recognisable, that it is at a level which is acceptable to the regulator and community and that any potential difficulty can be adequately remediated, or the activity stopped, if a significant threat were to arise. The establishment of baseline environmental measurements in key areas, and effective use of cumulative environmental risk assessment tools in advance of a major ramp-up beyond the exploratory phase, are important in this context.

What then are the knowledge and research needs to ensure this level of confidence amongst the regulators, the community and the industry? They relate to several needs. First is the need for baseline data against which to measure change. Second is the need for knowledge to be able to predict change before it happens. Third, using the data and the knowledge together is the need to be able to

effectively deal with a minor impact before it has significant consequence. Added to this is the need for the data used and the knowledge gained to be transparent and readily available.

Baseline studies

The need to be discerning about baseline measurements arises from the almost impossible task of acquiring data to cover the millions of square kilometres of land area in which shale gas exploration might arise. There will consequently be a need to prioritise areas for baseline data collection and in order to answer specific questions or address concerns that might arise. There is also a need to recognise that in some instances the data will only have been collected when exploration wells are drilled. For example there is very limited data available on most of Australia's deep aquifer systems; shale gas wells

will provide that information – provided the operator is required to collect that data and make it available, not only to the regulator, but also more widely. Baseline data will be required for groundwater, soils and surface water, for ecosystems and landscape changes, for methane emissions, for seismicity and for social issues. For many of these environmental issues snap shot baselines studies are inadequate and baseline will need to run for some years if we are to get a handle on the cumulative impact of shale gas on biodiversity at a landscape scale.

Groundwater

We lack data on many deep groundwater systems or an understanding of those systems, and therefore of the potential impact of shale gas exploration and production on those systems. We do not fully understand the chemistry of many groundwater systems, their behaviour, their dynamics, and in particular there are many areas where we have a poor understanding of the physical structure and geology of the basins. As a consequence, we are unable to develop satisfactory 3D models for managing the basins. It is likely that new data will become available through shale gas projects, which will greatly enhance our basin models, but government will need to take steps to ensure that the information is available to researchers and industry.

Whilst the amount of water used in shale gas operations is likely to be less than that of CSG operations it is important that creative strategies are developed for using, reusing and where necessary disposing of that water. Given the aridity of many of the areas where shale gas operations will occur, it is important to undertake research in order to develop innovative approaches to these issues.

Greenhouse gas management

While some data on GHG emissions from shale gas is available from overseas, the magnitude of GHG emissions is not known with accuracy and published results normally include wide bands to represent the uncertainty. The applicability of this data to Australia is not clear. There is a need to collect data on GHG emissions applicable to Australian conditions, to monitor those emissions both prior to production and during production and to develop strategies to mitigate the risks. Additionally, it is possible that some Australian shale gas will be relatively high in carbon dioxide; research into how the CO_2 might be cost effectively separated from shale gas and geologically sequestered would be relevant to Australian geological conditions.

Basin models

Much of Australia's wealth comes from our sedimentary basins – our food, our water and our mineral and energy resources, including unconventional gas. Basins are also used for disposal of fluids and can potentially be used for compressed air energy storage and other innovative opportunities. Exploitation of those resources is resulting in competition between the needs of the users of those resources and this competition will be exacerbated by shale gas developments. At present we lack adequate models for managing Australian basins in a sensible manner. Therefore a high priority for research and the acquisition of new knowledge, particularly but not exclusively for shale gas projects, is to develop better models that will enable us to manage our basins in a more sustainable manner and more fully understand the interactions between the subsurface and the surface and between the range of resource impacts. This will require the collection of more subsurface data and the close cooperation of Geoscience Australia, State agencies and research groups.

Understanding shale rocks

Despite the increasing importance of the fine grained rocks which host shale gas, they are not well known and are poorly understood. The chemical processes which occur within them, including the maturation of the organic material

within them and the gas adsorbtion processes which take place, are not well documented. Additionally whilst there is some evidence that it might be possible to preferentially produce liquid hydrocarbons from shale gas, perhaps by changing the production methods, this too is not understood and would benefit from more research. In all, there is a need to better understand shales so that exploration techniques and gas production methods can be improved.

Hydraulic Fracturing

Hydraulic fracturing has been underway in Australia for a number of years but overall our level of knowledge of this topic is far below that of the United States. Australian rocks have their own peculiarities and it will be necessary to develop new and improved approaches to hydraulic fracturing here in Australia. It is important to greatly improve our knowledge of the geomechanical and geotechnical properties of Australian sediments, including through the development of field research facilities and field research trials, where Australian researchers and industry together with international researchers, can develop appropriate technologies

Hydraulic fracturing and related activities require particular knowledge and experience, which for the most part is not readily available in Australia. This need can be met partly by bringing specialists to Australia, but steps are also needed to ensure that the requisite skills are developed here to enable the industry to move ahead. Additionally, in some basins there may be unique hydraulic fracturing issues relating to shale gas (and tight gas) production in Australia. For example, in the Cooper Basin, it is not possible to obtain useful microseismic information because the standard downhole tools are unable to withstand the very high subsurface temperatures (of the order of 200°C). Therefore, one of the most effective ways for monitoring hydraulic fracturing is not available in one of the most active shale gas areas. This technology need requires further research and development.

Emissions

Like all other natural gas activities, the extraction, production, processing, transport and distribution of shale gas results in greenhouse gas (GHG) emissions. As part of the extraction process for shale gas, GHG emissions may occur during hydraulic fracturing and well completion processes. While most of the available data on GHG emissions from shale gas is from overseas, the magnitude of these GHG emissions is not known with accuracy and published results normally include wide bands to represent the uncertainty. The applicability of this data to Australia is not clear. There is a need to collect data on GHG emission applicable to Australian conditions, to monitor those emissions both prior to production and during production and to have strategies promulgated to mitigate the risks.

Human health

There have been many claims made and concerns raised regarding the potential impact of shale gas operations on human health, but there is limited overseas data and very little data in Australia. The issue is not unique to shale gas, but it would seem wise to seek to obtain reliable epidemiological data at an early stage, in order to provide a firm base either to allay community concerns or to address issues before they become real concerns.

Well integrity

The Expert Working Group found it difficult to obtain information on long term well integrity and on the rate of well failure. It concluded that there is a need to study well integrity in Australia, in conjunction with industry, in order to confirm whether or not this is a major issue for the shale gas industry in the longer term. There is also a need to research the applicability of emerging techniques such as fibre optics to long term downhole monitoring of well integrity. Associated with this issue is that of abandoned wells, including both the issue of well remediation to avoid contamination of aquifers

and of orphan wells. This issue is not yet a major problem in Australia, but in time it is likely to become one. There is a need for Australian and international industry, governments and researchers, to jointly study the issue in order to establish a way forward.

Induced Seismicity

The topic of induced seismicity has been discussed at length in Chapter 9. Whilst the overseas evidence suggests it is unlikely to constitute a major hazard in Australia, it is nonetheless important to better understand the precise nature of the hazard – its risk and its potential impact. At the present time Geoscience Australia operates the national seismic grid. However this grid will need to be greatly enhanced if it is to address questions that may arise from shale gas operations. It is unrealistic to expect to have a high resolution seismic grid covering the entire continent and therefore it will be necessary to select key basins in which GA, or other groups such as AGOS in partnership with GA, would operate upgraded grids, with a view to be able to confidently recognise induced seismicity separately from natural seismicity.

Risk assessment

The petroleum industry has a deep knowledge of drilling and production operations, and the nature and frequency of accidents/hazards/events arising from those operations. The industry (and the regulators) are also well aware of the consequence of those events on operations; how to minimise their likelihood and how to remediate them. In other words, industry and regulators are able to confidently undertake a full risk assessment strategy for operational activities. However, at the present time, as evident from this report, while it is possible

to identify a range of potential environmental hazards that could give rise to adverse impacts on landscape biodiversity, groundwater, surface water or air or human health, for the most part we do not have the data and simplifications of logic in the current spatially predictive tools that make them robust, reliable and easy to use. New tools need to be developed very fast to deal with shale gas and other industries with similar types of distributed impact on the landscape function. We need these tools to determine the likelihood of those events occurring and ensure there are adequate mitigation strategies in place if they were to occur. Some of the knowledge gaps already identified will help us to identify mitigation strategies, with the aim of developing more resilient systems. There is a need to go beyond just identifying risks and start to acquire quantitative data on frequency and consequence of risks, with a view to developing a full risk management approach to environmental and related issues, for all shale gas projects. This will need the close cooperation of industry, government, scientists and the community.

Regulation

One of the important issues for effective regulation of shale gas is the limited experience that most regulatory bodies have in this area. The knowledge need in this instance relates to the level of knowledge of regulators regarding shale gas production. The Expert Working Group is of the view that governments, at the State level and especially in cooperation with industry, need to ensure that they have informed and trained regulators in the particular features of shale gas production and of unconventional gas generally. This will be especially important as new companies with limited experience start to produce shale gas.

Conclusions

As pointed out, there are no profound gaps in our technological knowledge relating to shale gas exploration and production that would constitute grounds for delaying the start of shale gas exploration and production. At the same time, there are gaps in our knowledge of the environment where shale gas developments are likely to occur and there will be great benefit in addressing a number of areas (such as cumulative environmental impact or improved production techniques) where the level of knowledge could be improved. Some of that improvement will come about through the activities of the shale gas industry itself and the new information that it will generate. Some of the responsibility will rest with organisations such as GA, CSIRO and relevant State authorities to compile and

disseminate that information. Some of it will need to be addressed by the research community working collaboratively across multi-disciplinary fields; recognising that many of the topics are relevant globally and that research should also be pursued in close cooperation with the international research community. Finally, and perhaps most importantly, it is essential to engage with the community in the collection of new information and the undertaking of new research and particularly so that they have the opportunity to articulate what knowledge they need. All of this will require adequate resourcing by industry and governments, both in terms of funding and access to data, appropriate governance and oversight arrangements for the research and data collection and close cooperation between industry, governments, researchers and the community.

Glossary of terms

2P reserves	Reserves that are 'proven and probable'.
absorption separation	The use of a liquid solvent to dissolve components of a gas stream and so remove them from the bulk gas. The dissolved components are then released again in a downstream stripping operation.
accelerometer	A measurement device for measuring local acceleration at high frequency.
ACOLA	Australian Council of Learned Academies: www.acola.org.au
acre	A unit of area: one acre equals 0.0015625 square miles, 4,840 square yards, 43,560 square feet, or about 4,047 square metres (0.405hectares).
activated alumina	A porous form of aluminium oxide that has a strong affinity for water. It is used to dehydrate the gas stream by adsorbing the water content.
Adsorption, adsorb	The process by which a substance (e.g. a gas) is incorporated into another substance through or on a surface. The opposite of desorption.
AER	Australian Energy Regulator.
alkane	Saturated hydrocarbons of the form $C_{2n}H_{2n+2}$ (e.g. ethane, C_2H_6).
amine absorption	The use of a solution of amines (such as monoethanolamine) to absorb acid gases such as carbon dioxide or hydrogen sulphide.
ammonium bisulphite	NH_4HSO_3.
ammonium persulphate	An oxidising agent: $(NH_4)_2S_2O_8$.
annulus	The space between two concentric cylinders or pipes.
Anticline, anticlinal	An upward folding subsurface geological feature.
aquifer	A subsurface water bearing geological strata which has high porosity and permeability that allows easy extraction of the water.
artesian	Water bores in which the water surface is above ground level and the water flows.
atm	Atmospheres, a measure of pressure. One atmosphere pressure equals 101,325 Pascals (Pa) or 14.2 psi (*q.v.*).
ATSE	Australian Academy of Technological Sciences and Engineering: www.atse.org.au
AWE	An Australian oil and gas exploration and production company.
AWT International	AWT is an independent well engineering consultancy providing services to the global upstream oil and gas industry.
b	Parameter in a hyperbolic well decline mathematical relationship.
barium, Ba	A heavy metal whose insoluble salts are employed to give a dense slurry in water (e.g. barium meal in X-ray medicine).
Barnett	Shale gas field in the SE United States.
barrel	Unit of volume common to the petroleum industry: 159 litres.
bcf	A billion or 1,000,000,000 cubic feet of gas at standard conditions. 1 bcf of natural gas is approximately 1.06 PJ of energy.
bcm	A billion (10^9) cubic metres of gas, at standard conditions.
biocide	A chemical added to water to kill biological organisms.
biogenic	Produced by living organisms or biological processes.
BOE	Barrel of oil equivalent.
BOP	Blow Out Preventer – equipment designed to prevent blowouts (q.v.) at the surface of the well.
borate salts	Chemical compounds that contain boron in the form of borate anions, BO_3^{3-}.
bore water	Water that has accumulated in aquifers, that is available for farming and irrigation by sinking a bore pipe into the aquifer.

BREE	Bureau of Resource and Energy Economics, part of the DRET Commonwealth of Australia Department.
bromine, Br	A chemical of the halide family, like chlorine Cl. Free bromine does not occur in nature, but occurs as colourless soluble crystalline mineral halide salts, analogous to table salt, NaCl.
Btu	Energy required to heat one pound of water by one degree Fahrenheit.
Butane	C_4H_{10}, often referred to as C4 because the molecule contains four carbon atoms. It boils at -1°C so is a gas under ambient conditions.
C	Centigrade, a measure of temperature (0C is water freezing, 100C is water boiling, at sea level).
C1, C2, C3 …….C12	Notation corresponding to the number of carbon atoms in a hydrocarbon molecule. C1 corresponds to methane, the main component of natural gas, whereas C12+ refers to the liquids commonly referred to as oil.
Ca, Ca^{2+}	Calcium, calcium ion.
capital costs	Expenditure on equipment that does not form part of the Profit and Loss statement, but rather is a component of a firm's cash flow and is depreciated against income.
Carbon dioxide, CO_2	An inert gas often found in association with natural gas and also produced from the combustion of any fossil fuel. The largest contributor to global warming.
Carbon Dioxide equivalent, CO_2e	The amount of CO_2 that would have the same global warming potential (GWP), when measured over a specified timescale (generally, 100 years).
casing, production casing, string casing	Steel pipes cemented into place lining the inside of a well bore. The casing string is the entire length of all the joints of casing run in a well. The production casing string separates the productive zones from other reservoir formations.
catalytic cracker	A chemical reactor that uses a catalyst. In the context of this report, it is used to convert ethane into ethylene, with some propylene and butadiene also produced.
CBL	Cement Bond Log.
CCGT	Combined Cycle Gas Turbine *(q.v.)*: An efficient gas turbine that recovers heat from the exhaust gases and generates steam to power a second turbine.
CCS	Carbon capture and storage: chemical capture and compression of CO_2, transport by pipeline to a suitable underground storage, and injection of the CO_2 into the subsurface rock strata.
citric acid	A weak organic acid with the formula $C_6H_8O_7$; found in lemons.
Cl_2	Chlorine.
Cl^-	Chloride ion.
Cleat	A minute (small) jointing in a subsurface geological formation.
CNG	Compressed natural gas, obtained by compressing natural gas above 200 atmospheres (20,000 kPa).
coal Rank	A term used to describe the amount of carbon in a specific coal. The higher the rank the higher the carbon content and the greater the metamorphic transformation of the coal over time.
coil tubing rigs	Drilling rigs that make use of metal tubing to form the well. The tubing is transported as a spool on a large reel.
completion	Installation of equipment to enable an efficient flow of natural gas from the well
compressive stress regime	Geological strata subject to compressive forces.
condensate	The petroleum fraction corresponding to molecules with between 5 carbon atoms (pentane) and 12 carbon atoms (dodecane).
Condensate separator	Mechanical separation of condensates from the gas phase.
corporate tax	Tax levied by Federal governments against a firm's net profit (net earnings).
cryogenic separation	Cooling of the gas stream to below -150°C. At these temperatures, some components become liquid and so can be readily separated from the remaining gases.

Crystal Ball	A plug-in module by Oracle Software for Microsoft Excel that enables probabilistic calculations to be performed: www.oracle.com/us/products/applications/crystalball/overview/index.html
cuttings	Cuttings, or drill cuttings, are formation rock chips removed from a borehole, that are usually carried to the surface by drilling fluid circulating up from the drill bit.
GAB	Great Artesian Basin.
Gas turbine	A type of rotating engine that burns natural gas and turns it into energy.
Giga-, G	A multiplier of 10^9 or 1,000,000,000.
CSG	Natural gas that is stored within coal seams, adsorbed onto the coal surface area.
CSG-LNG	Coal seam gas used for the production of Liquefied Natural Gas (LNG).
D	Debt: Total Liabilities on a firm's Balance Sheet.
D_i	Parameter in a hyperbolic well decline mathematical relationship.
Darcy	A measure of permeability of rock. Defined by Darcy's law.
decline rate	The rate of decline of a shale gas well after completion.
DEEWR	Commonwealth Department of Education Employment and Workplace Relations.
dehydrator	Equipment for water removal.
de-methaniser	Cryogenic distillation or absorption separation of methane from heavier gas components and lighter liquids.
desiccants	Solid adsorbents such as silica gel or activated alumina used to absorb water.
desorption, desorb	The process by which a substance is released from or through a surface. For CSG, the progressive giving up of gas from its attachment to the coal particle as pressure is released. The opposite of adsorption.
dimethyl formamide	an organic compound with the formula $(CH_3)_2NC(O)H$.
dip	The downward slope of a coal seam or other lithology from the horizontal.
dolomite	A common rock-forming carbonate mineral composed of calcium magnesium carbonate $CaMg(CO_3)_2$.
DRET	Commonwealth Department of Resources, Energy and Tourism.
DRI	Direct Reduced Iron: an iron product produced by oxygen removal from iron ore without melting using reducing gas (carbon monoxide and hydrogen).
drill rig	Equipment used to drill the hole.
drill string	Casing string *(q.v.)*
E	Shareholder Equity in a firm's Balance Sheet.
EBIT	Earnings Before Interest and Taxation.
EBITDA	Earnings Before Interest, Taxation and Depreciation and Amortisation.
EIA	United States Energy Information Agency.
EIR	Environmental Impact Report.
ethane	C_2H_6, often referred to as C2 because the molecule contains two carbon atoms. It boils at -89°C so is a gas under ambient conditions.
ethylene	C_2H_4, a chemical produced from ethane that is then used by the plastics industry to make many plastics, including polyethylene.
ethylene glycol	Organic compound: $HO–CH_2CH_2–OH$; toxic if ingested; anti-freeze; an odourless liquid that has a strong affinity for water.
exothermic	Producing heat.
extensional stress regime	Geological strata subject to extensional forces.
F	Fahrenheit, a measure of temperature (32F is water freezing, 212F is water boiling, at sea level).
fault	Geological description of a fracture in rock along which there has been a noticeable amount of displacement.
Fayetteville	Shale gas field in the SE United States.
FCF	Free Cash Flow: determined from after tax EBIT *(q.v.)*, plus depreciation, less capital expenditure.
fibre-optic	The medium and technology associated with the transmission of light impulses along a glass or plastic fibre or wire.
FIFO	Fly in, fly out, especially to remote mining or petroleum operations.
filtration (micro- , ultra-, nano-)	A process for the separation of larger particles or molecules from a solution. Microfiltration removes particles of greater than 0.1 to 10 micron, ultrafiltration removes particles or molecules of greater than around 10 nanometres or 10,000 molecular weight, while nanofiltration removes molecules of around 200 molecular weight.

fiscal regime	A government's fiscal policies in relation to taxation and expenditure.
flaring	Combustion of a proportion of flowback or other gases above the surface in a purpose-built elevated burner.
flowback	The flow of natural gas (and liquids) within several days after hydraulic fracturing.
fluvio-lacustrine	Pertaining to or produced by the action of both rivers (fluvio) and lakes (lacustrine).
foreland basin	A depression that is created adjacent to a mountain belt as it expands. The basin receives sediment that is eroded off the adjacent mountain belt.
formation	The fundamental unit of lithostratigraphy. Also expressed as geological formation. Formations allow geologists to correlate geologic strata over large distances.
formation water	Water that occurs naturally within the pores of a water-bearing rock formation. Oil and gas reservoirs have a natural layer of formation water that lies underneath the hydrocarbons.
fracking	The fracturing of rock with a liquid under high pressure to create artificial openings and cracks in the rock to increase the rock's permeability.
fractionator	A distillation column used to separate components of a gas or liquid stream.
fugitive emissions	Releases of gas (methane and carbon dioxide) to the atmosphere from the leakage or venting of that gas from the earth or a process.
GA	Geoscience Australia, part of DRET.
gamma logging	A method of measuring naturally occurring gamma radiation in order to characterise a rock or sediment in a borehole.
gel, cross-linked gel	A solid, jelly-like material usually derived from petroleum products (e.g. 'Vaseline').
geo-steering	The act of adjusting the borehole position in order to reach particular geological targets based on information obtained while drilling.
geomechanical modelling	Uses the mechanical properties (strength, elasticity, stress, etc.) and physical laws of motion to accurately model and predict 3D deformation of a rock formation during drilling.
geophone	A device that converts ground movement into voltage. This information is recorded over time and deviations from the expected voltage depict a seismic response.
glutaraldehyde	An organic compound with the formula $CH_2(CH_2CHO)_2$, used for disinfecting medical equipment.
gravitational separation	The use of gravity to separate a mixture of gas and liquid into two separate streams.
ground penetrating radar	A geophysical method to image the subsurface using high frequency (usually polarised) electromagnetic radiation pulses reflected off subsurface structures.
groundwater	All subsurface water as distinct from surface water. More specifically, the part of the subsurface water that is in the zone of saturation, including underground streams.
GST	Australian Goods and Services Tax.
GTL	Gas to liquids. A chemical reaction process that converts natural gas into heavier hydrocarbons that are liquids at room temperature and pressure and can be used as transport fuels.
guar gum	De-husked, ground guar beans.
H_2S	Hydrogen sulphide.
Haynesville	Shale gas field in the SE United States.
ha, hectare	A metric unit of area defined as 10,000 square metres.
heavy metals	Metals that are high on the periodic table (e.g. copper, lead, manganese).
Henry hub	Hub pricing of natural gas in the United States.
heterolithic	Alternating lithologies; for example, heterolithic bedding is a sedimentary structure made up of alternating beds or rock layers from deposited sand and mud.
HFS	Hydraulic Fracture Stimulation.
HHFCE	Household final consumption expenditure, an estimate of the impact on the standard of living.
High Wall	A description of the face of an advancing excavation in the earth's surface resulting from the mining of shallow coal or a similar mineral.
horizontal drilling	Drilling into the earth in an initially vertical direction, followed by a change in drilling direction to the horizontal at a suitable depth.
hub pricing	Pricing determined by supply and demand in a liquid market.
hydrocarbon	A chemical compound containing carbon and hydrogen.
hydrochloric acid, HCl	A strong acid.
hydroxyethyl	Hydroxyethyl guar gum is a water thickening agent.
hydrate	A chemistry term indicating that a substance contains water.

hydraulic fracturing	The fracturing of rock with a liquid under high pressure to create artificial openings and cracks in the rock to increase the rock's permeability.
IEA	International Energy Agency.
infrared sensing	An electronic sensor that measures infrared radiation from objects within its field of view.
ion	An atom or molecule in which the total number of electrons is not equal to the total number of protons, giving the atom a net positive or negative electrical charge.
IP, initial production	Initial gas production per day at well completion.
isopropanol, isopropyl alcohol	Chemical compound with the molecular formula C_3H_7OH. A type of alcohol (compared with beverage ethanol C_2H_5OH).
Joule	A unit of energy, equivalent to applying a force of one Newton through a distance of one metre.
K_E	Cost of Equity: effectively the return a firm needs to earn to repay the equity holders (shareholders) of a company.
kerogen	A mixture of organic compounds that comprise a portion of the organic matter in sedimentary rocks.
K_D	Cost of Debt: effectively the return a firm requires to repay debt.
km	Kilometre is a metric unit of length equal to 1000 m or 0.62 of a mile.
kPa	Kilopascals: a measure of pressure (1 atmosphere = 101.325 kPa)
KOP	Kick Off Point: Typically located 150m vertically above the shale target, the KOP defines the point at which the well curves from vertical to horizontal.
lateral	Indicating towards a sideways direction.
LCA	Life cycle analysis: analysis of emissions through the entire life of a unit of fuel.
lease	Payment to a landowner for the use of land.
limestone	A sedimentary rock consisting chiefly of the minerals calcite and aragonite, which are different crystal forms of calcium carbonate ($CaCO_3$).
lithology	The study of the general physical characteristics of rocks. Also used to describe the rocks in a particular subsurface zone.
litre, l	A metric unit of volume, equal to 1 cubic decimetre.
LNG	Liquefied Natural Gas – natural gas in the liquid state that has been cooled to -162°C.
LRD	Long Radius Drilling: drilling of a hole in the earth's surface in which the hole is gradually deviated along a curved radius.
m	Metre is a metric unit of length.
magnetic sensing	Sensors that can detect changes and alterations in a magnetic field.
Marcellus	Shale gas field in the NE United States.
mcm/d	Million cubic metres per day.
mD	milli Darcy (q.v.) – a measure of permeability.
Mega, M	A multiplier of 10^6, or 1 million, 1,000,000.
metamorphic	Geological transformation of materials involving heat and pressure under the earth.
methane	CH_4, often referred to as C1 because the molecule contains one carbon atom. It is the main component of all natural gas supplies, including shale gas.
micropore	Very fine pores with holes roughly 5-30 microns in diameter.
microseismic	A faint movement of the earth.
mineral oil	Light mixtures of alkanes in the C15 to C40 range from a non-vegetable (mineral) source, particularly a distillate of petroleum.
mineral scale	Deposits that form on pipes and equipment in contact with waters containing metallic compounds (e.g. oxides, carbonates, sulphates).
MIT	Massachusetts Institute of Technology.
MMbls	Million barrels.
MMBtu	One million British Thermal Units, Btu (A British measure of energy common in the petroleum industry). 1 Btu=1,055 Joule; 1MMBtu = 1.055 GJ.
M_L	Measure of earthquake intensity on a logarithmic scale; the Local Magnitude scale; approximately equal to the Richter scale.
MMscf	One million standard cubic feet (A British measure of volume common in the petroleum industry).
molecular sieves.	Solid Adsorbent beds used for removal of gas impurities and in particular water.
MPa	Megapascal, measure of pressure equivalent to 1,000,000 Pascals.
Mscf	One thousand standard cubic feet.

Mscf/d	One thousand standard cubic feet per day.
mud	In the sequential well drilling process, water-based fluid (water plus additives termed "mud") is used to cool the drill bit, carry rock cuttings back to the surface, and maintain the stability of the well bore.
Na, Na^+	Sodium, sodium ion.
neutron logging	A method using the natural radioactivity of strata to create a detailed record of the geological formations in a wellhole.
NG	Natural gas – predominately methane, CH_4.
NGL, Natural Gas Liquids	Natural Gas Liquids – Hydrocarbons that are heavier than methane. In most contexts, this is the fraction from C2 (ethane) through to C12 (condensate).
Nitrogen, N_2	An inert gas. The atmosphere contains 78 vol% nitrogen.
NORM	Naturally Occurring Radioactive Materials.
NPAT	Net Profit After Tax.
OBM	Oil Based Mud (q.v.).
OECD	Organisation for Economic Cooperation and Development.
oil or C12+	The petroleum fraction corresponding to molecules with greater than 12 carbon atoms.
oil shale	Shallow shale containing oil. Mined by conventional methods and retorted at high temperature at the surface to distil the contained oil, or by in situ treatment with steam. Should not be confused with "shale oil", which is oil contained in the natural gas extracted from deep shales.
operating costs	Costs associated with a company's operations that are deducted against revenue to determine profit.
orthogonal	Intersecting or lying at right angles.
p_{50}	Probability defined by the 50th percentile on the probability distribution.
pad	A temporary drilling site, usually constructed of local materials.
pay zone	The reservoir rock in which oil and gas are found in exploitable quantities.
Pascal, Pa	A measure of pressure: one Newton force per square metre.
permeability	The ability, or measurement of a rock's ability, to transmit fluids, typically measured in darcies or millidarcies.
PJ	Peta Joule: 1 PJ equals 10^{15} Joules of energy.
PJpa	Peta Joules per annum.
play	A petroleum business investment involving extraction of resources from the earth.
play-based	The particular geological concept used as a basis for exploring for oil.
polyacrylamide	A polymer ($-CH_2CHCONH_2-$) formed from acrylamide subunits.
pore	Small void space within a rock.
porosity	The interconnection of pores within a rock; also a measure of the flowability of a fluid within a rock that contains pores.
potassium	A metallic element.
potassium carbonate	K_2CO_3 is a deliquescent (water absorbing) white salt.
potassium chloride, KCl	a salt similar to common salt, sodium chloride.
potentiometric surface	A surface of a liquid within a rock where the pressure on that surface is equal at all points.
ppm	Parts per million (10,000 ppm = 1%).
probabilistic	An analysis that involves probability distributions of the variables.
produced waters	Subsurface water produced from the gas well during production.
propane	C_3H_8, often referred to as C3 because the molecule contains three carbon atoms. It boils at -42°C so is a gas under ambient conditions.
proppant	Material (usually sand-sized) used to provide permeability and volume within the fractures caused by hydraulic fracturing (e.g. sand grains or fine silica beads).
propylene	C_3H_6, a chemical produced from ethane or propane that is then used by the plastics industry to make many plastics, including polypropylene.
PRRT	Australian Petroleum Resources Rent Tax.
psi	Per square inch, a measure of pressure.
q	Parameter in a hyperbolic well decline mathematical relationship: well gas flow.
quartz	Naturally occurring form of silica (q.v.).

q.v.	*Quod vide*: Latin for "which see".
radioactivity	Spontaneous disintegration or decay of the nucleus of an atom by emission of particles.
radium	Radioactive metallic chemical element.
radon	Gaseous radioactive chemical element.
reservoir	Rock strata that contains liquid or gas within its porosity; not a large void space or cavern under the earth.
reverse osmosis	A process for the separation of salt from a solution. The pores within the reverse osmosis membrane are large enough to allow water through, but stop the transmission of most salts.
RFF	Resources For the Future.
RGP	"Required Gas Price": The gas price required in a financial calculation to just earn the firm's cost of capital, representing a marginal investment if achieved.
riparian	Referring to riverine systems .
riverine	Pertaining to rivers.
%Ro	Unit for vitrinite reflectance. The percentage of reflected light from a sample immersed in oil.
royalty	A payment to a State government taken for a firm's revenue stream.
S	Sulphur.
saline	Containing salt or salts.
sand, sands	Subsurface sandstone.
sandstone	A sedimentary rock composed mainly of sand-sized minerals or rock grains.
SBM	Synthetic Based Mud (*q.v.*).
sedimentary basin	Region of the earth of long-term subsidence creating accommodation space for infilling by sediments.
sedimentary sequence	The sequential deposition of different sands and muds over time now forming the rock lithologies.
seismicity	Movement of the earth; the occurrence or frequency of earthquakes.
seismic measurement, 3D seismic	Imaging of the earth's subsurface structures and geology using acoustic methods.
severance tax	State-based tax in the United States levied against a firm's revenue.
shale	A rock structure beneath the earth's surface formed from mud deposited by riverine, lake or marine systems over geological timescales.
shale oil	The oil associated with a shale gas deposit.
silica	An oxide of silicon, SiO_2; naturally occurring as quartz.
SIMP	Social Impact Management Plan.
silica gel	A porous form of silicon dioxide (silica sand) that has a strong affinity for water. It is used to dehydrate the gas stream by adsorbing the water content.
slickwater	Hydraulic fracturing water whose properties (e.g. surface tension) have been modified through the use of additives.
SLO	Social Licence to Operate.
SO_4^{2-}	Sulphate ion.
sodium	A metallic element.
sodium carbonate	Na_2CO_3 is a sodium salt of carbonic acid; washing soda
sodium chloride	Common salt.
SPE	United States Society of Petroleum Engineers.
strata	Layers of sedimentary rock.
stress regime	Description of the relative magnitude of horizontal and vertical tectonic stress components acting on sedimentary layers.
strontium, Sr	A reactive metal that naturally occurs as the carbonate or sulphate.
sub-artesian	Water bores in which the water surface is below ground level.
sweetening	Removal of acid gases (H_2S, CO_2) from natural gas or other fluid.

SWIS	South West Integrated System: electricity distribution system in Western Australia.
tax	Tax rate used to determine WACC and FCF *(q.v.)*.
tcf	Trillions (10^{12}) of cubic feet, at standard conditions.
tcm	Trillions (10^{12}) of cubic metres, at standard conditions.
tectonic	Pertaining to the structure or movement of the earth's crust.
thermogenic	Tending to produce.
thorium	A naturally occurring radioactive chemical element.
tight gas	Natural gas trapped in low permeability (0.001-0.1 milli-Darcy) and low porosity reservoir sandstones and limestones.
tight sand	Sandstone of low permeability, possibly containing natural gas.
tiltmeter	An instrument designed to measure very small changes from the horizontal level.
TOC	Total organic content.
toe-up	'Horizontal' wells can be flat (900 to the vertical), toe-up (end or toe of the lateral higher than the heel), or toe-down.
toe-down	'Horizontal' wells can be flat (900 to the vertical), toe-down (end or toe of the lateral lower than the heel), or toe-up.
ton	907 kg (2,000 pounds) – short ton.
tonne	1000kg (2205 pounds) – metric tonne.
TRD	Tight Radius Drilling: drilling a hole beneath the earth with a small radius during the transition from vertical to horizontal.
uranium	A radioactive metallic element.
US EPA, EPA	United States Environmental Protection Agency
US DoE	United States Department of Energy.
USGS	United States Geological Survey.
vitrinite	Vitrinite is a type of maceral, where "macerals" are organic components of coal or shale analogous to the "minerals" of rocks.
viscosifier	Ensures water based mud has sufficient velocity to transport rock cuttings to the surface in well drilling.
Visual Basic	A programming component of Microsoft Excel: http://msdn. microsoft.com/en-us/vstudio/hh388573.aspx
Vro	Vitrinite reflectance – a measurement of reflectivity which is used as a proxy for determining thermal history of organic matter – from kerogen to coal.
viz.	Adverb meaning "namely".
WACC	Weighted Average Cost of Capital: determined from the company's Debt and Equity, its leverage, and the Cost of Debt and the Cost of Equity. After tax WACC is calculated by taxing the Debt component to account for the tax deductibility of interest payments.
WBM	Water Based Mud (*q.v.*)
weighting agent	Finely ground solid material with a high specific gravity used to increase the density of a drilling mud.
wellbore	The drilled hole or borehole, including the openhole or uncased portion of the well.
wellhead	The equipment at the surface above the well.
well stimulation	A treatment performed to restore or enhance the productivity of a well.
Wet gas	Natural gas containing hydrocarbon liquids.
wireline	An electrical cable to lower tools into a borehole and transmit data.
Woodford	Shale gas field in the SE United States.
Workover	A re-stimulation of an existing well to encourage greater gas flows.
wt.%	Weight percent solution; equal to the weight of a solute/ weight of the total solution after mixing.
Young's modulus	A measure of the stiffness of an elastic material.

Scientific and Engineering Units and Conversions

Decimal numbering system

Multiple	Scientific exponent	Scientific Prefix	Abbreviation
Millionth	10^{-6}	micro	μ
Thousandth	10^{-3}	milli	m
Thousand	10^{3}	kilo	k
Million	10^{6}	Mega	M
Billion	10^{9}	Giga	G
Trillion	10^{12}	Tera	T
Quadrillion	10^{15}	Peta	P

Energy Measurement

Energy resource	Measure	Abbreviation
Oil and condensate	Production, reserves: Litres (usually millions or billions) or barrels (usually thousands or millions)	L, ML, GL bbl, kbbl, MMbbl
	Refinery throughput/capacity: Litres (usually thousands or millions) or barrels per day (usually thousands or millions)	ML, GL per day, GL/day bd, kbd, MMbd,
Natural gas	Cubic feet, (usually billions or trillions)	bcf, tcf
	Or cubic metres (usually millions or billions of cubic metres)	m^{3}, mcm, bcm
LNG	Tonnes (usually millions)	t, Mt
	Production rate: Million tonnes per year, tonnes per day	Mtpa, tpd
LPG	Litres (usually megalitres) or barrels (usually thousands or millions)	l, kl, Ml, or L, kL, ML
	Production rate: megalitres per year, barrels per day	bbl, MMbl
Coal	Tonnes (usually millions or billions)	t, Mt, Gt
	Production rate: tonnes per year (usually kilotonnes or million tonnes per year)	tpa, ktpa, Mtpa
Electricity	Power Capacity: watts, kilowatts, megawatts, gigawatts, terawatts Energy Production or use: watt-hours, kilowatt-hours, megawatt-hours, gigawatt-hours, terawatt-hours	W, kW, MW, GW, TW Wh, kWh, MWh, GWh, TWh

Fuel-specific to standard unit conversion factors

Oil and condensate	1 barrel	=	158.987 litres
	1 gigalitre (GL)	=	6.2898 million barrels
	1 tonne (t)	=	1250 litres (indigenous)/ 1160 litres (imported)
Ethanol	1 tonne	=	1266 litres
Methanol	1 tonne	=	1263 litres
LPG, Average	1 tonne	=	1760-1960 litres
LPG, Naturally occurring	1 tonne	=	1866 litres
Natural gas	1 cubic metre (m^{3})	=	35.315 cubic feet (cf)
Liquefied natural gas	1 tonne	=	2174 litres
Electricity	1 kilowatt-hour (kWh)	=	3.6 megajoules (MJ)

Energy content conversion factors

	PJ/bcf	MJ/m³
Natural gas (average)	1.1000 (54 GJ/t)	38.8
Ethane (average)	1.6282	57.5

Crude oil and condensate	PJ/mmbbl	By volume MJ/L	By weight GJ/t
Indigenous (average)	5.88	37.0	46.3
Imports (average)	6.15	38.7	44.9
LPG			
Propane	4.05	25.5	49.6
Butane	4.47	28.1	49.1
Mixture	4.09	25.7	49.6
Naturally occurring (average)	4.21	26.5	49.4
Other			
Liquefied natural gas	3.97	25.0	54.4
Naphtha	4.99	31.4	48.1
Ethanol	3.72	23.4	29.6
Methanol	2.48	15.6	19.7

Standard conversions

Length			
1 kilometre	=	0.6214	miles
1 mile	=	1.6093	kilometres
1 metre	=	3.2808	feet
1 foot	=	0.3048	metres
1 cm	=	0.3937	inches
1 inch	=	2.5400	centimetres

Area			
1 acre	=	0.405	hectare, ha
1 hectare, ha	=	2.47	acre
1 square mile, mi²	=	2.589	square km, km²
1 square km., km²	=	0.386	square mile, mi²

Volume			
1 cubic metre	=	35.3147	cubic feet
	=	1000	litres
1 cubic foot	=	0.0283	cubic metres
1 thousand standard cubic metres (k scm)	=	0.0353	MMscf
1 thousand standard cubic feet (Mscf, kscf)	=	28.32	scm
1 litre	=	0.001	cubic metres
1 gallon	=	3.7854	litres
1 kilolitre	=	6.2898	U.S. barrels (petroleum)
1 U.S. barrel (bbl)	=	0.1590	kilolitres

Mass			
1 metric tonne	=	1.1023	short tons
1 short ton	=	0.9072	metric tonnes
1 kilogram	=	2.2046	pounds
1 pound	=	0.4536	kilograms

Pressure			
1 kiloPascal	=	0.1450	pounds / square inch
1 psi	=	6.8947	kilopascals
1 megaPascal (MPa)	=	9.8692	atmospheres
1 atm	=	0.1013	megaPascals, MPa

Energy			
1 kilojoule	=	0.9485	British thermal units
	=	1.0000	Kilowatt second
1 British thermal unit (Btu)	=	1.0543	kilojoules, kJ
1 thousand British thermal units (MBtu)	=	1.0543	megajoules, MJ
1 million British thermal units (MMBtu)	=	1.0543	gigajoules, GJ

Temperature			
Temperature in °C	=	$T_C = 5/9 \ (T_F - 32)$	
Temperature in °F	=	$T_F = 9/5 \ (T_C) + 32$	

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Expert Working Group

Professor Peter Cook CBE, FTSE (Chair)

Professor Peter Cook of the University of Melbourne, is a geologist, academic and Consultant. Until 2011, Professor Cook was the foundation Chief Executive of the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC): previously he was Director of the British Geological Survey (1990- 1998) and Division Chief/Associate Director of the Bureau of Mineral Resources (1982-1990). Professor Cook has held academic positions in the UK, Australia, France and the USA, and has received many awards and honours for his work. He is the author or co-author of more than 160 reports and publications. He was a Coordinating Lead Author for the IPCC Special Volume on CO_2 Capture and Storage; his book "Clean Energy Climate and Carbon" was published March, 2012.

Dr Vaughan Beck FTSE (Deputy Chair)

Dr Beck is the Senior Technical Advisor to the Australian Academy of Technological Sciences and Engineering (ATSE). He was until recently the Executive Director -Technical (ATSE) responsible for the Academy's research projects and the development of policy advice to government in areas such as climate change, energy, water, built environment, innovation, technology and education. Currently Dr Beck is Chair of the Working Group on Low Carbon Energy, International Council of Academies of Engineering and Technological Sciences (CAETS). Dr Beck has a diploma and a degree in mechanical engineering, a master degree in structural engineering and a PhD in fire safety and risk engineering.

Professor David Brereton

Professor Brereton is Deputy Director – Research Integration, Sustainable Minerals Institute (SMI), University of Queensland, a role he has held since late 2011. Previously, as foundation Director of Centre for Social Responsibility in Mining, University of Queensland since late 2001, David oversaw its growth into a world leading centre of research expertise on the social challenges facing the mining and minerals sector. David has over 25 years experience in applied research and teaching and has worked in senior research roles in both the university and government sectors, focusing on the use of applied social science to improve organisational practice and policy.

Professor Robert Clark AO, FAA, FRSN

Professor Clark was most recently appointed Professor and Chair of Energy Strategy and Policy at the University of New South Wales where his role focuses on evaluating the potential for unconventional gas to play a role in Australia's reduced-carbon-footprint energy mix, including responsible strategies and policy with regard to environmental impact. Professor Clark was formerly the Chief Defence Scientist (CDS) of Australia and Chief Executive Officer of the Defence Science and Technology Organisation (DSTO). As CDS he was a member of Australia's Defence Committee, served as the Australian Principal of the 5-nation Defence Technical Cooperation Program (US, UK, Australia, NZ, Canada) and was a member of the PMSEIC.

Dr Brian Fisher AO, PSM, FASSA

Dr Brian Fisher, AO, PSM is Managing Director, BAEconomics Pty Ltd. Prior to this he was Chief Executive Office, Concept Economics Pty Ltd and before joining Concept Economics, Vice-President at CRA International. Before joining CRA International he was Executive Director of the Australian Bureau of Agricultural and Resource Economics (ABARE) where he specialised in public policy analysis. Between 1996 and 2001 Dr Fisher was involved as a senior consultant with Australia's international climate negotiating team. He was a convening lead author for the Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report, a lead author on the IPCC Third Assessment Report and a convening lead author for the Fourth Assessment Report. Prior to his appointment at ABARE he was Professor of Agricultural Economics, University of Sydney.

Professor Sandra Kentish

Professor Kentish is Head of the Department of Chemical and Biomolecular Engineering at The University of Melbourne. She is also an invited Professor at the Centre for Water, Earth and the Environment within the Institut National de la Recherche Scientifique (INRS) in Canada. Professor Kentish has broad interests in industrial separations, particularly the use of membrane technology for energy and water applications. Before commencing an academic career, Professor Kentish spent nine years in industry, with positions in Exxon Chemicals, Kodak Australasia and Kimberly Clark Australia.

Mr John Toomey FTSE

Mr Toomey has wide professional experience spanning many decades in the planning and execution of major Development and Infrastructure Projects both in Australia and overseas, including mines, industrial complexes, rail and port facilities, and water storage and conservation works. He also has had deep involvement in the direction and management of major research and development projects in mining engineering, minerals processing and geological exploration and hydrology. He has been involved with the CRC program since its inception and is a past President of AMIRA. He was formerly Manager Research and Director Special Research Program BHP Coal, Development Manager Thiess Dampier Mitsui Coal and General Manager Nabalco Engineering.

Dr John Williams FTSE

Dr Williams recently retired after nearly six years as Commissioner of the NSW Natural Resources Commission (NRC). He was former Chief Scientist, NSW Department of Natural Resources following his retirement from CSIRO as Chief of Land and Water in 2004. In 2005, he was awarded the prestigious Farrer Memorial Medal for achievement and excellence in agricultural science. John is currently Adjunct Professor in Public Policy and Environmental Management at the Crawford School of the Australian National University and Adjunct Professor, Agriculture and Natural Resource Management, Institute Water, Land and Society, Charles Sturt University. Dr Williams is a founding member of the Wentworth Group of Concerned Scientists.

All EWG members have declared any relevant interests.

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Professor John Burgess, FTSE, was appointed as one of several consultants to the Expert Working Group (for details see entry under Evidence Gathering, Consultancy Reports) and in addition assisted the Expert Working Group in the compilation of the overall report. This important contribution is gratefully acknowledged with thanks.

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Evidence gathering

Meetings were held across Australia and two Workshops were held in Canberra during the Review. A large number of people contributed their time and knowledge to the Review through written submissions, through meeting with the EWG or though participating in workshops including the following:

The views expressed in the report do not necessarily reflect the views of the people and organisations listed in the following sections.

1 Consultation Sessions

The Expert Working Group is grateful for the opportunity to consult with the following organisations, where multiple people have been engaged:

- Australian Petroleum Production and Exploration Association (APPEA)
- Bureau of Resources and Energy Economics (BREE)
- Committee for Economic Development of Australia (CEDA)
- Council of Canadian Academies
- CSIRO
- Department of Industry, Innovation, Climate Change, Science, Research and Tertiary Education (formerly Department of Climate Change and Energy Efficiency – DCCEE)
- Department of Resources, Energy and Tourism (DRET)
- Department of Sustainability, Environment, Water, Population and Communities, (SEWPaC) Office of Water Science
- Dow Chemicals
- Esso
- National Farmers' Federation
- NSW Government Department of Trade and Investment, Regional Infrastructure and Services: Resources and Energy Division

- Office of the NSW Chief Scientist & Engineer
- Santos
- Schlumberger
- South Australian Department for Manufacturing, Innovation, Trade, Resources and Energy (DMITRE)
- The Royal Academy of Engineering
- The Royal Society
- Western Australian Department of Mines and Petroleum (DMP)

The Expert Working Group is grateful for the opportunity to consult with the following individuals:

Dr Chris Armstrong, *Office of the NSW Chief Scientist & Engineer*

Mr Craig Arnold, *Dow Chemicals*

Ms Peta Ashworth, *CSIRO*

Professor Robin Batterham AO FREng FAA FTSE, *The University of Melbourne*

Dr Tom Bernecker, *Geoscience Australia*

Mr Richard Borozdin, *Western Australian DMP*

Professor Kathleen Bowmer, *CSU Institute Land Water and Society & CSIRO Land and Water*

Professor Andrew Brennan, *La Trobe University*

Mr David Byers, *APPEA*

Mr Ian Cronshaw, *International Energy Agency*

Mr Colin Cruickshank, *Santos*

Mr John Dashwood, *Esso*

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Dr Jamie Pittock, *Australia and United States Climate, Energy and Water, US Studies Centre; The Australian National University*

Dr Trevor Powell FTSE   , *STIR Science Services*

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Professor Sheik Rahman, *The University of New South Wales*

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Dr Alan Walker, *The Royal Academy of Engineering*

Mr Adam Walters, *Greenpeace*

Ms Alexandra Wickham, *DMITRE*

Mr Rick Wilkinson, *APPEA*

Ms Larissa Wood, *APPEA*

Dr John Wright FTSE, *Wright Energy Consulting*

2 Written Submissions

As part of the evidence gathering for the Review, a call for input was sent to Fellows of all four Learned Academies, and identified key stakeholders. The Expert Working Group is very grateful for receiving written submissions from:

Call for input

- Emeritus Professor Peter Flood, University of New England
- Dr Trevor Powell FTSE, STIR SCIENCE SERVICES
- Professor Mike Sandiford and Associate Professor Tim Rawling, The University of Melbourne
- Dr John Wright FTSE, Wright Energy Consulting
- Australian Petroleum Production and Exploration Association (APPEA)
- Beach Energy
- Committee for Economic Development of Australia (CEDA)
- CSIRO
- Department of Industry, Innovation, Climate Change, Science, Research and Tertiary Education (formerly DCCEE)
- Department of Resources, Energy and Tourism
- Esso Australia Pty Ltd
- Geoscience Australia
- National Farmers' Federation
- South Australia Department for Manufacturing, Innovation, Trade, Resources and Energy (DMITRE)
- Western Australian Department of Mines and Petroleum

Background Papers for December Workshop

As part of the December 2012 workshop, workshop participants were asked if they would be willing to provide a background paper. The Expert Working Group is grateful to have received written input from:

- Dr Dennis Cook
- Dr Neil Sherwood, CSIRO
- Ms Peta Ashworth, CSIRO
- Dr Charles Jenkins, CSIRO & CO2CRC
- Department of Resources, Energy and Tourism
- Geoscience Australia
- Western Australian Department of Mines and Petroleum

3 Consultancy Reports

The following consultancies were commissioned by ACOLA Secretariat Ltd for the Review.

AWT International

Title: "Shale Gas Prospectivity Potential"
Prepared by: AWT International
Date: January 2013

Niche Tasks

Title: Interim Report on Shale Gas Financial Modelling
Prepared by: Professor John Burgess FTSE
Date: November 2012

Title: Second Interim Report on Shale Gas Modelling
Prepared by: Professor John Burgess FTSE
Date: December 2012

Centre for Social Research in Energy and Resources (CSRER)

Title: Social Licence and Communications Report
Prepared by: Dr Declan Kuch, Dr Gary Ellem, Dr Mark Bahnisch, Professor Stephen Webb
Date: January 2013

Dr Dennis Cooke

Title: A brief Review of GeoScience Issues associated with Shale Gas development in Australia
Prepared by: Dr Dennis Cooke
Date: January 2013

Eco Logical Australia

Title: Shale Gas Developments in Australia: Potential impacts and risks to ecological systems
Prepared by: Dr Julian Wall, Mark Vile, Katrina Cousins
Date: January 2013

FROGTECH

Title: Geological Risks of Shale Gas in Australia
Prepared by: FROGTECH
Date: January 2013

Sinclair Knight Merz (SKM)

Title: Unconventional Gas in Australia – Infrastructure needs
Prepared by: Dr Richard Lewis
Date: January 2013

Review Panel

This report has been reviewed by an independent panel of experts. Members of the Review Panel were not asked to endorse the Report's conclusions and recommendations. The Review Panel members acted in a personal, not organisational, capacity and were asked to declare any conflicts of interest. ACOLA gratefully acknowledges their contribution.

Professor Hugh Possingham FAA

Professor Possingham is Director of the ARC Centre of Excellence for Environmental Decisions (CEED) & the National Environmental Research Program Environmental Decision Hub (NERP Decisions). He holds a variety of additional roles including The Wentworth Group of Concerned Scientists (founding member), Chief Editor of Conservation Letters (an international scientific journal), Council of the Australian Academy of Science (recently stepped down), and several Environmental NGO scientific advisory committees. The Possingham lab developed the most widely used conservation planning software in the world, Marxan, which was used to underpin the rezoning of the Great Barrier Reef and is currently used in over 100 countries by over 3000 users to build the world's marine and terrestrial landscape plans. Professor Possingham has co-authored over 450 refereed publications and book chapters and holds two Eureka prizes.

Professor Lesley Head FASSA FAHA

Professor Head is an ARC Australian Laureate Fellow and Director of the Australian Centre for Cultural Environmental Research (AUSCCER) at the University of Wollongong. She is a geographer who has been President of the Institute of Australian Geographers and chaired the Geography committee of the Australian Academy of Science. Most recently, she has worked mostly in cultural geography, with projects on backyard gardens, wheat and invasive plants, which developed from an earlier interest in Aboriginal land use, ethnobotany and fire. Professor Head began her career using palaeoecology and archaeology to study long term changes in the Australian landscape, and the interactions of prehistoric peoples with their environments. Today she is building on this multidisciplinary background at AUSCCER, which is applying cultural research methods to the pressing issues of sustainability and climate change

Professor John Loughhead FREng FTSE OBE

Professor Loughhead is Executive Director, United Kingdom's Energy Research Centre (UKERC). Before joining UKERC, John was Corporate Vice-President of Technology and Intellectual Property at Alstom's head office in Paris. A mechanical engineer by training, Professor Loughhead's professional career has been predominantly in industrial research and development for the electronics and electrical power industries, including advanced, high power industrial gas turbines, new energy conversion systems, spacecraft thermal management, electrical and materials development for electricity generation and transmission equipment, and electronic control systems. He is the UK member of the European Energy Research Alliance, a member of the European Advisory Group on Energy, and Advisor to the European Commission Directorate-General Research, Assessor for the Technology Strategy Board, Non-Executive Director of the Ministry of Defence Research & Development Board, and a member of the UK's Energy Research Partnership.

Appendix 1
Unconventional hydrocarbon resources in Australian sedimentary basins: an overview

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Introduction

The unprecedented growth in unconventional hydrocarbon exploration during the first part of the 21st century has transformed the upstream petroleum industry in Australia. This period has seen the growth of the fledgling coal seam gas (CSG) industry into a major supplier of the eastern energy market, and the exploration boom in shale and tight gas has elevated Australia's international profile as a destination for unconventional hydrocarbon exploration. The first successful flow from a shale gas well in the Cooper Basin in 2011 has been followed by the first shale gas production from the basin in 2012, and a series of discoveries in other sedimentary basins across Australia. Although much of the industry activity so far has been in basins with proven potential for conventional hydrocarbons and/or coal, unconventional hydrocarbon exploration is increasingly targeting frontier basins. The pace of exploration and development is expected to accelerate with the commencement of CSG-based LNG exports from facilities currently under construction in Queensland.

The key drivers for this growth have been: the rising domestic and Asia-Pacific regional energy demands; recent advances in extraction technologies, such as multi-stage hydraulic fracturing and pad drilling, and; the success of the shale gas industry in North America. Unlike conventional oil and gas, unconventional hydrocarbon resources do not rely on buoyancy-driven processes, or structural and stratigraphic trapping mechanisms, such that the resources are commonly distributed over a large area of a given basin (Law and Curtis, 2002). Moreover, unconventional hydrocarbon reservoirs (which, in the case of CSG, shale gas and shale oil, are the same as the source rock) have low permeabilities that effectively prevent the mobilisation of trapped hydrocarbons. These characteristics necessitate extractive methods that are intensive in technological, capital and energy inputs, such as hydraulic fracturing and horizontal drilling (McCabe, 1998; Geoscience Australia and BREE, 2012). As a result, unconventional hydrocarbon resources have largely been uneconomic until recent times.

Unconventional hydrocarbons in Australia

Unconventional hydrocarbon resources of current exploration interest in Australia are CSG, shale gas and oil, and tight gas and oil.

CSG consists primarily of methane generated within coal seams. CSG is derived thermogenically, i.e. through thermal maturation of coal usually resulting from burial within the basin, or biogenically, i.e. through microbial activity resulting from the introduction of meteoric water into coal seams at comparatively shallow depths. It is not uncommon for a thermogenic CSG accumulation to be subsequently supplemented by secondary biogenic generation, e.g. in the Sydney and Bowen-Surat basins (Faiz and Hendry, 2006; Draper and Boreham, 2006). Gas is held in both sorbed and free states within micropores and cleats (natural fractures). Gas production generally requires an initial stage of dewatering to lower the hydrostatic pressure within the coal seams and allow gas desorption. Hydraulic fracturing may be used to enhance the gas flow in some (but not all) cases. CSG exploration so far has generally targeted coal seams located at depths less than 1000 m, however, deeper seams are now being explored, e.g. in the Bowen and Cooper basins.

Most currently identified CSG resources in Australia are located in the eastern sedimentary basins (Figure 1), hosted within the Lower to Upper Permian and Jurassic coal measures of dominantly fluvio-lacustrine origin. Seams within the Permian coal measures of the Bowen, Galilee, Sydney, Gunnedah, Gloucester and Cooper basins (Figure 1) generally have good lateral continuity and thickness, having been deposited under cold climatic conditions. The Jurassic Walloon Coal Measures of the Surat and Clarence-Moreton basins (Figure 1), by contrast, were deposited under a warm, humid climate, and the individual seams are consequently thinner and laterally discontinuous. These geological differences have implications for the methods required to extract CSG in these basins. Moreover, due to the higher rank, the Permian coals have a higher gas content than their Jurassic counterparts. However, in CSG production, the younger Jurassic coals often achieve a higher gas (and water) flow due to their greater porosity and permeability.

Additional CSG potential may be offered by the Triassic (e.g. Nymboida and Ipswich basins underlying the Clarence-Moreton Basin) and Cretaceous (e.g. Maryborough and Eromanga basins) coals of eastern Australia, and the mostly sub-bituminous Permian to Cretaceous coals of central and western Australia (e.g. Perth, Canning and Arckaringa basins). However, many of these basins are unlikely to have the level of prospectivity that the Permian and Jurassic basins have, due to the lower coal rank or laterally discontinuous or restricted distribution coal seams. In addition, the potential for biogenic gas generation implies that the Cretaceous to Cenozoic brown coal basins, some of which cover large areas (e.g. the Murray Basin), are prospective for CSG. Some of these basins have attracted intermittent exploration interest, most recently in the Gippsland Basin.

Shale gas and oil are hydrocarbons generated and trapped within organic-rich, fine-grained rocks including shale, siltstone, fine-grained sandstone, limestone or dolomite. As with CSG, shale gas may be thermogenic or biogenic in origin. The term "oil shale" generally refers to organic and fine-grained, oil-prone source rocks that are thermally immature for hydrocarbon generation and, thus, are distinct from shale oil. On the other hand, tight gas and oil, unlike shale gas, shale oil or CSG, are conventionally generated and migrated hydrocarbons. They are, however, hosted in very low permeability sandstone or carbonate reservoirs with less than 10% porosity and less than 0.1 millidarcy (mD) permeability (Holdich, 2006). Accumulations may be laterally continuous as with CSG, shale gas and shale oil, or they may be trapped conventionally in structures and stratigraphic plays. The production of shale and tight gas/oil relies on hydraulic fracturing to initiate flow.

Shale and tight gas potential is distributed across a number of Australian basins (Figures 2 and 3). Some of these plays are also associated with a significant oil potential. The age of target formations varies widely from the Proterozoic

(e.g. Beetaloo and McArthur basins; Figure 2), Cambro-Ordovician (e.g. Amadeus and Georgina basins), Permian (e.g. Arckaringa and Perth basins) to the Cretaceous (e.g. Eromanga Basin). Target formations in eastern Australian basins are commonly of Permian (e.g. Cooper and Bowen basins) or Jurassic–Cretaceous (e.g. Gippsland and Otway basins) age. This contrasts with many of the producing shale gas basins of North America, which are predominantly Devonian, Carboniferous and Cretaceous, and the dominantly Silurian shale gas basins of eastern Europe.

Moreover, many productive North American shales are marine in origin and dominated by type I and II kerogen (hydrocarbon-generating organic compounds), whereas the Australian shale and tight gas plays encompass a wider range of depositional environments and organic matter types. In Australia, some of the most promising exploration targets are dominantly non-marine formations containing type II and/or III kerogen. The dominance of type III kerogen in some formations implies that they are gas prone (as opposed to oil prone). Examples include the Permian fluvio-lacustrine Roseneath-Epsilon-Murteree succession and the Patchawarra and Toolachee formations (Gidgealpa Group) of the Cooper Basin, and the fluvio-lacustrine to shallow marine Permian to Jurassic successions in the Perth Basin, both of which comprise thick, heterolithic successions containing a mixture of shale, tight and deep CSG target zones. However, other Australian shale and tight gas plays are of marine origin and have been identified as being oil prone, e.g. the Cambrian Arthur Creek Formation of the Georgina Basin and the Cretaceous Toolebuc Formation of the Eromanga Basin.

Another important difference between many Australian and North American shale plays lies in their previous and current tectonic settings. Many Australian shale and tight gas basins originated as extensional and sag basins, while many North American shale plays originated in a compressive foreland basin setting. Currently, many Australian basins are under a compressive crustal stress regime, whereas the stress regime acting on North American basins is more variable. These tectonic differences are likely to have implications

for formation pressures and fracture networks within the target formations and, therefore, in the success of extractive operations such as hydraulic fracturing.

Finally, although some of the known successful North American shale gas plays (e.g. the Devonian Antrim Shale) are biogenically sourced, the degree of biogenic contribution to Australian shale gas resources remains unknown.

Resource potential and assessment

Australia's total unconventional hydrocarbon resource endowment is poorly constrained. Currently available national resource estimates have very large associated uncertainties and, in the case of shale and tight gas, are only based on a partial assessment of selected basins.

According to previous studies, the total in-place CSG resources in Australia may exceed 250,000 PJ or 227 tcf (Table 1; Baker and Slater, 2009; Underschultz et al., 2011). Total 2P reserves are over 35,905 PJ or 33 tcf (Table 1), of which 33,001 PJ or 30 tcf are in Queensland's Bowen and Surat basins (Geological Survey of Queensland, 2012) and the remainder in the Sydney-Gunnedah, Gloucester, Clarence-Moreton basins in New South Wales (AGL Energy, 2011; Eastern Star Gas, 2011; Metgasco, 2012; Figure 1). CSG reserves and production in Queensland have increased substantially since 2006, and a strong growth is expected to continue into the foreseeable future, given the comparatively high level of exploration success, and the growing eastern Australian and export markets.

In 2011, the United States Department of Energy, Energy Information Administration (US EIA), completed a shale gas resource assessment of the Perth, Canning, Cooper and Maryborough basins (Figure 2). The report concluded that these four basins collectively contained in excess of 435,600 PJ or 396 tcf of technically recoverable shale gas (Table 1; US EIA, 2011). Although shale gas production has commenced in the Cooper Basin, there are no production or reserve statistics currently available. Moreover, there are no current

national resource estimates for shale oil (not including oil shales) in Australia.

Previous tight gas resource estimates indicate an in-place resource of 11,400 PJ or 10 tcf in the Perth Basin (Campbell, 2009), 8,800 PJ or 8 tcf in the Cooper Basin (Campbell, 2009; Beach Energy, 2011b), and 2,200 PJ or 2 tcf in the Gippsland Basin (Campbell, 2009; Lakes Oil, 2010; Figure 3). As such, Australia has at least 22,000 PJ or 20 tcf of tight gas resource in place (Table 1; Geoscience Australia and BREE, 2012), although this is obviously a gross underestimation given the potential in a number of other basins. There are no national resource estimates available for tight oil in Australia.

Many currently employed resource assessment methods are based on a deterministic approach, whereby the resource estimate heavily relies on the volumetric calculation of the target formation, in combination with its compositional and geochemical properties. A bulk recovery factor is often applied to the entire identified target formation in an attempt to exclude the technically unrecoverable proportion of the resource. Several scenarios (typically in terms of the 'best', 'mean' and 'worst') may be run to broadly reflect uncertainties in the input parameters used in the assessment. However, this approach has some major shortcomings. First, the assessments do not consider recoverability of the resource in terms of the likely productivity at the well, i.e. how much of the total resource volume can technically be tapped by individual production wells and for how long. Typically, production at a given unconventional hydrocarbon well declines rapidly from an initial peak (in the case of CSG, following the preliminary dewatering) to a protracted period of slowly declining production (Figure 4). Second, the full range of uncertainties surrounding the resource estimates may not be reflected by the 'best' and 'worst' scenarios, if the uncertainties surrounding individual input parameters are not statistically captured during the calculations.

A clear illustration of the problems associated with the deterministic methodology was provided by the significant recent downgrading of shale gas resource estimates in the United States and

Poland. In 2011, the United States Geological Survey (USGS) published a revised mean estimate of 84 tcf of undiscovered technically recoverable gas in the Marcellus Shale (Appalachian Basin), using a productivity-based, probabilistic method (Coleman *et al.,* 2011). The previous estimate for the same formation, using a deterministic method, was 262 tcf of technically recoverable gas (US DOE, 2009). In Poland, the previous national resource estimate of 187 tcf of technically recoverable shale gas by the US EIA (2011) was revised in 2012 by the Polish Geological Institute using the USGS probabilistic method. The new assessment concluded that the ultimately recoverable resource is most likely to be in the range 12 to 27 tcf, with an absolute maximum of 68 tcf (Polish Geological Institute, 2012).

Geoscience Australia, in collaboration with its counterparts in the States and Northern Territory, has commenced an assessment of Australia's unconventional hydrocarbon resource potential. In consultation with the USGS, a nationally consistent assessment methodology is being developed to derive unconventional hydrocarbon resource estimates of Australia's prospective onshore basins that conform to an internationally accepted standard. In this approach, the technically recoverable resource estimates are constrained by probability-based, well productivity models (Figure 4), derived from existing production data. In frontier areas with no production history, as in the case of Australian shale and tight gas/oil plays, models based on the productivity characteristics of other potentially comparable areas (e.g. North America) are applied. Uncertainties regarding the geologic input data are also captured by the assessment methodology, such that the final resource estimates are expressed as a range of values and associated probabilities. This methodology avoids the overestimation of resource volumes that may potentially arise from deterministic methods.

The Geoscience Australia assessments aim to provide industry, government, research and public stakeholders with a realistic insight into Australia's unconventional hydrocarbon resource potential. Resource assessments will be supplemented by analyses of source rock, oil and gas samples collected during exploration

drilling (via industry collaborative agreements), which will contribute to a developing scientific knowledge base of Australian unconventional hydrocarbon resources.

Issues and challenges

Due to the short history of exploration and production, geologic uncertainty poses a large risk to unconventional hydrocarbon exploration in Australia. Despite recent advances in geological understanding and technology, the success factors in unconventional hydrocarbon exploration and production remain difficult to ascertain. The key geologic controls on the location of exploration sweetspots are poorly understood. Geological differences imply that the degree of guidance that the North American experience could provide in Australian unconventional hydrocarbon exploration and resource assessment may be limited. For example, techniques applied to predict the location of shale targets in North American marine basins may not be successful in Australian non-marine basins. Moreover, the significance of differences in the stress regime, composition and stratigraphy of target formations on gas flows and fracture stimulation behaviour remain largely unknown at this stage. The production characteristics of wells remain difficult to predict with certainty, especially in terms of the effects of secondary reservoir stimulation (e.g. hydraulic fracturing) on the well lifespan. This poses a major hurdle to unconventional hydrocarbon resource assessment in both producing and frontier areas.

A major current obstacle to unconventional hydrocarbon exploration in Australia is the limited access to specialised drilling technology, such as that required for fracture stimulation (PESA, 2011). There will also be a need for additional pipeline infrastructure to improve the capacity and connectivity of the existing network, as well as to extend the network into prospective frontier areas. As a consequence of

established conventional hydrocarbon and/or CSG production, the eastern and southwestern regions of Australia are served by a comparatively dense network of production and pipeline infrastructure. The future commercialisation of unconventional hydrocarbon resources in Australia, therefore, is likely to initially focus on basins in these regions (e.g. the Cooper and Perth basins), and the more remote, frontier basins may remain undeveloped for some time. However, the commencement of LNG export from Queensland scheduled in 2014 will expose the eastern gas markets to international pricing, providing an additional economic impetus for the exploration and development of frontier basins. Moreover, further development of LNG export facilities in Darwin will also open up export opportunities for shale and tight gas from some central and northern Australian basins, some of which do not have a ready domestic market at this stage.

The rapid growth of the CSG industry in eastern Australia over the last three years has resulted in debate on the potential impacts on groundwater resources and surface waters arising from: dewatering and hydraulic fracturing of coal seams; the use of chemical additives during fracture stimulation, and; the disposal of production water. Scientific uncertainties over the long-term effects of CSG extraction on water resources and regional biodiversity are being addressed through Australian Government research overseen by an Independent Expert Scientific Committee. Such research will be important for informing the future development of the shale and tight gas/oil industry in Australia. Some Australian basins that may be prospective for shale and tight gas/oil overlap the distribution of potentially significant groundwater resources in arid areas (Figure 5, compare with Figures 2 and 3). A national assessment, which defines the location, extent and volumes of unconventional hydrocarbon resources, is essentially to inform government, public, industry and other key stakeholders in the development of a successful industry in Australia.

Table 1: Estimated gas resources in Australia

Resource Category	Conventional Gas		Coal Seam Gas		Tight Gas		Shale Gas		Total Gas	
	PJ	tcf	PJ	tcf	PJ	tcf	PJ	tcf	PJ	tcf
Economic Demonstrated Resources	113400	103	35905	33	-	-	-	-	149305	136
Subeconomic Demonstrated Resources	59600	54	65529	60	-	-	2200	2	127329	116
Inferred resources	~11000	~10	122020	111	22052	20	-	-	155072	141
All identified resources	184000	167	223454	203	22052	20	2200	2	431706	392
Potential in ground resource	unknown	unknown	258888	235	unknown	unknown	435600	396	694488	631
Resources – identified, potential and undiscovered	184000	167	258888	235	22052	20	435600	396	900540	819

Source: Geoscience Australia and BREE (2012). Conventional gas demonstrated resources as of January 2011; CSG demonstrated resources as of January 2012. Note CSG 2P reserves and 2C resources are used as proxies for Economic Demonstrated Resources and Subeconomic Demonstrated Resources respectively.

Figure 1: Major sedimentary basins with CSG potential in Australia. Note that the shading indicates the entire extent of the basins and does not delineate actual CSG plays within the basin

Figure 2: Major sedimentary basins with shale gas/oil potential in Australia. Note that the shading indicates the entire extent of the basins and does not delineate actual shale gas/oil plays within the basin

Figure 3: Major sedimentary basins with tight gas/oil potential in Australia. Note that the shading indicates the entire extent of the basins and does not delineate actual tight gas/oil plays within the basin

Figure 4. A typical gas production curve (upper) and the probability distribution of estimated ultimate gas recovery (lower) based on actual North American shale gas plays, after Gautier (2012). Each curve in the lower plot is derived from the aggregation of estimated ultimate recovery values for all wells within a given shale gas play. The USGS assessment method uses productivity models based on such production data to estimate the technically recoverable resource volumes

Figure 5. Distribution of palaeovalleys in central and western Australia after Bell et al. (2012). The palaeovalleys are infilled with dominantly Cenozoic sediments that may host significant groundwater resources in the arid to semi-arid regions of Australia

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Appendix 2
Greenhouse Gas Emissions: Further Details on Emissions Data

This Appendix provides further detail on the analysis and assumptions of the different literature sources on the emissions of greenhouse gases from the extraction of shale gas. References and terms are detailed in the References and Glossary of Terms sections of the main report.

Well completion emissions

The discrepancies between O'Sullivan & Paltsev (2012) and Howarth *et al.* (2011) for the amount of methane generated during well completion are substantial (see Table A.2.1 below).

The results listed in the table below for O'Sullivan and Paltsev are applicable to the mean values for each of the shale gas fields investigated. In the case of Howarth *et al.,* the results are stated to be the average results from various sources. However, O'Sullivan and Paltsev note that the result quoted by Howarth *et al.* is for a particular Haynesville well and that *"the performance of*

the particular Haynesville well in question is not representative of a typical Haynesville well".

The results of Hultman *et al.* (2011) are based on data published by the US Environmental Protection Agency (EPA, 2010). Hultman *et al.* note that there is a high level of uncertainty associated with the EPA results. Further, the results of Hultman *et al.* for methane generated are the lowest compared to the data given by the other two referenced sources in Table A.2.1. Hultman *et al.* also assume that the emissions during workovers (a re-completion operation that is assumed to occur approximately once every 10 years) are the same as for initial well completion.

It is important to understand the reasons for the differences between O'Sullivan & Paltsev (2012) and Howarth *et al.* (2011) for the amount of methane generated during well completion. Howarth *et al.* quote references in support of their figures for methane emitted during flow back and it is possible to deduce an implied model for flow back methane emission as follows:

Table A.2.1: Estimates of methane generated and GHG emissions per well during well completion*

Methane generated (tonne CH_4)	% Captured	% Flared	% Vented	Net GHG Emissions (tonne CO_2e)	Reference
228** 147 – 635***	70%	15%	15%	1,250 877 – 3,782	O'Sullivan and Paltsev, 2012
228 147 – 635			100%	3,669 – 15,816	O'Sullivan and Paltsev, 2012
138	0%	15%	85%	3,030	Hultman *et al.,* 2011
250 – 4,620****	0%	0%	100%	6,290 – 115,600	Howarth *et al.,* 2011

*A global warming potential of 25 for methane has been assumed.

**Average for five shale gas formations analysed (O'Sullivan and Paltsev, 2012).

***The low value corresponds to the Barnett field and the high figure represents the Haynesville field.

****Two shale gas fields are reported; the low value corresponds to the Barnett field and the high figure represents the Haynesville field.

FLOWBACK [Howarth] $\sim= IP \times \{N$, number of days of Flowback$\}$

where: IP = Initial gas production per day at well completion

N= 9 days for Barnett and 10 days for Haynesville

O'Sullivan & Paltsev adopted a linear-increasing model to estimate the amount of flow back during well completion; namely:

FLOWBACK [O'Sullivan] $= IP \times \{N$, number of days of Flowback$\} \times 0.5$

where: N = 9 days

As can be seen from these relationships, the Howarth *et al.* value is approximately twice the O'Sullivan and Paltsev value for the methane emitted for the same initial gas production.

In addition to basic differences in the above models adopted by both authors, there are differences in the data adopted for IP, the initial gas production at well completion, as shown in Table A.2.2.

As noted previously, the results of O'Sullivan and Paltsev are the mean values for each of the shale gas formations, whereas these authors state that the results for Howarth *et al.* are for an unrepresentative Haynesville well. Accordingly, the differences both in the models and the data for IP account for a substantial part of the discrepancies given in Table A.2.1 for the amount of methane emitted.

Howarth *et al.* (2011) assumed that all of the methane produced during flowback is vented, whereas O'Sullivan & Paltsev (2012) assumed that based on USA "current field practice" that nominally there is 70% capture, 15% venting and 15% flaring. Further, assuming efficiencies for these processes, O'Sullivan and Paltsev adopted the following figures: capture 63%, flaring 14.7% and venting 22.3%.

Using estimates for the life-time production of the well, Table A.2.3 shows methane emissions as a proportion of lifetime production of the wells.

Separately, Jiang *et al.* (2011) provided estimates of the emissions associated with the preproduction of shale gas that are applicable for the Marcellus gas formation. The preproduction estimates are based on the assumptions that during well completion the methane released is flared with a combustion efficiency of 98% and that there is a single hydraulic fracturing emission event (with its associated flaring and venting emissions). Jiang *et al.* also noted that the data is subject to considerable uncertainty and thus provided estimates for the mean and standard deviation for the various components of preproduction for the Marcellus field. These estimates are detailed in Table A.2.4 below. Jiang *et al.* used a GWP of 25 for methane to predict these results.

Table A.2.2: Initial Gas Production (IP) estimates at completion

Author	IP, Initial methane Production at well completion (x 10^3 m^3 /day)	
	Barnett Formation	Haynesville Formation
O'Sullivan & Paltsev (2012)	61	262
Howarth *et al.* (2011)	37	640

Table A.2.3: Methane returned during flowback, as a percentage of life-time production

Author	Barnett	Haynesville	Average
Howarth *et al.* (2011) 100% venting	1.1%	3.2%	1.6%[*]
O'Sullivan& Paltsev (2012) Methane generated (equivalent to 100% venting)	0.52%	0.99%	
O'Sullivan& Paltsev USA "Current field practice"	0.13%	0.24%	

*The average is for two shale (Barnett and Haynesville) and three tight sand formations. A minimum of 0.6% is calculated for the Uinta tight sand formation.

Table A.2.4: Preproduction Emissions for the Marcellus Shale Gas Formation – estimates of probability parameters for CO_2e emissions

Life Cycle Stage	Mean (g CO_2e/MJ)	Standard Deviation (g CO_2e/MJ)
Well Pad Preparation	0.13	0.1
Drilling	0.21	0.1
Hydraulic fracturing	0.35	0.1
Completion	1.15	1.8
Total	1.84	1.8

Source: Jiang *et al.,* 2011

Table A.2.5 Fugitive Methane Emissions During Production, Processing, Transport and Distribution (expressed as a percentage of methane produced over the lifecycle of a well)

Stage	Lifecycle Amount
Routine venting and equipment leaks at well site	0.3 to 1.9%
Emissions during liquid unloading	0 to 0.26%
Emissions during gas processing	0 to 0.19%
Emissions during transport, storage and distribution	1.4 to 3.6%
Total	1.7 to 6.0%

Source: Howarth *et al.,* 2011

From Table A.2.4, it is noted that Jiang *et al.* predicted a value of 1.84 g CO2e/MJ for total preproduction emissions. It appears that Jiang *et al.* used "completion" to refer to the methane emissions associated with flowback that are associated with hydraulic fracturing. From results presented by Jiang *et al.,* the range of emissions associated with "completion" is approximately 0.1 to 4.5 g CO2e/MJ. This range is larger than the range quoted for the "current field practice" by O'Sullivan & Paltsev (2012); this is to be expected because the results of the later authors are based on the mean results for various shale gas formations.

Water resource management is a critical component of shale gas extraction. Jiang *et al.* took into consideration those emissions associated with drilling water and hydraulic fracturing water use resulting from water taken from surface water resources or a local public water system, truck transport to the well pad, and then from the pad to disposal via deep well injection. It was assumed that no GHG emissions are related with producing water if it comes from surface water resources.

Production, Processing, Transmission and Distribution

Based on data for conventional gas wells, Howarth *et al.* (2011) quoted estimates for the quantity of methane released during production and processing shown in Table A.2.5.

Greenhouse Gas Emissions from Electricity Generation

In order to calculate the CO_2e emissions in future scenarios where shale gas might be used in Australia to generate electrical power, the following methodology has been used:

1. The emissions of CO_2e from the current Australian fossil fuel generating fleet were calculated as a weighted average from the emissions and production information provided by a report by Deloitte (2011).

2. The present CO_2e emissions from the Australian generating fleet were calculated from the emissions data in 1. above, plus the fugitive and other methane and CO_2e emissions reported by Hardisty *et al.* (2012) for coal and conventional

gas fired power. Emission data for the renewable technologies, although small, were also taken from the data of Hardisty *et al* and used to calculate their emissions. The following generation mix was assumed for the current base case in terms of energy generated:

Black Coal	48%
Brown Coal	21%
Gas (10% OCGT + 90% CCGT)	21%
Renewables	10%

3. SCENARIO 1: The power generating fleet in 2030 was estimated for a growth rate in electricity supply of 1.5% per year, with the technology mix given in the Commonwealth Government Energy White Paper (DRET, 2012). This leads to the following technologies for power supply in 2030 (no brown coal, and the energy generation for black coal the same as today):

Black Coal	31%
Gas (OCGT 50% + CCGT 50%)*	27% (all shale gas)
Renewables	42%

*Since a greater amount of energy is being generated by intermittent renewables under these two scenarios, the ratio of OCGT to CCGT was assumed to be 50% each.

4. SCENARIO 2: It was assumed for a second scenario that all coal-based generation disappears by 2030 and the electricity generation for Australia is dominated by gas and renewables:

Gas (OCGT 50% and CCGT 50%)	50%
Renewables	50%

5. The CO_2e emissions for the two scenarios outlined in Scenarios 1 and 2 above were run for two cases: the 100% venting case for flowback completion for shale gas, and the 10% venting and 90% flaring case for flowback. The LCA CO_2e emissions for the OCGT and CCGT cases were calculated from the gas turbine efficiencies given for 2030 in the BREE study (2012a); these emissions are very similar for CCGT to the power generating component of the emissions reported in the Hardisty *et al*.

study (2012) for generation in China using CCGT. The pre-production emissions and the gas production emissions were taken from Table 10.3 in the main report. The fugitive emissions for flowback were taken from the analysis of O'Sullivan and Paltsev (2012) in Table 10.3. Since the OCGT and CCGT technologies have different emission rates, and consume different amounts of gas energy (in MJ), the pre-production, completion and gas production emissions were separately calculated and then combined to represent the proportions of OCGT and CCGT assumed.

6. The calculations were undertaken probabilistically, taking the ranges in parameters for the various studies mentioned previously as p_{10} and p_{90} values. The proportion of both OCGT and CCGT in 2030 were also input to the calculation probabilistically, with a range from 35% to 65%, with a mean of 50%.

The results from O'Sullivan and Paltsev (2012) have been examined in detail as part of the present work. In particular, the calculations from the various shale gas fields in the USA in terms of both the initial production rate and the ultimate production for the 100% venting and reduced emission completions cases have been verified by calculation, given the O'Sullivan and Paltsev's assumptions. In addition, a likely case for Australia of 10% venting and 90% flaring has also been considered to calculate the actual emissions using basic data from O'Sullivan and Paltsev (2012). This case gives fugitive emission results which are similar to, but slightly lower than, O'Sullivan and Paltsev's "green completions" case.

The detailed probabilistic calculations also provide information on the range of the technology specific emissions for electrical power generation (t CO_2e/MWh). Comparing the *CCGT* and *black coal sub-critical* generation cases, the following p_{10}, p_{50} and p_{90} values were predicted, given the variability reported by Deloitte (2011) for black coal and the analysis of methane emissions and their ranges presented in this report for gas-fired turbines:

Technology	p_{10} (t CO_2e/MWh)	p_{50} (t CO_2e/MWh)	p_{90} (t CO_2e/MWh)
CCGT	0.54	0.59	0.64
Black Coal (Sub-critical)	0.82	1.00	1.20

Clearly the p_{50} values (means) for the two technologies are very different (0.59 *vs.* 1.00 tCO_2e/MWh for CCGT and black coal sub-critical, respectively). Examination of the probabilistic parameters shows that the p_{90} for CCGT and the p_{10} for black coal sub-critical do not overlap, so there is only a very small probability based on this analysis that the poorest future shale gas-fired CCGT facilities will overlap with the best black coal sub-critical units in terms of specific GHG emissions. In other words, there is a very low probability that CCGT using shale gas in the future will have higher emissions than the highest efficiency black coal sub-critical generators now, including all fugitive and production emissions associated with methane. The situation could be different if new, but unlikely, black coal ultra-supercritical facilities with lower specific emissions approaching gas firing were built in Australia in the future.

Appendix 3
Financial Analysis of Shale Gas: Detail

This appendix describes a financial model for shale gas applied to both United States and Australian conditions. The calculations were undertaken by Prof. John Burgess FTSE as part of this ACOLA shale gas study. Prof. Burgess provided two reports on this financial modelling to the EWG and has provided permission for information from these reports to be reproduced in this report. References and terms are detailed in the References and Glossary of Terms sections of the main report.

Methodology for the Financial Model

The financial model developed for this report calculates the gas price required to ensure that an investment in shale gas earns at least the cost of capital. It is a probabilistic calculation, which means that several of the important variables are probabilistically distributed. These include:

- The parameters for the gas well decline rate over time.
- The probability distributions of the initial decline rates for a gas field.
- The development and completion costs, and leasing costs, of gas wells.
- Operating costs.

Cash Flow Relationships

As in a previous ATSE report (ATSE, 2010), the relevant cash flows for an investment opportunity are the *free cash flows* (FCF) (Higgins, 2001). These are defined as:

$$FCF = EBIT (1-tax) + depreciation - capital\ expenses \quad (1)$$

where: EBIT = earnings before interest and taxes, after depreciation

= revenues – operating costs – royalties* – severance tax** – depreciation

tax = income tax rate

*Royalties are paid to the private owners of the mineral resource in the United States.

**Severance tax is a tax in the United States levied by State governments against gas revenue.

In the present shale gas model development, free cash flows are calculated from equation (1) each year for the life of the investment. These free cash flows are then discounted at an appropriate rate to determine the NPV, which is the sum of all the discounted free cash flows.

The appropriate rate of discount for the yearly free cash flows is the weighted average cost of capital (WACC) (Higgins, 2001):

$$WACC = \{(1\text{-}tax)K_D D + K_E E\}/(D+E) \quad (2)$$

where: K_D = cost of debt
K_E = cost of equity
D = firm's level of debt
E = firm's level of equity

Since inflation is not taken into account (i.e. all cash flows are real dollars), the cost of debt and cost of equity are adjusted downwards for inflation in this work.

For any given year, the free cash flows are discounted according to (with discounting at the end of the year in question):

FCF$_{n,disc}$ = FCF$_n$/(1+WACC)^n (3)

where n = number of years since the start of investment, over the life of the investment

The NPV is then given by:

NPV = = $\sum$(FCF$_{n,disc}$) (4)

The relationships described by equations (1) to (4) above have been used in the shale gas financial model development.

Fiscal Regimes in the United States and Australia

In order to calculate the present value of an investment, the fiscal regime of the country in question must be employed in the cash flow calculations. The fiscal regime that applies to the petroleum industry in the United States consists of a combination of corporate income tax, severance tax and royalty payments (Ernst and Young, 2012). In Australia, the fiscal regime consists of a combination of corporate income tax, and either a Petroleum Resources Rent Tax (PRRT) or State royalty-based taxation. (Ernst and Young, 2012; Australian Tax Office, 2012). Table A.3.1 below provides a comparison of the two fiscal regimes and the assumptions used in this study.

Shale Gas Well Initial Production and Decline in Production Properties

The properties of the shale gas wells in a field need to be defined probabilistically in order to undertake the financial calculation. There are two key parameters in this regard: (i) the probability distribution of the initial gas production levels from wells in the field, and (ii) the decline rate of production over time from the wells in the field.

Figure A.3.1 shows a typical probability distribution of initial shale gas production (Jacoby et al., 2012). In this case it is from the Barnett shale gas field in the United States. As can be seen from the figure, the initial gas production probability distribution is skewed towards lower gas production rates and has high variance. In the absence of other data at this point in time, the log-normal distribution curve shown has been employed for all gas fields in the present simulations, with the parameters changed in proportion to the stated initial production rate from the field in question.

Each well in a shale gas field declines rapidly in production. This rapid decline is usually modelled as a hyperbolic decline of the form (Cheng et al., 2010):

q = $q_i(1+D_i bt)^{-1/b}$ (5)

where 0< = b <= 1 and D_i >=0

A diagram showing several reported hyperbolic decline curves for gas fields in the United States has been reported for the Haynesville, Marcellus, Eagle Ford, Woodford and Fayetteville fields (US

Figure A.3.1: Typical probability distribution of initial gas production, Barnett gas field 2005-10

Initial Production (Mscf/d)

The solid curve is a log-normal best fit to the data
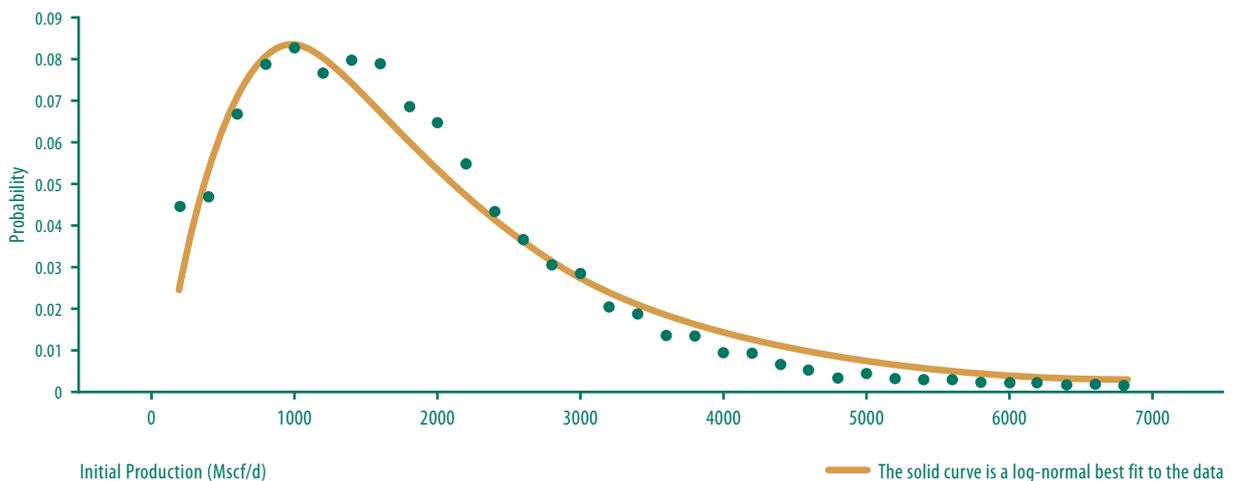
Source: Jacoby et al., 2012

Table A.3.1: Comparison of fiscal regimes in the United States and Australia

Item	United States Fiscal Regime	Australian Fiscal Regime
Royalties	12.5% to 25% of revenue, payable to the private land owner. 12.5% has been used in this study.	Paid to the States based on the value of the petroleum product extracted. They range from are generally 10% to 12.5% onshore, depending on the Australian State that owns the resource. The value of the product is determined by deducting the costs involved in processing, storing and transporting the petroleum to the point of sale from the gross value of the product at the wellhead. Royalties may be credited against the PRRT (below). A value of 10% of revenue has been used in this study.
Severance Tax	Payable to the US State where the product is extracted. 5% has been used in this study.	None
Income Tax	Federal 35% and State (0% to 12%) applied to net earnings (EBIT). 5% State taxes have been assumed in this study, giving an overall income tax level of 38.5%	Commonwealth Government income taxes are 30% applied to net earnings (EBIT). Since PRRT is deductible for income tax purposes, the income tax is levied after PRRT is paid from the EBITDA, and the EBIT is then determined from the post-PRRT EBITDA by deducting depreciation.
Goods and Services Tax	None	In Australia, GST is paid at a rate of 10% on product sales. Any GST paid on financial "inputs" to sales revenue is deductible against the GST payable. GST is levied before any other taxes.
Petroleum Resources Rent Tax (PRRT)	None	The petroleum resource rent tax is a Federal scheme that applies to onshore petroleum extraction activities from 1st July, 2012 (The "Expanded PRRT Scheme"). The taxable profit for PRRT purposes is: Taxable profit = (assessable receipts) – (deductible expenses) PRRT is imposed on a project basis. A liability to pay PRRT is incurred where (assessable receipts) is greater than (deductible expenses). PRRT is paid at a rate of 40%. PRRT is levied before income tax, and is deductible for income tax purposes. Any royalties paid to States are granted as a credit under the expanded PRRT scheme. "Assessable receipts" include all receipts, whether of a capital or revenue nature, related to a petroleum project. "Deductible expenses" include expenses of both a capital and revenue nature. There are three categories of these expenses: (i) exploration expenses, (ii) general project expenses (including land, development, drilling, completion and costs of production), and (iii) closing down expenses.
Land Leases	Paid to the private owner of the land. A typically value of $5,000 per acre has been used here. Lease costs are capitalised in the year in which they are incurred.	Costs associated with land acquisition are regarded as "deductible expenditure" for the PRRT and capital costs (with associated depreciation) for income tax purposes. Taken as 5% of revenue in this study.
Depreciation	Development costs are allowed to be depreciated in the first year in which they are incurred for an independent producer. If the producer is an integrated oil and gas company, the law allows 70% depreciation in the first year, with the remaining 30% depreciated over the next 60 years (0.5% per year after the first year). An independent producer has been assumed here.	Exploration permit costs, land costs and drilling and completion costs can be depreciated in Australia and deductible against income for income tax purposes. There are two ways in which the decline in value of the asset may be determined: (i) the diminishing value method (DV), or (ii) the prime cost method (PC). The PC method is used here, with an asset effective life of 15 years.
Drilling Costs	Drilling and completion costs are capitalised in the year in which they are incurred.	Drilling and completion costs are regarded as "deductible expenditure" for the PRRT and capital costs (with associated depreciation) for income tax purposes.

EIA, 2012). Figure A.3.2 shows a typical decline curve, in this case for the Marcellus field.

The D_i and b parameters for the different fields from the curve fitting process are as shown in the Table A.3.2 below.

The average parameter values for the fields in Table A.3.2 are D_i=0.86 and b=0.31, and these were the parameters used in the generic decline curve in the present financial model. In addition, each of these parameters was made probabilistic. Sensitivity analysis was performed by inputting the actual fitted hyperbolic decline data for the different fields in the model, but it was found that the model result was relatively insensitive to these parameters relative to the initial production rate parameter, to which it was very sensitive.

Results of the United States Financial Analysis

The present financial model was "calibrated" against United States shale gas extraction data to ensure its validity. A report from Massachusetts

Institute of Technology (MIT, 2011) has described aspects of the economic modelling of shale gas extraction. An appendix to this MIT report provides more detail on the assumptions made (MIT, 2011). For the purposes of comparison in the present study, the MIT data were used together with the initial production distribution and production decline curves described above to model the required gas prices in the United States.

The following assumptions were made in the MIT report:

Royalties	12.5%
Severance tax rate	5%
Corporate tax rate	38.25%
Depreciation	According to US fiscal rules (assumed to be 100%)
	Lease costs depreciated according to percentage production depletion
Cost of capital (after tax)	10%
Operating costs	$0.75/MMBtu (range $0.50 to $1.00) = $0.71/GJ (range $0.48 to $0.95)
Land required per well	640 acres (one square mile) = 260 ha

Figure. A.3.2: Hyperbolic well decline of a shale gas field, Marcellus field in the United States

Source: US EIA, 2012   Year   The solid curve is a hyperbolic function best fit to the data
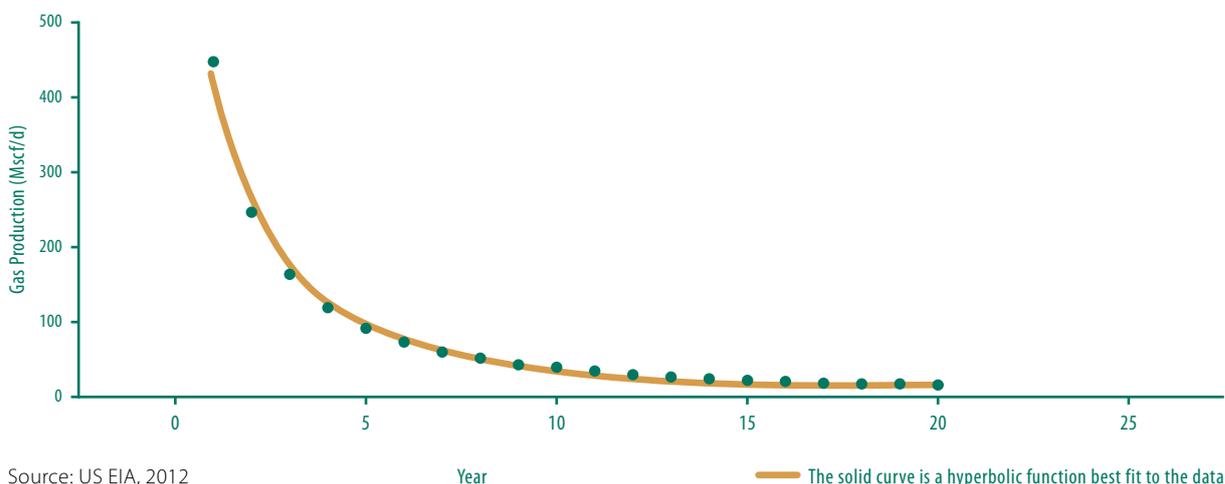
Table A.3.2: Hyperbolic decline parameters for some shale gas fields in the United States

Field	Year 1 Initial Production(Mscf/d)	D_i	b
Haynesville	1690	0.81	0.01
Eagle Ford	1160	0.77	0.02
Woodford	731	0.93	0.51
Marcellus	446	0.90	0.56
Fayetteville	420	0.90	0.47

Source: US EIA, 2012

A breakout box in the main text of the report provides information on capital costs, initial gas production rates (IP) and operating costs in the United States (MIT, 2011).

As can be seen from the text in the main body of the report, most of the gas price predictions from the present work agree reasonably with the MIT study.

The present model also outputs the range of gas price required in addition to the mean. Table A.3.3 below shows these ranges for the various fields in terms of p_{50}, p_{20} and p_{80} required gas prices.

Figure A.3.3 shows a further analysis of the data in the form of a plot of calculated required price *versus* a type of capital intensity parameter: the (*capital cost per well*) divided by the (*initial gas production per well*). A high value of this parameter indicates a field that has a high capital investment intensity, and *vice versa*.

As can be seen, there is a reasonable trend evident between "required gas price" and "capital intensity". The one notable exception is the Haynesville data point from the MIT study, which resides towards the top left-hand side of the plot. This discrepancy has been discussed with an author of the MIT Report (O'Sullivan, 2012) and the difference is related to the rapid decline in gas flows from wells in this field. The MIT result shown in the figure should be taken as correct, since the MIT analysis had access to more accurate field production data than the present study.

Further confirmation of usefulness of the relative "required gas prices" predicted by the present model can be found through a comparison with a United States shale gas cost curve. A curve of this type was presented in an article in Business Spectator on 13th November 2012 (Liddington-Cox, 2012). In a cost curve graph provided with the article, the following relative gas cost order for US shale fields was presented in the cost curve diagram, with the present model "required gas price" predictions also shown in brackets after the name of the field:

Table A.3.3: Predicted required gas prices ranges predicted by the present work, expressed in terms of the p_{20}, p_{50} and p_{80} points on the probability distribution

Field	RGP($/GJ)	RGP($/GJ)	RGP($/GJ)
	p_{50}	p_{20}	p_{80}
Barnett	$5.96	$5.10	$6.81
Fayetteville	$5.24	$4.58	$6.09
Haynesville	$3.05	$2.71	$3.36
Marcellus	$3.73	$3.26	$4.20
Woodford	$5.34	$4.62	$6.02

Figure A.3.3: Plot of required gas price versus capital intensity for both the MIT study and the present work

Capital cost per well/Initial gas production ($/Mscf/day)

Circles (●) represent the MIT data (MIT 2011), while squares (■) represent the predictions from this work
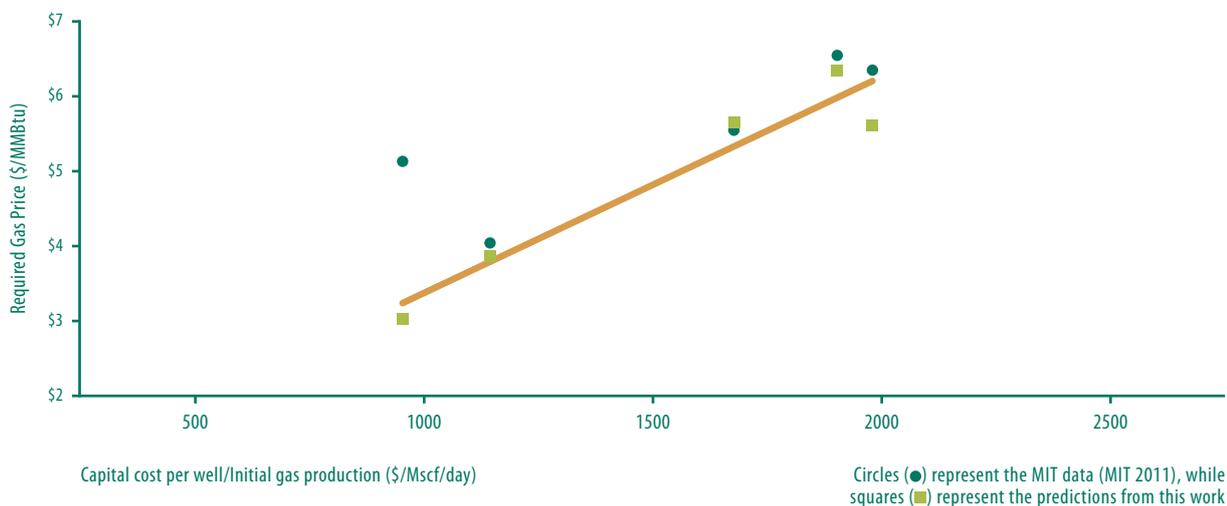
Gas cost < $5/GJ in order low to high: Marcellus ($3.73/GJ), Haynesville ($3.05/GJ), then Fayetteville ($5.24/GJ)

Gas cost >$5 and < $6/GJ in order low to high: Barnett ($5.96/GJ), then Woodford ($5.34/GJ).

The present model is thus in broad ranking agreement with the published US cost curve, but differs in the detail. It is particularly noteworthy that the two lowest cost producers studied here (Marcellus and Haynesville) and the two highest cost producers (Barnett and Woodford) have been successfully predicted by the present study. This is according to the assumptions made in the present work regarding capital costs and gas production profiles and the data from MIT. With better data, the required gas prices predicted by the model would no doubt come closer to the values reported. It is also unsure how much liquid petroleum product credits are affecting the data presented in this cost curve, in the context that the present model does not include the financial benefit of co-liquids production.

Australian preliminary financial analysis

Australian Fiscal Regime

Thus, for the Australian fiscal regime, the following relationships effectively apply for a given fiscal year:

Gross Income =	Revenue – Operating Costs
State Royalty =	(Gross Income) x (Royalty Rate)
PRRT Taxable Profit =	(PRRT Assessable Receipts) – (PRRT Deductible Expenditure)
PRRT Liability =	(PRRT Taxable Profit) x (PRRT rate (40%)), for PRRT Taxable Profit >= 0
Amount Payable =	(PRRT Liability) or (State Royalty), whichever is greater
EBITDA =	(Gross Income) – (Amount Payable)
EBIT =	EBITDA – Depreciation
NPAT =	EBIT x (1- income tax rate (30%))
FCF =	NPAT + Depreciation – Capital Expenditure

GST is payable in Australia at rate of 10% on (*Revenue – Capital Costs – Operating Costs*) due to GST input credits from expenditures. During shale gas extraction capital costs (in the form of drilling and completion costs) continue throughout most of the life of the field. GST payable by the shale gas extraction company is therefore a minor tax component, amounting to $0.10 to $0.20/GJ of gas produced. For this reason, GST has not been included in the results in this report.

In addition to the fiscal regime, there are other factors that could change the economics of shale gas extraction in Australia:

- Australian land acquisition (or lease) costs are likely to be lower than those in the United States, especially in remote regions.

- Australian drilling and completion costs are likely to be higher than in the United States, due to remoteness and higher costs generally in Australia. This also applies to Australian operating costs.

- The costs associated with infrastructure (electrical power, fuel, pipelines, other transportation) are likely to be higher in Australia than in the United States.

The key operational parameters – (i) initial gas production from shale gas wells, (ii) the probability distribution of initial gas production rates, and (iii) the decline rates of Australian wells in different locations, are still essentially unknown. This is because only very few wells have been recently drilled in Australia and the data is not yet available.

Effect of Fiscal Regime

In order to evaluate the influence of the two different fiscal regimes, the shale gas well production data and drilling and completion costs for two fields from the United States was simulated as if those wells were subject to Australian taxes. The two fields in question were the Barnett and the Marcellus. The Australian fiscal regime (as described above) was applied to these wells, with landowner costs the same as in the United States and treated as capital. In this way, the two fiscal regimes could be directly compared.

Table A.3.4 shows the "required gas price" calculated for the two fiscal regimes for the data of the Marcellus and Barnett fields. As can be seen, the calculated required gas prices in the two countries are very similar, indicating that for the same well data the two fiscal regimes are more-or-less equivalent. This is an interesting result, since the natures of the two fiscal regimes are quite different. However, the various royalties and taxes come together in the two countries to give essentially the same outcome.

Shale gas well properties

As noted above, the properties of the shale gas wells in a field need to be defined probabilistically in order to undertake a financial calculation. There are two key parameters in this regard: (i) the probability distribution of the initial gas production levels from wells in the field, and (ii) the decline rate of production over time from the wells in the field. In the United States, data for each field of this type is generally available.

In Australia, very few shale gas wells are in production: two recent examples are (i) the

Santos "Moomba – 191" vertical well in the Cooper Basin, and (ii) the Beach Petroleum Encounter -1 well, also in the Cooper Basin. It was reported (Cruickshank, 2012) and has been noted in public shareholder documents (Santos, 2012) that the Moomba-191 well has three hydraulic fracturing sections and had an initial gas production of 85 mcm/d (3,000 Mscf/d). As at the end of 2012, the well had only been in production for 12 weeks, and since then the production has declined to around 80 mcm/d (2,500 Mscf/d). Beach Petroleum reported that the Encounter-1 well had 6 fracture stimulation stages and flowed at a maximum rate of 59.5 mcm/d (2,100 Mscf/d).

Clearly, since there are few producing wells in Australia, a probability distribution similar to that shown in the break outbox is not available for Australian conditions. In this study, a log-normal distribution of initial gas flows like that was assumed, with a mean of 85 mcm/d (3,000 Mscf/d) and a standard deviation of 62 mcm/d (2,200 Mscf/d). This assumption is based on the observed initial production in the Moomba-191 well. The mean value of initial production rate for a given field in Australia could be different to this value

Table A.3.4: Comparison of "required gas price" using two different gas field data parameters in Australia and the United States (not including GST)

Shale Gas Field	United States fiscal regime	Australian fiscal regime
Marcellus	$3.73/GJ	$3.74/GJ
Barnett	$5.96/GJ	$6.20/GJ

Figure A.3.4: Hyperbolic decline of a shale gas well with an initial production rate of 3,000 Mscf/d using United States average data, together with the reported decline of the Santos Moomba-191 well in the Cooper Basin
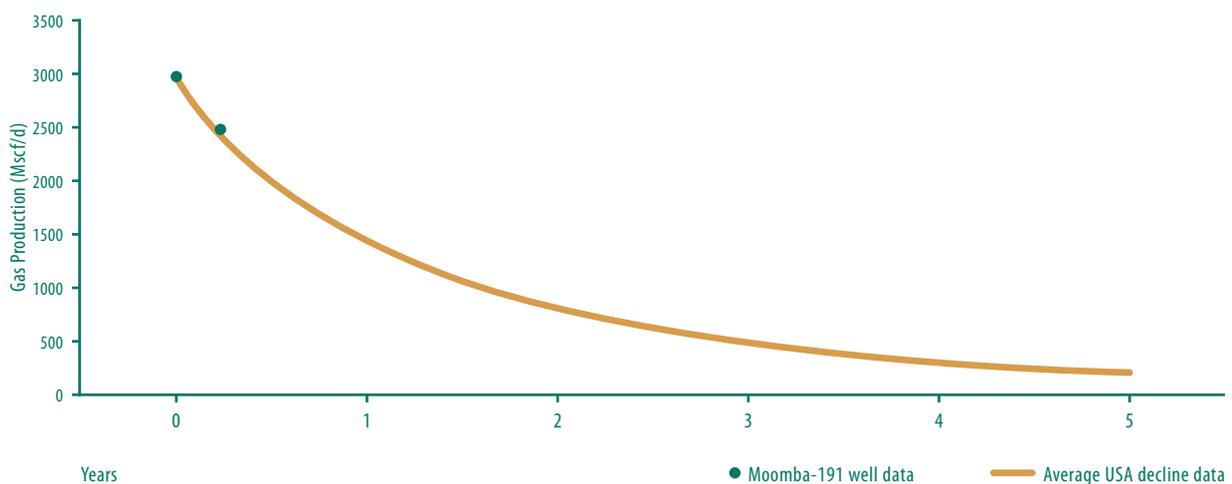
and for this reason a sensitivity analysis has been undertaken in the work presented here. For this sensitivity analysis below, the initial production parameter has been varied in the range 42 mcm/d to 141.5 mcm/d (1,500 to 5,000 Mscf/d).

It is clearly too early in the life of the well to determine whether the Moomba-191 or the Beach Petroleum Encounter-1 wells will follow the average decline curve of wells in the United States. However, the data at this early stage seems close to this curve, as shown in Figure A.3.4. Time will tell if this trend continues. However, for the purposes of the preliminary financial modelling for Australia, the average decline rate for the fields in the United States has been assumed. A sensitivity analysis of this parameter has also been conducted in the present work by varying D_i in the range 0.1 to 0.95, below.

Other input financial data for Australia

The following further assumptions have been made in order to financially model the economics of shale gas in Australia:

Exchange Rate	$1.00 USD per $1.00 AUD
State Royalties	10% (expensed against (*revenue – costs*))
Landowner costs	5% (expensed against *revenue*)
Petroleum Resources Rent Tax (PRRT)	40%, according to Australian fiscal rules
Income Tax	30%
Depreciation	According to Australian fiscal rules, with an effective asset life of 15 years
Cost of capital (after tax)	10%
Operating cost	$0.95/GJ (sensitivity range $0.5 to $1.50)
Capital Costs	

Information on capital costs of well drilling and completion in Australia were discussed recently as part of the study (Cruickshank, Santos, 2012; Pepichelli, 2012). The following points summarise these discussions:

- Costs of drilling and completion in Australia are "3 to 4 times" those in the United States. For a $3.5M well in the Barnett field, this would indicate a cost of $10.5M to $14M in Australia.

- A 3km deep vertical well in the Cooper Basin would cost $11-12M for drilling and completion with up to 6 hydraulic fracturing stages, as a "rough" estimate.
- Santos has publically announced a shale gas price in the range of $6 to $9 per GJ in Australia.

Clearly, more information is required on this important capital cost parameter. However, for the purposes of this preliminary analysis a base-case a capital cost for drilling and completion of **$12M** has been assumed. Sensitivity analysis in the range $6M to $16M for this cost has also been undertaken in the present study, and the results of this analysis are given in the main body of the report.

Financial Model Methodology

The financial model developed in this work calculates the gas price required to ensure that an investment in shale gas earns at least the cost of capital. It is a probabilistic calculation, which means that several of the important variables are probabilistically distributed. These include:

- The parameters for the gas well decline rate over time
- The probability distributions of the initial decline rates for a gas field
- The development and completion costs, and leasing costs, of gas wells
- Operating costs

Details on the probability distributions determined and assumed for these parameters in the calculation are given below in this appendix.

Figure A.3.5 below shows the flowchart for the present financial model.

By way of explanation of Figure A.3.5, the calculation overall is iterative in order to build up the probability distribution of the required gas price to make the shale gas investment viable for the owners of the gas extraction company. The overall iteration is undertaken by Oracle "Crystal Ball" (CB) (Oracle, 2012), a plug-in for Microsoft Excel. Thousands of iterations for each run are available under this software.

Figure A.3.5: Flowchart for shale gas financial model

Read input parameters: financial data & costs, well production data, no. of wells per year(N), no. of years(M), drilling trajectory

iterate for no. of years, M

Ascribe initial gas flows for each well as a function of the initial production probability distribution

iterate for no. of years, M

Calculate well production hyperbolic function probabilistically:
$ft = (1+Di*b*t)^{\wedge}(-1/b)$ $t=1,M$

Calculate weighted average flow over 12 months for years 1 to 5 and adjust flows for these wells

iterate for no. of years, M

Calculate well flows for each year of field life, taking into account: (i) Initial well production, (ii) year when well was drilled, and (iii) calculated decline rate for each well

Calculate probabilistic total gas production for each year

iterate ~1000 times in Crystal Ball

iterate to minimum NPV and required gas price: ~10 iterations

Calculate cash flows for each year for two price guesses:
EBITDA = (gas price)*(gas production) − (wells drilled) *(cost per well) − (operating cost per well)

Calculate EBIT, NPAT and Free Cash Flows according to appropriate financial relationships, incl. depreciation

Calculate NPV over the field life for two guessed gas prices:
NPV = sum [(free cash flow)/((1+kc)^t)] , j=1,M

Calculate new gas prices to minimise NPV

RESULT: probabilistic range of gas prices yielding an investment return equal to the cost of capital for a given set of parameters

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Any given CB iteration calculates the financial outcomes, including gas price, for a fixed set of input variables. These input variables are either fixed throughout the whole calculation procedure (e.g. the cost of capital), or constant for each CB iteration (e.g. a capital cost selected from a probability distribution defined in CB). Visual Basic language, a component of Microsoft Excel, has been used to undertake most of the calculations and to control CB in the model via a "Macro".

For each iteration of CB, the following calculations are undertaken as illustrated in Figure A.3.5

- The number of wells in the field and the rate of drilling and completing wells is assumed as input to the model. Associated costs per well are also defined. The shape of the drilling trajectory in terms of when drilling and completion ceases during the life of a field is also input as data. Up to 5 wells per year

for up to 30 years may be simulated in the present model(a total of 150 wells).

- Each well has the same probability distribution for the initial rate of production. These probability distributions can be field dependent, assuming data is available. In the work to date, a log-normal distribution for this parameter has been assumed, based on a best-fit of the data in CB (see below). CB selects a different initial rate of production for each well based on the probability distribution.

- A hyperbolic gas production rate decline has been assumed, as per gas industry practice (see further detail below). The two key parameters in this decline are also probabilistically distributed, as detailed below In this way, each well in every CB iteration not only has a different initial gas production, but a different decline trajectory over the life of the field. Appropriate correction is applied in the early years of the wells life (years 1 to 5) to determine the weighted average gas production over the full year in these years for the financial calculation. This is necessary because of the steep decline in production in these years and the fact that the financial calculation is undertaken incrementally at integer one year periods.

- The production of each set of wells for each year is tracked over the life of the field in the calculation. In this way, an aggregated gas production for each year of the field is determined from a well based on (i) its initial production, (ii) when it was drilled and (iii) calculated decline over the years. Capital costs (*viz.* drilling and completion costs, and leasing costs) are also tracked for each year of operation.

Sensitivity of Results for Shale Gas Required Price in Australia

Capital Cost Sensitivity

In order to assess the sensitivity of the model to the capital costs of drilling and completion in Australia, the capital cost was varied from $6M to $16M per well. The results of this analysis are shown in Table A.3.5 below. In the following the "lower" and "upper" values in the ranges refer to one standard deviation below and above the mean. In all the sensitivity analyses below, all parameters other than the parameter being varied to test sensitivity have been held constant at the values in the base case above.

As can be seen, the required gas price for financial viability in Australia is very sensitive to the capital costs of drilling and completion.

Initial Well Production Sensitivity

The initial production rate (IP) was varied in the model to determine the sensitivity of the "required gas price" to this parameter. The standard deviation of the log-normal probability distribution of initial well productions for the field was also adjusted in proportion to the given IP rate in the simulation (see Appendix). Table A.3.6 shows these results.

Table A.3.5: Sensitivity of "price of gas required" (RGP) to capital costs of drilling and completion in Australia

Capital cost ($M/well)	RGP ($/GJ)	Lower Range of RGP	Upper Range of RGP
$6M	$4.00	$2.90	$5.07
$8M	$5.00	$3.84	$6.14
$10M	$6.00	$4.57	$7.39
$12M	$7.00	$5.32	$8.65
$14M	$8.92	$6.19	$9.67
$16M	$8.89	$6.88	$10.89

Table A.3.6: Sensitivity of "price of gas required" (RGP) to initial gas production rate (IP) in Australia

IP Rate (mcm/d)	RGP($/GJ)	Lower Range of RGP	Upper Range of RGP
42.5	$12.31	$9.08	$15.55
56.6	$9.52	$7.05	$12.00
85 (base case)	$6.98	$5.32	$8.65
113	$5.80	$4.44	$7.17
142	$5.08	$3.92	$6.22

Figure A.3.6: Decline rates from an initial production rate of 85 mcm/d (3,000 Mscf/d) for varying values of the decline parameter D_i for b=0.31
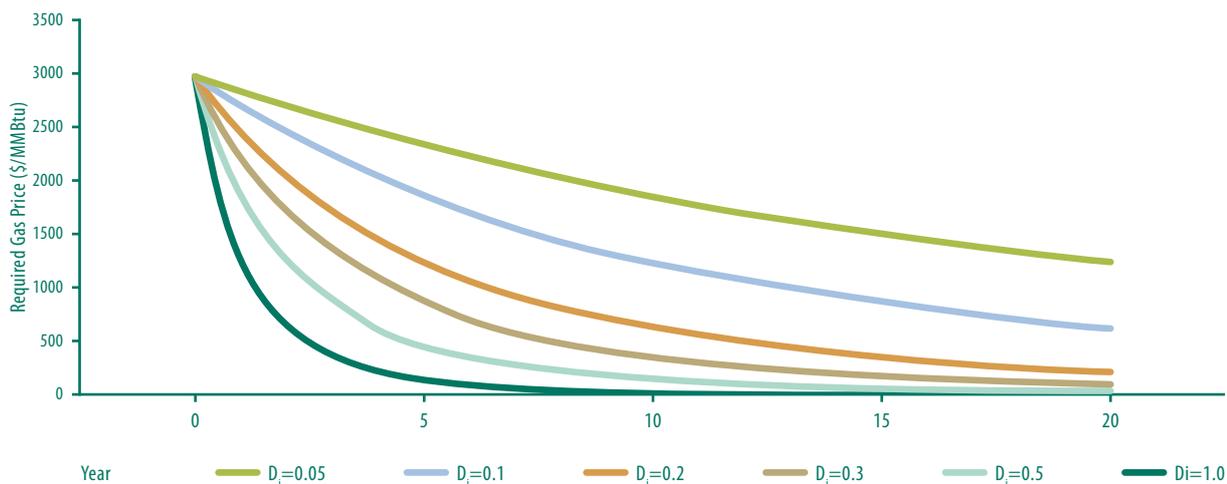
As can be seen, the "required gas price" for financial viability is very sensitive to the initial gas production rate (IP). This is particularly true at lower IP rates, where the required gas price is modelled to be relatively high. The Beach Petroleum Encounter-1 well had a stated maximum production rate of 59.5 mcm/d (2,100 Mscf/d), which would imply a relatively high "required gas price" of around $10/GJ, if all other factors being constant and as assumed here. Clearly, information on this gas production parameter is required in order to remove uncertainty about shale gas costs in Australia.

Decline Rate Sensitivity

The decline rate of gas production from the initial rate is modelled by a hyperbolic decline with parameters D_i and b. The model is most sensitive to the parameter D_i, as shown in Figure A.3.6. For a value of b = 0.31 (the average of the United States data examined), large changes in decline rate can be modelled by simply varying the parameter D_i, as shown in the figure. In the United States, shale gas well declines are fitted by the parameter D_i close to a value of D_i = 1.0 (viz. a rapid decline).

Table A.3.7 shows the sensitivity of "required gas price" to the decline parameter D_i and the decline curves in Figure A.3.2. As can be seen from the table, the lower decline rates for low values of D_i has the effect of decreasing the "required gas price" because the gas flow during the life of the well remains at a high level. However, at values between 0.8 and 1.0, which is the case generally in the United States where wells decline rapidly, the "required gas price" is not particularly sensitive to the decline rate parameter D_i. The exception to this is the Haynesville field in the United States, which was reported to have a very rapid decline and thus a higher "required gas price" than a simple analysis would indicate (O'Sullivan, MIT, 2012). It remains to be seen how shale gas wells decline in Australia over time in comparison to those in the United States and what financial effects this will have.

Operating Cost Sensitivity

The operating cost for wells in the United States was reported as $0.71/GJ by the MIT study (MIT, 2011a). For the work here, the base operating cost was assumed to be 0.95/GJ, reflecting higher costs in Australia. The sensitivity to this parameter was evaluated by running the financial model with operating costs in the range $0.47 to $1.42/GJ, as shown in Table A.3.8.

As can be seen, the model is relatively insensitive to a wide range in operating costs. This conclusion is consistent with that in the MIT study (MIT, 2011, 2011a).

Probabilistic Parameters – United States shale gas financial model

The probability distributions of all the appropriate variables were defined in the Crystal Ball plug-in package in Microsoft Excel.

Well drilling and completion costs were modelled probabilistically by a normal distribution function with a mean given by the *Mid* values in Table A.3.2 and a standard deviation given by the difference between the *Mid* and the *High* and *Low* values.

Operating costs were modelled probabilistically by a triangular distribution with a most likely value of $0.70/GJ and a high and low value of $0.95/GJ and $0.47/GJ respectively.

Lease costs were modelled probabilistically by a triangular distribution with a most likely value of $12,346/ha ($5,000/acre) and a high and low value of $24,691/ha ($10,000/acre) and $6,173/ha ($2,500/acre) respectively.

The well decline parameter D_i was probabilistically modelled with a normal distribution with a mean of 0.86 and a standard deviation of 0.07 from a curve fit analysis of the reported data. D_i was also constrained by $0 < D_i < 1$. The well decline parameter **b** was probabilistically modelled with a triangular distribution with a most likely value of 0.31, a minimum value of 0.01 and a maximum value of 1.0.

The initial gas flow probability distributions were described by the log-normal distribution shown in Figure A.3.1, with a mean of 48.1 mcm/d (1,700 Mscf/d), a standard deviation of 35.4 mcm/d (1,250 Mscf/d) and a location of-14.2 mcm/d (-500 Mscf/d) for the Barnett field. Other fields were probabilistically modelled by calculating the ratio of the initial Barnett field flow to the other field's initial flow, and then modifying the mean, standard deviation and location in their log-normal distribution according to this ratio.

Table A.3.7: Sensitivity of "gas price required" to the gas production decline parameter D_i

Decline Parameter D_i	RGP($/MMBtu)	Lower Range of RGP	Upper Range of RGP
0.2	$4.12	$3.28	$4.97
0.3	$4.69	$3.67	$5.71
0.5	$5.63	$4.28	$6.98
0.86 (base case)	$6.98	$5.32	$8.65
1.0	$7.19	$5.46	$8.94

Table A.3.8: Sensitivity of "price of gas required" (RGP) to operating costs in Australia

Operating Cost ($/MMBtu)	RGP($/MMBtu)	Lower Range of RGP	Upper Range of RGP
$0.47	$6.42	$4.72	$8.10
$0.95 (base case)	$6.98	$5.32	$8.65
$1.42	$7.50	$5.77	$9.22

Probabilistic Parameters – Australian shale gas financial model

The probability distributions of all the appropriate variables were defined in the Crystal Ball plug-in package in Microsoft Excel.

Well drilling and completion costs were modelled probabilistically by a normal distribution function with a mean and standard deviation given by:

Capital cost ($M/well)	Standard Deviation ($M/well)
$6M	$2.0M
$8M	$2.0M
$10M	$2.5M
$12M	$3.0M
$14M	$3.0M
$16M	$3.5M

Operating costs were modelled probabilistically by a triangular distribution with a most likely, low and high values of:

Operating Cost Likely Value ($/GJ)	Low Value ($/GJ)	High Value ($/GJ)
$0.47	$0.24	$0.71
$0.95	$0.71	$1.18
$1.42	$0.95	$1,90

The well decline parameter D_i was probabilistically modelled with a normal distribution with a mean and a standard deviation of:

Mean D_i	Standard Deviation D_i
0.2	0.02
0.3	0.03
0.5	0.05
0.86 (base case)	$0.07
1.0	$0.07

The well decline parameter b was probabilistically modelled with a triangular distribution with a most likely value of 0.31, a minimum value of 0.01 and a maximum value of 1.0 for each case.

The initial gas flow probability distributions were described by the log-normal distribution shown in Figure A.3.1, with means and standard deviations as follows:

Mean IP (mcm/d)	Standard Deviation IP (mcm/d)
42.5	31.1
56.6	41.5
85 (base case)	62.3
113	83.0
142	104

In each case the *location* of the log-normal distribution was -11.3 and the *upper truncation* was 283 mcm/d. The minimum initial gas flow was set at 5.7 mcm/d.

Appendix 4
Australian Bioregions and Shale Gas

Source: Eco Logical Australia, 2013; based on work by: Thackway & Cresswell, 1995.

Bioregion	Description
Brigalow Belt North	The Brigalow Belt North bioregion in Queensland contains Permian volcanics and Permian-Triassic sediments of the Bowen and Galilee Basins that comprise undulating to rugged ranges and alluvial plains, support sub-humid to semi-arid woodlands of ironbarks (*Eucalyptus melanophloia, E. crebra*), Poplar Box (*E. populnea*), Brown's Box (*E. brownii*), Blackwood (*A. argyrodendron*) Brigalow (*Acacia harpophylla*) and Gidgee (*A. cambagei*) (EA 2000). The main rural land use is beef cattle grazing on pastoral leases, with about 90% of the bioregion grazed. A thriving horticulture industry is centred within an irrigation area around Bowen and coal mining is a major economic driver. Over 20% of the bioregion has been cleared of native vegetation to date, with woody vegetation loss in excess of 50% in Upper Belyando and Belyando Downs sub-regions. The Brigalow Belt North is an under-represented bioregion, having less than 10% of its extent formally reserved, despite over 60 threatened flora and fauna species have been recorded in the bioregion. This region is a stronghold of the *Brigalow (Acacia harpophylla dominant and co-dominant)*, the *Natural Grasslands of the Queensland Central Highlands and the northern Fitzroy Basin*, the *Weeping Myall Woodlands* and the *Semi-evergreen vine thickets of the Brigalow Belt (North and South) and Nandewar Bioregions* ecological communities, each listed as Endangered under the EPBC Act.
Carnarvon	Carnarvon is an arid bioregion in Western Australia that traverses part of the Southern Carnarvon Basin. It comprises Quaternary alluvial, aeolian and marine sediments that overly Cretaceous strata. It supports a mosaic of saline alluvial plains with samphire and saltbush low shrublands, Bowgada (*A. ramulosa var. linophylla*) low woodland on sandy ridges and plains, Snakewood (*A. xiphophylla*) scrubs on clay flats, and tree to shrub steppe over hummock grasslands on and between red sand dune fields. Limestone strata with *A. startii / bivenosa* shrublands outcrop in the north, where extensive tidal flats in sheltered embayments support mangrove communities (EA. 2000). The often sparse vegetation is largely contiguous. The bioregion supports extensive cattle and sheep grazing. About 85% of the bioregion is grazed, with unmanaged goats contributing to total grazing pressure.
Central Arnhem	Central Arnhem is a bioregion that coincides with the McArthur Basin in the Northern Territory. It supports gently sloping terrain and low hills on Cretaceous sandstones and siltstones and lateritised Tertiary material. It supports Darwin Woollybutt (*E. miniata*) and Darwin Stringybark (*E. tetrodonta*) open forest and woodland with grassy understorey (EA 2000). Almost all the land is Aboriginal freehold with Hunbulwar the largest community. There are currently no major industries, only about 1% of the bioregion is grazed by domestic stock, and the landscape is relatively intact although it is burnt frequently. Only 6 threatened flora and fauna species have been recorded in this bioregion, although survey effort to date has been low. The bioregion is a stronghold for the *Arnhem Plateau Sandstone Shrubland Complex* ecological community which is listed as Endangered under the EPBC Act. Central Arnhem is under-represented, with less than 10% of its extent secured within the formal reserve system.

Bioregion	Description
Channel Country	The Channel Country bioregion coincides with the Cooper Basin in Queensland and South Australia. It is characterized by vast braided flood and alluvial plains surrounded by gravel or gibber plains, dunefields and low ranges on Cretaceous sediments. The bioregion supports forbfields and Mitchell grass (*Astrebla sp.*) downs, with intervening braided river systems (channels) of Coolabah (*E. coolibah*) woodlands and lignum/saltbush (*Muehlenbeckia sp./ Chenopodium sp.*) shrublands (EA 2000). Vegetation is generally sparse and intact, although minor clearing has occurred on the Goneaway Tablelands in Queensland. Over 90% of the Channel Country is grazed by domestic stock, with macropods and invasive animals (pig, goat, rabbit, donkey, horse) contributing to total grazing pressure. A loss of native perennial grass and forb species has occurred in non-spinifex areas as a result of over-grazing. The bioregion supports about 20 threatened flora and fauna species. Despite a large area of the bioregion reserved in NSW (i.e. Sturt National park), less than 10% of the area of the Channel Country is formally reserved, thus it is an under-represented bioregion.
Dampierland	Dampierland is a semi-arid tropical bioregion in Western Australia that intersects part of the Canning Basin. It comprises four (4) distinctive systems (EA 2000): (1) Quaternary sandplains overlying Jurassic/Mesozoic sandstones with red soil hummock grasslands on hills; (2) Quaternary marine deposits on coastal plains, with mangroves, samphire – *Sporobolus* grasslands, *Melaleuca acacioides* low forests, and *Spinifex – Crotalaria* strand communities; (3) Quaternary alluvial plains associated with the Permian and Mesozoic sediments of Fitzroy Trough that support tree savannas of *Crysopogon – Dichanthium* grasses, with scattered *Eucalyptus microtheca – Lysiphyllum cunninghamii*, interwoven with riparian forests of River Gum (*E. camaldulensis*) and Cadjeput *Melaleuca* fringe drainages; and (4) Devonian reef limestones in the north and east, often manifest as spectacular gorges, that support sparse tree steppe over *Triodia intermedia* and *T. wiseana* hummock grasses and vine thicket elements. The main agricultural industries are beef cattle (about 75% of the bioregion is grazed) and horticulture. The region contains Ramsar-listed wetlands and 10 threatened flora and fauna species have been recorded. Dampierland is an under- represented bioregion, with only 1% of its extent formally reserved.
Davenport Murchinson Ranges	This arid bioregion is within the Georgina Basin in the Northern Territory. It supports a chain of low rocky ranges formed from folded volcanics and sandstone, siltstone and conglomerates that contrast with the flat sandplain surrounds of the Tanami bioregion. Vegetation is contiguous and includes hummock grasslands and low open woodlands dominated by eucalypt and *Acacia* species. About 60% of the bioregion is grazed by domestic stock and burning is common. Feral donkeys and horses occur in large populations, most notably in the eastern part of the bioregion, and the invasive weed Parkinsonia (*Parkinsonia aculeata*) is problematic within rivers and creeks that flow north from the Davenport Range. The bioregion supports 10 threatened flora and fauna species but is under-represented, with less than 10% of its extent formally reserved.
Desert Uplands	Desert Uplands is an semi-arid bioregion coinciding with the Galilee Basin in central Queensland. It comprises sandstone ranges and sand plains that support woodlands of White's Ironbark (*E. whitei*), Inland Yellow Jacket (*E. similis)* and White Bloodwood (*Corymbia trachyphloia*) (EA 2000). About 95% of the bioregion is grazed by domestic stock, and a modest level of inappropriate land clearing has occurred in the past, particularly in the Jericho sub-region. About 25 threatened flora and fauna species have been recorded in the Desert Uplands, and loss of biodiversity is recognised as a key management issue. The bioregion is likely to support *The community of native species dependent on natural discharge of groundwater from the Great Artesian Basin,* listed as Endangered under the EPBC Act.

Bioregion	Description
Finke	The Finke bioregion overlaps the South Australian and Northern Territory and includes part of the Amadeus Basin. It comprises arid sandplains, and dissected uplands and valleys formed from Pre-Cambrian volcanics. It supports spinifex hummock grasslands and acacia shrublands on red earths and shallow sands, and includes three major inland rivers – the Finke, Hugh and Palmer – each of which feeds into Lake Eyre during major flooding. Major land uses are cattle grazing (about 90% of the bioregion is pastoral leasehold) and Aboriginal land management. The bioregion contains 29 threatened flora and fauna species, and a rich diversity of desert fauna. Athel Pine (*Tamarix aphylla)* and Buffel Grass (*Pennisetum ciliare*) are significant invasive weeds in the Finke bioregion.
Geraldton Sandplains	Located over part of the Southern Carnarvon Basin in Western Australia, the semi-arid Geraldton Sandplains bioregion supports mainly proteaceous scrub-heaths on the sandy earths of an extensive, undulating, lateritic sandplain mantling Permian to Cretaceous strata (EA 2000). It supports extensive York Gum (*E. loxophleba*) and Jam (*A. acuminata*) woodlands that occur on outwash plains associated drainage. It is a centre of high endemism, particularly for flora and reptiles, and various vegetation communities are identified as being 'at risk' in the absence of reservation. The bioregion also comprises nationally important wetlands, Grazing is practiced across at least 80% of the bioregion, and dryland cultivation and cropping and associated vegetation clearing is also prevalent.
Gibson Desert	The Gibson Desert is an intact arid bioregion in Western Australia that comprises lateritic gibber plains, dunefields and sand plains on flat-lying Jurassic and Cretaceous sandstones of the Canning Basin. It supports Mulga (*A. aneura*) woodland over Lobed Spinifex (*Triodia basedowii*) on lateritic "buckshot" plains and mixed shrub steppe of acacia, hakea and grevillea over Soft Spinifex (*T. pungens*) on red sand plains and dune fields. Lateritic uplands support shrub steppe in the north and mulga scrub in the south. Quaternary alluvia associated with palaeo-drainage features support Coolabah (*E. coolibah*) woodlands over bunch grasses (EA 2000). Conservation and Aboriginal Lands are the main land uses, with no known grazing of domestic stock. There are no invasive flora in the Gibson Desert, however invasive fauna include feral pig, fox, rabbit, wild dog, cat and feral camel (which is increasing in numbers). A total of four mammal species and 1 reptile species are listed as threatened.
Great Sandy Desert	The Great Sandy Desert is a vast arid bioregion that covers a large part of the Canning Basin in Western Australia, extending into the Northern Territory. It is characterised by red sand plains, dunefields and remnant rock outcrops. It is intact in terms of contiguous cover, comprising mainly tree steppe grading to shrub steppe in the south (open hummock grassland of *T. pungens* and *Plectrachne schinzii,* scattered Desert Walnut (*Owenia reticulata)* and bloodwoods, *Acacia* spp, *Grevillea wickhamii* and *G. refracta*). Desert Oak (*Casuarina decaisneana*) occurs in the far east of the region. Calcrete and evaporite surfaces traverse the desert, and include extensive salt lake chains with samphire low shrublands, and *Melaleuca glomerata – M. lasiandra* shrublands (EA 2000). Tourism, mining and mineral exploration are the main land uses in the Great Sandy Desert. Pastoral leases cover the far western and eastern edges – about 7% of the bioregion is grazed. The region contains 30 threatened fauna species, including 10 considered to be extinct.
Gulf Coastal	The Gulf Coastal bioregion coincides with the McArthur Basin in the Northern Territory. It comprises gently undulating plains, meandering rivers and coastal swamps, with some scattered rugged areas. The bioregion s dominated with Darwin Stringybark woodlands and samphire shrublands. Pastoral leasehold and Aboriginal Land are the most common tenures, with the main industries being grazing and mining. About70% of the bioregion is grazed, although grazing potential outside the eastern margin is considered to be low. A total of 16 threatened flora and fauna species have been recorded in the bioregion, and the bioregion is considered to be in a reasonably stable condition with no major land condition issues.

Bioregion	Description
Gulf Fall and Uplands	The Gulf Fall and Uplands bioregion coincides with the McArthur Basin in the Northern Territory and Queensland. It comprises spectacular gorges, undulating terrain with scattered low, steep hills on Proterozoic and Palaeozoic sedimentary rocks. Skeletal soils and shallow sands support Darwin Boxwood and Variable-barked Bloodwood (*Corymbia erythrophloia*) woodland to low open woodland with spinifex understorey (EA 2000). Cattle grazing and mining are the major industries, however the historic extent of clearing appears to have been low and the landscape exhibits a contiguous mosaic of vegetation types. About 70% of the Gulf Fall and Uplands bioregion is grazed and the landscape is burnt frequently. A total of 15 threatened flora and fauna species have been recorded in the bioregion.
MacDonnell Ranges	The MacDonnell Ranges of Central Australia partly coincide with the Amadeus Basin in the Northern Territory. The bioregion comprises visually spectacular high relief ranges and foothills covered with spinifex hummock grassland, sparse acacia shrublands, and woodlands along ephemeral watercourses. The main industries are cattle and tourism, with Alice Springs the major centre. The arid vegetation mosaic of the MacDonnell Ranges is contiguous, and about 60% is grazed by domestic cattle, with kangaroo, and feral pig, rabbit, camel, donkey and horse adding to overall grazing pressure. The MacDonnell Ranges is a diverse arid region, containing 38 threatened flora and fauna species.
Mitchell Grass Downs	Mitchell Grass Downs spans across central Queensland into the Northern Territory and coincides with the Galilee and Georgina Basins. It comprises undulating downs on shales and limestones with grey and brown cracking clays, and supports Mitchell Grass (*Astrebla spp.)* grasslands and *Acacia* low woodlands (EA 2000). It is an under-represented bioregion, with less than 10% of its extent formally reserved. Over 30 threatened flora and fauna species have been recorded in the bioregion, and is likely to support *The community of native species dependent on natural discharge of groundwater from the Great Artesian Basin,* listed as Endangered under the EPBC Act. The Mitchell Grass Downs support cattle and sheep grazing (the latter confined to eastern parts of the bioregion in Queensland), with over 95% of the bioregion grazed. The rate of vegetation clearing in the bioregion has been mixed, with concerted clearing of gidgee scrubs in the Southern Woody Downs sub-region in Queensland having commenced in the 1950s, and ongoing loss of Myall (*A. pendula*) for drought fodder. The bioregion supports increasing numbers of woody weeds of national significance, such as Prickly Acacia (*Acacia nilotica subsp. indica*).
Naracoorte Coastal Plain	The Naracoote Coastal Plain in South Australia and Victoria is a broad coastal plain of Tertiary and Quaternary sediments with a regular series of calcareous sand ridges separated by inter-dune swales, closed limestone depressions and young volcanoes at Mount Gambier. It is part of the Otway Basin, Vegetation is dominated by heathy woodlands and mallee shrubland with wet heaths in the inter-dune swales. This bioregion has been extensively cleared for agriculture with grazing the major land use. Due to its variety of habitats, the Naracoorte Coastal Plain supports a highly diversity of biota. A number of species are on the western margins of their distribution from the wetter southeast of Australia, the southern extreme for drier mallee vegetation, or are unique to the bioregion. The bioregion supports EPBC-listed *Seasonal Herbaceous Wetlands (Freshwater) of the Temperate Lowland Plains* and is an important over-wintering area for the nationally endangered Orange-bellied Parrot (*Neophema chrysogaster*), The bioregion supports 35 listed flora and fauna species.

| Bioregion	Description
Ord Victoria Plain	The Ord Victoria Plain is a semi-arid bioregion coinciding with the Canning Basin in Western Australia, and includes ridges, plateaus and undulating plains on Cambrian volcanics and Proterozoic sedimentary rocks. The lithological mosaic has three main components: (1) Abrupt ranges and scattered hills mantled by shallow sand and loam soils supporting *Triodia* hummock grasslands with sparse low trees including Snappy Gum (*E. racemosa*); (2) Cambrian volcanics and limestones forming extensive plains with short grass (*Enneapogon* spp.) on dry calcareous soils and medium-height grassland communities (*Astrebla* and *Dichanthium*) on cracking clays. Riparian forests of River Gum fringe drainage lines; and (3) in the south-west, lateritised upland sandplains (EA 2000). Extensive grazing is the main industry with at least 80% of the bioregion is grazed. Despite this, the native vegetation mosaic is reasonably intact across the extent of the bioregion. A total of 8 threatened species have been recorded in the bioregion. The level of formal reservation is less than 10%.
Sturt Plateau	The Sturt Plateau coincides with the Beetaloo and McArthur Basins in the Northern Territory. It comprises gently undulating plains on lateritised Cretaceous sandstones; neutral sandy red and yellow earths, and supports Variable-barked Bloodwood woodland with spinifex understorey (EA 2000). The major land use is extensive cattle grazing, with almost 80% of the bioregion grazed. Land clearing has been negligible, however use of fire is extensive and frequent. A total of 10 threatened fauna species have been recorded in the bioregion, but no threatened plants. Weeds spreading along and away from the new Alice Springs to Darwin railway corridor have introduced a new threat to the bioregion.
South East Coastal Plain	The South East Coastal Plain occurs in southern Victoria and coincides with the Otway Basin. It incorporated undulating Tertiary and Quaternary plains that have been extensively cleared for agriculture. The vegetation includes lowland forests, open forests with shrubby or heathy understoreys, grasslands and grassy woodlands, heathlands, shrublands, freshwater and coastal wetlands, mangrove scrubs, saltmarshes, dune scrubs and coastal tussock grasslands (EA 2000). The bioregion has a number of values including EPBC listed *Seasonal Herbaceous Wetlands (Freshwater) of the Temperate Lowland Plains* (with Ramsar listings) and various endemic flora. Over 100 threatened flora and fauna species have been recorded in the bioregion.
South Eastern Queensland	The Maryborough Basin occurs entirely within South Eastern Queensland bioregion, which comprises sediments of the Moreton, Nambour and Maryborough Basins, including extensive alluvial valleys and Quaternary coastal deposits. The bioregion is very biologically diverse, containing various rainforests, tall moist forests, dry open forests, woodlands, wetlands, heaths and mangrove/ saltmarsh communities (EA 2000). It has over 150 federally listed threatened species, and many endemic species. A total of 13 wetlands in the bioregion are recognised as nationally significant. The bioregion is heavily populated and subject to considerable development pressure. Extensive areas of native vegetation have been cleared (and continue to be cleared) for urbanisation and agricultural expansion. This region is a stronghold of the *Littoral Rainforest and Coastal Vine Thickets of Eastern Australia* ecological community, listed as Critically Endangered under the EPBC Act.
Southern (Victorian) Volcanic Plain	A flat to undulating plain in south-western Victoria, extending into South Australia, the Southern Volcanic Plain Bioregion coincides with part of the Otway Basin. The region is distinguished by volcanic deposits that formed an extensive basaltic plain with stony rises, old lava flows, numerous volcanic cones and old eruption points. It is dotted with shallow lakes and wetlands. Vegetation formerly consisted of damp sclerophyll forests, woodlands and grasslands which have been mostly cleared for agriculture. The extensive depletion and fragmentation of ecosystems in the region means that remnants are nearly all highly significant for conservation, including occurrences of the EPBC-listed *Natural Temperate Grassland of the Victorian Volcanic Plain*, EPBC-listed *Seasonal Herbaceous Wetlands (Freshwater) of the Temperate Lowland Plains*, and 28 wetland of national importance. Over 100 threatened flora and fauna species have been recorded in the bioregion.

Bioregion	Description
Swan Coastal Plain 	The Swan Coastal Plain coincides with the Perth Basin in Western Australia. It exhibits a Warm Mediterranean climate and contains low lying coastal plains that is mainly covered with Banksia or Tuart woodlands on sandy soils, Swamp Sheoak (*Allocasuarina obesa*) on outwash plains, and paperbark in swampy areas. In the east, the plain rises to Mesozoic sediments dominated by Jarrah (*E. marginata*) woodland. The outwash plains, once dominated by Swamp Sheoak – Marri woodlands and *Melaleuca* shrublands, are extensive only in the south (EA 2000). A variety of plants are endemic to the region, and there are 26 wetlands of national significance. The bioregion also supports a number of threatened ecological communities, including two communities dominated by Marri (*Corymbia calophylla*).
Sydney Basin 	The only bioregion in New South Wales with shale gas potential, the Sydney Basin comprises Mesozoic sandstones and shales, producing skeletal soils, sands and podzolics that support a variety of forests, woodlands and heaths within a distinctive landscape of sandstone plateaus and valleys. The Sydney Basin contains a number of important freshwater catchments that supply drinking water to Sydney and other major centres. It is a highly diverse region, containing coastal swamps and heaths, rainforests, tall eucalypt forest, dry eucalypt woodlands, and a number of important wetlands. It supports the *Blue Gum High Forest*, the *Cumberland Plain Shale Woodlands and Shale-Gravel Transition Forest*, the *Littoral Rainforest and Coastal Vine Thickets of Eastern Australia* and the *Turpentine-Ironbark Forest in the Sydney Basin Bioregion* ecological communities which are each listed as Critically Endangered under the EPBC Act, and also the *Shale/Sandstone Transition Forest* and *Upland Basalt Eucalypt Forests* communities, listed as Endangered under the EPBC Act. The Sydney Basin is a highly populated bioregion and is subjected to a number of development pressures.
Tanami 	The Tanami is a tropical arid bioregion that traverses parts of the Canning and Georgina Basins in Western Australia and the Northern Territory. It comprises mainly red Quaternary sandplains overlying Permian and Proterozoic strata which are exposed locally as hills and ranges. The sandplains support mixed shrub steppes of Corkbark Hakea (*Hakea suberea*), desert bloodwoods, acacias and grevilleas over *Triodia pungens* hummock grasslands. Wattle scrub over *T. pungens* hummock grass communities occur on the ranges. Alluvial and lacustrine calcareous deposits occur throughout. In the north they are associated with Sturt Creek drainage, and support *Crysopogon* and *Iseilema* short-grasslands often as savannas with River Red Gum (EA 2000). Over 1500 taxon have been recorded in the Tanami, including 26 threatened flora and fauna, About 25% of the Tanami is suitable for domestic grazing. Feral camels, horses and donkeys are a major management issue, and Parkinsonia is establishing around watering points of pastoral leases.
Yalgoo 	Yalgoo Bioregion in Western Australia is an arid to semi-arid bioregion in the Perth Basin. It is characterised by low woodlands to open woodlands of *Eucalyptus*, *Acacia* and *Callitris* on red sandy plains of the Western Yilgarn Craton and southern Carnarvon Basin. It includes the Toolonga Plateau of the southern Carnarvon Basin. It is rich in ephemeral species (EA 2000). Tenure is predominantly pastoral leasehold and sheep grazing is the main enterprise type. The region supports a rich diversity of flora and fauna, including 23 listed taxa.

Appendix 5
Geological Epochs

Geological Epochs with ages of the prospective shale gas basins shown (after Geoscience Australia).
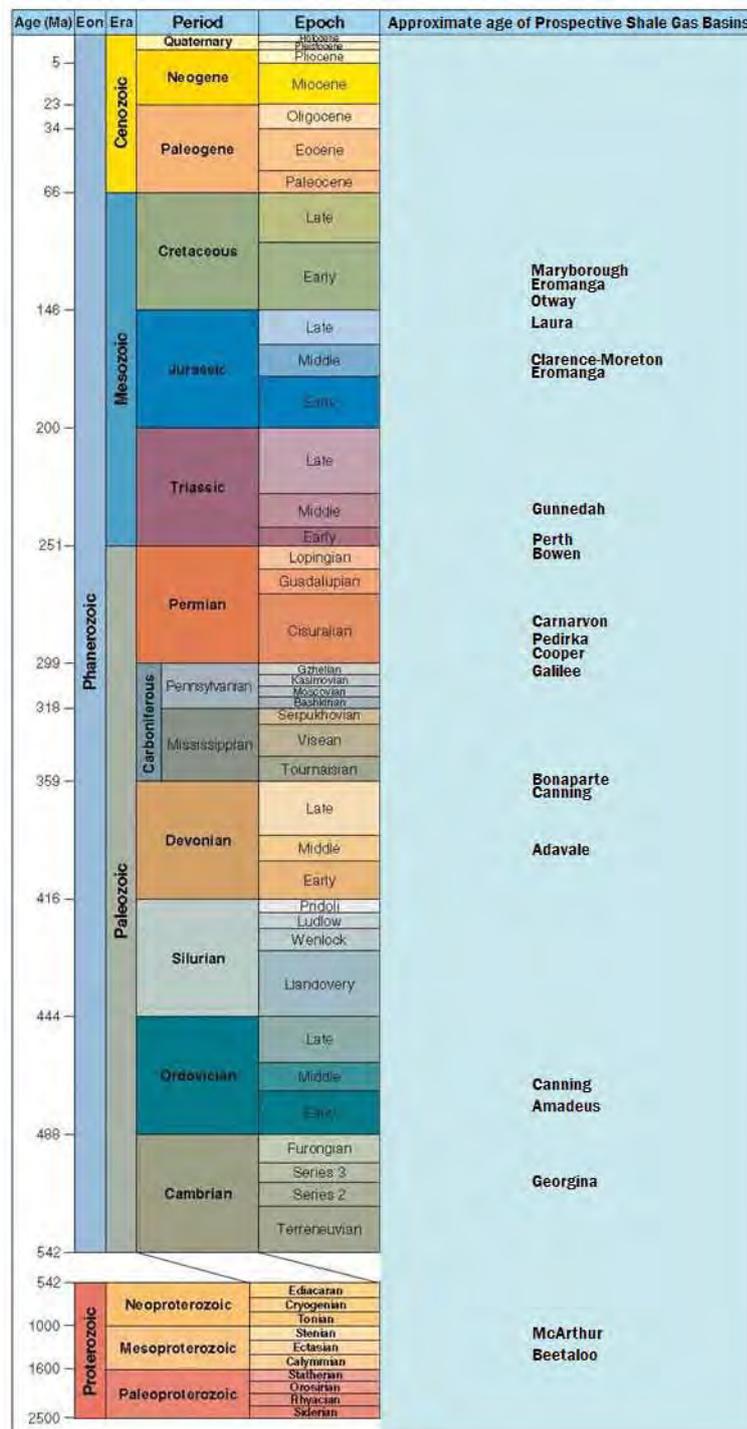
About Securing Australia's Future

In June 2012 the Australian Government announced Securing Australia's Future, a $10 million investment funded by the Australia Research Council in a series of strategic research projects for the Prime Ministers Science, Engineering and Innovation Council (PMSEIC), delivered through the Australian Council of Learned Academies (ACOLA) via the Office of the Chief Scientist and the Chief Scientist.

Securing Australia's Future is a response to global and national changes and the opportunities and challenges of an economy in transition. Productivity and economic growth will result from: an increased understanding in how to best stimulate and support creativity, innovation and adaptability; an education system that values the pursuit of knowledge across all domains, including science, technology, engineering and mathematics; and an increased willingness to support change through effective risk management.

PMSEIC identified six initial research topics:

 i. Australia's comparative advantage

 ii. STEM: Country comparisons

 iii. Asia literacy – language and beyond

 iv. The role of science, research and technology in lifting Australian productivity

 v. New technologies and their role in our security, cultural, democratic, social and economic systems

 vi. Engineering energy: unconventional gas production

The Program Steering Committee responsible for the overall quality of the program, including selection of the Expert Working Groups and the peer review process, is comprised of three Fellows from each of the four Learned Academies:

 Professor Michael Barber FAA FTSE (Chair)

 Mr Dennis Trewin AO FASSA (Deputy Chair – Research)

 Professor Ruth Fincher FASSA

 Professor Mark Finnane FAHA

 Professor Paul Greenfield AO FTSE

 Professor Iain McCalman AO FAHA FASSA FRHS

 Professor Peter McPhee AM FAHA FASSA

 Dr Graham Mitchell AO FAA FTSE

 Dr Jim Peacock AC FAA FTSE FRS

 Dr Susan Pond AM FTSE

 Professor John Quiggin FASSA

 Dr Leanna Read FAICD FTSE

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