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

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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.

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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 industry¹ to limit methane emissions to no more than 0.1% of total gas production is commendable.

Findings

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

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

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



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

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

Currently, the National Greenhouse Gas Inventory reports methane emissions based on default emission factors, none of which relate specifically to the production of coal seam gas in Australia. The National Inventory Report (NIR) states that emissions from 'production' are estimated using a single emission factor of 0.058 tonnes of methane per kilotonne of methane produced, i.e. 0.0058%. The NIR states that this value is validated by measurements made by CSIRO. 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 lost 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.



In summary, our review finds that:

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

Recommendations

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

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



1. Introduction

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

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

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

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

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

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

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

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



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

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

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

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



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

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

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

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

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

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



2.2. The Paris climate change agreement

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

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

In order to achieve this goal, the Paris Agreement also aims to achieve net-zero greenhouse-gas emissions in the second half of this century². 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)

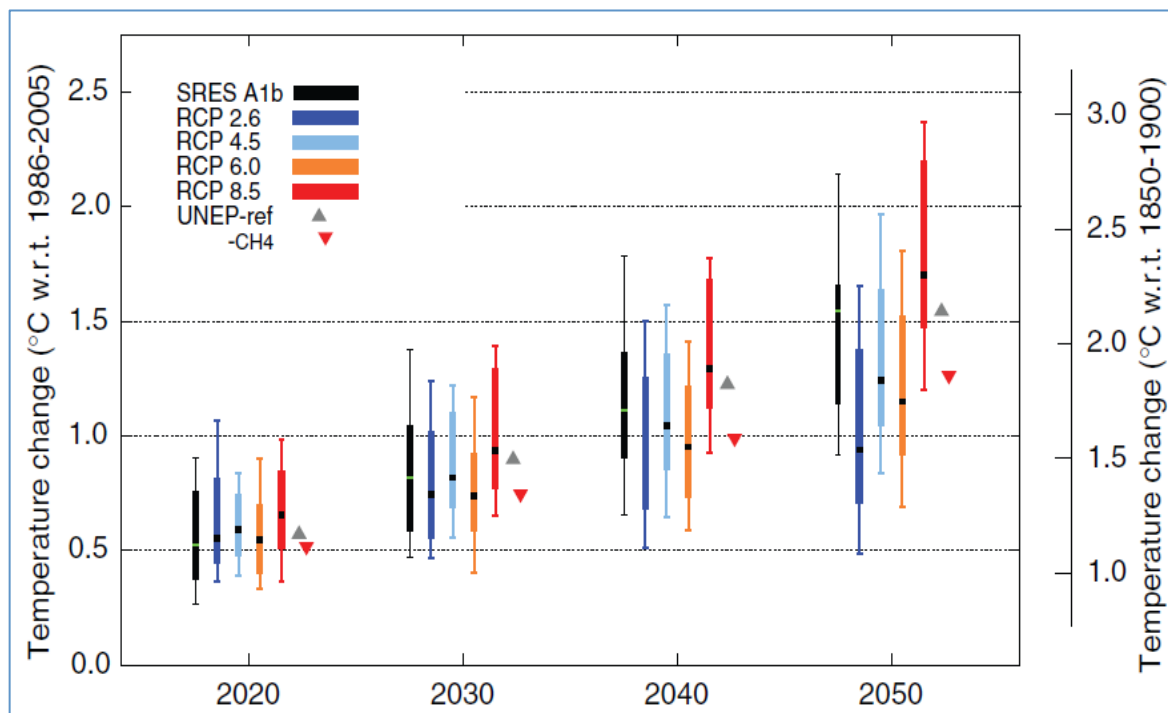


Figure 1: Global average 10-year mean surface temperature increase based on the current four IPCC model ensembles (dark blue: RCP 2.6, light blue: RCP 4.5, orange: RCP 6.0 and red: RCP 8.5), and the previous model ensembles (black: SRES A1b). Left vertical scale is temperature change with regards to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

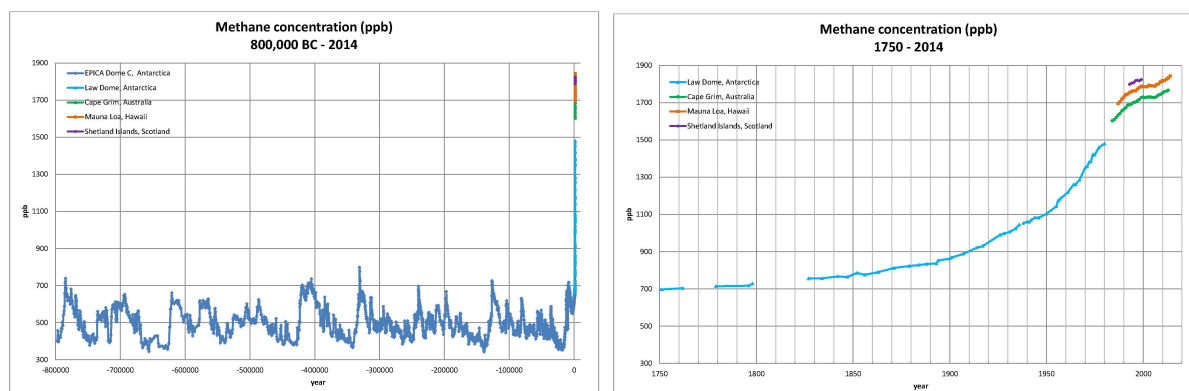


Figure 2: Atmospheric methane concentration shown in parts per billion (ppb), from hundreds of thousands of years ago, through to 2014. Left: Timeframe 800,000BC to 2014, showing concentrations have not been higher than 800ppb until very recent. Right: Timeframe 1750 to 2014, showing concentrations have 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. Fuglestedt, 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 ecosystems as the short-term temperature increase will be slower (Figure 3, right graph).

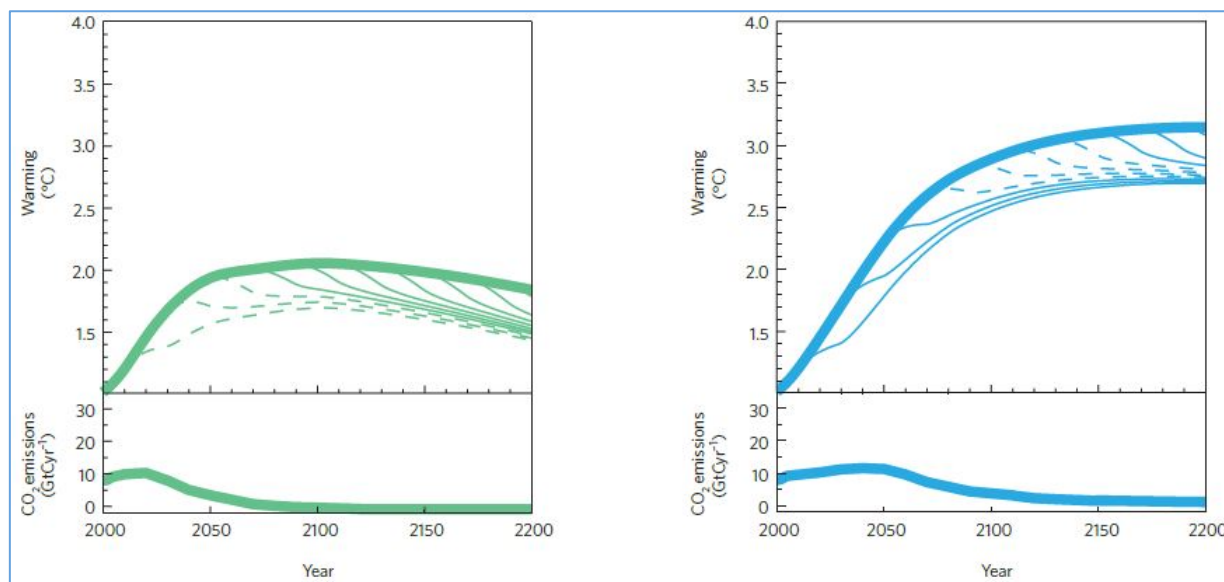


Figure 3: from Bowerman, Frame et al. (2013). Impact of short-lived climate pollutants (SLCP, incl. methane) in the RCP2.6 and RCP4.5 scenarios (1.5°C and 2.4°C warming at the end of the century respectively).

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 cost⁴: two thirds of the benefits have a far greater valuation than the incurred abatement costs. The benefit however would not necessarily flow to those allocating investment for methane abatement. Emission reduction in the coal, oil and gas sector account for two-thirds of the benefits as the technologies to mitigate emissions are readily available. Methane emission reductions are therefore complementary to carbon dioxide reduction measures in order to limit global mean warming to less than 2°C.

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

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



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

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

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

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

2.4.1. Fire and explosion risks of methane emissions

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

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

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

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

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

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



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

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

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

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

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

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

2.4.3. Water-quality health impacts related to methane emissions

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

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

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

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



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

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

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

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

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

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

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

and lastly, but importantly,

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



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

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

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

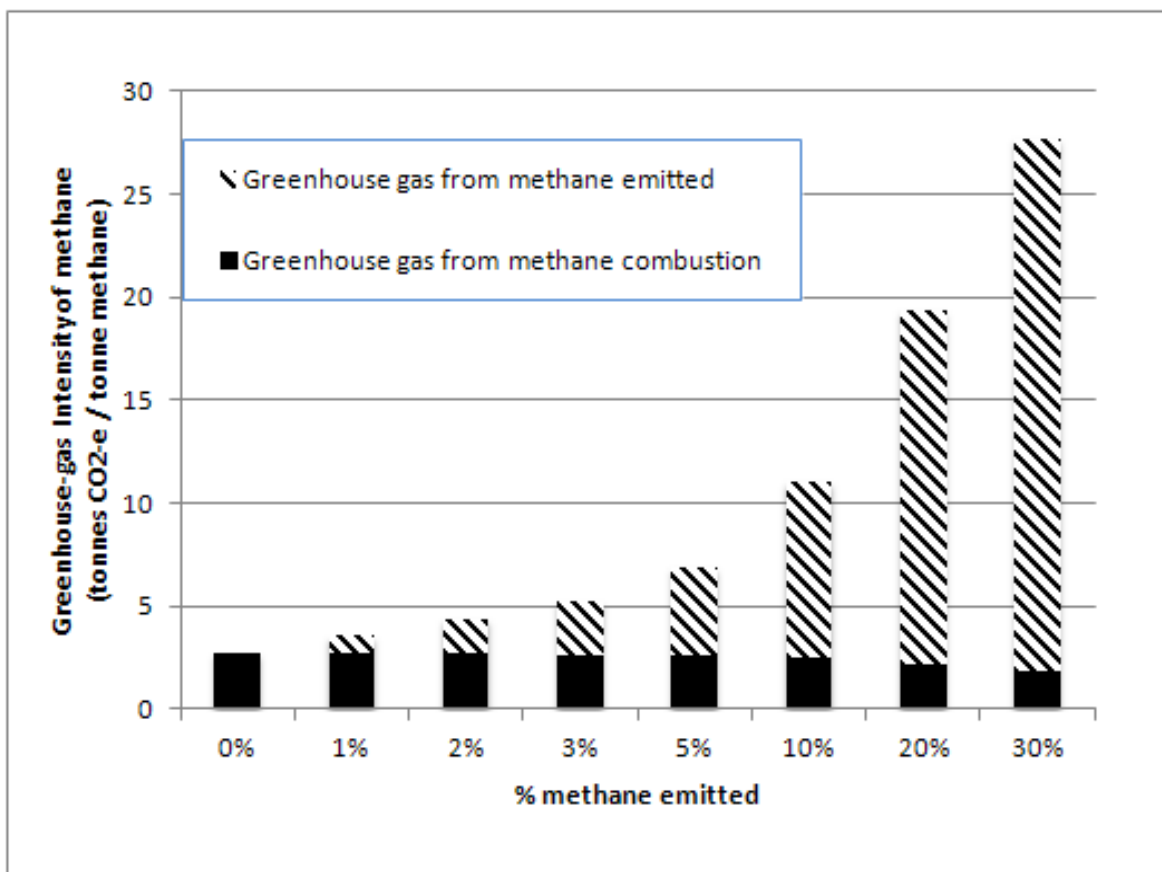


Figure 4: The climate impact of gas as an energy source greatly depends on what fraction is emitted to the atmosphere, versus what fraction is burned as fuel. Here we assume a global warming potential of 86 (appropriate to the 20-year timescale), with the y-axis showing the tonnes of CO₂-e emitted for each one tonne of methane gas produced.



3.2. Coal-versus-gas comparison studies and critiques

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

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

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

"much lower than estimates from other gas production sectors"

and that

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

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

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

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

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

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

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

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

The above studies generally and arbitrarily use the 100-year global warming potential for methane, although the sensitivity of study results to the 20-year global warming potential may also be presented in the above studies. To avoid the arbitrary nature of choosing a global warming timeframe,



Alvarez, Pacala et al. (2012) developed the concept of Technology Warming Potential (TWP) that allows a limited climate-impact comparison of different technologies.

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

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

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



4. U.S. to extend methane emission regulations

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

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

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

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



Figure 5: Dense well spacing in the U.S. state of Wyoming

<http://www.sacurrent.com/sanantonio/the-shale-booms-hard-sell-begins-pushing-up-against-reality/Content?oid=2341996>



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

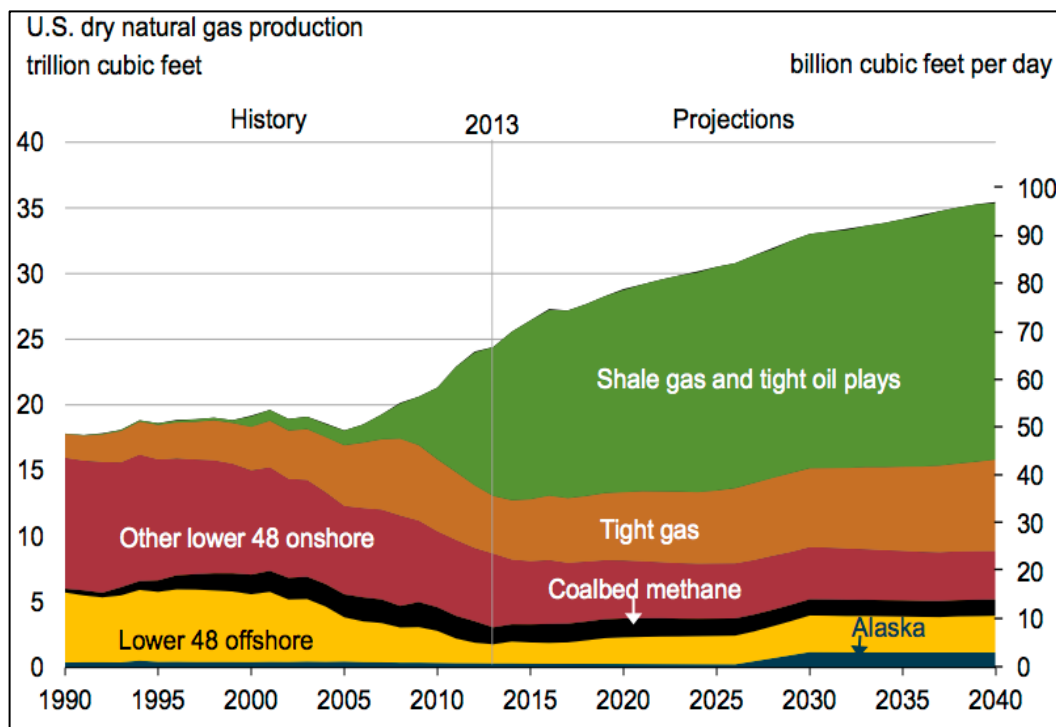


Figure 6: U.S. gas production 1990-2040 as per the EIA Annual Energy Outlook, 2015 Reference case scenario. Historical production until 2013, forecast from then onwards.

(EIA, Sieminski, A., 2015)

<http://instituteforenergyresearch.org/analysis/eias-annual-energy-outlook-2015-fossil-fuels-remain-predominant-energy-providers/>

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

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

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



Table 1

Ways in which methane can be emitted by unconventional oil and gas production and processing, gas transport and distribution, and use of gas by end-users			
Methane emission source	Emissions may occur...		
	... 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.		✓	



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

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

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



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

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

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



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

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

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

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

Table 2

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



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

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

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

This work concluded that:

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

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

Howard continued:

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



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

According to Allen (2014):

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

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

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

Super-emitters may exist for reasons such as:

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



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

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

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

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

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

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

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

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

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



Table 3

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



Oct 2014	Schneising, Burrows et al. (2014), Univ. of Bremen, Germany	American Geophysical Union	Current inventories underestimate methane emissions from Bakken (North Dakota, Canada) and Eagle Ford (Texas) shale gas production areas, found to be 10% and 9% of production respectively, based on satellite data.
June 2014	Allen (2014), Univ. of Texas	Current Opinion in Chem. Engr.	Current inventories underestimate the amount of methane entering the atmosphere.
June 2014	Pétron, Karion et al. (2014), Univ. of Colorado	American Geophysical Union	Using measurements from aircraft, losses of methane estimated to be 2 to 8% of production from oil and natural gas operations in the Denver-Julesburg Basin (Colorado).
April 2014	Caulton, Shepson et al. (2014), Purdue Univ.	Proceedings of the National Academy of Science	An instrumented aircraft platform operated over southwestern Pennsylvania identified methane emissions from well pads in the drilling phase 100 to 800 times "greater than U.S. [EPA] estimates for this operational phase", or 3 to 17% of production in this region.
Feb 2014	Brandt, Heath et al. (2014), Stanford Univ.	Science	"...measurements at all scales show that official inventories consistently underestimate actual [methane] emissions 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".

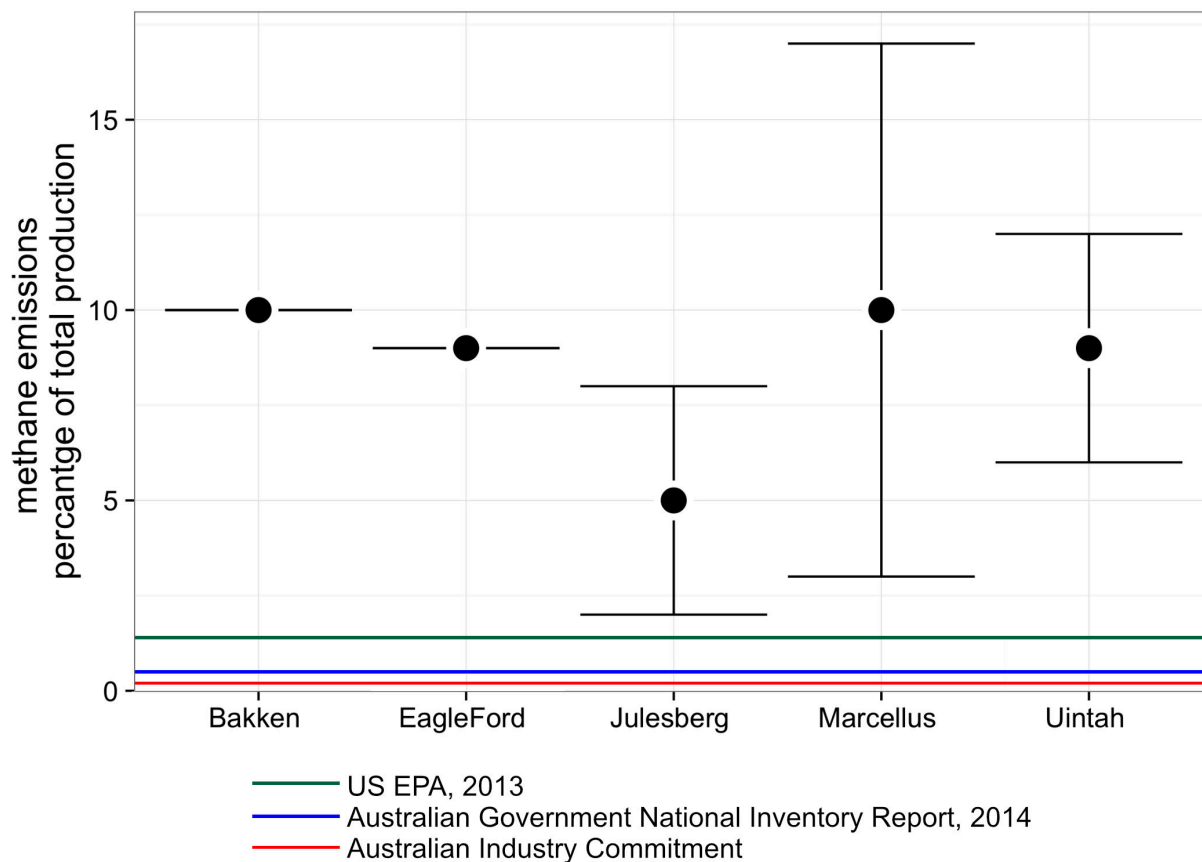


Figure 8: U.S. reported methane emissions (shown as black horizontal line), vs recent 'top-down' measurements for various unconventional gas basins (with reported ranges shown as error bars)

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)).

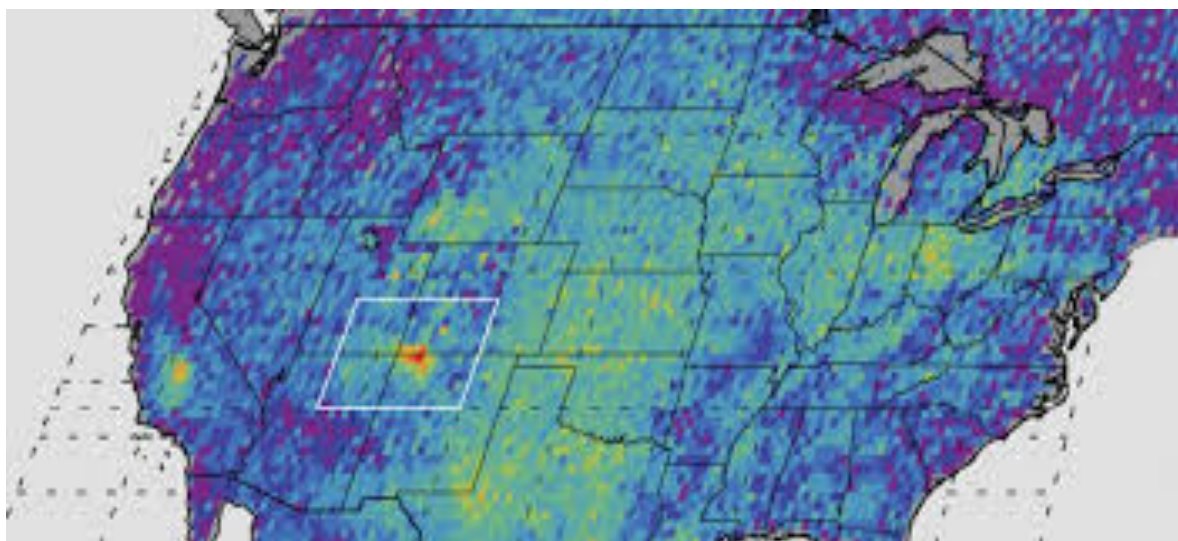


Figure 9: U.S. methane emissions 'hot-spot' revealed by satellite measurements. (Kort et al. 2014)

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.

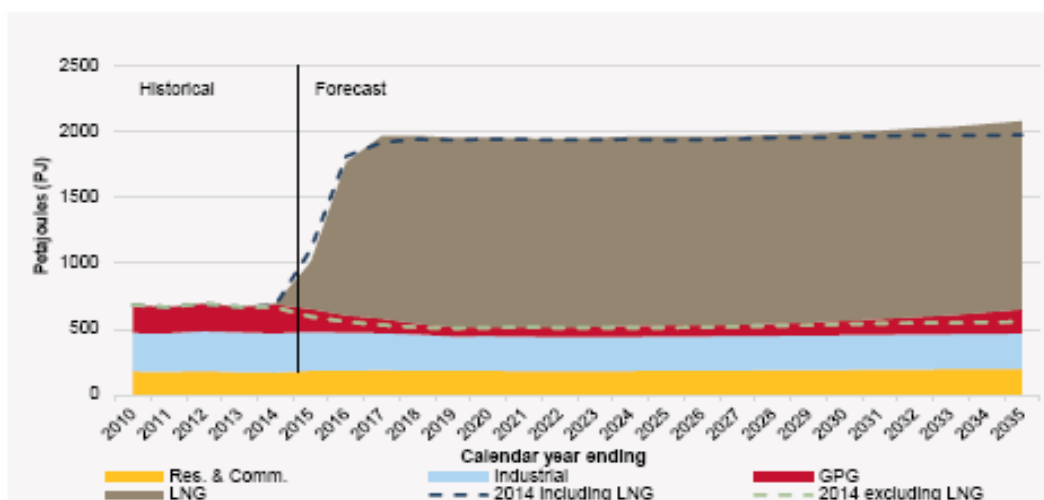


Figure 11: Eastern Australian gas production, recent past and projected future. Australian Energy Market Operator National Gas Forecasting Report, Dec. 2015

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 year⁷ (PJ/yr), proved-and-probable (2P) coal seam gas reserves would deplete after 29 years. If the other classes of reserves and resources shown in Table 5 were found to be economical to recover, those reserves and resources would extend current rates of gas production out for another 96 years, or 125 years in total. Cook, Beck et al. (2013) reported similar resource numbers.

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

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



Table 5

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

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

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

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

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

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

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

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



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

Table 6

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

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



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

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

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

Emissions for these two categories are considered in turn.

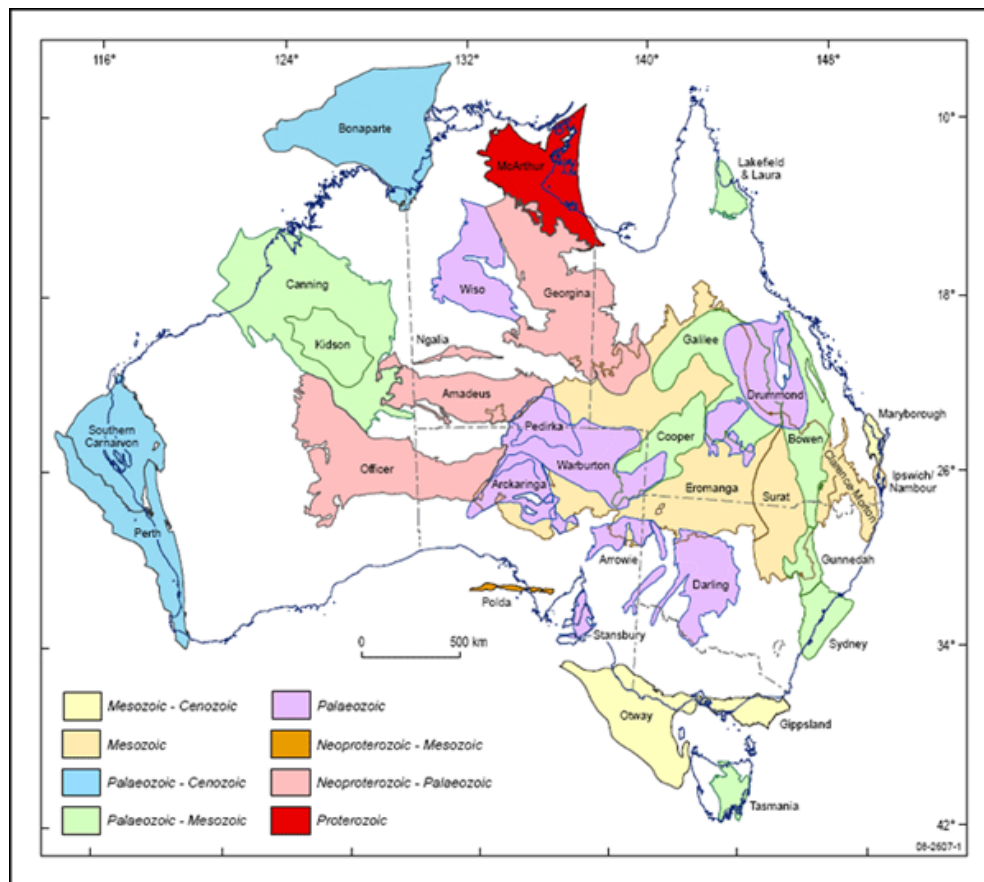


Figure 13: Australia's onshore sedimentary basins (Geoscience Australia, 2016).
<http://www.ga.gov.au/about/what-we-do/projects/energy/onshore-petroleum>



5.3.1. Fuel combustion emissions

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

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

In the case of coal seam gas, all three of the LNG plants at Gladstone, Queensland use a process based on the use of gas turbines to drive the compressors required to liquefy the gas, and also to drive generators that provide the electricity used for a multitude of purposes throughout the plants. A report prepared by Lewis Grey Advisory for the Australian Energy Market Operator (AEMO)⁸ estimates that the liquefaction process uses 8% of the input gas. Negligible quantities of emissions from this source are included in the most recent NGGI, which covers the financial year 2013-14, because LNG production did not start until late in calendar year 2014. These emissions will be included in all future national inventories. They will also be included in NGRS 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 equipment⁹.

⁸ Lewis Grey Advisory, 2015. *Projections of gas and electricity used in LNG*. Prepared for AEMO.

<http://www.aemo.com.au/Search?a=Lewis%20Grey%20Advisory>

⁹ Lewis Grey Advisory, *op. cit.*



Overall, the annual energy consumption for extracting, transporting and liquefying coal seam gas at the three plants (six liquefaction trains) is estimated by Lewis Grey Advisory to be about 123 PJ of gas and 9.3 terawatt-hours (TWh) of electricity. In its most recent electricity forecasting report¹⁰, 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 provide 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>



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



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

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

5.3.3. Exploration

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

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

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

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



Table 8

Fugitive emissions from gas production, processing and transportation, as reported in the NGGI (kilo-tonnes CO ₂ -e)					
Source category	2004-05		2013-14		
	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 NGRS *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 NGRS *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 CH₄ levels from major leaks or vents made locating minor leak points difficult’. They noted that in one case ‘CH₄ 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 NGRS 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)).

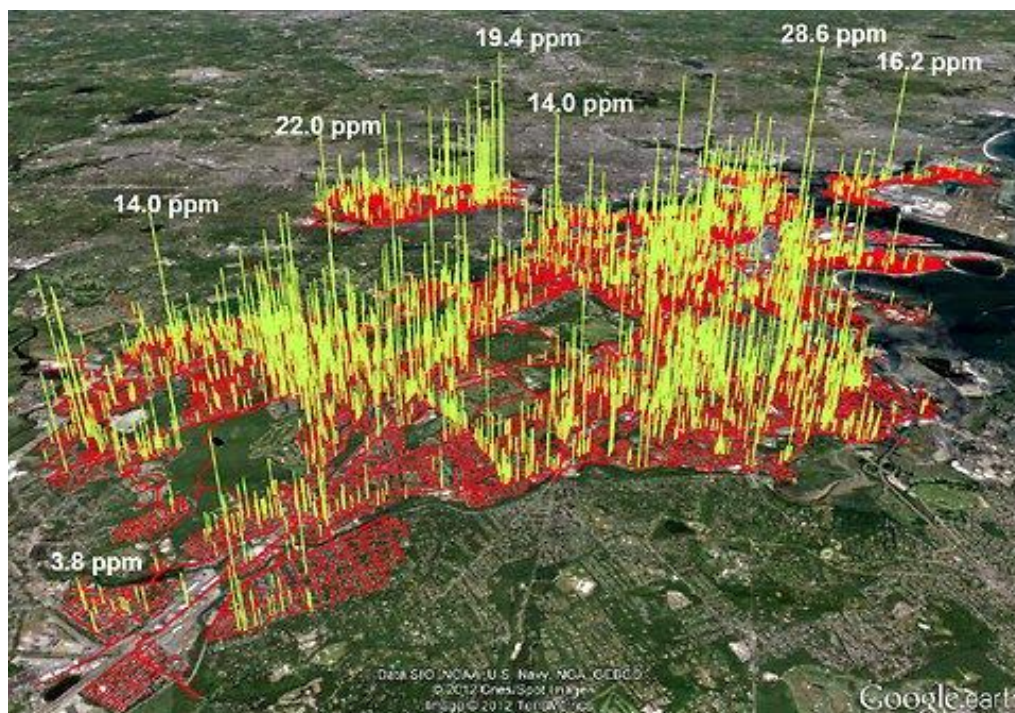


Figure 14: 3,356 methane leaks mapped in the city of Boston (Phillips, 2013)

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 Guidelines¹⁴. 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 limited to equipment located strictly on well pads. Equipment outside of well pads, which CSIRO researchers noticed was a significant source of methane emissions (e.g. entire gas processing plants, compressor stations, and water treatment plants) did not fall within the scope of CSIRO's investigations.

¹³ This technical discussion paper is no longer available on Australian Government websites.

¹⁴ <http://www.environment.gov.au/climate-change/greenhouse-gas-measurement/nger/technical-guidelines>



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

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

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

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

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

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

"On-pad measurements were made at most wells except in a few cases where high ambient CH₄ levels from major leaks or vents made locating minor leak points difficult. In one case at Well B2, CH₄ 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 CH₄ 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 stations¹⁵ 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 CO ₂ and CH ₄ EFs, where appropriate."
E.18	During the review, Australia informed the ERT of the considerable projected growth in unconventional gas production (e.g. shale and coal bed methane) in Australia. The ERT notes that key EF [emissions factor] data used in the inventory calculations are based on data from the United States of America and may not be representative of the emissions from well completion activities associated with the commissioning of new production. The ERT recommends that Australia make efforts to improve the data for the emissions from this category, including the development of updated EFs that represent production activities in unconventional gas production." In its National Inventory Report, the Australian Government identified planned improvements to address UNFCCC-identified issue E.18.



5.5. Australian methane-emission comparisons

In the National Inventory Report 2014 (Australian Government (2016)), the methane component of "fugitive emissions from oil and natural gas" was reported to be 5,453,000 tonnes CO₂-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.

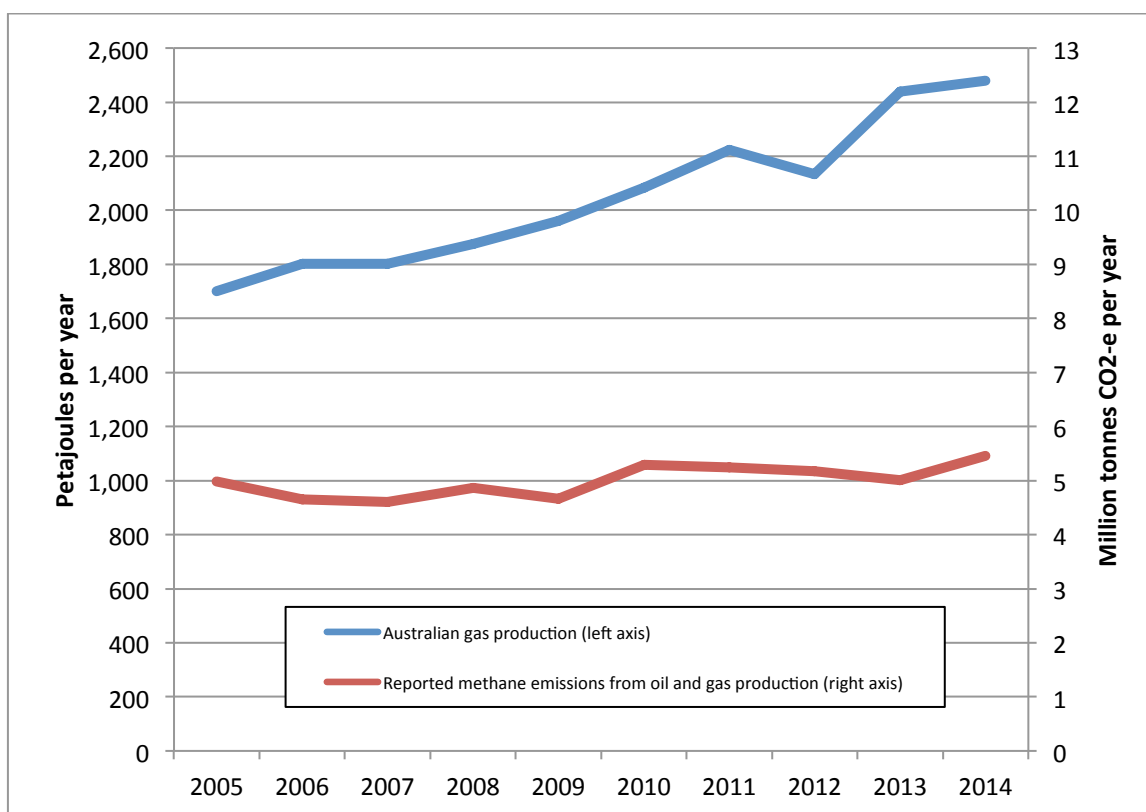


Figure 15: Australian annual gas production and reported methane emissions



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/



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 (CO₂-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 CO₂-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 CO₂-e units by 26%, as methane emissions are multiplied with the GWP for a conversion to CO₂-e equivalent emissions. Reported fugitive methane emissions from oil and natural gas would increase by 2 million tonnes CO₂-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 CO₂-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	Unconventional 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 CO₂-e; 100 yr – 20 yr GWP)
	PJ/yr	% of gas production	million tonnes CO₂-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 CO₂-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 gas basins. This is further described in the MEI companion report entitled:

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



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

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

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

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

Table 13

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



Total minimum fugitive and combustion emissions upstream of the point of combustion are estimated to be 13.6 tonnes of CO₂-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 CO₂-e per TJ, this makes the full fuel-cycle greenhouse gas emissions 65.6 tonnes of CO₂-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 Elsentrou, 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 Initiative¹⁸:

"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 estimated¹⁹ that around 40% of the gas that is vented and flared on onshore federally-leased land could be economically captured with currently available control technologies.

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



According to the Environmental Defense Fund:

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

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

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

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

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

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

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

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

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

¹⁹ <http://www.gao.gov/products/GAO-11-34>

²⁰ <https://www.edf.org/sites/default/files/methaneLeakageFactsheet0612.pdf>



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

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

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

- 2013: The U.S. state of Wyoming is the first to require operators to find and fix methane leaks.
- 2014: The U.S. state of Colorado adopts the U.S. EPA's "Standards for Performance of Crude Oil and Natural Gas Production, Transmission and Distribution". Companies subsequently reported they had repaired more than 1,500 gas leaks in the last few months of 2014. Ohio also acts to regulate methane emissions.
- 2015: The Canadian province of Alberta announces plans to reduce oil and gas methane emissions by 45 per cent by 2025.
- January 2016: The U.S. state of Pennsylvania announces a "nation-leading strategy to reduce emissions of methane" during "development and gas production, processing, and transmission by requiring leak detection and repair (LDAR) measures, efficiency upgrades for equipment, improved processes, implementation of best practices, and more frequent use of leak-sensing technologies."
- February 2016: The U.S. state of Alaska announces a \$US 50 million program to clean-up legacy oil and gas wells including attention to methane emissions. The U.S. state of New Jersey passes legislation to hasten repair and replacement of leaking gas pipelines. Following the Aliso Canyon gas storage facility release, the California state legislature proposes new nation-leading methane emission-prevention regulations.
- March 2016: The U.S. Methane Challenge Program is formally launched by the U.S. EPA²¹.

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" website²².

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

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

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



7.3.2.1. Space-satellite methane emission detection and quantification

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

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

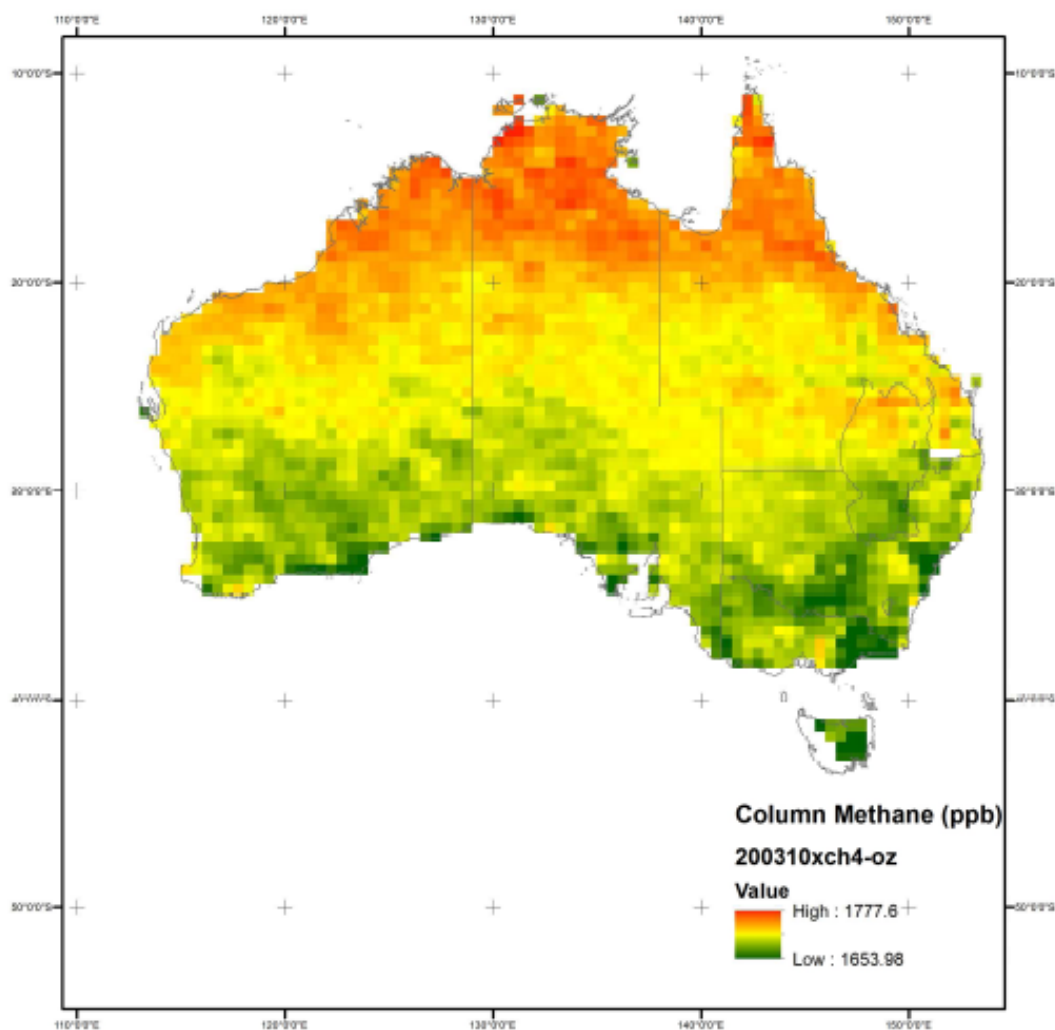


Figure 16: October 2003 satellite-data analysis of methane present in the air over Australia. (Day, Ong et al. (2015))



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

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

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

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

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

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

The Sentinel satellites, part of Europe's Copernicus program, are the continuation of the work started with ENVISAT (the SCIAMACHY 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 2020²⁴.

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 emissions²⁵.

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 Mars²⁶.

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

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

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

²⁵ <http://news.sys-con.com/node/3738950>

²⁶ www.jpl.nasa.gov/news/news.php?feature=6192



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

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

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

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

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

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



7.3.3. Sedimentary basin management plans needed

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

Dafny and Silburn (2014) and Apte, McCabe et al. (2014) have pointed out that significant gaps remain in terms of subsurface understanding. Additional field data needs to be acquired to narrow down uncertainties around the spatial extent 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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