22nd May 2017

NSW Government,
Planning and Environment,
Major Projects Assessments,
Narrabri Gas Project,

Madam/Sir,

Re: **Assessment of the Narrabri Gas Project**

We thank you for the opportunity to make a submission on the Narrabri Gas Project..

This Project has implications that transcend the borders of NSW.

It is with the national implications in mind that the Bayside Climate Change Action Group is making this submission, hereby attached.

Sincerely

David Rothfield
Acting President
Bayside Climate Change Action Group

14B Ebden Ave.
BLACK ROCK VIC 3193

Submission to NSW Government - Planning & Environment
Major Projects Assessments Narrabri Gas Project
22nd May 2017

*This submission is by **The Bayside Climate Change Action Group** (BCCAG) in Victoria. BCCAG's vision is 'A safe climate for all'. We work to raise awareness about the consequences of climate change, to influence decision makers at all levels of government to implement necessary mitigation strategies and to encourage sustainable practices amongst Bayside residents.*

Summary

This submission relates to the Environmental Impacts Statement (EIS) submitted by Santos in relation to its proposed Narrabri Gas Project. Having studied the EIS, the Bayside Climate Change Action Group (BCCAG) strongly objects to this project. We are confident that others closer to the locality than we are, will find objections arising from unacceptable risks to the immediate environment. Our submission, places the project in a wider context, that of its impact on Australia's greenhouse gas emissions, and potentially our ability to meet our international climate change commitments.

The risks of substantial fugitive emissions are explored and shown to be a cause of extreme concern to anyone who wishes to embark on a serious policy of emissions reduction in response to climate change. We furthermore show that, contrary to popular perception, the demand for gas on the domestic market is actually declining as alternative renewable energy sources become more cost competitive. Allowing CSG projects such as this, with its many attendant risks works contrary to policies aimed at mitigating the impacts of climate change.

Introduction

We live in a world threatened with the dramatic and devastating consequences of climate change. The Australian Government has joined the global community in committing to limiting global warming and transitioning to a zero-carbon economy by mid-century. With extreme weather events, such as Cyclone Debbie setting new norms and record ocean temperatures bleaching the Great Barrier Reef now for two consecutive years, we are reminded of the consequences of ignoring the risks that climate change poses to the fabric of our way of life.

It is in this context that planning authorities must view regional energy production plans such as the Narrabri Coal Seam Gas Project. The crucial test for this project is whether Coal Seam Gas production has a proven track record of reducing emissions or whether undeclared and unmeasured fugitive emissions actually mask a significant addition to declared emissions. Planners must also question the validity of such a large, disruptive CSG project, ostensibly needed for the domestic market, at a time when the domestic gas market is shrinking and being replaced by more cost effective renewable energy systems.

Quantifying Greenhouse Gas Emissions

According to the Santos EIS, ' ...The most material greenhouse gas emissions from the project are associated with carbon dioxide venting and combustion of fuel during gas processing. .'. That Santos can overlook the potential contribution of fugitive methane emissions on such a far-flung project is astounding, given the substantial evidence now available of the presence of high methane levels in CSG production areas.

In 2014, Scientific American quoted two studies that concluded that, on a global scale, gas fields may be leaking enough methane to make the fuel as polluting as coal for the climate (Appx 1.).

In 2016 The Melbourne Energy Institute (MEI) published a review of current and future methane emissions from Australian unconventional oil and gas production. (Appx 2.) This review includes the following assessments.

- There is significant uncertainty about methane emission estimates reported by oil and gas producers to the Australian Government.
- Current Australian methane emission estimation methods ignore this potential source (of migratory or fugitive emissions).
- Migratory emissions could significantly increase with continued depressurisation of the coal seams.
- If methane emissions from unconventional gas production are being significantly under-reported, this could have a large impact on Australia's national greenhouse gas (GHG) accounts.

Until now, estimates of fugitive emissions have been based on those occurring at the point of combustion only. This may have been valid when production took place at large, central industrial locations. However, the CSG production process is spread over a far-flung scattered network encompassing a range of activities from exploratory drillings at multiple sites, sinking of multiple production wells, transport of gas via an interconnected network of hundreds of kilometres of pipes and various control devices and processing at a remote central processing plant. There is evidence of varying degrees of leakage taking place at all of these production stages.

Do we need more gas?

Until now, governments and industry have promoted natural gas as a necessary 'transition fuel', between coal fired generation and renewables. This belief arose during a time when gas was considered cheap and renewables were considered expensive.

This is no longer the case. Gas prices have risen dramatically in recent years as Australian gas has become available on the international market. Over the same period, wind and solar generation costs have plummeted so that today they can, in most situations, compete with new coal. As a result, we have witnessed a decline in gas demand across Eastern Australia.

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The MEI studied the causes of this trend in a report published in 2015, *Switching off gas – An examination of declining gas demand in eastern Australia* (Appx 3.) The key points from this report include:

- According to the Australian Energy Market Operator (AEMO), since 2012, the amount of gas consumed in eastern Australia has declined each year and will continue to decline.
- With the recognition of declining demand, AEMO's previous concerns about gas supply shortfalls were withdrawn.
- Developing coal seam gas has proven to not be as easy, nor as cheap as had been expected – which has contributed to gas price pressures.
- Retail gas prices are increasing, also due to increasing distribution and retail costs
- In eastern Australia, there are potentially half a million to a million homes where residents are unaware that they can immediately start to save hundreds of dollars annually on their heating bill by using their existing reverse-cycle air conditioners (RCAC) (for heating) instead of gas.

The following table from the MEI report shows the savings that typical households in different regions of Eastern Australia can make by switching from gas heating to electric RCAC heating.

Table 7: Gas-versus-RCAC space-heating running costs, derived from analysis done by the ATA (20). (MEI)

Location	**Home Type**	**Gas space-heating costs** (energy- only, excludes fixed supply charges)	**RCAC space-heating costs** (energy- only, excludes fixed supply charges)	**Heating cost savings with RCAC**	**% savings with RCAC**
		($/year)	($/year)	($/year)	(%)
Canberra, ACT	large	$2,255	$522	$1,733	77%
Melbourne, VIC	large	$1,049	$391	$658	63%
Orange, NSW	medium	$1,370	$949	$421	31%
South NSW	small	$599	$415	$184	31%
Adelaide, SA	small	$180	$124	$56	31%
This table lists only five of the 156 region/zone and dwelling-type combinations examined by the ATA.					

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Governments have a responsibility and a duty of care to all their citizens to take effective action to mitigate climate change and to ensure they have access to the best advice on saving energy costs. In relation to energy policy, that responsibility and duty obligates them to ensure renewable energy can compete on a level playing field with high emissions producing energy generators. That includes recognition of the societal costs resulting from emissions.

Coal seam gas production may possibly be less emissions intensive than coal fired generation, though until we have independent verification, we must regard such a proposition with skepticism. Furthermore, an investment in gas production means fewer resources are available for zero emissions energy production from renewables. That in turn means a slower transition process to a zero-carbon economy.

Conclusions

1. There is reason to believe that emissions from CSG production such as the Narrabri Project, are being significantly under-reported, thus compromising the validity of Australia's GHG accounting.
2. The demand for gas on the domestic market in eastern Australia is declining as retail gas costs increase and the cost of renewable energy production decreases.
3. Allowing a CSG project such as the Narrabri Project to proceed, with its attendant environmental risks, goes contrary to government policy to promote a timely transition to a zero-carbon economy. In so doing it throws in to doubt Australia's ability to meet its international climate change commitments.

Appendices

1. Scientific American. *Leaky methane makes gas bad for global warming* (2014).
2. Melbourne Energy Institute. *A review of current and future methane emissions from Australian unconventional oil and gas production* (2016).
3. Melbourne Energy Institute. *Switching off gas. An examination of declining gas.*

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Leaky Methane Makes Natural Gas Bad for Global Warming

If leaks continue at present rates, natural gas may not help combat climate change

By Gayathri Vaidyanathan, ClimateWire on June 26, 2014

Scientists who have measured methane emissions over gas fields in the Uinta Basin of Utah say emissions are close to 9 percent. U.S. EPA suggests a leakage rate of 1.2 percent - equal to the annual emissions of 112 million cars. *Credit: Joshua Doubek via Wikimedia Commons*

Natural gas fields globally may be leaking enough methane, a potent greenhouse gas, to make the fuel as polluting as coal for the climate over the next few decades, according to a pair of studies published last week.

An even worse finding for the United States in terms of greenhouse gases is that some of its oil and gas fields are emitting more methane than the industry does, on average, in the rest of the world, the research suggests.

"I would have thought that emissions in the U.S. should be relatively low compared to the global average," said Stefan Schwietzke, a researcher at the National Oceanic and Atmospheric Administration's Earth Systems Research Laboratory in Boulder, Colo., and lead author of the studies. "It is an industrialized country, probably using good technology, so why are emissions so high?"

The natural gas industry globally was leaking between 2 and 4 percent of the gas produced between 2006 and 2011, the studies found. Leakage above 3 percent is enough to negate the climate benefits of natural gas over coal, so the findings indicate there is probably room for the industry to lower emissions.

The studies were published in the journals *Environmental Science & Technology* and *ACS Sustainable Chemistry and Engineering*.

Leakage equal to the emissions of 112M cars?

The insights go to the heart of the debate surrounding the use of natural gas in the United States today. The nation is in an oil and gas boom due to technological advances that have unlocked vast new reserves and vaulted the nation beyond energy behemoths like Russia and Saudi Arabia.

The Obama administration has supported the natural gas industry, in part for the fuel's climate benefits. Gas emits about half as much carbon dioxide as coal in the power plant, so the government has promoted gas as a transition fuel to a post-carbon future.

The fine print, however, is that natural gas may be as detrimental to the climate as coal in many ways. Its climate challenge lies not during electricity generation, but further upstream—during extraction, processing and distribution of gas from the oil and gas wells to gas burners.

From wellheads, pipes, valves, compressors and various other equipment, gas wells leak raw methane, a greenhouse gas that is 86 times as potent as carbon dioxide over a 20-year time scale, according to the Intergovernmental Panel on Climate Change. While CO_2 persists in the atmosphere for centuries, wreaking climate havoc slowly, methane works more rapidly for a short while before decaying into less virulent gases. For the climate equation, both CO_2 and methane emissions matter, scientists say.

So far, no one—not industry, academia or government—has a good grasp on how much methane is leaking from natural gas production. Scientists have been racing to find out, but the fact-finding process has been slow, partially because of the relative opacity of the industry.

The natural gas industry says its emissions are close to zero. It also maintains that regulations are unnecessary to cut down on leaks, as companies have an economic incentive to capture methane. "The industry has led efforts to reduce emissions of methane by developing new technologies and equipment," Howard Feldman, director of regulatory and scientific affairs at the American Petroleum Institute, said earlier this year.

Scientists who have measured methane emissions over gas fields in the Uinta Basin of Utah say emissions are close to 9 percent (*ClimateWire*, Aug. 7, 2013). U.S. EPA suggests a leakage rate of 1.2 percent—equal to the annual emissions of 112 million cars.

Schwietzke's studies jump into the fray with a more global perspective.

Revamping an inventory

NOAA scientists sometimes go down to the Port in Los Angeles and attach air monitors to ships that can measure the levels of methane, CO_2, ethane and other gases in the atmosphere. These are part of NOAA's network of monitoring sites, composed of ships, aircraft and tall towers sprinkled throughout the world, from the depths of the Amazon to frigid Antarctica.

Over the past two decades, the network has measured an average 550 teragrams of methane emitted to the atmosphere per year. The gas is emitted by wetlands (plants decaying in swamps emit the gas), rice fields, animals, the burning of wood or biomass, and oil and gas fields. The researchers wanted to figure out how much of the total methane was emitted by the natural gas industry.

Their task was complicated because natural gas, oil and coal are all roughly similar. Extraction of all three releases similar byproducts—methane and ethane, among others—to the atmosphere, albeit in different quantities.

So Schwietzke used inventories from EPA, the IPCC and other sources to estimate oil field and coal emissions. This partitioning had been done previously, but Schwietzke redid the inventory, driven by the understanding that all scientific findings are plagued by uncertainty. The previous inventories partitioning oil and coal had not stated how certain they were in their results.

Schwietzke found this problematic, since EPA and other inventories are known to be somewhat fallible (*EnergyWire*, Feb. 24).

Once he had his uncertainties, Schwietzke input his oil and coal numbers into a computer model. He also input methane emissions from wetlands, landfills, biomass burning and agriculture, all derived from previous scientific studies. The only missing link was emissions from the natural gas industry.

The computer model subtracted the range of emissions Schwietzke input from the real-world NOAA measurement of methane in the atmosphere. Its output was the average global methane leakage from the natural gas industry. This was at most 5 percent of global annual natural gas production.

High Utah rates not the norm

To further refine his results, Schwietzke input the data into a more complicated three-dimensional atmospheric model. This model further constrained the global average emissions rate of methane to 2 to 4 percent.

Using real-world global data, his models suggest that natural gas producers are leaking to the atmosphere, on average, between 2 and 4 percent of the natural gas they produce.

That is enough to negate the climate benefits of gas over coal in the next two decades, the studies find. Various life-cycle analyses have found that in order for gas to be better than coal for the climate, the methane leakage rate has to be less than 3 percent. That overlaps the leakage found by Schwietzke.

Schwietzke's studies also suggest that the highest emissions rates in literature, such as the 9 percent recorded in the Uinta Basin of Utah, are not the norm across the United States. These fields deviate very significantly from the global norm, and likely from the national norm, Schwietzke said. He expressed surprise that such fields could occur in a technologically advanced nation like the United States.

"It could be that the industry practices they use in this basin are really bad," he said.

ABOUT THE AUTHOR(S)

Gayathri Vaidyanathan

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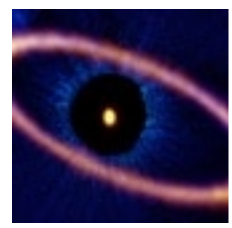

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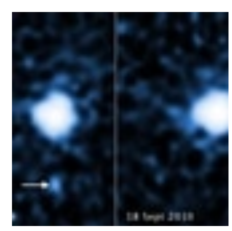

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MELBOURNE ENERGY INSTITUTE

THE UNIVERSITY OF MELBOURNE

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

October 2016

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Tim Forcey - Energy Advisor, Melbourne Energy Institute[1]
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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).

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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.

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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.

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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)

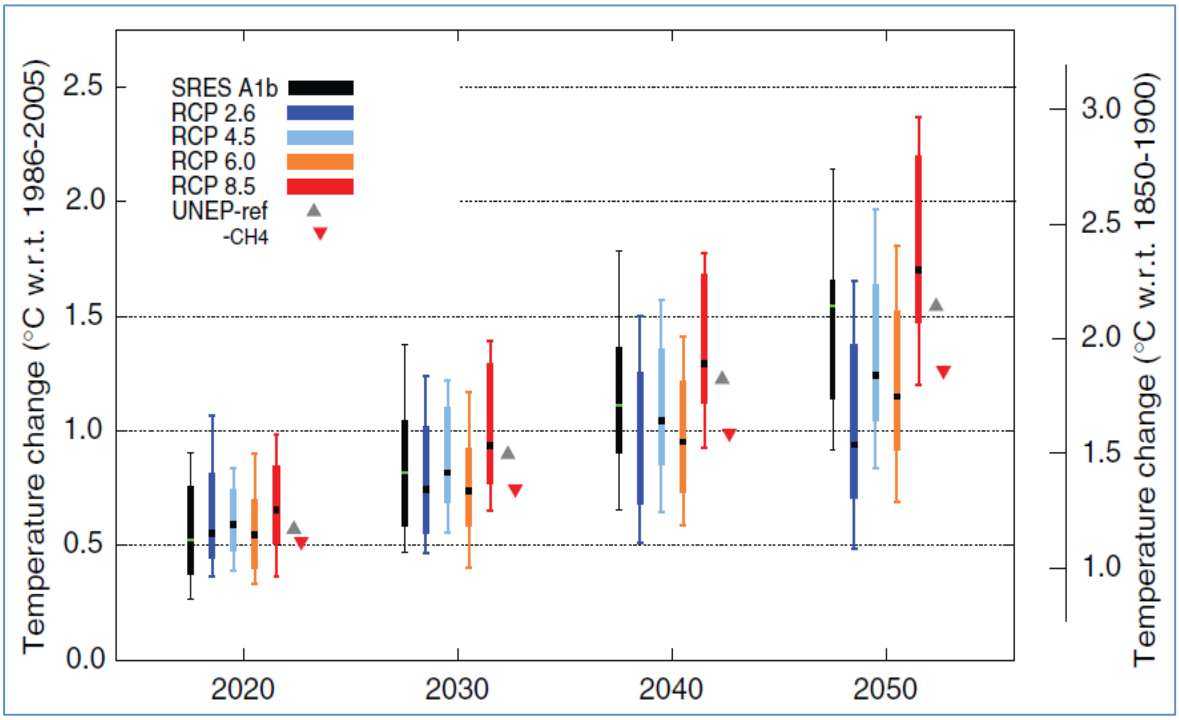

Figure 1: Global average 10-year mean surface temperature increase based on the current four IPCC model ensembles (dark blue: RCP 2.6, light blue: RCP 4.5, orange: RCP 6.0 and red: RCP 8.5), and the previous model ensembles (black: SRES A1b). Left vertical scale is temperature change with regards to 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)).

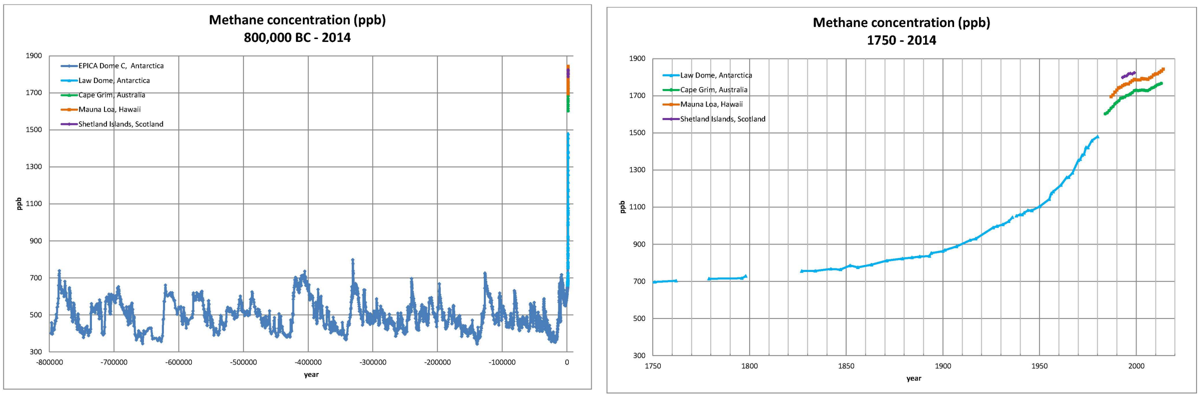

Figure 2: Atmospheric methane concentration shown in parts per billion (ppb), from hundreds of thousands of years ago, through to 2014. Left: Timeframe 800,000BC to 2014, showing concentrations have not been higher than 800ppb until very recent. Right: Timeframe 1750 to 2014, showing concentrations have 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).

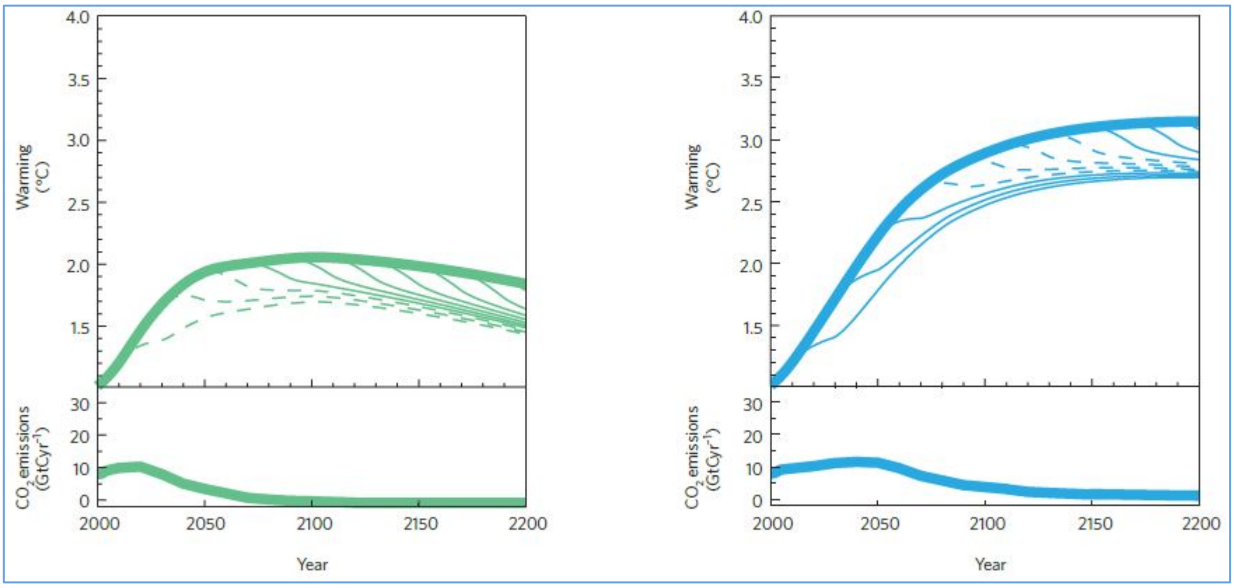

Figure 3: from Bowerman, Frame et al. (2013). Impact of short-lived climate pollutants (SLCP, incl. methane) in the RCP2.6 and RCP4.5 scenarios (1.5°C and 2.4°C warming at the end of the century respectively). The thick line represents the global warming (upper panel) and carbon dioxide emissions (lower 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.

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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.

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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.)

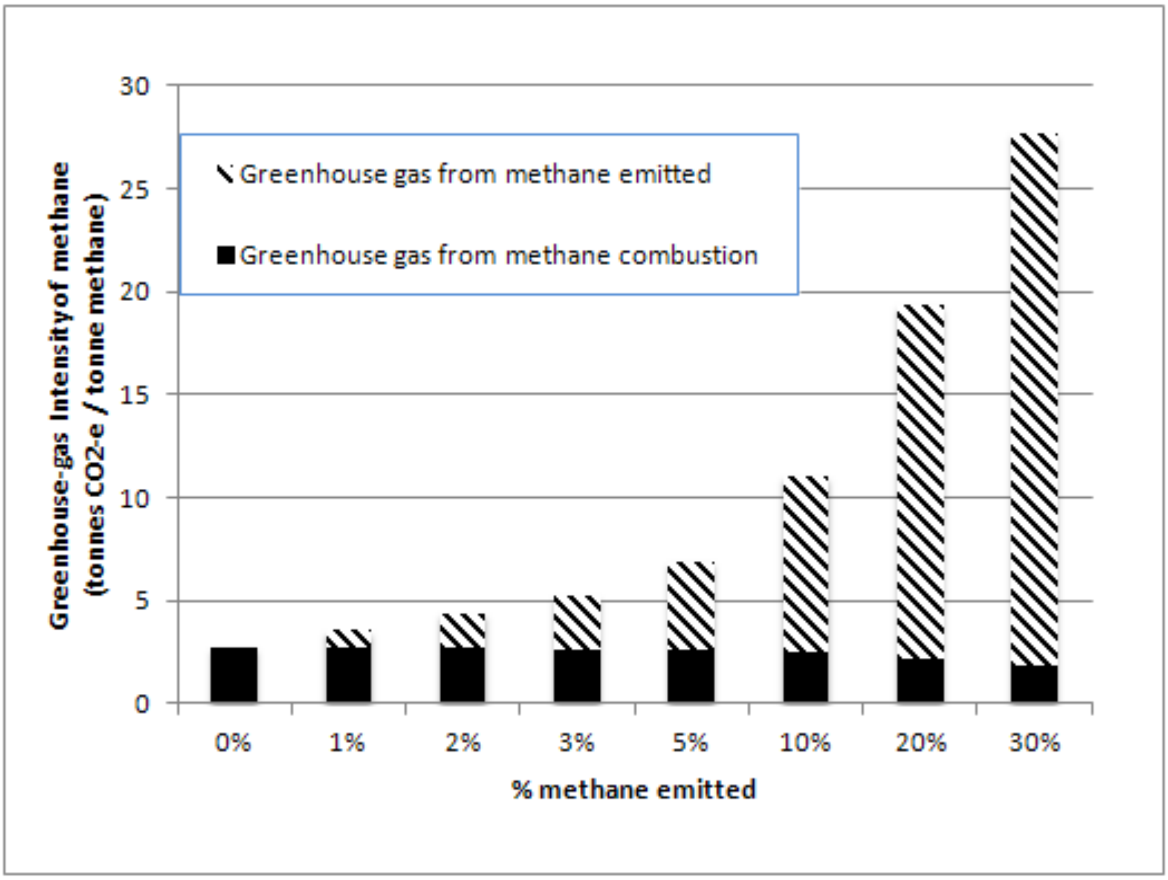

Figure 4: The climate impact of gas as an energy source greatly depends on what fraction is emitted to the atmosphere, versus what fraction is burned as fuel. Here we assume a global warming potential of 86 (appropriate to the 20-year timescale), with the y-xis showing the tonnes of CO_2-e emitted for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

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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,

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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

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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).

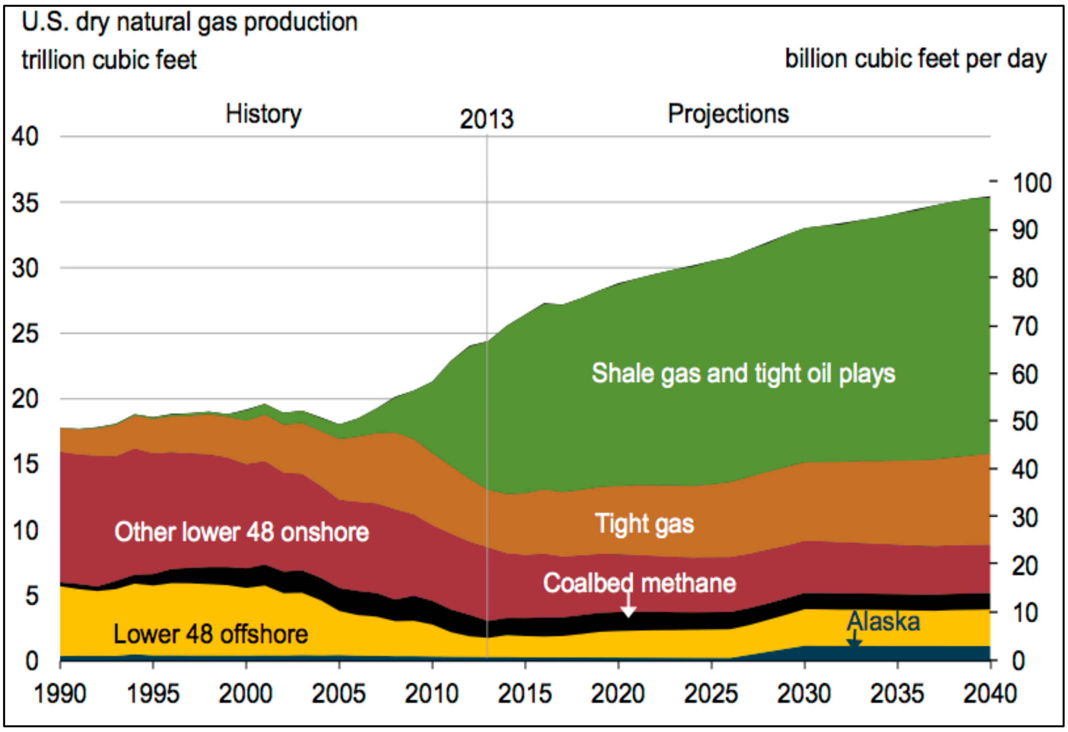

Figure 6: U.S. gas production 1990-2040 as per the EIA Annual Energy Outlook, 2015 Reference case scenario. Historical production until 2013, forecast from then onwards.
(EIA, Sieminski, A., 2015)
http://instituteforenergyresearch.org/analysis/eias-annual-energy-outlook-2015-fossil-fuels-remain-predominant-energy-providers/

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.

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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.		✓	

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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)).

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'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

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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).

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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".

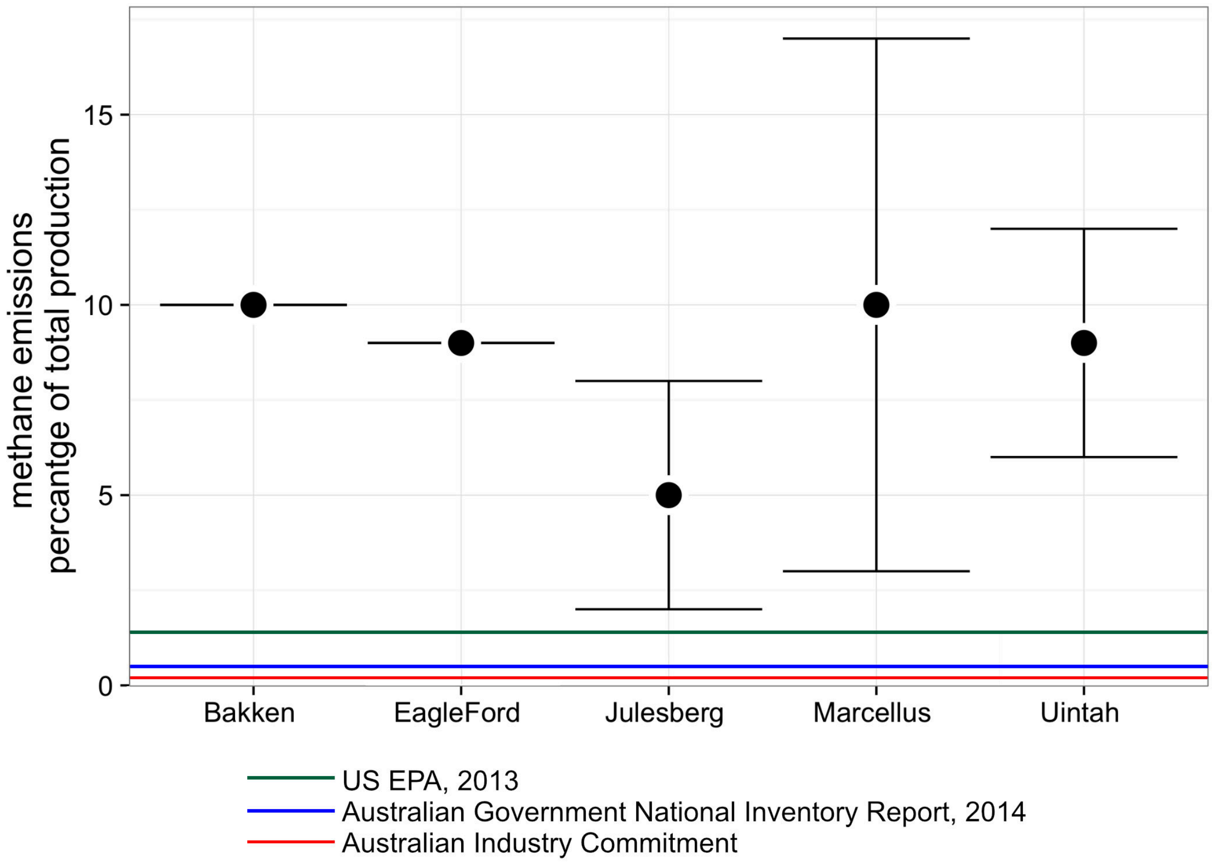

Figure 8: U.S. reported methane emissions (shown as black horizontal line), vs recent 'top-down' measurements for various unconventional gas basins (with reported ranges shown as error bars)

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)).

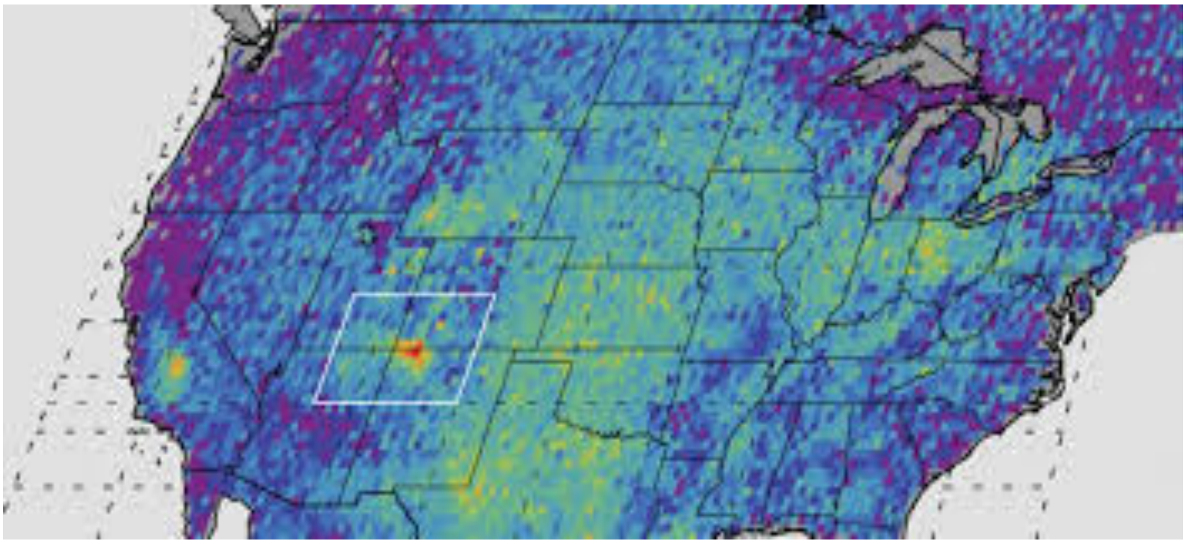

Figure 9: U.S. methane emissions 'hot-spot' revealed by satellite measurements. (Kort et al. 2014)

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).

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))

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.

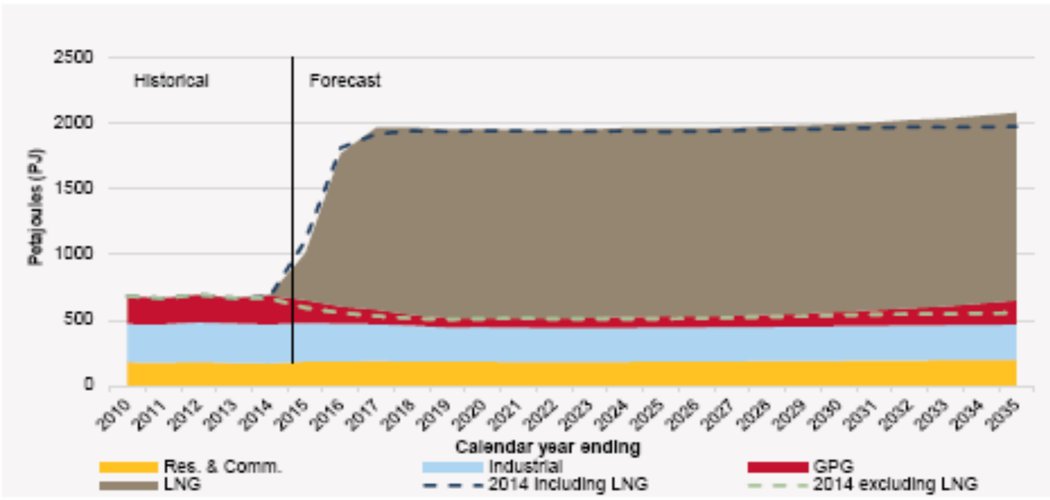

Figure 11: Eastern Australian gas production, recent past and projected future.
Australian Energy Market Operator National Gas Forecasting Report, Dec. 2015

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

<table>
<tr><th colspan="4">Australian shale oil, shale gas, and tight gas prospective resource estimates</th></tr>
<tr><th>Type of resource</th><th></th><th>Level of uncertainty</th><th>References</th></tr>
<tr><td>Shale oil</td><td>18 billion barrels</td><td>Potentially in the ground, technical recoverable</td><td>EIA (2013)</td></tr>
<tr><td rowspan="3">Shale gas</td><td>6% of world's total shale gas resource</td><td>Undiscovered, prospective</td><td>EIA (2013)</td></tr>
<tr><td>396 TCF
(435,600 PJ)</td><td>Potentially in the ground, technically recoverable</td><td rowspan="3">Cook, Beck et al. (2013),
GA and BREE (2012)</td></tr>
<tr><td>2 TCF
(2,200 PJ)</td><td>Sub-economic demonstrated (2C)</td></tr>
<tr><td>Tight gas</td><td>20 TCF
(22,000 PJ)</td><td>Sub-economic possible (3C)</td></tr>
</table>

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.

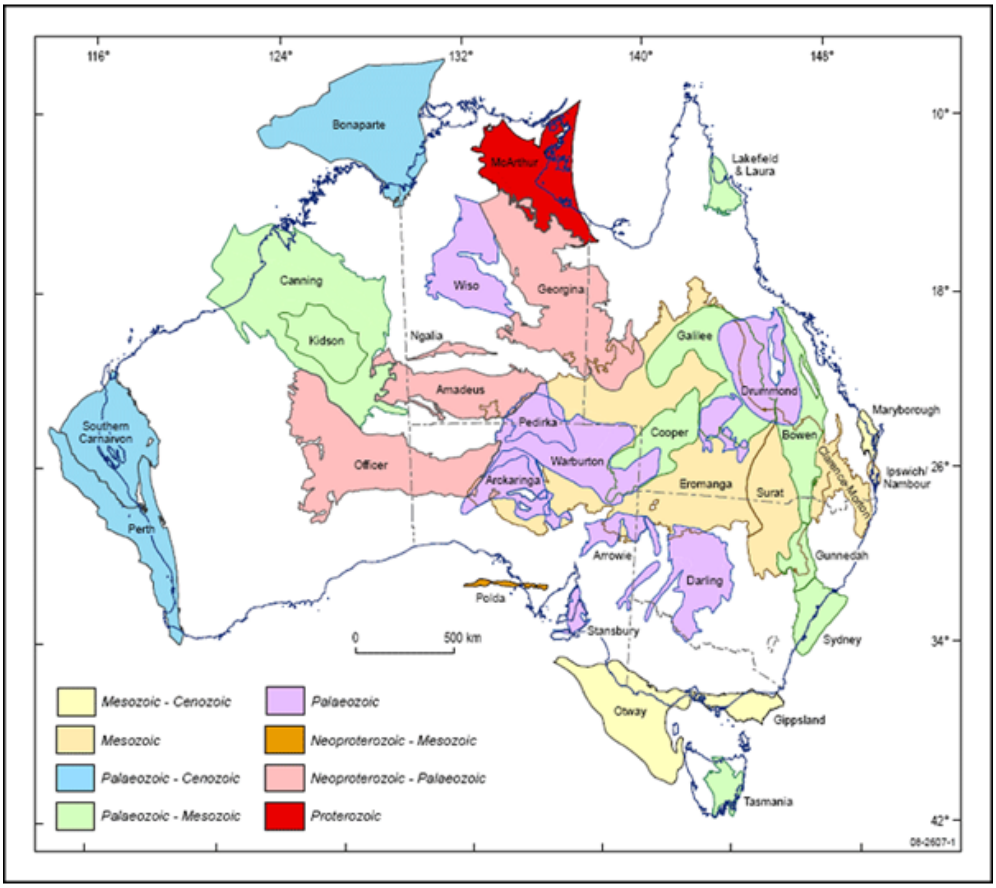

Figure 13: Australia's onshore sedimentary basins (Geoscience Australia, 2016.
http://www.ga.gov.au/about/what-we-do/projects/energy/onshore-petroleum

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*.

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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

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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	

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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)).

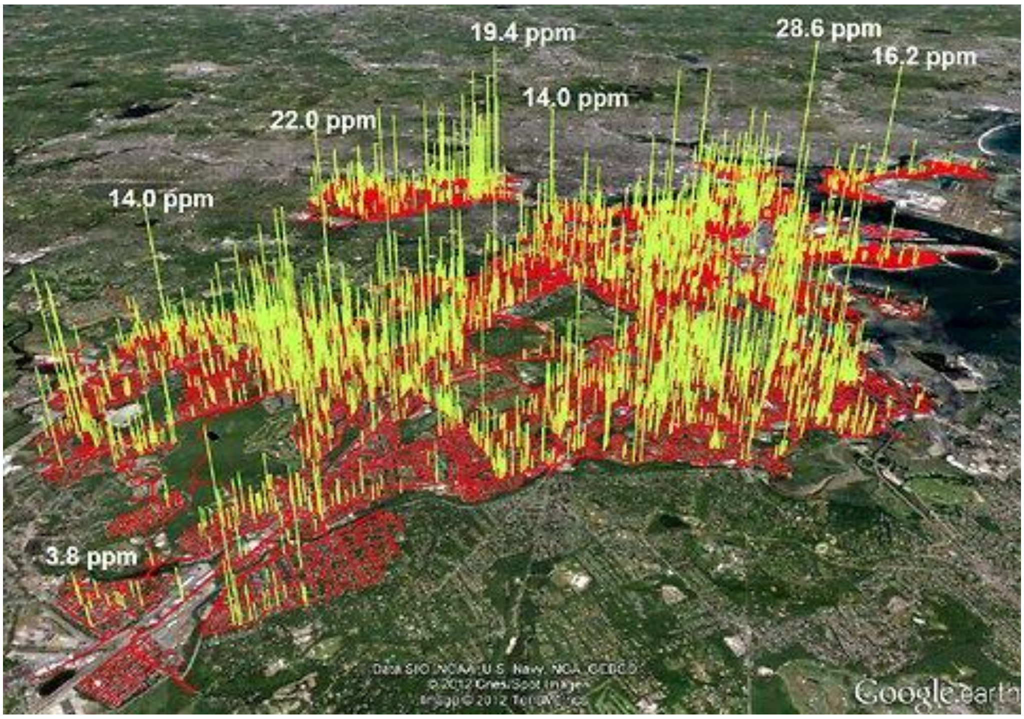

Figure 14: 3,356 methane leaks mapped in the city of Boston (Phillips, 2013)

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.

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[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 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."

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.

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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.

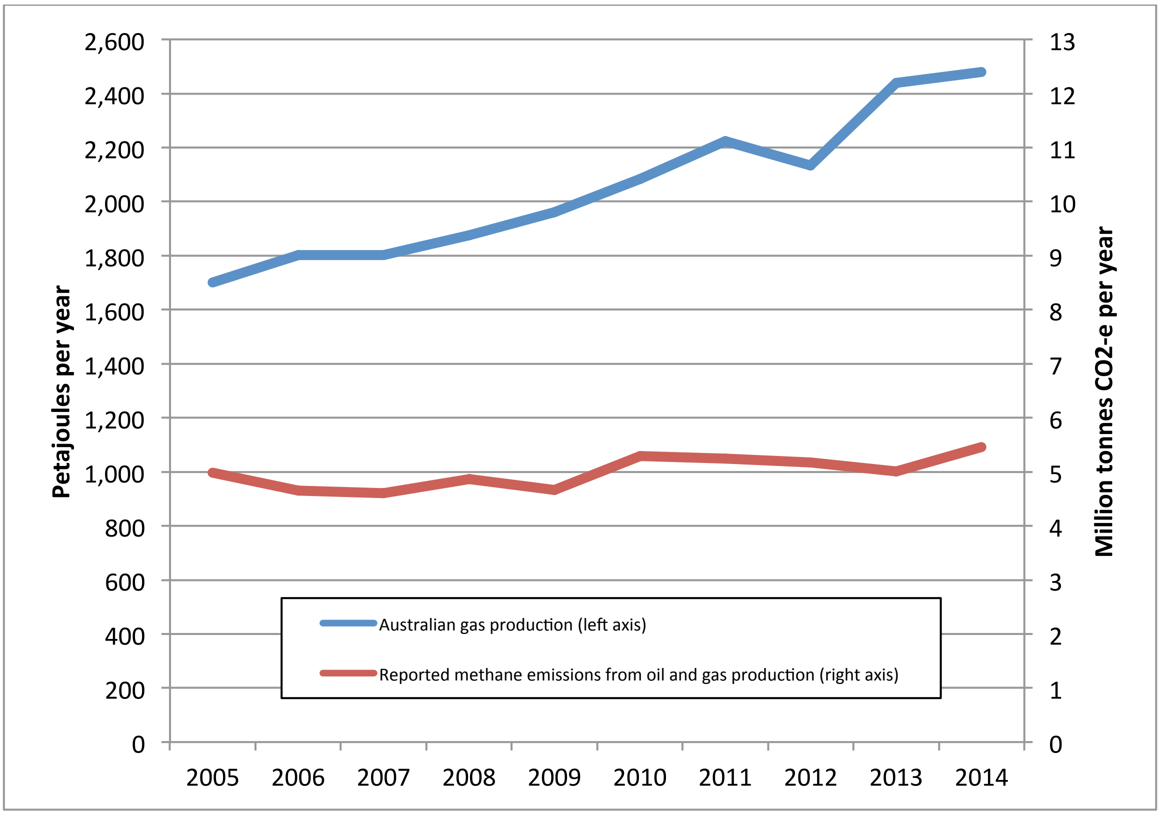

Figure 15: Australian annual gas production and reported methane emissions

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/

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/

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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".*

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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

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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

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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).

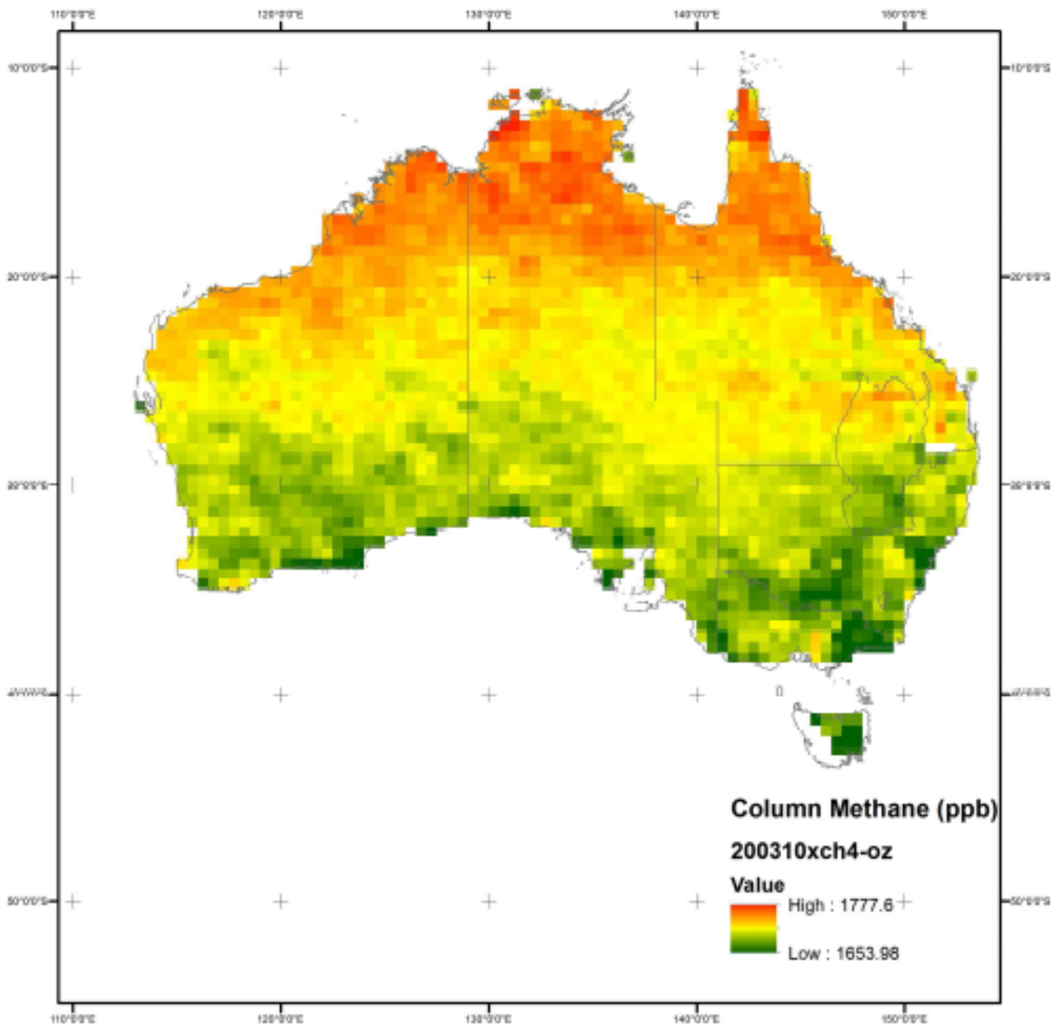

Figure 16: October 2003 satellite-data analysis of methane present in the air over Australia. (Day, Ong et al. (2015))

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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

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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)

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THE UNIVERSITY OF MELBOURNE

MELBOURNE ENERGY INSTITUTE

Switching off gas - An examination of declining gas demand in Eastern Australia

26 August 2015

Tim Forcey - Energy Advisor, Melbourne Energy Institute (MEI)

Table of Contents

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About the University of Melbourne Energy Institute (MEI)

The University of Melbourne Energy Institute (MEI) 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 Author

Tim Forcey has over 30 years of experience in industrial energy with ExxonMobil, BHP Billiton, and Jemena, including specific experience with assets such as the Bass Strait Joint Venture and the Queensland Gas Pipeline.

During his time at the Australian Energy Market Operator, Tim led the publication of the 2011 Gas Statement of Opportunities, the 2012 South Australian Electricity Report, and the AEMO 100% Renewable Energy Study - Modelling Inputs and Assumptions.

With MEI, Tim has published reports and articles covering gas and electricity demand, gas-to-electricity fuel-switching, and pumped hydro energy storage technology and commercial applications.

Tim has also worked part-time as a home energy consultant with the Moreland Energy Foundation – Positive Charge and has volunteered with the Alternative Technology Association and Beyond Zero Emissions.

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1. Executive Summary

Following on from our research into "domestic gas"[1] demand specific to New South Wales (1) (2), the University of Melbourne Energy Institute (MEI) have examined the future of domestic gas across the entire interconnected eastern-Australian gas market. Our key findings are as follows.

Dramatic changes in the eastern-Australian gas market are prompting projections of sharp declines in domestic gas demand. Data from the Australian Energy Market Operator (AEMO) indicate that gas demand in eastern Australia peaked in 2012 and has declined since. Gas demand will continue to decline, possibly falling to half of the peak by 2025, according to a scenario prepared by MEI. (See Figure A.)

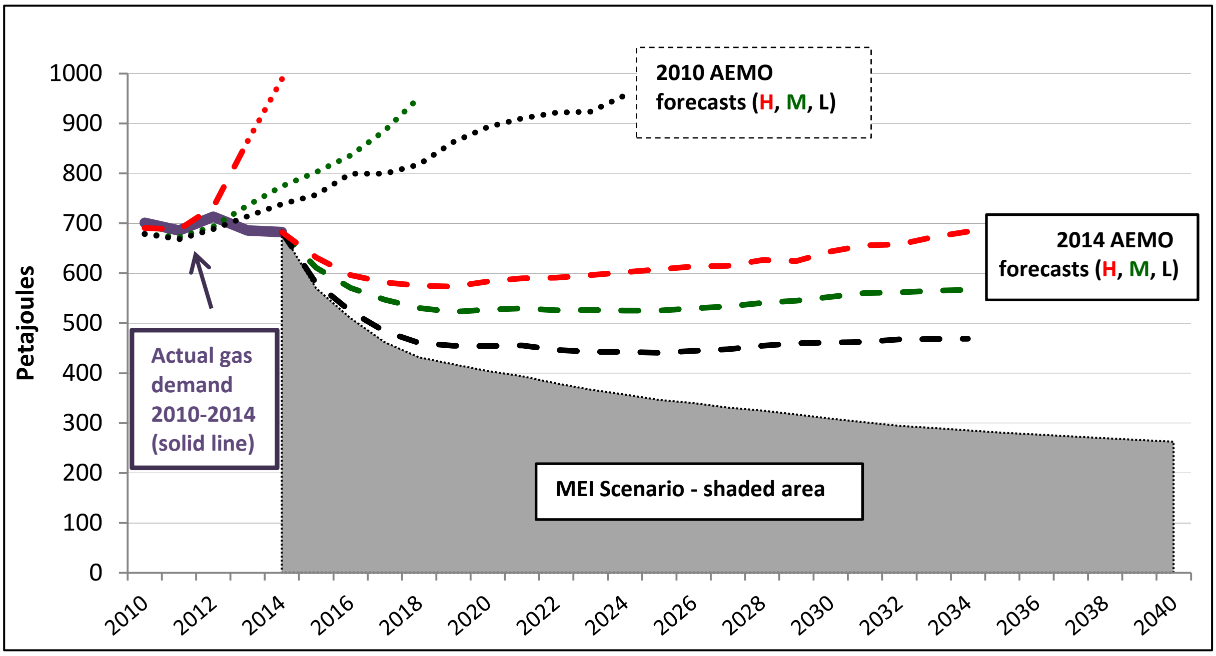

Figure A: Gas demand in eastern Australia – actual demand and scenarios of future demand.

Already domestic gas prices in eastern Australia have increased as they become linked to overseas prices following the start of gas exports to Asia from Gladstone Queensland, and also because of the high costs of producing coal seam gas. Rising gas prices and other factors are having a large negative impact on the use of gas in the electricity generation and industrial sectors.

[1] The term "domestic gas" means gas consumed within eastern Australia and excludes gas exported from

Furthermore in the buildings sector, gas faces increased competition from efficient-electrical appliances: heat pumps and induction cooktops. Renewable-energy-harvesting heat pumps, used for space and water heating, are a disruptive technology especially when applied in Australian homes and climate zones. Rather than burning one unit of gas energy to recover less than one unit of heat energy (i.e. < 100% efficient), heat pumps use electricity to leverage a refrigerant cycle and recover up to five units of free, renewable-ambient heat thereby achieving efficiencies of up to 500%. Heat pump space heaters, widely known in Australia as reverse-cycle air conditioners, have the added advantage of providing space-cooling during summer and other warm-weather periods and as a result are already in place in millions of Australian homes.

Rising gas prices and other factors are driving "economic fuel-switching" from gas to electricity as building owners and managers install heat pumps and replace gas stoves with efficient and controllable induction cook-tops. Increasing uptake of rooftop solar photovoltaic (PV) systems and fast-evolving electric-battery storage technologies will further accelerate economic fuel-switching.

Economic fuel-switching results in significant energy-cost savings for former domestic gas consumers. Based on analysis by MEI and the Alternative Technology Association, people living in up to one million homes across eastern Australia (and most particularly in Victoria) can start saving hundreds of dollars on their heating bill ***tomorrow*** if they switch off their gas heater and turn on their reverse-cycle air conditioner.

Space-heating cost savings of $1,733/year (a savings of 77%) were modeled for a large home in Canberra and $658/year (63%) for a large home in Melbourne. Unfortunately, householders are unaware of these remarkably-large and quick savings because of out-of-date and inaccurate information. It is possible that in Victoria alone, households could collectively and immediately save on the order of $250 million/year by using as a space-heater the reverse-cycle air conditioners they already have in their homes.

Over the longer-term, these new economic drivers mean that many households will progressively replace old gas appliances with new electric appliances and some will see the advantages of leaving the gas grid completely. This "second-electrification of the Australian home" may lead to a "death spiral" where more and more customers leave the gas grid, which then leads to increased costs for those customers that remain connected.

The changing economics of gas-use in buildings and industry have important implications for infrastructure planning. There is now no economic need for any new house or suburb in eastern Australia to be connected to the gas grid. Governments, housing developers, and homeowners can now look for opportunities to cut spending on gas infrastructure.

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Complementing economic fuel-switching, the benefits of building energy-efficiency measures are well known yet many highly-economic opportunities remain. This means we can also "explore" for gas in eastern-Australian attics and lounge rooms by deploying insulation, draught-proofing, and improved windows and window treatments (e.g. drapes, and blinds).

Ending gas waste in the buildings sector, where often up to 50% of purchased gas is immediately "thrown-away" because of inefficient use, will make available large volumes of gas for higher-value industrial uses. There are also many economic fuel-switching and energy-efficiency opportunities available to industry, as eastern Australia enters this new era of high-price gas.

Ending gas waste will also extend the depletion of conventional gas reserves in eastern Australia for at least an additional decade, as illustrated by Figure B. In AEMO's medium scenario, approximately 10,000 petajoules of domestic gas is consumed by 2032 whereas in the MEI Scenario, that amount of gas is not used until more than a decade later.

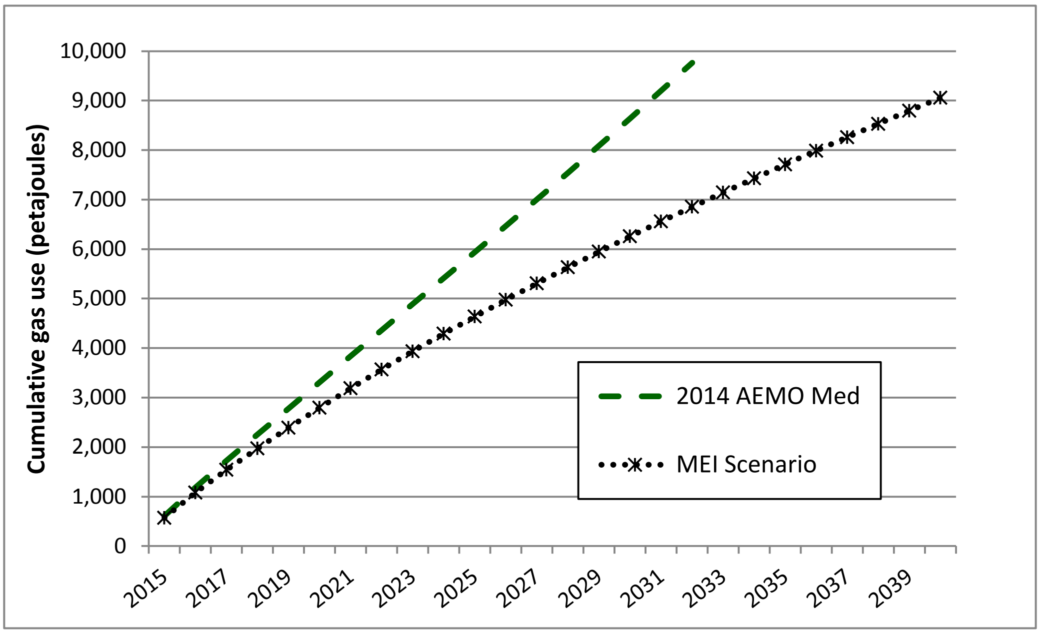

Figure B: Eastern Australia cumulative "domestic gas" consumed / reserves depletion. (MEI)

Similarly to the electricity industry, for decades strategic management of gas in eastern Australia meant looking only at the supply side rather than taking into account opportunities for gas demand reduction. This report recommends that eastern-Australian governments develop an **Integrated Resource Plan (IRP)** that considers not just gas-supply options but also includes gas-demand-management options such as economic fuel-switching and energy-efficiency measures.

2. Full List of Key Points

The following is a full list of key points that are detailed in this report:

1) According to data from the Australian Energy Market Operator (AEMO), **the amount of gas consumed in eastern Australia peaked in 2012**.

2) According to AEMO data and forecasts, since 2012 the amount of **gas consumed** in eastern Australia has declined each year and **will continue on a declining trend**. AEMO's high, medium, and low demand scenarios indicate that by 2025, gas demand in eastern Australia will have fallen from the 2012 peak by 15%, 26%, or 38% respectively. AEMO forecasts that gas demand will decline in the industrial and electricity generation sectors.

3) With the recognition of declining demand, AEMO's previous **concerns about gas supply shortfalls** and suggestions of gas infrastructure expansion have been **withdrawn**.

4) For decades, the eastern-Australian gas market was a buyer's market where consumers enjoyed access to some of the cheapest gas in the developed world. However, in recent years, **wholesale and retail gas prices have dramatically increased.** The economics of gas for eastern Australia have changed and a **"seller's market"** now prevails. This change is driven by the new capability, commencing in 2014, for LNG to be exported to Asia from Queensland. This has allowed "domestic gas" prices to be linked to **world-parity gas prices**.

5) **Developing coal seam gas** has proven to **not** be as **easy nor** as **cheap** as had been expected. This has also contributed to rising gas price pressures. The development of other unconventional gas in eastern Australia (shale gas and "tight" gas) is also not expected to be "cheap".

6) Retail gas prices are increasing not only because of increasing wholesale gas prices but also because of **increasing gas distribution and retailing costs**.

7) To date, AEMO has not forecast that the amount of gas used in buildings will change much over the next 20 years. MEI's view is that economic **fuel-switching in buildings will to be a significant** near and medium-term **phenomenon**. AEMO have indicated that their next version of gas forecasts will acknowledge fuel-switching from gas to electricity in the residential sector.

8) In eastern Australia, there are potentially 500,000 to 1,000,000 homes where residents are unaware that they can immediately start to save **hundreds of dollars per year** on their heating bill by using their **existing** reverse-cycle air conditioners (RCACs) instead of gas. This economic fuel-switching frees up gas for industry.

9) Many **people lack information** about the cheapest way to heat their homes and water. Communication is hampered by incorrect or insufficient information in the community and marketplace.

10) The efficiency of ducted-gas space-heating systems in Australian homes can be as poor as 50% or less. In some cases, **half or more of the purchased gas is immediately wasted** and not used to effectively warm people in their homes.

11) Contrasting with the poor performance of ducted-gas, some non-ducted RCACs achieve efficiencies of more than 500% when they capture more than **four units of free renewable heat** from the outside air for every one unit of electricity applied. Though not eligible for renewable-energy credits, **reverse-cycle air conditioners are very significant harvesters of renewable energy** in eastern Australia, rivaling rooftop-solar panels in their output.

12) Some homeowners can **save hundreds of dollars per year by switching from a gas hot water service to a heat-pump water heater** (HPWH). HPWHs act as "energy-storage hot-water-batteries" when charged at night, when grid-supplied electricity is cheap, or at mid-day if a home's solar PV panels generate excess electricity.

13) Installing reverse-cycle air conditioners, heat-pump water heaters or other gas-free water heaters, and induction cooktops allows "all-electric" Australian homes to become gas free and **eliminate the gas bill**.

14) With the wide availability of efficient-electrical appliances, there is **no longer any <u>economic</u> need to connect gas to new Australian homes and suburbs**.

15) In eastern Australia, gas "exploration and mining" can, in a sense, occur in eastern-Australian attics and lounge rooms via the deployment of economic **energy-efficiency measures** such as insulation, draught-proofing, improved windows and window treatments (e.g. drapes, and blinds).

16) As a result of AEMO not yet reflecting economic fuel-switching in their gas demand forecasts, AEMO's "low" gas demand scenario may not be low enough to bracket all reasonably-possible outcomes. The **"MEI Scenario"** presented in this report takes fuel-switching and energy-efficiency measures into account. As a result, in the MEI Scenario **gas demand in eastern Australia falls to approximately half** of the 2012 peak over the next ten years.

17) Providing warmer and cheaper-to-operate homes can lead to **improved home health outcomes,** especially for the sick and elderly.

18) Ending **gas waste**, particularly in the buildings sector, **will free up large volumes of gas for higher-value industrial uses**. For example, in twenty years time, approximately 70% of the gas used in the Larger-Industrial sector could be sourced from gas "saved" in the Residential, Commercial, and Smaller-Industrial sector.

19) The large volume of gas that can be saved via economic fuel-switching and energy-efficiency measures in the buildings sector (up to 1,000 petajoules) rivals the volumes of gas that might be produced from large gas-field developments.

20) There are also many fuel-switching and energy-efficiency **opportunities available to industry** as eastern-Australia enters this new era of high-price gas.

21) Energy-efficiency measures and economic fuel-switching in buildings from gas to electricity can help Australia to economically **decarbonise**, especially as eastern Australia's electricity is increasingly produced with renewable energy.

22) As gas demand declines in all market sectors, eastern Australia's remaining **gas reserves stretch out** for more than an additional decade.

23) As gas prices rise and the preference for lower-carbon energy and chemical feedstocks increases, the distributed production of **renewable biogas** may become a viable industry in eastern Australia and a replacement for fossil gas.

24) Eastern Australia needs **an Integrated Resource Plan (IRP)** that considers not just gas-supply options, but also gas-demand-management options, including economic fuel-switching and energy-efficiency measures. To date the focus of the Australian Energy Market Operator has been on the gas supply-side.

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3. Background - the eastern-Australian gas supply system

As shown by Figure 1 (3), gas is supplied to eastern-Australian demand centres by a pipeline network connecting Queensland (QLD), New South Wales (NSW) including the Australian Capital Territory (ACT), Victoria (VIC), Tasmania (TAS), and South Australia (SA). No gas pipelines connect eastern Australia to Western Australia or the Northern Territory.

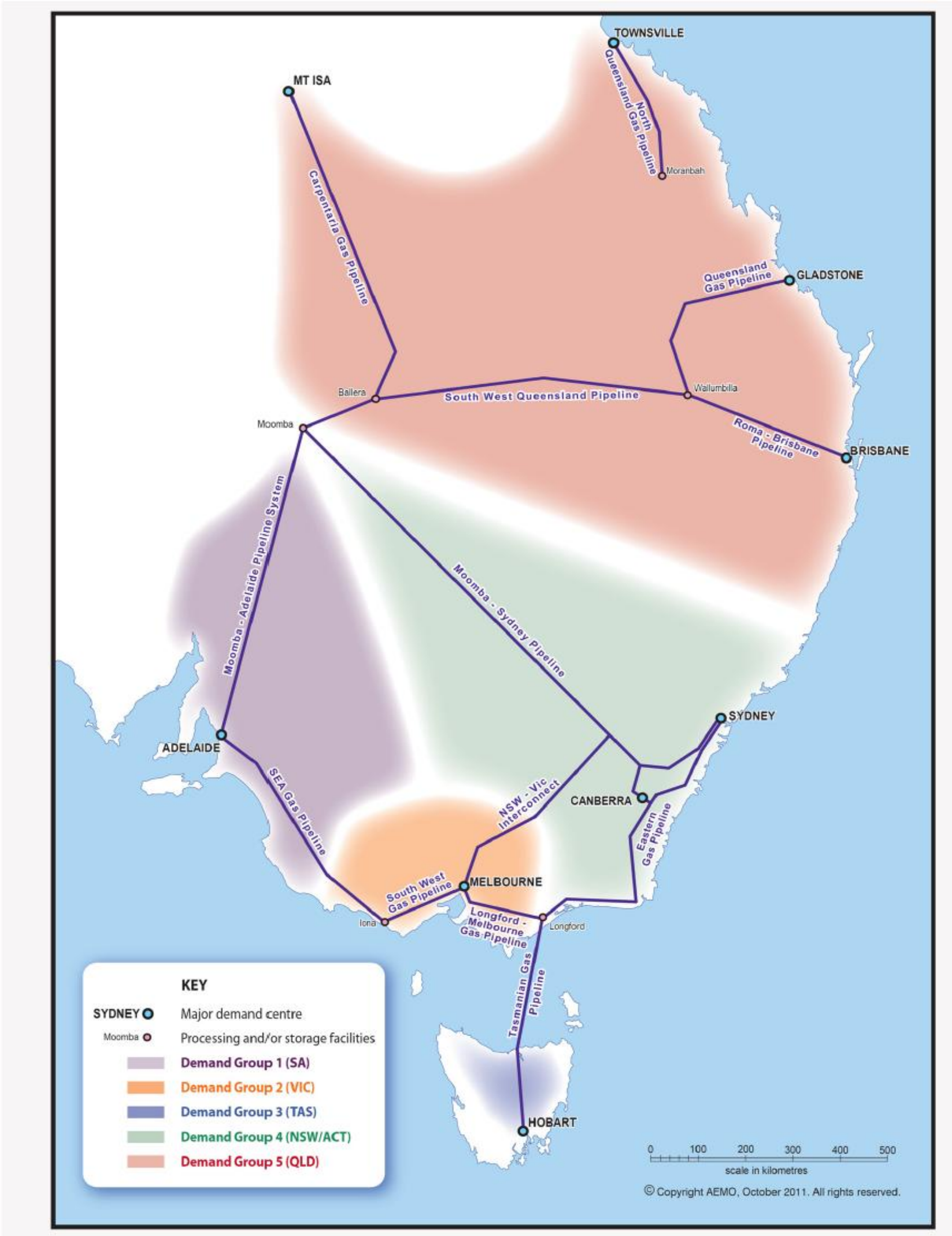

Figure 1: The interconnected eastern-Australian gas market (3).

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LNG exports are not included in this "domestic gas" demand study

Starting in December 2014 (4), increasing volumes of liquefied natural gas (LNG) are being exported from Gladstone, Queensland, as illustrated by Figure 2. Eventually, export gas volumes will exceed the amount of "domestic gas"[2] used in eastern Australia by approximately three times. However, this report describes only the future of eastern Australia "domestic gas" demand.

Figure 2 also illustrates actual past "domestic gas" use by demand sector and AEMO's "medium" forecast of future demand.

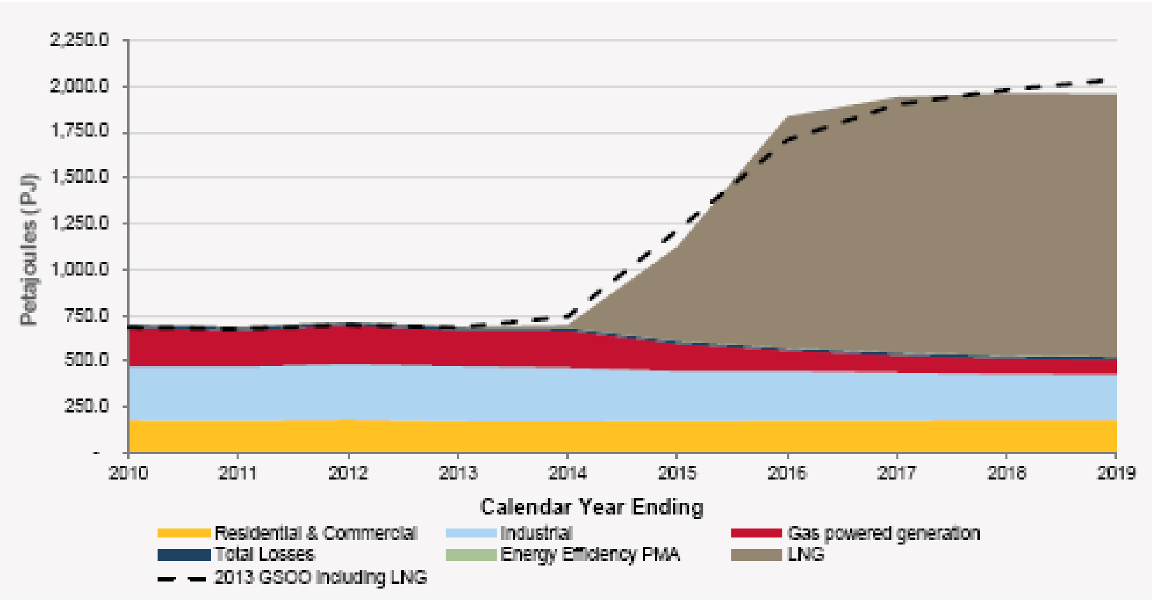

Figure 2: Annual gas consumption in eastern Australia including "domestic gas" and LNG exports, AEMO medium forecast. (AEMO (5))

Table 1 shows actual gas consumption figures for 2014 in petajoules per year (PJ/yr). In 2014, the greatest use of gas was in the Larger-Industrial sector, consuming 42.9% of the total.

Table 1: 2014 actual gas used in eastern Australia, by demand sector

Gas Demand Sector	PJ/yr in 2014	%
Gas used in the Larger-Industrial (LI) sector	292.5	42.9
Gas used for electric gas-powered generation (GPG)	201.5	29.5
Gas used in residential, commercial, and smaller-industrial (RCSI)	171.9	25.2
Losses	16.3	2.4
Total	682.2	100

[2] The term "domestic gas" refers to the gas used within eastern Australia and does not include gas that is exported.

4. The rising price of gas in eastern Australia

For decades, the eastern-Australian gas market was a buyer's market. Consumers enjoyed access to some of the cheapest gas in the developed world. However, the economics of gas in eastern Australia have changed. A "seller's market" now prevails. This change has been driven by the new capability, commencing in 2014, for LNG to be exported to Asia from Gladstone, Queensland. This has allowed "domestic gas" prices to be linked to world-parity gas prices. In recent years, eastern-Australian wholesale and retail gas prices have dramatically increased, and analysts expect gas prices to continue to rise over the next ten to twenty years (6) (7) (8) (9) (10) (11) (12). Wholesale gas prices, formerly in the range of $3 to $4 per gigajoule, are increasing to as high as $7 to $8 per gigajoule, and possibly higher in Queensland (13).

Gas prices will be unaffected by increased domestic gas supply, according to a report published in February 2015 by the New South Wales Legislative Council Select Committee on the 'Supply and Cost of Gas and Liquid Fuels in New South Wales' (2) which states:

> "…increased domestic supply of gas will not by itself lead to reductions in gas prices, or even in the rate of price increases. This is because the predominant driver of domestic gas prices will be the international gas price…"

Also contributing to rising gas-price pressures is that producing coal seam gas (CSG) in eastern Australia, primarily for LNG export, has proven to be more expensive than expected (14). CSG production costs have risen from estimates of $3 to $4 per gigajoule in 2011 (3) to as high as $7 to $8 per gigajoule in 2015 (15). Esso Australia expressed concerns about there not being enough gas to supply the needs of the new LNG plants, as the Santos "GLNG" project sought access to third-party supply (16). The development of other unconventional gas in eastern Australia (i.e. shale and "tight" gas) is also not expected to be "cheap", and rather is estimated to cost "at least $7 per gigajoule" (17).

Another factor cited as contributing to rising gas prices is "the lack of competitive and transparent domestic gas industry" (18) which is the subject of an inquiry by the Australian Competition and Consumer Commission (ACCC) (19).

Wholesale gas costs represent only 20 to 25% of total retail gas prices in most eastern-Australian jurisdictions (20). In Victoria, current residential gas prices (energy-unit costs only, excluding fixed costs) can range from $16 to $22 / gigajoule (including GST). Retail gas prices can rise not only because of rising wholesale gas prices, but also because of increasing gas distribution (21) and retailing costs. In 2014, the Consumer Utilities Advocacy Centre (Victoria) reported that retail gas prices had increased 66% since 2008 and would increase another 24% in the next year (22). Recently ANZ reported that gas costs for an average Melbourne household could rise from $1,200 per year (in 2014) to $1,600 per year by 2020 (13).

In late 2014, the Grattan Institute reported that the average household gas bill in Sydney will, "in the next few years", rise by $100/year and that in Melbourne bills might go up by $320 to $435 per year (8).

5. Gas demand peaked in 2012 and will continue to decline

According to data from the Australian Energy Market Operator (AEMO) (5), the amount of gas consumed in eastern Australia[3] peaked in 2012 at 713 PJ/yr. (See Figure 3 and also (23).)

According to AEMO's most recent data and 20-year forecasts[4], the amount of gas consumed in eastern Australia has declined each year since 2012 and will continue on a declining trend. AEMO's high, medium, and low demand scenarios indicate that by 2025 gas demand in eastern Australia will have fallen from the 2012 peak by 15%, 26%, or 38% respectively.

AEMO's most recent gas demand forecasts differ markedly from forecasts published by AEMO five years ago. As shown on Figure 3, in 2010 each of AEMO's "high", "medium" and "low" scenarios pointed to rapidly rising gas demand (24). It is apparent that AEMO's 2010 gas demand scenarios failed to bracket all reasonably-possible future outcomes. Similar shortcomings have been documented regarding AEMO's electricity demand forecasts (25).

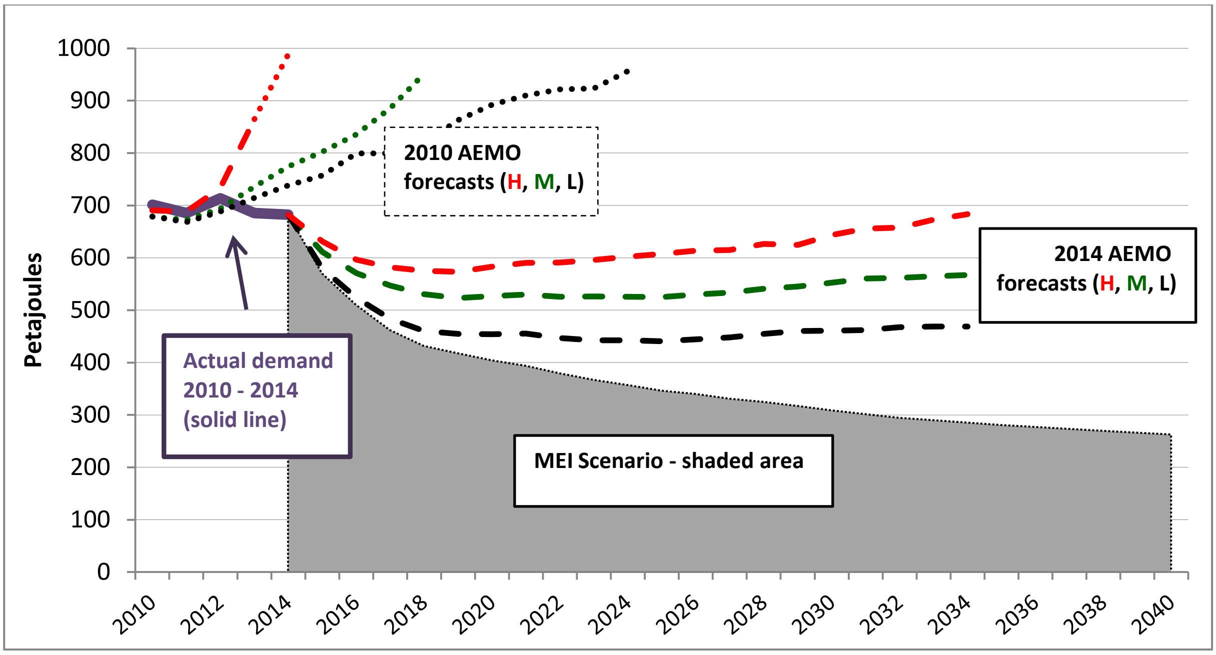

Figure 3: Gas demand in eastern Australia – actual demand and scenarios of future demand.

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[3] This report covers only the gas used within eastern Australia, which is known as "domestic gas". This report excludes analysis of gas used for LNG exports.

[4] Each year, AEMO provides a 20-year outlook for gas demand.

AEMO break "domestic gas" demand forecasts into the following four parts:

- gas used for electric power generation (GPG)
- gas used in the Larger-Industrial (LI) sector
- gas used in the Residential, Commercial, and Smaller-Industrial sectors (RCSI)
- gas lost from the gas transmission and distribution systems.

AEMO forecast that less gas will be used for generating electricity (see Section 7) and in the Larger-Industrial (LI) sector (see Section 8). However in the buildings sector, AEMO does not yet forecast that much change will occur over the next 20 years. Interestingly, AEMO recently indicated that their next version of gas forecasts will, for the first time, include acknowledgement of the practice of "economic fuel-switching" from gas to electricity in the buildings sector (26). (See Section 9.)

The MEI Scenario – where gas demand declines more steeply than AEMO's "low" forecast

MEI's view is that fuel-switching in buildings has the potential to become a significant near and medium-term phenomenon (see Sections 9 and 10). Because AEMO do not yet reflect fuel-switching in their forecasts, AEMO's "low" gas demand scenario may not be low enough to bracket all reasonably-possible outcomes. The "MEI Scenario" presented in this report takes fuel-switching into account.

In the MEI Scenario (see Figure 3 above and Section 9), as a result of fuel-switching in buildings and declining gas demand in other sectors, demand for gas in eastern Australia falls to approximately <u>half</u> of the 2012 peak over the next ten years. Later sections of this report discuss some of the consequences of rapidly declining gas demand.

6. Declining gas demand dampens calls for new infrastructure

AEMO, in their 2013 Gas Statement of Opportunities (27), highlighted gas supply concerns for winter days in New South Wales starting in 2018. However, in their 2014 Gas Statement of Opportunities (28), AEMO declared there were no longer supply concerns for NSW or for anywhere in eastern Australia through until 2034. Contributing to this change was a reduction in AEMO's gas demand forecasts, including a 17% reduction in forecast gas demand for NSW specifically. The view that no new supply infrastructure was required in eastern Australia was foreshadowed by research done by the University of Melbourne Energy Institute (1).

7. Less gas to be used for electricity generation

Over the next five years, according to AEMO forecasts, the amount of gas used for electrical power generation (GPG) will dramatically decline (5). (See Figure 4.) This occurs because of rising gas prices, the lack of a carbon price, and the expansion of renewable electricity generation (wind and solar). Also, the failure of electricity demand to grow at an historical pace has led to a surplus of existing coal-fired electricity generation capacity in eastern Australia against which gas cannot compete.

In the near term, significant volumes of low-cost "LNG ramp gas" are being disposed to electricity generation (29). However with the last of the six LNG production facilities in Queensland nearing start-up, low-cost LNG ramp gas is being removed from that market (30).

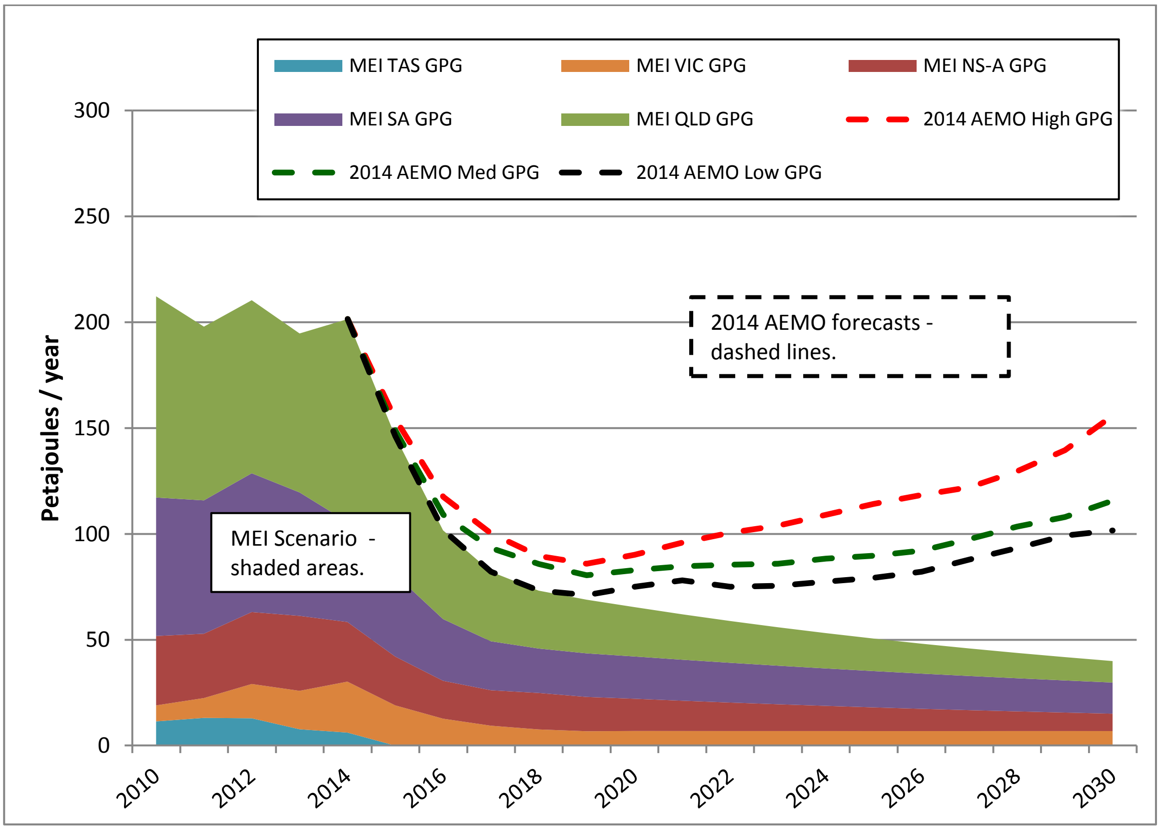

Figure 4: Gas used for electrical power generation (GPG), actual and forecasts[5].

[5] "NS-A" refers to New South Wales and the Australian Capital Territory.

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As shown on Figure 4, AEMO's forecasts for the electricity-generation sector show gas demand rebounding in around 2020 on the expectation that coal plants will be retired and gas-powered generators will be used to take their place (5). In contrast to AEMO's forecasts, the MEI Scenario projects the continuous decline of gas demand in this sector because the following factors prevent gas from returning to this sector in any significant way:

- high gas prices persist
- renewable energy and energy storage penetration increases[6]
- the implementation of electricity demand-management practices.

As shown by Figure 5, output from AEMO's electricity Generation Expansion Plan (31) is consistent with the MEI Scenario, where very little gas will be used for electricity generation.[7] However AEMO apply subsequent market modeling methods to arrive at the forecasts presented in Figure 4 (32).

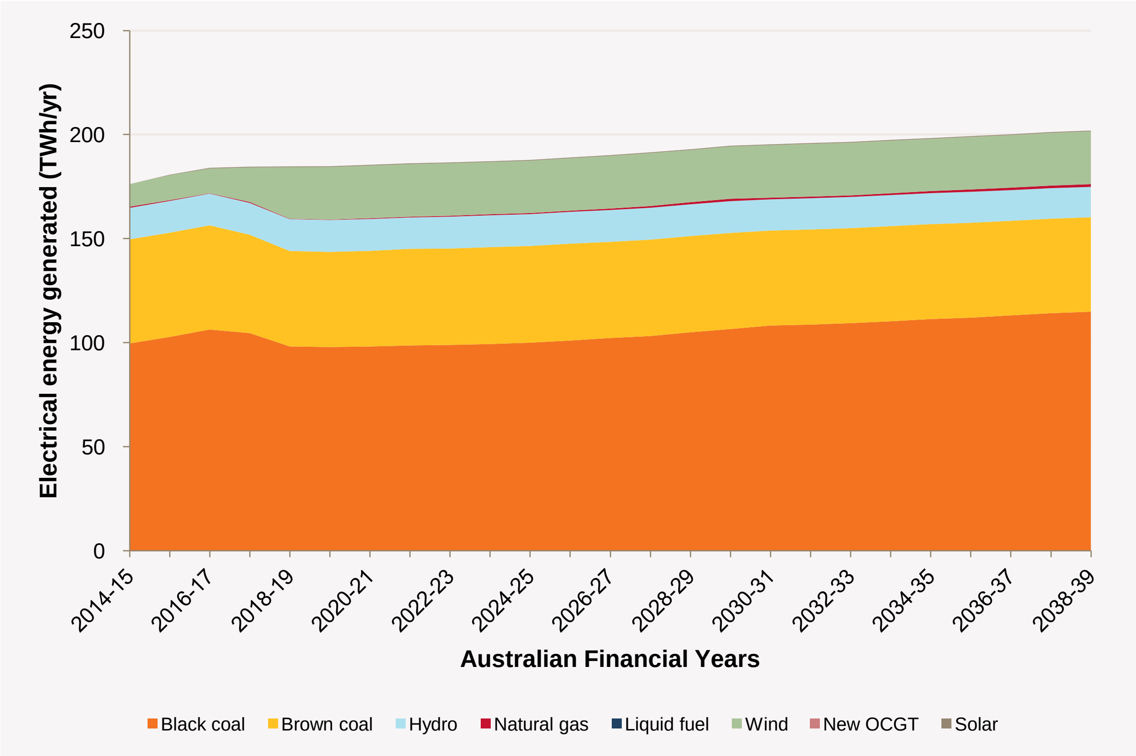

Figure 5: Gas will be used sparingly for electricity generation, according to the AEMO Generation Expansion Plan (31).

[6] A recently announced policy of the Australian Labor Party would increase the use of renewable energy in electricity generation from 14% in 2014 to 50% in 2030. The Australian Government has not announced a target for 2030. AEMO's Generation Expansion Plan targets 41,000 GWh of electricity derived by large-scale renewables in 2020.

[7] In the Australian Financial Year 2020-21 (for example), Figure 5 shows just 0.34 TWh/yr of electricity which would have been generated by burning only ~ 3 PJ/yr of gas.

8. Gas demand declines in the Larger-Industrial sector

AEMO forecasts that gas demand in the Larger-Industrial sector[8] will decline because of industrial closures and less favourable economic conditions, including increasing gas prices (5).

The MEI Scenario adopts AEMO's "low" forecast, as shown in Figure 6. Gas demand in the Larger-Industrial sector (LI) declines by 40% from 2014 to 2030 (an average of over 3%/yr).

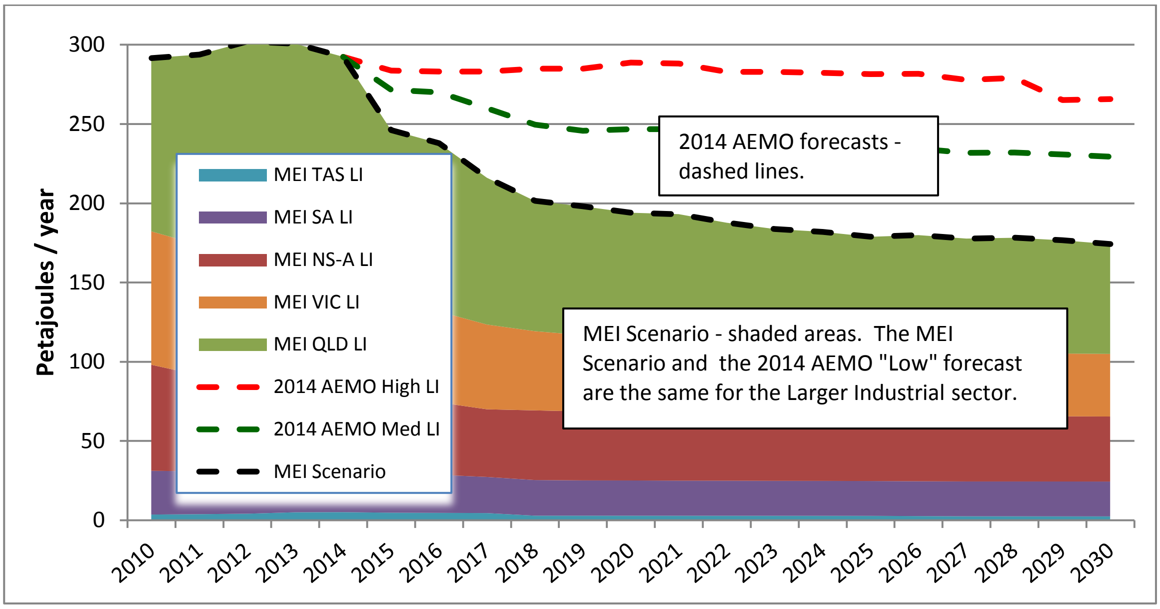

Figure 6: Gas used in the Larger-Industrial (LI) sector.

Eastern-Australian industries burn for process-heating approximately 93% of the gas they purchase. Chemical feedstocks are often cited as a critical market for gas. However, only about 20 PJ/yr[9] of reticulated gas[10] (~ 3% of all reticulated gas used in eastern Australia) is required as chemical feedstock.

[8] AEMO define "Larger-Industrial" as consumers of more than 10 terajoules of gas per year.
[9] (7) and other information sources.
[10] Reticulated gas is primarily composed of the molecule methane. A separate gaseous hydrocarbon product composed primarily of the molecule ethane is used as chemical feedstock in Altona, Victoria, and Botany Bay, NSW. However, given that ethane is generally more highly valued than the more-common methane, ethane is not generally used as fuel. Ethane is therefore not included in the figures above.

In the MEI Scenario, industry's <u>share</u> of gas demand grows

In the MEI Scenario, the fraction of all gas consumed in eastern Australia that is used in the Larger-Industrial (LI) sector increases from 44% in 2015 to 58% in 2030. This indicates a movement of gas-use away from sectors where economic substitutes are readily and economically available (gas used for electricity generation and in buildings) and toward sectors where economic substitutes are less available and gas is more highly valued. As will be shown in Section 12, in twenty years time, approximately 70% of the gas used in the Larger-Industrial sector can be sourced from gas "saved" in the Residential, Commercial, and Smaller-Industrial sector.

This contrasts with AEMO's 2014 "low" demand forecast where the share of gas used in the Larger-Industrial sector *falls* from 44% in 2015 to 39% in 2030 as gas is preferentially consumed in lower-value applications such as for heating buildings and water. MEI's view is that this outcome is unlikely.

Fuel-switching potential in manufacturing

In manufacturing, fossil gas is used to provide process heat at various temperature levels.
As the price of gas rises, lower-temperature process heat can be economically provided by energy sources other than fossil gas. In those process applications where fossil gas is used to provide higher-temperature heat (e.g. greater than 1300°C), it is more challenging to find economic alternatives to gas. In a draft study for the Australian Renewable Energy Agency (ARENA), IT Power quantified the amount of gas-derived energy used at various temperature levels and potential renewable energy alternatives (33). (See Table 2.) Electricity-based technologies (e.g. heat pumps, electric-induction heating, electric-resistive heating, electric-arc heating) can be powered by renewable or non-renewable energy sources and some of these technologies can be used to achieve high process temperatures. However, as a result of increasing gas prices and the lack of a price on carbon, industrial fuel-switching from gas to coal may also occur (7).

Table 2: Process heat supplied by fossil gas in manufacturing and renewable energy alternatives

Process heat level used in manufacturing	**Less than 250°C**	**250°C to 1300°C**	**Greater than 1300°C**
Share of total process heat requirement (33)	9%	45%	47%
Applicable renewable energy technologies for process heat generation			
Electric heat pump – air source	yes		
Electric heat pump – ground source (geothermal)	yes		
Geothermal - direct	yes		
Biomass combustion	yes	yes	
Biogas combustion	yes	yes	yes
Solar thermal - direct	yes	yes	yes

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Energy-efficiency gas-savings in manufacturing

ClimateWorks described typical historical Australian-industrial energy-efficiency improvements that reduce energy demand by 1%/yr (34). Energy efficiency improvements of that order could reduce gas demand in the manufacturing sector by approximately 10% by 2025. Rapidly-rising gas prices could increase the uptake of energy-efficiency measures above the pace historically experienced in the manufacturing sector.

In its 2013 work for the Industrial Energy Efficiency Data Analysis (IEEDA) project commissioned by the Australian and state governments through the National Strategy on Energy Efficiency, ClimateWorks (35) summarised potential energy savings averaging 11% that were identified by the manufacturing industry across Australia, as shown in Table 3. Of the energy efficiency opportunities identified by industry, some will have been implemented already (many with a payback period of less than two years), implementation may be under way for others, but some were classified as not being economically attractive at the time. The onset of rising gas prices may mean that the economics of gas-saving projects has improved so that more projects can now proceed.

Table 3: Potential energy savings in manufacturing

Manufacturing sub-sector	**Potential energy savings** (35)
	(% of total energy used)
Chemicals and energy manufacturing	16 %
Other manufacturing, construction and services	14 %
Metals manufacturing	7 %
Average across all industries	11 %

Various case studies describing heat-energy-saving opportunities in Australian industry have been documented (36).

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9. The MEI Scenario includes declining demand for gas in buildings

This and the following two report sections explore the concept that gas used in eastern-Australian buildings has begun a long-term decline, leading to a future where very little gas is used in buildings and light industry and rather is predominantly consumed by higher-value larger-industrial applications.

Figure 7 shows that the greatest part of demand in the residential, commercial, and smaller-industrial sector (RCSI[11]) sector is for residential gas use. According to AEMO (5), gas used in the RCSI sector peaked in 2012 and by 2014 had declined by 6%. Figure 7 also shows AEMO's high, medium, and low forecasts for the RCSI sector (dashed lines). Unlike AEMO's forecasts of gas demand in the electricity generation and Larger-Industrial sectors, the dashed lines indicate that AEMO are not yet forecasting any significant gas demand decline in the RCSI sector.

AEMO's forecasts for the RCSI sector (dashed lines in Figure 7) contrast with the MEI Scenario (shaded areas in Figure 7) in which significant economic fuel-switching from gas to electric appliances occurs.

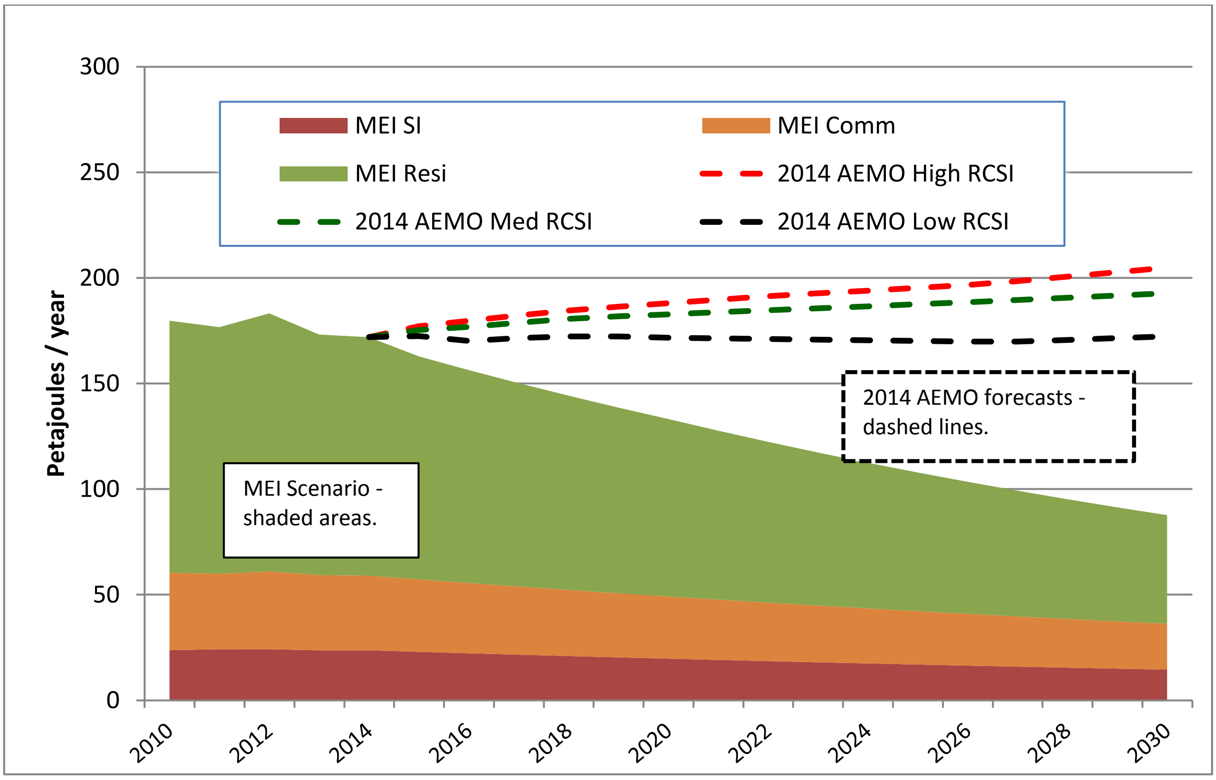

Figure 7: Gas used in the residential, commercial, and smaller-industrial (RCSI) sector.

[11] AEMO define "smaller-industrial" (SI) consumers as those using less than 10 terajoules of gas per year.

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In the MEI Scenario, by 2025 gas demand in the RCSI sector declines by 40% from the 2012 peak. This is a decline of 75 PJ/yr. Compared with the AEMO “medium” forecast, the MEI Scenario consumes ***~ 1,000 petajoules less gas*** in this sector over the period 2015 to 2030, which is an accrued volume of gas equivalent to a large gas field. (See Section 16.)

As mentioned above, the greatest part of demand in the RCSI sector is residential gas demand, and this is shown for each state in Figure 8. Actual residential gas demand in eastern Australia is shown for the years 2010 to 2014.

As shown in Figure 8 and Table 4, in 2014 Victorian residential gas demand (76.3 PJ/yr) was greater than residential gas demand in all of the other eastern Australia states combined. This is because of Victoria’s greater population (compared with Tasmania and South Australia), more southerly latitude (compared to Queensland and New South Wales / Australian Capital Territory) and historical availability since the early 1970’s of relatively low-cost gas from the offshore Bass Strait oil and gas fields (37).

Residential gas demand in New South Wales (including the ACT) follows Victoria, at 20.6% of the total. Residential gas demand in Queensland (2.8%) and Tasmania (0.5%) is small compared with the other eastern-Australian states/territory.

Declining residential gas demand in South Australia has recently been forecast by Core Energy (38).

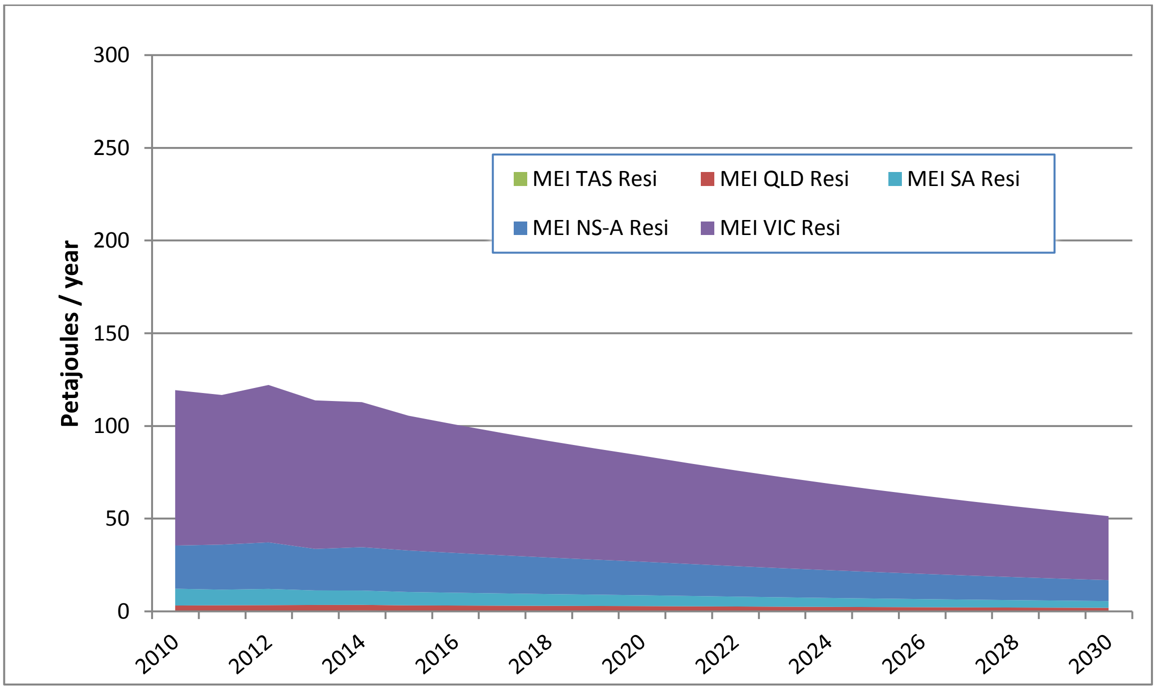

Figure 8: Residential gas demand (actuals since 2010 and MEI Scenario for 2015 to 2030. (MEI) Note, no AEMO forecasts of residential gas demand are available for comparison.

As shown in the following tables, residential gas demand can be broken down into four services: space-heating, water-heating, cooking, and other. Table 4 highlights that of all gas used in eastern-Australian residences in 2014, more than half (55.4 PJ/yr) was used just for Victorian space-heating. The next greatest use was for Victorian water-heating (16.9 PJ/yr).

Table 4: Breakdown of 2014 residential gas demand (petajoules / year) (MEI)

State/territory	Space-heating	Water-heating	Cooking	Other		Total
	(PJ/yr)	(PJ/yr)	(PJ/yr)	(PJ/yr)		(PJ/yr)
Queensland	0.1	1.7	0.5	0.5		2.8
NSW / ACT	7.8	9.3	2.3	1.2		20.6
Victoria	55.4	16.9	3.3	0.7		76.3
Tasmania	0.3	0.1	< 0.1	0.1		0.5
South Australia	2.4	3.5	1.0	0.3		7.2
Total	66.0	31.5	7.1	2.8		107.4

Table 5 shows gas demand for each service as a percentage of the state-total residential gas demand. In 2014 the greatest use of gas in Victorian and Tasmanian homes is for space-heating. On the other hand, in Queensland, New South Wales / ACT, and South Australia, gas used for water-heating is more dominant.

Table 5: 2014 gas demand for four residential services, as a % of state-total residential gas demand (MEI)

State/territory	Space-heating	Water-heating	Cooking	Other	Total
Queensland	4%	61%	18%	18%	100%
NSW / ACT	38%	45%	11%	6%	100%
Victoria	73%	22%	4%	1%	100%
Tasmania	60%	20%	~0%	20%	100%
South Australia	33%	49%	14%	4%	100%

Figure 8 illustrates that by 2025 in the MEI Scenario, residential gas demand has fallen to half of the 2012 peak. As described in the following sections of this report, the following drivers of gas demand in buildings are included in the MEI Scenario:

- economic fuel-switching from gas to efficient-electrical appliances
- economic energy-efficiency measures
- other consumer price and behavioural responses
- warmer winters.

10. Economic fuel-switching in the residential sector

This section describes how, in eastern Australia, there are potentially 500,000 to 1,000,000 homes where residents are unaware that they can immediately start to save hundreds of dollars per year on their space-heating bill. To do this, they need to turn on their existing reverse-cycle air conditioner (RCAC) heat pumps[12] and turn off their gas.

This section also describes how, longer-term, an increasing number of householders will economically invest in more RCACs and other efficient-electrical appliances that allow them to significantly reduce or totally eliminate their gas bill.

As described below, because of rising gas prices, falling electricity prices (energy-only component) especially for homes with access to rooftop-solar PV, and the emergence of highly-efficient-electrical appliances, the time is not far away when very little gas will be used in Australian homes and commercial buildings.

Economic fuel-switching in the buildings sector will free up significant amounts of gas for use by industry.

What is economic fuel-switching?

In this report, "economic fuel-switching" is the concept where gas consumers switch to using electrical appliances for their space-heating, water-heating, cooking, and possibly other heating needs.

Residential fuel-switching from gas to renewables-based electricity, in concert with energy-efficiency measures (see Section 11), was proposed by Beyond Zero Emissions in 2013 as a way for homeowners and commercial building managers to reduce greenhouse gas emissions and move to 100% renewable energy (39). In 2014, ClimateWorks likewise suggested fuel-switching from gas to renewables-based electricity was key to a deep-decarbonisation scenario (34).

[12] Refrigerators and most home air conditioners are heat pumps that use a refrigeration cycle to move heat "uphill", in a sense, from a cold location to a warmer location. A reverse-cycle air conditioner (RCAC, known simply as a "heat pump" in Tasmania and overseas) is a device that can shift heat from inside of a building to outside (usually in summer) and from outside of a building to inside (usually in winter). Heat pumps for residential space-heating have been sold in the United States since the 1970's. Sales there are now on the order of two million per year.
An RCAC operating in heating mode is essentially recovering free renewable ambient heat (a form of solar energy) from the air outside of the building, raising the temperature of that heat, and shifting it to inside the building. In so doing, RCACs, with efficiencies of over 500% for top-of-the-line models, are far more efficient and have lower operating costs than simple electric-resistive heating devices (fan heaters, oil column heaters, panel heaters, etc.) that achieve efficiencies of only 100%, and also have superior efficiency to gas-fired heaters that are limited to efficiencies of less than 90% and perhaps as low as 50% or less.
Heat-pump water heaters (essentially RCACs that heat water) are eligible for renewable energy credits in Australia. RCAC space-heaters are eligible for renewable energy credits in the UK but not in Australia.

In 2014, the Grattan Institute found that following an increase in wholesale gas prices of $5 per gigajoule, typical Melbourne, Sydney, and Adelaide homes can save $1,024, $628, and $517 respectively on the combined running-costs of space-heating, water-heating and cooking if they switch from gas to efficient-electric appliances (8). (See Table 6.)

Table 6: Running costs for space-heating, water-heating, and cooking are less with electricity (8)

Capital City		Melbourne	Sydney	Adelaide
Gas	$/year	$1,606	$942	$1,071
Electricity	$/year	$582	$314	$554
Savings with electricity	**$/year**	**$1,024**	**$628**	**$517**

In 2014, the Alternative Technology Association (ATA) (20), funded by the Consumer Advocacy Panel, conducted a detailed region-by-region and appliance-by-appliance analysis identifying the economic benefits of householders switching from gas to efficient-electrical appliances for space heating, water-heating, and cooking. Covering all of eastern Australia, the ATA published results for 156 region/zone and dwelling-type combinations.

Householders can start saving immediately by heating with their air conditioner

Table 7 shows gas-versus-RCAC space-heating cost comparisons for just five of the ATA's modelled regions and home-types in eastern Australia. The largest savings identified apply to a large house in Canberra ($1,733 per year). A large home in Melbourne might save $658 per year. In every case, heating with an RCAC involved lower running costs. In no region or home type was gas heating found to be the cheapest option.

Table 7: Gas-versus-RCAC space-heating running costs, derived from analysis done by the ATA (20)**. (MEI)**

Location	**Home Type**	**Gas space-heating costs** (energy- only, excludes fixed supply charges)	**RCAC space-heating costs** (energy- only, excludes fixed supply charges)	**Heating cost savings with RCAC**	**% savings with RCAC**
		($/year)	($/year)	($/year)	(%)
Canberra, ACT	large	$2,255	$522	$1,733	77%
Melbourne, VIC	large	$1,049	$391	$658	63%
Orange, NSW	medium	$1,370	$949	$421	31%
South NSW	small	$599	$415	$184	31%
Adelaide, SA	small	$180	$124	$56	31%
This table lists only five of the 156 region/zone and dwelling-type combinations examined by the ATA.					

With respect to current space-heating practices in eastern Australia, MEI have identified that there may be between 500,000 and 1,000,000 homes (particularly in Victoria) where RCACs have already been installed, but the householder is not aware that using the RCAC in winter can be the cheapest way to heat their home (i.e. instead of using their gas heating). Were the householder to be informed of the possibility of savings, he/she might opt to switch off their gas heating, switch on their RCAC, and start saving money immediately.

Although Saddler reports signs that fuel-switching for space-heating is possibly already underway in NSW and the ACT (30), for many householders in Victoria, the ATA's findings will be news. This is because gas heating has traditionally been seen as the cheaper option in Victoria. As described by the ATA (20), homeowners lack the knowledge that the economics of space-heating have changed. Gas appliance marketing can often mislead consumers. The ATA recommends that it is necessary to:

> "… strengthen the regulatory oversight of the marketing of gas
> as cheaper and more efficient than electricity."

The amount of money that a householder can save is a function of the size of the home, their regional climate, and the gas and electricity prices[13] that prevail in each region/zone. The ATA made assumptions about the efficiency of gas and RCAC heating systems which will vary from home-to- home, as is described in the following sections of this report. In the author's personal in-home experience, heating costs were reduced by 70% when recently-purchased RCACs were used instead of a 20-year-old ducted-gas heating system (37) (40).[14]

Across eastern Australia, the amount of money that householders can save by using RCACs for heating instead of gas may be very large. For example, were 500,000 Victorian households able to save $500 per year, this adds up to a savings of $250 million dollars per year.

The following report sections describe in more detail how these new space-heating economics have come about because of:

- rising gas prices,
- falling electricity prices (energy-only costs, excluding fixed supply charges), especially for householders with access to rooftop-solar PV
- the emergence of efficient RCACs,
- the recognition of the poor performance of, in particular, ducted-gas heating.

[13] In these comparisons, it is appropriate to use energy-only prices, excluding fixed supply charges.
[14] As discussed later in this report, heating-cost savings achieved by using an RCAC instead of gas will depend on the effectiveness of the gas and electrical appliances being compared in delivering heat to where it is needed, the electricity and gas prices that consumers are able to negotiate with their suppliers, and well as comfort and convenience preferences.

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Residential gas and electricity prices are converging

The Victorian Government organisation Sustainability Victoria (SV) offers Victorians a comparison of gas-versus-electric heating running costs (41). In their comparison calculations, SV uses only a single electricity price of \$0.277/kWh to cover all parts of Victoria and all retail offers. Unfortunately this is an unreasonably high price to select for space-heating comparisons. For example, current available offers include off-peak electricity (energy-only, excluding fixed supply charges) of \$0.10/kWh (incl. GST), shoulder-period prices as low as \$0.14/kWh (incl. GST), and flat-tariff rates as low as \$0.17/kWh.

The gas price of \$16.6/gigajoule used by Sustainability Victoria aligns with current residential gas prices (energy-only component). This price converts to \$0.06/kWh which is not far less than the off-peak price for electricity and is about the same as recent tariffs paid to rooftop-solar PV owners for electricity exported to the grid.[15] The significance of this comparison is that formerly electricity was viewed as an expensive form of energy while gas was seen as cheap. In reality, today the energy-only component of gas and electricity prices is converging.

Even with such a high electricity price, Sustainability Victoria's results still show RCACs to be the lowest cost option in most cases. SV and other consumer-information-oriented organisations need to offer more sophisticated comparison tools that allow users to vary inputs such as energy prices and device efficiencies.

[15] A rooftop solar PV feed-in tariff of \$0.062/kWh applies in Victoria as at 1 January 2015.

Rampant penetration of RCACs, for space-cooling and heating

Already nearly 3.9 million eastern-Australian homes (approximately half of all homes) have at least one RCAC. This is an increase of 30% from 3.0 million in 2008 (2014 ABS survey data (42)). Figure 9 shows that RCAC penetration is greatest in South Australia at nearly 60% and ranges from 53 to 47% in Queensland, New South Wales, Tasmania[16], and the ACT.

As shown in Figure 9, RCAC penetration is lowest in Victoria with only 38% of homes having at least one RCAC (42). However, penetration of RCACs in Victoria has increased from just 29% in 2008 and is expected to continue to increase, possibly reaching levels similar to those presently seen in the other eastern-Australian states.

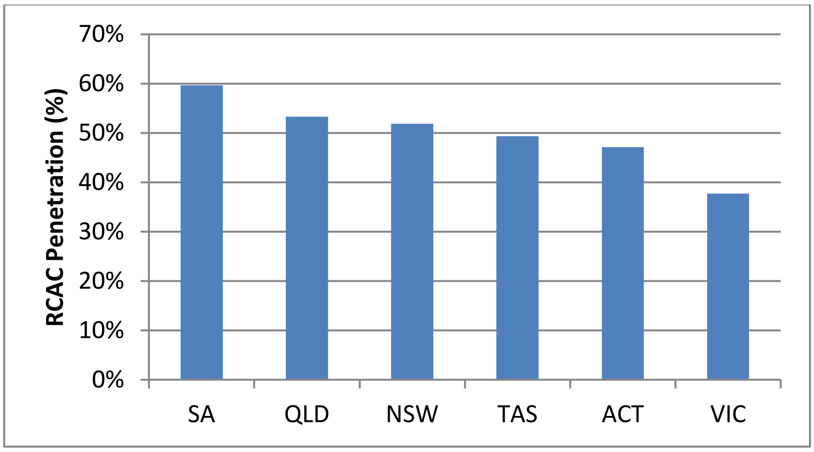

Figure 9: % of eastern-Australian homes with at least one RCAC - 2014 (42).

[16] For many years in Tasmania, RCACs have been widely used for space-heating. This is because of the historical availability of hydroelectricity and the non-availability of gas.

Relating to residential space-heating, the relevant questions are:

- In how many of these already-RCAC-equipped homes do residents use their existing RCAC(s) for space-heating?
- In homes where, to date, gas has been used for space-heating instead of an existing RCAC, how rapidly might a householder switch if they learned that their RCAC was their cheaper option?

ABS statistics do not address those questions directly. However, Figure 10 shows that electricity (RCAC and resistive) is the preferred method of space-heating, versus gas[17], in Queensland, Tasmania, South Australia, and New South Wales. In the ACT, the use of gas and electricity for space-heating is evenly split, whereas Victoria stands alone with gas being clearly the preferred method of space-heating.

Figure 10: Of homes using gas or electricity as main energy source for space-heating, % that use electricity (2014 data excluding wood, LPG, and other heating methods.) (MEI)

In the MEI Scenario, Victoria's significant use of gas for space-heating is displaced by electricity as the following occurs:

- Victorians learn that RCACs are, in many cases, significantly cheaper to operate than gas heating,
- more RCACs are deployed in Victoria for both cooling and heating purposes.

The following sections describe the common circumstances where heating with RCACs is significantly cheaper than using gas.

[17] Wood, LPG, and other heating methods excluded.

Ducted-gas space-heating is often an ineffective way to warm a home

Ducted-gas space-heating is the practice of using one central gas-combustion heater fitted with an air blower and a network of ducts (either under-floor or in the attic space) to carry warm air to the majority of rooms within a house. Around 40% of homes in Victoria and the ACT use ducted-gas space-heating, whereas in no other eastern Australia state does its prevalence exceed 4% (43).

Ageing ducted-gas systems can be inefficient at delivering heat to where it is needed (44). As with any gas heating system, some of the energy contained within the purchased gas is lost in the hot flue gases. Additional heat is lost from the ducts by the mechanisms of conduction, convection, radiation and air leakage. Under-floor ducts often go uninspected for decades and yet can suffer damage from animals, children, or under-floor maintenance or renovation activities. (See Figure 11.)

Blowing air around the house and through the ducting system can increase the leakage of warm air out of the house and the ingress of cold air. These losses can be exacerbated if internal doors block the flow of air back to the heater air intake. Lastly, ducted systems may direct heat to rooms where heat is not needed. The practice of closing a limited number of hot-air registers in unused rooms is often recommended, but this has the side-effect of over-pressuring the ducts upstream of the closed registers which then increases warm air leakage.

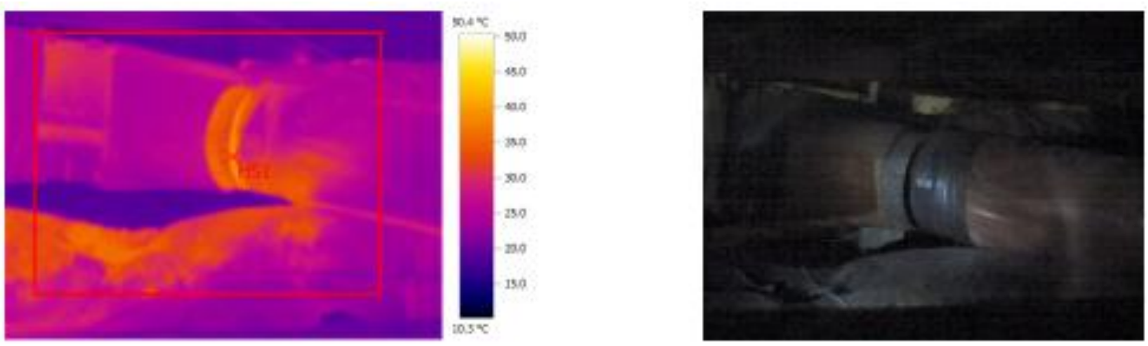

Figure 11: Thermal and visual images of crushed and parted underfloor heating ducts. Damage was unrepaired for more than ten years.

The performance of ducted-gas systems can be improved if:

- a highly efficient furnace is installed that uses condensing technology,
- robust and well-insulated ducts are installed and regularly maintained and inspected,
- the building is tightly sealed[18] to reduce over and under-pressuring the system.

The efficiency of ducted-gas space-heating systems in Australian homes can be as poor as 50% or less. In other words, in some homes half or more of the gas purchased for space-heating is, in a sense, immediately wasted and not used to effectively warm people in their homes.

Figure 12 compares an inefficient ducted-gas heating system with a non-ducted RCAC that is **13 times** more efficient (39).

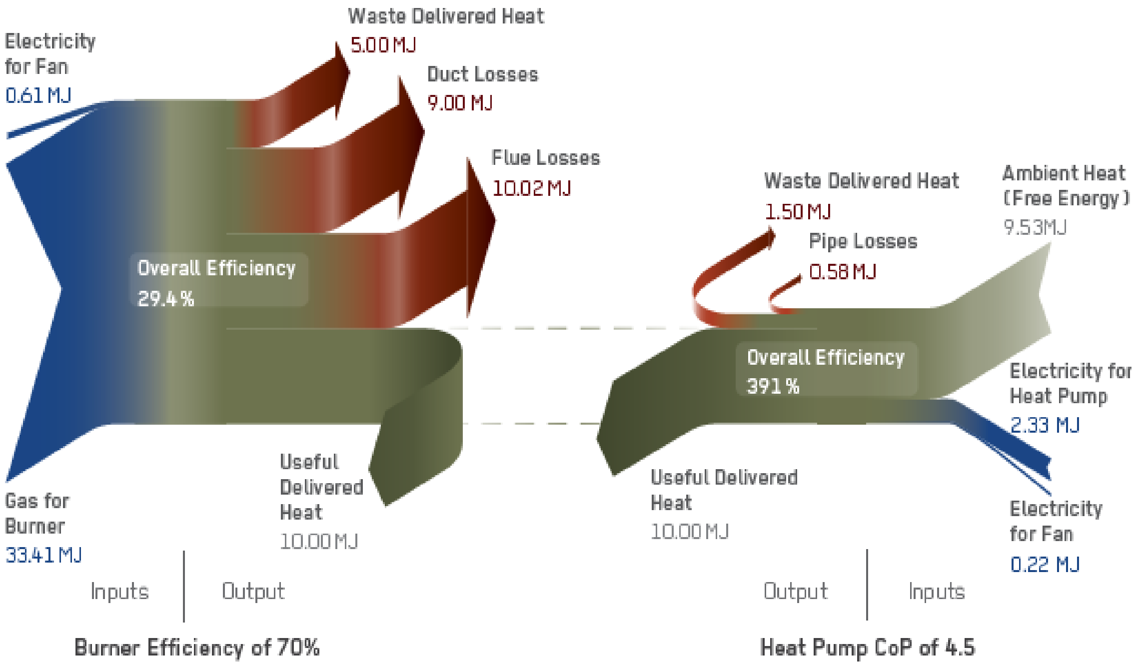

Figure 12: Comparing the effectiveness of delivering 10 megajoules (MJ) of useful heat from an ageing ducted-gas space-heating system (left-side) versus a modern wall-mounted (non-ducted) RCAC heat pump (right-side) (39).

[18] Gas heating systems must be regularly inspected to ensure there is no build-up within the home of the poisonous gas carbon monoxide, especially in "tight" or well-sealed homes that have a low level of passive air leakage.

Modern reverse-cycle air conditioners are efficient renewable-energy generators

Contrasting with the potentially-poor performance of ducted-gas, some non-ducted RCACs (see Figures 13 and 14) achieve efficiencies of more than 500% when they capture up to 4.8 units of free, renewable-ambient heat from the outside air for every one unit of electricity applied (45). If the RCAC wall unit is located in the room directly where heat is needed, energy losses are minimal.

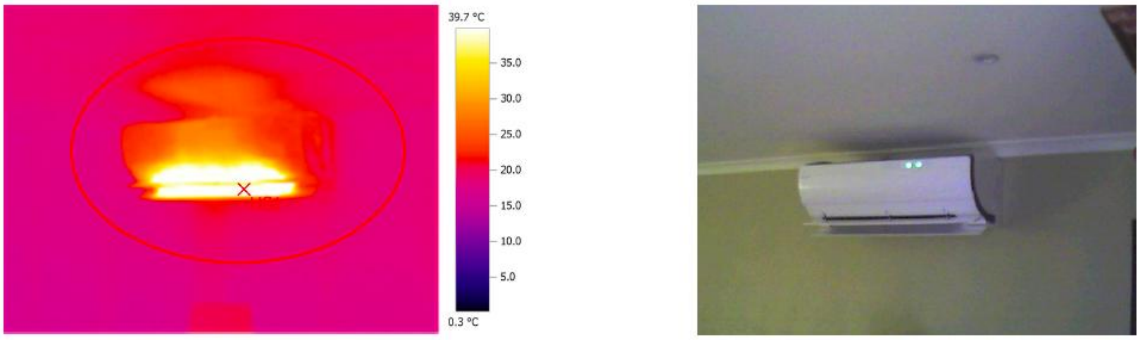

Figure 13: Thermal and visual images of an RCAC producing heat at 50˚C.

For every 1 unit of electrical energy used, up to 4.8 units of renewable-ambient heat goes in here.

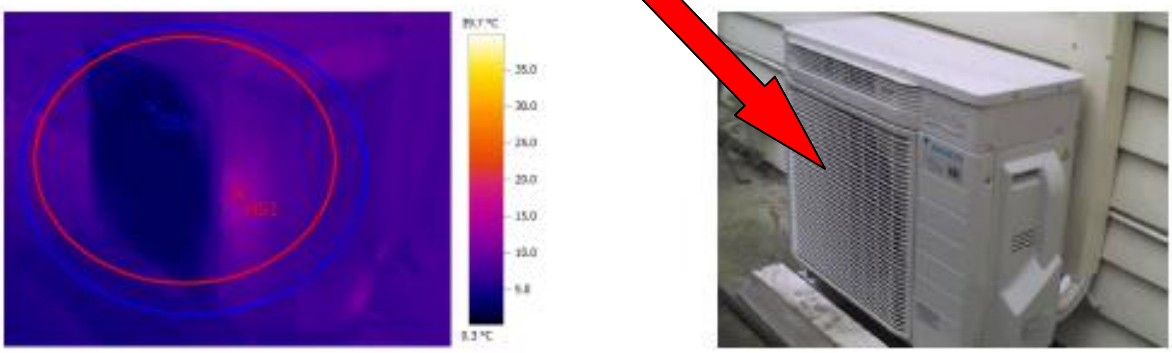

Figure 14: Thermal and visual images of exterior part of an RCAC collecting heat from 9˚C ambient air, with heat exchanger operating at 2˚C.

Unlike in the United Kingdom (46), RCACs are not eligible for renewable-energy credits in Australia. Nevertheless, RCACs are a disruptive technology and are already very significant harvesters of renewable energy in Australia, exceeding rooftop-solar photovoltaic (PV) panels in their energy recovery/production. Figure 15 illustrates that in 2014 the renewable energy recovered by RCACs exceeded that of rooftop-solar PV. In the coming years, RCAC-recovered renewable energy has the potential to double as more buildings in Australia (and in particular in Victoria, as described above) adopt this method of space-heating.

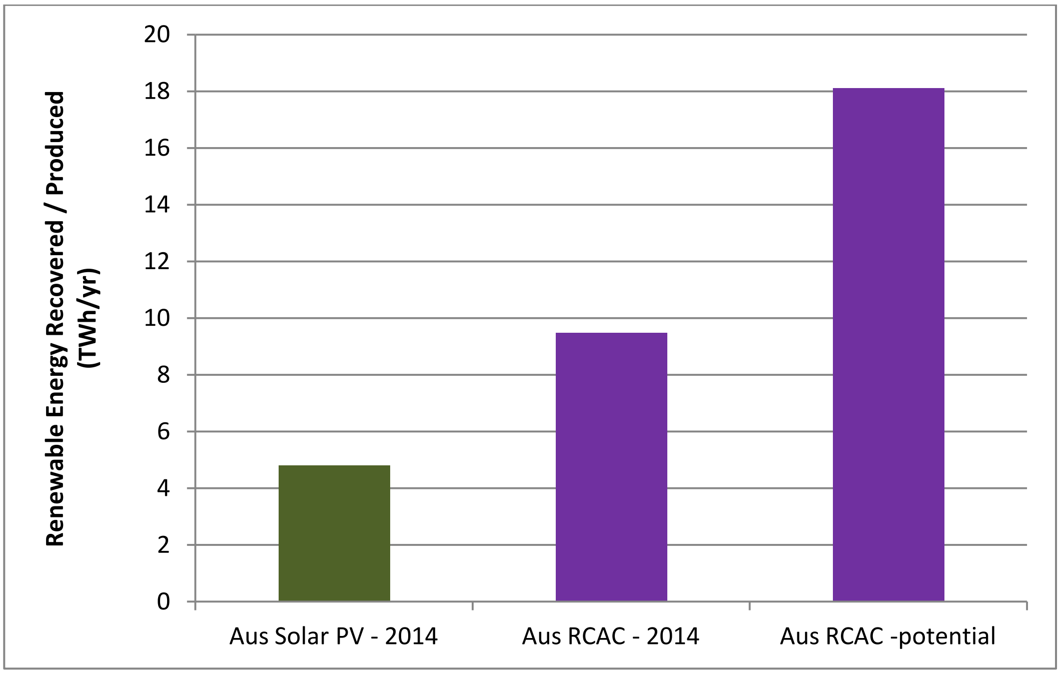

Figure 15: Comparison of Australia-wide rooftop-solar-PV renewable energy recovery/production (47) versus the amount of renewable energy recovered / produced by RCACs. (MEI)

Other aspects of space heating

Individual comfort and convenience preferences also come in to play when deciding between gas and electric heating. If residents are accustomed and familiar with using gas, switching to electricity may mean a change in habits that can take time even if cost savings are large. Residents may be willing to "pay extra" for the quick heat up time of ducted-gas, whereas with an RCAC, a timer might need to be set to allow the RCAC to achieve the same early-morning warm outcome as gas.

The dryness of both gas and RCAC heating has been cited as a comfort and health concern (48). However now available in Australia are RCACs that use a desiccant wheel to humidify the heated air in order to eliminate this concern (49).

Householders can save by replacing all old gas appliances with new electric

The ATA also identified the economic benefits of householders switching off gas as a householder's three key gas appliances (space heating, water-heating, and cooktops) near the end of their lives. For example, the Sydney-area owner of a "large home" presently heated by gas can save $1,284 (net present value) by switching to an RCAC when their gas heater is in need of replacement (20).

Governments can now save on gas infrastructure costs

The ATA found that there is no economic need for any new homes or suburbs anywhere in eastern Australia to connect to gas. Similar to recommendations made by the Grattan Institute (8), the ATA report called for an end to government subsidies for expanding gas supply networks, specifically recommending that

> "an urgent review of policy and programs that subsidise/support the expansion of gas networks is required."

The Grattan Institute reported that a Sydney household that uses gas for cooking and hot water could save $600/yr by disconnecting from the gas network and instead using electricity to supply these services. The Grattan analysis ignored the up-front costs of buying new appliances (8).

These studies call in to question the need for homes to be connected to both the electricity grid and the gas grid. Subsidies as high as of $60,000 per home have been reported for Victoria's rural gas-grid extensions known as the "Energy for the Region's Program", should as few as 20% of homes take-up the gas option (50). According to the Grattan Institute:

> *"People in regional Victoria may initially welcome the option of connecting to natural gas. With the predicted increase in gas prices, however, households in regional areas may well be better off from continuing to use other fuel sources, rather than connecting to the gas network. In some cases, regional consumers who commit to gas in good faith may find themselves financially disadvantaged"* (8).

Infrastructure costs can be reduced, if rather than expanding the gas grid, it can be rationalised. As consumers switch from gas to electricity, the existing electricity grid would become more productively used.

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Hot water fuel-switching options

Some homeowners can save hundreds of dollars per year by switching from gas hot water to a heat-pump water heater (HPWH, shown in Figure 16). Already more than 170,000 heat-pump water heaters have been installed in eastern Australia with most of them receiving renewable energy certificates (51). Rooftop-solar-thermal hot water generators, of which there are more than 700,000 in Australia, if electric-boosted, can also be another economically-attractive gas-free hot water option in regions that have a superior direct-solar resource (39). HPWHs can act as “energy-storage hot-water-batteries” if:

- charged at night when grid-supplied electricity is cheap, or
- charged at mid-day when a home’s solar PV panels would otherwise be exporting excess electricity (52).

Figure 16: Heat-pump water heater (HPWH).

For every 1 unit of electrical energy used, up to 3.5 units of renewable-ambient heat goes in here.

Induction cooktops, gas-free homes, and the gas grid death-spiral

The installation of RCACs, HPWHs (or solar-thermal hot water with electric boost), and efficient and controllable induction cooktops (see Figure 17) allows "all-electric" Australian homes to become gas free (39) (53). This "second electrification" of the Australian home is also being driven by the widespread deployment of rooftop-solar photovoltaic (PV) panels[19]. In future, electricity storage batteries and electric vehicles will also become widely used.

Figure 17: Efficient, controllable electric-induction cooktop – where the pot or pan acts as the heating element.

A utility market "death spiral" may occur when declining gas or electricity sales (due to factors such as customers switching fuels, implementing energy-efficiency measures, or making behavioural changes, etc.) require suppliers and distributors to further increase prices in order to maintain revenue. These ever-higher prices then further accelerate demand decline and result in a shrinking customer base. This phenomenon has been described regarding Australia's electricity industry (54).

Eastern-Australian gas consumers who opt to completely disconnect from the gas network can eliminate the gas bill with its fixed charges of generally more than $200 per year (20). With declining gas volumes, energy distributors and retailers may increase fixed supply charges in order to maintain revenue. Given that electricity offers a broader range of services than gas, and that gas services in most buildings can be provided by electric alternatives, the gas network may face a greater risk of a death spiral than does the eastern-Australian electricity grid (55) (56).

[19] According to the Clean Energy Council report "Clean Energy Australia 2014", as at the end of 2014, 1,421,601 household rooftop-solar photovoltaic (PV) systems have been installed in Australia, or one installation for every six Australian homes.

AEMO have only begun to model fuel-switching

As mentioned in Section 5, to date AEMO's official annual gas forecasts (5) do not indicate that the amount of gas used in buildings will change much over AEMO's 20-year outlook planning period. However AEMO's recently published "Emerging Technologies Information Paper" (26), does, for the first time, provide some quantitative analysis of fuel-switching in residential buildings.[20]

Unfortunately, AEMO's Emerging Technologies Information Paper examines only the economics of residents making future investments in new heating systems. AEMO ignores the potential for residents who already have both gas space-heating and RCAC(s), but who have traditionally used only gas for heating, to suddenly understand that using the existing RCAC is the cheaper option, and to then make a switch.

Nevertheless, AEMO's Emerging Technologies Information Paper indicates that electricity demand could, in around 2034, increase because of fuel-switching by 2,552 gigawatt-hours per year (GWh/yr). Curiously, AEMO have not published any figure for the corresponding decline in gas demand. Using a factor of five[21], 2,552 GWh/yr converts to a decline in gas demand, due to residential fuel-switching, of 46 PJ/yr. This is a very significant reduction in gas demand (57). However, this potential gas demand decline is not as imminent nor as great as the 75 PJ/yr decline in residential gas demand (by 2025) projected by the MEI Scenario (due to fuel-switching and other drivers as described in Section 9). The gas savings to be made in the MEI Scenario are greater than AEMO's assessment in part because AEMO has not yet included the possibility of "immediate" fuel-switching.

New ATA modelling, done for MEI, confirms fuel-switching reduces gas demand

The ATA has created a "bottom-up" residential fuel-switching time-series model that incorporates the data from the "Are We Still Cooking with Gas Report" (20). It also models residents with existing RCACs progressively learning that using that their RCAC can be the cheaper way to heat a home, and then making an immediate switch.

MEI contracted the ATA to model multiple future residential fuel-switching scenarios. The ATA's results confirm the fuel-switching outcomes included in the MEI Scenario. Of interest is the ATA's finding that a greater degree of fuel-switching occurs for space-heating as opposed to water-heating. This is because of the space-cooling side-benefits achievable with RCACs and the reflexive nature of "emergency" hot water service replacement decisions, among other factors.

[20] AEMO plans to extend this analysis to commercial and industrial consumers.

[21] See the last line of Table 7 where ratios of gas-replaced-by-electricity range from three to 18 in the chosen examples.

11. Energy efficiency and other factors reducing gas use in buildings

In the MEI Scenario, fuel-switching drives the greatest reduction of gas demand in buildings. However this section describes additional gas demand drivers including energy-efficiency measures, consumer behaviour and price responses, warmer winters, and energy-retailer marketing activities.[22]

Energy-efficiency measures: "exploring" for gas in your attic

In eastern Australia, gas "exploration" and "mining" can economically take place in eastern-Australian attics and lounge rooms via the deployment of energy-efficiency measures such as insulation (see Figure 18), draught-proofing, and improved windows and window treatments (e.g. drapes and blinds) (58) (59) (60) (61). According to the Australian Bureau of Statistics, 30% of Australian homes still have no form of insulation (62). The Insulation Council of Australia and New Zealand (ICANZ) cite five-year economic payback for insulation upgrades (63). Sustainability Victoria reported that an energy efficient household can save about 40% on an average household's energy costs (64).

Figure 18: Uninsulated attic in Melbourne, Victoria.

[22] In the MEI Scenario, double-counting of gas demand drivers has been avoided. For example, in the case where a switch from gas to electric space-heating occurs, subsequent energy-efficiency measures (e.g. insulation) will reduce electricity demand, not gas demand.

Hot water systems and piping are also often poorly insulated, if at all. (See Figure 19.)

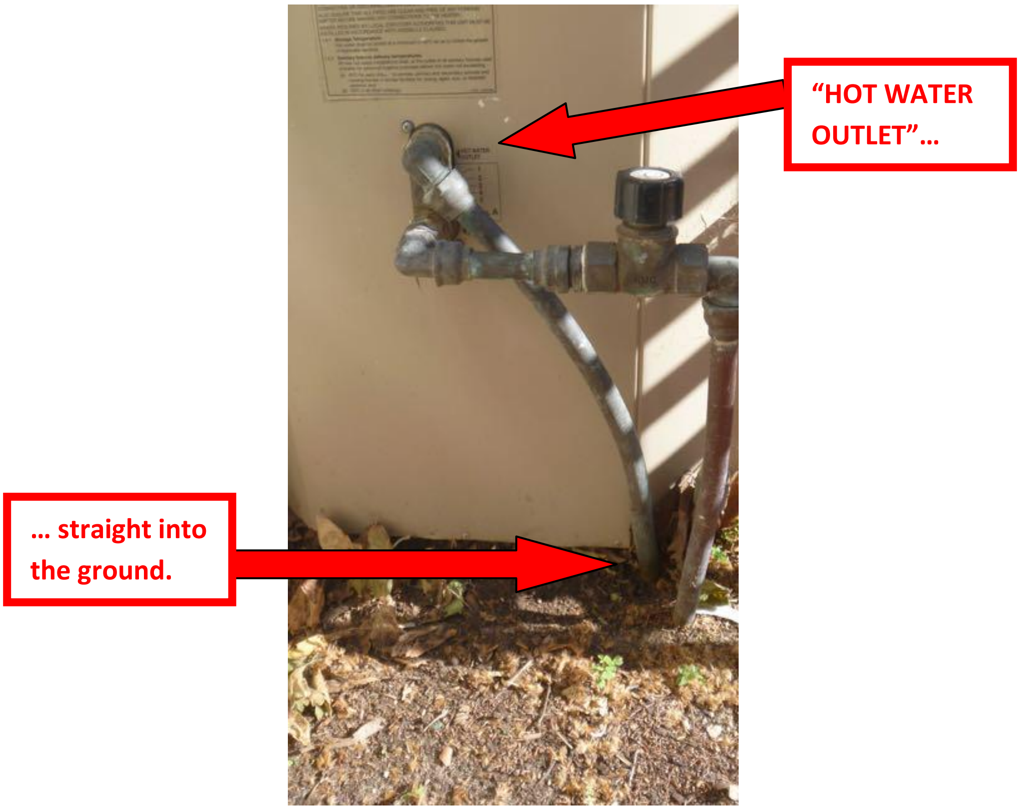

Figure 19: Uninsulated hot water outlet pipe running directly into the ground (Victoria).

Continuing deployment of efficient showerheads can reduce the amount of gas used for hot showers by over 40% compared with inefficient showerheads (65).

Saddler found that by 2030, an approximate 1 PJ/yr (10%) reduction in the amount of gas used in NSW commercial buildings may result from a range of Commonwealth building energy-efficiency measures in place in 2013 (66).

Providing warmer and cheaper-to-operate homes can lead to improved home health outcomes especially for the sick and elderly (67).

Consumer behavioural and price responses

Increasing gas prices will increase consumer bills as quantified in Section 4. Users of larger-than-average amounts of gas will, of course, see larger cost increases. Consumers may respond to larger bills by changing behaviours. Saddler describes how consumers responded to rising electricity prices being often in the news and a topic of political debate, by reducing their demand for electricity (66). If rising gas prices become a widespread news topic, gas consumers could respond in a way similar to that seen with electricity price rises.

Winters are getting warmer

Core Energy describes the impact of warmer winter temperatures, caused by climate change and the urban-heat-island effect, on reducing gas demand (65). NIEIR quantifies this for the New South Wales buildings sector at 0.095 PJ/yr, year-on-year as winter temperatures rise each year (65). Over ten years, this amounts to a 1 PJ/yr reduction in gas demand in NSW.

In their August 2014 earnings report, AGL cited a "record mild winter" as a reason that gas sales were down 9.3% for the full financial year ending 30 June 2014 (68). Likewise, Energy Quest (69) reported that the warmest early-winter period *on record* in NSW contributed to non-electricity-generation related gas demand across eastern Australia being down 10% in the quarter ending 30 June 2014.

Electricity-only retailers actively promoting fuel-switching from gas

Some energy retailers sell mostly electricity and little or no gas. Especially while electricity demand remains at below historical levels (25), these retailers have an incentive to actively promote fuel-switching from gas to electricity. In Japan, this strategy allowed electricity retailers to nearly double the revenues gained from individual households (70).

12. Switching off gas in buildings frees up gas for industry

Ending gas waste, particularly in the buildings sector, will free up large volumes of gas that could have higher-value industrial uses. As shown in Figure 20, in twenty years time, approximately 70% of the gas used in the Larger-Industrial sector could be sourced from gas "saved" in the Residential, Commercial, and Smaller-Industrial sector.

In the MEI scenario, the fraction of gas used by larger industry increases from 44% (2015) to 58% (2030). This indicates the future movement of gas use away from sectors where economic gas substitutes are available, and toward the industrial sector where economic gas substitutes are less available and gas is valued more highly.

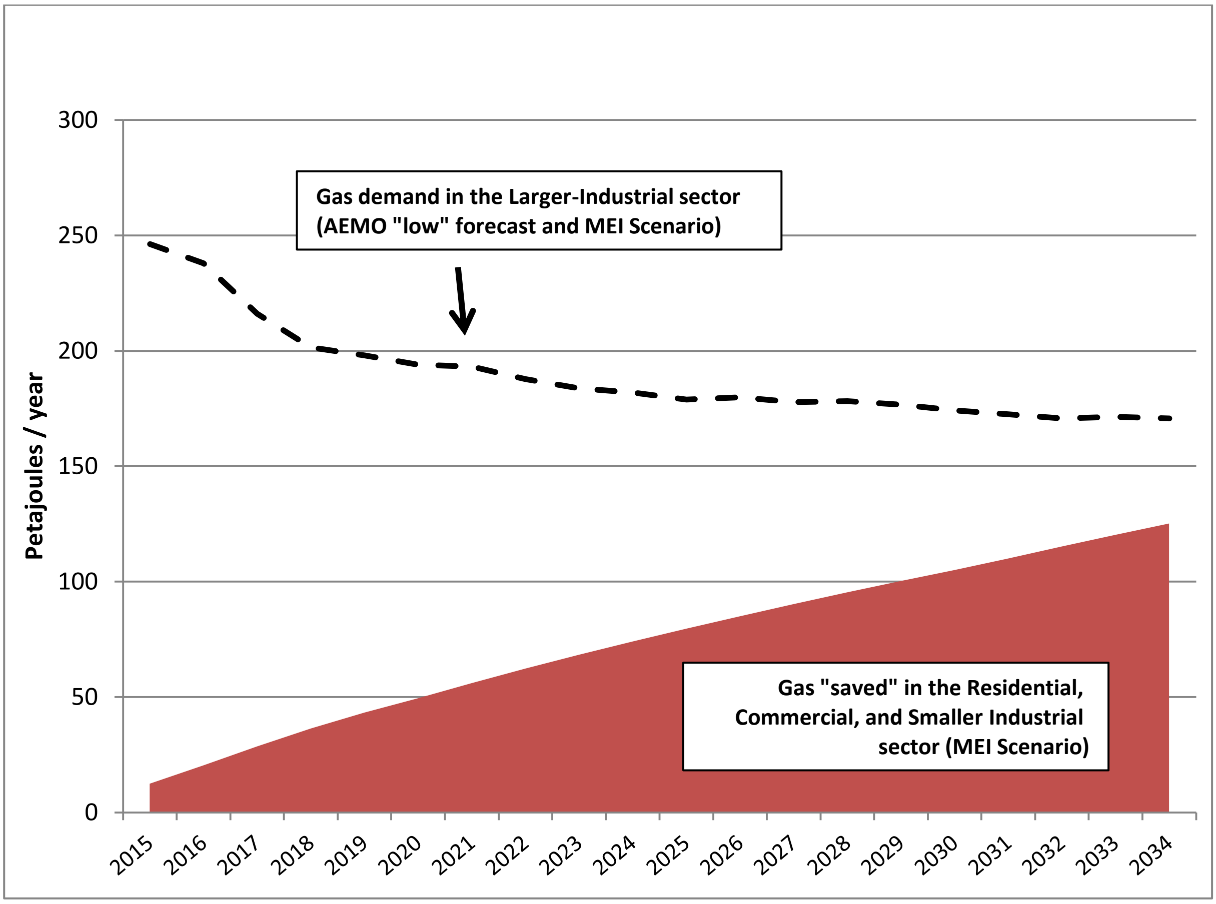

Figure 20: Demand in the Larger-Industrial sector compared with gas "saved" in the Residential, Commercial, and Smaller-Industrial sector. (MEI Scenario)

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13. Switching off gas in buildings aids decarbonisation

Energy-efficiency measures and economic fuel-switching in buildings from gas to electricity can help Australia to economically decarbonise, especially as eastern Australia's electricity is increasingly produced with renewable energy. ClimateWorks identified that virtually no gas is used in buildings by 2050 in a Deep Decarbonisation scenario (34). The ATA's study of the greenhouse gas emissions impact of gas-to-electricity residential fuel-switching (71) found:

- *"Emissions were lower when switching all three traditionally gas-fueled (space-heating, water-heating and cooking) uses to efficient-electrical appliances. This was consistent across household scenarios and across all locations apart from in Mildura, Victoria, where there was a small increase as a result of the switch.*
- *Space-heating was consistently found to be less emissions-intensive when delivered by efficient-electrical appliances, as opposed to gas.*
- *The emissions impact of water-heating varied by location – with all Victorian and some NSW/ACT locations experiencing a modest increase in emissions with a switch to efficient-electric, while South Australia, Queensland and other parts of NSW experienced a reduction.*
- *Minor emissions increases from switching to efficient-electric are likely to be even smaller in coming years as Australia's electricity grid utilises more renewable generation."*

14. Declining gas demand decelerates gas reserves depletion

Figure 21 compares how gas reserves are consumed in AEMO's 2014 medium forecast versus the MEI Scenario. In the AEMO forecast, approximately 10,000 petajoules of gas are consumed over the period 2015 to 2032. In the MEI scenario, because gas demand declines in all sectors, 10,000 petajoules of gas is not consumed until a decade later. This illustrates the opportunity that declining gas demand presents for measured consideration of reserves depletion in concert with identification of gas supply and demand management options. (See Section 16.)

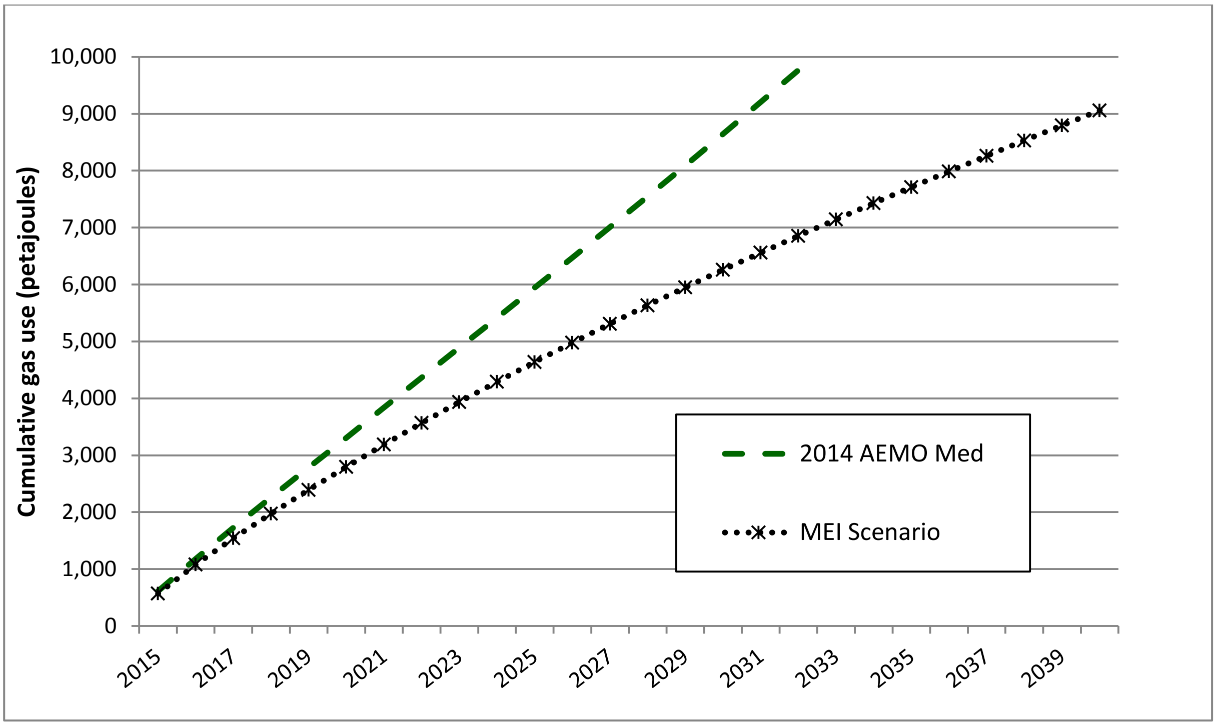

Figure 21: Eastern Australia cumulative "domestic gas" consumed / reserves depletion. (MEI)

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15. New industries? Biogas and gas for transport

Biogas

As fossil gas prices rise and the preference for lower-carbon energy and chemical feedstock sources increases, the distributed production of renewable biogas may become economic in eastern Australia. Renewable biogas is gas derived from biomass sources and municipal waste.

Bioenergy and gas from waste (72) is proving to be a significant resource in countries such as Denmark and Germany (73).

In 2013, the Sydney of City identified that up to 50 PJ/yr of gas[23] could be produced from sources located around Sydney (74) (75). As an example, Sydney Water reports that up to 5 PJ/yr of gas could be created available from their own waste sources (76).

In 2012, the CSIRO's work for AEMO's "100% Renewable Energy Study" for eastern Australia identified a recoverable biogas resource of more than 200 PJ/yr (77). This can be compared with 2030 gas demand in the MEI Scenario of approximately 300 PJ/yr.

Gas for transport

Neither AEMO's forecasts nor the MEI Scenario explicitly describe any significant or growing use of gas in the transport sector. Other analysts point to growing use of gas for powering heavy transport in Australia over the coming decades (34) (78).

[23] Note that the City of Sydney study does not utilise timber plantations or native forest timber. The study did include a small amount of bioenergy (~ 0.4 PJ/yr) from pine wood processing residues.

16. Needed: An Integrated Resource Plan that considers demand-side opportunities

Eastern Australia needs an Integrated Resource Plan (IRP) that considers both gas-supply and gas-demand management options such as economic fuel-switching and energy-efficiency measures. Furthermore, as fuel-switching from gas to electricity occurs, the demand for electricity will increase. Therefore consideration of electricity generation and distribution must also be part of the Integrated Resource Plan.

Examples of Integrated Resource Planning in use in the United States include the Arizona Public Service, the Public Service Company of Colorado, and PacifiCorp (79).

1990 Gas and Fuel least-cost supply planning never completed

In the early 1990's, Victoria's Gas and Fuel Corporation started work on gas demand management and least-cost supply planning (80) (81). One objective was:

> "…to provide an evaluation of the potential to enhance and/or supplement natural gas supplies in Victoria, over the next 20 years, through demand management."

Identified measures included appliance development promotion, household thermal design, and consumer education.

The Gas and Fuel Corporation described "Integrated Analysis"…

> "…in which the cost-effective demand management programs are allowed to compete against supply alternatives in the long-term supply/demand balance in order to minimise the cost of end-use energy services to the community."

However that Gas and Fuel Corporation program was terminated prior to completion.

AEMO focus has been on the supply side

To date, AEMO has tended to focus on gas-supply options to the exclusion of demand-side opportunities. This is highlighted by the following statement from Section 2.4 of AEMO's April 2015 Gas Statement of Opportunities:

> *"Analysis indicates that sufficient commercially viable reserves and resources are available to satisfy projected gas demand for at least the next 20 years. To ensure that gas consumption can be met, however, **new gas reserves need to be developed**."* (bold font added)

Indeed, AEMO's April 2015 Gas Statement of Opportunities did not highlight <u>any</u> gas demand-side opportunities.

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AEMO publishes the Gas Statement of Opportunities (GSOO) in accordance with Section 91DA of the National Gas Law. A stated aim of the GSOO is to:

> "…provide industry participants, investors, and policy-makers with transparent information to support decision-making to ensure gas – a key resource – is managed in Australia's long-term interests."

Regarding that aim, our report suggests that the current often inefficient and wasteful use of gas, particularly in the buildings sector, is not in Australia's long-term interests. AEMO and other relevant authorities should develop an Integrated Resource Plan that, in addition to supply-side opportunities, also identifies and recommends economic opportunities for fuel-switching from gas to electricity and economic energy-efficiency measures. Such a plan is likely to identify that large and economic gas "discoveries" can be found in industry and in the buildings of eastern Australia, as described in earlier sections of this report.

As an example, the 1,000 petajoules (PJ) of gas "savings" that accrues in the RCSI sector (see Section 9) is equivalent to a significantly-large gas field. This volume of gas can be compared with the Minerva field in the offshore Otway (Victoria) basin that was reported to initially contain 330 PJ of gas (82), or to the offshore Kipper field in Bass Strait (Victoria) that was reported to contain 680 PJ of gas (83).

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17. Summary of ways to ease the transition to higher gas prices

The Australian federal government, eastern-Australian state governments, and local councils can pursue policies to ease the transition to higher gas prices, such as:

- informing gas consumers (individuals and businesses) of the economic and other advantages of switching to other energy sources and of applying energy-efficiency measures
- acting on recommendations such as those documented by the Alternative Technology Association and the Consumer Utilities Advocacy Centre (22) with respect to residential fuel-switching from gas to electricity (20)
- removing subsidies that encourage uneconomic use of gas, where other options exist such as using efficient-electrically-powered appliances
- removing subsidies that encourage uneconomic expansion of the gas grid
- strengthening the regulatory oversight of the marketing of gas and gas appliances, which are often claimed to be cheaper, more efficient, and more environmentally benign than all electrically-powered appliances
- facilitating the identification and financing of economic fuel-switching and energy efficiency projects
- reducing infrastructure costs by rationalising the gas grid where economic
- creating, maintaining, and implementing an Integrated Resource Plan.

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