The Australia Institute
Research that matters.

Scientific inquiry into Hydraulic Fracturing in the Northern Territory

Submission

The development of unconventional gas in the Northern Territory would reduce energy security by linking the Territory to volatile east coast or world markets. Considerable costs could be incurred, while the benefits of royalties are likely to be modest.

Rod Campbell
Bill Browne
Hannah Aulby
April 2017

ABOUT THE AUSTRALIA INSTITUTE

The Australia Institute is an independent public policy think tank based in Canberra. It is funded by donations from philanthropic trusts and individuals and commissioned research. Since its launch in 1994, the Institute has carried out highly influential research on a broad range of economic, social and environmental issues.

OUR PHILOSOPHY

As we begin the 21st century, new dilemmas confront our society and our planet. Unprecedented levels of consumption co-exist with extreme poverty. Through new technology we are more connected than we have ever been, yet civic engagement is declining. Environmental neglect continues despite heightened ecological awareness. A better balance is urgently needed.

The Australia Institute's directors, staff and supporters represent a broad range of views and priorities. What unites us is a belief that through a combination of research and creativity we can promote new solutions and ways of thinking.

OUR PURPOSE – 'RESEARCH THAT MATTERS'

The Institute aims to foster informed debate about our culture, our economy and our environment and bring greater accountability to the democratic process. Our goal is to gather, interpret and communicate evidence in order to both diagnose the problems we face and propose new solutions to tackle them.

The Institute is wholly independent and not affiliated with any other organisation. As an Approved Research Institute, donations to its Research Fund are tax deductible for the donor. Anyone wishing to donate can do so via the website at https://www.tai.org.au or by calling the Institute on 02 6130 0530. Our secure and user-friendly website allows donors to make either one-off or regular monthly donations and we encourage everyone who can to donate in this way as it assists our research in the most significant manner.

Level 1, Endeavour House, 1 Franklin St
Canberra, ACT 2601
Tel: (02) 61300530
Email: mail@tai.org.au
Website: www.tai.org.au

INTRODUCTION

The Australia Institute welcomes the opportunity to make a submission to the Scientific inquiry into hydraulic fracturing in the Northern Territory. Our submission focuses on Theme 7.7 of the Background and Issues Paper, economic impacts and also addresses other themes that the Institute has conducted research on.

THEME 7.7 ECONOMIC IMPACTS - ENERGY SECURITY

Comments on Northern Territory and east coast gas markets

The Northern Territory has substantial supplies of conventional gas and is a small market. As a result, gas is currently cheap and available in the NT - a similar situation to what prevailed in eastern Australia for many years.

The tranquillity of the east coast gas market was broken by the construction of export LNG terminals in Gladstone, Queensland, which linked it to the world market and drove up prices. Worse still, the huge cost overruns of the export facilities, opaque market arrangements and lower than expected yields from Queensland coal seam gas fields[1] have seen gas prices increase to above world prices, even to the point where Australian gas can be cheaper to buy in Japan than in Australia.[2]

While the NT does export gas via the Darwin LNG Inpex terminal, this largely serves the offshore Bayu-Undan field, while other conventional reserves supply the NT. While this balance is maintained, NT gas supply security is unlikely to be affected. The biggest threat to security of gas supply in the Northern Territory is through potential connections to the chaos of the Eastern Australian market, or expansion of export facilities in Darwin.

The development of unconventional gas supply in the Territory would create incentive for exactly these kinds of links, presenting a risk for NT energy security. As unconventional gas is not needed to supply the local Northern Territory market, the

[1] Chambers (2013) Export fears as gas wells fall short, http://www.theaustralian.com.au/business/mining-energy/export-fears-as-gas-wells-fall-short/news-story/c38d5957fce9f8e34af9076d2b48c342

[2] West (2017) Gas crisis? Or glut? Why Japan pays less for Australian LNG than Australians do, https://theconversation.com/gas-crisis-or-glut-why-japan-pays-less-for-australian-lng-than-australians-do-74438

proponents of unconventional projects will need infrastructure to take any production to eastern or overseas markets. Linking to these markets is unlikely to be in the interests of Territory gas consumers, exposing Territorians to volatile, higher prices and the need to compete against foreign or east coast consumers for NT gas.

Surplus gas - consumption and supply in the NT

NT gas consumption fell from 1,184 million cubic meters to 1,154 cubic meters between 2013-14 and 2014-15.[3] More recent data has not yet been released, but is likely to be well below earlier forecasts due to declining costs of renewable energy and abandonment of projects such as the pipeline to the Gove alumina refinery.

Power and Water Corporation (PWC) has signed long-term contracts with existing conventional gas supplies, as is made clear in its annual reports:

> In 2015-16, Power and Water sourced close to 100 per cent of its natural gas from Eni Australia BV's Blacktip gas field in the Joseph Bonaparte Gulf, which lies some 110km off the Territory's northwest coast. The balance was secured from Darwin LNG pursuant to Power and Water's contingency gas supply arrangements.
>
> The Dingo Gas Supply Agreement was concluded with Magellan Petroleum prior to the company's onshore Australian assets being purchased by Central Petroleum Limited. The agreement allowed Power and Water to coordinate the tie-in of Central Petroleum's Gas Supply pipeline into the Owen Springs Power Station for the supply of high methane content gas, which will help improve efficiency to the power station's generators.[4]

These conventional gas supplies are able to supply the Territory in the long term. This was the purpose of an agreement with producer Eni in 2005-06:

> It is pleasing to note that in addition to the challenges faced, the Corporation delivered a number of significant achievements over the 2005-2006 year. A reliable future gas supply was accomplished with the signing of a Gas Sales Agreement with Eni Australia B.V. for the purchase of some 750 petajoules (Pj)

---

[3] Department of Industry, Innovation and Science (2016) *Australian Energy Statistics*, Table Q Australian consumption and production of natural gas, by state, physical units, https://industry.gov.au/Office-of-the-Chief-Economist/Publications/Pages/Australian-energy-statistics.aspx# , note based on approximation of 1,000 million cubic metres to 40 Petajoules. See International Energy Agency (2011) World Energy Outlook, p304, Box 8.3: What's in a bcm?, http://www.worldenergyoutlook.org/weo2011/

[4] PWC (2016) *Annual Report*, p35, https://www.powerwater.com.au/__data/assets/pdf_file/0017/133163/2016_Power_and_Water_Annual_Report.PDF

> of gas over the next 25 years, commencing early in 2009. In addition, a Gas Transport Agreement was signed with the Australian Pipeline Trust to transport the gas from the processing plant near Wadeye to the existing Amadeus Basin Darwin Pipeline. This will ensure that the Corporation has sufficient gas to meet the future power needs of the Territory and to continue providing a reliable power supply.[5]

The power needs of the Territory have not increased since that agreement was signed, quite the opposite. In addition to the gas demand reduction mentioned above, the decommissioning of the Gove aluminium smelter, a major energy user, has seen Territory energy use decline:

> The significant fall in energy use in the Northern Territory is mainly attributed to the closure of the Gove alumina refinery in May 2014.[6]

Expected demand from Gove was a major factor in the commissioning of supply from Eni.[7] Its closure has left PWC with large amounts of surplus gas which it hopes to sell via a new pipeline to the eastern Australian gas market:

> **Surplus gas**
>
> The Northern Gas Inter-connector Pipeline (NGP) will enable the sale of Power and Water's surplus gas to the eastern seaboard.[8]

The Australia Institute has long opposed the Northern Gas Pipeline (NGP) project.[9] It risks exposing Territorians to the problems of the east coast market, problems it will do nothing to solve. The 25-35Pj of gas that would be sold through it represent less than 2 percent of the volume of the east coast market (including exports).[10] Further expansion of Territory gas supply through exploitation of unconventional resources

[5] PWC (2006) Annual report 2006, p2, https://www.powerwater.com.au/__data/assets/pdf_file/0012/1515/2006_Annual_Report_-_web.pdf

[6] Department of Industry, Innovation and Science (2016) *Australian Energy Statistics*, p14, https://industry.gov.au/Office-of-the-Chief-Economist/Publications/Documents/aes/2016-australian-energy-statistics.pdf

[7] Manning (2013) *Rio Tinto to keep Gove alumina refinery running*, http://www.smh.com.au/business/rio-tinto-to-keep-gove-alumina-refinery-running-20130213-2edbo.html

[8] PWC (2016) Annual report, p35, bold in original

[9] Campbell (2015) *Passing gas: Economic myths around the Northern Territory's North East Gas Interconnector pipeline*, http://www.tai.org.au/content/passing-gas-economic-myths-around-northern-territorys-north-east-gas-interconnector-pipeline, appended to this submission.

[10] Robertson (2015) Pipe dream: a financial analysis of the Northern Gas Pipeline, http://ieefa.org/wp-content/uploads/2016/05/Pipe-Dream-A-Financial-Analysis-of-the-NEGI-MAY-2016.pdf

would increase calls by these suppliers for links to the east coast market, bringing risk and instability to Territorians.

The factor driving the construction of the NGP is not a desire to ensure Territorians are paid top dollar for their gas. If that were the case the infrastructure would ensure gas could be delivered to more than one customer. The current proposal is to deliver gas only to Incitec Pivot in Mt Isa.[11] Instead, it appears that the rationale is to stop PWC from having to pay suppliers for gas it does not need and cannot use.

The NGP will cost NT gas users dearly, despite former Chief Minister Adam Giles' claim that taxpayers will not pay for it.[12] Taxpayers may not pay the capital costs, but the prices that the pipeline's owners will charge PWC will be recouped by charging more to its customers – almost every Territorian. As pointed out by the Institute for Energy Economics and Financial Analysis:

> The [NGP] is being built to dispose of gas that was acquired by the Northern Territory government's Power and Water Commission under a take or pay arrangement. Essentially if the PWC can dispose of this gas for any return it is better off than just paying for the gas and not taking delivery.[13]

While this inquiry may not be directly concerned with gas infrastructure projects such as the NGP, it is important to understand that infrastructure investment can lead to increased demand for gas, particularly when excess capacity has been built due overly optimistic expectation of gas demand. Conversely, prospective gas producers will always call for more investment in infrastructure. This has certainly been the case in east coast Australia and is also the case with the NGP and would-be unconventional gas producers in the NT. Development of unconventional gas in the NT will lead to further calls for infrastructure investment in the interests of producers rather than the Northern Territory public.

[11] Renault (2015) *Fertiliser giant Incitec Pivot a big winner in Northern Territory gas pipeline decision* http://www.abc.net.au/news/rural/2015-11-18/nt-gas-pipeline-to-benefit-fertiliser-giant-incitec-pivot/6950326

[12] MacDonald-Smith et al (2015) Jemena to build NT gas pipeline to supply Incitec Pivot http://www.smh.com.au/business/energy/jemena-to-build-nt-gas-pipeline-to-supply-incitec-pivot-20151115-gkzpw8.html

[13] Robertson (2015) Pipe dream: a financial analysis of the Northern Gas Pipeline, http://ieefa.org/wp-content/uploads/2016/05/Pipe-Dream-A-Financial-Analysis-of-the-NEGI-MAY-2016.pdf

THEME 7.7 ECONOMIC IMPACTS – NET BENEFITS AND DISTRIBUTION

From an economic perspective, the main benefit that would accrue to the NT community from developing unconventional gas resources would be royalties. Mining and gas royalties are a not a major source of funding for Australian state and territory governments[14]. The arguable exception is Western Australia, which receives 15% of its revenue from mining royalties.[15] The NT Budget for 2016-17 is for $132 million in royalty revenue from all mining, just 2% of its $6.55 billion budgeted revenue. Revenue from the Commonwealth Government accounts for over 50% of Territory Revenue.[16]

Increasing gas production through unconventional developments will not change this balance. Claims that further gas production can bring "independence from Canberra" or that it is the Territory's "only hope" are misguided. [17]

The inability of unconventional gas to make serious revenue for state governments is demonstrated by the experience of Queensland. Even after years of gas production and now several years of exports, Queensland gas royalties for this year are budgeted at $68 million. This represents just 0.01 percent of Queensland government revenue.[18]

It should also be noted that the gas industry has a record of avoiding and minimising all payments to Australian governments. Despite Australian gas production increasing to the point where we will become the largest gas exporter in the world, payments received under the Petroleum Resource Rent Tax (PRRT) are declining. The recent LNG

[14] Peel, Denniss and Campbell (2014) *Mining the age of entitlement: State government assistance to the minerals and fossil fuel sector*, http://www.tai.org.au/content/mining-age-entitlement

[15] WA Treasury (2017) Budget Paper 3 Economic and Fiscal Outlook, http://static.ourstatebudget.wa.gov.au/16-17/2016-17-wa-state-budget-bp3.pdf?, p89.

[16] NT Department of Treasury and Finance (2016) Budget Paper 2 Fiscal Outlook and Strategy, http://www.treasury.nt.gov.au/PMS/Publications/BudgetFinance/BudgetPapers/I-BP2-1617.pdf, p17.

[17] Chlanda (2017) Fracked gas our only hope: Northern Institute professor, http://www.alicespringsnews.com.au/2017/04/21/fracked-gas-our-only-hope-northern-institute-professor/ ; Herbert (2015) *Bidders for North East Gas Interconnector named*, http://www.abc.net.au/news/rural/2015-04-02/gas-pipeline-interconnector/6367606

[18] Queensland Treasury (2016) Budget Paper 2: Budget Strategy and Outlook 2016-17, https://s3-ap-southeast-2.amazonaws.com/s3-media-budget/pdfs/budget+papers/bp2/4.%20Revenue.pdf

projects are not projected to pay any PRRT for decades.[19] Large gas companies also routinely pay no company tax in Australia, despite generating huge revenues here.[20]

Balanced against the modest increases in revenue, costs that accrue to the state through infrastructure provision and other forms of subsidy need to be considered. The Northern Territory government and community incur costs in building infrastructure for the mining and fossil fuel industries. Between 2008-09 and 2013-14 the Territory government spent $381 million on measures that wholly benefited the mining and fossil fuel industries.[14] The NT government's expenditure focused on the Inpex gas development. Such expenditure would likely continue with unconventional development as discussed above. This has major implications for the distribution of costs and benefits from mining and gas projects, directing more costs onto the community.

The NT is not unusual in this respect. Western Australia's Treasury noted in 2011 in relation to the development of the Northwest Shelf gas project:

> In 2010 net present value terms, the cost of Western Australia's assistance to the North West Shelf project (e.g. payment of subsidies to the State's power utility to help cover the losses it initially incurred under crucial 'take or pay' gas contracts) is estimated to be around $8 billion.[21]

Queensland Treasury's comments are aimed at mining, but the principle is the same for gas projects:

> Governments face budget constraints and spending on mining related infrastructure means less infrastructure spending in other areas, including social infrastructure such as hospitals and schools. For many projects directly related to assisting mining industry development, such as land acquisitions for state development areas, the expected timeframes for cost recovery are extremely long (sometimes decades). The opportunity cost of this use of limited funds is a real cost to government and the community.[22]

---

[19] Aston (2015) Multinational oil and gas giants paying no petroleum resource rent tax, http://www.smh.com.au/business/the-economy/multinational-oil-and-gas-giants-paying-no-petroleum-resource-rent-tax-20151217-glpusi.html

[20] Kenny (2017) Global gas giants use loophole to avoid tax on billions from Australian operations, http://www.smh.com.au/federal-politics/political-news/global-gas-giants-use-loophole-to-avoid-tax-on-billions-from-australian-operations-20170425-gvrwn9.html

[21] WA Treasury (2011) *GST Distribution Review: WA Submission*, http://www.gstdistributionreview.gov.au/content/submissions/downloads/issues_paper/wa_gov.pdf, page 13.

[22] Queensland Treasury (2013) *Queensland Treasury Response to Commonwealth Grants Commission*

While the costs of assisting mining and gas projects can often be found in budget papers, other costs are more difficult to assess. Environmental costs associated with unconventional gas development also need to be considered. The Australia Institute's research on some of these issues is outlined in the following sections.

THEME 7.3 AIR - CLIMATE CHANGE

The Australia Institute has conducted and commissioned research on methane emissions from unconventional gas extraction. These emissions have been severely underestimated thus far in Australia. Development of unconventional gas in the Northern Territory is likely to lead to significant increases in Territory emissions, but unless Australian methodology changes, these emissions may not be accounted for.

The current methodology for measuring greenhouse gas emissions from unconventional gas extraction is based on assumed and outdated methane emissions factors, rather than direct measurement of wells, pipelines and other gasfield infrastructure. The estimate used by the Australian Government is 0.058 tonnes of methane leaked per kilotonne of methane produced, or 0.0058%. This estimate is based on a historic US emissions factor designed for measuring conventional gas emissions and is no longer used in the USA. Actual measurements by 16 peer reviewed research projects, using improved technology to take direct measurements from gas fields in the US, have ranged from 2-17% of production.[23]

The impact of these unaccounted-for methane emissions is seen in recent research showing that US methane emissions have risen 30% in the last decade. The study used evidence from atmospheric observations to trace the largest rise of these emissions to the central part of the US, where oil and gas extraction has expanded dramatically over the same time period.[24]

In addition to higher emissions from gasfield operations, new research has found that below ground dewatering of aquitards required for unconventional gas extraction may

---

Response to Terms of Reference for Commonwealth Grants Commission 2015 Methodology Review, https://cgc.gov.au/index.php?option=com_attachments&task=download&id=1727

[23] Lafleur et al, 2016, *A review of current and future methane emissions from Australian unconventional oil and gas production*, Melbourne University Melbourne Energy Institute, http://energy.unimelb.edu.au/library/a-review-of-current-and-future-methane-emissions

[24] Turner et al, 2016, *A large increase in U.S. methane emissions over the past decade inferred from satellite data and surface observation,* Geophysical Research Letters, Volume 43, Issue 5, 16 March 2016, p 2218-2224

have caused methane emissions from underground gas deposits to be released into rivers and other weak areas.[25]

As well as the obvious implications of underestimated methane emissions and the ability to meet our Paris climate commitments, there are also cost implications as producers capture a lower portion of reserves than anticipated.

Further information on the fugitive and migratory emissions of unconventional gas emissions can be found in two recent reports from the Melbourne Energy Institute, commissioned by the Australia Institute, *A review of current and future methane emissions from Australian unconventional oil and gas production* and *The risk of migratory methane emissions resulting from the development of Queensland coal seam gas.* Both reports are attached as appendices to this submission.

THEME 7.6 SOCIAL IMPACTS - INSURANCE

Insurance companies have refused to insure against risks associated with unconventional gas extraction, both in Australia and in the US.

In the US, 'homeowners can be confronted with uninsurable property damage for activities that they cannot control. And now a growing number of banks won't give new mortgage loans on homes with gas leases because they don't meet secondary mortgage market guidelines.'[26]

In the north west of NSW, farmers have been refused insurance cover for risks and contamination associated with unconventional gas extraction.[27]

THEME 7.7 ECONOMIC IMPACTS – PROPERTY VALUES

The presence of unconventional gas wells on properties in Queensland have led to banks refusing to accept those properties as securities to give bridging loans. A 2016 letter from the Commonwealth Bank to property owners in Chinchilla, Queensland,

[25] Lafleur et al, 2017, *The risk of migratory methane emissions resulting from the development of Queensland coal seam gas,* Melbourne Energy Institute, http://tai.org.au/content/risk-migratory-methane-emissions-resulting-development-queensland-coal-seam-gas

[26] New York State Bar Association Journal Nov/Dec 2011, pg 12

[27] Caskey, 2015, *CSG too risky for insurers,* http://www.farmonline.com.au/story/3365648/csg-too-risky-for-insurers/

shows that the presence of coal seam gas wells on the property is the reason their application for a bridging loan to buy another property was refused. [28]

A 2014 study by the NSW Valuer Generals on links between property values and unconventional gas industry did not make firm conclusions as a result of the lack of available data on house sales in the period since the industry commenced. It did, however, note anecdotal evidence that 'negative perceptions of CSG led to a reduction in the number of potential purchasers and an increase in the time taken to sell properties.'[29]

THEME 7.7 ECONOMIC IMPACTS - OTHER INDUSTRIES

The rapid expansion of unconventional gas projects has damaged Australia's manufacturing industry through its labour market impacts and effect on gas prices. The unconventional gas industry has also damaged local economies where it operates, impacting small business, agriculture, and local government sectors.

Economic modelling by the Queensland unconventional gas company Arrow LNG for its Economic Impact Assessment found that this project would displace $441.5 million worth of manufacturing output and 1,000 manufacturing jobs in Queensland.[30]

The most detailed examination of the economic impacts of unconventional gas development on local economies was conducted in the Darling Downs. The study was carried out between 2008 and 2013 by the industry-funded Sustainable Minerals Institute (SMI) at the University of Queensland. [31]

This study surveyed stakeholders from different sectors in the local community including the local business community, agriculture, local government, advocacy groups and environmental consultants, as well as the mining and unconventional gas industries.

---

[28] Robertson, 2016, *Commonwealth Bank: coal seam gas makes property 'unacceptable' as loan security,* https://www.theguardian.com/environment/2016/sep/30/commonwealth-bank-coal-seam-gas-makes-property-unacceptable-as-loan-security

[29] Office of the Valuer General, *Study on the impact of the coal seam gas industry on land values in NSW*

[30] See Grudnoff, M (2015) *An analysis of the economic impacts of Arrow Energy's Gladstone LNG Plant.*

[31] Everingham, J, Collins, N, Rodriguez, D, Cavaye, J, Vink, S, Rifkin, W & Baumgartl, T (2013) *Energy resources from the food bowl: an uneasy co-existence. Identifying and managing cumulative impacts of mining and agriculture. Project report*, CSRM, The University of Queensland: Brisbane.

Far from mining and unconventional gas providing economic benefits, local businesses felt that it had reduced financial capital, human capital, infrastructure, social capital and natural capital.

Local businesses have to compete with inflated gas industry wages in order to recruit and retain staff and they experience increased rent and competition for services (particularly trade and mechanical repairs). There are also disruptions to farmers from the rollout of access roads, pipelines, water treatment plants and other infrastructure. Big increases in truck traffic tend to disrupt other forms of transport and damage roads.

Further information about the economic and social impacts can be found in our 2015 report on the impacts of the Queensland unconventional gas industry, *Be careful what you wish for,* attached as an appendix to this submission.

THEME 7.6 SOCIAL IMPACTS - EMPLOYMENT

Gas extraction is a capital-intensive industry; gas companies employ few people relative to the capital invested. Despite this, Australia's gas industry has a history of exaggerating the jobs that will be created from gas projects.

A 2011 report prepared for Santos by Allen Consulting Group found that a potential coal seam gas development in Northwest NSW would increase employment opportunities in NSW by "around 2,900 ongoing full time positions", even though the project would only create about 30 gas industry jobs. Over 500 jobs would apparently be created in the public sector, at taxpayer expense.[32]

A 2012 report prepared for the Australian Petroleum Production and Exploration Association (APPEA) by Deloitte found that the "economy-wide impacts" of new oil and gas projects included increasing Australia's employment by 103,000 full-time equivalent jobs in 2012.[33] APPEA used this research to justify its claim that the natural gas industry (oil was not mentioned) was responsible for 100,000 jobs in 2012.[34]

[32] Lamacraft, Brown and Claughton (2014) *Santos "a first class operator",* http://www.abc.net.au/news/rural/programs/nsw-country-hour/2014-06-20/nsw-santos-on-jobs-and-water/5538608 , The Allen Consulting Group (2011) *The economic impacts of developing coal seam gas operations in Northwest NSW,* http://www.acilallen.com.au/cms_files/acgeconomicimpactcoalseam2011.pdf

[33] Deloitte Access Economics (2012) *Harnessing our comparative energy advantage,* p 31

[34] APPEA (n.d.) *Campaign messages,* https://www.ournaturaladvantage.com.au/campaign-messages/

In fact, the ABS found that employment in oil and gas extraction increased by 9,400 between May 2012 and May 2013 (to 24,700). Even when temporary construction jobs created to build the projects are taken into account (about 40,805),[35] that would still be 49,795 jobs short of APPEA's 100,000 jobs claim.

Employment in the gas industry is in decline. As of February 2017, there are 19,200 total employed people in oil and gas extraction, 16,900 fewer than the peak in August 2015 (36,100).[36]

Far from creating many additional jobs, the coal seam gas industry has been found to reduce employment in certain sectors. A study of Queensland's unconventional gas expansion by CSIRO's Gas Industry Social and Environmental Research Alliance found that for every 10 additional people employed in coal seam gas, 18 agricultural jobs were lost. The expansion did cause a growth in construction and professional service jobs (jobs related to short-term construction) but virtually no additional retail or manufacturing jobs.[37]

Figure 1: Coal seam gas (CSG) employment spillovers over different sectors

	Elasticity	Additional job for each new CSG job
Local goods sector		
Construction	0.832 (0.426)*	1.414
Professional services	0.704 (0.259)**	0.422
Retail trade	0.011 (0.140)	0.024
Accommodation and food services	0.375 (0.263)	0.471
Other services	−0.385 (0.247)	−0.890
Tradable goods sector		
Manufacturing	0.068 (0.199)	0.160
Agriculture	−0.314 (0.182)*	−1.790

Source: Fleming and Measham (2014) Local economic impacts of an unconventional energy boom, p 90

Territorians seeking employment for any unconventional project in the Northern Territory will have to compete with experienced workers from interstate, including the 16,900 fewer people employed now than they were at the industry's employment peak. These thousands of highly-qualified workers are more likely to fill positions than

35 Calculation by The Australia Institute based on available Bureau of Resources and Energy figures: The Australia Institute (2013) *Did the gas industry create 100,000 jobs last year?*, http://www.factsfightback.org.au/did-the-gas-industry-create-100000-jobs-last-year-check-the-facts/

36 ABS (March 2017) *Labor Force, Australia, Detailed, Quarterly*, http://www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/6291.0.55.003Feb%202017?OpenDocument

37 Fleming and Measham (2014) *Local economic impacts of an unconventional energy boom*, p 78-94

unskilled Territorians with no experience in gas field construction and operation. When the gas industry employs local people, they tend to be skilled workers who relocate from local manufacturing and agriculture.

Experience in Queensland has shown that construction workforces are almost entirely male non-residential workers living in workers camps on the outskirts of towns. These workers are often referred to as fly-in, fly-out (FIFO) or drive-in, drive-out (DIDO). Few people from local regional communities are likely to be employed in either the construction or the operational phases of the gas fields.

CONCLUSION

The development of unconventional gas would present the Northern Territory community with considerable risks and few benefits. It is likely to reduce energy security by linking the Territory to volatile east coast or world markets. Considerable costs could be incurred in relation to gas infrastructure, while the benefits of royalties are likely to be modest.

THE UNIVERSITY OF MELBOURNE

MELBOURNE ENERGY INSTITUTE

A review of current and future methane emissions from Australian unconventional oil and gas production

October 2016

Dimitri Lafleur - PhD student, Australian-German Climate and Energy College[1]
Tim Forcey - Energy Advisor, Melbourne Energy Institute[1]
Hugh Saddler - Hon. Assoc. Professor, Crawford School[2]
Mike Sandiford - Professor of Geology, School of Earth Sciences[1]

1. University of Melbourne
2. Australian National University

MELBOURNE ENERGY INSTITUTE

`

Table of Contents

Melbourne Energy Institute
McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

Melbourne Energy Institute
McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

About the University of Melbourne Energy Institute (MEI)

The University of Melbourne Energy Institute is an access point for industry, government and community groups seeking to work with leading researchers on innovative solutions in the following areas: new energy resources; developing new ways to harness renewable energy; more efficient ways to use energy; securing energy waste; and framing optimal laws and regulation to achieve energy outcomes.

About the Authors

Dimitri Lafleur is a PhD student at the Australian German College of Climate and Energy Transitions at the University of Melbourne. Dimitri worked for the oil and gas company Shell for 11 years in the Netherlands and Australia after graduating from the University of Utrecht with an MSc geology/geophysics. Dimitri is researching the climate impact of fugitive emissions of the fossil fuel industry and unconventional gas in particular.

Tim Forcey is a Chemical Engineer with over 30 years of experience in industrial energy with ExxonMobil, BHP Billiton, and Jemena, including specific experience with assets such as the Bass Strait oil and gas joint venture and the Queensland Gas Pipeline. With the Melbourne Energy Institute, Tim has published reports and articles covering gas and electricity demand, gas-to-electricity fuel-switching, applications of heat pump technology, and pumped-hydro energy storage.

Dr Hugh Saddler is Principal Consultant in the Climate Change Business Unit of Pitt & Sherry and an Honorary Associate Professor at the Crawford School of Public Policy at the Australian National University. He has been fully engaged in the analysis of major national energy policy issues in the UK and Australia as an academic, government employee and consultant. He is the author of a book on Australian energy policy and of over 70 scientific papers, monographs and articles on energy, technology and environmental policy.

Prof Mike Sandiford is Chair of Geology at the University of Melbourne, and was Foundation Director of the Melbourne Energy Institute from 2009-2016. Mike has published over 170 peer-reviewed scientific papers. He was recipient of consecutive ARC professorial fellowships (2000-2009), the Mawson Medal from the Australian Academy of Sciences in 2004 for outstanding contributions to Australian Earth Science, the Hobbs Medal, the Carey Medal, and has thrice been awarded the Stilwell Medal from the Geological Society of Australia. He is a fellow of the Australian Academy of Science and the Geological Society of Australia.

Acknowledgement

The University of Melbourne Energy Institute acknowledges The Australia Institute (TAI) for their support of this research.

Executive summary

Background

Methane is a powerful greenhouse gas, 86 times more powerful than carbon dioxide when its atmospheric warming impacts are considered over a 20-year time period, and 34 times more powerful over a 100-year time period. Reducing methane emissions is therefore an important part of any strategy to avoid dangerous climate change, as agreed by world leaders at the December 2015 Paris conference. Given the vast growth potential of unconventional oil and gas in Australia, this review addresses the current understanding of methane emissions by that industry, referencing recent developments in overseas jurisdictions.

If natural gas is to provide maximum net climate benefit versus coal, the release of methane to the Earth's atmosphere (both intentional and unintentional) must be held to less than about one per cent of total gas production. In this context, the commitment of the Australian CSG-LNG industry[1] to limit methane emissions to no more than 0.1% of total gas production is commendable.

Findings

In its most-recent greenhouse-gas inventory submitted to the United Nations, the Australian Government reported that methane emissions from the oil and gas industry amounted to 0.5% of gas production. Despite rapid increases in produced-gas volumes, Australia's oil and gas sector-methane emissions have been reported as declining since 1990 and increasing only slightly since 2005. At face value, this result is in-line with industry commitments to keep methane emissions low.

However, this low level of reported methane emissions contrasts with unconventional gas developments in the United States where emissions ranging from 2 to 17% of production have been reported. These measurements have led the U.S. Environmental Protection Agency (EPA) to increase official estimates of methane emissions from the total 'upstream' oil and gas production sector by 134%, and to revise its estimates of emissions from gas production to 1.4% of total production. As a result, U.S. regulators are placing increasing scrutiny on unconventional methane emissions, with Canadian Prime Minister Justin Trudeau and U.S. President Barack Obama recently agreeing to new initiatives to reduce methane emissions.

[1] Coal seam gas (CSG) produced for the purpose of being exported as liquefied natural gas (LNG).

In the U.S., new technologies including satellite and aircraft-based systems have been used to detect methane emissions and quantify emission rates. Of particular relevance to Australia is the recent documentation of the San Juan Basin methane 'hot-spot' at the world's largest CSG-producing region. U.S. research has found that a few 'super-emitters' can dominate the methane-emissions profile of an oil and gas producing area. A key learning is that methane-emission surveys must comprehensively examine all potential emission points in order to ensure no 'super-emitters' are missed. Few of these technologies have yet been applied in Australian oil and gas fields, so the occurrence or otherwise of 'super-emitters' in Australia is unknown.

Detection and attribution of migratory emissions is a key concern. Migratory emissions may occur naturally, or as a result of the preliminary CSG-production phase of coal-seam dewatering, or as a result of cumulative activity by gas producers and other activities such as groundwater pumping. The pathway of migratory emissions can be impacted by the use of hydraulic fracturing and the presence of pre-existing water or minerals exploration bores. Gassy water bores and gas bubbles rising from streams and rivers provide clear evidence of migratory methane-emissions in Australian coal seam gas fields, although the scale of the issue is not able to be constrained and its relationship to coal seam gas development remains tenuous because of a lack of baseline information. In combination, such issues make it difficult to assess whether industry is meeting its methane-emissions commitment.

Currently, the National Greenhouse Gas Inventory reports methane emissions based on default emission factors, none of which relate specifically to the production of coal seam gas in Australia. The National Inventory Report (NIR) states that emissions from 'production' are estimated using a single emission factor of 0.058 tonnes of methane per kilotonne of methane produced, i.e. 0.0058%. The NIR states that this value is validated by measurements made by CSIR0. However, the CSIRO study was confined to methane leakage at well pads. CSIRO noted that large methane emissions emanating from neighbouring water-gathering lines, water-pump shaft seals, and gas compression plants were not measured because they were outside the prescribed scope of their study. Such observations suggest that the factor of 0.058 tonnes of methane per kilotonne of methane produced may substantially underestimate 'production' emissions for the associated network of gathering lines, compressors and pumps along with wellheads.

If Australia's methane emissions from unconventional gas production are higher than reported, this represents an opportunity cost in terms of last gas sales and a liability to future carbon pricing. Using the current global warming potentials of 34 (100-year) and 86 (20-year), and a carbon pricing regime of A$25 per tonne CO2-e, the potential economic costs of methane emissions from the Australian unconventional gas industry rise by A$230 - 580 million annually for each additional 1% of methane emitted. At double the current rate of production, and with methane emissions at 6% of gas production as appears to be the case in some U.S. gas fields, the forgone revenue from reduced sales volumes would amount to $2.2 billion per year at a gas sales price of $10/GJ, while carbon pricing liability would amount to A$2.8 - 7 billion per year.

McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

In summary, our review finds that:

- no baseline methane-emission studies were completed prior to the commencement of the Australian CSG-LNG industry
- there is significant uncertainty about methane-emission estimates reported by oil and gas producers to the Australian government, and by the Australian government to the United Nations. The United Nations has requested that Australia improve its methodologies.
- Australian methane-emission reporting methodologies rely to a significant extent on assumed emissions factors rather than direct measurement
- the assumptions used to estimate methane emissions include some that are out-dated, and some that lack demonstrated relevance to the Australian unconventional oil and gas industry
- despite Australian Government greenhouse-gas reporting requirements having been established in 2009 and Australia's unconventional gas industry operating at significant scale since 2010 and rapidly expanding since, there has as yet been no comprehensive, rigorous, independently-verifiable audit of gas emissions. Indeed, to quote CSIRO, "reliable measurements on Australian oil and gas production facilities are yet to be made." (Day, Dell'Amico et al. (2014))
- if methane emissions from unconventional oil and gas production are being significantly under-reported, this could have a large impact on Australia's national greenhouse accounts.

Recommendations

Given the scale of Australia's prospective unconventional oil and gas reserves, the importance of the industry in economic terms, and the uncertainty surrounding current and future emissions, it is critical that greater certainty and transparency is established around the industry's methane emissions. To ensure that methane emissions from unconventional oil and gas production are minimised we recommend that

- in existing and prospective unconventional oil and gas production regions, baselines are established so that the methane-emissions character of a region is known prior to expansion of oil and gas production or deployment of wells and other equipment
- commitments made by CSG-LNG producing companies in Environmental Impact Statements (EISs) are mandated and confirmed with regular, rigorous, and verifiable audits. Factor-based assumptions should be replaced with direct measurement where emissions may be significant.
- the latest-globally-available technologies and techniques are used to detect, quantify, cross-check, and minimise methane emissions
- priority is given to the implementation of methane-emission-detection techniques that can ensure no 'super-emitters' go undetected.

1. Introduction

This report reviews current understanding of the methane emissions that may result from Australian unconventional oil and gas production. Informed by recent research from the United States and elsewhere, potential gaps in our knowledge about the Australian oil and gas industry's methane emissions are summarised, as are ways to fill those knowledge gaps. Actions are outlined for Australian industry, regulatory bodies, legislators, and researchers.

Oil and gas has 'conventionally' been produced from underground rock layers consisting of sandstone or carbonates. These rock layers must have adequate permeability and porosity in order for oil and/or gas to flow relatively-freely to a well bore.

'Unconventional' oil and gas is produced from underground rock layers that have lower permeability and porosity. Unconventional oil is produced from underground shale layers, while unconventional gas can be produced from shale, coal seams, and 'tight' sandstones.

In order for oil and/or gas to flow from rocks with low permeability and porosity, unconventional oil and gas is produced using technologies including:

- large numbers of densely-spaced wells
- horizontal directional drilling
- coal-seam dewatering
- fluid-flow stimulation methods such as hydraulic fracturing (i.e. fracking).

Unconventional gas production has rapidly expanded in Australia over the last decade. This is predominantly in the form of coal seam gas (CSG) produced in Queensland where more than $A 60 billion has been invested in gas production and liquefied natural gas (LNG) export facilities. With gas production set to triple, Australia is set to overtake Qatar as the world's largest LNG exporter. Australia is very prospective for ongoing expansion of coal seam gas production as well as unconventional oil and gas that may be produced from tight sandstones and shale.

Gas is comprised mainly of methane (CH_4). Direct emission of methane to the atmosphere during production and distribution need to be minimised because methane is a powerful greenhouse gas, with significant climate impact. Methane emissions can also have local health and safety impacts, and can contribute to regional air pollution and asthma via its contribution to the formation of low-level (tropospheric) ozone. Emitted methane also represents a loss of saleable product and revenue for gas producers and resource owners.

In the United States, official methane emissions from unconventional oil and gas production are based on estimates made by the U.S. Environmental Protection Agency (EPA). For the last few years, with funding of around $US 18 million, researchers have been challenging the validity of reported U.S. emissions data by conducting 'bottom-up' ground-level field measurements and analysing 'top-down' atmospheric data recorded via satellites, aircraft, and air-quality monitoring towers.

This recent research has led the several U.S. states and the U.S. EPA to regulate some methane emissions from oil and gas production activities. In February 2016, the U.S. EPA more than doubled estimates of methane emissions from 'upstream' oil and gas production facilities (Table 4).

On 10 March 2016 at a joint press conference with Canadian Prime Minister Justin Trudeau, U.S. President Barack Obama described new initiatives to reduce the amount methane emitted by the oil and gas industry.

In Australia, there are, at present, no regulations that directly limit methane emissions from oil and gas production. Currently, the oil and gas industry reports methane emissions to the Australian Government using the National Greenhouse and Energy Reporting Scheme (NGERS). However, the emissions reported by industry are generally estimates based on factors developed years ago by the United States oil and gas industry for estimating the amount of methane emitted using conventional production methods. Reviewers have questioned the relevance of these factors for use by the Australian coal seam gas industry. However, with the 2014 repeal of the Australian carbon-pricing mechanism, no financial transactions currently rely on these estimates.

Not reported in any jurisdiction globally are estimates of 'migratory' methane emissions that maybe impacted by unconventional oil and gas production. Migratory emissions occur when methane migrates upward and laterally out of its original reservoir, eventually reaches the Earth's surface, and enters the atmosphere possibly at a considerable distance away from the site of original oil and gas drilling or other disturbance.

2. Why it is important to focus on methane emissions from Australian unconventional oil and gas

This section describes why it is important to focus on methane emissions from Australian unconventional oil and gas production. The very large scale of Australia's current and possible-future unconventional oil and gas industry are briefly described, as is the potential for this industry to produce large volumes of methane emissions. This is followed by a discussion of the impacts of methane emissions on global climate change and on local and regional health, safety, and environment. As described in Section 7, gas-producing companies also have financial and reputational reasons to focus on methane emissions.

2.1. Australia's unconventional oil and gas industry and emission potential is large

The last decade has seen a rapid expansion of Australian unconventional gas production. Predominantly, this has been in the form of coal seam gas produced in Queensland.
In that state, more than $A 60 billion has been invested in facilities to produce, liquefy, and export gas. (See further discussion of coal seam gas in Section 5.1.) In 2017, gas production across eastern Australia will be three times what it was in 2013. When Queensland's gas exports are combined with those of Western Australia and the Northern Territory, Australia will overtake Qatar as the world's-largest gas exporting country.

In addition to coal seam gas, Australia is highly prospective for unconventional oil and gas that may be produced from tight sandstones and shale layers (Section 5.2). Taken together, sufficient gas resources exist in Australia that, if produced at current rates, would not deplete until well beyond one hundred years from today.

Given the massive size of these gas resources, Australia's oil and gas industry could also be among the world leaders in emitting methane to our Earth's atmosphere. As further described in Section 5, if Australian unconventional gas production expands to twice its present size (to 3,000 petajoules per year), and if a methane-emission rate of 6%-of-production prevails, the resulting emissions would be equivalent to approximately half of Australia's total nation-wide greenhouse-gas emissions currently reported across all sectors.

2.2. The Paris climate change agreement

In December 2015 with the adoption of the Paris Agreement, the global community agreed to limit dangerous climate change by:

> "holding the global average temperature to well below 2°C above pre-industrial levels and ... pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels" (UNFCCC (2015)).

In order to achieve this goal, the Paris Agreement also aims to achieve net-zero greenhouse-gas emissions in the second half of this century[2]. An important basis for the 2°C target in the Paris Agreement is the probability that planetary warming triggers 'positive' climate-feedbacks. A key objective of the Agreement is to reduce the probability of reaching tipping points that will trigger irreversible change to the Earth as we know it, including changes to human life, society, flora, fauna, and biodiversity.

Lenton, Held et al. (2008) postulated various elements that could trigger a different state of our Earth's climate. Examples of tipping elements include:

- the melting of Arctic summer sea-ice,
- the melting of the West Antarctic, Greenland and East Antarctic ice sheets,
- the overturning of the Atlantic Ocean thermohaline circulation
- dieback of the Amazon forest.

Joughin, Smith et al. (2014) and Rignot, Mouginot et al. (2014) found evidence for the current collapse of various West Antarctic ice sheets with no obstacles to further retreat, suggesting the West Antarctic tipping point has already been reached. Joughin, Smith et al. (2014) showed that current warming will result in a 1.2 metre sea-level rise from the West Antarctic Amundsen Sea sector. The full discharge of that ice from that sector would result in sea-level rise of three metres (Feldmann and Levermann (2015). It has been suggested that the Arctic summer-ice tipping point has also been reached (Lindsay and Zhang (2005)).

The main driver of climate change is human-induced (anthropogenic) greenhouse-gas emissions that result from burning fossil fuels and land use change. Given that the halfway mark to 2°C was surpassed in 2015 (1°C of warming since pre-industrial times, Met Office (2015)) and that only a limited carbon budget remains, large greenhouse-gas emission reductions in the next 20 to 30 years are critical in order to achieve the goals of the Paris Agreement. If emissions continue to rise as they have done in the recent past (the so-called RCP 8.5 Business-as-Usual scenario, Figure 1), a 2°C global temperature increase could be reached as early as between 2040 and 2050 (Figure 1, right-hand scale).

[2] Article 4.1 of the Paris Agreement (2015)

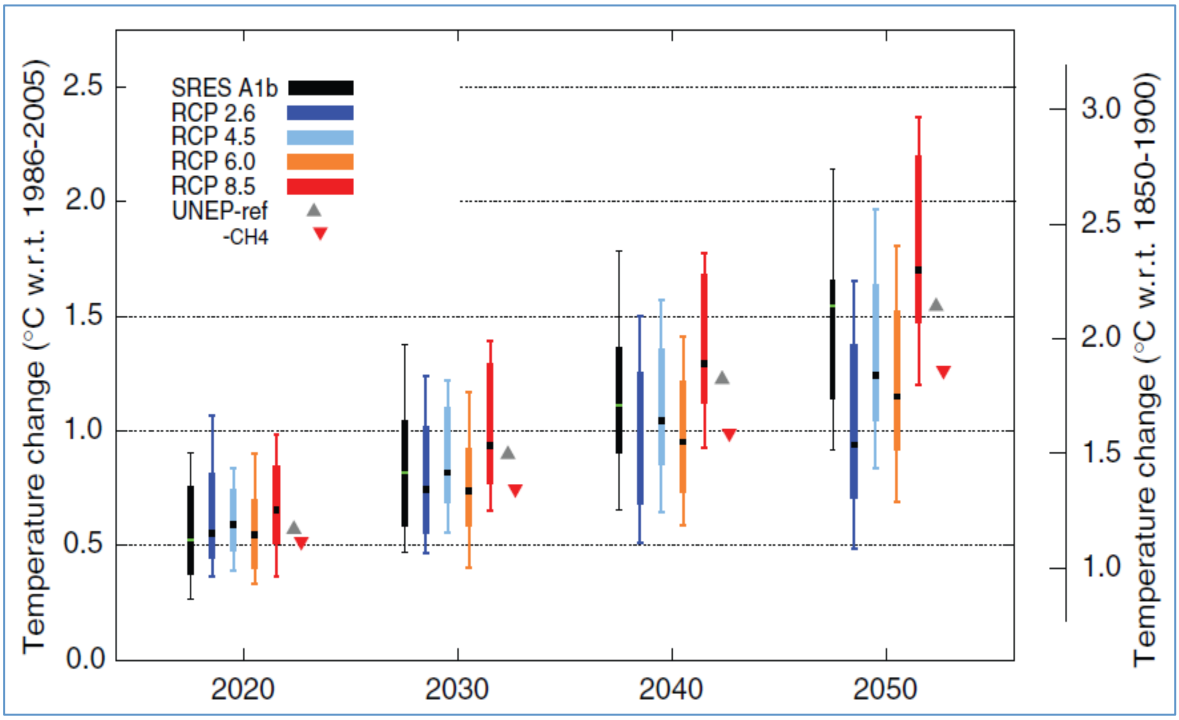


Figure 1: Global average 10-year mean surface temperature increase based on the current four IPCC model ensembles (dark blue: RCP 2.6, light blue: RCP 4.5, orange: RCP 6.0 and red: RCP 8.5), and the previous model ensembles (black: SRES A1b). Left vertical scale is temperature change with regards to 1986-2005 average; right vertical scale is temperature change with regards to 1850-1900 average. The bars represent 17-83% confidence intervals; the whiskers represent 5-95% confidence interval. The triangles represent UNEP model estimates (grey: the reference model and red: the model implementing CH4 emission reduction technologies). The 'business as usual' scenario (RCP 8.5) reaches a 2°C warming most likely between 2040 and 2050 (Figure 9.24a in IPCC (2013))

In the lead up to the Paris Agreement, most nations submitted intended nationally-determined contributions (INDCs) and pledged national greenhouse emission reductions for the period to 2030. If nations achieve emission reductions no greater than their INDCs, the total annual emissions (50 to 56 Gt CO2-e/yr) would be 1.6 times above the emission reductions required (37 Gt CO2-e/yr) to stay within 2°C (Meinshausen, Jeffery et al. (2015), Meinshausen (2015), Meinshausen (2016)). Current INDCs would cause a 2.6 to 3.1°C warming above pre-industrial times to occur by the year 2100 (Rogelj, Elzen et al. (2016, under review), CAT (2015)). Hence, greater emission reductions are necessary than the INDCs that have currently been submitted.

Australia's current pledge is to reduce 2030 emissions to a level 26 to 28% below the 2005 emissions level (UNFCCC (2015)). Based on a 'fair' contribution for a global 'least-cost' 2°C path, Australia's contribution should be higher than has so far been pledged. For example, an Australia showing global climate leadership would aim at a 66% reduction of 2030 emissions compared to 2010 emissions.

Based on equal cumulative per-capita since 1950 approach, Australia should adopt a 52% reduction (Meinshausen, Jeffery et al. (2015)), (Australia's INDC factsheet in Meinshausen (2016)).

The international community is committed to reducing carbon dioxide emissions in the next decennia. Given the commitment to the 2°C target, reducing methane emissions as soon as possible will provide the largest impact on global peak temperature, as well as the largest eco-system benefit. This role of methane emission reductions in a carbon-constrained world will be explained in the next section.

2.3. Methane emission reductions are most effective when done in the near term

This section discusses why near term methane emission reductions have the largest effect given the international commitment to the Paris Agreement.

The concentration of methane in our Earth's atmosphere has tripled since pre-industrial times and continues to rapidly rise (see Figure 2). Figure 2 also shows that following a decade of slow growth (1997-2006), the concentration of methane in the atmosphere has increased at an accelerating rate in the last decade (Turner, Jacob et al. (2016)).

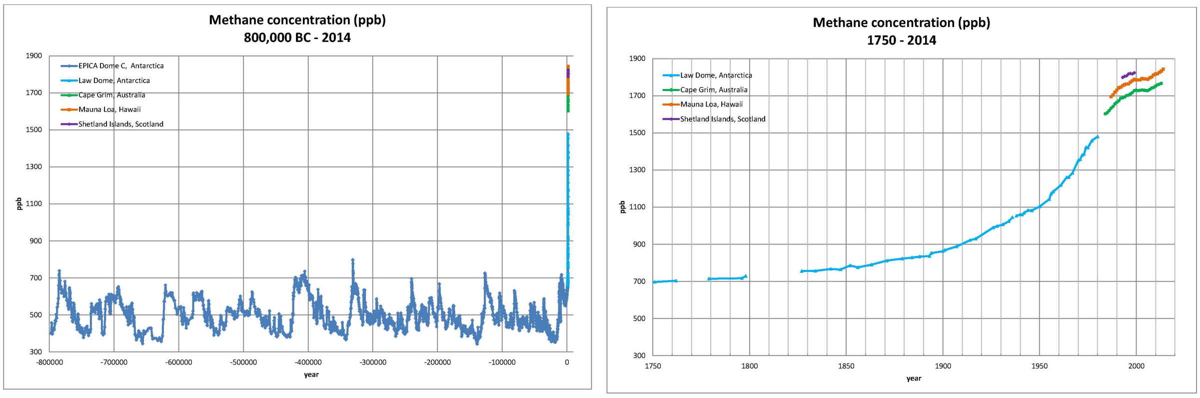


Figure 2: Atmospheric methane concentration shown in parts per billion (ppb), from hundreds of thousands of years ago, through to 2014. Left: Timeframe 800,000BC to 2014, showing concentrations have not been higher than 800ppb until very recent. Right: Timeframe 1750 to 2014, showing concentrations have almost tripled since 1750, and the rate of increase has accelerated again since 2006. Data source: EPA (2016). Data are from historical ice core studies (Loulergue, Schilt et al. (2008), Etheridge, Steele et al. (2002)) and recent air monitoring sites (NOAA (2014), NOAA (2015), Steele, Krummel et al. (2002)).

Given its chemical structure, methane is a more powerful greenhouse gas (has a higher 'global warming potential' or GWP) than carbon dioxide (on a per-kilogram basis). The global warming potential of methane equals the contribution to the climate forcing from one kilogram of methane when compared with the impact of one kilogram of carbon dioxide, integrated over a time period (e.g. Fuglestvedt, Berntsen et al. (2003)).

Carbon dioxide remains in the atmosphere for centuries, whereas methane decomposes to form carbon dioxide in approximately ten to twelve years (Myhre, G. and Shindell, D., 2013). Using standard comparison metrics (IPCC (2013)) methane is considered to be 86 times more powerful as a greenhouse gas than carbon dioxide when considered over a 20-year timeframe (GWP_{20} = 86), and 34 times more powerful when considered over a 100-year timeframe (GWP_{100} = 34)[3].

The use of GWP_{20} allows for an emphasis on the short-term impacts of a gas. The near term consequences of CH4 are certainly important: if one is concerned about tipping points in the next decades, about near term temperature thresholds, the use of GWP_{20} emphasises the near term effects of CH4 emissions. If CH4 emissions were to be reduced drastically in the near term, it would buy the planet some time with regards to the targets stipulated in the Paris agreement.

In this report we have decided to use a 20-year GWP for methane. The main reason is that there is a global agreement to stay within 2 degrees of warming. This warming may be reached as soon as 2040 if emissions are not curbed. This is a timeframe over which current and near-term methane emissions have the largest impact.

Bowerman, Frame et al. (2013) showed that under a RCP2.6 scenario (equivalent to a 1.5°C increase in global mean surface temperature at the end of the century), the climate will benefit most when methane emissions are reduced early, together with strong reductions in carbon dioxide.
The commitment to the Paris agreement implies strong reductions in carbon dioxide emissions in the near term. Reducing methane emissions and introducing strong methane emission reduction policies will therefore have the greatest effect on peak temperature when done in the near term (Figure 3, left graph).

[3] Note that there are inconsistencies between how methane emissions are reported to the IPCC and how they would be reported if the latest available science would be applied. The Australian Government reports methane emissions in units of tonnes CO2 equivalent (t CO2e), using the 100-year Global Warming Potential (GWP) of methane of 25. As agreed at the Doha 2012 conference, to convert methane emissions to CO2-e, they are multiplied by the 100-year GWP value of 25 as defined in the 4th IPCC Assessment report (2007). This conversion factor has been used by all parties reporting in the 2nd commitment Kyoto period (2013-2020). Australia is therefore currently following the international convention, although the National Inventory Report 2014 (August 2016) still uses a GWP of 21 for surface mines, presumably because it relies on reports that were prepared much earlier. In the 5th Assessment report (2013) methane's 100-year GWP has been revised to 28-34, depending on whether carbon cycle feedback are excluded or included. The change is due to the way GWP values are normalized against CO2, not because changes in our understanding of methane. Because the radiative absorption of CO2 decreases with increasing CO2 concentration, the GWP of methane relative to CO2 has increased with time from 25 in 2007 to 28 in 2013 (or 34 with feedbacks). It is important to note that the radiative forcing of CO2 dominates because of much higher abundance (400ppm, compared to 1.8 ppm methane).
If convention decided to increase the 100-year GWP for methane to 34, then all the historical reporting would likely also be adjusted to prevent a stepwise increase in emissions. Here we use a 20-year GWP of 86, and a 100-year GWP of 34 (including carbon cycle feedback), because those are the most recent best estimates.

In the situation where carbon dioxide emissions peak later than anticipated (e.g. RCP4.5), reducing methane emissions in the short term can delay global peak temperature and allow for a slightly larger carbon dioxide budget (Bowerman, Frame et al. (2013)). This delay will also be beneficial to global eco-systems as the short-term temperature increase will be slower (Figure 3, right graph).

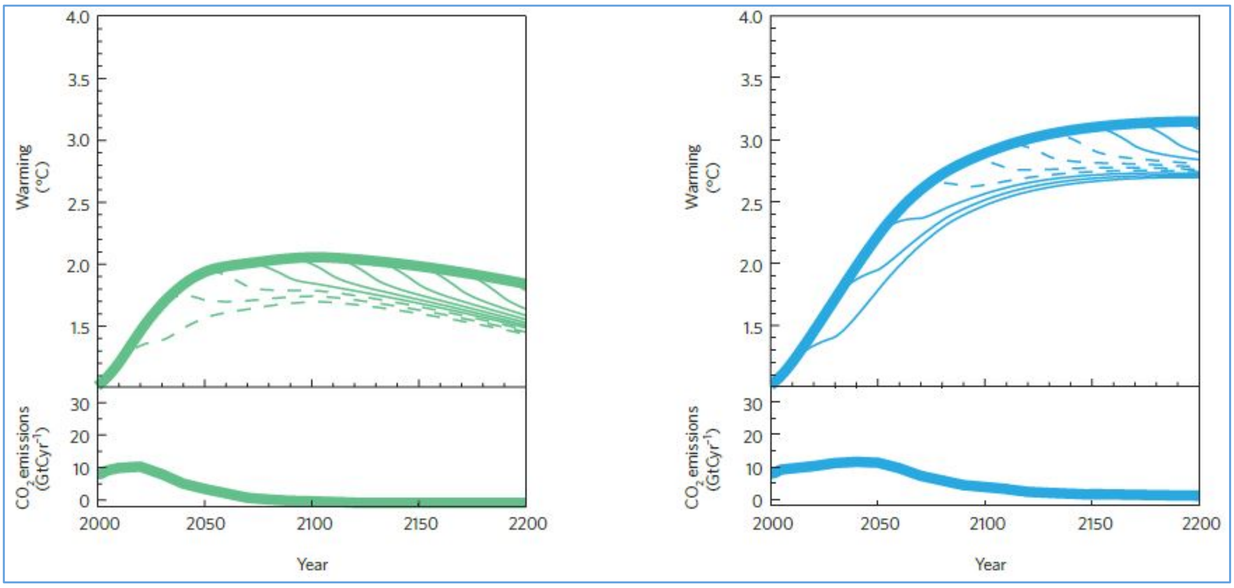


Figure 3: from Bowerman, Frame et al. (2013). Impact of short-lived climate pollutants (SLCP, incl. methane) in the RCP2.6 and RCP4.5 scenarios (1.5°C and 2.4°C warming at the end of the century respectively). The thick line represents the global warming (upper panel) and carbon dioxide emissions (lower panel). The thin lines represent the impact of cutting SLCPs at different times: a dashed line corresponds to SLCP cuts that have more than 0.06°C impact on peak warming relative to delaying the SLCP measures by two decades, whereas a solid line corresponds to SLCP cuts that less than 0.06°C impact.

Shindell, Kuylenstierna et al. (2012) calculated the financial valuation of the benefits of avoiding global warming, crop loss and loss of life by reducing short lived climate pollutants such as methane. These benefits outweigh the abatement cost[4]: two thirds of the benefits have a far greater valuation than the incurred abatement costs. The benefit however would not necessarily flow to those allocating investment for methane abatement. Emission reduction in the coal, oil and gas sector account for two-thirds of the benefits as the technologies to mitigate emissions are readily available. Methane emission reductions are therefore complementary to carbon dioxide reduction measures in order to limit global mean warming to less than 2°C.

In some future-energy scenarios, gas is considered to play a role in the transition to lower greenhouse-gas emitting energy sources (IEA (2012), IEA (2015), EIA (2015)). This is because burning gas results in 60% of the carbon dioxide emissions that occur when the same amount of energy is produced by burning coal. If Australia is to move away from coal and produce more gas (including LNG for export), in order to reduce carbon dioxide emissions and to meet its INDC,

[4] Since financial discounting emphasises near term impacts, a GWP20 or GTP20 for methane is used.

it would be prudent to mitigate methane emissions at the same time: if the climate benefit of reducing carbon dioxide emissions comes with an overhang of direct methane emissions, any benefit will be smaller than expected because methane is also a potent greenhouse gas (Sections 3, 4 and 5).

For these reasons, avoiding preventable methane emissions should be a standard practice and introduction of methane reduction policies in the near term would have the largest effect in light of the Paris Agreement.

2.4. Local and regional health, safety, and environmental impacts of methane emissions

As described in this section, in addition to the global climate impacts of methane, it is also important to minimise methane emissions in order that local and regional health, safety, and environmental impacts are also minimised.

2.4.1. Fire and explosion risks of methane emissions

Methane is colourless, odourless, yet flammable gas. If ignited, methane can pose a fire or explosion risk to people, infrastructure, or vegetation located nearby.

Methane is flammable in air when present at concentrations between 5 and 15% (by volume). At concentrations above 15%, the methane/air mixture is too 'rich' to burn; however, subsequent dilution with air can bring a release of concentrated methane into the flammable range.

Since methane is lighter than air, it will tend to quickly rise and disperse and eventually reach concentrations lower than what is required for the mixture to be flammable. However, methane emitted into confined spaces where it cannot disperse poses an explosion risk.

Once ignited, a methane fire can cause nearby vegetation or flammable infrastructure to also ignite. Ignition of methane present in a Queensland exploration well has been reported (Australian Government (2014)).

In gas-producing regions, methane present in water bores, in household water taps, and bubbling from the Condamine River in Queensland has been intentionally ignited.

Rather than simply venting (i.e. releasing or emitting) excess methane into the air, gas-facility operators may choose to burn methane by using a purpose-constructed 'flare'. Burning methane in this way (i.e. 'flaring') reduces the risk of fire occurring anywhere except at the flare. (Converting methane to carbon dioxide in the flare also reduces the climate impact of the original pollutant.) However, if not properly managed, flares themselves can constitute a fire risk to any people, infrastructure or vegetation nearby. Depending on their design, flares can also emit light, noise, and visible discharges such as smoke or soot that a local community may find objectionable. In certain situations, gas-facility operators may opt to not use an available flare and instead vent excess methane in order to reduce fire risk (for example on days of 'total fire ban') or the potential for community complaints.

2.4.2. Air quality and respiratory health impacts related to methane emissions

Methane (a colourless and odourless gas) is lighter than air. When released into the air, methane will tend to quickly rise and disperse.

Methane at high concentrations (where air is excluded) can asphyxiate humans and animals. For humans, exposure to oxygen-deficient atmospheres may produce dizziness, nausea, vomiting, loss of consciousness, and death. At very low oxygen concentrations, unconsciousness and death may occur without warning.

Breathing methane in air at low or dilute concentrations has not been identified as a health risk (Stalker (2013)). However, at a regional level, via its role in the formation of low-level (tropospheric) ozone, methane can contribute to smog and increase the frequency of asthma attacks (White House (2014)).

Gas released into the air, though predominantly consisting of methane, may also contain other contaminants that are hazardous to human health. These other contaminants may have come from the original coal, shale or sandstone reservoir, or have been added as part of processing the gas for transport or sale.

The act of burning methane (e.g. by using a flare, furnace, gas engine or other device), can produce pollutants such as formaldehyde which is a known respiratory health hazard, and other combustion by-products which contribute to the formation of smog.

2.4.3. Water-quality health impacts related to methane emissions

As a result of unconventional oil and gas extraction, methane has been known to enter drinking water supplied by water bores. When dissolved in and consumed with drinking water, methane has not been identified as a health risk (Osborn, Vengosh et al. (2011)). However, if methane enters aquifers used for drinking water, it can become a fire and/or explosion risk if the methane is released into confined spaces or ignited at the point of discharge from piping or water taps.

The presence of methane in water used for drinking or agriculture may indicate a risk of other contaminants. For example In 2015 in New South Wales, BTEX (benzene, toluene, ethyl benzene, xylenes) was found in water that had been extracted from coal seams by a CSG-producing company (NSW Government (2015)). BTEX in the community and environment is closely controlled because benzene is a known carcinogen.

2.4.4. Other flora, fauna, and biodiversity impacts of methane emissions

Methane emissions rising from the ground may impact the flora and fauna situated in close proximity to the release. This has been observed in the Queensland coal seam gas development area where vegetation stress has been observed at seep locations (Norwest (2014)). Loss of animal life is possible where methane displaces air, thereby creating a low-oxygen environment.

3. Methane emissions are critical when assessing the climate impact of gas

This section describes why the climate impact of using gas greatly depends on how much methane is emitted to the atmosphere when that gas is produced, transported, and used.

As described in Section 2.2, world leaders have agreed to act to limit dangerous climate change. Improving the efficiency of energy-use and shifting from fossil to renewable energy sources have been identified as a way to help achieve this goal.

However, often the climate change impact of gas is not compared with energy-efficiency and renewable energy alternatives, but rather with the impact of another fossil fuel: coal. Some proponents have claimed that gas can have lower climate impacts than coal (APGA (2016), APLNG (2016), APPEA (2016), CEFA (2016), ENA (2015)). Coal is composed predominantly of the element carbon. When carbon is burned, it is converted to carbon dioxide, a greenhouse-gas.

Gas, on the other hand, is composed largely of methane, which in turn is composed not only of the element carbon but also of hydrogen. This means that when gas is burned, some of the resulting useful energy is produced by oxidising hydrogen as well as carbon. The result is that combustion of gas produces significantly more energy per unit produced CO2 than coal.

Both gas and coal have a range of energy and chemical end-uses, however a major use of coal is for electricity generation. A commonly-cited comparison is whether it is better for our climate to use gas or coal for electricity generation. This comparison depends on many factors including:

- gas and coal composition
- how much methane is emitted when coal is mined (Kirchgessner, Piccot et al. (2000), Hayhoe, Kheshgi et al. (2002))
- how much energy is required to process and transport coal or gas to the site of electricity generation
- the efficiency of the electricity-generation equipment employed
- whether climate-impacting pollutants such as sulphate aerosols and black carbon are considered in the comparison (Wigley (2011))

and lastly, but importantly,

- how much methane is emitted during gas production, transport and end use.

3.1. Emitting methane can outweigh the climate impact of burning methane

When considering the climate-impact of using gas as a fuel, it is important to recognise that the impact of methane emissions can greatly exceed the climate-impact of final gas combustion (at which point the methane in the gas is converted to carbon dioxide and water).

Figure 4 illustrates that if more than about 3% of produced methane is emitted to the atmosphere, the climate impact on the 20-year timescale of the emitted methane is more important than the climate impact of the remaining combusted methane. For example, as shown by the column labelled "20%", if methane emissions are 20% of total gas production, the climate impact of those emissions is eight times greater than climate impact of burning the remaining gas on the 20-year time-scale (on 100-year time scales it would reduce to about three times.)

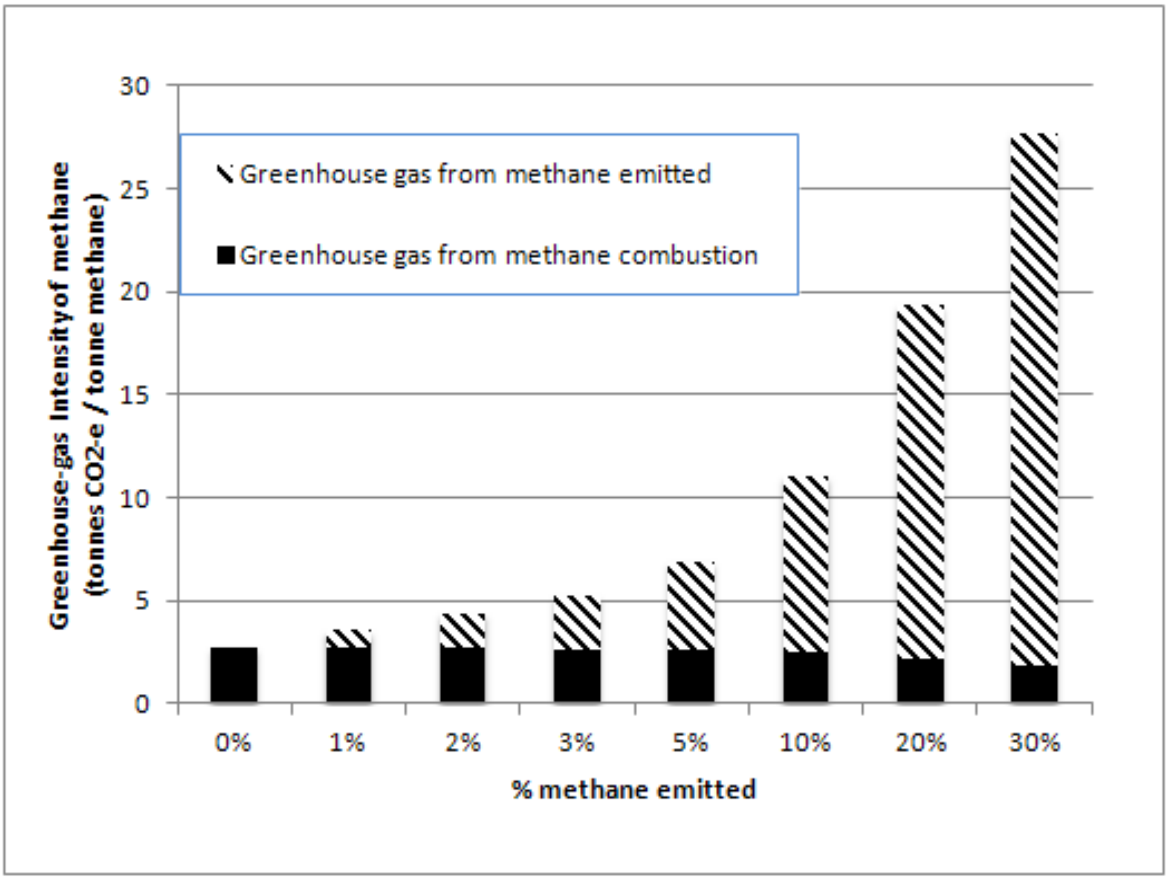


Figure 4: The climate impact of gas as an energy source greatly depends on what fraction is emitted to the atmosphere, versus what fraction is burned as fuel. Here we assume a global warming potential of 86 (appropriate to the 20-year timescale), with the y-xis showing the tonnes of CO_2-e emitted for each one tonne of methane gas produced.

Melbourne Energy Institute
McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

3.2. Coal-versus-gas comparison studies and critiques

A number of studies have compared the climate impact of using coal versus gas as a fuel.

In 2011, a report commissioned by the Australian Petroleum Production and Exploration Association (APPEA), Clark, Hynes et al. (2011) found that using coal seam gas to generate electricity could produce less greenhouse-gas emissions than if coal were used. With respect to methane emissions that occur during coal seam gas production, processing, and transport, Clark et al. assumed that "best practice" would be applied "especially to the prevention of venting and leaks in upstream operations", and that for the category of emissions entitled "Flaring, venting, potential leaks", ... "an estimate of 0.1% gas lost is industry accepted practice."

CSIRO (Day, Connell et al. (2012)) found that the 0.1% figure used by Clark, Hynes et al. (2011) was:

> "much lower than estimates from other gas production sectors"

and that

> "it is not clear how this level was established."

The investment advisors Citigroup (Prior (2011)) reviewed the report by Clark and considered a sensitivity case in which "gas lost" was increased by eleven times, to 1.1% of production.

In 2011, Deutsche Bank Group (Fulton et al. (2011)) called for more research and analysis to be done regarding the coal-vs-gas comparison, stating:

> "Given the potential implications of life-cycle [greenhouse-gas] emissions comparisons... and the fact that many of the metrics and assumptions used today are from older studies, more research and analysis is needed on the life-cycle [greenhouse-gas] intensity of both fuels [gas and coal] so that clean energy policies are properly calibrated to incentivize investment decisions..."

Also in 2011, the investment advisers Merrill Lynch (Heard, Bullen (2011)) in their review entitled "Green gas debate: Who is hiding the fugitives", stated:

> "A thorough independent expert assessment of full life-cycle [greenhouse gas] emissions ... would be a worthwhile input in assessing the gas industry's claims."

Hardisty, Clark et al. (2012) found no climate benefit when gas is used for electricity generation instead of coal...

> "...if methane leakage approaches the elevated levels recently reported in some US gas fields (circa 4% of gas production)..."

The above studies generally and arbitrarily use the 100-year global warming potential for methane, although the sensitivity of study results to the 20-year global warming potential may also be presented in the above studies. To avoid the arbitrary nature of choosing a global warming timeframe, Alvarez, Pacala et al. (2012) developed the concept of Technology Warming Potential (TWP) that allows a limited climate-impact comparison of different technologies.

Alvarez et al. suggested the methane-emission threshold at which point using gas for electricity generation provides no benefits over using coal occurs at a methane-emissions level equal to 3.2% of total gas production. (As with all similar comparisons of gas-versus-coal, this analysis depends on the assumptions made by the researcher.)

In the case where gas is exported as LNG and used within the importing country to make electricity, the methane-emission threshold at which gas becomes more greenhouse-gas intensive than coal will be less than the 3.2% described by Alvarez. This is because of the additional greenhouse-gas emitted along the LNG export-and-import supply chain. The LNG-export case is quite relevant for Australia and is now also relevant for the United States given the recent start of LNG exports from that country.

As will be described in Sections 4 and 5, methane emissions from unconventional gas production may significantly exceed the 'Alvarez threshold' of 3.2%, which means there may be no climate benefit gained by using gas for electricity generation. The climate impact of methane emissions must also be taken into account when gas is considered for other energy applications.

4. U.S. to extend methane emission regulations

This section describes how recent research has lead to the United States Environmental Protection Agency significantly revising upwards its methane-emissions estimates for the oil-and-gas sector and to the Obama Administration intending to enact further methane emissions regulations.

4.1. The U.S. leads the world in unconventional oil and gas production

The U.S. leads the world in the development and deployment of 'unconventional' oil and gas production technologies including large numbers of densely-spaced wells, horizontal directional drilling, coal-seam dewatering, and hydraulic fracturing (i.e. fracking).

Gas is often a by-product of oil production and there are now more than one million wells producing gas in the United States (Figure 5).

Figure 5: Dense well spacing in the U.S. state of Wyoming
http://www.sacurrent.com/sanantonio/the-shale-booms-hard-sell-begins-pushing-up-against-reality/Content?oid=2341996

Over the last 25 years, gas produced in the United States by unconventional methods (from coal seams, shale layers, and tight sandstone reservoirs) has grown from around 15% of supply to now make-up about two-thirds of supply (Figure 6).

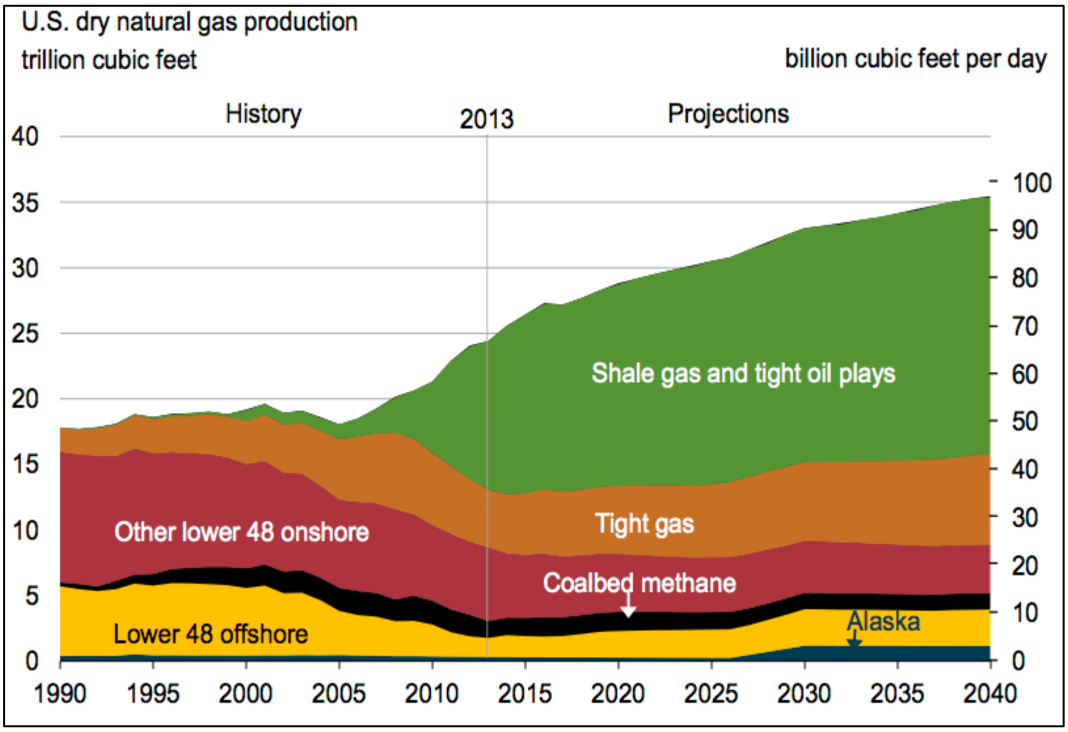


Figure 6: U.S. gas production 1990-2040 as per the EIA Annual Energy Outlook, 2015 Reference case scenario. Historical production until 2013, forecast from then onwards.
(EIA, Sieminski, A., 2015)
http://instituteforenergyresearch.org/analysis/eias-annual-energy-outlook-2015-fossil-fuels-remain-predominant-energy-providers/

4.2. Ways methane may be emitted as a result of unconventional oil and gas production

Gas is often a by-product of oil production. In turn, methane is often the largest chemical component of gas. Given the impacts listed in Section 2.4, for decades methane emissions have been a concern when oil or gas is produced via conventional methods. Methane emissions can be minimised with adequate oil and gas production facility design, construction, operation and maintenance. However in recent times, aspects of unconventional oil and gas production (i.e. large number of densely-spaced wells, horizontal directional drilling, producing from shallow, dewatered coal seams, hydraulic fracturing) mean there can be even greater potential for methane emissions when those techniques are used.

Table 1 broadly categorises seven ways in which methane may be emitted into our Earth's atmosphere when oil and gas is produced by unconventional methods, transported, and ultimately consumed by gas end-users. Some of these methane-emission pathways are further described in Sections 5 and 7.

Table 1

Ways in which methane can be emitted by unconventional oil and gas production and processing, gas transport and distribution, and use of gas by end-users			
	Emissions may occur...		
Methane emission source	**... during initial drilling and field development**	**... during commercial production phase**	**... potentially for many years after the production phase**
Emissions from **surface-production equipment:** leaks from pipes and equipment, venting/releases during the water and gas production phase, incomplete combustion in flares and gas-engine-driven pumps and compressors, etc.	✓	✓	
Acute well venting and releases: occurring during the drilling, well completion, coal-seam dewatering, and production phases.	✓	✓	
Sub-surface methane leaks from wellbores: occurring during drilling, production, and well-abandonment phases. Leaking methane may rise to the surface in the direct vicinity of the wellhead, or may join the category of migratory emissions if it rises to the surface at some distance from the wellhead.	✓	✓	✓
Migratory emissions: migration of methane from subsurface gas reservoirs to the surface (possibly at a considerable distance from the wellhead) during all phases of gas drilling and afterward (Section 5.6).	✓	✓	✓
Gas transportation pipelines and distribution piping: leakage and gas venting/releases.		✓	
LNG handling and shipping: gas venting/releases and leakage during transport of LNG from Australia to overseas locations.		✓	
Gas end-users: methane leaks and releases.		✓	

McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

4.3. Quantifying methane emissions with 'top-down' and 'bottom-up' methods

In addition to being colourless and odourless, methane is lighter than air. When released into our Earth's atmosphere, methane will generally quickly rise and disperse. This behaviour means that detection and quantification of methane-emission volumes may require sophisticated techniques.

The dispersive nature of methane is illustrated by Figure 7, showing methane rising into the atmosphere from a gas storage facility at Aliso Canyon, California, in 2015. Although methane cannot be visually detected using the visible-light spectrum, it can be detected with infrared-spectrum sensing technology as shown in Figure 7.

Figure 7: 2015 methane leak made visible with infrared imaging, Aliso Canyon, California. (Earthworks/Reuters)

While Figure 7 illustrates the scale of the large Aliso Canyon gas leak, devising ways to quickly identify less-obvious methane releases and to quantify the volume of methane emitted across entire sections of the oil and gas industry has challenged experts around the world.

The next section describes new research that indicates the amount of methane being emitted into our Earth's atmosphere because of U.S. unconventional oil and gas production is large and significantly exceeds official-reported estimates.

Methane-emission measurement methods can be characterised as 'top-down' or 'bottom-up'.

'Top-down' methane-emission measurement refers to using satellites, aircraft, and/or ground-based towers in an attempt to measure the full extent of methane emissions across an extensive land area.

'Bottom-up' measurement refers to methods that endeavour to determine how much methane is emitted from specific individual emission points such as a single valve or vent. 'Bottom-up' methods use measurement apparatus that is sited in close proximity to the emission point.

Table 2 summarises certain characteristics of 'bottom-up' and 'top-down' methane-emission measurement methods.

Table 2

Comparison of methane-emission measurement methods		
	'Bottom-up' methods	**'Top-down' methods**
Can identify and quantify emissions from individual emissions points and sources	Yes	Generally not used for this purpose.
Can distinguish between different sources of methane emissions	Yes	Generally not used for this purpose. May be able to distinguish between oil & gas vs biogenic sources (e.g. isotope or other trace contaminant analysis).
Detects all emissions over a wide area	Can do this only if every individual emission source or point is known and assessed. May miss 'super-emitters'. (See below).	Aims to do so.
Shows trends with time	Can be expensive to do so if there are many individual emission sources or points.	Aims to cost-effectively do so.

'Bottom-up' measurements are an important tool that the gas industry can use to minimise the amount of methane emitted from individual equipment pieces at gas-production, processing, and transport facilities. Industry can make use of various methane detection and flux-quantification techniques in order to enhance workplace health and safety, reduce loss of product, and reduce environmental impacts.

However, 'bottom-up' methane-emission measurement techniques have certain shortcomings when they are used to assess the total amount of methane emitted from widespread gas production and transmission infrastructure. For a broad assessment across a large land area where many emission points may exist, 'bottom-up' methods require knowledge about where all potential emission points might be and/or what gas field operations result in methane leaks. Unfortunately, if some emission points or methane-emitting operations are unknown or not assessed, total emissions from a large land area or region will be understated. Furthermore, often 'bottom-up' methods are not applied over continuous and long time periods and therefore can miss individual but significant emission events characterised as 'super-emitters' (see below). As described below, there have been cases where inappropriate use of 'bottom-up' methane-measurement equipment has been indicated.

Allen, Torres et al. (2013) conducted 'bottom-up' measurements of methane emissions at 190 onshore gas sites in the United States including "150 production sites with 489 hydraulically fractured wells, 27 well completion flowbacks, 9 well unloadings, and 4 workovers".
This work concluded that:

> "well completion emissions are lower than previously estimated; the data also show emissions from pneumatic controllers and equipment leaks are higher than Environmental Protection Agency (EPA) national emission projections."

However, later it was found by Howard (2015) and Howard et al. (2015) that these measurements systematically underestimated methane emissions because of detection instrument sensor failure. Important measurements by Allen et al. were reported to be "too low by factors of three to five".

Howard continued:

> "...it is important to note that the ... sensor failure in the ... study went undetected in spite of the clear artefact that it created in the emissions rate trend as a function of well gas CH4 content and even though the author's own secondary measurements made by the downwind tracer ratio technique confirmed the ... sensor failure. That such an obvious problem could escape notice in this high profile, landmark study highlights the need for increased vigilance in all aspects of quality assurance for all CH4 emission rate measurement programs" (Howard (2015)).

'Bottom-up' studies may also fail to assess every emission source. Sources may be unknown, unexpected, or outside of the scope assigned to assessors. CSIRO's experience (Day, Dell'Amico et al. (2014)) detailed in Section 5.4.7 is one example of the latter. Because emission-points can be vast in number, 'bottom-up' studies may of necessity measure only a limited number of points and then attempt to apply the limited results to an entire class of emission points.

According to Allen (2014):

> "The difficulty with 'bottom-up' approaches is obtaining a truly representative sample from a large, diverse population. ... For many types of emissions sources in the natural gas supply chain, however, extreme values can strongly influence average emissions."

Related to this, a third key concern with 'bottom-up' emission measurement and estimation is the existence of so-called 'super-emitters'. According to Zavala-Araiza, Lyon et al. (2015):

> "Emissions from natural gas production sites are characterized by skewed distributions, where a small percentage of sites - commonly labelled super-emitters - account for a majority of emissions."

Super-emitters may exist for reasons such as:

- intentional venting of methane from gas/water separation operations
- intentional well-venting events
- intentional venting of methane in preference to flaring
- other intentional methane venting
- incomplete combustion of methane in gas-engine driven pumps, compressors and electricity generators
- loss of well integrity during the drilling, operations, or 'well-abandonment' phases
- equipment malfunctions or other loss of equipment integrity.

4.4. 'Top-down' U.S. methane emissions measurements point to under-reporting

Several key methane-emission research publications are summarised in Table 3. Many of these publications point to significant under-reporting of methane emissions from unconventional oil and gas production in the United States and Canada. Some of these researchers conducted 'top-down' methane-emission measurements using satellites, aircraft, monitoring towers, and ground-based equipment.

Of particular note, satellite data suggests that U.S. methane emissions (all sources) have increased by more than 30% over the period 2002-2014:

> "The large increase in U.S. methane emissions could account for 30-60% of the global growth of atmospheric methane seen in the past decade" (Turner, Jacob et al. (2016)).

This increase in U.S. methane emissions has occurred during a time when the U.S. oil and gas industry drilled over 500,000 wells.[5]

In 1999, atmospheric composition measurements in urban areas showed higher levels of hydrocarbons in certain U.S. cities versus other cities (Katzenstein, Doezema et al. (2003)). Since then, various researchers have demonstrated that in U.S. states such as Colorado, New Mexico, North Dakota, Pennsylvania, Texas, and Utah, the oil and gas industry seems to be responsible for greater volumes of methane emissions than are reported.

Until recent years, methane emissions in the U.S. were reported to be 0.5 to 2% of total gas production (Harrison, Campbell et al. (1996), Allen, Torres et al. (2013), EPA (2013)). However, many of the research publications listed in Table 3 highlight the possibility of very large methane emission rates. One reference reported methane emissions as high as 30% of gas production (U.S. Dept. of Energy (2010)).

Figure 8 illustrates the ranges in methane emissions (from 2 to 17% of total gas production) reported in recent publications for key U.S. unconventional gas producing regions.

[5] EIA (2002-2010) http://www.eia.gov/dnav/pet/pet_crd_wellend_s1_m.htm , Oil and Gas Journal (2011-2012) http://www.ogj.com/articles/print/vol-110/issue-1a/general-interest/sp-forecast-review/strong-drilling.html, http://www.ogj.com/articles/print/volume-111/issue-1/special-report-forecast-review/slower-drilling-pace-likely-in-us.html , Baker-Hughes (2013-2014) http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-wellcountus

`

Table 3

Key, recent research publications describing North American methane emissions (reverse-chronological)			
Date	**Lead author**	**Publisher / publication**	**Summary of research**
March 2016	Turner, Jacob et al. (2016), Harvard Univ.	Geophysical Research Letters	Using satellite data and surface observations, **a 30% increase in U.S. methane emissions is indicated** over the past decade during a time **when emission inventories indicate no change.**
Dec 2015	Zavala-Araiza et al. 2015) Environ. Defense Fund	Proceedings of the National Academy of Science	Methane emissions at Barnett shale region of Texas were found to correspond to **1.5% of natural gas production, "1.9 times** the estimated emissions based on the U.S. EPA Greenhouse Gas inventory, **3.5 times** that using the EPA Greenhouse Gas Reporting Program, and **5.5 times** that using the Emissions Database for Global Atmospheric Research (EDGAR)."
Oct 2015	Howarth, R. (2015) Cornell Univ.	Energy and Emission Control Techn.	Considered global flux of C^{14} to conclude methane emission rate of **3.8% for conventional gas** and **12% for shale gas.**
Aug 2015	Marchese, A. et al. (2015) Colorado State Univ.	Environmental Science and Technology	Facility-level measurements obtained from 114 gas-gathering facilities and 16 processing plants in 13 U.S. states. Methane loss rate from this part of the gas production system was found to be 0.5%, which is up to **14 times higher** than tabulated by the U.S. EPA.
June 2015	Howard (2015), Indaco Air Quality Services	Energy Science and Engineering	The bottom-up methane-emission measurements reported in a landmark study (Allen, Torres et al. (2013)) were found to be **low by factors of three to five** due to **instrument sensor failure.**
1 April 2015	Peischl, Ryerson et al. (2015), Univ. of Colorado	American Geophysical Union	Using aircraft, **loss rates** for the Haynesville, Fayetteville, and north-eastern Marcellus shales found to **range from 0.2 to 2.8%.**
Oct 2014	Kort, Frankenberg et al. (2014), Univ. of Michigan	Geophysical Research Letters	Satellite observations indicate high methane-emissions **'hot-spot'** at the location of the **largest CSG-producing region** in the U.S. (New Mexico).

Oct 2014	Schneising, Burrows et al. (2014), Univ. of Bremen, Germany	American Geophysical Union	**Current inventories underestimate** methane emissions from Bakken (North Dakota, Canada) and Eagle Ford (Texas) shale gas production areas, found to be **10% and 9%** of production respectively, based on satellite data.
June 2014	Allen (2014), Univ. of Texas	Current Opinion in Chem. Engr.	**Current inventories underestimate** the amount of methane entering the atmosphere.
June 2014	Pétron, Karion et al. (2014), Univ. of Colorado	American Geophysical Union	Using measurements from aircraft, **losses of methane** estimated to be **2 to 8% of production** from oil and natural gas operations in the Denver-Julesburg Basin (Colorado)**.**
April 2014	Caulton, Shepson et al. (2014), Purdue Univ.	Proceedings of the National Academy of Science	An instrumented aircraft platform operated over southwestern Pennsylvania identified methane emissions from well pads in the drilling phase **100 to 800 times "greater than U.S. [EPA] estimates** for this operational phase", or **3 to 17%** of production in this region.
Feb 2014	Brandt, Heath et al. (2014), Stanford Univ.	Science	"...measurements at all scales show that **official inventories consistently underestimate actual [methane] emission**s with the [U.S. and Canadian natural gas] and oil sectors as important contributors." Possible methane emission rates range from **4 to 7%** of gas production. (Howarth (2014))
Aug 2013	Karion, Sweeney et al. (2013), Univ. of Colorado	Geophysical Research Letters	Airborne methane measurements point to **6 - 12% emission rate** in the Uintah Basin, Utah, **7 to 13 times higher** than U.S. EPA estimates of 0.88%.
Feb 2012	Pétron, Frost et al. (2012) Petron, G. (Univ. of Colorado)	Journal of Geophysical Research	Air samples collected from a tower in north-eastern Colorado from 2007 to 2010 indicated **"between 2.3% and 7.7% of the annual production being lost to venting."** "The methane source from natural gas systems in Colorado is most likely underestimated **by at least a factor of two**."
Sept 2010	U.S. Dept. of Energy (2010)		Measurements indicate that when producing gas from coal seams in the Powder River Basin, Wyoming, **up to 30%** of produced methane can be emitted to the atmosphere.
Aug 2003	Katzenstein, Doezema et al. (2003)	Univ. of California	Surface sampling in the southwestern U.S. "suggests that **total U.S. natural gas emissions may have been underestimated**' by a factor of around two".

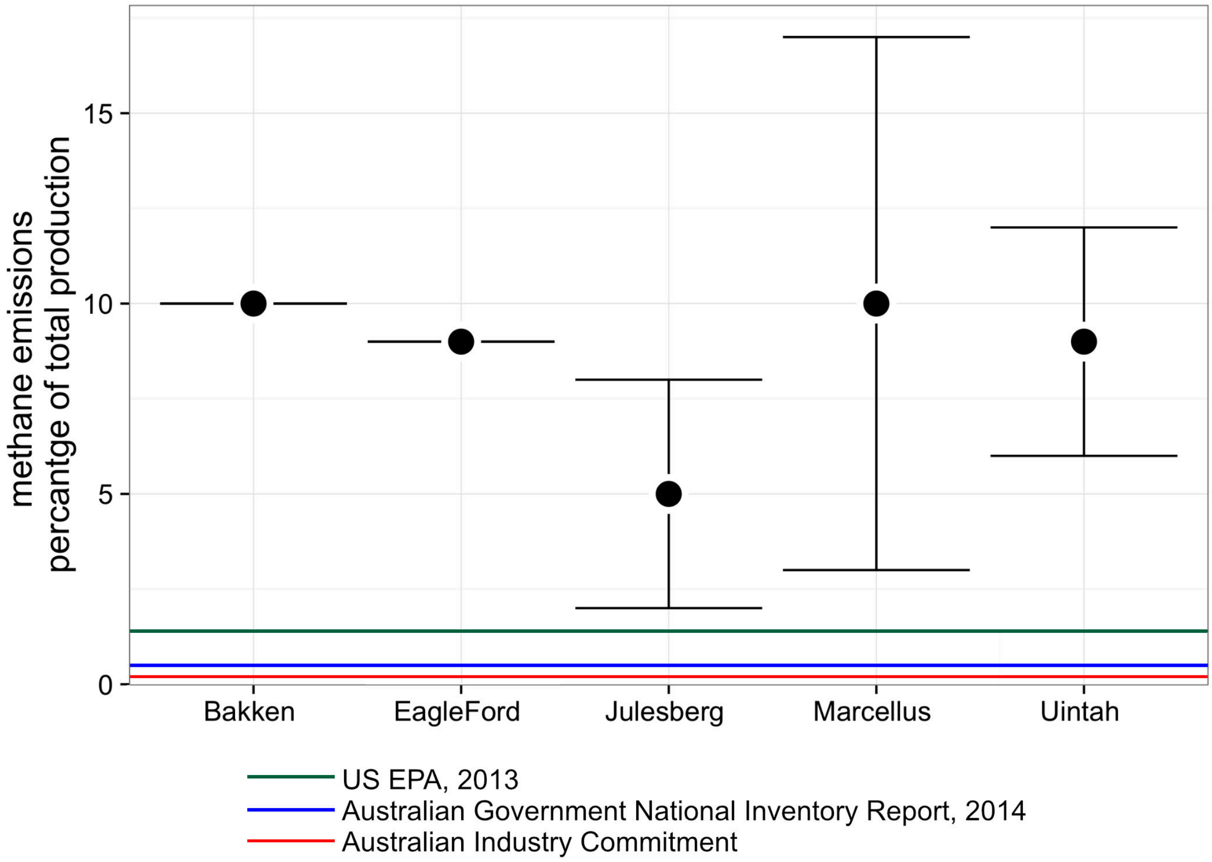


Figure 8: U.S. reported methane emissions (shown as black horizontal line), vs recent 'top-down' measurements for various unconventional gas basins (with reported ranges shown as error bars)

4.5. Methane-emission 'hot-spot' seen from space at largest U.S. CSG-producing region

Most U.S. methane-emissions research focuses on areas where oil and gas is produced from shale. Although Australia is said to have large shale potential, the greatest source of unconventional gas production today is Queensland coal seam gas. Although, as will be discussed in later sections, certain aspects of methane emissions resulting from shale oil and/or gas production are relevant to the coal seam gas operations in Queensland, it is even more relevant to review what is known about methane emissions from the United States' largest coal seam gas production area: the San Juan Basin. This basin, located in northwest New Mexico and southwest Colorado, is also a source of conventional oil and gas.

Satellite observations analysis was published in October 2014 that indicated a methane-emissions 'hot-spot' existed over the San Juan Basin during the 2003-2009 period of satellite data collection (Figure 9 and Kort, Frankenberg et al. (2014)).

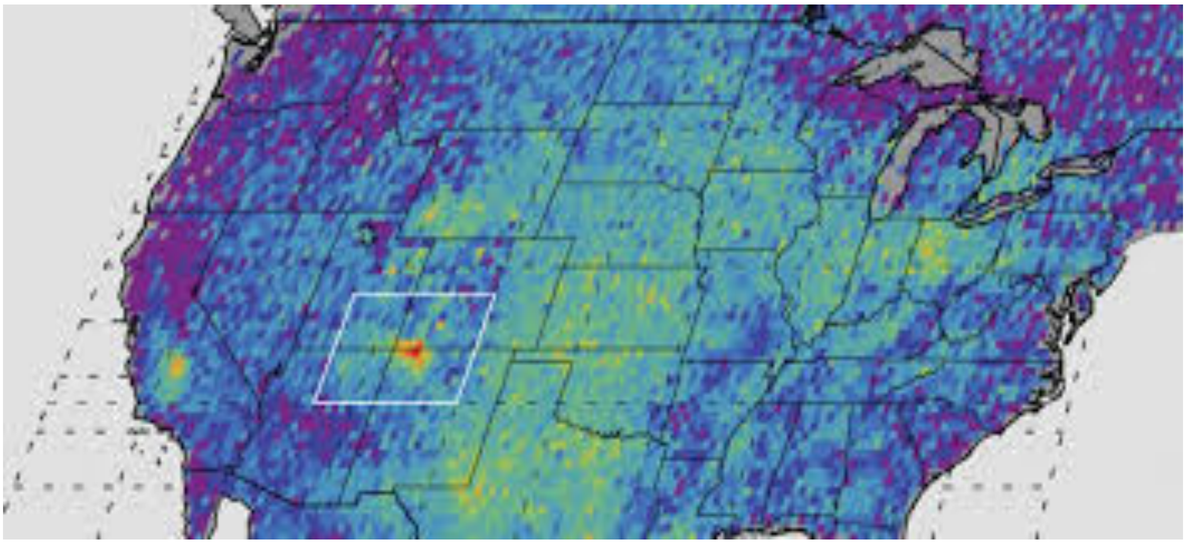


Figure 9: U.S. methane emissions 'hot-spot' revealed by satellite measurements. (Kort et al. 2014)

Based on the satellite data, methane emissions in the San Juan Basin are estimated to be 0.6 million tonnes per year. This quantity is 1.8 times greater than reported methane emissions for the region and equivalent to nearly 10% of the total amount of methane emitted as a result of U.S. gas production (as estimated by the U.S. EPA).

The San Juan Basin methane-emission 'hot-spot' continues to be under investigation by U.S. researchers. See the MEI companion report entitled *"The risk of migratory methane emissions resulting from the development of Queensland coal seam gas"* for further discussion of methane emissions from this region.

4.6. U.S. EPA increases estimated emissions from upstream oil and gas sector by 134%

On 23 February 2016, the U.S. EPA revised their estimates of methane emitted by the oil and gas sector during the year 2013. Table 4 shows that estimates for gas transmission, storage, and distribution were revised downward; however, estimates for the 'upstream' sectors denoted as "Petroleum Systems" and "Field Production (and gathering)" were increased by 134%.

The estimated methane emissions from the oil and gas sector as a percentage of total U.S. gas production in 2013 increased from 1.2 to 1.4%.

On 24 February 2016, speaking at an energy conference in Houston Texas, U.S. EPA Administrator Gina McCarthy said:

> "The new information shows that methane emissions from existing sources in the oil and gas sector are substantially higher than we previously understood.
>
> ...studies from groups like EF and its industry and research partners at Colorado State University, Carnegie Mellon, University of Texas, Washington State University, and others are contributing to our more-complete understanding of emissions from this sector.
>
> So the bottom line is - the data confirm that we can and must do more on methane." (EPA (2016))

Table 4

U.S. EPA estimates of methane emissions in the oil and gas sector occurring during the year 2013 (U.S. EPA GHG inventories)				
Sector	Previous estimate	Feb. 2016 revised estimate	Change	% Change
	(million tonnes of methane emitted / year)			
Petroleum Systems	1.009	2.535	1.526	+ 151%
Field Production (and gathering)	1.879	4.230	2.351	+ 125%
'Upstream' subtotal	**2.888**	**6.765**	**3.877**	**+ 134%**
Processing	0.906	0.906	-	-
Transmission and Storage	2.176	1.151	-1.025	- 47%
Distribution	1.333	0.458	-0.875	- 66%
Total	**7.303**	**9.280**	**1.977**	**+ 27%**
Methane emissions as a% of total U.S. gas production[6]	1.2%	1.4%		

[6] Based on 2013 U.S. gas production of 29.5 trillion cubic feet (31,400 petajoules).

Melbourne Energy Institute
McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

4.7. U.S. regulated emission sources in 2012; new rules to cover existing sources

Since at least 2012, the Obama Administration has been working toward tightening U.S. methane emission regulations. On 17 April 2012, the U.S. EPA set rules that included:

> "...the first federal air standards for [new] natural gas wells that are hydraulically fractured, along with requirements for several other sources of pollution in the oil and gas industry..." (EPA (2012))

Building on President Obama's June 2013 broad-based Climate Action Plan that aimed "to cut the pollution that causes climate change and damages public health", the March 2014 "Strategy to Reduce Methane Emissions" recognised that:

> "reducing methane emissions is a powerful way to take action on climate change"

and stated that with respect to methane emissions in the oil-and-gas sector:

> "...the Administration will take new actions to encourage additional cost-effective reductions..." (White House (2014))

On 14 January 2015, the Obama Administration announced:

> "...a new goal to cut methane emissions from the oil and gas sector by 40 to 45 per cent from 2012 levels by 2025, and a set of actions to put the U.S. on a path to achieve this ambitious goal." (White House (2015))

In August 2015 the U.S. EPA proposed new rules to reduce methane emissions from hydraulically-fractured oil wells and also to:

> "extend emission reduction requirements further "downstream" covering equipment in the natural gas transmission segment of the industry that was not regulated in the agency's 2012 rules." (EPA (2015))

And just recently on 10 March 2016 at a joint press conference with Canadian Prime Minister Justin Trudeau, President Obama said:

> "Canada is joining us in our aggressive goal to bring down methane emissions in the oil and gas sector in both our countries and, together, we're going to move swiftly to establish comprehensive standards to meet that goal."

while U.S. EPA Administrator Gina McCarthy blogged that:

> "EPA will begin developing regulations for methane emissions from existing oil and gas sources." (EPA (2016))

McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

5. Australian methane emissions from unconventional gas production

This section describes Australia's rapidly-growing CSG-to-LNG industry and potentially-large 'tight' gas and shale oil-and-gas resources (Sections 5.1 and 5.2).

Section 5.3 then presents Australia's oil-and-gas-related methane-emission estimation methods that rely to a significant extent on assumed emissions factors.

Section 5.4 describes, chronologically, the results of limited Australian methane-emission field investigations and actual methane emission measurements, along with reviews of Australia's methane-emission estimation and reporting methods. These reviews point out that much of Australia's emissions reporting relies not on direct field-measurement of emissions but rather on assumed factors that may inadequately reflect, in particular, Australian coal seam gas operations.

Section 5.5 reports that methane emissions for 2014 were equivalent to 0.5% of total Australian gas production. This rather low-level of reported emissions are compared with recently-published estimates of U.S. oil and gas field emissions that range from 2 to 17% of production.

Furthermore, Section 5.6 refers to a companion 'migratory emissions' report that describes the potential for Australian coal seam gas production and other subsurface activities to cause methane to migrate away from its natural reservoir, reach the Earth's surface, and enter the atmosphere at some distance from CSG-production operations.

Based on the above, concluding Section 5.7 summaries key reasons why methane emissions related to Australian oil and gas industry operations may be under-reported.

Later sections of this report present scenarios describing how large methane emissions from this sector could be, full fuel-cycle greenhouse gas emissions of the CSG-LNG industry, and finally actions needed to reduce methane emissions and improve the quality of methane-emissions reporting.

5.1. The rapidly-growing eastern Australian CSG-to-LNG industry

The most significant form of unconventional oil or gas produced in Australia to date is coal seam gas. This industry operates mainly in Queensland and also in New South Wales. The large amount of coal seam gas present in those states led to the recent construction of six liquefied natural gas (LNG) 'trains' in Gladstone Queensland, at a cost of more than $A 60 billion. LNG was first exported from Gladstone in December 2014. Six trains are expected to be fully operational by the end of 2016 (Figure 10).

Figure 10: Liquefied natural gas (LNG) plants at Gladstone, Queensland (LNG World News)

As a result of this new CSG-to-LNG industry, the amount of gas produced in eastern Australia will soon triple (Figure 11). By 2017, the amount of coal seam gas produced in eastern Australia each year will rise to a level twelve times greater than what it was a decade prior.

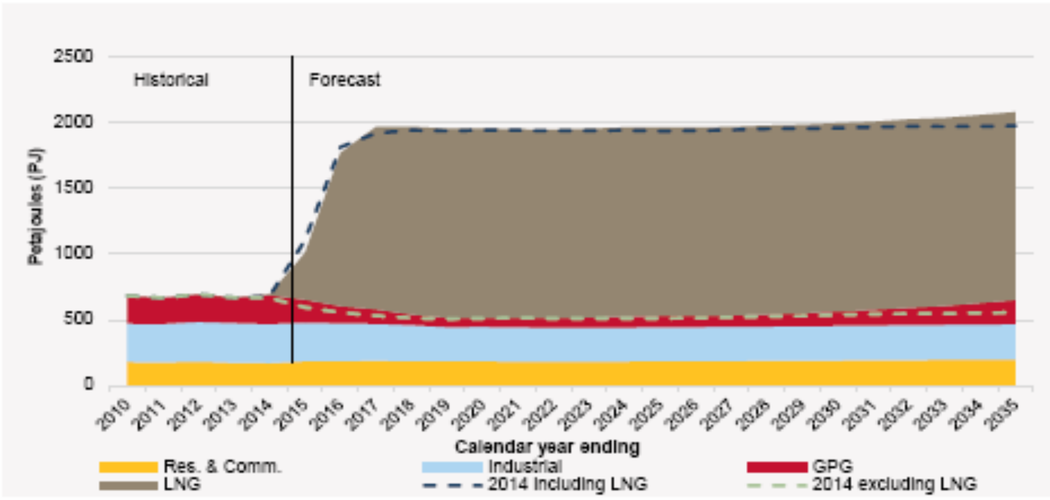


Figure 11: Eastern Australian gas production, recent past and projected future.
Australian Energy Market Operator National Gas Forecasting Report, Dec. 2015

Around 6,000 coal seam gas wells have so far been drilled in Queensland and New South Wales to support this industry (Figure 12).

Figure 12: Aerial photo of over 160 CSG wells near Tara, Queensland (Google Earth)

Because coal seam gas wells have a limited life and often deplete more rapidly than conventional gas wells, the Australian coal seam gas industry plans to drill a minimum of 1,000 wells each year over the next twenty years to maintain gas supply to the six LNG trains. Therefore it is planned that by 2035 this industry will have drilled a minimum of 30,000 coal seam gas wells in eastern Australia.

Table 5 shows certain results of AEMO's 2016 assessment of eastern Australian coal seam gas reserves and resources (AEMO (2016)). At a production rate of 1,500 petajoules per year[7] (PJ/yr), proved-and-probable (2P) coal seam gas reserves would deplete after 29 years. If the other classes of reserves and resources shown in Table 5 were found to be economical to recover, those reserves and resources would extend current rates of gas production out for another 96 years, or 125 years in total. Cook, Beck et al. (2013) reported similar resource numbers.

Given the large coal seam gas resources in Queensland and New South Wales, in 2011 the Australian Energy Market Operator (AEMO (2011)) described a scenario where 20 LNG trains were built at Gladstone. In other words, that scenario described LNG production and export capacity 3.3 times greater than what is in place today.

[7] 1,500 PJ/yr is approximately equal to the current or near-term Australian CSG production rate. See AEMO's National Gas Forecasting Report (December 2015) for context.

Table 5

CSG reserves and resources in Eastern Australia					
	'Proved plus probable' (2P) CSG reserves	CSG 'possible' reserves plus 'contingent resources'	CSG 'prospective resources'		Sum of all CSG reserves and resources
CSG reserves and resources (AEMO (2016))	44,000 PJ	70,000 PJ	75,000 PJ		189,000 PJ
Reserve life (CSG reserves and resources divided by a production rate of 1,500 PJ/yr)	29 years	46 years	50 years		125 years

5.2. Australia's 'tight' and shale oil-and-gas potential

In addition to coal seam gas resources, Australia also has very large 'tight' gas and shale oil and gas prospective resources, as listed in Table 6.

Shale oil and shale gas are oil and/or gas held in a shale reservoir.

'Tight' gas is defined as gas contained in low-permeability sandstone reservoirs. ‘Tight oil' may also refer to shale oil.

The EIA (2013) estimated that 18 billion barrels of technically-recoverable shale oil may be found in Australia’s sedimentary basins, in particular in the Canning Basin in Western Australia (9.7 billion barrels, Figure 13) and the McArthur Basin (Beetaloo sub-basin) in the Northern Territory (4.7 billion barrels).

Australia's largest shale gas resources are thought to be in the Canning Basin, assessed at a prospective resource level of 229 TCF (252,000 PJ) (Cook, Beck et al. (2013)).

Much of these shale and 'tight' resources are considered uneconomic under current market conditions given their remote location and other factors. Technological breakthroughs or improving market conditions may change the economics for tight and shale gas resources. The scale of tight and shale gas operations could be very significant, and of similar scale or even larger than the coal seam gas industry. Similar to coal seam gas development, large-scale shale and tight resource development would require thousands of wells.

Santos has drilled some tight gas wells in the Cooper Basin (Queensland and South Australia, Figure 13). These wells then connected to existing gas processing and pipeline infrastructure. Beach Petroleum, Drillsearch, and Senex continue to explore the Cooper Basin with a high rate of success.

Table 6

Australian shale oil, shale gas, and tight gas prospective resource estimates			
Type of resource		**Level of uncertainty**	**References**
Shale oil	18 billion barrels	Potentially in the ground, technical recoverable	EIA (2013)
Shale gas	6% of world's total shale gas resource	Undiscovered, prospective	EIA (2013)
	396 TCF (435,600 PJ)	Potentially in the ground, technically recoverable	Cook, Beck et al. (2013), GA and BREE (2012)
	2 TCF (2,200 PJ)	Sub-economic demonstrated (2C)	
Tight gas	20 TCF (22,000 PJ)	Sub-economic possible (3C)	

Further out on the development horizon is 'deep' coal seam gas: deep coal formations that require hydraulic fracturing to induce commercial flow. In May 2015, Santos connected its first 'deep' coal seam gas well to its Moomba infrastructure in the Cooper Basin (inferred from shareholder announcements to be at depths of around 2,000 metres).

5.3. Gas industry methane emissions in the National Greenhouse Gas Inventory (NGGI)

In the structure of national inventories, as specified in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, emissions arising from the use of energy are divided into two categories:

- 1A - fuel combustion activities
- 1B - fugitive emissions from fuels

Emissions for these two categories are considered in turn.

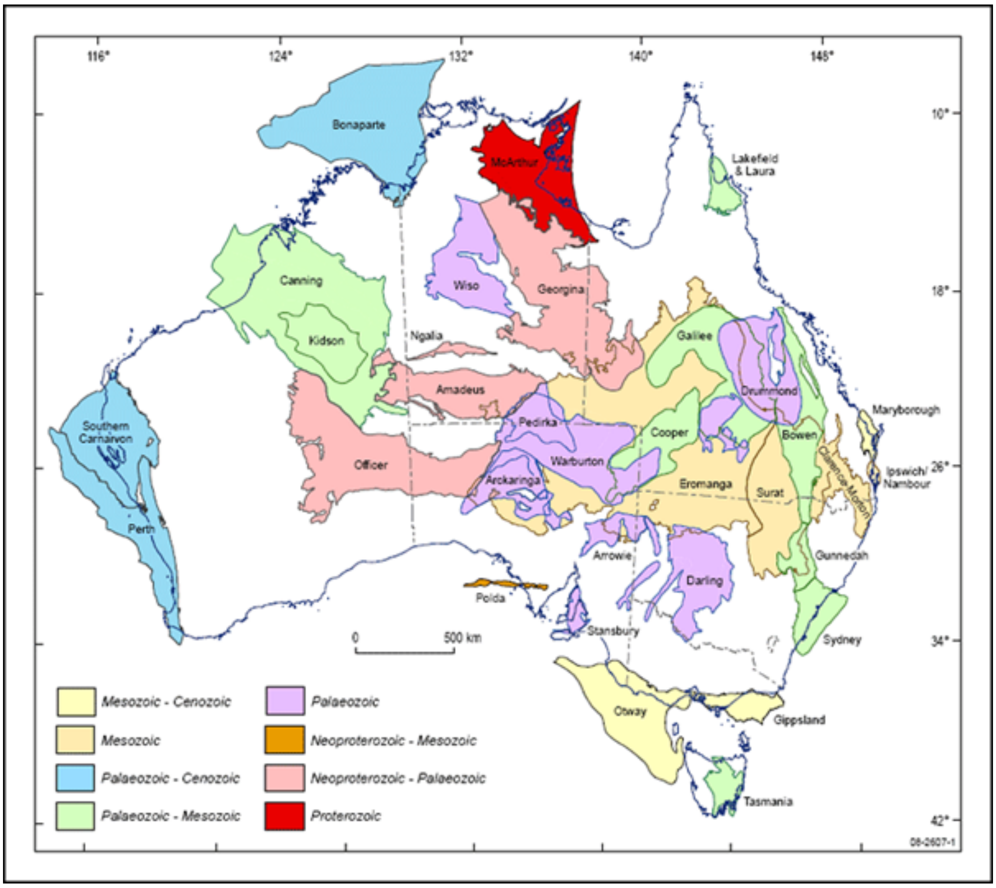


Figure 13: Australia's onshore sedimentary basins (Geoscience Australia, 2016.
http://www.ga.gov.au/about/what-we-do/projects/energy/onshore-petroleum

5.3.1. Fuel combustion emissions

Gas industry combustion emissions included in the national inventory mainly arise from the use of gas in gas engines, including both reciprocating and turbine engines, to power compressors, pumps and other equipment, which may be used:

- in the gas fields
- at gas processing plants
- on gas transmission pipelines
- at LNG plants
- in gas distribution systems.

In the case of coal seam gas, all three of the LNG plants at Gladstone, Queensland use a process based on the use of gas turbines to drive the compressors required to liquefy the gas, and also to drive generators that provide the electricity used for a multitude of purposes throughout the plants. A report prepared by Lewis Grey Advisory for the Australian Energy Market Operator (AEMO)[8] estimates that the liquefaction process uses 8% of the input gas. Negligible quantities of emissions from this source are included in the most recent NGGI, which covers the financial year 2013-14, because LNG production did not start until late in calendar year 2014. These emissions will be included in all future national inventories. They will also be included in NGERS public reports, but will probably not be separately identifiable because they will be included in the aggregated reports of the various joint venture partners.

Each of the three LNG-plant consortia owns and operates a separate transmission pipeline from its gas fields, located a considerable distance south west of Gladstone. Gas-transmission compressors may be powered either by gas engines or electric motors. Lewis Grey Advisory suggests that two of the lines may currently use electricity while the other uses gas. In either case, the associated emissions will be included in the national inventory, either directly as emissions from gas combustion, or indirectly as electricity generation emissions.

Production of coal seam gas differs from production of conventional natural gas in that very large numbers of individual wells are required, production usually requires water to be pumped out of the wells, and that gas emerges at low pressure and therefore requires compression to be transported through a network of gathering lines to a central point where it is compressed up to transmission pressure. Powering this equipment requires large amounts of energy. Initially, the CSG-producing companies all used gas-engine drive for this equipment but all are now progressively shifting across to electric motor drive for much, but by no means all of the equipment[9].

---

[8] Lewis Grey Advisory, 2015. *Projections of gas and electricity used in LNG*. Prepared for AEMO. http://www.aemo.com.au/Search?a=Lewis%20Grey%20Advisory
[9] Lewis Grey Advisory, *op. cit*.

Overall, the annual energy consumption for extracting, transporting and liquefying coal seam gas at the three plants (six liquefaction trains) is estimated by Lewis Grey Advisory to be about 123 PJ of gas and 9.3 terawatt-hours (TWh) of electricity. In its most recent electricity forecasting report[10], the Australian Energy market Operator (AEMO) has revised the latter figure down somewhat; AEMO now expects CSG-field electricity consumption to be about seven TWh per year (AEMO, 2016). The two figures for gas and electricity are equivalent to about 93 TJ of gas and 5.3 gigawatt-hours (GWh) of electricity per petajoule (PJ) of produced LNG. Emissions from all of this energy use will be included in the NGGI as and when they occur.

5.3.2. Fugitive emissions from fuels

The *IPCC Guidelines* subdivide fugitive emissions from the oil and gas industry into a number of sub- and sub-sub-categories relating to the gas industry. The various divisions were changed between the 1996 (as revised) and the 2006 editions of the *Guidelines*. Australia reports against what is essentially the 1996 structure, presumably so as to provider a clear and consistent time series from 1990 onward. When interpreting the reported emissions data, it is important to understand what is meant by and included under venting, as distinct from leakage. The 2014 National Inventory Report explains the distinction in the following terms:

> "The approach used for defining vents and leaks is provided below, and has been developed with a view to completeness and consistency with American Petroleum Institute's (API) 2009 *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*:
>
> - vents are emissions that are the result of process or equipment design or operational practices;
>
> and
>
> - leaks are emissions from the unintentional equipment leaks from valves, flanges, pump seals, compressor seals, relief valves, sampling connections, process drains, open-ended lines, casing, tanks, and other leakage sources from pressurised equipment not defined as a vent." (p. 118)

[10] AEMO, 2016. National Electricity Forecasting Report. http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report

McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

Table 7 shows the source category structure used for reporting 2013-14 emissions in the Australian Greenhouse Emissions Information System (AGEIS). The table includes brief descriptions of the categories relating to production, processing and transporting of gas, including coal seam gas.

Table 7

Emission-source category	**Description / explanation**
Fugitive emissions from fuels	
Solid fuels	NA
Various sub-categories	
Oil and natural gas	
Oil	NA
Various sub-categories	
Natural gas	
Exploration	
flared	Uncontrolled or partially controlled emissions from gas well drilling, drill stem testing and well completion
vented	
Production	Fugitive emissions occurring between the production well head and the inlet point of the gas processing plant (or the transmission pipeline if processing is not required)
Processing	Emissions other than venting and flaring at gas processing facilities
Transmission and storage	Emissions occurring between the inlet point of the transmission pipeline and its outlet to either a major consumer (including an LNG plant) or a distribution network
Distribution	Emissions resulting from leakage from gas distribution networks
Other	Includes emissions from well blowouts, pipeline ruptures etc.
Venting and flaring	
Venting	
oil	
gas	Managed venting at gas processing facilities
Flaring	
oil	
gas	Managed flaring at gas processing facilities
combined	

Table 8 shows the emissions under each of the above categories relevant to gas production and processing, as reported in the 2013-14 NGGI.

For comparison, the table also shows the corresponding values for 2004-05 when there was negligible coal seam gas production. This will help to identify where coal seam fugitive emissions are being reported. Each of the source categories is discussed in turn.

5.3.3. Exploration

Between 2005 and 2014 total emissions from flaring, total emissions for venting, total emissions of carbon dioxide and total emissions of methane are all reported as increasing by a factor of about 4.5. The 2014 National Inventory Report (NIR) shows the total number of oil and gas wells completed increasing by a factor of 5.3 over the same period and notes that:

> "The sharp recent expansion of the coal seam gas industry is evident in the sharp increase in the number of production wells since 2008."

The NIR explains that the methane emission factor for well completions used the 2009 API emissions factor for onshore well completions, which is 25.9 tonnes methane per completion day. There is a different, higher factor for offshore wells. Factors for flaring and drilling mud degassing are also reported. It is our understanding that these latter two emission sources are mainly associated with conventional oil and natural gas wells, not coal seam gas wells.

The NIR does not provide enough data to allow the calculations of total emissions to be replicated. However, an approximate calculation, using total well numbers and well-completion emission factors gives a total estimate for 2014 which is slightly lower than the reported total for 2014, as shown in Table 8. This suggests that if the API emission factor of 25.9 tonnes of methane per completion-day is appropriate for Australian conditions, then the NGGI gives an acceptably-accurate estimate of methane emissions from drilling and completion of coal seam gas exploration and production wells. Unfortunately, we have been unable to find any published systematic data on methane emissions from Australian coal seam gas well completions. It is therefore not possible to determine whether the API emission factor is applicable to Australia.

Table 8

Fugitive emissions from gas production, processing and transportation, as reported in the NGGI (kilo-tonnes CO_2-e)

	2004-05		2013-14		
Source category	**CO_2**	**methane**	**CO_2**	**methane**	**Total**
Fugitive emissions from fuels					
Natural gas					
Exploration					
Flared	25	8	113	34	148
Vented	0	258	0	1154	1154
Total	25	266	113	1187	1302
Production	0	69	0	85	
Processing					
Transmission and storage	0.44	230	0.56	290	291
Distribution			5	2377	2382
Other					
Venting and flaring					
Venting					
Gas	3104	1315	4119	1109	5230
Flaring					
Gas	989	332	2185	96	2305
Combined					

Note: For some source categories, the total includes small quantities of nitrous oxide

Interestingly, the NGERS *Technical Guidelines*[11] (Section 3.46A) provide two options for reporting fugitive emissions from well drilling and completion activities. The first is direct measurement of gas volumes released (Section 3.46B), either from all wells and well types in a basin, or from a sample of such wells. The section sets out in considerable detail the procedures to be followed in taking measurements and the calculation steps to be followed to convert the measured data to total emission estimates. The second option (Section 3.84) is use of the relevant API emission factor. It would appear that to date, all CSG-producing companies have used the second option.

[11] Department of the Environment, 2014. *Technical Guidelines for the Estimation of Greenhouse Gas Emissions by Facilities in Australia.* http://www.environment.gov.au/climate-change/greenhouse-gas-measurement/nger/technical-guidelines

5.3.4. Production

The NIR defines this source category in the following terms:

> "This category represents emissions from natural gas production and processing, and includes emissions from the unintentional equipment leaks from valves, flanges, pup seals, compressor seals, relief valves, sampling connections, process drains, open-ended lines, casing, tanks and other leakage sources from pressurised equipment not defined as vent." (p. 125)

A different approach to defining, with exactly the same effect, is used in the NGERS *Technical Guidelines*:

> "This Division applies to fugitive emissions from natural gas production or processing activities, other than emissions that are vented or flared, including emissions from:
>
> (a) a gas wellhead through to the inlet of gas processing plants
> (b) a gas wellhead through to the tie-in points on gas transmission systems, if processing of natural gas is not required
> (c) gas processing facilities
> (d) well servicing
> (e) gas gathering
> (f) gas processing and associated waste water disposal and acid gas disposal activities." (p. 339)

Two of the main differences between coal seam gas fields and conventional onshore gas fields are that coal seam gas production requires a much larger number of individual wells and that gas typically emerges from wells at much lower pressures. Consequently, coal seam gas fields require a far more extensive network of gathering lines and far more use of pumps and compressors, as demonstrated by the very large expected consumption of electricity for electric motor compressor drive. All else being equal, these differences could mean that methane emissions per unit of gas produced are higher for coal seam gas than for conventional gas.

The NIR states that emissions are estimated using a single emission factor of 0.058 tonnes of methane per kilotonne of methane produced, i.e. 0.0058%. The NIR states that this value is validated by measurements made by a CSIRO study of coal seam gas fugitive emissions (Day *et al*., 2014):

> "The methane emission factor for general leakage of 0.058 t CH4/kt production was validated by a measurement study undertaken by the Commonwealth Scientific and Industrial Research Organisation (CSIRO) during 2013/14 (Day et al., 2014). The study collected field data measurements from 43 coal seam gas wells and found the median and mean emission leakage rates corresponded to emission factors of about 0.005 and 0.102 t CH4/ kt production, respectively. CSIRO concluded that the range of leakage rates measured were consistent with the existing emission factor of 0.058 t CH4/kt production." (p. 125)

In fact, the CSIRO measurements were confined to methane leakage emissions detected on a sample of production well platforms. The work emphatically does not support the use of this single, very low emission factor for all fugitive emissions from the "gas wellhead through to the tie-in points on gas transmission systems".

This is particularly significant because in the course of the study the researchers noted large methane emissions emanating from neighbouring water-gathering lines, water-pump shaft seals, and gas compression plants. For example, they point out that they were not able to take measurements at some wells because 'high ambient CH_4 levels from major leaks or vents made locating minor leak points difficult'. They noted that in one case 'CH_4 released from a vent on a water gathering line was drifting over the pad components so it was not possible to determine if there were other leaks against the high background'.

However, because these emissions were outside the scope of the CSIRO study, which was confined to production well platforms, they were not measured. Nevertheless, the CSIRO researchers do comment on the potential scale and significance of emissions from these other sources, stating that:

> "We found a significant CH4 emission point from a water gathering line near Well B13. Methane was being released from two vents ... at a rate sufficient rate to be audible a considerable distance from the vents. ... Based on the prevailing wind speed, we estimate that the CH4 emission rate from the two vents was at least 130 [grams per minute].... This is a factor of three more than the highest emitting well examined during this study."

That admission alone is sufficient to confirm that the use of 0.058 tonnes of methane per kilotonne of methane produced is inappropriate, and is likely to be substantially underestimating production emissions.

The NIR prescribes one of two methods for estimating and reporting emissions from this source category. Method (1) (Section 3.72) is clearly designed to be applied to conventional natural gas production, as it uses equipment specific emission factors for various types of tanks. These are used in association with conventional gas production to store separated natural gas liquids, including condensate and LPG. They are not relevant to coal seam gas production.

Method (2) (Section 3.73) is designed to be applied to all types of gas production and uses equipment type specific emission factors, in this case sourced for the *API Compendium*[12]. The equipment types potentially relevant to coal seam gas production are listed in Table 6-4, p. 6.16 of the *Compendium*, and include wellheads, reciprocating gas compressors, meters/piping, dehydrators and gathering pipelines.

[12] American Petroleum Institute, 2009. *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry*. http://www.api.org/~/media/Files/EHS/climate-change/2009_GHG_COMPENDIUM.pdf?la=en

As described above, the National Inventory currently includes an estimate of emissions from coal seam gas wellheads, which was derived from the emissions factor specified in the API *Compendium*, and has been found to be consistent with emissions measured at coal seam gas wellheads in Australia. However, emissions from all the other equipment types are, effectively, assumed to be zero. This means that the national emissions inventory currently understates emissions for coal seam gas production. The possible amount of the understatement is completely unknown.

As we read the NGERS *Technical Guidelines*, the coal seam gas producing companies should be reporting their emissions in accordance with Method 2 above. Detailed NGERS reports are of course strictly confidential, meaning that it is impossible to know whether the companies are complying with this reporting requirement. There is certainly no publicly available data, and it might be assumed that if the coal seam gas producing companies were reporting in this way, the resultant total emissions estimate would be included in the National Inventory.

It is understood the CSIRO is currently, or will shortly be, undertaking Phase 2 of its measurement of fugitive emissions from coal seam gas production. This Phase will seek to measure emissions from at least some of the potential leakage sources occurring between the numerous coal seam gas production wellheads and the tie-in points of the three gas transmission pipelines. It is unclear whether any of the CSG-producing companies have made any of their own measurements. If they have, none of the results have been made public.

5.3.5. Processing

Unlike conventional gas, coal seam gas does not require processing upstream of the transmission pipeline or the LNG plant. It is therefore appropriate that coal seam gas emissions from this source category are set at zero. Parenthetically however, it is strange that fugitive emissions associated with conventional gas processing are set at zero, without the citation of any supporting measurement data. Note that in 2008, supply of gas to much of WA was severely disrupted for several months by the rupture of a gas (methane) pipeline, and subsequent explosion and fire, the Varanus Island gas processing plant.

5.3.6. Transmission and storage

The NIR explains that losses from transmission lines are estimated as a uniform 0.005% of gas throughput, based on measurements made many years ago on the Moomba to Sydney gas pipeline. In the last year or two the estimates have also been scaled up by total pipeline length.

Until mid-2014 all coal seam gas production was flowing through established pipelines, mainly to markets in Gladstone and in the Brisbane region. Some was also flowing west to Moomba, thence to markets in the southern states. Each of the three Gladstone LNG consortia has built its own dedicated pipeline, each several hundred kilometres in length, from its coal seam gas fields to Gladstone. Gas started flowing through the first of these during the second half of 2014. This means that the national inventory figures in Table 8 include no significant additional emissions associated with coal seam gas, because up to mid 2014, coal seam gas was simply replacing conventional gas in the slowly growing domestic markets. However, from 2015 onward the national inventory should include the additional emissions arising from transmission of coal seam gas to the LNG plants, calculated in the same way as all other gas pipeline fugitive emissions. Because of both the volumes of gas and the length of the pipelines, this is likely to result in a significant increase in reported fugitive emissions from gas transmission.

The NIR does not mention emissions from gas storage. We understand that there are only a few gas storage facilities in Australia and we are not aware of any such facilities associated with coal seam gas production or use.

5.3.7. Distribution

These emissions relate to coal seam gas only to the extent that coal seam gas forms part of the total quantities of gas supplied through distribution networks to small consumers (termed mass market customers by the industry) in Queensland, NSW and SA. Note that these consumers account for a minority share of total gas consumption in these three states; most gas is consumed by electricity generators and large industrial customers.

5.3.8. Venting

In the words of the NIR, venting is defined as “emissions that are the result of process or equipment design or operational practices”. In practice, a large source of venting emissions is due to the separation and release of the carbon dioxide present in raw natural gas. Conversion of gas to LNG requires the almost complete removal of such carbon dioxide prior to refrigeration. On the other hand, coal seam gas contains negligible quantities of carbon dioxide, meaning that separation is not required. Hence zero venting emissions are associated with coal seam gas production and processing.

The large increase in venting between 2005 and 2014 has arisen because of increased production of conventional natural gas with high carbon dioxide content in Western Australia and the Northern Territory, most of which is converted to LNG.

5.3.9. Migratory emissions

There is also the possibility that depressurisation of the coal seams as a result of dewatering could result in gas migrating through existing geological faults, water bores, abandoned exploration wells or even the soil. This potentially significant source of methane leakage that is not covered at all under the NIR, but can be measured through atmospheric testing and modelling.

5.3.10. Summary

Emissions associated with the production of coal seam gas and its processing to LNG in Queensland arise from both use of fossil fuel derived energy for these activities and fugitive emissions of coal seam gas at various points along the supply chain.

The major uses of energy are electricity, and some gas, in production and pipeline transport, mainly to power compressors and pumps, and gas in processing to LNG at the three LNG plants, where gas turbines provide all the motive power needed to operate the plants. The quantities of electricity and gas consumed are well understood and the associated emissions are reported through NGERS and included in the NGGI.

By contrast, fugitive emissions are poorly understood. It appears that all data reported re based on the use of default emission factors, none of which relate specifically to the production of coal seam gas in Australia. The fugitive emission factors for drilling and well completion are the same as those used for conventional gas activities, but result in higher reported emissions because of the much large number of wells required for coal seam gas production. While there is no a priori reason to suppose that the emission factors are not applicable to coal seam gas activities, there are no publicly available measurement data to confirm, or otherwise, the assumed emission factor values. Emission factors for methane emissions on production well pads are small and are based on recent measurements by the CSIRO.

However, limited available observations suggest that by far the largest source of fugitive emissions is likely to be leakage from the extensive network of gathering lines, compressors and pumps which connect producing gas wells to the transmission pipeline tie-in points. On the basis of publicly available information, it appears that no systematic measurements have been made of emissions from these sources. In both individual company reports and in the national emissions inventory emissions from this source are set at zero. Consequently, it is probable that official data on total greenhouse gas emissions arising from the production of coal seam gas, and its conversion to LNG, significantly understate the true level of emissions.

Another potentially significant source of methane leakage that is not covered by the NIR is "migratory emissions" where methane leaks to the atmosphere through existing below-ground pathways as a result of depressurisation of the coal seams through dewatering. A separate report by the University of Melbourne Energy Institute examines migratory emissions.

5.4. Australian methane-emission field investigations and reviews of reporting methods

This section summarises, chronologically as listed in Table 9, the scope and results of certain limited field investigations and measurements of methane emissions, along with reviews of Australian oil-and-gas-related methane-emission reporting methods.

The reviews identified shortcomings that may cause Australia's methane emissions from this sector to be under-reported.

Table 9

Chronological listing of field investigations and reviews of emission estimation and reporting methods		
Date	**Field Investigation**	**Review**
2010 and 2011	Queensland regulatory authority wellhead investigation	
2012	Southern Cross University mobile surveys	CSIRO
"		Pitt & Sherry
2013		Pitt & Sherry
"		New South Wales Chief Scientist
"		Australian Government
2014	CSIRO well pad equipment investigation	
"	Gas industry mobile survey	
2016		United Nations Framework Convention on Climate Change (UNFCCC)
"		This report, University of Melbourne Energy Institute

5.4.1. 2010 and 2011 investigation of Queensland CSG wellhead emissions

In 2010 in Queensland, people living near coal seam gas production equipment reported gas emissions. As a response, the Queensland government arranged to test 58 wellheads. Of these, 26 wellheads were found to be emitting methane. The most significant emissions were found at one wellhead emitting methane at a concentration of 6% methane-in-air, a potentially flammable mixture. Four other wellheads were found to be emitting methane at concentrations equal to or greater than 0.5% methane-in-air. The remaining 21 leaking wellheads were found to be emitting methane at concentrations less than 0.5% methane-in-air. The lowest reported methane concentration was 20 parts-per-million (Queensland DEEDI (2010)).

Following on from these investigations, the Queensland regulatory authority issued compliance directions to eleven gas companies to inspect and report on 2,719 coal seam gas wells in place in Queensland at that time. Five wellheads were reported to be emitting methane at concentrations greater than 5% methane-in-air. Another 29 wellheads were reported to be leaking methane at concentrations between 0.5% and 5% methane-in-air. Other leaking wellheads, where methane concentrations were less than 0.5%, were reported as being "numerous", but no further details were provided (Queensland DEEDI (2011)).

Subsequent to the above, the Queensland Government issued a Code of Practice covering coal seam gas wellhead-emissions detection and reporting (Queensland Government (2011)).

In the 2010-2011 actions described above, no attempts were made to quantify the rate at which methane was being emitted (i.e. no 'methane flux' was measured, for example, in kilograms per hour).

No emission sources other than wellheads were investigated at this time.

5.4.2. Southern Cross University mobile survey (2012)

Land-vehicle-mounted equipment has been widely used overseas to detect and map methane emissions, particularly in urban environments. For example, Figure 14 illustrates results of a vehicle survey in Boston in the U.S., which identified 3,356 methane leaks from the gas distribution system of the city of Boston (Phillips, Ackley et al. (2013)).

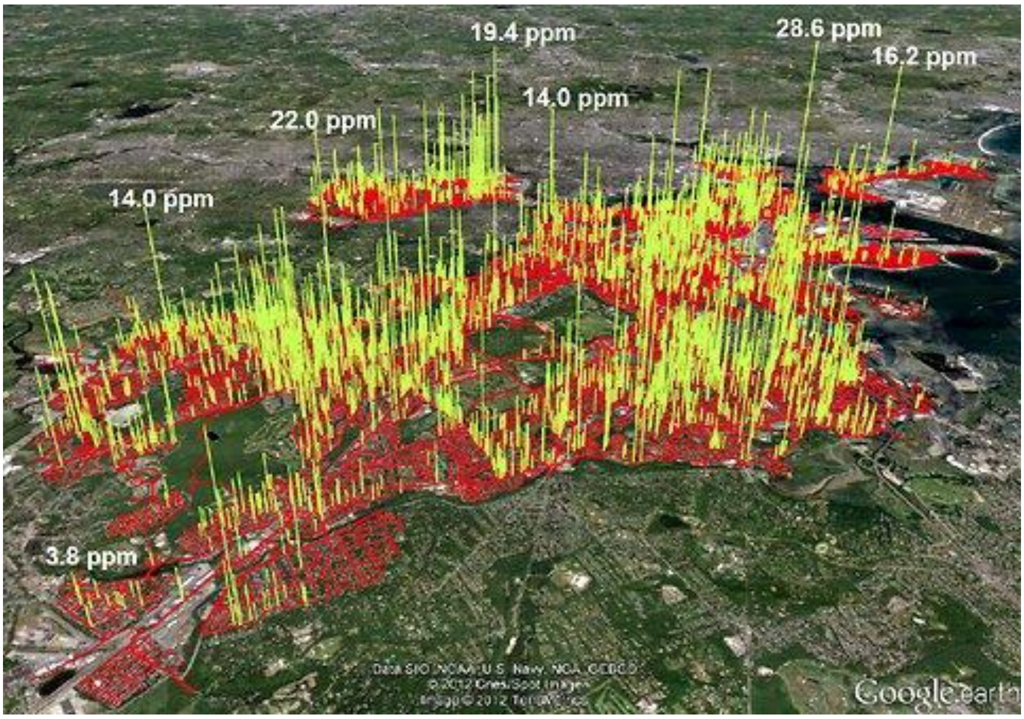


Figure 14: 3,356 methane leaks mapped in the city of Boston (Phillips, 2013)

In 2012, researchers from Southern Cross University used a vehicle-mounted mobile methane-emission detector to record "the first assessment of greenhouse gases in Australian CSG fields" (Maher, Santos et al. (2014)). Measurements recorded in the Tara, Queensland region indicated:

> "...a widespread enrichment of both methane (up to 6.89 parts-per-million (ppm)) and carbon dioxide (up to 541 ppm) within the production gas field, compared to outside. The methane and carbon dioxide carbon-13 isotope source-values showed distinct differences within and outside the production field, indicating a methane source within the production field that has a carbon-13 isotope signature comparable to the regional CSG."

The researchers concluded:

> "Data from this study indicates that unconventional gas may drive large-scale increases in atmospheric methane and carbon dioxide concentrations, which need to be accounted for when determining the net greenhouse gas impact of using unconventional gas sources.

> Considering the lack of previous similar studies in Australia, the identified hotspots of greenhouse gases and the distinct isotopic signature within the Tara gas field demonstrate the need to fully quantify greenhouse-gas emissions before, during and after CSG exploration commences in individual gas fields."

Though this study measured methane concentrations, it did not attempt to quantify a methane emission rate. Nor did this study attempt to identify specific methane emission points or causes.

5.4.3. 2012 CSIRO review of CSG-industry methane-emission reporting (2012)

In their October 2012 report entitled "Fugitive Greenhouse Gas Emissions from Coal Seam Gas Production in Australia", (Day, Connell et al. (2012)), the CSIRO reported that with regard to Australian methane-emissions reporting:

> "The fugitive emissions data reported to [the] National Greenhouse and Energy Reporting Scheme (NGERS) are subject to significant uncertainties and do not provide information specific to the CSG industry. The bulk of the reported fugitive emissions are due to venting and flaring which can be estimated to reasonable confidence - in some cases with Tier 3 [direct measurement] methods. However, for CSG production, most of the emissions from this sector are estimated using Tier 1 and Tier 2 [factor and estimate-based] methods described in the American Petroleum Institute's (API 2009) Compendium of Greenhouse Gas Emission Methodologies for the Oil and Natural Gas Industry, with emissions factors based on U.S. operations."

And in summary,

> "... it is clear that a comprehensive data set relating to the true scale of fugitive emissions from the CSG industry does not yet exist."

A key recommendation of this CSIRO study was that:

> "A programme of direct measurement and monitoring is required to more accurately account for fugitive emissions from CSG than is currently available."

As described in Section 5.4.7, the CSIRO were subsequently commissioned by the Australian Government to conduct limited methane emission measurements at coal seam gas well pads.

5.4.4. Pitt & Sherry reviews of CSG-industry methane-emission reporting (2012 and 2013)

Also in 2012, Pitt & Sherry (Saddler (2012)) conducted a "review of literature on international best practice for estimating greenhouse-gas emissions from coal seam gas production".

Pitt & Sherry reported:

> "There is effectively no public information about methane emissions associated with unconventional gas production in Australia. This is a matter of some public policy concern, given the projected large growth in production of CSG."

Regarding emission-estimation and reporting methods used in Australia, Pitt & Sherry reported:

> "The key point about all these methodologies is that they were specifically designed for use by the conventional natural gas industry, not for CSG production. This may well be appropriate for equipment used at gas processing facilities, since this is essentially the same for both gas sources. It may also be appropriate for gathering pipelines and compressors. However, it is less likely to be appropriate for well heads and it certainly does not address the possibility of uncontrolled emissions of methane escaping through the ground around wells, as has been claimed to occur in some CSG fields. It should also be noted that the emission factor values recommended in the API Compendium are mostly derived from measurements made in the USA in the 1990s, and so may not be appropriate for Australia today, and in the future."

In addition to the above shortcomings, in 2013 Pitt & Sherry (Saddler (2013)) reported that 'migratory' or 'diffuse' methane emissions are not included in methane-emission reporting required by NGERS. (The potential for methane migratory emissions occurring as a result of Australian coal seam gas extraction is discussed in Section 5.6).

5.4.5. NSW Chief Scientist commentary on emissions reporting (2013)

In July 2013, the New South Wales Chief Scientist and Engineer (2013) confirmed that with respect to estimates of methane emissions resulting from coal seam gas production:

> "...current estimates are made using methods for the conventional gas industry and do not take into account factors in the CSG industry such as increased well density and potential for hydraulic fracturing."

5.4.6. Australian Government technical discussion paper identifies concerns (2013)

In April 2013, the Australian Government (2013) released a technical discussion paper entitled:

> "Coal Seam Gas: Enhanced Estimation and Reporting of Fugitive greenhouse-gas emissions under the National Greenhouse and Energy Reporting (Measurement) Determination"[13]

This discussion paper presented proposals for enhancing...

> "... methods used by companies for the estimation of greenhouse-gas emissions during the exploration and production of coal seam gas."

The discussion paper recognised that:

> "... currently the NGER (Measurement) Determination does not differentiate between the methods used for the estimation of emissions from conventional gas and methods used for coal seam gas (CSG) production. Nonetheless, in practice, there are significant operational differences between conventional natural gas and CSG; most notably CSG production generally involves a higher density of well heads within a well field and CSG production may also involve the subterranean hydraulic fracturing process known as 'fracking'. This latter aspect is important as there is overseas evidence to suggest that use of fracking techniques may generate more emissions than when conventional CSG extraction techniques are used."

The Australian Government's technical discussion paper sought to:

> "... address the implications of the differences between conventional gas and CSG and to elaborate CSG-specific proposals for the estimation of fugitive emissions for the first time."

Following these reviews, in July 2013, Section 3.46B was added to the NGERS Technical Guidelines[14]. It describes more specific reporting requirements for well completions and well workovers. This new section applies to the reporting year ending 30 June 2014 and afterward.

5.4.7. CSIRO well pad methane emission measurements (2014)

In June 2014, Australia's CSIRO published what was referred to as "the first quantitative measurements of methane emissions from the Australian coal seam gas industry" (Day, Dell'Amico et al. (2014)).

However, as the CSIRO reported, their work scope was as prescribed by the Australian Government (Department of Climate Change and Energy Efficiency) and was <u>limited to equipment located strictly on well pads</u>. Equipment outside of well pads, which CSIRO researchers noticed was a significant source of methane emissions (e.g. entire gas processing plants, compressor stations, and water treatment plants) did not fall within the scope of CSIRO's investigations.

---

[13] This technical discussion paper is no longer available on Australian Government websites.
[14] http://www.environment.gov.au/climate-change/greenhouse-gas-measurement/nger/technical-guidelines

Five CSG-producing companies provided CSIRO access to 43 selected well pads in New South Wales and Queensland. Equipment at the well pads included a wellhead, a dewatering pump and gas-engine (if fitted), separator, pipework and associated valves, instruments, and fittings.

The largest well-pad emission source that CSIRO was able to measure was a vent from which methane was being released into the atmosphere at a rate of 44 grams per minute. This is equivalent to 23 tonnes of methane per year if these emissions were to continue for a full year. CSIRO's findings here contrast with CSG-LNG project Environmental Impact Statements commitments to "zero venting" of methane (Hardisty, Clark et al. (2012)).

At another gas operations site, the largest source of methane emissions was a buried gas-gathering line. CSIRO reported that:

> "We attempted to measure the emission rate ... however because of the diffuse nature of the emissions through the gravel, this was not successful."

CSIRO also highlighted significant methane releases from gas-engine exhausts (i.e. uncombusted methane fuel). One engine was emitting uncombusted methane at a rate of 11.8 grams per minute (or six tonnes per year if continuous), an emission rate 236 times greater than the factors that apply under NGERS reporting. (Note that in the electricity-generation comparison by Hardisty, Clark et al. (2012) of gas versus coal (see Section 3.2), no emissions from gas-engine exhausts were considered.)

In some instances CSIRO's attempts to measure leaks at well pads were overwhelmed by large methane emissions emanating from neighbouring water-gathering lines, water-pump shaft seals, and gas compression plants that CSIRO were not asked to investigate. The researchers described their experiences as follows:

> "On-pad measurements were made at most wells except in a few cases where high ambient CH_4 levels from major leaks or vents made locating minor leak points difficult. In one case at Well B2, CH_4 released from a vent on a water gathering line was drifting over the pad components so it was not possible to determine if there were other leaks against the high background. Similar conditions were encountered at Wells C3 and E4 where variable plumes from leaks around the water pump shaft seals precluded reliable leak detection. In one case we attempted to measure emissions from a well about 500 m downwind of a gas compression plant but the CH_4 emissions from the plant prevented any measurements being made on that site."

As an example of "significant" volumes of methane being released beyond well pads and therefore beyond CSIRO's assigned scope of investigation:

> "We found a significant CH4 emission point from a water gathering line near Well B13. Methane was being released from two vents ... at a rate sufficient rate to be audible a considerable distance from the vents. ... Based on the prevailing wind speed, we estimate that

> the CH_4 emission rate from the two vents was at least 130 [grams per minute].... This is a factor of three more than the highest emitting well examined during this study."

In a reply to questions asked in the Australian Senate in 2014, CSIRO highlighted CSG/water separation activities as a particular operational source of methane emissions requiring further investigation (Australian Senate (2014)). CSG/water separation difficulties have been previously reported in the United States. Atmospheric venting of up to 30% of produced methane was found at gas-production sites where inadequate gas/water separation facilities were provided (U.S. Dept. of Energy (2010)).

In summary, the researchers qualified their limited fieldwork as follows:

> "...there are a number of areas that require further investigation. Firstly, the number of wells examined was only a very small proportion of the total number of wells in operation. Moreover, many more wells are likely to be drilled over the next few years. Consequently the small sample examined during this study may not be truly representative of the total well population. It is also apparent that emissions may vary over time, for instance due to repair and maintenance activities. To fully characterise emissions, a larger sample size would be required and measurements would need to be made over an extended period to determine temporal variation."

CSIRO's methane emission findings contrast with CSG-LNG projects Environmental Impact Statements that "best practice" would be employed by the industry, and that methane emissions would be limited to 0.1% of production (Clark, Hynes et al. (2011), Prior (2011), Hardisty, Clark et al. (2012)).

The CSIRO's limited well pad investigations are cited in the Australian Government's National Inventory Report (Australian Government (2016)) as validating the continued use of the 0.0058%-of-production emission factor for "general leakage". This factor was provided by the Australian Petroleum Production and Exploration Association (APPEA) and is based on 1994 analysis of emissions resulting from conventional gas production. Concerningly, continued use of the 0.0058% emission factor for "general leakage" in Australian emission inventories is questionable because:

- the CSIRO-reported mean (average) emissions value was 1.8 times higher than the Australian Government-accepted inventory emission factor (0.0102% vs 0.0058%)
- the CSIRO-reported mean emissions value excluded measurements from two well pads that, if included, would raise the CSIRO mean emissions value by four times to 0.04%. This highlights the skewed distribution of methane emission sources and the impact of 'super-emitters' (see Section 4.3).
- did not measure emissions from many other obvious emission sources near well pads

And furthermore, as noted by the CSIRO:

> "While wells represent a major segment of the CSG production infrastructure, it is important to note that there are many other components downstream of the wells which have the potential to release greenhouse gases. These include processing and compression plants, water treatment facilities, gas-gathering networks, high-pressure pipelines and several LNG production facilities currently under construction near Gladstone. In the study reported here, we have only examined emissions from a small sample of CSG wells; none of the other downstream infrastructure has been considered at this stage."

5.4.8. Gas industry mobile survey (2014)

Following on from the Southern Cross University research, in a report prepared for the Gas Industry Social and Environmental Research Alliance (GISERA), researchers used vehicle-mounted mobile equipment and measured methane concentrations in air as high as 18 parts-per-million (Day, Ong et al. (2015)). The researchers reported "numerous occasions where elevated methane concentrations were detected" but did not identify the emission sources.

A methane concentration of 5.8 parts-per-million was measured near an operating gas vent. This finding is contrary to commitments made in Queensland CSG-LNG project Environmental Impact Statements that there was to be "zero venting" of methane (Hardisty, Clark et al. (2012)).

Based on roadside measurements, a methane-emission rate of 850 kilograms/day was indicated near a gas plant, however the researchers stated:

> "Because of the uncertainties associated with these emission rate estimates it is stressed that the data presented ... are indicative only and cannot be interpreted as accurate emission rates from these facilities. Further work is required to better define the emissions from these sources.
>
> The atmospheric ‘top-down’ method using a network of fixed monitoring stations[15] proposed for Phase 3 of this project is likely to significantly reduce the uncertainty of flux estimates for [methane] sources, including major CSG infrastructure such as gas processing facilities."

[15] See Section 7.3.2.3 for a discussion of the capabilities of fixed (stationary) air quality monitoring stations.

5.4.9. UNFCCC review of Australian inventory submission (2016)

Following a review, in April 2016 (UNFCCC (2016)), the United Nations Framework Convention on Climate Change (UNFCCC) expert review team (ERT) reported on Australia's greenhouse gas inventory submission. With respect to emission from oil and gas production operations, the ERT described where action is needed for Australia to improve its submission. Some of these actions are described in Table 10.

Table 10

Partial list of oil-and-gas-related greenhouse gas inventory improvement described by UNFCCC	
UNFCCC issue no.	
E.12	"Improve the transparency of the discussion on the reasons underlying the following observed trends: large inter-annual changes in CH_4 emissions from natural gas production and processing; and the decline in CH_4 emissions from distribution while CO_2 emissions increased."
E.14	"Update the AD [activity data] for petroleum storage so that it truly reflects the actual AD the were applied to estimate emissions of petroleum storage since 2009."
E.17	"A new liquefied natural gas plant recently started operations in Australia. The ERT noted that the key emission data and country-specific CO_2 and CH_4 EFs used to report the emissions for this category, which considers several plants, were developed before the opening of the new plant, and may therefore not be representative of emissions from this plant type. The ERT recommends that Australia collect data on emissions from any new plant types, and update the country-specific CO2 and CH4 EFs, where appropriate."
E.18	During the review, Australia informed the ERT of the considerable projected growth in unconventional gas production (e.g. shale and coal bed methane) in Australia. The ERT notes that key EF [emissions factor] data used in the inventory calculations are based on data from the United States of America and may not be representative of the emissions from well completion activities associated with the commissioning of new production. The ERT recommends that Australia make efforts to improve the data for the emissions from this category, including the development of updated EFs that represent production activities in unconventional gas production." In its National Inventory Report, the Australian Government identified planned improvements to address UNFCCC-identified issue E.18.

5.5. Australian methane-emission comparisons

In the National Inventory Report 2014 (Australian Government (2016)), the methane component of "fugitive emissions from oil and natural gas" was reported to be 5,453,000 tonnes CO_2-e. This quantity is approximately 0.5% of the total amount of methane produced for sale by the Australian oil and gas industry in 2014. As will be described below, this emissions rate is much lower than assessments reported recently by researchers investigating emissions from unconventional oil and gas operations in the United States.

Figure 15 illustrates that since 2005 Australian gas production has increased by 46%. Over this same time period, reported methane emissions have increased by only 9%. These discordant trends may indicate under-reporting of methane emissions.

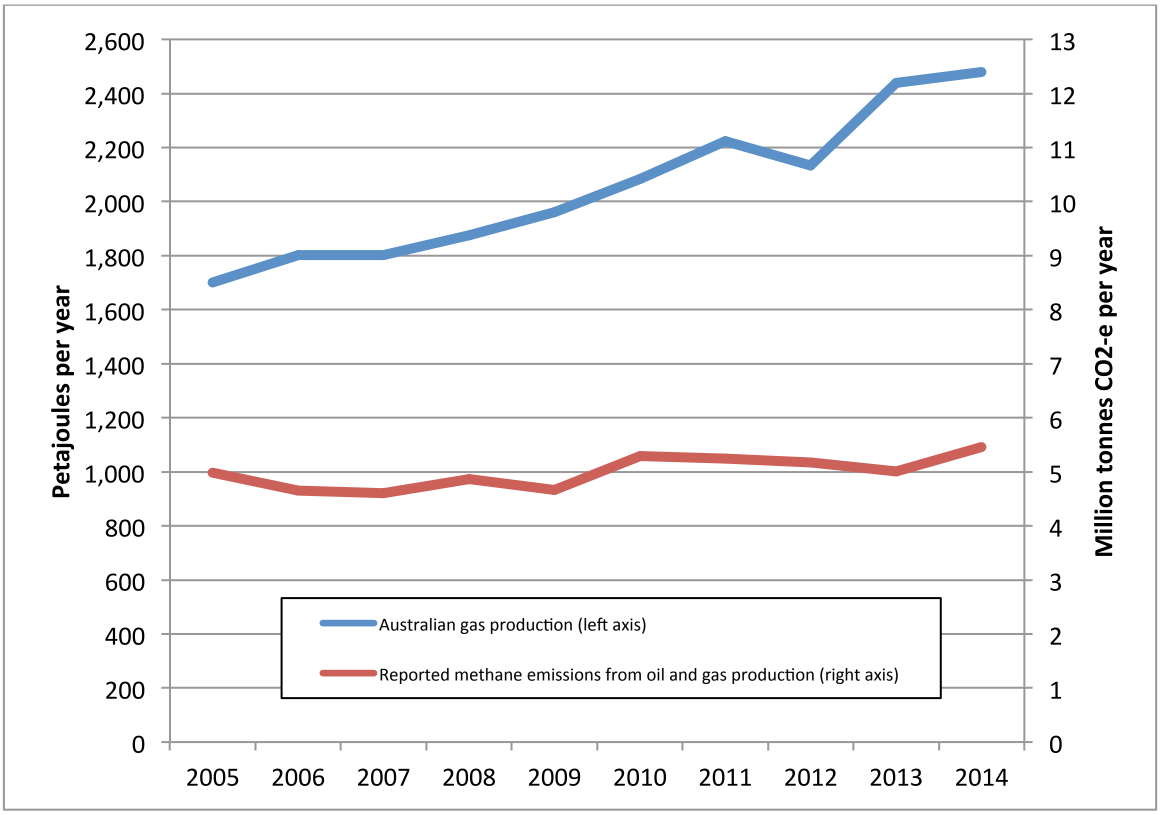


Figure 15: Australian annual gas production and reported methane emissions

As described above, Australia's reported methane emissions from the oil and gas sector are equivalent to at 0.5% of gas production. This relative level of methane emissions:

- exceeds by 25 times the level highlighted in a 2014 media release by the Australian Petroleum Production and Exploration Association (0.02%)[16]
- exceeds by five times the level of methane emissions (0.1%) expected according to the original Queensland CSG-LNG project Environmental Impact Statements (Clark, Hynes et al. (2011), Prior 2011), Hardisty, Clark et al. (2012))
- is only 36% of the U.S. EPA's recently revised estimates (1.4%, as described in Section 4.6)
- is far below levels reported for U.S. oil and gas-producing regions based on data recorded via aircraft or space satellites (2 to 17% of production).

Figure 8 compares certain estimated methane-emission levels reported for the U.S. and Australia with certain 'top-down' measurements conducted in the United States. (See also Table 11 for data and references.)

5.6. The risk of migratory emissions from Queensland coal seam gas

The MEI companion report on migratory emission entitled

> *"The risk of migratory methane emissions resulting from the development of Queensland coal seam gas"*

focuses on the single potential emission source known as 'migratory methane emissions'.

Current Australian methane-emission estimation methods ignore this potential source. The likelihood of migratory emissions occurring as a direct consequence of gas extraction, at present or in the future, is difficult to assess due to a lack of available data. The heterogeneity of the geology in the area where Queensland's Condamine Alluvium exists increases the risk of migratory emissions occurring.

[16] http://www.appea.com.au/media_release/csiro-report-points-to-environmental-benefits-of-csg/

McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

`

Table 11

Reported oil and gas-related methane-emission estimates and top-down measurements				
		Basis	**% of production**	**Reference**
Australia	Oil and gas industry media release	limited well-pad measurements	0.02%	Footnote [17]
	Fugitive emissions reported in Queensland CSG-LNG environmental impact statements	factor-based estimates	0.1%	Clark, Hynes et al. (2011), Prior (2011), Hardisty, Clark et al. (2012)
	Australian Government reported (for the year 2014)	largely factor-based estimates	0.5%	See Section 5.5
U.S.	U.S. EPA (for the year 2013, latest revision)	largely factor-based estimates	1.4%	See Section 4.6
	U.S. Denver-Julesberg basin	aircraft measurements	2 to 8%	Petron, Karion et al. (2014), see Table 2
	U.S. Eagle Ford Basin (Texas)	satellite-based measurements	9%	Schneising, Burrows et al. (2014), see Table 2
	U.S. Bakken Basin (North Dakota)	satellite-based measurements	10%	Schneising, Burrows et al. (2014), see Table 2
	U.S Uintah Basin (Utah)	aircraft-based measurements	6 to 12%	Karion, Sweeney et al. (2013), see Table 2
	U.S. Marcellus Basin (southwestern Pennsylvania)	aircraft-based measurements	3 to 17%	Caulton, Shepson et al. (2014), see Table 2

[17] http://www.appea.com.au/media_release/csiro-report-points-to-environmental-benefits-of-csg/

McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

Current Australian methane-emission estimation methods ignore this potential source. The likelihood of migratory emissions occurring as a direct consequence of gas extraction, at present or in the future, is difficult to assess due to a lack of available data. The heterogeneity of the geology in the area where Queensland's Condamine Alluvium exists increases the risk of migratory emissions occurring.

Migratory emissions could significantly increase with continued depressurisation of the coal seams while multiple users are extracting water from various aquifers. Migration of methane along existing natural faults and fractures is possible and may increase with continued depressurisation even when the leakage rates today may be minimal without disturbance. Water bores and coal exploration bores are known sources of methane emissions and the presence of free methane can be the direct consequence of the depressurisation of the coal seams. Well integrity of dedicated gas wells but also existing bores that were not designed to prevent migratory emissions is an area of concern.

The companion report on migratory emissions contains a more detailed discussion of migratory emissions.

5.7. Lost revenue and potential liabilities associated with future methane emission scenarios from unconventional gas production

This section outlines the value of lost gas production and potential carbon liabilities associated with methane emission scenarios resulting from Australian unconventional gas production, under various global warming potential assumptions, assuming some form of carbon pricing is reinstated at a future time.

In 2014, the Australian Government reported greenhouse gas emissions across all sectors totalling 525 million tonnes (CO_2-e) of which 5.4 million tonnes were attributed to oil and gas sector emissions. (Australian Government 2016) Consistent with current United Nations reporting guidelines, methane emissions are reported as having a 100-year global warming potential (GWP) of 25 tonnes of CO_2-e per tonne of methane emitted. The value of 25 for the 100-year GWP is based on the 4th Assessment Report of the IPCC (2007). In the 5th Assessment Report (2013) the IPCC updated the 100-year GWP for methane to 34 including carbon cycle feedbacks and 28 excluding carbon cycle feedbacks. The use of the updated GWP would increase the total methane emissions in CO_2-e e units by 26%, as methane emissions are multiplied with the GWP for a conversion to CO_2-e equivalent emissions. Reported fugitive methane emissions from oil and natural gas would increase by 2 million tonnes CO_2-e. Adjusting the reported greenhouse gas emissions for all Australian sectors for a 20-year methane GWP of 86 would increase the total by approximately 50% to 787 million tonnes CO_2-e.

Table 12 summarises predicted growth in total methane emissions from the Australian unconventional gas industry for several scenarios using different assumptions about the proportion of fugitive emissions and the growth in industry output. (For 2016, approximately 1,500 petajoules per year of unconventional gas will be produced in Australia, mostly in the form of Queensland coal seam gas.) We consider methane-emissions scenarios ranging from 0.5% of gas production (the current government-reported average of 0.5%) to 15% of gas production (a figure similar to some of the highest estimates of U.S. gas field emissions presented in Table 3).

Table 12

Liabilities for differing scenarios for methane emissions from Australian unconventional oil and gas production, in terms of lost value and potential carbon impost.

Column	A	B	C	D	E
Case	Unconven-tional gas production rate	Methane emissions rate	Methane greenhouse-gas emissions (100 yr – 20 yr GWP)	Sales value of lost gas (at $A 10 / gigajoule)	Carbon impost ($A 25/tonne CO_2-e; 100 yr – 20 yr GWP)
	PJ/yr	% of gas production	million tonnes CO_2-e/yr	million $A/yr	million $A/yr
1	**1,500 (*)**	0.5	5 - 12	75	115 - 290
2	"	2	18 - 46	300	459 - 1,162
3	"	6	55 - 139	900	1,367 - 3,485
4	"	10	92 - 232	1,500	2,296 - 5,808
5	"	15	136 - 348	2,250	3,443 - 8,712
6	**3,000**	0.5	9 - 23	150	230 - 581
7	"	2	37 - 93	600	918 - 2,323
8	"	6	110 - 279	1,800	2,755 - 6,969
9	"	10	184 - 465	3,000	4,590 - 11,615
10	"	15	275 - 697	4,500	6,887 - 17,423

* 1,500 PJ/yr is approximately equal to current or near-term (2016, 2017) CSG production capacity.

Table 12 (Column C) presents figures for ten 'cases' where methane-emissions range from 0.5 to 15% of total unconventional gas production. Table 12 also shows the financial impact of these emissions by applying a gas sales-value of $A 10 / gigajoule and a carbon impost of $A 25 / tonne of CO_2-e (Columns D and E).

As an example, Case 8 illustrates a 6%-of-production methane emission rate. This case shows that were the Australian unconventional gas industry to expand to twice its present size, and if the specified gas sales value and carbon impost applies, the value of lost gas sales would total $A 1.8 billion per year while the carbon impost would be between $2.7 - $7 billion per year depending on whether the CO2-e is calculated on at the 100-year, as is convention, or 20-year timescale, as might be considered relevant in setting near term targets such as 2030.

5.8. Conclusions

In summary, the information presented in Section **5** shows that Australia's unconventional gas industry is rapidly growing. There is also potential for unconventional oil production. Unfortunately, reviews of Australia's methane-emission estimation and reporting methods for this industry sector highlight shortcomings that may mean reported emissions, at only 0.5% of total-gas-production, are lower than what is actually occurring.

As summarised by CSIRO researchers in 2012:

> "... it is clear that a comprehensive data set relating to the true scale of fugitive emissions from the CSG industry does not yet exist."

This remains the situation today. No investigations have yet been published that quantify methane emissions across all potential emission points that exist throughout coal seam gas production, processing, and gas transport infrastructure.

In its National Inventory Report, the Australian Government cites CSIRO's investigations of just 43 well pads as validating the "general-leakage" emission factor assumption of just 0.0058%-of-production, while ignoring CSIRO's conclusion that:

> "In addition to wells, there are many other potential emission points throughout the gas production and distribution chain that were not examined."

In a reply to questions asked in the Australian Senate in 2014, CSIRO highlighted CSG/water separation activities as a particular operational source of methane emissions requiring further investigation.

In 2016, the UNFCCC "expert review team" (ERT) noted that regarding Australia's greenhouse gas inventory submission to the United Nations:

> "... key EF [emissions factor] data used in the inventory calculations are based on data from the United States of America and may not be representative of the emissions from well completion activities associated with the commissioning of new production."

The UNFCCC's review team went on to recommend that:

> "... Australia make efforts to improve the data for the emissions from this category, including the development of updated EFs that represent production activities in unconventional gas production."

Referring to the UNFCCC recommendations, the Australian Government identified improvement measures that it "hopes":

> "...can lead to the development of more representative EFs." (Australian Government (2016))

Finally, Section 5.6 highlighted the potential for migratory methane emissions to occur in Queensland's coal seam as basins. This is further described in the MEI companion report entitled:

> *"The risk of migratory methane emissions resulting from the development of Queensland coal seam gas".*

6. Full fuel-cycle greenhouse gas emissions from exported CSG

Full life-cycle emissions for the exported LNG include not only supply side emissions associated with production, but also emissions arising from processing shipping and use at the destination. Table 13 shows estimated greenhouse emissions arising from the various stages of production, processing and shipping coal seam gas in the form of LNG to Japan.

No estimate has been made of emissions associated with pipeline transport from port to point of consumption in the destination country, because there are a variety of LNG destinations. However, these emissions are likely to be very small. We assume that the imported gas will all be used for electricity generation and at other large industrial sites. For any gas supplied through distribution networks to small consumers, emissions could be considerably higher, because of the higher level of fugitive emissions from typical gas distribution systems, compared with those supplying large consumers such as power stations.

As discussed earlier, methane emissions from coal seam gas transport between wellhead and pipeline tie-in may be quite large. Hence the estimated total emissions shown here should be seen as a minimum value.

Table 13

Stage/activity	Emission source	Fuel (if applicable)	Emission factor (see text)	Emissions (tonnes CO_2-e/TJ gas delivered
Production and processing to LNG	Energy combustion (Scope 1)	gas	123 PJ/24 Mt LNG	5.05
	Energy combustion (Scope 2)	electricity	9.3 TWh/24 Mt LNG	5.80
Exploration	Reported fugitive methane under NIR		26 t/completion day	0.22
Production, well platform only	Reported fugitive methane under NIR		0.058 t/t produced	0.17
Production, other sources	Reported fugitive methane under NIR		Not estimated	
Shipping	Energy combustion	gas (boil off)	22.5 g CO_2/tonne nm	1.67
Regasification	Energy combustion	gas	1% of throughput	0.52
TOTAL supply system				13.6
Gas combustion				52.0
TOTAL fuel cycle				65.6

Total minimum fugitive and combustion emissions upstream of the point of combustion are estimated to be 13.6 tonnes of CO_2-e per terajoule (TJ) of gas delivered to the final user in the importing country. Using a direct-combustion emission factor of 52 tonnes of CO_2-e per TJ, this makes the full fuel-cycle greenhouse gas emissions 65.6 tonnes of CO_2-e per TJ of gas consumed.

6.1. Calculation assumptions and method

Production and processing to LNG	Energy consumption estimates from Lewis Grey Advisory, as discussed above.
Exploration	Estimate uses the per well emission factor from the National Inventory, as discussed above. It assumes an average production-life per well of 20 years and that the total number of wells drilled to support the three LNG trains will be 8,000. Note that wells drilled in Queensland up to June 2015 totalled a little over 7,000 and that annual numbers drilled reached a peak in 2013-14 and fell sharply in 2014-2015. (Queensland Department of Natural Resources and Mines, 2016)
Production (well platform only)	Estimate uses the per well emission factor from the National Inventory, as discussed above. The figure is 0.058 tonnes methane per tonne produced, as discussed above, converted to CO_2-e.
Production, other sources	No estimates available, as discussed above.
Shipping	It is assumed that all the fuel used in shipping comes from LNG boil-off, thereby reducing the volume of LNG delivered. The estimate is for a voyage from Gladstone to Yokohama, a distance of 4,045 nautical miles. The emission factor of 15 g CO_2 per tonne-nautical mile is towards the low end of the range reported by Wang, Rutherford and Desai, 2014, and is scaled up by a factor of 1.5 to allow for fuel use and resultant emissions on the empty return voyage.
Regasification	There are a number of different regasification technologies, using different energy sources and with different associated emissions. The technologies used at the regasification terminals to which the LNG will be exported are not known. It has been assumed that the technology will use gas boil-off as fuel and that the quantity used will equal 1% of the gas output. This is around the mid-point of the range quoted by Elsentrout, B., Wintercorn, S. and Weber, B. (2006).

7. Recommendation for industry and regulators; addressing methane-emission knowledge gaps

7.1. Australian oil and gas industry action needed to minimise current methane emissions

Within the rapidly-growing Australian CSG-LNG industry, reducing methane emissions may not have been top priority compared to constructing the $A 60 billion Queensland CSG-LNG facilities and subsequently initiating gas exports. Furthermore, the July 2014 removal of the carbon price reduced the economic incentives to minimise methane emissions.

Nevertheless, there remain reasons why the Australian oil and gas industry should act to reduce methane emissions including:

- moving toward the low-level of methane emissions expressed in CSG-LNG project Environmental Impact Statements (reported to be as low as 0.1% of production, see Section 5)
- reduced safety hazards and health impacts for industry workers and neighbouring community members
- global climate change mitigation
- reduced product loss
- reduced potential for future carbon liabilities
- improved reputation in the community and social 'licence-to-operate'
- improved public-perceptions regarding the role gas can play in the rapid movement to a net-zero-carbon future.

According to the Global Methane Initiative[18]:

> "In oil and gas systems, there are numerous opportunities to reduce methane emissions. Many emission reduction activities consist of relatively simple operational changes that can have a large impact for a relatively small cost. Opportunities to reduce methane emissions generally fall into the following categories:
>
> - change out existing equipment
> - Improve maintenance practices and operational procedures
> - study and undertake new capital projects."

The U.S. Government Accountability Office estimated[19] that around 40% of the gas that is vented and flared on onshore federally-leased land could be economically captured with currently available control technologies.

[18] The Global Methane Initiative is an international public-private initiative that advances cost effective, near-term methane abatement and recovery. http://globalmethane.org

According to the Environmental Defense Fund:

> "Cost-effective technologies exist to reduce routine and non-routine emissions of methane during oil and gas exploration and production. The U.S. Environmental Protection Agency (EPA), in conjunction with the natural gas and oil industry, has developed and tested more than 100 ways to reduce methane emissions while increasing revenues by keeping more product in the pipeline."[20]

Studies done for the U.S. (ICF International (2014)) and Canada (ICF International (2015)) found significant opportunities for cost-effective methane-emission reduction. For example:

> "Industry could cut methane emissions by 40% below projected 2018 levels at an average annual cost of less than one [U.S.] cent on average per thousand cubic feet of produced natural gas [$A 0.012 per gigajoule] by adopting available emissions-control technologies and operating practices. [When] the full economic value of recovered natural gas is taken into account, [a] 40% reduction is achievable."

Hardisty, Clark et al. (2012) put forward recommendations for the oil and gas industry regarding venting from pilot wells, well completions and workovers, compressor stations and pneumatic devices. Capturing gas and flaring wherever possible are obvious mitigation measures. Mitigating emissions should involve high quality equipment, adhering to high standards and implementation of leak detection programs.

Apte, McCabe et al. (2014) recommended procedures for well abandonment (coal exploration wells, coal seam gas wells, water bores and mineral exploration wells.

The oil and gas industry (and other stakeholders) can make use of emerging technologies to rapidly identify and quantify methane emissions. Examples include:

- drone technology to rapidly survey gas infrastructure (Section 7.3.2.3)
- the use of a 30 kilogram camera fitted with optimised infrared (IR) hyperspectral imaging to rapidly quantify methane fluxes as small as 25 grams per hour (Gålfalk, Olofsson et al. (2015)).

To rapidly reduce methane emissions, industry should focus on identifying methane 'super-emitters'.

Beyond the immediate industry actions described in this section, Section 7.2 describes recommended actions needed to regulate methane emissions in Australia. Section 7.3 describes actions that need to be taken by a broader range of Australian stakeholders to close knowledge-gaps and improve the access to information about methane emissions from unconventional oil and gas production.

[19] http://www.gao.gov/products/GAO-11-34
[20] https://www.edf.org/sites/default/files/methaneLeakageFactsheet0612.pdf

7.2. Regulating methane emitted by the Australian oil and gas industry

Currently in Australia, there are no specific federal or state regulations that limit, for climate or environmental protection reasons, the amount of methane that can be emitted by the oil and gas industry.

Formerly this was also the situation in the U.S and Canada. However, there has been significant change in those countries in recent years. In addition to the U.S. and Canadian federal government announcements described in Section 4, other recent initiatives at federal and state/province level include:

- 2013: The U.S. state of Wyoming is the first to require operators to find and fix methane leaks.
- 2014: The U.S. state of Colorado adopts the U.S. EPA's "Standards for Performance of Crude Oil and Natural Gas Production, Transmission and Distribution". Companies subsequently reported they had repaired more than 1,500 gas leaks in the last few months of 2014. Ohio also acts to regulate methane emissions.
- 2015: The Canadian province of Alberta announces plans to reduce oil and gas methane emissions by 45 per cent by 2025.
- January 2016: The U.S. state of Pennsylvania announces a "nation-leading strategy to reduce emissions of methane" during "development and gas production, processing, and transmission by requiring leak detection and repair (LDAR) measures, efficiency upgrades for equipment, improved processes, implementation of best practices, and more frequent use of leak-sensing technologies."
- February 2016: The U.S. state of Alaska announces a $US 50 million program to clean-up legacy oil and gas wells including attention to methane emissions. The U.S. state of New Jersey passes legislation to hasten repair and replacement of leaking gas pipelines. Following the Aliso Canyon gas storage facility release, the California state legislature proposes new nation-leading methane emission-prevention regulations.
- March 2016: The U.S. Methane Challenge Program is formally launched by the U.S. EPA[21].

In Australia (as described in Section 5.3) the oil and gas industry is required to report estimates of methane emissions via the National Greenhouse and Energy Reporting Scheme (NGERS). However there are no specific federal or state regulations that limit, for regional or global environment/climate-protection reasons, the amount of methane emitted by the oil and gas industry.

[21] https://www3.epa.gov/gasstar/methanechallenge/

Regarding methane-emission regulation in Australia, a 2013 report by the New South Wales Chief Scientist and Engineer stated:

> "Fugitive and other air emissions can be mitigated through the application of best practice technology, operations and maintenance of wells and pipelines. Should mitigation measures fail, and emissions occur, then a well-planned and integrated monitoring and modelling system to detect, warn and potentially isolate the cause of the leak is required. Compliance with fugitive and air emissions standards should be enforced by regulators." (NSW Chief Scientist and Engineer (2013))

Given the significant potential for the growing Australian unconventional oil and gas industry to emit methane (as described in Section 5), there is a need for:

- reported methane-emission measurements to be independently verified by a regulatory body
  - This authority should have the power to conduct measurements when and where it deems necessary and to enforce industry best practices if and as required. This independent authority could be funded by levies placed on the industry.
- methane-emissions reported to NGERS to be based largely on direct measurements
- measured and reported methane emissions to include migratory emissions
- reporting, via a centralised geo-referenced database, of hydraulic fracture length and distance of fracture tip to edge of adjacent formation. This increases understanding of the potential risk for migratory methane emissions
- methane-emission volumes to be explicitly limited by regulation.

7.3. Filling methane-emission knowledge gaps

Our review has found that there is inadequate knowledge held by, and inadequate information available to stakeholders (e.g. the Australian and global community, land-holders, legislators, regulatory agencies, industry, academia) about:

- the ways in which methane may be emitted in Australia as a result of unconventional oil and gas production
- the potential amount of methane that may be emitted over the coming decades and centuries
- actions needed to minimise methane emissions.

Specifically with respect to methane emissions resulting from coal seam gas production, a report by the New South Wales Chief Scientist and Engineer stated:

> "There is currently an absence of fugitive emissions data for CSG activities in Australia. Therefore there is a requirement for further research, baseline and ongoing monitoring

> to understand the level of fugitive emissions from the industry." (NSW Chief Scientist & Engineer (2013))

This section summarises some actions needed to close knowledge gaps and provide information in order for Australian and global stakeholders to be confident that methane emissions from Australian unconventional oil and gas production are kept below an understood and accepted level.

7.3.1. Establishing baselines: developing an understanding of pre-development conditions

A 'baseline' is defined as information that is used as a starting point by which to compare other information.

It is impossible to fully understand the impact of an industry if baseline data and knowledge of pre-development conditions is not available. Likewise, it is very difficult to assess whether any deteriorating conditions seen post-development, for example with regard to aquifers, atmospheric emissions, or vegetation are the consequence of industry activity. As described above, the NSW Chief Scientist and Engineer cited the need to collect baseline data so that any methane-emission impacts of coal seam gas development can be understood 'before' and 'after' development. In more detail, the NSW Chief Scientist's report described:

> "the importance of both obtaining baseline measurements of methane over a period of time (to account for seasonal variations) and using sophisticated techniques to monitor an area, to be able to distinguish between natural sources of methane, methane being emitted through other bores, and CSG fugitive emissions." (NSW Chief Scientist & Engineer (2013))

To establish a methane-emissions baseline for any area being considered for oil and gas development, data must be independently collected and analysed adequately in advance of the regulatory approval and/or the start of industry activity. Such data may include, but is not limited to the following:

- 'bottom-up' and 'top-down' methane-emission survey data collected at a sufficient number of locations, including randomised selection of locations
- mapping and monitoring of any natural methane seeps, including gas flux and composition
- establishment of water-monitoring wells in order to monitor aquifer water levels and water quality, including concentrations of oxygen, carbon dioxide, methane and other contaminants
- establishment of gas-monitoring wells in order to monitor gas flow and pressure gradients
- collection and analysis of drill-core data
    - Since there is often a lack of shallow-formation data, this should include permeability and thickness data of key aquitards and transition zones. Coring intervals should extend to shallow sections.
- permeability data of aquitards, in particular in areas where any aquitard may be thin or porous
- depth-migrated shallow-seismic-survey interpretations are needed in order to demonstrate a good understanding of any fault network in and above hydrocarbon reservoirs.

Techniques that may be used to collect some of the data listed above are further described in Section 7.3.2.

The data collection and analysis described above may form part of a Sedimentary Basin Management Plan as described in Section 7.3.3.

Even in areas where unconventional oil and gas production is already underway, there may be opportunities still to establish useful baseline information. For example, in 2013 the gas-producing company QGC had to temporarily shut-in most of its wells in the Argyle field in order to address problems with field compression and gathering systems (Norwest (2014)). Establishing baselines should be a priority before further industry development reduces the opportunity.

7.3.2. Methane-emissions monitoring: real-time, 'top-down'

Ideally, monitoring of methane emissions would take the form of a 'Google-Maps-like' website where the public could access comprehensive, continuous, high-resolution, quantitative emissions measurements taken real-time and identifying all significant methane-emission sources that exist in a given land area.

In future, the above goal could be achieved by using one or a combination of the following three air-quality monitoring methods:

- very-high-resolution satellite measurements
- a large and widespread network of ground-based monitoring stations
- regularly-scheduled unmanned aircraft fly-overs.

In addition to methane and other gas concentration data, weather data (e.g. wind direction and speed) would also need to be collected and processed so that quantitative methane-flux data could be published online and in near-real time.

One example of real-time air-quality monitoring is information published by the Victorian EPA "Airwatch" website[22].

Such a 'top-down' methane-emission monitoring system does not yet exist anywhere in the world. Until such a methane-monitoring system is deployed, there will be significant uncertainty about how much methane is emitted as a result of Australian unconventional oil and gas industry activity. However, given the rapid technology advances evident in fields such as satellite-based instruments, drone aircraft, and direct methane detection and flux quantification, with support from stakeholders, it may be possible to realise the above vision in less than a decade.

The three 'top-down' methane-emission monitoring methods listed above are discussed in the following sub-sections, as are the advantages of 'top-down' versus 'bottom-up' methods.

[22] http://www.epa.vic.gov.au/our-work/monitoring-the-environment/epa-airwatch

7.3.2.1. *Space-satellite methane emission detection and quantification*

Sections 4.4 and 4.5 described researchers' use of satellite-based observations to quantify methane emissions from U.S. oil and gas fields.

In an Australian report prepared for the Gas Industry Social and Environmental Research Alliance (GISERA) (Day, Ong et al. (2015)), researchers also used satellite measurements to illustrate levels of methane emissions in some CSG-producing regions of Queensland such as the Surat Basin (Figure 16).

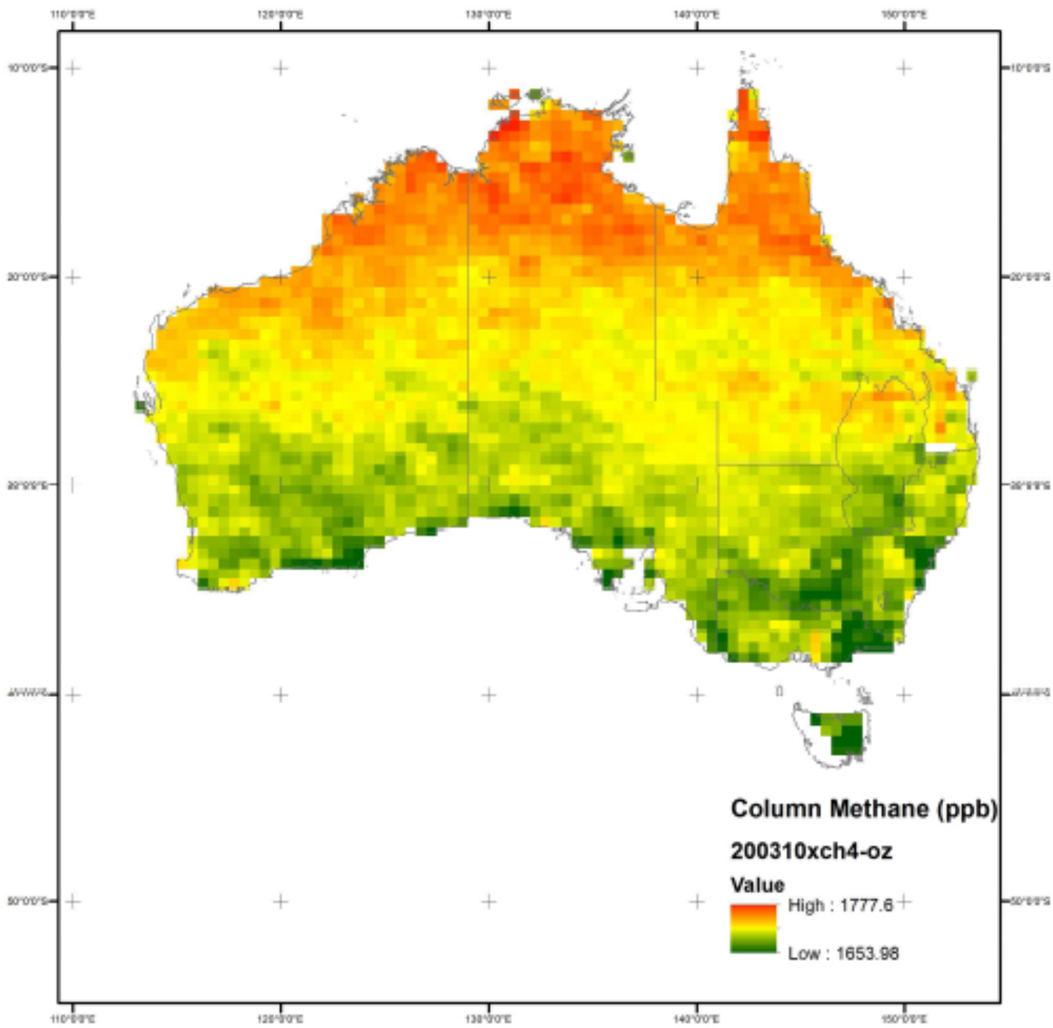


Figure 16: October 2003 satellite-data analysis of methane present in the air over Australia. (Day, Ong et al. (2015))

As in the U.S. studies, the satellite data analysed was collected using the SCIAMACHY instrument installed on the ENVISAT satellite. Data available from SCIAMACHY covered only the period 2003 to 2009, which pre-dates the 2013 start of very large-scale production of coal seam gas in Queensland.

Confirming the value of satellite data for use in monitoring methane emissions, the researchers stated:

> "If it is important to track the regional scale [methane emission] trends after the establishment of the CSG industry..., it may be useful to acquire longer term data of this nature."

The researchers identified other available satellite data as shown in the following list, but did not report on any analysis of data from these sources:

- Atmospheric Chemistry Experiment-Fourier Transform Spectrometer (ACE-FTS) (Canadian Space Agency (2016))
- Japan's Aerospace Exploration Agency (JAXA (2016)) Greenhouse gases Observing SATellite (GOSAT), launched in 2009
- Atmospheric Infrared Sounder (AIRS), launched aboard the NASA satellite Aqua in 2002 (NASA (2016))
- TROPOspheric Monitoring Instrument (TROPOMI)[23]
- Infrared Atmospheric Sounding Interferometer (IASI), launched in 2006 on-board the European Metop-A satellite (EUMETSAT (2016)).

Future satellite missions will observe greenhouse gases. For example, France and Germany are progressing mini-satellite MERLIN (Methane Remote Sensing Mission) toward launch in 2019.

The Sentinel satellites, part of Europe's Copernicus program, are the continuation of the work started with ENVISAT (the SCHIAMACHY platform described above). 'Sentinel 5' is a polar-orbiting atmosphere-monitoring mission that will monitor carbon dioxide, carbon monoxide, and methane at high resolution. Launch is scheduled no earlier than 2020[24].

At present, a shortcoming of satellite-based methane monitoring methods is the inability to operate at high resolution or to distinguish between individual emission sources. However, satellite data can provide useful baseline information and can be used to track emission changes over time.

Our review recommends that space-satellite data be used via an active and ongoing program to monitor methane emissions in current oil and gas-producing areas, and to establish baselines in areas of current and future interest to fossil-fuel developers.

[23] http://www.tropomi.eu/TROPOMI/Home.html
[24] http://www.eumetsat.int/website/home/Satellites/FutureSatellites/CopernicusSatellites/Sentinel5/index.html

7.3.2.2. Using piloted and unpiloted aircraft for top-down emission investigations

As described in Section 4.4, piloted fixed-wing aircraft were used in the United States to conduct top-down methane emission investigations over large land areas. No similar studies have yet been conducted in Australia.

An impediment to conducting piloted fixed-wing investigations are the costs involved. However, lower-cost investigations may be possible as a result of recent technology developments in the areas of:

- methane and related air-contaminant detection and flux-quantification instruments and data interpretation
- un-piloted aircraft (i.e. 'drones').

In 2014 in Australia, DRACO Analytics announced they had received funding from the Victorian Government to develop a drone-based methane-emissions detection system. A trial was planned with Melbourne Water to monitor methane emissions from water treatment systems (Draco Scientific (2014)).

In 2015, the United Kingdom Environment Agency reported the use of small fixed-wing and rotary (helicopter-type) unmanned aerial systems (UAS) to measure methane flux from landfill sites (Environment Agency (2015)).

On 23 March 2016, developers funded by the U.S. Department of Energy announced development of a low-cost methane-detection drone. The developers envision these devices could operate autonomously near any gas-production infrastructure to continuously monitor methane emissions[25].

On 28 March 2016, the U.S. National Aeronautics and Space Administration (NASA) announced progress applying drone-based methane-detection technology on Earth that is similar to technology used in experiments conducted on Mars[26].

Our review recommends the investigation of the cost and capabilities of using piloted and unpiloted aircraft to monitor methane emissions in current oil and gas-producing areas, and to establish baselines in areas of current and future interest to fossil-fuel developers.

7.3.2.3. A widespread network of ground-based air-quality monitoring towers

Stationary ground-based towers equipped with air-quality monitoring equipment are in use today to monitor a range of air pollutants.

[25] http://news.sys-con.com/node/3738950
[26] www.jpl.nasa.gov/news/news.php?feature=6192

Given that methane is lighter than air, when released, methane will tend to quickly rise and disperse. This makes quantify methane emissions by using towers more challenging than may be the case with heavier air pollutants. Data describing atmospheric air movement (e.g. wind speed, direction) and local topography is also needed in order to model the trajectory and dispersion of a methane release and to quantify the rate at which methane is being emitted into the atmosphere.

Nevertheless, for example in the U.S. state of Colorado, Pétron, Frost et al. (2012) reported on the use of the National Oceanic and Atmospheric Administration (NOAA) Boulder Atmospheric Observatory (a single 300 metre-tall tower monitoring site) and other methods to characterise hydrocarbon atmospheric emissions. That study found inventories underestimated methane emissions by "at least a factor of two" and possibly by up to a factor of 4.6 times.

Berko et al. (2012) reported on the installation of the single-tower 'Arcturus' atmospheric monitoring station near Emerald, Queensland that was used to monitor greenhouse gases. Facilities included a ten-metre-high mast. In work commissioned by the Australian Gas Industry Social and Environmental Research Alliance (GISERA), Day, Ong et al. (2015) reported on progress to establish two fixed air-monitoring stations in the Surat Basin, Queensland. The first facility, 'Ironbark', which began operating on 17 November 2014, includes a ten-metre-high mast.

Our review recommends the continued investigation of the feasibility of a widespread long-term network of ground-based air-quality monitoring towers/stations in regions of active or prospective unconventional oil and gas production. We envision that in order to definitively quantify methane emissions, an extensive network of monitoring towers spaced 10 to 20 kilometres apart would be required. For example, a 200-kilometre by 200-kilometre gas production area would require 150 or more monitoring towers. This system would greatly improve modelling that aims to locate sources based on emission data (known as 'inverse' modelling).

Similarly, a long-term monitoring network in the Walloon coals outcropping area would be able to show if the depressurisation of the coals at depth increases methane emissions after heavy precipitation events. (The pressure gradient caused by natural rainwater recharge will mobilise gas. It is not known if methane emissions increase after heavy precipitation events because of ongoing depressurisation.)

Installing a secured gas analyser (e.g. Picarro or Los Gatos) at every monitoring station would cost around $50,000 per station. However, with technological development, gas analysers are becoming more mobile and less costly. The cost to build and maintain the network of monitoring facilities described above may mean that satellite or aircraft-based methane monitoring is more cost effective.

7.3.3. Sedimentary basin management plans needed

Sustainable and well-managed extraction of commodities (e.g. water and fossil fuels) from sedimentary basins requires a holistic sedimentary basin management plan (Rawling and Sandiford (2013))[27]. Without understanding the workings of a sedimentary basin that may provide multiple services, it is impossible to foresee the potential risks and consequences of human interventions.

Dafny and Silburn (2014) and Apte, McCabe et al. (2014) have pointed out that significant gaps remain in terms of subsurface understanding. Additional field data needs to be acquired to narrow down uncertainties around the spatial extend of the Condamine Alluvium and the transitional layer and the properties of the transitional layer. None of the hydrological models include all the hydrological processes that play a role (Dafny and Silburn (2014)).

In cases where there are competing demands on sedimentary basins, such as provision of water and fossil fuels, there is a need for an integrated geological-hydrological model. This model would assess the implications of formation heterogeneity, irregular formation thickness, coal-seam dewatering and depressurisation, and water extraction by all users. We acknowledge the computational challenges of such a complex model. This is further described in the Melbourne Energy Institute companion report entitled:

> *"The risk of migratory methane emissions resulting from the development of Queensland coal seam gas".*

[27] See also http://energy.unimelb.edu.au/research/eere/sedimentary-basin-management-initiative

8. Unit conversions

1 kJ (kilojoule) = 0.948 Btu (British thermal units)

1 PJ (petajoule) = 0.948 T Btu (trillion British thermal units)

1 TCF (trillion cubic feet) of gas = 1010 T Btu (trillion British thermal units)

1 TCF (trillion cubic feet) of gas = 1065 PJ (petajoules)

1 TCF (trillion cubic feet) of gas = 21 million tonnes of LNG

1 million tonnes of liquefied natural gas (LNG) = 48.6 T Btu (trillion British thermal units)

Source: BP Statistical Review (2015)

McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

9. References

AEMO (2011). "Gas Statement of Opportunities".

AEMO (2016). "Gas Statement of Opportunities".

Allen, D. T. (2014). "Atmospheric Emissions and Air Quality Impacts from Natural Gas Production and Use." Annual Review of Chemical and Biomolecular Engineering **5**(1): 55-75.

Allen, D. T., V. M. Torres, J. Thomas, D. W. Sullivan, M. Harrison, A. Hendler, S. C. Herndon, C. E. Kolb, M. P. Fraser and A. D. Hill (2013). "Measurements of methane emissions at natural gas production sites in the United States." Proceedings of the National Academy of Sciences **110**(44): 17768-17773.

Allen, M. R., J. S. Fuglestvedt, K. P. Shine, A. Reisinger, R. T. Pierrehumbert and P. M. Forster (2016). "New use of global warming potentials to compare cumulative and short-lived climate pollutants." Nature Clim. Change.

Alvarez, R. A., S. W. Pacala, J. J. Winebrake, W. L. Chameides and S. P. Hamburg (2012). "Greater focus needed on methane leakage from natural gas infrastructure." Proceedings of the National Academy of Sciences **109**(17): 6435-6440.

APGA (2016). "Natural gas: unheralded, but efficient and clean says industry leader." Retrieved April 18, 2016, from http://www.apga.org.au/blog/2016/03/17/natural-gas-unheralded-but-efficient-and-clean-says-industry-leader/.

APLNG (2016). "Cleaner energy." Retrieved April 18, 2016, from http://www.aplng.com.au/home/cleaner-energy.

APPEA (2016). "Cleaner energy." Retrieved April 18, 2016, from http://www.appea.com.au/oil-gas-explained/benefits/cleaner-energy/.

Apte, S., P. McCabe, R. Oliver and L. Paterson (2014). Condamine River Gas Seeps Investigations - Independent Review.

Australian Government. (2014). "Background review: bore integrity."

Australian Government. (2016). "National Inventory Report 2014 and Revised Kyoto Protocol National Inventory Report 2013."

Australian Government. (2013). "Coal Seam Gas: Enhanced Estimation and Reporting of Fugitive Greenhouse Gas Emissions under the National Greenhouse and Energy Reporting (Measurement) Determination."

Australian Senate, Economics Legislation Committee. (2014). Question No.: SI-124. www.aph.gov.au

Berko, H. et al. (2012). "Installation Report for Arcturus (ARA): An inland baseline station for the continuous measurement of greenhouse gases".

Bowerman, N. H. A., D. J. Frame, C. Huntingford, J. A. Lowe, S. M. Smith and M. R. Allen (2013). "The role of short-lived climate pollutants in meeting temperature goals." Nature Clim. Change **3**(12): 1021-1024.

Brandt, A. R., G. A. Heath, E. A. Kort, F. O'Sullivan, G. Pétron, S. M. Jordaan and e. al. (2014). "Methane Leaks from North American Natural Gas Systems." Science **343**(6172): 733–735.

Canadian Space Agency. (2016). "Atmospheric Chemistry Experiment-Fourier Transform Spectrometer " Retrieved April 19, 2016, from http://www.ace.uwaterloo.ca/instruments_acefts.html.

Climate Action Tracker (2015). "INDCs lower projected warming to 2.7°C: significant progress but still above 2°C." Retrieved April 18, 2016, from http://climateactiontracker.org/news/224/indcs-lower-projected-warming-to-2.7c-significant-progress-but-still-above-2c-.html

Caulton, D. R., P. B. Shepson, R. L. Santoro, J. P. Sparks, R. W. Howarth, A. R. Ingraffea, M. O. Cambaliza, C. Sweeney, A. Karion and K. J. Davis (2014). "Toward a better understanding and quantification of methane emissions from shale gas development." Proceedings of the National Academy of Sciences **111**(17): 6237-6242.

CEFA (2016). "Taking gas beyond the pipeline." Retrieved April 18, 2016, from http://www.cefa.com.au/.

Clark, T., R. Hynes, P. Mariotti, A. P. Production and E. Association (2011). Greenhouse gas emissions study of Australian CSG to LNG, Australian Petroleum Production & Exploration Association Limited.

Cook, P., V. Beck, D. Brereton, R. Clark, B. Fisher, S. Kentish, J. a. Toomey and J. Williams (2013). Engineering energy: unconventional gas production.

Dafny, E. and M. D. Silburn (2014). "The hydrogeology of the Condamine River Alluvial Aquifer, Australia: a critical assessment." Hydrogeology Journal **22**(3): 705-727.

Day, S., L. Connell, D. Etheridge, T. Norgate and N. Sherwood (2012). Fugitive greenhouse-gas emissions from coal seam gas production in Australia., CSIRO, Australia.

Day, S., M. Dell'Amico, R. A. Fry and H. Javanmard Tousi (2014). Field Measurements of Fugitive Emissions from Equipment and Well Casings in Australian Coal Seam Gas Production Facilities, CSIRO, Australia.

Day, S., C. Ong, A. Rodger, D. Etheridge, M. Hibberd, E. van Gorsel, D. Spencer, P. Krummel, S. Zegelin, R. Fry, M. Dell'Amico, S. Sestak, D. Williams, Z. A. Loh and D. Barrett (2015). Characterisation of Regional Fluxes of Methane in the Surat Basin, Queensland.

Draco Scientific. (2014). "Australian-designedsensors to target greenhouse-gas emissions." Retrieved April 19, 2016, from http://www.dracoanalytics.com/wp-content/uploads/2014/10/Mendleson-Agency-Release.pdf?ccfe82.

EIA (2013). Technically Recoverable Shale Oil and Shale Gas Resources - An Assessment of 137 Shale Formations in 41 Countries Outside the United States, US Energy Information Administration.

EIA (2015). Annual Energy Outlook with projections to 2040, EIA, US Energy Information Administration.

EIA (2016). Short term energy outlook, EIA, US Energy Information Agency.

ENA (2015). Australia's bright gas future, ENA, Energy networks association.

Environment Agency (2015). "Measuring landfill methane emissions using unmanned aerial systems: field trial and operational guidance".

EPA (2012). Overview of final amendments to air regulations for the oil and gas industry. EPA.

EPA (2013). Inventory of US Greenhouse Gas Emissions and Sinks 1990-2011, EPA, U.S. Environmental Protection Agency

EPA (2015). Proposed Climate, Air Quality and Permitting Rules for the Oil and Natural Gas Industry: Fact Sheet.

EPA (2016, February 24, 2016). "Administrator Gina McCarthy, Remarks on Climate Action at CERA in Houston Texas, As Prepared." Retrieved April 18, 2016, from https://yosemite.epa.gov/opa/admpress.nsf/8d49f7ad4bbcf4ef852573590040b7f6/5c432a7068e191e985257f630054fea8!OpenDocument.

EPA (2016). "EPA Taking Steps to Cut Methane Emissions from Existing Oil and Gas Sources." Retrieved April 18, 2016, from https://blog.epa.gov/blog/2016/03/epa-taking-steps-to-cut-methane-emissions-from-existing-oil-and-gas-sources/.

EPA. (2016). "Climate Change Indicators in the United States; Atmospheric Concentrations of Greenhouse Gases." Retrieved 3 June 2016, from https://www3.epa.gov/climatechange/science/indicators/ghg/ghg-concentrations.html.

Etheridge, D.M., L.P. Steele, R.J. Francey, and R.L. Langenfelds. 2002. Historic CH_4 records from Antarctic and Greenland ice cores, Antarctic firn data, and archived air samples from Cape Grim, Tasmania. In: Trends: A compendium of data on global change. Oak Ridge, TN: U.S. Department of Energy. Accessed September 13, 2005. http://cdiac.ornl.gov/trends/atm_meth/lawdome_meth.html (Law Dome, Antarctica: approximately 1008 AD to 1980 AD)

EUMETSAT. (2016). "IASI, the Infrared Atmospheric Sounding Interferometer." Retrieved April 19, 2016, from http://wdc.dlr.de/sensors/iasi/.

Feldmann, J. and A. Levermann (2015). "Collapse of the West Antarctic Ice Sheet after local destabilization of the Amundsen Basin." Proceedings of the National Academy of Sciences **112**(46): 14191-14196.

Fuglestvedt, J. S., T. K. Berntsen, O. Godal, R. Sausen, K. P. Shine and T. Skodvin (2003). "Metrics of climate change: Assessing radiative forcing and emission indices." Climatic Change **58**(3): 267-331.

Fulton, M. et al. (2011). "Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal".

GA and BREE (2012). Australian Gas Resource Assessment 2012. Canberra, Geoscience Australia (GA), Bureau of Resources and Energy Economics (BREE) and Department of Resources, Energy and Tourism.

Gålfalk, M., G. Olofsson, P. Crill and D. Bastviken (2015). "Making methane visible." Nature Climate Change.

GISTEMP Team. (2016). "GISS Surface Temperature Analysis (GISTEMP)." Retrieved April 19, 2016, from http://data.giss.nasa.gov/gistemp/.

Hardisty, P. E., T. S. Clark and R. G. Hynes (2012). "Life cycle greenhouse-gas emissions from electricity generation: A comparative analysis of Australian energy sources." Energies **5**(4): 872-897.

Harrison, M. R., L. M. Campbell, T. M. Shires and R. M. Cowgill (1996). Methane emissions from the natural gas industry, EPA.

Hayhoe, K., H. S. Kheshgi, A. K. Jain and D. J. Wuebbles (2002). "Substitution of natural gas for coal: climatic effects of utility sector emissions." Climatic Change **54**(1-2): 107-139.

Heard, D. and Bullen, J. (2011). "Green gas debate: Who is hiding the fugitives?"

Howard, T. (2015). "University of Texas study underestimates national methane emissions at natural gas production sites due to instrument sensor failure." Energy Science & Engineering **3**(5): 443-455.

Howard, T. et al. (2015). "Sensor transition failure in the high flow sampler: Implications for methane emission inventories of natural gas infrastructure." Journal of the Air & Waste Management Association 65(7):856-862.

Howarth, R. (2015). "Methane emissions and climatic warming risk from hydraulic fractuering and shale gas development implications for policy". Energy and Emission Control Technologies 2015:3 45-54

Howarth, R. (2014). "A bridge to nowhere: methane emissions and the greenhouse gas footprint of natural gas". Energy Science and Engineering 10.1002/ese3.35

IEA (2012). World Energy Outlook 2012 Golden rules for a golden age of gas, IEA.

IEA (2013). Redrawing the Energy-Climate Map, a World Energy Outlook special report. Paris, OECD/IEA, .

IEA (2015). World Energy Outlook 2015, OECD Publishing.

ICF International (2014). "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries.

ICF International (2015). "Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Natural Gas Industries.

IPCC (2013). 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change T. F. [Stocker, D. Qin, G.-K. Plattner et al., Intergovernmental panel on climate change (IPCC)**:** 1535 pp.

JAXA. (2016). "Gosat Project, Greenhouse gases Observing SATellite ", from http://www.gosat.nies.go.jp/index_e.html

Joughin, I., B. E. Smith and B. Medley (2014). "Marine ice sheet collapse potentially under way for the Thwaites Glacier Basin, West Antarctica." Science **344**(6185): 735-738.

Karion, A., C. Sweeney, G. Pétron, G. Frost, R. Michael Hardesty, J. Kofler, B. R. Miller, T. Newberger, S. Wolter and R. Banta (2013). "Methane emissions estimate from airborne measurements over a western United States natural gas field." Geophysical Research Letters **40**(16): 4393-4397.

Katzenstein, A. S., L. A. Doezema, I. J. Simpson, D. R. Blake and F. S. Rowland (2003). "Extensive regional atmospheric hydrocarbon pollution in the southwestern United States." Proceedings of the National Academy of Sciences **100**(21): 11975-11979.

Kirchgessner, D. A., S. D. Piccot and S. S. Masemore (2000). "An improved inventory of methane emissions from coal mining in the United States." Journal of the Air & Waste Management Association **50**(11): 1904-1919.

Kort, E. A., C. Frankenberg, K. R. Costigan, R. Lindenmaier, M. K. Dubey and D. Wunch (2014). "Four corners: The largest US methane anomaly viewed from space." Geophysical Research Letters **41**(19): 6898-6903.

Lenton, T. M., H. Held, E. Kriegler, J. W. Hall, W. Lucht, S. Rahmstorf and H. J. Schellnhuber (2008). "Tipping elements in the Earth's climate system." Proceedings of the National Academy of Sciences **105**(6): 1786-1793.

Lindsay, R. and J. Zhang (2005). "The thinning of Arctic sea ice, 1988-2003: Have we passed a tipping point?" Journal of Climate **18**(22): 4879-4894.

Loulergue, L., A. Schilt, R. Spahni, V. Masson-Delmotte, T. Blunier, B. Lemieux, J.-M. Barnola, D. Raynaud, T.F. Stocker, and J. Chappellaz. 2008. Orbital and millennial-scale features of atmospheric CH_4 over the past 800,000 years. Nature 453:383–386. www.ncdc.noaa.gov/paleo/pubs/loulergue2008/loulergue2008.html (EPICA Dome C, Antarctica: approximately 797,446 BC to 1937 AD).

Maher, D. T., I. R. Santos and D. R. Tait (2014). "Mapping methane and carbon dioxide concentrations and δ13C values in the atmosphere of two Australian coal seam gas fields." Water, Air, & Soil Pollution **225**(12): 1-9.

Marchese, A. J. et al. (2015). "Methane emissions from United States Natural Gas Gathering and Processing". Environmental Science and Technology 49, 10718-10727.

Meinshausen, M. (2015). "Are we on track for 2°C?", from https://www.mitigation-contributions.org/.

Meinshausen, M. (2016). "INDC Factsheets." from http://www.climate-energy-college.net/indc-factsheets.

Meinshausen, M., L. Jeffery, J. Guetschow, Y. R. du Pont, J. Rogelj, M. Schaeffer, N. Höhne, M. den Elzen, S. Oberthür and N. Meinshausen (2015). "National post-2020 greenhouse gas targets and diversity-aware leadership." Nature Climate Change.

Meinshausen, M., N. Meinshausen, W. Hare, S. C. Raper, K. Frieler, R. Knutti, D. J. Frame and M. R. Allen (2009). "Greenhouse-gas emission targets for limiting global warming to 2 degrees C." Nature **458**(7242): 1158-1162.

Met Office (2015). "Global temperatures set to reach 1 °C marker for first time."   Retrieved April 18, 2016, from http://www.metoffice.gov.uk/news/release/archive/2015/one-degree.

Nabel, J. E. M. S., J. Rogelj, C. M. Chen, K. Markmann, D. J. H. Gutzmann and M. Meinshausen (2011). "Decision support for international climate policy – The PRIMAP emission module." Environmental Modelling & Software **26**(12): 1419-1433.

NASA (2016). "Atmospheric Infrared Sounder (AIRS) Instrument Guide." Retrieved April 19, 2016, from http://disc.sci.gsfc.nasa.gov/AIRS/documentation/airs_instrument_guide.shtml.

New South Wales Chief Scientist and Engineer (2013). "Initial Report on the Independent Review of Coal Seam Gas Activities in NSW."

New South Wales Government, T. (2015). Final investigation report into AGL Gloucester BTEX (Waukivory Pilot Project) PEL285.

NOAA (National Oceanic and Atmospheric Administration). 2014. Monthly mean CH_4 concentrations for Cape Grim, Australia. Accessed December 29, 2014. ftp://ftp.cmdl.noaa.gov/data/trace_gases/ch4/flask/surface/ch4_cgo_surface-flask_1_ccgg_month.txt (Cape Grim, Australia: 1984 AD to 2013 AD).

NOAA (National Oceanic and Atmospheric Administration). 2015. Monthly mean CH_4 concentrations for Mauna Loa, Hawaii. Accessed June 5, 2015. ftp://ftp.cmdl.noaa.gov/data/trace_gases/ch4/in-situ/surface/mlo/ch4_mlo_surface-insitu_1_ccgg_month.txt (Mauna Loa, Hawaii: 1987 AD to 2014 AD).

Norwest (2014). Condamine river gas seep investigation - technical report. Brisbane, QLD, Norwest Energy Consultants Pty. Ltd.

Osborn, S. G., A. Vengosh, N. R. Warner and R. B. Jackson (2011). "Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing." Proceedings of the National Academy of Sciences **108**(20): 8172-8176.

Peischl, J., T. Ryerson, K. Aikin, J. Gouw, J. Gilman, J. Holloway, B. Lerner, R. Nadkarni, J. Neuman and J. Nowak (2015). "Quantifying atmospheric methane emissions from the Haynesville, Fayetteville, and northeastern Marcellus shale gas production regions." Journal of Geophysical Research: Atmospheres **120**(5): 2119-2139.

Pétron, G., G. Frost, B. R. Miller, A. I. Hirsch, S. A. Montzka, A. Karion, M. Trainer, C. Sweeney, A. E. Andrews, L. Miller, J. Kofler, A. Bar-Ilan, E. J. Dlugokencky, L. Patrick, C. T. Moore, T. B. Ryerson, C. Siso, W. Kolodzey, P. M. Lang, T. Conway, P. Novelli, K. Masarie, B. Hall, D. Guenther, D. Kitzis, J. Miller, D. Welsh, D. Wolfe, W. Neff and P. Tans (2012). "Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study." Journal of Geophysical Research **117**(D4).

Pétron, G., A. Karion, C. Sweeney, B. R. Miller, S. A. Montzka, G. J. Frost, M. Trainer, P. Tans, A. Andrews and J. Kofler (2014). "A new look at methane and nonmethane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin." Journal of Geophysical Research: Atmospheres **119**(11): 6836-6852.

Phillips, N. G., R. Ackley, E. R. Crosson, A. Down, L. R. Hutyra, M. Brondfield, J. D. Karr, K. Zhao and R. B. Jackson (2013). "Mapping urban pipeline leaks: Methane leaks across Boston." Environmental pollution **173**: 1-4.

Prior, E. (2011). "Coal seam gas and greenhouse emissions".

Queensland DEEDI (2010). Investigation report - Leakage testing of coal seam gas wells in the Tara 'rural residential estates' vicinity, Queensland Department of Employment, Economic Development and Innovation.

Queensland DEEDI (2011). "Coal Seam Gas Well Head Safety Program". Queensland Department of Employment, Economic Development and Innovation.

Queensland Government (2011). Code of Practice for coal seam gas well head emissions detection and reporting. Q. Government.

Rawling, T. A. and M. Sandiford (2013). Multi basin usage/cumulative impact, Melbourne Energy Institute, University of Melbourne.

Rignot, E., J. Mouginot, M. Morlighem, H. Seroussi and B. Scheuchl (2014). "Widespread, rapid grounding line retreat of Pine Island, Thwaites, Smith, and Kohler glaciers, West Antarctica, from 1992 to 2011." Geophysical Research Letters **41**(10): 3502-3509.

Rogelj, J., M. d. Elzen, N. Höhne, T. Fransen, H. Fekete, H. Winkler, R. Schaeffer, F. Sha, K. Riahi and M. Meinshausen (2016, under review). "Paris Agreement climate proposals need boost to keep warming well below 2°C."

Saddler, H. (2012). Review of literature on international best practice for estimating greenhouse-gas emissions from coal seam gas production. Report prepared for the Department of Climate Change and Energy Efficiency. Pitt & Sherry.

Saddler, H., and Gotham, K. (2013). "Review of methods for the estimation of greenhouse gas emissions from diffuse sources associated with unconventional gas fields". Report prepared for the Department of Climate Change and Energy Efficiency. Pitt & Sherry.

Schneising, O., J. P. Burrows, R. R. Dickerson, M. Buchwitz, M. Reuter and H. Bovensmann (2014). "Remote sensing of fugitive methane emissions from oil and gas production in North American tight geologic formations." Earth's Future: 2014EF000265.

Shindell, D., J. C. Kuylenstierna, E. Vignati, R. van Dingenen, M. Amann, Z. Klimont, S. C. Anenberg, N. Muller, G. Janssens-Maenhout and F. Raes (2012). "Simultaneously mitigating near-term climate change and improving human health and food security." Science **335**(6065): 183-189.

Smith, S. M., J. A. Lowe, N. H. Bowerman, L. K. Gohar, C. Huntingford and M. R. Allen (2012). "Equivalence of greenhouse-gas emissions for peak temperature limits." Nature Climate Change **2**(7): 535-538.

Stalker, L. (2013). Methane origins and behaviour, CSIRO Australia.

Steele, L.P., P.B. Krummel, and R.L. Langenfelds. 2002. Atmospheric methane record from Shetland Islands, Scotland (October 2002 version). In: Trends: A compendium of data on global change.
Oak Ridge, TN: U.S. Department of Energy. Accessed September 13, 2005.
http://cdiac.esd.ornl.gov/trends/atm_meth/csiro/csiro-shetlandch4.html (Shetland Islands, Scotland: 1993 AD to 2001 AD)

Turner, A. J. A., D. J. Jacob, J. Benmergui, S. C. Wofsy, J. D. Maasakkers, A. Butz, O. Hasekamp, S. C. Biraud and E. Dlugokencky (2016). "A large increase in US methane emissions over the past decade inferred from satellite data and surface observations." Geophysical Research Letters: n/a-n/a.

UNFCCC (2015). Adoption of the Paris Agreement, draft decision. UN. Paris.

UNFCCC (2015). Australia's Intended Nationally Determined Contribution to a new Climate Change Agreement.

UNFCCC (2016). Report on the individual review of the inventory submission of Australia submitted in 2015, Note by the expert review team.

U.S. Department of Energy. (2010). "CBM Gas Separator".

Wigley, T. L. (2011). "Coal to gas: the influence of methane leakage." Climatic Change **108**(3): 601-608.

White House. (2014). "Climate Action Plan. Strategy to Reduce Methane Emissions".

White House. (2015). "FACTSHEET: Administration Takes Steps Forward on Climate Action Plan by Announcing Actions to Cut Methane Emissions". www.whitehouse.gov

Zavala-Araiza, D., et al. (2015). "Reconciling divergent estimates of oil and gas methane emissions." Proceedings of the National Academy of Science **112**(51): 15597-15602.

Zavala-Araiza, D., D. Lyon, R. n. A. Alvarez, V. Palacios, R. Harriss, X. Lan, R. Talbot and S. P. Hamburg (2015). "Toward a functional definition of methane super-emitters: Application to natural gas production sites." Environmental science & technology **49**(13): 8167-8174.

McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

THE UNIVERSITY OF MELBOURNE

MELBOURNE ENERGY INSTITUTE

The risk of migratory methane emissions resulting from the development of Queensland coal seam gas

February 2017

Dimitri Lafleur - PhD student, Australian-German Climate and Energy College
Mike Sandiford - Professor of Geology

`

Table of Contents

Melbourne Energy Institute
McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

`

About the University of Melbourne Energy Institute (MEI)

The University of Melbourne Energy Institute is an access point for industry, government and community groups seeking to work with leading researchers on innovative solutions in the following areas: new energy resources; developing new ways to harness renewable energy; more efficient ways to use energy; securing energy waste; and framing optimal laws and regulation to achieve energy outcomes.

About the Authors

Dimitri Lafleur is a PhD student at the Australian German College of Climate and Energy Transitions at the University of Melbourne. Dimitri worked for the oil and gas company Shell for eleven years in the Netherlands and Australia after being graduated from the University of Utrecht with an MSc geology/geophysics. Dimitri is researching the climate impact of fugitive emissions of the fossil fuel industry and unconventional gas in particular.

Prof Mike Sandiford is Chair of Geology at the University of Melbourne, and was the Foundation Director of the Melbourne Energy Institute from 2009-2016. Mike has published over 170 peer-reviewed scientific papers. He was recipient of consecutive ARC professorial fellowships (2000-2009), the Mawson Medal from the Australian Academy of Sciences in 2004 for outstanding contributions to Australian Earth Science, the Hobbs Medal, the Carey Medal, and has thrice been awarded the Stilwell Medal from the Geological Society of Australia. He is a fellow of the Australian Academy of Science and the Geological Society of Australia.

Acknowledgement

The University of Melbourne Energy Institute acknowledges The Australia Institute (TAI) for their support of this research.

Melbourne Energy Institute
McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

`

Executive summary

In sedimentary basins migration of methane and other fluids occurs naturally in response to multiple factors. Natural methane surface seeps are well known in many gas provinces. The pathways for such seeps can be enhanced and new pathways created through subsurface resource developments, leading to so-called induced migratory emissions. Distinguishing induced migratory emissions from natural emissions is important for a range of considerations, including resource recovery efficiency and safety, carbon budgets and environmental impacts.

As a companion to a more extensive paper on the measurement and reporting of methane emissions of unconventional gas[1], this paper reviews the current understanding of migratory emissions associated with CSG developments in eastern Australia. The paper forms part of series of contributions from the Melbourne Energy Institute's Sedimentary Basin Management Initiative aimed at providing new approaches to optimising the value of subsurface sedimentary basin resources.

The current paucity of publicly available data makes it impossible to definitively assess the impact of coal seam gas (CSG) production has had, if any, on the creation of new migratory emissions pathways and the enhancement of known methane seeps, such as in the Condamine River in Queensland. Similarly, in the absence of thorough baseline data, the cumulative impacts of water production from various aquifers for multiple purposes would compromise unique attribution of cause and effect in any observed enhancement of such seeps.

Where multiple resource use impacts the hydrostatic pressure of key aquifers, the consequences for subsurface gas flows needs particular consideration. For example, hydrostatic pressure reduction in the Condamine Alluvium, largely for agricultural use, and depressurization of the Walloon coals for gas recovery, both enhance the prospects for gas exchange especially in zones where the two aquifers are connected. In the case of the Condamine, to better resolve these issues it is crucial to characterise the local hydrogeology. Specifically, continuity of the upper aquitard in the Walloon coals, is of importance as it prevents free gas from moving towards the surface and reduces the connectivity between the Condamine Alluvium and the Walloon coal aquifers. In several locations the aquitard is known to be thin or absent.

Natural faults and fractures with enhanced permeability are natural fluid migration pathways. Known gas seeps such as the Condamine are understood to be associated with ancient fault lines. As with aquifers, hydrological connectivity in permeable faults can be altered by subsurface resource developments in ways that impact hydraulic gradients and reduce confining pressures. Characterising the distribution and character of such potential pathways is essential to mitigating risk.

[1] Melbourne Energy Institute, 2016, A review of current and future methane emissions from Australian unconventional oil and gas production

Fractures induced by hydraulic fracturing ('fracking') can introduce new migration pathways beyond the coal measures into overlaying and underlying formations if the fracturing job is poorly executed. This risk maybe enhanced if the surrounding geology is not well understood.

Water bores and coal exploration bores are potential sources of methane emissions and it has been acknowledged that the existence of methane in water bores can be the consequence of gas migration from the coal seams due to depressurisation. Well integrity is an important long-term issue not only in dedicated oil and gas wells but also in existing bores that were not designed to prevent migratory emissions.

Melbourne Energy Institute
McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

`

1. Introduction

The MEI report

> *"A review of current and future methane emissions from Australian unconventional oil and gas production (September 2016)"*

describes several ways that methane from unconventional oil and gas production may be emitted into the atmosphere.

This present companion report

> *" The risk of migratory methane emissions resulting from the development of Queensland coal seam gas (September 2016)"*

focuses on the potential emission sources known as 'migratory methane emissions'.

In this report, migratory methane emissions are defined as where, as a result of unconventional oil and gas development, methane may migrate upward and laterally out of its original reservoir. Migratory methane may eventually reach the Earth's surface and enter the atmosphere possibly at a considerable distance away from the site of original oil and gas drilling or other disturbance.

Coal seam gas (CSG) is a relatively new approach to accessing subsurface gas resources, representing one of the new “unconventional” approached. Coal seam gas developments have rapidly expanded in Australian coal basins, allowing the development of new export capacity. A key issue in any new approach to accessing sub-surface resources is understanding unintended consequences, such as migratory emissions. Assessments of induced emissions need to be framed against the backdrop of natural emissions. For example, the migration of gas and other fluids is a natural process in sedimentary basins, that for example leads to accumulations of conventional gas fields. In many sedimentary basins it is well documented that methane seeps naturally to the surface.

The nomenclature "unconventional oil and gas" covers a range of oil and gas reservoir types. To date, overseas migratory emissions research has focused mainly on shale reservoirs in the United States. That research found that well integrity is a potentially serious problem in unconventional gas basins such as the Marcellus Shale. Although not yet developed, Australia has large shale formations. While Australian stakeholders should to be mindful of such research, this report deals specifically with the issue of migratory emissions from CSG basins.

This report does not cover in depth the process of how gas is released from the coals targeted by the coal seam gas industry. This topic has been studied and reviewed by various stakeholders including industry, government, and researchers (e.g. Rice (1993), Levine (1996), Laxminarayana and Crosdale (1999), Mastalerz, Glikson et al. (1999), Hildenbrand, Krooss et al. (2006), Scott, Anderson et al. (2007), Flores, Rice et al. (2008), Strąpoć, Picardal et al. (2008), Moore (2012), Hamilton, Esterle et al. (2012).

Melbourne Energy Institute
McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

In this report, the concept of coal seam gas production is described followed by a discussion of five enablers that can help gas to migrate to the surface.

In Australia, CSG developments have been mostly focussed in Queensland, in the Surat and Bowen basins, where concerns about induced migratory emissions have been raised by the visible seeps in the Condamine River. The focus of this report is therefore the Condamine region.

2. The concept of coal seam gas extraction

Gas can be present in coal seams in commercial quantities only if there is enough pressure to keep the gas adhered (adsorbed) to the coals. When it is, gas can be released by dewatering the coal seams which decreasing the water pressure in the coal seams. The released gas is extracted through a grid of wells. Gas will only start flowing when the pressure in the coals is reduced to a critical level that typically involves extraction of significant volumes of water from the coal seam formation (see Section 3.2). The level of depressurisation required depends on the pressure exerted on the coal by the surrounding rock and water.

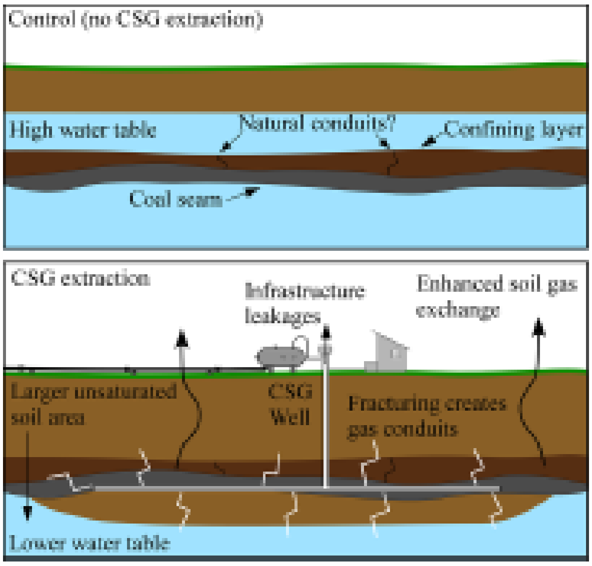
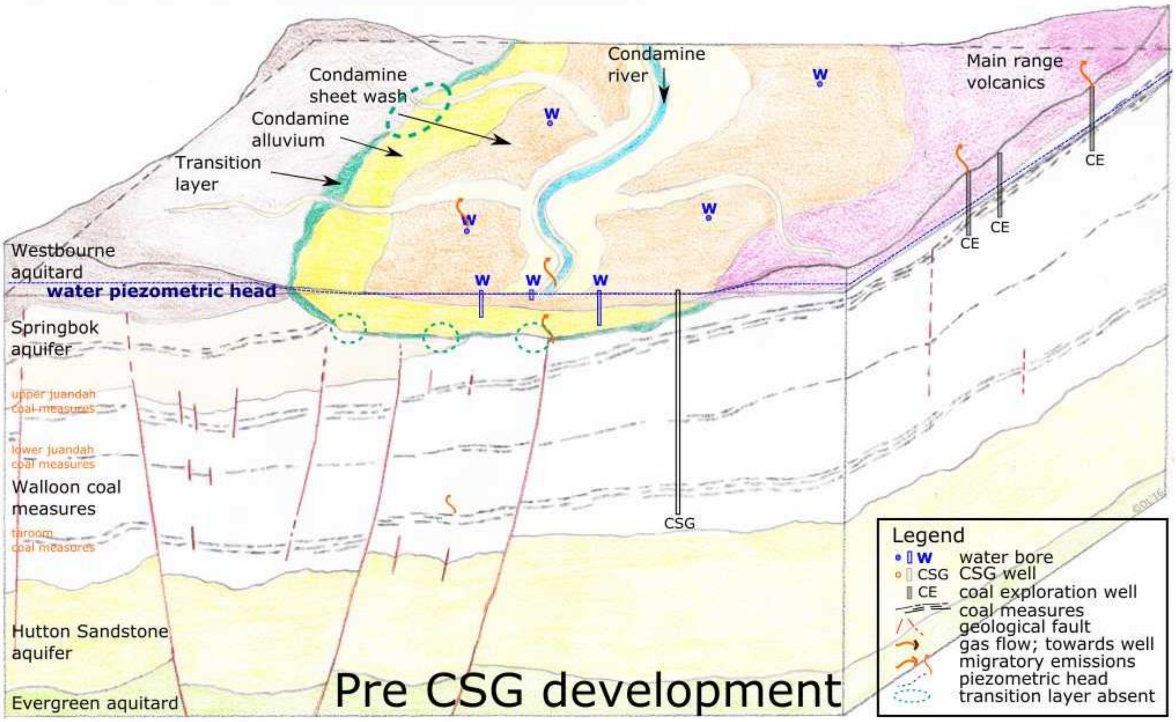


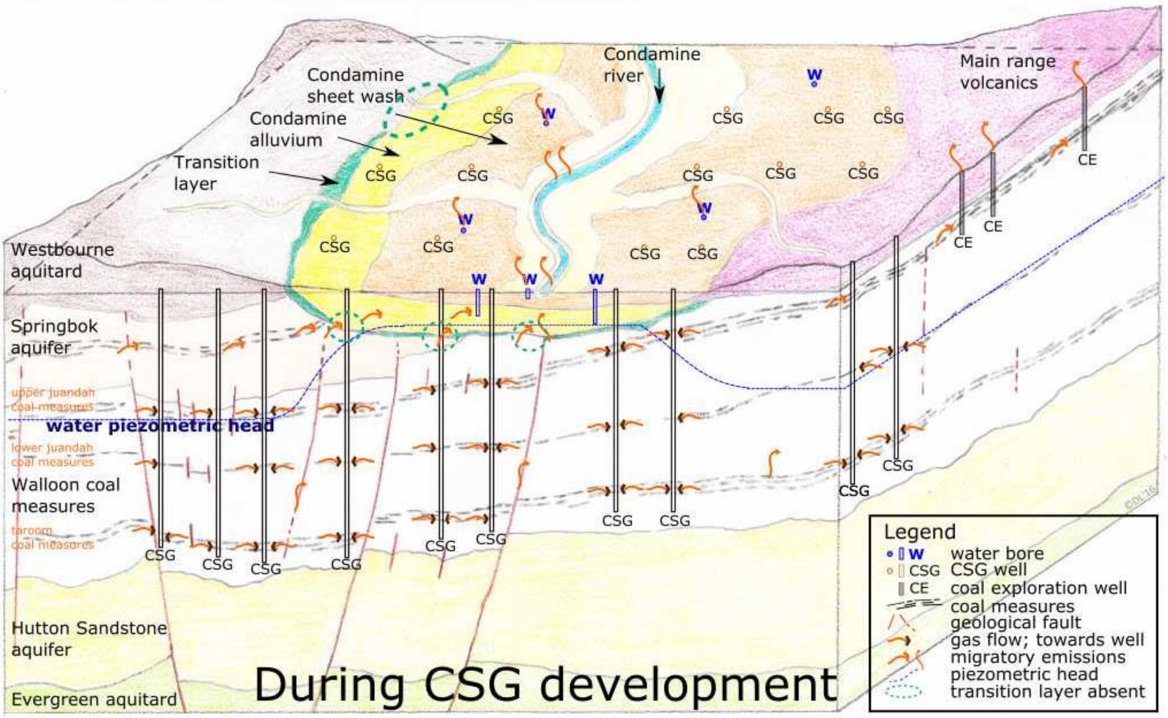
Figure 1. Migratory methane emissions.
Top figure: Water table and coal seams where no CSG extraction is underway.
Bottom figure: Depicts coal seam dewatering, hydraulic fracturing and migratory methane emissions.
Tait et al. (2013)

Extracting coal seam gas arguably poses more significant environmental risk than extracting gas from conventional reservoirs (sandstones, carbonates, or even deep shales) for two reasons: the gas resides in coal and is at shallow depths (less than 1000 metres below the surface). The possibility of gas migrating to the surface has been raised as a potential risk (for example, Tait, Santos et al. (2013)). Figure 1 depicts the process of depressurising a coal seam and extracting the water, which can enable gas to flow toward possible gas migration pathways.

Figure 2 (three parts) provides schematic geological cross-sections depicting possible gas migration pathways and the evolution of the potentiometric surface of the Walloon coal aquifer for the before, during, and after CSG-production phases.

Since the aquifers are in hydraulic connection with each other, gas may migrate to the surface via stratigraphic pathways, via faults, or using the changing pressure gradient that results from coal seam dewatering and depressurisation. Migratory emissions may be minimal without any disturbance along existing natural geological conduits, but migration of gas along natural conduits may increase significantly when aquifers are depressurised, thereby changing the hydraulic gradients and reducing the confining pressure on the gas.





McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

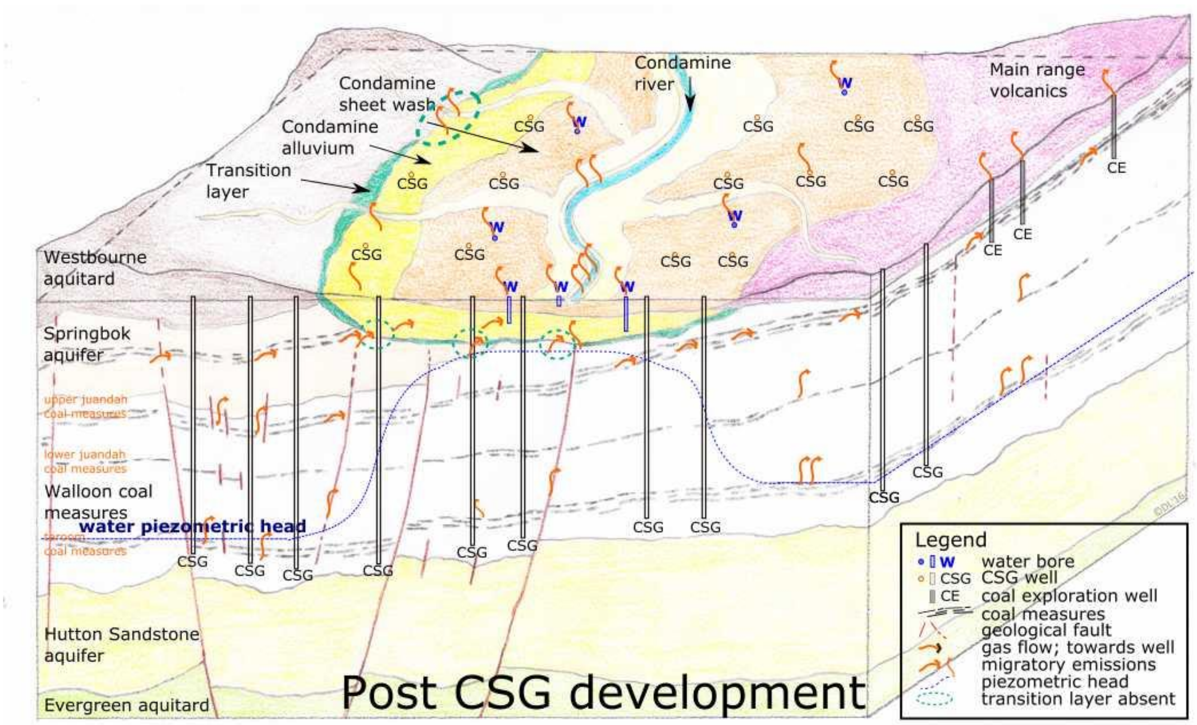


Figure 2: Schematic geological cross-section depicting the impact of the CSG development stages in a multi-user basin. Methane pathways and methane emissions are shown in orange. Brown arrows show gas flow to wells, an orange arrow show potential migratory emissions. Faults are shown in red. The piezometric head (potentiometric surface) of the Walloon coals is shown in blue. Dashed green circles show where the transition layer is absent.
CE: Coal exploration wells. W: Water wells. CSG: CSG dewatering and gas production wells.

3. Possible migratory pathways for methane in the Bowen and Surat Basins

In this section we review information pertinent to our understanding of natural and induced migratory emissions in Australia's two main CSG basins, the Bowen and Surat basins, with a particular focus on the Condamine region.

Australia has natural methane seeps, such as

- the "Burning Mountain" coal bed in New South Wales (Fleming (1972))
- the seeps near Alberton in the Gippsland Basin (O'Brien, Tingate et al. (2013))
- the offshore Terrigal gas seeps in the Sydney basin.

The Gasfields Commission Queensland has published a list of Queensland gas seeps[2].

[2] http://www.gasfieldscommissionqld.org.au/resources/gasfields/fact-sheets/historical-evidence-of-landscape-gas-seeps-in-qld.pdf

Methane emissions from some seeps around the Condamine River are reported to have recently intensified[3], but are not regularly monitored. We are unaware of any reports of significant methane seeps in the Condamine river prior to the commencement and seeps prior to CSG development, except anecdotal evidence (DNRM Queensland Government 2012). Gray (1967) describes a gas blowout in a water bore some 10km south east of Brigalow (30km south east of Chinchilla) that lasted 40hours. It occurred while drilling through the formations of the Injune Creek Group (that include the Walloon coals). This indicates free gas within the Injune Creek Group. To closest reported 'microseeps' to the Condamine river are anomalously high soil methane concentrations in soil samples at 2m depth, related to a soil gas surveys 5km south of the Condamine river between Glenmorgan and Surat Geochemical Exploration Services Inc. (1991). They are referred to as microseeps but are not comparable to the Condamine river seeps in their current state. A description of the Condamine seeps can be found in Section 5, including references and recommendations from reviews by the Queensland government, Norwest (commissioned by Origin), and the Chief Scientist to the Queensland Government.

The next sections discuss the possible migratory emissions pathways in detail.

3.1. Migratory emissions enabled by the geological stratigraphy

This section describes the stratigraphy (the sequence of rock formations) of the main Queensland CSG-producing areas and how this stratigraphy may allow gas to migrate to the surface.

At present, the Queensland coal seam gas industry has two main targets:

- the Bandanna formation in the Bowen Basin
- the Walloon coal measures in the Surat Basin.

[3] http://www.abc.net.au/news/2016-02-14/condamine-river-mysterious-bubbling-intensifying-landholders-say/7139676

Melbourne Energy Institute
McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

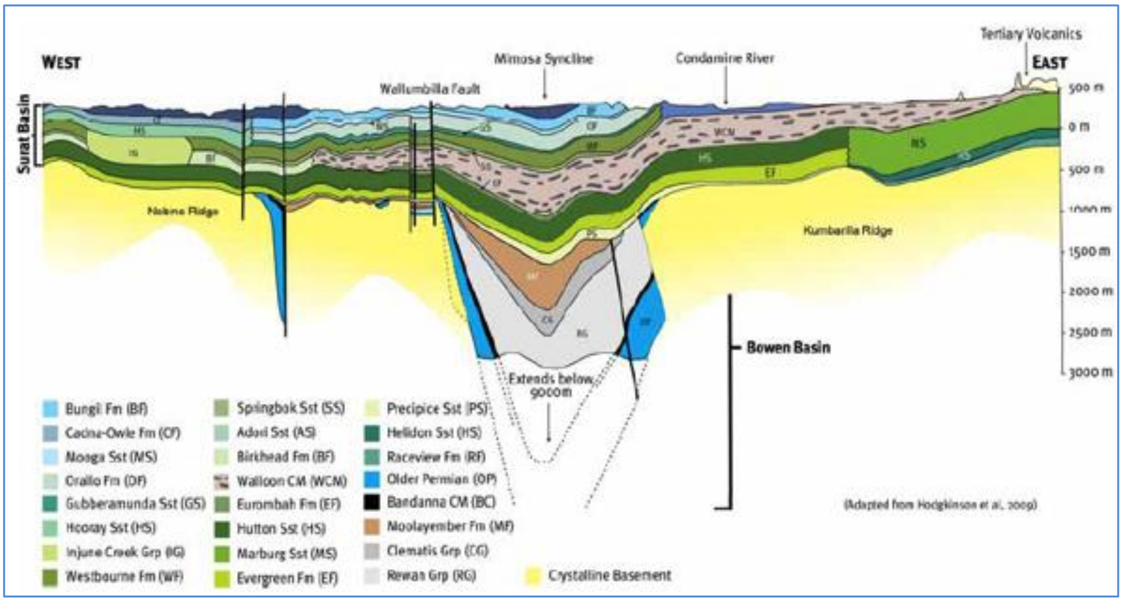


Figure 3: Schematic geological cross-section depicting the Surat Basin overlying the Bowen Basin. (Queensland Water Commission (2012) from Hodgkinson, Preda et al. (2009).

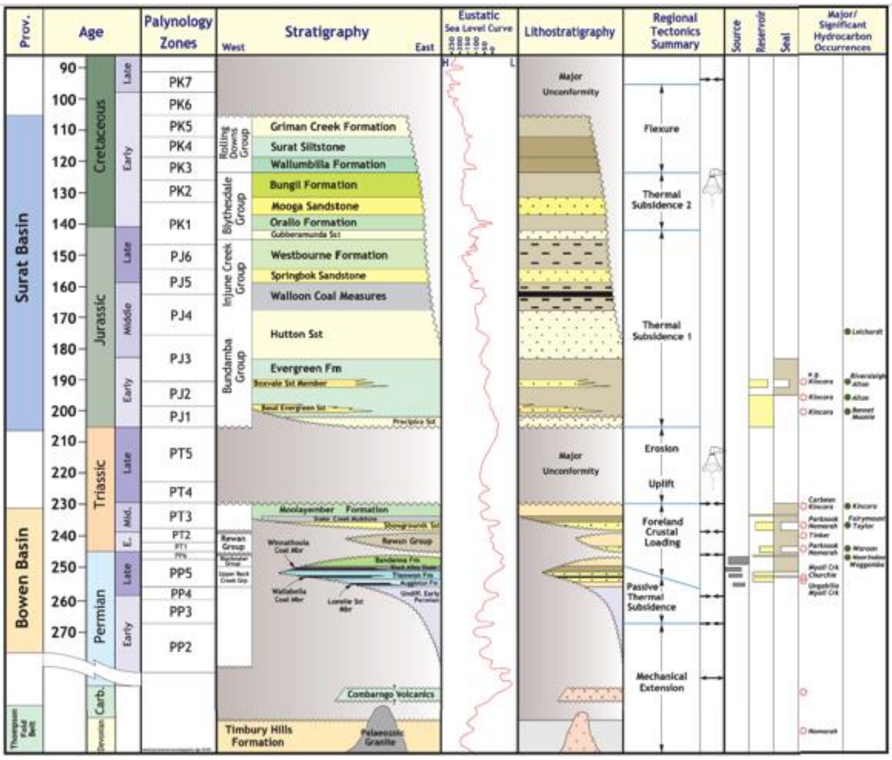


Figure 4: Stratigraphy of the Surat and Bowen Basins. (Norwest (2014)

Figure 3 shows a schematic geological cross-section of the Surat Basin and the underlying Bowen Basin. Figure 4 shows the stratigraphical sections of the Surat and Bowen Basins, showing the sequence of formations deposited on top of each other.

The Bandanna formation is overlain and underlain by thick formations (called 'aquitards') that are not likely to allow flow of gas and/or water. The permeability of these aquitards is very low and they are a proven seal to conventional oil and gas reservoirs in the Bowen Basin. They are likely to act as a gas-migration inhibitor where they are continuous. Faults are most likely present (Section 3.3) and could act as preferential conduits for flow; however, given the proven seal characteristics from existing petroleum exploration studies, migration through this unit is considered to be less likely.

The Walloon coal measures are overlain by the Springbok sandstone and the Westbourne formation (Green, Carmichael et al. (1997)). The latter is a sequence of siltstone and mudstones that is between 100 and 200 metres thick (Exon (1976)).

In the area around the Condamine River and its tributaries, this sequence is overlain by the Condamine Alluvium (Exon (1976), Queensland Water Commission (2012), DNRM Queensland Government (2016)). The Condamine Alluvium is an unconfined aquifer that is actively recharged by rainfall. Its deposits incise into the Walloon coal measures, cutting through the Springbok Aquifer.

Some studies introduce a base layer in the Condamine Alluvium, called the ‘transition zone’, which consists of alluvial clays and weathered coal measures (Figure 5). This layer is present in some areas but absent in others (Dafny and Silburn (2014)). This heterogeneity makes is difficult to develop a conceptual model based on homogeneous hydrological properties, which has implications for the ability to reduce hydrological uncertainties (Dafny and Silburn (2014)).

The Queensland Water Commission (2012) states that, in general, the thickness of the transition zone is around 30 metres, but there are areas where alluvial sands (i.e. very porous material) sit on top of the coal measures. This report also shows that in the area around Dalby, and further downstream of the main Condamine River towards Chinchilla this layer is less than five metres thick.

This report also includes a map of the Upper and Lower Walloon Coal measures aquitard, defined as mudstone-siltstone layers that separate the Walloon coal measures from the underlying Hutton Sandstone and the overlying Springbok Sandstone, respectively. (The Upper Walloon Coal measures aquitard is a different formation than the so called transition zone defined at the bottom of the Condamine Alluvium.) The maps show that in the area south and west of Miles, the Upper Walloon coal measures aquitard have a thickness of less than five metres (Figure 6 and

Figure 7). The report indicates there is a high chance of the Walloon coals being in direct contact with the Condamine Alluvium and that “a higher degree of interconnectivity is expected in these areas”. Klohn Crippen Berger (2011) reports similar results to the Queensland Water Commission in their conceptualisation study for the Healthy HeadWaters program. In the central area of the Surat Basin, formation-pressure data suggest that hydraulic communication between the Hutton Sandstone (below the Walloon coals) and deeper Precipice Sandstone via the Evergreen aquitard is also possible (Hodgkinson, Hortle et al. (2010)). The Evergreen formation is a seal for conventional oil elsewhere.

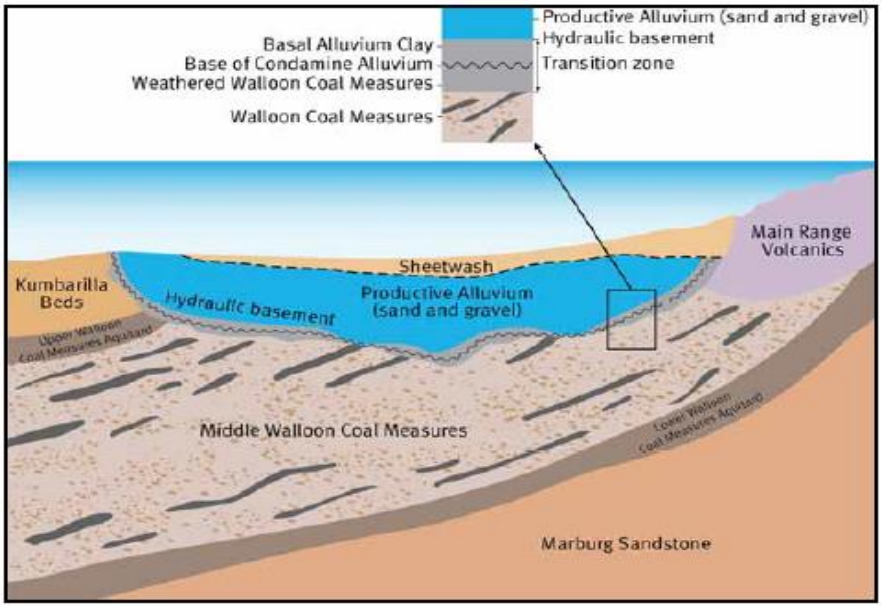


Figure 5: Schematic showing the transitional layer in-between the eroded Walloon coal measures and the Condamine Alluvium (Queensland Water Commission (2012))

The Queensland Water Commission report also states that there is very limited data available that describes the permeability of the Condamine Alluvium transition layer, or the Walloon coal upper aquitard. Given these layers are key flow-inhibition layers, more data needs to be collected to establish their effectiveness as aquitards, in particular in areas where they are inferred to be very thin. In a significant update of the Water Commission report (DNRM Queensland Government (2016), the Office for Groundwater Impact Assessment, states that there is at least a 30m vertical separation between the base of the Condamine Alluvium and targeted coal seams (Office of Groundwater Impact Assessment (2016)). However, it also mentions coals present within 10m below the transition zone in observation bores.

Taking into account the fact that the Walloon coal measures are dipping at a slight angle due to the presence of the Undulla Nose (an area where formations are dipping down and a known coal seam gas 'sweet spot' (Hamilton, Esterle et al. (2012)), it is possible that the coals are in direct contact with the overlying strata. The risk of gas flowing into the overlying porous formation during depressurisation as a consequence of the stratigraphy is therefore believed to be real. If flow is currently possible due to the natural geological heterogeneity, then it remains possible as more coal seam gas is produced from the coals (Section 3.2).

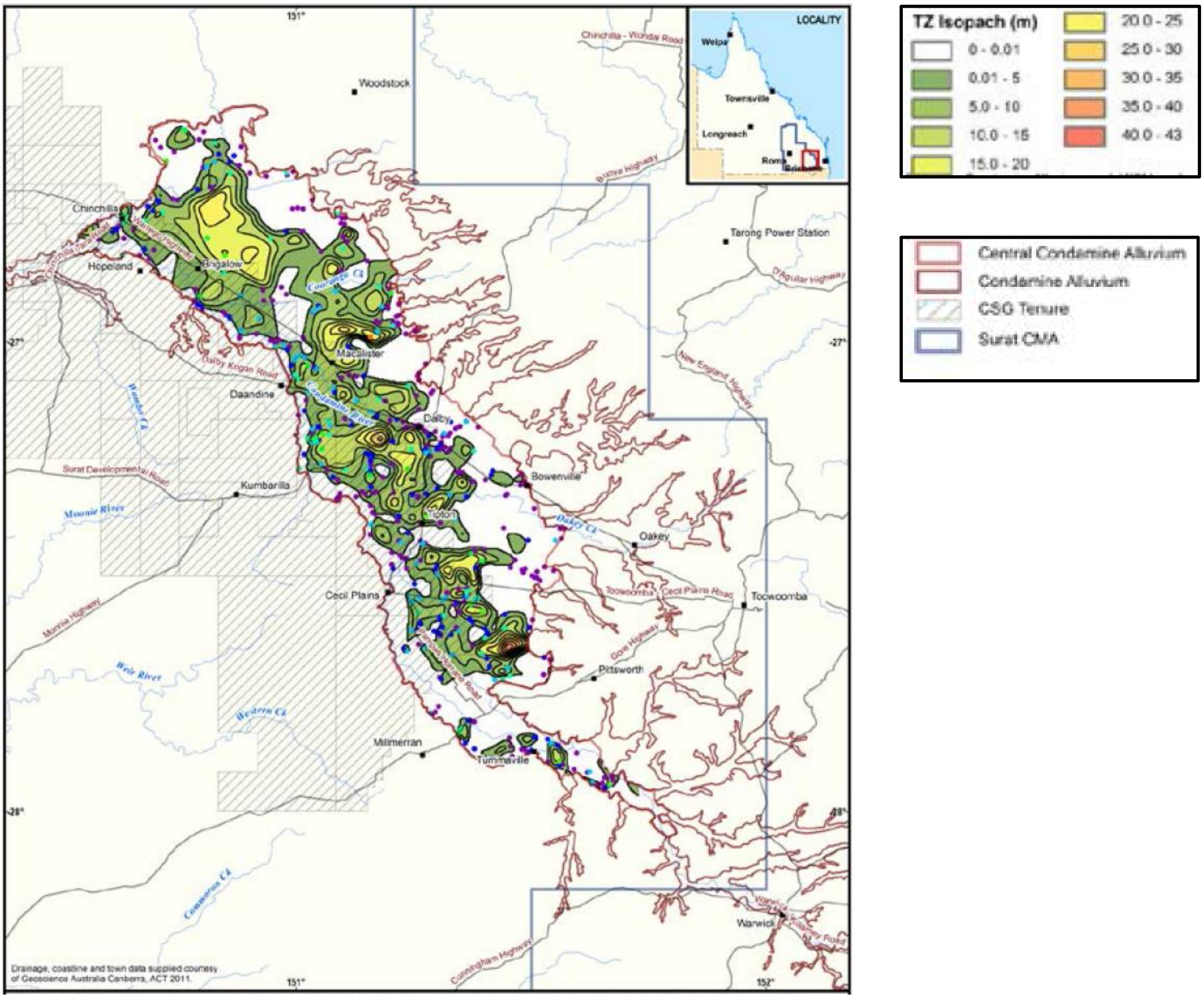


Figure 6: Inferred thickness of the transitional layer around the area of Chinchilla, Dalby and Toowoomba based on water bore data. Darkest green < 5 metres DNRM Queensland Government (2016).

Methane emissions are also possible through the Walloon coal seams themselves at locations where the formation is exposed at the surface. (These areas are known as coal 'outcrops'; they are called 'subcrops' when the formation is situated at a depth beneath the surface). Day, Dell'Amico et al. (2013) suggested that a natural-seep field-survey should be carried out in an area where the Walloon coals outcrop/subcrop. However, the survey area chosen by Day, Ong et al. (2015) covers subcropping Walloon coals and does not overlap with the Walloon coal seam outcropping area. The Walloon coals outcrop north and northeast of the coal seam gas development area (Klohn Crippen Berger (2011)). In terms of monitoring, it may be useful to install monitoring stations in the coal outcropping area in order to investigate if coal seam depressurization increases methane emissions after heavy precipitation events. Although the outcrops have mostly already lost their gas because they are in contact with the atmosphere, gas can reach the atmosphere from deeper parts of the formations via these outcrops.

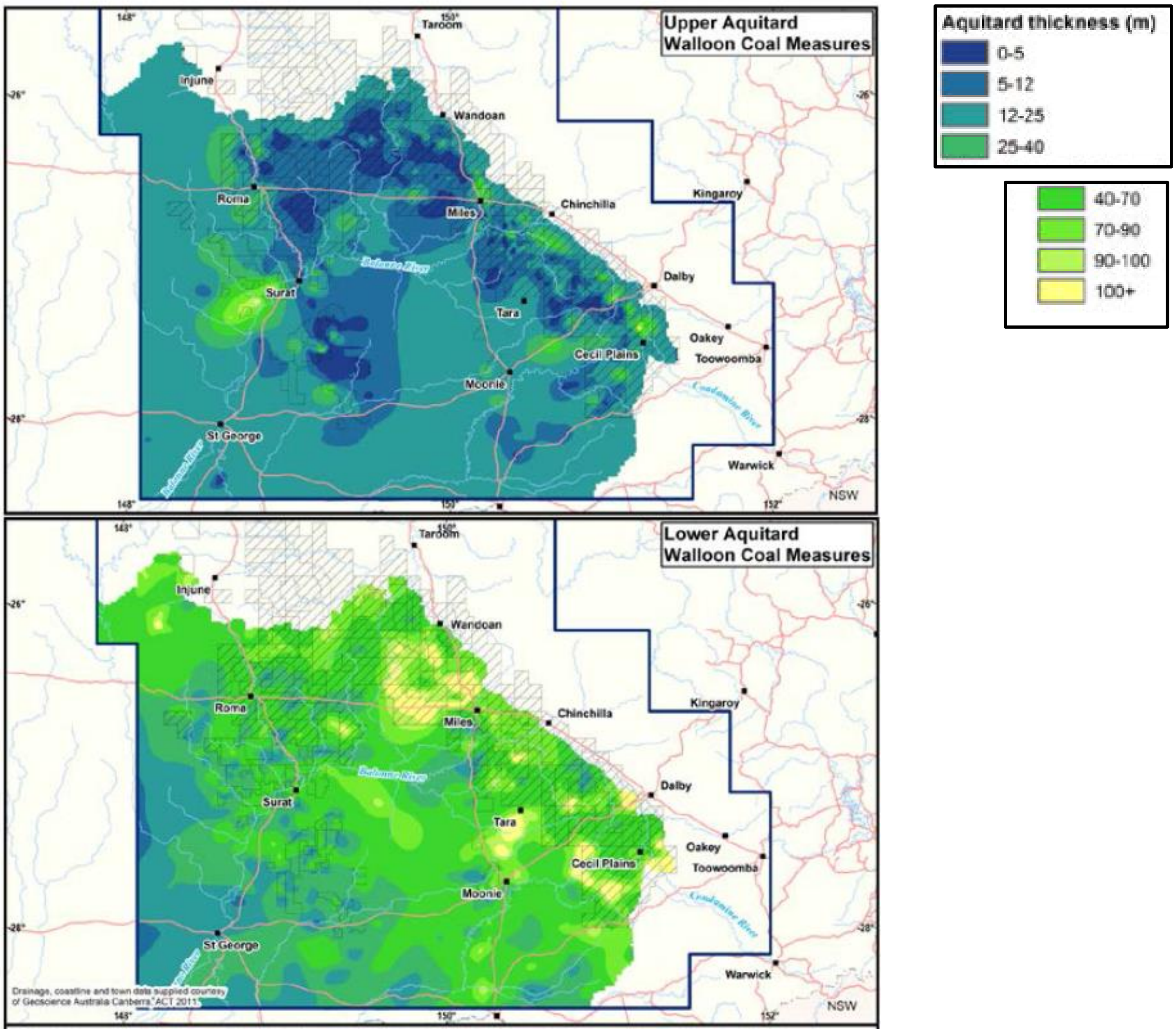


Figure 7: Thickness-map of the Upper and Lower Aquitard overlying and underlying the Walloon coal measures, respectively. The area to the south and west of Miles has very limited cover of the Upper Aquitard. Dark blue < 5m, yellow < 100m DNRM Queensland Government (2016). to yellow light to dark green shading: thickness < 5 metres, 5-20 m, 21-40 m, > 40 m DNRM Queensland Government (2016).

3.2. Migratory emissions enabled by aquifer pressure gradient

This section describes how methane emissions can reach the surface using the pressure gradient that exists in the subsurface. An aquifer has a pressure gradient that is usually vertical (i.e. increasing with depth). When a geological formation is depressurised, the pressure gradient within the formation changes, as does the pressure gradient between formations. This has consequences for the overall pressure gradient and its direction, which in turn can impact gas movement. Solubility of the gas phase also plays a big role in the ability for gas to move: gas solubility increases linearly with increasing pressure. Depressurising decreases pressure, thereby reducing the solubility of the gas phase linearly. Eventually gas may reach 'ebullition pressure', the pressure at which gas is moving freely to zones of equal or lower pressure. In order to assess the methane migratory risk in relation to pressure gradient changes, an understanding is required of the extraction and recharge rates of the various aquifers and the connectivity between aquifers.

Groundwater in the Condamine Alluvium is intensively extracted for agriculture. In total, 64,250 megalitres (ML) is extracted each year (DNRM Queensland Government (2016)) for agricultural purposes. This volume exceeds annual recharge, estimated to be only 35,000 ML/yr (SKM (2002)). Since the 1960s, the water level in the Condamine Alluvium has declined by six metres in the area around the Condamine River, and up to 26 metres in areas further away from the river.

Hillier (2010) demonstrates that there is a hydraulic connection between the Condamine Alluvium and the Walloon coals. This is based on:

- the increase in dissolved salts in alluvial bores in the direction downstream of the Condamine River. This can only be explained by flow from a more saline aquifer (Walloon coals) to a less saline aquifer (Condamine Alluvium). The flow of water is from below as well as from the side.
- the different groundwater levels found in the Walloon coals and the Condamine Alluvium: because the water level in the Walloon coals is approximately 20 metres higher than the water level in the Condamine Alluvium (Queensland Water Commission (2012)), the hydrostatic head is higher, which should induce a flow from the Walloon coals to the Condamine Alluvium[4].

Iverach, Cendón et al. (2015) confirm local connectivity between the Condamine Alluvium and the Walloon coals using a combination of groundwater methane concentration, $\delta^{13}C$-isoptopic composition, groundwater tritium and dissolved organic carbon.

Many models have been built to estimate the volume of water that would be extracted from the Walloon coals over the lifetime of the coal seam gas developments (Table 1). These models all show that three to six times more water will be extracted from the Walloon coals than from the Condamine Alluvium.

As water is extracted from the Walloon coals, water will flow from the Condamine Alluvium to the Walloon coals. The impact on the actual water level is estimated to be small due to the very high storage-coefficient characteristic of the Alluvium, being a very good aquifer with high

[4] It is noted the Office of Groundwater Impact Assessment (2016) concludes that differences in groundwater levels persist suggesting flow is limited.

porosity. Nevertheless approximately 1,160 megalitres of water per year is projected to flow from the Alluvium to the coals for at least the next 100 years (DNRM Queensland Government (2016))[5].

Water extraction estimates for the Condamine Alluvium and Walloon coals					
	Extraction		**Recharge**		**Information Source**
	Average (ML/y)	Peak (ML/y)	Total (ML/y)	Walloon coals -> Condamine Alluvium (ML/yr)	
Condamine Alluvium	64,250				DNRM Queensland Government (2016)
	55,000		35,000		Queensland Water Commission (2012)
			36,000	Eastern flank: 1,604	SKM (2002), Hillier (2010)
				Western flank: 441	SKM (2002), Hillier (2010)
Walloon Coals	70,000				DNRM Queensland Government (2016)
	75,000				Industry data (2012)
	98,000				Preliminary, Queensland Department of Natural Resources and Mines (DNRM) based on Industry data (2012)
		125,000 (first 3 years of full CSG production)			Queensland Water Commission (2012)
	127,500 (2010 to 2050)	175,000 (ca.2020)			Scenario 2, based on 2012 gas production (Klohn Crippen Berger (2012))
	112,500 (2010 to 2050)	180,000 (ca.2030)			Scenario 1, based on Environmental Impact Statements and inferred expansion (Klohn Crippen Berger (2012))
		200,000 (ca. 2020 to 2025)			University of Southern Queensland and RPS Aquaterra (2011)
		213,000 (year unknown)			Centre for Water in the Minerals Industry (2008); based on an LNG production rate of 28 million tonnes per year

Table 1: Overview of modelled extraction and recharge rates for the Condamine Alluvium and Walloon coals aquifers.

[5] The Healthy HeadWaters program does not provide an estimate of how much water will flow from the Condamine Alluvium to the Walloon coals.

The water extracted by the coal seam gas industry is not part the Murray-Darling plan, but through this mechanism has an indirect impact on the Condamine Alluvium, which will be subject to the new Sustainable Diversion Limits that limit extraction in 2019 under the Murray-Darling Basin management plan.

A significant body of work by the Queensland Department of Natural Resources and Mines has been released into the public domain at a late stage of our review (Consultation draft of the Underground Water Impact Report by the DNRM Queensland Government (2016) and a hydrogeological investigation report by the Office of Groundwater Impact Assessment (2016)). These reports will greatly assist in the understanding of groundwater management and aquifer connectivity. Conclusions from this work suggests that in general the connectivity between the aquifers is low (in particular based on hydrochemical data and pumping tests), albeit data in the area where the transition zone is absent remains very limited. The same report however forecasts a 1,160 ML/y flow from the Condamine Alluvium to the Walloon coals.

We hypothesise that migratory methane emissions could significantly increase with continued depressurisation of the coals seams. Water extraction from the Condamine Alluvium used for agricultural purposes will reduce the hydrostatic pressure, making it easier for gas to flow upward. Dewatering and depressurisation of the Walloon coals, thereby desorbing gas, together with the continued water extraction from the Condamine Alluvium, would enhance gas flow from the Walloon coals through the transition zone into the alluvium. This could significantly increase gas releases from weak or porous zones such as the Condamine River.

Over the long term, it is assumed that the Condamine Alluvium will lose water volume to the Walloon coals. In other words, if the Walloon coals are extensively depressurised, it would reverse the current pressure gradient, and allow water flow from the Condamine Alluvium to the Walloon coals. This could make a pressure assisted migratory route harder (gas may still rise through the stratigraphy). However, if the reduction in hydrostatic pressure in the Condamine Alluvium due to water extraction is greater than the hydrostatic pressure reduction in the Walloon coals due to depressurisation, gas will continue to migrate, and exacerbate migratory methane emissions.

Given the heterogeneous geology and the dynamics of aquifer depressurisation, the lack of an integrated high resolution geological hydrological model makes an assessment of the risks of migratory emissions very difficult.

3.3. Migratory emissions enabled by faults and natural fractures

This section describes how subsurface faults and natural fractures can be pathways that assist gas to migrate from coal seams to the surface.

Coals exhibit natural fractures in the form of cleats (face and butt cleats). Cleats can form through compaction during the burial process and coalification, or they can form as a consequence of strain applied to the coals by tectonic events (on a much longer timescale). Dawson and Esterle (2010) define four types of cleats. Cleat spacing is shown to be inversely proportional to cleat length. In other words: fractures within coals can be very close together but their length will be very limited. Fractures that are longer, and may penetrate the entire seam will be more sparsely spaced. Laubach, Marrett et al. (1998) propose a relationship between the width of the opening of the cleats (the aperture), the number of cleats, and the maximum permeability, based on hundreds of measurements in the San Juan Basin (Moore (2012)). Coals can therefor exhibit varying permeability: Coals seams in the area known as the Undulla nose have higher permeability than elsewhere (WorleyParsons (2010). This was also concluded by the Healthy HeadWaters coal seam gas feasibility study (Klohn Crippen Berger (2011)). In general the industry finds coal seams are less permeable than anticipated (DNRM Queensland Government (2016))

Coal seams are not continuous. Besides coals seams ending because no coals were deposited, faults can offset coals seams. Horizontal drilling experience has seen wells 'losing' the coal seam when a well was drilled through an unexpected fault (e.g. Fairview-117H, Tipperary Oil and Gas and Santos (2005)).

APLNG (2010) and WorleyParsons (2010) state that there is evidence that coal permeability declines near regional faults such as the Leichhardt and Moonie faults. This may reduce the ability of gas to use these faults as migration pathways.

Faults have been interpreted from seismic data (Norwest (2014)), a standard procedure in the oil and gas industry. It is unknown how well the faults are resolved on seismic close to the surface (imaging faults close to the surface is difficult). Likewise, it is unknown how many shallow faults that gas field operators have identified from seismic information. It is also unknown how much methane is being naturally emitted from faults. Lafleur and Fest (in preparation, 2016) examine possible gas flux from faults south of the Condamine River, but it is not known if emissions may be exacerbated over the lifetime of coal seam gas field production.

Bearing in mind the geological heterogeneity described above (Section 3.1), the changing hydrological properties and the potential faults (e.g. the fault relevant to the Condamine seep according to CSIRO[6]), conduits are likely to be very localised features where geological and hydrological properties permit the easiest path for gas to flow to the surface.

3.4. Migratory emissions enabled by man-made hydraulic fractures

Hydraulic fracturing (i.e. fracking) involves high-pressure fluid injection with the primary objective to open or increase permeability of a subsurface reservoir. Hydraulic fracturing can be used during coal seam gas production as a way to increase the permeability of the coal seams, but it is not known in how many wells the method has been applied. It certainly is not necessary in every well.
The orientation of the fractures depends on the stress regime that exists in the basin. To initiate

[6] http://www.abc.net.au/news/2016-02-14/condamine-river-mysterious-bubbling-intensifying-landholders-say/7139676

(or enhance) a fracture, the fluid pressure needs to exceed the minimal stress component (Hubbert and Willis (1972)). The fractures will then propagate perpendicular to the direction of the minimal stress.

In-situ stress data from the Bowen Basin suggests that the vertical stress component in the upper kilometre is in most cases the minimal principal stress direction (Hillis, Enever et al. (1999)).
For hydraulic fracturing, this means that fractures are very likely to propagate in a horizontal direction. Brooke-Barnett, Flottmann et al. (2015) show that the Surat Basin is under a similar stress regime, but much more variable. Flottman, Brooke-Barnett et al. (2013) show that hydraulic fracturing applied in the top 500 metres will induce horizontal fractures, whereas deeper fracturing will most likely result in more vertical fractures.

Vertical-induced fractures introduce possible gas migration pathways beyond the coal measures into overlaying and underlying formations. In areas where vertical fractures are planned, their lateral extent needs to be well understood in order to limit the creation of possible pathways.

The publication of hydraulic fracture lengths and the estimated distance of the fracture tip to adjacent formations in a centralised database, would increase understanding of the impact of hydraulic fracturing. This would be particularly useful where vertical fractures are anticipated.

3.5. Methane emissions assisted by wells and bores

This section describes how wells and bores may assist both non-migratory and migratory methane emissions.

Well integrity depends on the ability of the well casing and the cement between casings to withstand degeneration. There are numerous studies that have raised concerns about well integrity, poorly decommissioned wells, poor enforcement of the well regulatory system or a regulatory system playing catch-up to an expanding industry (e.g. Dusseault, Gray et al. (2000), Miyazaki (2009), Bair, Freeman et al. (2010), Wojtanowicz and Kinik (2011), Bishop (2013), Ingraffea, Wells et al. (2014), Boothroyd, Almond et al. (2016)).

Boothroyd, Almond et al. (2016) conclude that 30% of the abandoned, decommissioned onshore oil and gas wells in the United Kingdom are leaking gas, with the onset of leaking occurring within as little as ten years after abandonment. These wells are conventional gas production wells, and emissions are not significant. Poor well decommissioning, however, can result in large emissions.

Watson and Bachu (2007) describe instances where a rapidly-expanding gas-field expansion resulted in corner-cutting to reduce drilling time and maximise project progress.

Ingraffea, Wells et al. (2014) point out that although wells that had been more recently drilled show less cement or casing impairment, this may be because of time lag: recently drilled wells simply have seen less analysis and less time to deteriorate and therefore have an incomplete record compared to older wells. The researchers analysed over 32,000 wells in the U.S state of Pennsylvania and found that

1.9% of these wells showed integrity loss. Unconventional wells (drilled predominantly in the Marcellus shale) show up to a six-times higher degree of integrity loss than conventional wells (9.8% versus 1.5%). This does not seem to relate to immaturity of the industry because wells before 2009 show a degree of integrity-loss similar to wells drilled after 2009.

Darrah, Vengosh et al. (2014) show that noble gas isotopes can be used to identify contamination of drinking water due to cement failure. In their study, poor cement jobs and casing failures are linked to contaminated drinking water wells overlying the Marcellus shales and the Barnett shales.

Using Notice of Violation records, Vidic, Brantley et al. (2013) find integrity issues in 3.4% of unconventional wells in Pennsylvania drilled into the Marcellus shale over the period 2008 to 2013.

Deteriorating cement and zonal isolation is also identified as a problem in the San Juan Basin (U.S.), where coal seam gas is produced. Chafin (1994) note that uncemented annuli over the coal-bearing formation created the migration path.

In their report on the Condamine River seeps, Norwest (2014) notes that a similar pathway is possible in poorly-completed or poorly-maintained wells, emphasising the potential for enhancing connectivity between coal seams and shallower aquifers via the well annulus. A simple method is known as 'Bradenhead pressure monitoring', involving monitoring the pressure between sections of well casing can be used to indicate well anomalies.

Norwest (2014) and Apte, McCabe et al. (2014) note that coal-exploration wells in Queensland are a potential source of methane emissions, especially as many have not been plugged. With ongoing depressurisation of the coal seams, old unplugged coal-exploration bores are likely to emit more methane in future.

Similarly, water bores can be a source of methane emissions. Water bores are not designed to accommodate the effects of depressurising coal seams. Klohn Crippen Berger (2016) report free-gas in water bores that may originate from coal seams, even in cases where there is no appreciable decline in the water table. It is noted that methane in the water bores is a safety hazard, compromises water quality, can damage pumps, and impacts the yield.

In a welcome development, the gas-producing company Origin is implementing a water-bore monitoring program, acknowledging there is a lack of subsurface data[7]. This program aims to provide a baseline assessment and will monitor the effects of precipitation and drought, groundwater recharge, and changes in reservoir pressure. In addition DNRM Queensland Government (2016) reports that by the end of 2016 most monitoring points will be installed for a water monitoring network. Current data suggests that the water pressure in the coals is declining, but the decline is in line with expectation of the CSG industry.

[7] http://www.aplng.com.au/pdf/factsheets/Baseline_Assessments.pdf

4. How analogous is the U.S. San Juan Basin to Australian CSG fields?

In order to understand possible methane emissions resulting from Australian coal seam gas production, it is useful to look elsewhere for analogues. The San Juan Basin, located in the U.S. state of New Mexico and straddling the border with Colorado, is a prime candidate. The coals in the San Juan Basin are fairly shallow at depths of 300 to 700 metres, and the basin has been producing for more than twenty years (since 1989). This is also the area that has the highest methane emissions in the United States, recorded by satellite measurements (see Figure 11).

Since 1989, New Mexico has produced approximately 11,000 petajoules of coal seam gas, mainly from the San Juan Basin (EIA (2015)). By 2009, nearly 8,000 coal seam gas wells had been drilled in the basin, and nearly 40,000 oil and gas wells in total. (Figure 8, Figure 9 and Figure 10)

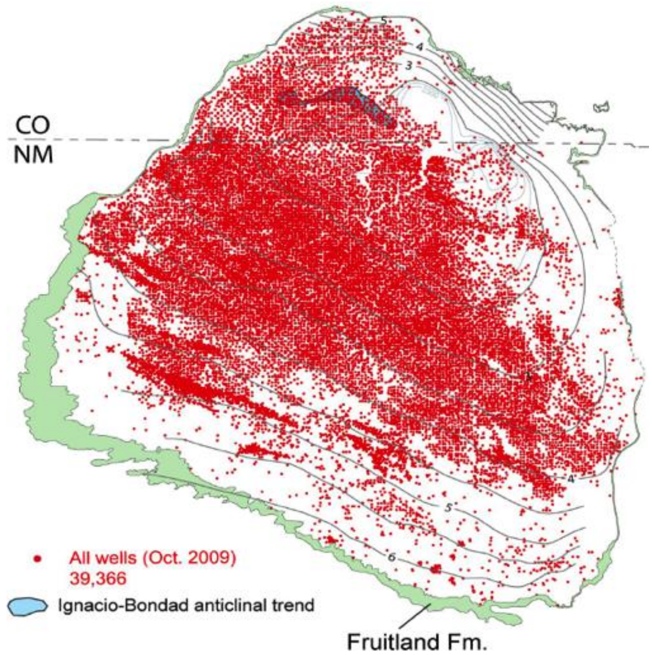


Figure 8: All oil and gas wells drilled in the San Juan Basin by the year 2009. Area shown covers an area approximately 100 kilometres by 100 kilometres. (Fassett (2013))

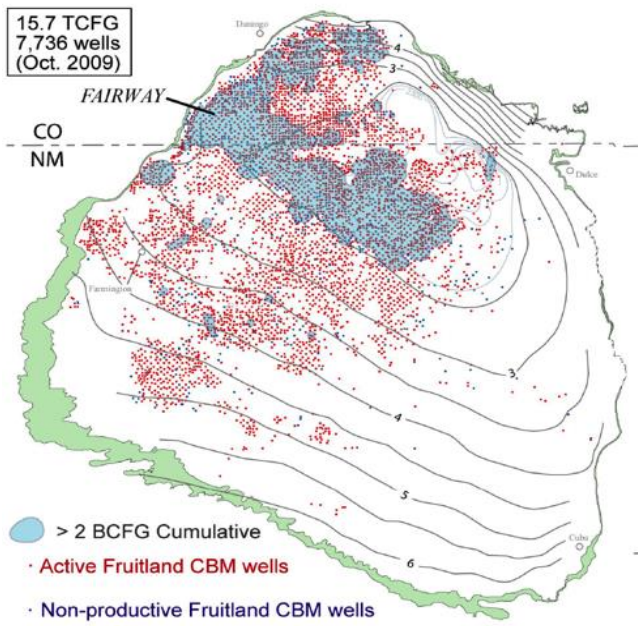


Figure 9: CSG wells drilled in the San Juan Basin by the year 2009. Area shown covers an area approximately 100 kilometres by 100 kilometres. (Fassett (2013))

The geology of the San Juan Basin has been extensively studied (Wray and Colorado Geological Survey (2000) and references therein). There are historic accounts of various natural gas seeps in the San Juan Basin. In the 1990s there appeared to be evidence suggesting that coal seam dewatering had led to an increase in natural surface seeps (Wray and Colorado Geological Survey (2000). Their research did not reveal any new gas seeps that were not already recognised, nor revealed it whether seeps can be initiated or prevented by depressurisation for coal seam gas production.

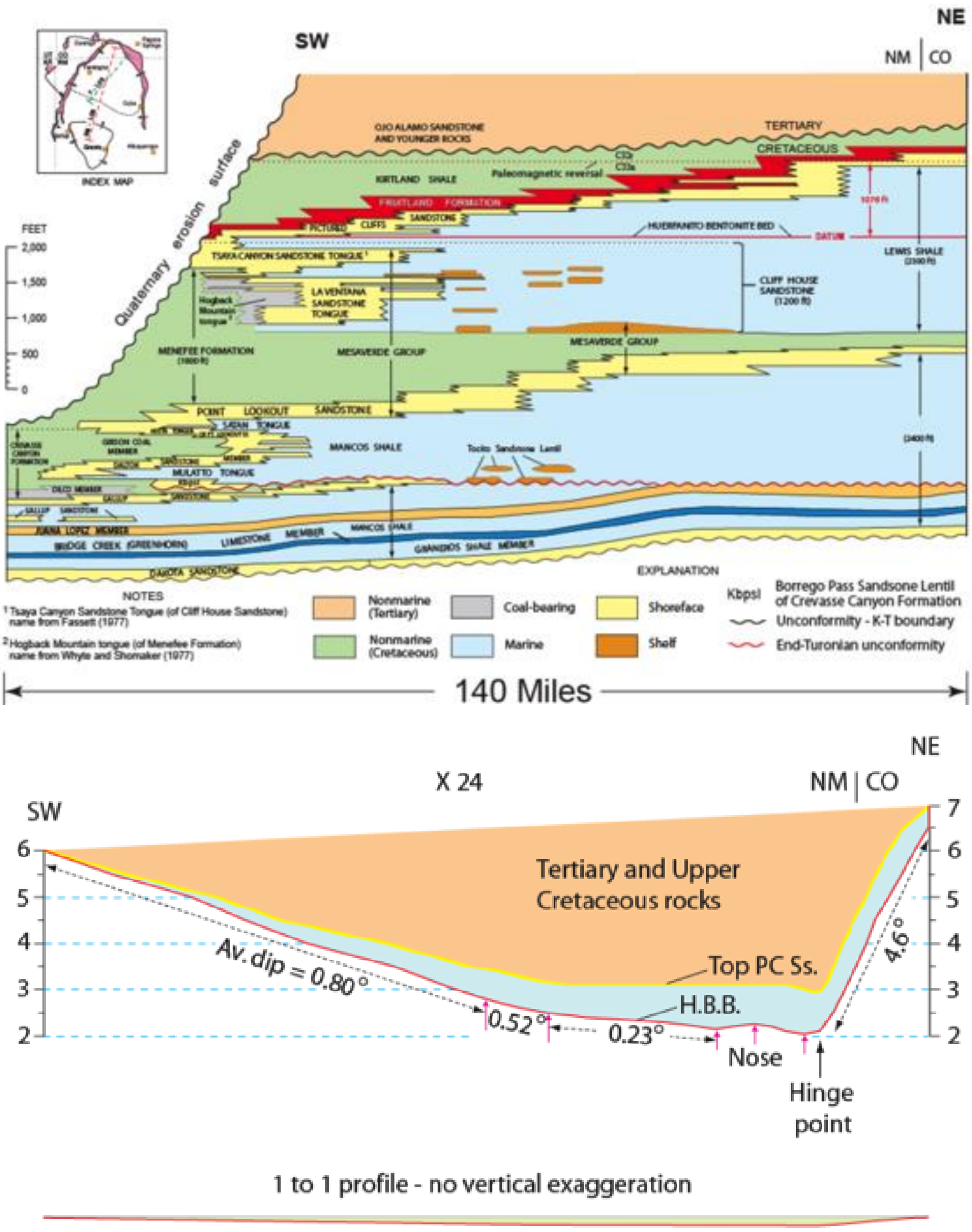


Figure 10: ***Top*****: SW-NE cross-section of the stratigraphy of the San Juan Basin. In red the Fruitland formation bearing the coal seams. The Fruitland formation lies at depths between ~300 to 700 metres.** ***Bottom*****: SW-NE cross-section of the San Juan basin, extending 12,000 km2. The Fruitland formation is 'draped' on top of the layer labelled "Top PC Ss." (Top Picture-Cliffs Sandstone), dipping at a very small angle in the Southern section (<1°) and slightly higher angle in the North (4-5°). Vertical axis is height above sea level of the base of the basin ('000 feet). From Fassett (2013).**

Oldaker (2015) presented a correlation between higher than normal precipitation and major methane emission events. Downhole video evidence, well packer testing and water quality and age testing (Snyder, Walter et al. (2003)) suggested that seeps are not due to increased coal seam gas production (Oldaker (2015)). However, as early as 1991, it was recognised that improperly cemented wells can act as conduits when coal seams are depressurised (Chafin (1994), Norwest (2014)). Pressure monitoring throughout the lifetime of a well (known as Bradenhead pressure monitoring) can be used to determine if gas or water flow can occur between well casing points and if well cementing has been inadequately performed.

Kort, Frankenberg et al. (2014) showed that the emissions from the Four Corners area of the U.S. (i.e., the San Juan Basin) can be observed from space (Figure 11). The researchers concluded that these emissions are most likely a result of fossil fuel production in the area, but stopped short of pointing to one specific industry. The researchers ruled out hydraulic fracturing as the main cause of the emissions given that technology is yet to be widely applied in that basin.

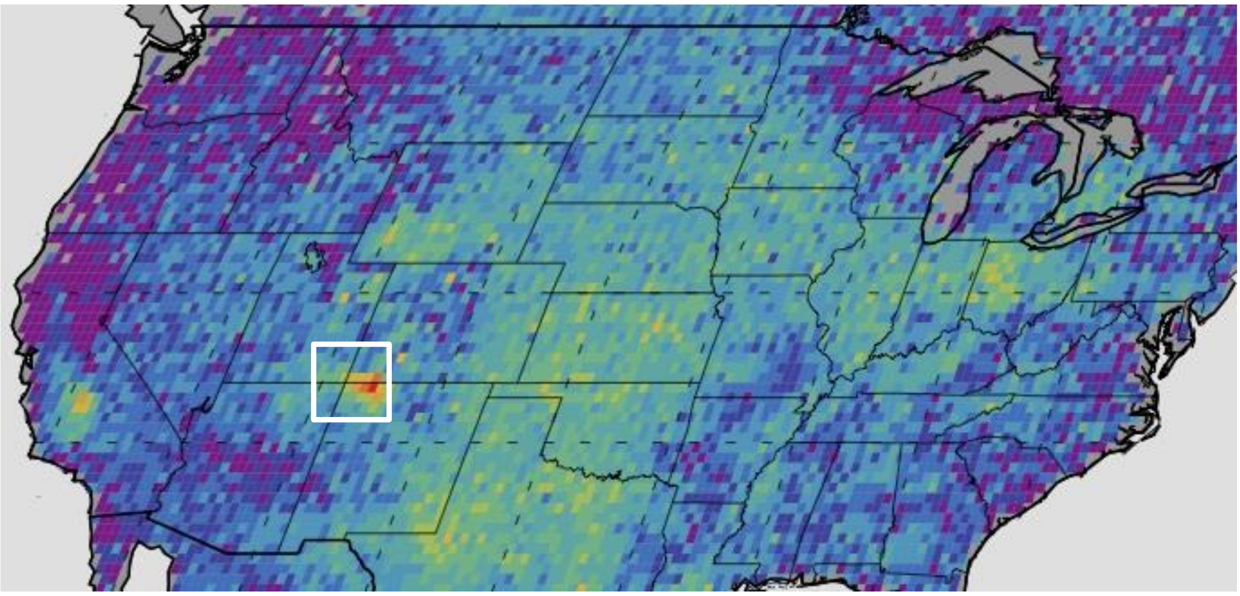


Figure 11: Column-averaged methane mole fractions from spectra collected by the SCIAMACHY satellite instrument, from 2003 to 2009 gridded at 1/3° resolution (Kort, Frankenberg et al. (2014)). The white rectangle depicts the Four Corner region.

As early as 1995, the Colorado Oil and Gas Conservation Commission concluded that the dewatering of the coal seams was the most likely explanation for the rise in emissions, leading to exacerbation of the emissions of the 'natural seeps'. Similar to the Bowen and Surat Basins of Queensland, the San Juan Basin had no baseline study. Since then however, the Colorado Oil and Gas Conservation Commission has commissioned an array of monitoring actions[8].

The centralised database for reporting and addressing complaints and spills of the Colorado Oil and Gas Conservation Commission is a good way of registering, monitoring and solving complaints

[8] See http://cogcc.state.co.us/library.html#/areareports

and issues. It also has a wealth of data and reports on monitoring, measurements and studies carried out in the state Colorado.

The geology of the San Juan Basin is different to the eastern Australia basins. The coals that are targeted in the San Juan Basin are situated in the Fruitland formation that lies in a synclinal structure (Figure 10). They are overlain by thick non-marine Kirtland Shale and underlain by the Pictured Cliffs sandstone (itself a productive gas reservoir) and the Lewis shale.

The San Juan Basin is also home to various conventional gas reservoirs. This makes differentiation of possible causes of methane emissions difficult. Nevertheless, Australia could learn much from recently-released data (such as Kort, Frankenberg et al. (2014)), previously-recorded incidents and governance.

5. The Condamine River gas seeps

This section describes gas seeps occurring in Queensland’s Condamine River near a CSG-producing area.

In May 2012, a landholder contacted the Queensland Government's LNG Enforcement Unit regarding gas seeps in the Condamine River, west of Chinchilla (Figure 12).

An initial investigation by the DNRM Queensland Government (2012) focused on public safety and environmental damage. The relevant permit-holder and gas-producing company, Origin, subsequently commissioned Norwest Energy to investigate (Norwest (2014)). Isotope analysis conclusively showed the source of the gas to be the Walloon coal and/or the Springbok sandstone, and not, for example related to decaying vegetation in the river bed.

Norwest stated that gas can be released from the underlying coals and reach the surface aided by either man-made pathways or natural pathways.

Man-made pathways can be created through water extraction from water bores or converted coal exploration bores, through coal seam dewatering, or through uncased well sections or deteriorating zonal isolation well sections between different formations.

Norwest (2014) states that apart from natural extreme precipitation events and associated falling and rising water tables, natural methane seeps can also be driven by the erosion of aquitards, past (Jurassic unconformity, where Walloon coal measures are overlain by the Cenozoic Condamine Alluvium) and present (bed erosion and shifting sediments) (Norwest (2014)).

Faulting can also assist gas migration. Faults may extend into overlying formations, and are interpreted as such from seismic (Figure 13, Figure 14, Norwest (2014)). It is not known which faults are conduits (allowing migration) or barriers (preventing migration). Professor Barrett of the Gas Industry Social and

Environmental Research Alliance (GISERA) states that the methane from the Condamine seeps comes to the surface along a small fault that intersects with the river[9].

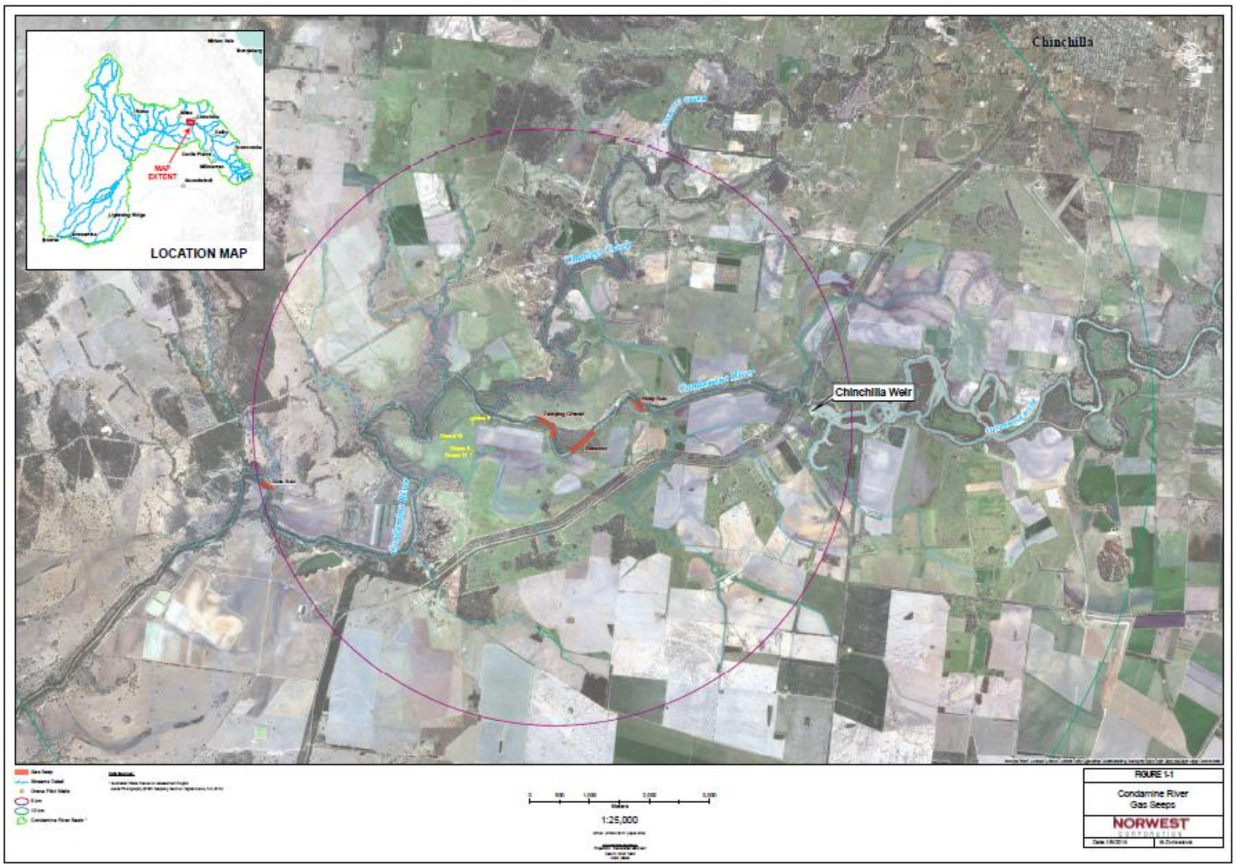


Figure 12: Location of the methane seeps west of Chinchilla (Norwest (2014)).

In 2014, Origin stated that it would conduct a seismic survey and drill eight monitoring bores in order to monitor pressure and groundwater level in real time APLNG (2014).

9 http://www.abc.net.au/news/2016-02-14/condamine-river-mysterious-bubbling-intensifying-landholders-say/7139676

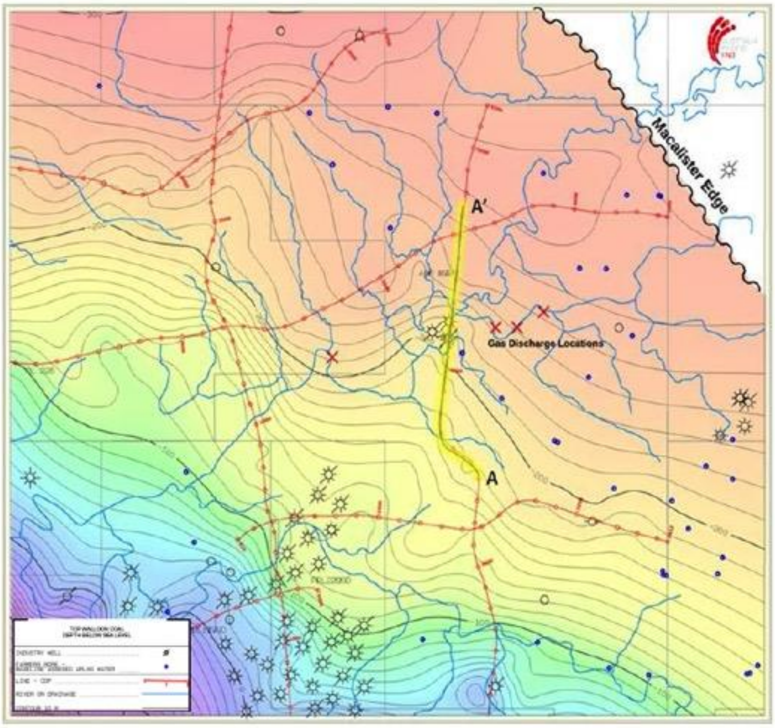


Figure 13: Depth map of top of Walloon coals around Chinchilla, Queensland (Norwest, 2014)

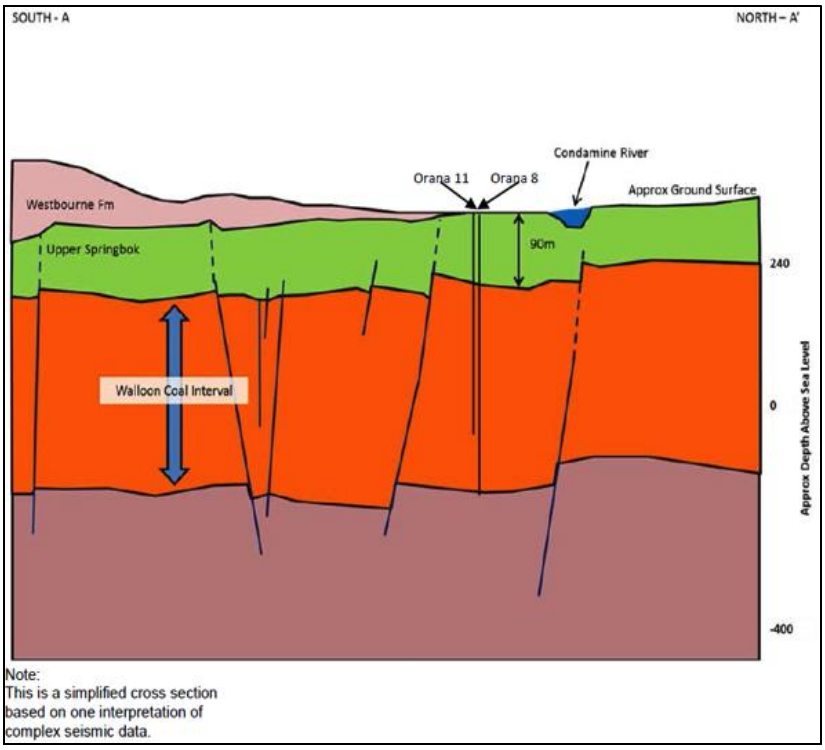


Figure 14: Simplified cross-section along AA' line in Figure 13.
Some faults are interpreted to extend into shallower formations (Norwest (2014).

Melbourne Energy Institute
McCoy Building, School of Earth Sciences, University of Melbourne, Victoria 3010, Australia
T: +61 3 8344 3519 F: +61 3 8344 7761 E: info-mei@unimelb.edu.au W: www.energy.unimelb.edu.au

In an independent review of the Condamine seeps coordinated by the Chief Scientist to the Queensland Government, Apte, McCabe et al. (2014) concluded that the seeps were still poorly understood. Apte, McCabe et al. (2014) recommended that the integration of a hydrological model with a high-resolution geological model would allow the impacts of stratigraphic heterogeneities on gas and water flow to be examined. Apte, McCabe et al. (2014) echoed Norwest's recommendation that a centralised geo-referenced database for gas data and water quality measurements would assist in understanding the impacts of natural variation and human activities. Apte, McCabe et al. (2014) also emphasised the need for more monitoring of emissions, and measurement of methane fluxes, over an adequate length of time (several years). The technology to do so is available and the numerous studies done in the U.S. San Juan Basin are considered to be the scientific standard (Section 4).

6. Sedimentary basin management plans needed

In the Queensland CSG-producing areas, there seems to be no clear understanding of the potential impacts of current and future human activities on the various aquifers. It is not clear how well the risks of gas-migration pathways are understood and being communicated to stakeholders. From the reports referred to above, it is clear there are insufficient data on permeability, lateral continuity of formations, and methane fluxes. For the Condamine area and in the wider Surat Basin, there is no integrated geological-hydrological model that allows for the analysis of the risk of gas migration.

Sustainable and well-managed extraction of commodities such as water and fossil fuels from sedimentary basins requires a holistic sedimentary basin management plan (Rawling and Sandiford (2013)). Without understanding the workings of a sedimentary basin that may provide multiple services, it is impossible to foresee the consequences of human interventions.

Dafny and Silburn (2014) and Apte, McCabe et al. (2014) have pointed out that significant gaps remain in terms of subsurface understanding. Additional field data needs to be acquired to narrow down uncertainties around the spatial extend of the Condamine Alluvium and the transitional layer and the properties of the transitional layer. None of the hydrological models include all the hydrological processes that play a role (Dafny and Silburn (2014)).

In cases where there are competing demands on sedimentary basins such as provision of water and fossil fuels, there is a need for an integrated geological-hydrological model. This model would assess the implications of formation heterogeneity, irregular formation thickness, coal seam dewatering and depressurisation, and water extraction by all users. We acknowledge the computational challenges of such a complex model.

7. Conclusion

This report highlights the potential for migratory methane emissions to occur in Queensland's coal seam gas basins. Due to a lack of available data, the likelihood of migratory emissions occurring as a direct consequence of the gas extraction, at present or in the future, is difficult to assess. Current Australian methane-emissions estimation methods largely ignore this potential source of emissions.

The heterogeneity of the geology in the area where the Condamine Alluvium exists, increases the risk of migratory emissions occurring. The emissions could significantly increase with continues depressurisation of the coal seams while multiple users are extracting water from various aquifers.

Migration of methane along existing natural faults and fractures is possible and may increase with continued depressurization even when the leakage rates today may be minimal without disturbance.

Water bores and coal exploration bores are known sources to methane emissions and the presence of free methane can be the direct consequence of the depressurisation of the coal seams. The well integrity of dedicated gas wells and other existing bores that were not designed to prevent migratory emissions is an area of concern.

8. References

APLNG (2010). Australia Pacific LNG Project Environmental Impact Statement. Volume 5: Attachments. Attachment 21: Ground Water Technical Report – Gas Fields. Australia Pacific LNG Project Environmental Impact Statement.

APLNG. (2014). "Condamine River seeps investigation update." Retrieved April 19, 2016, from http://www.aplng.com.au/sites/default/files/NW%20Report%20Release_FINAL.pdf.

Apte, S., P. McCabe, R. Oliver and L. Paterson (2014). Condamine River Gas Seeps Investigations - Independent Review.

Bair, E. S., D. C. Freeman and J. M. Senko (2010). Expert Panel Technical Report Subsurface Gas Invasion Bainbridge Township, Geauga County, Ohio

Bishop, R. E. (2013). "Historical analysis of oil and gas well plugging in New York: is the regulatory system working?" NEW SOLUTIONS: A Journal of Environmental and Occupational Health Policy **23**(1): 103-116.

Boothroyd, I., S. Almond, S. Qassim, F. Worrall and R. Davies (2016). "Fugitive emissions of methane from abandoned, decommissioned oil and gas wells." Science of The Total Environment **547**: 461-469.

Brooke-Barnett, S., T. Flottmann, P. K. Paul, S. Busetti, P. Hennings, R. Reid and G. Rosenbaum (2015). "Influence of basement structures on in situ stresses over the Surat Basin, southeast Queensland." Journal of Geophysical Research: Solid Earth **120**(7): 4946-4965.

Chafin, D. T. (1994). Sources and migration pathways of natural gas in near-surface ground water beneath the Animas River Valley, Colorado and New Mexico, US Geological Survey.

Dafny, E. and M. D. Silburn (2014). "The hydrogeology of the Condamine River Alluvial Aquifer, Australia: a critical assessment." Hydrogeology Journal **22**(3): 705-727.

Darrah, T. H., A. Vengosh, R. B. Jackson, N. R. Warner and R. J. Poreda (2014). "Noble gases identify the mechanisms of fugitive gas contamination in drinking-water wells overlying the Marcellus and Barnett Shales." Proceedings of the National Academy of Sciences **111**(39): 14076-14081.

Dawson, G. and J. Esterle (2010). "Controls on coal cleat spacing." International Journal of Coal Geology **82**(3): 213-218.
Day, S., M. Dell'Amico, D. Etheridge, C. Ong, A. Rodger, B. Sherman and D. Barrett (2013). Characterisation of regional fluxes of methane in the Surat Basin, Queensland–Phase 1: A Review and Analysis of Literature on Methane Detection and Flux Determination, CSIRO, Australia.
Day, S., C. Ong, A. Rodger, D. Etheridge, M. Hibberd, E. van Gorsel, D. Spencer, P. Krummel, S. Zegelin, R. Fry, M. Dell'Amico, S. Sestak, D. Williams, Z. a. Loh and D. Barrett (2015). Characterisation of Regional Fluxes of Methane in the Surat Basin, Queensland. Phase 2: A pilot study of methodology to detect and quantify methane sources GISERA.
DNRM Queensland Government (2012). Summary Technical Report - Part 1. Condamine River Gas Seep Investigation, Queensland Department of Natural Resources and Mines (DNRM).
DNRM Queensland Government (2016). Underground Water Impact Report for the Surat Cumulative Management Area.
Dusseault, M. B., M. N. Gray and P. A. Nawrocki (2000). Why oilwells leak: cement behavior and long-term consequences. International Oil and Gas Conference and Exhibition in China, Society of Petroleum Engineers.
EIA (2015). Coalbed methane production 1989-2014, US EIA.
Exon, N. F. (1976). Geology of the Surat Basin in Queensland, Australian Government Publishing Service.
Fassett, J. E. (2013). "The San Juan Basin: A Complex Giant Gas Field, New Mexico and Colorado." Search and Discovery.
Fleming, A. (1972). "Investigations into Permian Geology and The Burning Mountain Coal Fire." B. Sc.(Honors) Thesis.
Flores, R. M., C. A. Rice, G. D. Stricker, A. Warden and M. S. Ellis (2008). "Methanogenic pathways of coal-bed gas in the Powder River Basin, United States: the geologic factor." International Journal of Coal Geology **76**(1): 52-75.
Flottman, T., S. Brooke-Barnett, R. Trubshaw, S.-K. Naidu, E. Kirk-Burnnand, P. Paul, S. Busetti and P. Hennings (2013). Influence of in Situ Stresses on Fracture Stimulation in the Surat Basin, Southeast Queensland. SPE Unconventional Resources Conference and Exhibition-Asia Pacific, Society of Petroleum Engineers.
Geochemical Exploration Services Inc. (1991). Soil gas survey, ATP-401P, Terra Grande, Inc.
Gray, A. R. G. (1967). "Natural gas occurrence in the Brigalow Area, March, 1967." Queensland Government Mining Journal **68**: 394-395.
Green, P., D. Carmichael, T. Brain, C. Murray, J. McKellar, J. Beeston and A. Gray (1997). "Lithostratigraphic units in the Bowen and Surat basins, Queensland." The Surat and Bowen Basins, south-east Queensland: 41-108.
Hamilton, S., J. Esterle and S. Golding (2012). "Geological interpretation of gas content trends, Walloon Subgroup, eastern Surat Basin, Queensland, Australia." International Journal of Coal Geology **101**: 21-35.
Hildenbrand, A., B. Krooss, A. Busch and R. Gaschnitz (2006). "Evolution of methane sorption capacity of coal seams as a function of burial history—a case study from the Campine Basin, NE Belgium." International Journal of Coal Geology **66**(3): 179-203.
Hillier, J. R. (2010). "Groundwater connections between the Walloon Coal Measures and the Alluvium of the Condamine River." A Report for the Central Downs Irrigators Limited.
Hillis, R., J. Enever and S. Reynolds (1999). "In situ stress field of eastern Australia." Australian Journal of Earth Sciences **46**(5): 813-825.

Hodgkinson, J., A. Hortle and M. McKillop (2010). "The application of hydrodynamic analysis in the assessment of regional aquifers for carbon geostorage: preliminary results for the Surat Basin, Queensland." Queensland. APPEA Journal **50**: 18.
Hodgkinson, J., M. Preda, A. Hortle, M. a. McKillop and L. Foster (2009). The Potential Impact of Carbon Dioxide Injection on Freshwater Aquifers: The Surat and Eromanga Basins in Queensland. Brisbane, Department of Employment, Economic Development and Innovation.
Hubbert, M. K. and D. G. Willis (1972). "Mechanics of hydraulic fracturing."
Ingraffea, A. R., M. T. Wells, R. L. Santoro and S. B. Shonkoff (2014). "Assessment and risk analysis of casing and cement impairment in oil and gas wells in Pennsylvania, 2000–2012." Proceedings of the National Academy of Sciences **111**(30): 10955-10960.
Iverach, C. P., D. I. Cendón, S. I. Hankin, D. Lowry, R. E. Fisher, J. L. France, E. G. Nisbet, A. Baker and B. F. J. Kelly (2015). "Assessing Connectivity Between an Overlying Aquifer and a Coal Seam Gas Resource Using Methane Isotopes, Dissolved Organic Carbon and Tritium." Scientific Reports **5**: 15996.
Klohn Crippen Berger (2011). Conceptualisation of the Walloon Coal Measures beneath the Condamine Alluvium. Healthy HeadWaters Coal Seam Gas Water Feasibility Study, Queensland Department of Environment and resource management.
Klohn Crippen Berger (2012). Forecasting coal seam gas water production in Queensland's Surat and southern Bowen basins. Healthy Headwaters.
Klohn Crippen Berger (2016). Potential effects of free gas on bore water supply from CSG development, Queensland Department of Natural Resources and Mines.
Kort, E. A., C. Frankenberg, K. R. Costigan, R. Lindenmaier, M. K. Dubey and D. Wunch (2014). "Four corners: The largest US methane anomaly viewed from space." Geophysical Research Letters **41**(19): 6898-6903.
Laubach, S. E., R. A. Marrett, J. E. Olson and A. R. Scott (1998). "Characteristics and origins of coal cleat: A review." International Journal of Coal Geology **35**(1–4): 175-207.
Laxminarayana, C. and P. J. Crosdale (1999). "Role of coal type and rank on methane sorption characteristics of Bowen Basin, Australia coals." International Journal of Coal Geology **40**(4): 309-325.
Levine, J. R. (1996). "Model study of the influence of matrix shrinkage on absolute permeability of coal bed reservoirs." Geological Society, London, Special Publications **109**(1): 197-212.
Mastalerz, M., M. Glikson and S. D. Golding (1999). Coalbed methane: scientific, environmental and economic evaluation, Springer Science & Business Media.
Miyazaki, B. (2009). "Well integrity: An overlooked source of risk and liability for underground natural gas storage. Lessons learned from incidents in the USA." Geological Society, London, Special Publications **313**(1): 163-172.
Moore, T. A. (2012). "Coalbed methane: a review." International Journal of Coal Geology **101**: 36-81.
Norwest (2014). Condamine river gas seep investigation - technical report. Brisbane, QLD, Norwest Energy Consultants Pty. Ltd.
O'Brien, G. W., P. R. Tingate, L. M. Goldie Divko, J. A. Miranda, M. J. Campi and K. Liu (2013). "Basin-scale fluid flow in the Gippsland Basin: implications for geological carbon storage." Australian Journal of Earth Sciences **60**(1): 59-70.
Office of Groundwater Impact Assessment (2016). Groundwater connectivity between the Condamine Alluvium and the Walloon coal measures.
Oldaker, P. (2015). "Twenty Years of CBM Production and Monitoring of the Pine River Subcrop and Gas Seeps - No Depletion." Search and Discovery Article.
Queensland Water Commission (2012). Underground water impact report.

Rawling, T. a. and M. Sandiford (2013). Multi basin usage/cumulative impact, Melbourne Energy Institute, University of Melbourne.
Rice, D. D. (1993). "Composition and origins of coalbed gas." Hydrocarbons from coal: AAPG Studies in Geology **38**(1): 159-184.
Scott, S., B. Anderson, P. Crosdale, J. Dingwall and G. Leblang (2007). "Coal petrology and coal seam gas contents of the Walloon Subgroup—Surat Basin, Queensland, Australia." International Journal of Coal Geology **70**(1): 209-222.
SKM (2002). South-East Queensland Recycled Water Project – Darling Downs Hydrological Study. Groundwater Modelling., SKM.
Snyder, G. T., C. Walter, S. Franks, U. Fehn, W. L. Pelzmann, A. W. Gorody and J. E. Moran (2003). "Origin and history of waters associated with coalbed methane: 129 I, 36 Cl, and stable isotope results from the Fruitland Formation, CO and NM." Geochimica et Cosmochimica Acta **67**(23): 4529-4544.
Strąpoć, D., F. W. Picardal, C. Turich, I. Schaperdoth, J. L. Macalady, J. S. Lipp, Y.-S. Lin, T. F. Ertefai, F. Schubotz and K.-U. Hinrichs (2008). "Methane-producing microbial community in a coal bed of the Illinois Basin." Applied and environmental microbiology **74**(8): 2424-2432.
Tait, D. R., I. R. Santos, D. T. Maher, T. J. Cyronak and R. J. Davis (2013). "Enrichment of radon and carbon dioxide in the open atmosphere of an Australian coal seam gas field." Environmental science & technology **47**(7): 3099-3104.
Tipperary Oil and Gas and Santos (2005). Fairview 117H well completion report PL 92 - Queensland. QDEX.
University of Southern Queensland and RPS Aquaterra (2011). Preliminary Assessment of Cumulative Drawdown Impacts in the Surat Basin Associated with the Coal Seam Gas Industry.
Vidic, R. D., S. L. Brantley, J. M. Vandenbossche, D. Yoxtheimer and J. D. Abad (2013). "Impact of shale gas development on regional water quality." Science **340**(6134): 1235009.
Watson, T. L. and S. Bachu (2007). Evaluation of the potential for gas and CO2 leakage along wellbores. E&P Environmental and Safety Conference, Society of Petroleum Engineers.
Wojtanowicz, A. K. and K. Kinik (2011). "Environmental risk of sustained casing pressure." Wiertnictwo, Nafta, Gaz **28**: 459-467.
WorleyParsons (2010). Spatial Analysis of Coal Seam Water Chemistry Task 1: Literature Review. Healthy HeadWaters Coal Seam Gas Water Feasibility Study.
Wray, L. L. and Colorado Geological Survey (2000). Geologic Mapping and Subsurface Well Log Correlations of the Late Cretaceous Fruitland Formation coal beds and carbonaceous shales – the Stratigraphic Mapping Component of the 3M Project, San Juan Basin, La Plata County, Colorado. Denver, Colorado, Colorado Geological Survey.

Be careful of what you wish for

The economic impacts of Queensland's unconventional gas experiment and the implications for Northern Territory policy makers.

Discussion paper

Mark Ogge
November 2015

ABOUT THE AUSTRALIA INSTITUTE

The Australia Institute is an independent public policy think tank based in Canberra. It is funded by donations from philanthropic trusts and individuals and commissioned research. Since its launch in 1994, the Institute has carried out highly influential research on a broad range of economic, social and environmental issues.

OUR PHILOSOPHY

As we begin the 21st century, new dilemmas confront our society and our planet. Unprecedented levels of consumption co-exist with extreme poverty. Through new technology we are more connected than we have ever been, yet civic engagement is declining. Environmental neglect continues despite heightened ecological awareness. A better balance is urgently needed.

The Australia Institute's directors, staff and supporters represent a broad range of views and priorities. What unites us is a belief that through a combination of research and creativity we can promote new solutions and ways of thinking.

OUR PURPOSE – 'RESEARCH THAT MATTERS'

The Institute aims to foster informed debate about our culture, our economy and our environment and bring greater accountability to the democratic process. Our goal is to gather, interpret and communicate evidence in order to both diagnose the problems we face and propose new solutions to tackle them.

The Institute is wholly independent and not affiliated with any other organisation. As an Approved Research Institute, donations to its Research Fund are tax deductible for the donor. Anyone wishing to donate can do so via the website at https://www.tai.org.au or by calling the Institute on 02 6130 0530. Our secure and user-friendly website allows donors to make either one-off or regular monthly donations and we encourage everyone who can to donate in this way as it assists our research in the most significant manner.

Level 5, 131 City Walk
Canberra, ACT 2601
Tel: (02) 61300530
Email: mail@tai.org.au
Website: www.tai.org.au

Summary

The gas industry frequently claims that unconventional gas development has brought an economic and jobs boom to Queensland, and promises the same for the Northern Territory. Research into what has actually happened in Queensland paints a far less positive picture. Territorians should carefully examine the accuracy of these claims to determine the likely economic and jobs impacts of unconventional gas development in the Northern Territory.

In contrast to the economic benefits promised, recent gas industry funded studies of the economic and social impacts of gas development in Queensland's unconventional gas fields have found:

- Local business stakeholders reported a deterioration in:
    - Financial capital
    - Local infrastructure
    - Local skills
    - Social cohesion
    - The local environment
- Unconventional gas has affected community wellbeing:
    - Fewer than one in four local people approved of the unconventional gas industry, with less than 6% believing it would "lead to something better". (See figure 2 below)
- Unconventional gas creates few additional jobs:
    - Spillover jobs outside the gas industry were negligible. There were virtually no spillover jobs created in local retail or manufacturing.
    - Gas jobs will be slashed by 80% at the end of the construction period.
- For every 10 unconventional gas jobs created, eighteen agricultural jobs were lost.

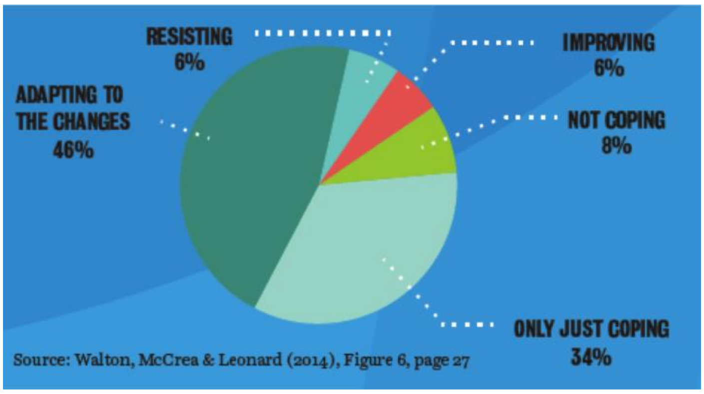
Figure 1: The impact of unconventional gas development on local businesses

How did local business stakeholders in Queensland's Darling Downs perceive the impact of unconventional gas and mining on their region?

Source: CSRM University of Queensland

Financial capital	Worse
Infrastructure	Worse
Labour force skills	Worse
Social networks	Worse
Environment	Worse

Figure 2: The social impacts of unconventional gas development on communities in Queensland's Darling Downs



Source: Walton, McCrea & Leonard (2014), Figure 6, page 27

There have also been few economic benefits for the wider economy. The industry emphasises the high *value* of the gas it exports, but the value of gas exports largely flow to the gas companies rather than to the Australian community. As the Reserve Bank of Australia concluded:

> The effect on Australian living standards will be less noticeable than [the increase in gas production] given the low employment intensity of LNG production, the high level of foreign ownership of the LNG industry and, in the near term, the use of deductions on taxation payments.[1]

Queensland's experience shows that reality does not match the unconventional gas industry's claims. Few benefits are realised outside the gas industry, and there are serious social and economic effects on local communities and existing businesses.

[1] Cassidy, N and Kosev, M (2015) *Australia and the Global LNG Market*, RBA

Table of Contents

Introduction

When seeking development approval, oil and gas companies justify their projects' significant environmental and social harm on the grounds that the projects will bring jobs and economic growth.

The huge profits at stake encourage companies to exaggerate the economic benefits of their projects and downplay their negative effects. These economic claims are made in formal approval processes and public relations activities and during lobbying of policy makers.

This kind of exaggeration has become routine for many resource companies, often reaching almost comic proportions. Notorious cases include the Rio Tinto Warkworth coal mine expansion in NSW where the company claimed it would create 44,000 additional jobs despite the expansion only requiring 130 additional workers. The NSW Land and Environment Court rejected the company's claims and overturned the approval, a decision that was upheld by the Supreme Court of NSW. Similarly the proponents of the proposed Carmichael coal mine said that the project would create 10,000 jobs. When challenged in court the company's own economic expert acknowledged that the actual figure was less than 1,476 jobs.

In 2013 the Australian Petroleum Production and Exploration Association (APPEA) claimed that the oil and gas industry had created 100,000 new jobs in a single year. According to the Australian Bureau of Statistics, the oil and gas industry in Australia added only 9,400 jobs that year, and employed 20,700 people in total.[2] Even adding the additional construction jobs would not bring the figure anywhere near the 100,000 jobs claimed. These additional construction jobs would have come largely at the expense of jobs in other industries, particularly given the very tight labour market at the time.

The absurdity of the claims belies the seriousness of the deception.

These projects have serious environmental and social impacts that are too often ignored by policy makers and bureaucrats, who have been willing to uncritically accept the assurances of resource companies. This has sometimes led to serious environment and social impacts for local communities from projects that provide little benefit to the wider population.

[2] The Australia Institute Facts Fight Back June 30 2013. http://www.factsfightback.org.au/did-the-gas-industry-create-100000-jobs-last-year-check-the-facts/

The huge unconventional gas projects approved in Queensland in 2010 are a case in point. The economic claims of the proponents were not tested by the government, despite its obligation to objectively assess the projects. Recent research examined in this paper clearly shows that few of the promised benefits have materialised and existing businesses and entire industries have been badly affected. Long-term jobs have been sacrificed for short-term gas construction jobs.

Only 6% of local people living in gas field areas think that the industry has improved their lives – as many as are actively resisting it. As well as active resisters, a further 42% say that they are “not coping” or “only just coping” with the changes the industry has made to their lives. Actual royalty payments are a small fraction of the estimates made at approval and flow on economic activity has failed to materialise because companies bypassed local industry and suppliers in favour of global supply chains.

The Northern Territory government has issued unconventional gas licenses for almost the entire territory. Speculative gas interests have a strong incentive to increase the value of their licenses by gaining environmental approvals and government promises to subsidise infrastructure.

Northern Territory policy makers can learn from the experience in Queensland. The economic claims of the unconventional gas industry must be subject to scrutiny and due diligence. Projects should only proceed if they provide a net benefit to the Territory community, not just quick profits for gas companies.

1. The impacts of unconventional gas developments on local businesses

While some people and businesses benefit from unconventional gas development, many other businesses and industries can be negatively impacted and jobs in other sectors are often lost as a result.

The most advanced unconventional gas development in Australia is in Queensland's Darling Downs. The gas industry uses this region as an example of the economic benefits that unconventional gas provides local communities.[3] The research tells a more complicated story.

The most detailed examination of the economic impacts of unconventional gas development in the Darling Downs is a study carried out between 2008 and 2013 by the industry-funded Sustainable Minerals Institute (SMI) at the University of Queensland. [4]

This study surveyed stakeholders from different sectors in the local community including the local business community, agriculture, local government, advocacy groups and environmental consultants, as well as the mining and unconventional gas industries.

The survey asked stakeholders to assess the effect of unconventional gas and mining in the region over a five-year period on the following key indicators:

1. **Financial capital:** Available revenue streams and economic resources.
2. **Built capital:** The physical infrastructure such as buildings, transport and equipment.
3. **Social capital:** The degree to which people know each other and collaborate and the level of trust people have in local organisations and institutions.
4. **Human capital:** Assets such as skills, knowledge, abilities and good health possessed by individuals that enable them to work, earn a living, contribute to society and thereby build other forms of capital.
5. **Natural capital**: Key natural resources, such as water, land, clean air, wildlife and forests that people can access for lifestyle or livelihood purposes.

[3] Natural Coal Seam Gas, Regional Development, APPEA http://www.naturalcsg.com.au/benefits/regional-development/

[4] Everingham, J, Collins, N, Rodriguez, D, Cavaye, J, Vink, S, Rifkin, W & Baumgartl, T (2013) *Energy resources from the food bowl: an uneasy co-existence. Identifying and managing cumulative impacts of mining and agriculture. Project report*, CSRM, The University of Queensland: Brisbane.

All stakeholder groups other than those representing mining and unconventional gas believed that the development of mining and unconventional gas had a negative impact on all or most types of capital. Even the mining and unconventional gas industries thought that local infrastructure had deteriorated as a result of mining and unconventional gas development in the region.

Figure 3: **Stakeholder responses assessing the change in different types of capital over the last 5 years as a result of interaction between gas and other industries**

	Financial capital	Human capital	Built capital	Social capital	Natural capital
Gas	Better	Better	Worse	Better	Better
Mining	Better	Better	Worse	Better	Better
Agriculture	Worse	Worse	Worse	Worse	Worse
Local business	Worse	Worse	Worse	Worse	Worse
Local government	Worse	Better	Worse	Same	Same
Community	Worse	Better	Worse	Worse	Worse
Advocacy	Worse	Worse	Worse	Worse	Worse

Far from mining and unconventional gas providing economic benefits, local businesses felt that it had reduced financial capital, human capital, infrastructure, social capital and natural capital.

Local businesses have to compete with inflated gas industry wages in order to recruit and retain staff and they experience increased rent and competition for services (particularly trade and mechanical repairs). There are also disruptions to farmers from the rollout of access roads, pipelines, water treatment plants and other infrastructure. Big increases in truck traffic tend to disrupt other forms of transport and damage roads.

Some businesses do benefit. Motels, bars and fast food chains experience a burst of demand during the brief construction phase, but may struggle afterwards. Waste disposal companies can profit from storing, transporting and treating the millions of litres of toxic “produced” or “flow-back” water and salt from the extraction process.

The CSRM report includes statements from stakeholders discussing the effect of the gas and mining boom in the region on existing local businesses:

> Obviously if you've got a major engineering or earth moving business, you attract business, you're doing incredibly well, or a motel.
>
> But, if you work in town at a local shop, or the council, you're doing incredibly poorly, because your rents have gone through the roof and suddenly you're flat out paying to be able to live in town. For us, we're seeing increased costs.
>
> All our professional services are $100 an hour plus, whereas they used to be [in the] 40s and 50s. Freight is dearer. We can't get labour. We're relying on backpackers a lot more because we just can't get permanent staff. So, it's quite an added cost to one sector of the community, while the other sector booms.[5]

Having to compete with inflated resource industry wages was also of great concern:

> What they're paying for wages [in some towns] is two and half times what the wage should be – just to hold men. That's forcing consumer goods up, to try to cover the costs of those wages… So it's all spinning down the line… [For example] from a hardware perspective, anyone doing renovations to their home, even just the little bits are all getting more expensive because these guys are trying to cover the increase in wages that they've had to pay to retain men. And the [resources] companies are walking into businesses and offering staff – mainly mechanics… huge wages.[6]

Other stakeholders described the corrosion of social capital:

> [I]n regards to a divide between people, not just landholders versus townies, but for instance I've got a lot of friends who used to work in agriculture and now work for gas companies – a lot of them. And some family members don't speak to them anymore because they're still on the land...
>
> But even in towns now… once you would go to the local pub in Dalby, it was all full of farmers and that sort of thing and now you've got guys in their high vis' and after a few rums things are getting… they do, it's starting to get quite ugly. There's quite a bit of animosity going on. And agricultural communities have never been like that – they're not. And now that's building up pretty much. [7]

[5] Everingham et al, p 38.
[6] Everingham et al, p 39.
[7] Everingham et al, p 51.

It is clear from interviews with businesses in unconventional gas development areas that the industry brings substantial costs. The CSRM study showed that business stakeholders perceived the costs as outweighing the benefits. Territory business organisations and policy makers should be aware of how this has played out in Queensland when considering the expansion of the gas industry in the NT.

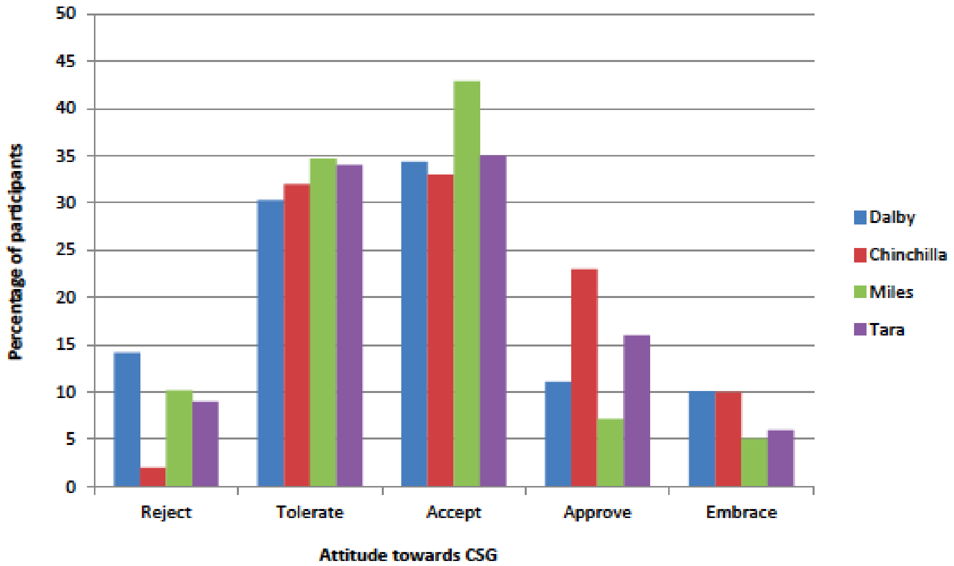
Negative impacts on local businesses also affect communities at the social level. The next section examines the social impacts in more detail.

2. Impacts on local communities

Unconventional gas development in Queensland's Darling Downs distresses local communities. Few people approve of the industry and even fewer believe it will improve conditions.

A recent CSIRO survey of the Western Darling Downs found that almost half the local population was "only just coping" with, "not coping" with or actively resisting the changes to their communities caused by unconventional gas development (see figure 4 below). This study was undertaken by researchers funded by the largest unconventional gas companies in Queensland, including Australia Pacific LNG and QGC.[8]

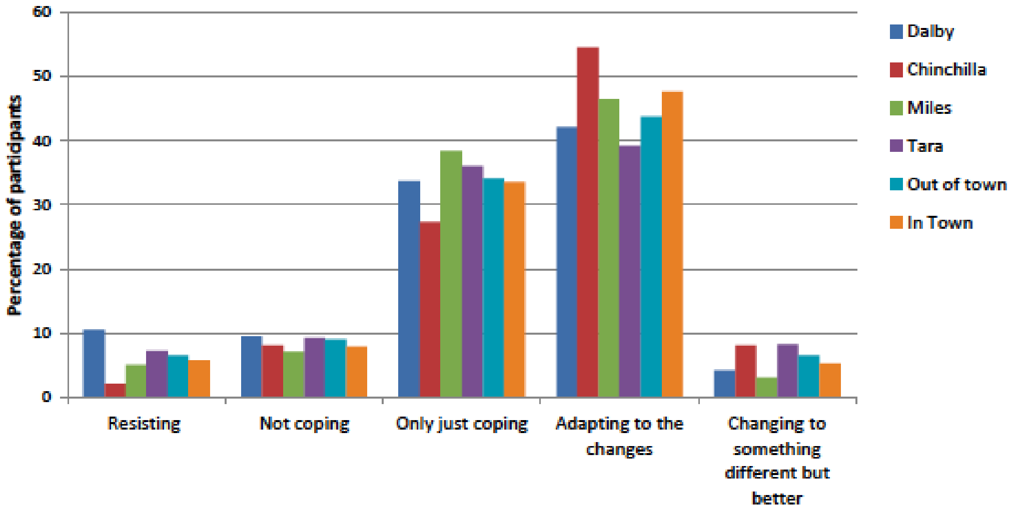
Figure 4: Attitudes towards unconventional gas in the region by suberegions (CSIRO)



Less than a quarter of people surveyed approved of the unconventional gas industry. Only 6% of people felt the community was improving as a result of the industry, while many were struggling to cope with the changes the industry had brought (see figure 5 below).

[8] Walton, A, McCrea, R & Leonard, R (2014). *CSIRO survey of community wellbeing and responding to change: Western Downs region in Queensland,* CSIRO Technical report: CSIRO, Australia.

Figure 5: Community responses to unconventional gas development in the Western Downs Queensland (CSIRO)

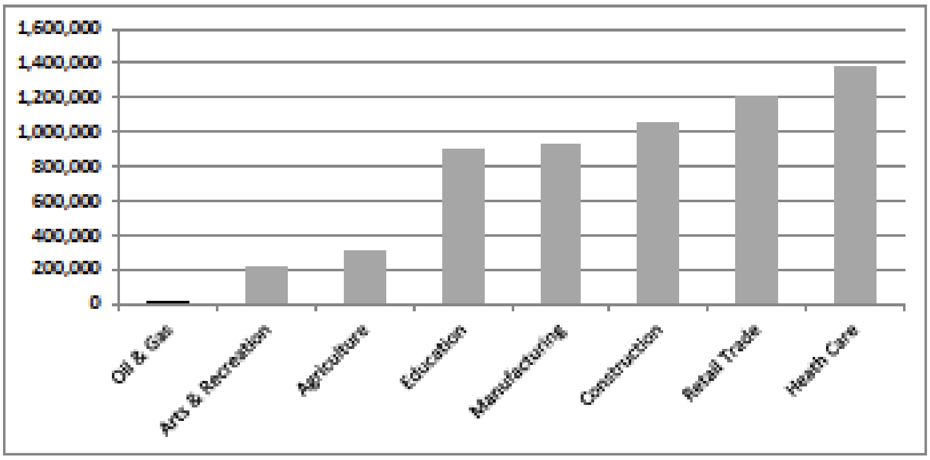


3. Unconventional gas does not employ many people.

According to the Australian Bureau of Statistics, in May 2015 the entire oil and gas industry in Australia employed 27,500 Australian workers, or less than a quarter of 1% of the Australian workforce.[9]

By way of comparison, the total employment provided by the oil and gas industry is considerably less than the retail hardware store Bunning's, which employs 33,000.[10]

Figure 6: Employment in Australia by selected industry



Employment in the gas industry is likely to decline. The vast majority of gas jobs are during the construction phase. As the construction phase winds up, the unconventional gas companies operating in Queensland are cutting their workforces by around 80%.[11]

Territorians seeking employment for any unconventional project in the Northern Territory will have to compete with experienced workers from interstate. The gas industry requires experienced, skilled workers. With the wind down of the CSG construction boom in Queensland, there is a large pool of highly-qualified workers who

---

[9] ABS (2013a). *6291.0.55.003 Labour Force, Australia, Detailed, Quarterly, September 2015*, Australian Bureau of Statistics, accessed 11/11/15, http://www.abs.gov.au/ausstats/abs@.nsf/mf/6202.0

[10] Bunnings (2013). *About Us: Who we are*, Bunnings, viewed 21 November 2013, http://www.bunnings.com.au/about-us.

[11] Bureau of Resource and Energy Economics, *Resource and Energy Major Projects 2013*.

are more likely to fill positions than unskilled Territorians with no experience in gas field construction and operation.

Experience in Queensland has shown that construction workforces are almost entirely male non-residential workers living in workers camps on the outskirts of towns. These workers are often referred to as fly-in, fly-out (FIFO) or drive-in, drive-out (DIDO). Few people from local regional communities are likely to be employed in either the construction or the operational phases of the gas fields.

If locals are employed on these projects, they are unlikely to be previously unemployed people. When the gas industry employs local people, they tend to be skilled workers who relocate from local manufacturing and agriculture.

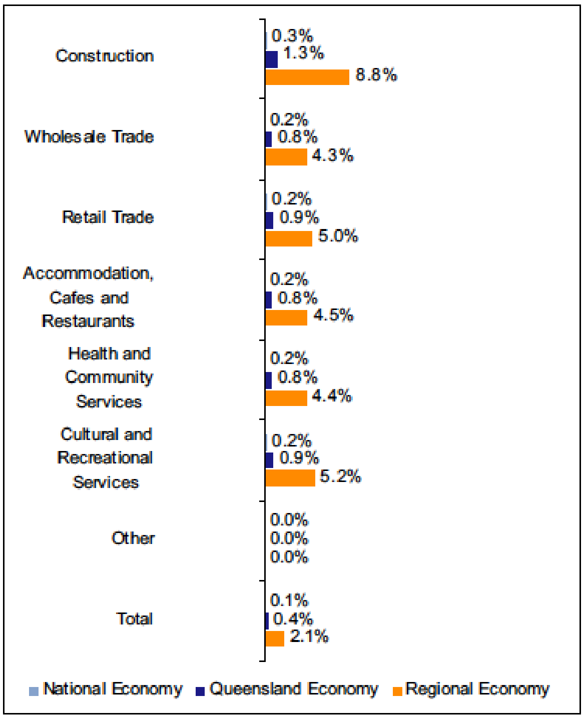
As explained above in section 1, this disrupts local businesses and forces them to compete with inflated gas industry wages to recruit or retain staff.

4. Promise versus reality

As discussed in section 3, unconventional gas extraction employs relatively few people. These jobs are mostly short term and include few people from local regional communities. The industry claims that the flow on effects result in people being employed elsewhere in the community. However recent research shows that these employment benefits have largely failed to eventuate.

For example, the original economic impact statement submitted to gain approval for the largest unconventional gas project in Queensland, Australia Pacific LNG (APLNG), claimed that the construction phase of the project would increase regional employment in the retail trade by 5 per cent, and in a range of regional service sectors by between 4.5 and 5.2 per cent.[12]

Figure 7: Australia Pacific LNG direct and indirect employment by industry



Source: KPMG, APLNG EIS Economic Impact Assessment report, Chart 5.3 p29

The reality was very different. At the height of the construction boom in 2013 a study was undertaken by the Gas Industry Social and Environmental Research Alliance (GISERA) into the local economic impacts of the unconventional gas boom.

[12] KPMG, *APLNG EIS Economic Impact Assessment report*, Chart 5.3 p29.

The study examined the actual economic impacts of unconventional gas development in Queensland's gas fields. As we can see in figure 5 below, the study found that in fact, while there was an increase in short term construction related jobs (construction and professional services), there were virtually no additional jobs in retail or manufacturing as a result of unconventional gas development.[13] A subsequent study by the same authors found that for every ten people employed in CSG, eighteen agricultural jobs were lost.[14]

Figure 8: Unconventional gas employment spillovers in different sectors of Queensland's Darling Downs economy

	Elasticity	Additional job for each new CSG job
Local goods sector		
Construction	0.832 (0.426) *	1.412
Professional services	0.704 (0.259) **	0.412
Retail trade	0.011 (0.140)	0.024
Services†	-0.205 (0.230)	-0.732
Traded sector		
Manufacturing	0.068 (0.199)	0.160

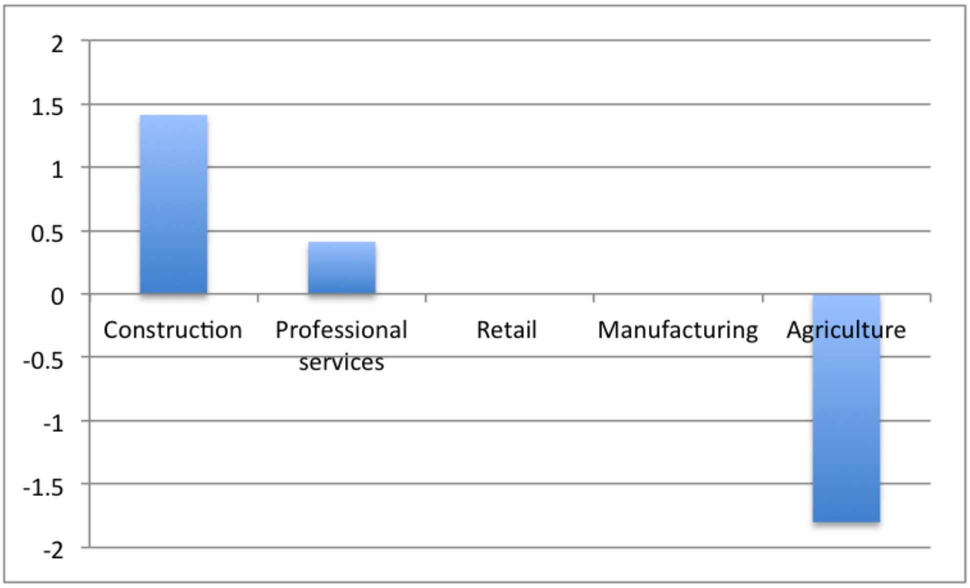
Notes: Elasticity values are 2SLS estimations for coefficient ψ in equation (2). The number of CSG wells in an SLA is used as instrument for the log change of mining employment. Values estimated using sample 3 (n = 48). F-stat first-stage = 10.74. Robust clustered std. errors at LGA levels in parentheses. *p < .10. **p < .05.
†Services sector include employment in accommodation, rental agencies, transport and 'other services'.

Source: Flemming and Measham (2013)

[13] Fleming, D & Measham, T (2013) *Local economic impacts of an unconventional energy boom: the coal seam gas industry in Australia. Report to the Gas Industry Social and Environmental Research Alliance (GISERA)*. June 2013. CSIRO, Canberra.

[14] Flemming, D & Measham, T (2015a) "Local economic impacts of an unconventional energy boom; The coal seam gas industry in Australia", *The Australian Journal of Agricultural and Resource Economics* 59(1) pp 78-94

Figure 9: Spillover job impacts per CSG job



Source: Flemming and Measham 2013 and 2015a

In other words, the unconventional gas boom had virtually no employment benefits outside of the gas industry itself. In the words of the authors, "job spillovers into non-mining employment are negligible". It also shows that agricultural jobs were lost and that the employment gains were almost entirely in short term construction jobs and professional services jobs (largely related to the construction phase).

The Queensland unconventional gas boom is one of the largest and most rapid resource expansions ever seen, and yet it led to virtually no increase in employment in local retail or manufacturing, and a significant loss of agricultural jobs.

The lack of any increase in retail employment in local communities is largely a result of the predominance of non-resident workers living in self-contained workers camps. These employees work long shifts that limit opportunities to spend their income in the local community.

The lack of flow on manufacturing jobs highlights industry's preference for sourcing materials and equipment from overseas. For example, the huge LNG export and processing facilities at Gladstone in Queensland were entirely designed and built overseas.

All three export terminals were built by the global oil and gas engineering company Bechtel. On their website, Bechtel promote their "efficiency" in not employing Australians. The website page shown in Figure 8 describes all three of the Gladstone LNG Processing plants and export terminals as being designed by Bechtel engineers in

Houston, Delhi and Shanghai, to be built in the Philippines, Indonesia and Thailand. The terminals were then floated over to Australia to be assembled.[15]

Figure 10: Bechtel description of design and construction process for their Curtis Island LNG terminals in Queensland

An efficient effort

Because of overlapping schedules, close proximity, and good cooperation, each project and all three customers have benefited from economies of scale and efficiency orchestrated by Bechtel.

For the sake of quality, speed, and cost control, Bechtel engineers in Houston, New Delhi, and Shanghai geared their designs for the three Curtis Island plants to modular construction. At Bechtel facilities in the Philippines, Indonesia, and Thailand, colleagues have been building some 250 modules for use in all three complexes.

Among the heaviest of 250 modular components: a propane chiller that weighs 2,500 metric tons—equivalent to more than five of the largest 747s, fully loaded.

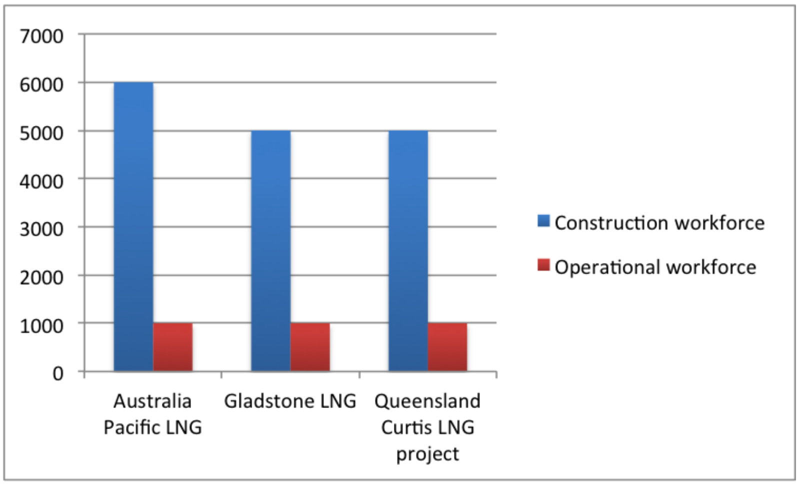
Source: Bechtel Website.

[15] Bechtel website, accessed 10 November 2015 http://www.bechtel.com/projects/curtis-island-lng/

5. Boom and bust

According to the Office of the Chief Economist of Australia, the three unconventional gas projects in Queensland employed 16,000 people during their brief[16] construction phase. The companies estimate that the workforce will be reduced by over 80% to 3,000 employees as the projects enter their operational phase.[17] This will represent less than 0.13% of Queensland's total workforce of over 2.3 million. [18]

Figure 11: Queensland unconventional gas operation and construction employment



Source: Office of the Chief Economist of Australia (2015).

The construction workforces may have been considerably smaller than reported by the Office of the Chief Economist. The office based the numbers on "fact sheets provided by the companies".[19] APLNG, the largest of Queensland's LNG projects says in its Economic Impact Assessment that "over the 11-year construction phase, there will be an approximate average of 3,300 people working on the Australia Pacific LNG project each year. Employment will peak from 2012 to 2014 inclusive". This is a little over half the number reported by the Office of the Chief Economist but would still represent more than a two-thirds reduction in the workforce between the construction and operational phase.

[16] The length of the construction period varies between the projects. In the case of Gladstone LNG, the construction period was 4 years. URS (2009) *GLNG Economic Impact Statement*.

[17] Office of the Chief Economist, *Resources and Energy Major Projects list April 2015,* accessed 11 November 2015, http://www.industry.gov.au/Office-of-the-Chief-Economist/Publications/Pages/Resources-and-energy-major-projects.aspx

[18] ABS Labour Force Statistics.

[19] Correspondence with the Office of the Chief Economist.

Any unconventional gas project in the Northern Territory would employ far fewer workers than in Queensland.

A large proportion of both the construction and operational workforce in Queensland worked on assembling the LNG terminals at Gladstone. Additional LNG terminals will not be required in the Northern Territory, as the gas will be exported via the Queensland terminals.

There is also likely to be a large pool of experienced gas workers in Western Australia and Queensland who are well placed to fill Northern Territory unconventional gas jobs. The three Queensland LNG terminals, the Northern Territory Inpex project and several Western Australian LNG terminals and offshore gas fields were all built simultaneously. The decision to allow all these projects to be built simultaneously created an acute skills shortage at the time. With the wind down of the construction phase of these projects there is an abundance of interstate skilled gas construction workers who will be far better placed to work in any gas projects in the NT than unemployed NT residents who lack these skills.

To the extent that NT residents are employed, they are likely to be skilled workers already employed in other industries, particularly manufacturing and agriculture. This effect drives up costs for other industries as they are forced to compete with the oil and gas industry for skilled workers.

6. Impacts on manufacturing

The rapid expansion of unconventional gas projects has damaged Australia's manufacturing industry through its labour market impacts and effect on gas prices.

Economic modelling by the Queensland unconventional gas company Arrow LNG for its Economic Impact Assessment found that this project would displace $441.5 million worth of manufacturing output and 1,000 manufacturing jobs in Queensland.[20]

Arrow LNG is just one of the four large unconventional gas projects in Queensland. The full employment impacts of this single project can be seen in Figure 12 below.

While the modelling suggests the project would a create a considerable number of short term construction jobs, these jobs come at the expense of long term jobs in other sectors, particularly manufacturing.

Once extinguished, manufacturing activity is difficult to rebuild. Plants and equipment require a large upfront investment, but only deliver returns over the long term. If a region is likely to experience further disruption from large resource projects, investors are unlikely to have confidence in manufacturing.

Figure 12: Average Annual Impact on Employment by Industry in Queensland of Arrow LNG project

Industry	Change in Employment (FTEs)			
	2013-14 to 2016-17 (Phase 1 Construction)	2018-19 to 2021-22 (Phase 1 Steady State Operation)	2022-23 to 2024-25 (Phase 2 Construction) (a)	2026-27 to 2029-30 (Phase 2 Steady State Operation) (a)
Queensland				
Agriculture	-59	-24	-66	-42
Mining	-65	-28	-69	-50
Manufacturing	-1,089	-25	-804	-200
Electricity and water	-10	25	39	55
Construction	1,833	127	1,325	257
Trade	221	58	255	130
Transport and storage	-246	-27	-186	-37
Business, finance and insurance services	-132	83	119	166
Public administration, defence, health and education	29	-6	-45	-19
Recreation and other services	22	-4	1	-8
Ownership of dwellings	6	0	3	0
Total Change in Employment in Queensland	**511**	**180**	**571**	**251**

Note: (a) It should be noted that operation of Phase 1 (trains 1 and 2) is ongoing during these time periods.
Source: Prime Research (unpublished).

Source: AEC Group (2011) Arrow LNG Economic Impact Assessment, table 5.3 p.43

[20] Grudnoff, M (2015) *An analysis of the economic impacts of Arrow Energy's Gladstone LNG Plant*.

As well as higher labour costs, unconventional gas projects have significantly increased the cost of gas for Australian manufacturers.

In their Economic Impact Assessment of 2010, GLNG noted that “a relatively mild increase in gas prices associated with the QCLNG Project may occur in the eastern Australian market”.[21]

At the same time Santos, the lead GLNG joint venture partner told its investors that that the linkage of Australian gas prices to global prices as a result of unconventional gas LNG exports would “transform” its asset base by exposing all but legacy domestic gas contracts to oil price rises. In other words, the gas that they had been selling to Australian customers would now be linked to Asian prices, which at the time were high for Australian prices. Increasing the price they were able to sell gas to Australian customers for, particularly manufacturers, was central to their commercial strategy, not an unintended by-product of it.

In fact, linking Australian domestic gas prices to higher Asian prices has more than doubled the wholesale gas price.

The recent collapse in the oil price, and subsequently Asian “oil linked” gas prices, has not caused a commensurate reduction in the price of gas being offered to manufacturers. This has led to claims of “cartel like behaviour”.[22] The ACCC’s ongoing inquiry into the East Coast gas market is investigating “the existence of, or potential for, anti-competitive behaviour and the impact of such behaviour on purchasers of gas”.[23]

Economic modelling by Deloitte Access Consulting shows that east coast gas price rises caused by unconventional gas exports have created an $81 billion windfall for the gas industry (mostly global oil and gas majors), but will cost the manufacturing industry $118 billion.[24] (see figure 13 below).

[21] *GLNG Economic Impact Statement,* volume 8 chapter 10, p 12.

[22] West, M (October 2015) “East coast gas market has all the hallmarks of a cartel”, accessed 11 November 2015, http://www.smh.com.au/business/comment-and-analysis/east-coast-gas-market-has-all-the-hallmarks-of-a-cartel-20151011-gk6b4i.html

[23] ACCC Project Overview, *East Coast Gas Inquiry,* accessed 11 November 2015, https://www.accc.gov.au/regulated-infrastructure/energy/east-coast-gas-inquiry-2015

[24] Deloitte Access Economics (2014) *Gas market transformations–Economic consequences for the manufacturing sector,* Table 1, p 3.

Figure 13: Industry output impacts for Australia as a result of gas price increases

Table i: Industry output impacts for Australia for the years 2015, 2018 and 2021 and cumulative Net Present Value (NPV) of output impacts over 2014 - 2021

	Value of difference from baseline			% difference			NPV
	2015	2018	2021	2015	2018	2021	Cumulative impact over 2014-2021
SKM scenario							
Output ($ million)							
Manufacturing	-23,199	-22,259	-30,386	-3.97	-3.48	-4.38	-118,069
Gas	8,922	17,672	24,225	47.81	65.63	57.07	80,746
Mining	-7,226	-6,031	-9,679	-3.55	-2.69	-3.96	-33,804
Agriculture	-1,110	-798	-1,430	-1.98	-1.32	-2.21	-4,705
Electricity and Water	-1,962	-1,989	-2,204	-3.36	-3.09	-3.12	-10,269
Construction and Trade	18,049	2,443	13,265	2.80	0.34	1.69	38,519
Transport	-2,328	-1,988	-3,288	-1.68	-1.31	-2.00	-11,044
Commercial & Services	3,015	-897	649	0.26	-0.07	0.05	1,695

Source: Deloitte Access Economics
Note: The discount rate of 7% was used to calculate the NPV figure.

Source: Deloitte Access Economics (2014)

No amount of additional gas extraction in the Northern Territory or elsewhere will reduce gas prices in Australia, as all gas will now go to the Asian market. As the NSW Independent Pricing and Regulatory Tribunal (IPART) put it:

> The increase in regulated retail gas prices 2014/15 reflects increased wholesale gas costs, as eastern Australia becomes part of a single global market for commodity gas, as well as increasing network charges.[25]

[25] *Inquiry into the supply and cost of gas liquid fuels in NSW, IPART 2014*, accessed 10 July 2015, http://www.parliament.nsw.gov.au/prod/parlment/committee.nsf/0/efb3f0c1908f7b21ca257dc70005b1b 2/$FILE/0023%20-%20IPART.pdf

7. Big numbers, small benefits

Gas companies often cite the amount of money they invest or the value of the gas they sell as proof of the economic benefits of their projects.

However these numbers say little about benefits for Australians if the money invested in a project is spent on equipment from overseas, profits flow to foreign investors and the companies pay little in tax or royalties.

The oil and gas industry in Australia is over 80% foreign owned,[26] which means that over 80% of the profits go directly off shore. It imports almost all its equipment and pays very low rates of tax. The theoretical company tax rate in Australia is 30%. All industries are able to claim exemptions and the average effective company tax rate of all industries in 2011/12 was 17.6%. That year the oil and gas industry in Australia paid an effective company tax rate of 5.4%.[27]

The Queensland LNG projects were approved without an estimate of royalty payments to the state government. Subsequent Queensland Treasury estimates of gas royalties have been slashed by half with Treasury acknowledging that original estimates were "overcooked" [28] APLNG is now challenging the Queensland Government's royalties rulings.[29]

Very low corporate tax paid by the proponents of these projects (Origin 3.6%, Shell .35%, Santos 0.07%) have been attributed to practices such as transfer pricing[30]

The big numbers for capital value or change in GDP tell us little about the benefit of gas exports to the wider Australian economy and community. As the Reserve Bank of Australia concluded in a recent paper on Australian LNG, while Australian production of LNG is expected to ramp up substantially over the next few years:

---

[26] Calculations by The Australia Institute based on published 2P reserves and production.

[27] *Taxation statistics 2011–12, Table 4: Company tax, Selected items by industry*, ABS 81550DO002_201112 Australian Industry.

[28] Ludlow, M (February 2016) "Queensland faces LNG royalties crunch", *The Australian,* accessed 1 April 2016, http://www.afr.com/business/energy/gas/queensland-faces-lng-royalties-crunch-20160207-gmnle0

[29] Ludlow (February 2016)

[30] Ludlow, M (April 2016) "Origin LNG consortium used 'transfer pricing' to cut taxes", *Australian Financial Review,* http://www.afr.com/news/politics/origin-lng-consortium-used-transfer-pricing-to-cut-taxes-20160426-gofb0q

The effect on Australian living standards will be less noticeable than this given the low employment intensity of LNG production, the high level of foreign ownership of the LNG industry and, in the near term, the use of deductions on taxation payments.[31]

[31] Cassidy, N & Kosev, M (2015) *Australia and the Global LNG Market,* RBA.

4. The Industrial footprint of shale gas

One important way in which unconventional gas development differs from other types of resource development is that it covers far greater areas. Mines are generally highly concentrated with relatively small footprints, but unconventional gas fields often cover tens of thousands of square kilometres with an industrial grid of wells, pipelines, access roads, compressor stations and water treatment plants.

The most mature shale gas field in the US, the Barnett Shale, has an average of 1.15 wells per square kilometre, but is as high as 6 wells per square kilometre due to “infill drilling” needed to extract gas as fields deplete.[32]

Every shale gas well needs to be fracked multiple times. Every frack requires 11–34 million litres of water[33] equating to 360–11,000 truckloads and “80–300 tonnes of industrial chemicals.[34] This is potentially an enormous increase in truck movements on the Territory’s roads and will inevitable impact other road users.

Pennsylvania in the United States has a mature shale gas industry. A gas industry study last year in Pennsylvania found that more than 6% of gas wells leaked, and up to 75% of wells could have some form of integrity failure.[35] In Pennsylvania more than 240 private drinking water wells have been contaminated or have dried up as the result of drilling and fracking operations over a seven-year period.[36]

---

[32] *Shale Gas Information Platform SHIP. GFZ,* accessed 10 November 2015, http://www.shale-gas-information-platform.org/categories/operations/the-basics.html

[33] *UNEP Global Environmental Alert Service: Gas Fracking: Can we safely squeeze the rocks?*

[34] Hazen and Sawyer (22 December 2009) *Impact Assessment of Natural Gas Production in the New York City Water Supply Watershed*.

[35] Davies, RJ, Almond, S, Ward, RS, Jackson, RB, Adams, C, Worrall, F, ... Whitehead, MA (2014) “Oil and gas wells and their integrity: Implications for shale and unconventional resource exploitation”, *Marine and Petroleum Geology,* 56, 239-254. doi: 10.1016/j.marpetgeo.2014.03.001

[36] Concerned Health Professionals of New York & Physicians for Social Responsibility (14 October 2015) *Compendium of scientific, medical, and media findings demonstrating risks and harms of fracking (unconventional gas and oil extraction)* (3rd ed.), http://concernedhealthny.org/compendium/

Conclusion

Gas companies routinely exaggerate the economic and jobs benefits of their projects. Too often policy makers accept these claims unquestioningly.

The Northern Territory is fortunate to have the Queensland unconventional gas experiment to reflect upon. The Queensland experience is that most of the economic benefits do not materialise, and serious collateral damage is done to existing industries and local communities.

If policy makers in the Northern Territory naively accept the economic claims of speculative gas companies and use taxpayer money to support this industry, Territorians will live the consequences for decades to come.

Passing gas

Economic myths around the Northern Territory's North East Gas Interconnector pipeline

August 2015

Rod Campbell

Briefing note

About TAI

The Australia Institute is an independent public policy think tank based in Canberra. It is funded by donations from philanthropic trusts and individuals and commissioned research. Since its launch in 1994, the Institute has carried out highly influential research on a broad range of economic, social and environmental issues.

Our philosophy

As we begin the 21st century, new dilemmas confront our society and our planet. Unprecedented levels of consumption co-exist with extreme poverty. Through new technology we are more connected than we have ever been, yet civic engagement is declining. Environmental neglect continues despite heightened ecological awareness. A better balance is urgently needed.

The Australia Institute's directors, staff and supporters represent a broad range of views and priorities. What unites us is a belief that through a combination of research and creativity we can promote new solutions and ways of thinking.

Our purpose—'Research that matters'

The Institute aims to foster informed debate about our culture, our economy and our environment and bring greater accountability to the democratic process. Our goal is to gather, interpret and communicate evidence in order to both diagnose the problems we face and propose new solutions to tackle them.

The Institute is wholly independent and not affiliated with any other organisation. As an Approved Research Institute, donations to its Research Fund are tax deductible for the donor. Anyone wishing to donate can do so via the website at https://www.tai.org.au or by calling the Institute on 02 6130 0530. Our secure and user-friendly website allows donors to make either one-off or regular monthly donations and we encourage everyone who can to donate in this way as it assists our research in the most significant manner.

Level 5, 131 City Walk
Canberra, ACT 2601
Tel: (02) 61300530
Email: mail@tai.org.au
Website: www.tai.org.au

Summary

The North East Gas Interconnector (NEGI) is a proposed gas pipeline between the Northern Territory and the eastern states. The project is strongly endorsed by gas companies, the Territory government and governments in other states, but analysis is lacking as to the actual benefits to Territorians and the rest of Australia.

While there is a shortage of analysis, there is no shortage of hyperbole. This paper busts four myths around the NEGI.

1. **The project is important for solving the east coast gas ‘crisis’.**

There is no east coast gas crisis. The eastern states are producing more gas than ever before and this is set to increase in the coming years. This is clearly shown in industry publications and is acknowledged by the Australian Energy Market Operator. Gas demand on the east coast is declining in response to high prices brought on by the recent commencement of exports to the world market.

2. **The NEGI will reduce household gas prices**

Australian domestic gas markets are now linked to world prices. Any production facilitated by the NEGI would have a minimal impact on world supply and therefore on Australian domestic gas prices.

3. **The NEGI is important for NT government revenue**

The NEGI is likely to make very little difference to the NT government’s revenue. At present, royalties from all mining, petroleum and gas extraction makes up only 2.9 per cent of the NT government’s revenue, $164 million out of a total $5,716 million in 2014-15. Put another way, 97 per cent of services in the NT are paid for by sources other than the mining and gas industries. The potential increase in gas extraction with the NEGI will not make a significant change to this.

4. **The NEGI will bring jobs and infrastructure to remote areas**

The gas industry is highly capital intensive and does not make many jobs once infrastructure is constructed. While several thousand people work on constructing the Ichthys project for example, at the time of the last 2011 census just 159 Territorians worked in the oil and gas industry. Nation-wide employment in oil and gas is 28,700, a fraction of one per cent of Australia’s 12 million employed people.

There is no incentive for gas companies to build any roads that they do not need and beyond the construction period they will not need to use those very often. Government investment in infrastructure around the NEGI must be subject to rigorous assessment and cost benefit analysis. The government should be putting its scarce resources into infrastructure projects that benefit Territorians, not gas companies.

Introduction

The North East Gas Interconnector (NEGI) is a proposed gas pipeline between the Northern Territory and the eastern states. A memorandum of understanding has been signed between the Territory and New South Wales governments to support the project.[1]

The NEGI is not certain to go ahead. With gas prices declining over the last year, the financial case for the project is uncertain. Controversy has surrounded the tender process, following revelations that one shortlisted bidder was a company with only $100 in equity and an address in suburban Sydney.[2]

Beyond these issues, huge claims have been made about the potential of the NEGI to provide benefits to Territorians and the eastern states. In this paper we look at four key areas relating to:

- East coast gas 'crisis'
- Domestic gas prices
- NT government revenue
- Jobs and infrastructure

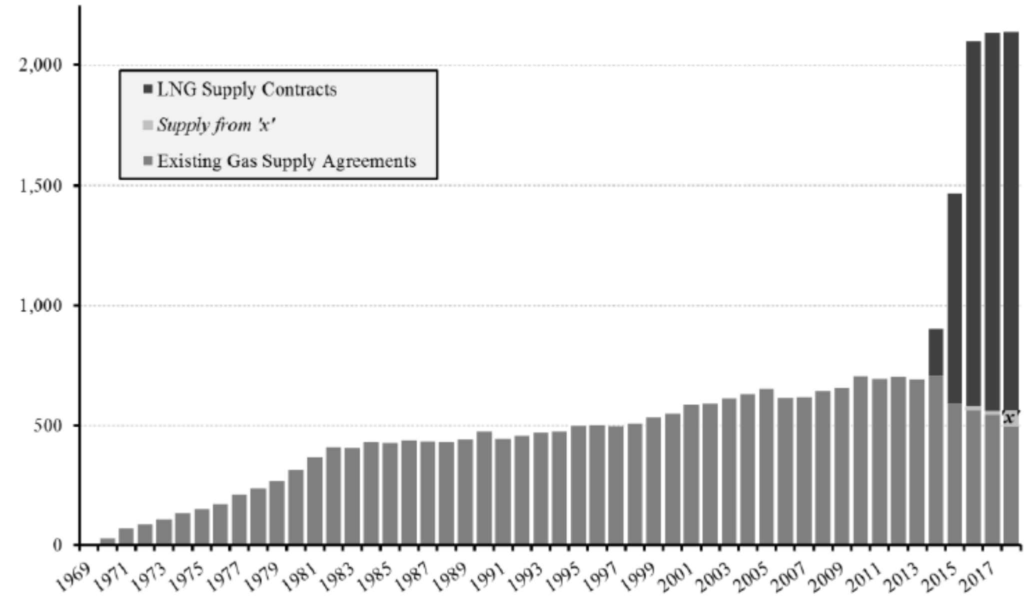
[1] http://dcm.nt.gov.au/__data/assets/pdf_file/0009/64872/Signed_MoU_November_7_2014.pdf
[2] http://www.theaustralian.com.au/business/mining-energy/firm-to-reap-1m-if-nt-pipeline-tender-fails/story-e6frg9df-1227353928414

1. The project is important for solving the east coast gas 'crisis'.

> ***[The NEGI is] a matter of urgency for the eastern states which are fast approaching an energy security crisis.***
>
> NT Chief Minister Adam Giles[3]

There is no east coast gas crisis. The eastern states are producing more gas than ever before and this is set to increase in the coming years. This is clearly shown in Figure 1 below, taken from an industry publication:

Figure 1: East coast gas supply 1969-2018



Source: AGL 'Solving for 'x' – the NSW Gas Supply Cliff', p8

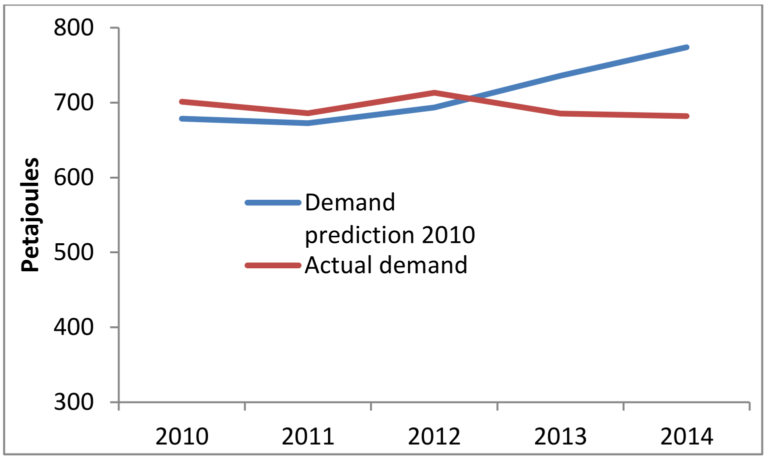
Figure 1 comes from a paper published by gas company, AGL. It shows gas supply on the east coast. In grey is supply to the domestic market, which grew slowly over decades and peaked between 2009 and 2014. From 2014-15 we see the huge increases in supply from the east coast, as export facilities come online.

The east coast has not traditionally exported gas, but new facilities in Gladstone, Queensland, have now linked the east coast to the world market. World demand is much bigger and prices are much higher. This is the reason why east coast demand and supply have increased – the gas is sold overseas.

The Australian Energy Market Operator (AEMO) was predicting that domestic demand for gas on the east coast would grow from 2010, creating fears of a shortage when export facilities also came online. However, as exports drew nearer gas prices rose and the east coast market responded by using less gas, as shown in Figure 2 below:

[3] http://newsroom.nt.gov.au/mediaRelease/10047

Figure 2: Predicted and actual east coast gas demand



Source: AEMO Gas statement of opportunities

AEMO is now forecasting that domestic east coast gas demand will decline below current levels out to at least 2030. Other researchers suggest NSW gas demand could halve in the coming years.[4]

2. The NEGI will reduce household gas prices

> ***By establishing a national grid we can help secure our energy needs and put downward pressure on household bills.***
>
> NSW Premier Mike Baird[5]

Because the east coast gas market is now connected to the world market through the Gladstone export terminals, the east coast gas price is connected to the world price. This is why east coast gas prices have tripled – the traditional prices of $3 to $4 dollars per gigajoule have gone up to match world prices at $9 dollars per gigajoule.[6]

With the opening of the Gladstone export facilities gas producers can choose to supply gas to either domestic or international customers. Domestic gas prices will therefore never go below the international price because if they did gas producers would sell gas at the higher international price rather than to domestic customers.

The only way east coast prices can go down is if world prices go down. Recent reductions in the world prices for oil and gas have given some price relief to east coast gas users, but supply from Northern Territory gas reserves that would use the NEGI would not be likely to significantly reduce this price.

---

[4] Melbourne Energy Institute, 2015, *The dash from gas. Could demand in New South Wales fall to half?* http://www.tai.org.au/content/dash-gas-could-demand-new-south-wales-fall-half

[5] http://dcm.nt.gov.au/__data/assets/pdf_file/0003/64299/nsw-nt-gas-pipline-mou-medial-release.pdf

[6] For further discussion see Grudnoff, 2013, *Cooking up a price rise*, http://www.tai.org.au/content/cooking-price-rise

3. The NEGI is important for NT government revenue

> ***The prize here for the Northern Territory is economic independence from Canberra.***
>
> Richard Cottee, CEO of Central Petroleum[7]

The NEGI is likely to make very little difference to the NT government's revenue. At present, royalties from all mining, petroleum and gas extraction makes up only 2.9 per cent of the NT government's revenue, $164 million out of a total $5,716 million in 2014-15.[8] Put another way, 97 per cent of services in the NT are paid for by sources other than the mining and gas industries. The potential increase in gas extraction with the NEGI will not make a significant change to this.

The reality of gas royalties is shown in the Queensland budget. In the last financial year Queensland earned just $51 million in gas royalties out of over $50 billion in revenue. When Queensland gas production gets to capacity in 2018-19, royalties are expected to get to $518 million, depending on gas prices and production rates. Putting this in the context of the rest of the budget, this represents 0.1 per cent of Queensland Government revenue this year, increasing to 0.9 per cent by 2018-19, when the current gas export plants should be at full production. Even at full production, Queensland's government will get less than one per cent of its revenues from the coal seam gas industry. 99 per cent of Queensland's public sector will be funded by other industries.[9]

Furthermore, the gas industry and the NEGI will receive considerable subsidy from the NT taxpayer. Despite the government's claims that it will be funded by the private sector, this year's "Budget Highlights" include:

> *$9.2 million to drive private sector development of a gas pipeline*[10]

This represents $9.2 million dollars subsidising the gas industry that could have been spent on social services such as schools and hospitals in the Territory. This is far from an isolated occurrence. Analysis of NT budget papers from 2008-09 to 2013-14 show that mining and fossil fuel companies benefited from $406 million dollars' worth of assistance measures. Assistance measures include the government's Resource Industry Development program and infrastructure provision.[11]

---

[7] http://www.abc.net.au/news/2015-04-02/gas-pipeline-interconnector/6367606

[8] NT Government budget papers, 2015. See Budget paper 3, p106, http://www.budget.nt.gov.au/wp-content/uploads/2015/04/Budget-2015-16_Budget-Paper-3.pdf

[9] See Queensland Government budget papers, 2015, Budget paper 2, p191, http://budget.qld.gov.au/budget-papers/documents/bp2-2015-16.pdf.
See also Campbell, 2015, *Laughing Gas: Fossil Fuels And The Queensland Budget*, https://newmatilda.com/2015/07/15/laughing-gas-fossil-fuels-and-queensland-budget

[10] NT Government budget papers, 2015. See Budget paper 3, p30, http://www.budget.nt.gov.au/wp-content/uploads/2015/04/Budget-2015-16_Budget-Paper-3.pdf

[11] The Australia Institute, 2014, *Mining the age of entitlement: State government assistance to the minerals and fossil fuel sector*, http://tai.org.au/content/mining-age-entitlement

Nor is the NT alone in spending money on its gas industry for little return. The development of the Northwest Shelf and government spending on it has been a running sore in WA-Commonwealth relations for many years:

> *The cost of Western Australia's assistance to the North West Shelf project (e.g. payment of subsidies to the State's power utility to help cover the losses it initially incurred under crucial 'take or pay' gas contracts) is estimated to be around $8 billion.*[12]

Queensland's Treasury also cautions against excessive spending on mining and fossil fuel projects:

> *Governments face budget constraints and spending on mining related infrastructure means less infrastructure spending in other areas, including social infrastructure such as hospitals and schools. For many projects directly related to assisting mining industry development, such as land acquisitions for state development areas, the expected timeframes for cost recovery are extremely long (sometimes decades). The opportunity cost of this use of limited funds is a real cost to government and the community.*[13]

Territory taxpayers should be watching the budgets and their wallets if their government is determined to "drive private sector development" using public money.

4. The NEGI will bring jobs and infrastructure to remote areas

> ***The pipeline will generate investment in regional infrastructure which means real jobs in the bush and roads that open up our remote areas, not only for the pipeline, but for other economic activity as well.***
>
> ***This is a critical nation-building project with the potential to create jobs and industry growth in the Northern Territory, particularly in regional areas.***
>
> NT Chief Minister Adam Giles[14]

Jobs

The gas industry is highly capital intensive and does not make many jobs once infrastructure is constructed. While several thousand people work on constructing the Ichthys project for example, at the time of the last 2011 census just 159 Territorians worked in the oil and gas industry. Nation-wide employment in oil and gas is 28,700, a fraction of one per cent of Australia's 12 million employed people.

---

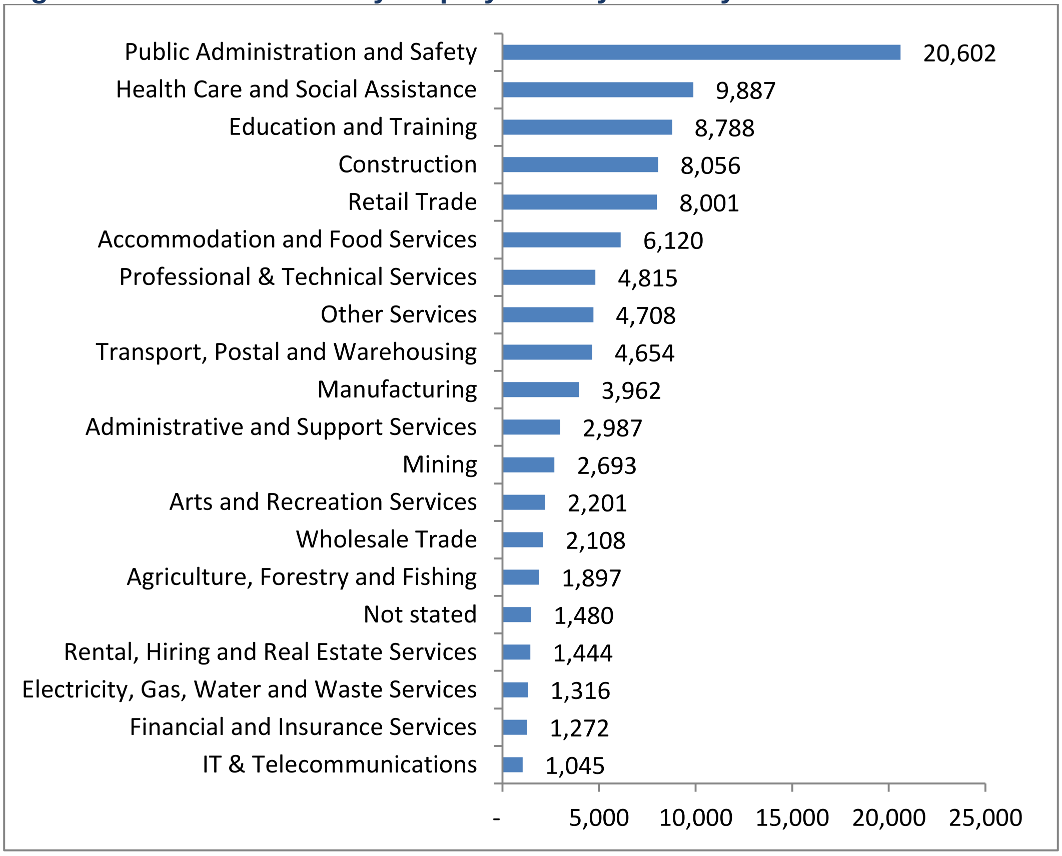
[12] WA Government, 2011, *GST Distribution Review: WA Submission*, p13, http://www.gstdistributionreview.gov.au/content/submissions/downloads/issues_paper/wa_gov.pdf

[13] Queensland Treasury, 2013, *Queensland Treasury Response to Commonwealth Grants Commission: Response to Terms of Reference for Commonwealth Grants Commission 2015 Methodology Review*, https://www.cgc.gov.au/index.php?option=com_attachments&task=download&id=1728

[14] http://newsroom.nt.gov.au/mediaRelease/10713?y=2013&m=3

All mining and gas makes up just three per cent of employment in the Northern Territory,as shown in Figure 3 below:

Figure 3: Northern Territory employment by industry

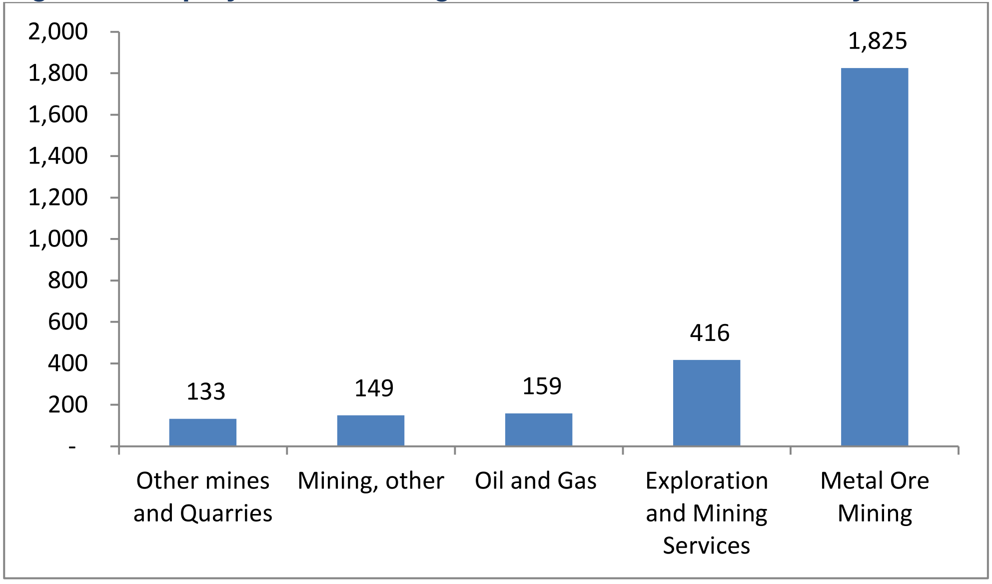


Source: ABS census, 2011, accessed through Tablebuilder Basic

Figure 3 shows that far bigger employers in the Territory are the public service, health care and education. While the Territory's public service is proportionately larger than other states, the predominance of service sectors within employment is common throughout Australia and most developed economies.

Within the mining industry, gas is one of the lowest employing, as shown in Figure 4 below:

Figure 4: Employment in mining industries, Northern Territory



Source: ABS census, 2011, accessed through Tablebuilder Basic

These figures show that if the Northern Territory government wants to create jobs, the gas industry is almost the worst place it should be directing its energy and revenue. Service industries, health and education are far more important employers than the extractive industries.

Infrastructure

If the construction of the NEGI is to bring investment in roads and other public infrastructure to remote areas, other than those needed for use by the gas industry, conditions will need to be negotiated very early and transparently by the Northern Territory government. There is no incentive for gas companies to build any roads that they do not need and beyond the construction period they will not need to use those very often.

Government investment in infrastructure around the NEGI must be subject to rigorous assessment and cost benefit analysis. The government should be putting its scarce resources into infrastructure projects that benefit Territorians, not gas companies. Government investment around the NEGI has high potential to cross-subsidise the pipeline while taking funding away from other potentially more beneficial and efficient uses.

Conclusion

The NEGI is not a “critical nation-building project”. It is a project that would benefit gas companies wanting to develop unconventional gas reserves in the Territory by giving them access to the east coast market and its export facilities. The project limited benefit to eastern states who have ample gas supply, albeit at prices far higher than has historically been the case due to exports through Gladstone. These prices will not be materially affected by the NEGI.

The potential gas royalties for the Territory should be seen in the context of the Territory budget. All mining royalties make up around three per cent of the Territory’s revenue. At best the NEGI would make a marginal difference to this. Worse, the NT taxpayer is already spending millions on promoting the project, despite its dubious financial viability.

The NEGI would create some temporary construction jobs, but very few long term jobs. Construction jobs are likely to be fly-in-fly-out and are unlikely to provide employment and training for remote communities. Any roads and infrastructure should be paid for by the developers, with government investment subject to rigorous assessment relative to its many other spending priorities.

Given the gas industry's modest contribution to employment and government revenue in any state, the NEGI will not bring major benefits to the Territory. Territorians should be wary of government and industry hyperbole and keep their hands on their wallets.