GREENHOUSE GAS EMISSIONS

9

9.1 Introduction

The extraction and subsequent use, namely, 'the life cycle',[1] of shale gas results in the emission of greenhouse gases (**GHG**) such as methane (**CH_4**) and carbon dioxide (**CO_2**).

During the public hearings, community consultations and in submissions, concern was raised that these emissions will exacerbate climate change and contribute to the adverse impacts associated with global warming. Some suggested that development of any onshore shale gasfields in the NT should therefore not go ahead under any circumstances.

9.1.1 Shale gas

Shale gas is a form of natural gas. Natural gas ranks third (24%) in Australia in terms of domestic energy consumption after oil and coal, and second (16%) in terms of national energy production after black coal. In 2014-2015, natural gas production in Australia rose by 5%, underpinned by an increased CSG production.[2] While recognising the importance of natural gas as a source of energy, it is nevertheless a fossil fuel and during its life cycle (extraction and use), it will contribute to global warming through the emission of GHG such as CH_4 and CO_2.

Natural gas is primarily composed of methane,[3] but it can also contain ethane, propane, butane and heavier hydrocarbons, carbon dioxide and small amounts of nitrogen, hydrogen sulfide and trace amounts of water. Natural gas is a source of fugitive emissions, which is the intentional and unintentional release of (principally) CH_4 (but also includes CO_2 and other gases) during the production, processing, transport, storage, transmission, and distribution phases of the life cycle. Energy is also required for the production, processing and transport of natural gas, and this energy use results in the liberation of further GHG and particulates. Carbon dioxide is emitted when natural gas is burned. For example, when gas is used to generate electricity, heat, or steam. Carbon dioxide is also vented, sometimes in large quantities, in the natural gas production process when raw natural gas is treated and carbon dioxide is removed to ensure that the gas meets pipeline specifications.[4]

While shale gas is the focus of this Inquiry, and therefore, this Chapter, it is recognised that coproduction of shale oil (or natural gas liquids, that is, hydrocarbon liquids) can occur. This matter is discussed further in Sections 6.1 and 9.6.1.

The Panel has formed the view that the assumed levels of gas production adopted in this Chapter are plausible and relevant for the purposes of conducting the risk assessments.

9.1.2 Greenhouse gases

From a review of GHG and CH_4 emissions, and considering the potential impacts arising from GHG, the key findings are that:

- global atmospheric concentrations of the major long-lived greenhouse gases continue to rise. For example, since pre-industrial times, the global mean CO_2 level has risen 45% to 403.3 ppm with a 0.6% increase per year for the last 10 years. Similarly, CH_4 concentrations have risen 157% to 1.85 ppm with a 0.4% increase per year for the last 10 years;[5]
- the total sources of methane emissions are approximately 558 Mt/y, with natural sources comprising approximately 41%, and anthropogenic sources approximately 59%, of this total. Fugitive emissions from fossil fuels comprise 32% of the anthropogenic methane emissions (105 Mt/y);

1 The life cycle of gas has two stages: first, the upstream stage, which comprises natural gas production, processing, transmission, and delivery, and secondly, the downstream stage of the energy conversion phase of natural gas for commercial or industrial or domestic purposes.
2 Department of Industry, Innovation and Science 2016b, pp 7 and 16.
3 Methane is a colourless, odourless gas that is lighter than air and is non-toxic. As a gas, it is flammable over a range of concentrations (5.4 - 17%) in air at standard pressure.
4 Climate Council 2017, p 10.
5 Parts per million.

- total annual global anthropogenic GHG emissions comprise 76% carbon dioxide and 16% methane emissions (the balance is nitrous oxide and fluorinated gases);
- to limit total human-induced warming to less than 2˚C would require cumulative CO_2 emissions from all anthropogenic sources since 1870 to remain below about 2,900 Gt CO_2 by 2100. This is referred to as the 'global carbon budget'. Total cumulative emissions from 1870 to 2016 were 2,199 Gt CO_2;
- in recent decades, changes in climate have caused impacts on ecosystems on all continents and across all oceans; and
- limiting the impacts of climate change will require substantial and sustained reductions in greenhouse gas emissions, which, together with adaptation, can limit climate change risks.

GHG warm the planet by absorbing energy and slowing the rate at which the energy escapes to space. They act like an insulating blanket for the Earth.[6] Different GHG can have different effects on the Earth's warming. Two key ways in which these GHG differ from each other are their ability to absorb energy and how long they stay in the atmosphere. The Global Warming Potential (**GWP**) parameter was developed to compare the global warming impacts of different gases. Specifically, it is a measure of how much energy the emissions of a unit mass of a gas will absorb over a given period of time, relative to the emissions of unit mass of CO_2.

Global atmospheric concentrations of the major long-lived greenhouse gases, CO_2, CH_4, nitrous oxide (**N_2O**) and a group of synthetic greenhouse gases (such as perfluorocarbons, hydrofluorocarbons and sulphur hexafluoride), continue to rise.[7] For example, the global mean CO_2 level in 2016 was 403.3 ppm, a 45% increase from around the year 1750, and a 0.6% increase per year for the last 10 years[8]. This is likely to be the highest level in at least the past two million years. The impact of all GHG in the atmosphere combined can be expressed as an 'equivalent CO_2' (**CO_2e**) atmospheric concentration, which reached 487 ppm in 2015 and 489 ppm in 2016.[9] Analysis of the different types (or isotopes) of carbon in atmospheric CO_2 shows that the additional CO_2 since 1750 in the atmosphere results from human activities, predominantly the burning of fossil fuels.[10]

Between 1750 and 2011, cumulative anthropogenic CO_2 emissions to the atmosphere were approximately 2040 Gt CO_2. About 40% of these emissions have remained in the atmosphere. The rest were removed from the atmosphere and stored on land (in plants and soils) and in the ocean[11]. Anthropogenic GHG emissions, together with other anthropogenic drivers, are the dominant cause of the observed warming since the mid-20th century. In 2016, total global anthropogenic GHG emissions continued to increase slowly by about 0.5% (±1%) to about 49.3 Gt CO_2e, excluding emissions from land use, land-use change and forestry (**LULUCF**). When including LULUCF emissions, the estimated global total GHG emissions are 53.4 Gt CO_2e.[12] The total annual global anthropogenic GHG emissions comprise approximately 76% carbon dioxide and 16% methane emissions (the balance is N_2O and fluorinated gases).[13]

Total emissions for Australia for the year to December 2016 (including LULUCF of 1.2 Mt CO_2e) are estimated to be 543.3 Mt CO_2e. This figure is 2.0% below emissions in 2000 and 10.2% below emissions in 2005. For the year to December 2016, emissions increased 1.4% on the previous year. The electricity sector is the largest contributor (35%) to Australia's GHG emissions, followed by stationary energy (18%), transport (17%), agriculture (13%), fugitive emissions (9%), and industrial processes and product use (6%).[14]

6 US EPA 2017d.
7 BoM 2016b.
8 WMO 2017.
9 Fraser et al. 2017.
10 BoM 2016b.
11 IPCC AR5 2014, pp 4 - 5.
12 Olivier et al. 2017.
13 IPCC AR5 2014, pp 4 - 5.
14 Australian Department of the Environment and Energy 2017k, p 9 ff.

9.1.3 Global methane

Since pre-industrial times, CH_4 concentration has risen 157% to 1.85 ppm in 2016, and it has increased 0.4% per year for the last 10 years.[15] Accordingly, in the past decade, the rate of increase of methane emissions has decreased relative to the rate of increase in CO_2 emissions. It is estimated that CH_4 has accounted for about 21% of the cumulative man-made global greenhouse effect since the pre-industrial era (1750).[16] Methane emissions comprise natural sources (wetlands and other sources) and anthropogenic sources (agriculture, biomass burning and fossil fuels). The total sources of methane emissions are approximately 558 Mt/y (averaged over the period 2003 to 2012), with natural sources comprising approximately 41% and anthropogenic sources approximately 59% of this total. Fugitive emissions from fossil fuels (105 Mt/y) comprise 32% of the anthropogenic methane emissions.[17] From this data on methane sources and sinks, it has been estimated that the net growth of methane emissions is approximately 10 million tonnes in the atmosphere every year.[18]

9.1.4 Global climate change

During each of the last three decades, the climate has been successively warmer at the Earth's surface than any preceding decade since 1850. For example, 2016 was the hottest year on record globally for the third year in a row, and all of the world's 10 warmest years have occurred since 1998.[19] According to NASA data, 2017 was the second-hottest year on record, and was the hottest year without the short-term warming influence of an El Niño event.[20] The globally averaged combined land and ocean surface temperature data showed a warming of 0.85˚C over the period 1880 to 2012.[21] Ocean warming dominates the increase in energy stored in the climate system, accounting for more than 90% of the energy accumulated between 1971 and 2010.[22]

There is evidence of observed climate change impacts in many regions. It has been observed that:

> *"in recent decades, changes in climate have caused impacts on natural and human systems on all continents and across the oceans. Impacts are due to observed climate change, irrespective of its cause, indicating the sensitivity of natural and human systems to changing climate". Further, that "changes in many extreme weather and climate events have been observed since about 1950. Some of these changes have been linked to human influences, including a decrease in cold temperature extremes, an increase in warm temperature extremes, an increase in extreme high sea levels and an increase in the number of heavy precipitation events in a number of regions". And that "continued emission of greenhouse gases will cause further warming and long-lasting changes in all components of the climate system, increasing the likelihood of severe, pervasive and irreversible impacts for people and ecosystems. Limiting climate change would require substantial and sustained reductions in greenhouse gas emissions, which, together with adaptation, can limit climate change risks".* [23]

Changing precipitation or melting snow and ice are altering hydrological systems, affecting water resources in terms of quantity and quality. Many terrestrial, freshwater and marine species have shifted their geographic ranges, seasonal activities, migration patterns, abundances, and species interactions in response to ongoing climate change. Several submissions identified the impact of climate change on human health.[24] For example, climate change affects the social determinants of health, such as clean air, safe drinking water, sufficient food and secure shelter. The consequential health impacts of climate change include human fatalities.[25] The World Economic Forum[26] has

15 WMO 2017.
16 This is based on the relative radiative forcing contribution from methane of 0.48 W/m^2 to the net anthropogenic radiative forcing function of 2.29 W/m^2 (IPCC WG I 2013, p 698).
17 Saunois et al. 2016.
18 Saunois et al. 2016.
19 Climate Council, submission 458, p 3.
20 Nuccitelli 2018.
21 IPCC AR5 2014, p 2.
22 IPCC AR5 2014, p 4.
23 IPPC AR5 2014, pp 6 - 8.
24 For example, R Schultz, submission 1180 and Tim Forcey, submission 548 (**T Forcey submission 548**).
25 World Health Organization 2017. The World Health Organization 2017 assessment, taking into account only a subset of the possible health impacts, concluded that climate change is expected to cause approximately 250,000 additional deaths per year between 2030 and 2050: 38,000 due to heat exposure in elderly people; 48,000 due to diarrhea; 60,000 due to malaria; and 95,000 due to childhood undernutrition. Globally, the number of reported weather-related natural disasters has more than tripled since the 1960s. Every year these disasters result in over 60,000 deaths, mainly in developing countries.
26 World Economic Forum 2017.

noted the pervasive nature of changing climate. It was rated the second most important trend that determines global developments, and the failure of climate change mitigation and adaptation was identified as the third most important interconnection between risks.

Models show that limiting total human-induced warming to less than 2˚C relative to the period 1861–1880 would require cumulative CO_2 emissions from all anthropogenic sources since 1870 to remain below about 2,900 Gt CO_2 by 2100.[27] This is referred to as the 'global carbon budget'.[28] Total cumulative emissions from 1870 to 2016 were 1,539 Gt CO_2 from fossil fuels and industry and 660 Gt CO_2 from land use change. The global emissions from fossil fuels and industry in 2016 were 36.3 Gt CO_2.[29] The global carbon budget concept has major implications for the future global use of fossil fuels.[30] Further, concern has been expressed at the current GHG trajectory. As noted in one submission from Climate Action Darwin,[31] the Director of the Fenner School of Environment and Society at the Australian National University has said that *"both observed temperature and sea-level rise are tracking at or near the top of the envelope of model projections".*

GHG emissions are known to be the major contributors to climate change. In 2015, Australia signed the agreement negotiated at the UNFCCC Paris Climate Conference (**COP21** or **Paris Agreement**). The Paris Agreement's central aim is to *"strengthen the global response to the threat of climate change by keeping a global temperature rise this century well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius."* [32] As part of the Paris Agreement, the Australian Government committed to reducing GHG emissions to 26–28% below 2005 levels by 2030. This will be a challenging task. The Australian emissions are projected to be 592 Mt CO_2e[33] in 2030, which will require a reduction of 990 Mt CO_2e to 1055 Mt CO_2e in cumulative emissions between 2021 and 2030.[34]

As noted in the following Section, concerns were expressed to the Panel about the use of fossil fuels and their impact on global warming. A number of submissions were made, noting that fossil fuels should not be extracted and used, and that there should be no development of any onshore shale gas industry in the NT. For example, Steffen observed that, based on a global carbon budget approach (see above), the "*exploitation of any new Northern Territory gasfields is inconsistent with the Paris 2.0˚C target*".[35] In addition, The Australia Institute provided a submission[36] on behalf of 31 scientists and experts, strongly urging that onshore shale gas development not go ahead in the NT under any circumstances. This was based on arguments founded upon the carbon budget framework.

The United Nations Framework Convention on Climate Change (**UNFCCC**) recommends that for methane, a 100-year GWP value of 25 be adopted based on the Intergovernmental Panel on Climate Change (**IPCC**) Fourth Assessment Report from the IPCC.[37] The IPCC Fifth Assessment Report[38] indicates that over a short period, such as 20 years, the GWP of methane is much higher, namely, between 84 and 86. It is usually more common to use a 100-year time frame and if this time frame is used, the IPCC Fifth Assessment Report indicates that the GWP is between 28 and 36. In this Chapter, a GWP of 36 is used for a 100-year timeframe and GWP of 86 is used for a 20-year timeframe, unless otherwise stated. Therefore, if 1 gram of methane is emitted, and for a 100-year timeframe with a GWP of 36, the equivalent emission is calculated as 36 g CO_2e.

9.2 Key concerns

Cogent arguments were made, and documented evidence was presented, during the public hearings and community forums expressing concern over the impacts of GHG emissions during

27 IPCC AR 5 2014, p 10.
28 The global carbon budget is defined as the maximum amount of CO2 from human sources that can be released into the atmosphere to limit warming to no more than 2˚C above pre-industrial levels (Steffen 2015).
29 Global Carbon Project 2017. The global CO2 emissions in 2016 from fossil fuels and industry comprise: coal (40%); oil (34%); gas (19%); cement (6%); and flaring (1%).
30 To have a 50% chance of preventing a 2˚C rise in global temperature, it has been estimated that 88% of global coal reserves, 52% of gas reserves and 35% of oil reserves are unburnable and must be left in the ground (see Steffen 2015).
31 Climate Action Darwin submission 446, p 1.
32 UNFCCC 2016.
33 Mt CO_2e = million tonne of CO_2 equivalents.
34 Department of the Environment and Energy 2016a, p iii.
35 Professor Will Steffen, submission 596.
36 The Australia Institute, submission 1252 (**The Australia Institute submission 1252**).
37 IPCC AR4 WG I 2007.
38 IPCC WG | 2013, p 714.

the extraction and use of any onshore shale gas.[39] For example, people voiced concerns about:

- rising GHG levels in Australia;
- the impact of increased GHG emissions on global warming;
- the impact of increased GHG emissions on the environment and on human health;
- the fact that alternatives to gas (namely, renewable energy) were not included in the Inquiry's Terms of Reference;
- the need to consider GHG offsets;
- the fact that no GHG target is proposed by the Government;
- a lack of consideration of the cumulative impacts from multiple onshore shale gasfields; and
- a lack of any real time and online monitoring data for GHG.

In response to these concerns, the Panel has:

- examined GHG emissions from onshore shale gas operations and uses;
- estimated the emissions associated with the upstream stage that comprises natural gas extraction, processing, transmission and delivery, together with the combined upstream and downstream stage of natural gas, which is referred to as the 'full life cycle'. The downstream stage represents the energy conversion phase of natural gas for commercial, industrial or domestic purposes; and
- evaluated the quantity of these emissions from any new shale gasfield in the NT and the consequential impact on, and risks to, global climate change.

The Panel has reviewed the scientific literature on the levels of GHG emissions, including methane, from shale gas operations and use. This information has been used to estimate expected emission levels and to assess how lower levels of emissions can be achieved. This Chapter draws upon data and literature from overseas, including the US given the very large shale gas industry in that country. Reference is made to Australian data where relevant.

It should be noted that there are differences between the emissions from conventional gas and CSG wells, which are prevalent in Australia, and the emissions from shale gas wells. In assessing the risks from any onshore shale gas industry in the NT, the Panel has assessed fugitive methane emissions during upstream operations, life cycle GHG emissions, and fugitive methane emissions from decommissioned wells. These assessments were conducted within a risk assessment framework with current mitigation measures in place and subsequently with additional mitigation measures aimed to reduce emissions and to assess whether acceptable levels of risk could be achieved (see Chapter 4).

9.3 Upstream GHG emissions

Examining GHG emissions during the upstream stage, including both carbon dioxide and methane, the key findings are that:

- upstream GHG emissions for a US shale gasfield (pre-2012) are typically 15.5 g CO_2e/MJ of life-time natural gas production;
- the upstream methane emission rate is 11.9 g CO_2e /MJ (or 1.8% of lifetime production) and this represents 77% of the total upstream emissions; and
- the application of available and proven emission-reduction technologies can result in typically 23% lower upstream GHG emissions and an overall 31% reduction in methane emissions compared with historical practices for shale gas wells.

The US National Energy Technology Laboratory (**NETL**) has developed a comprehensive model that covers both upstream and downstream stages of natural gas production and both methane emissions and carbon dioxide emissions from energy use.[40] The model shows that for a typical shale gasfield in the US, the key contributors to GHG emissions are fugitive emissions from

39 Arguments and evidence that were presented in the final round of consultations and were contained in the recent submissions received by the Panel provided background to several changes that were made to the Draft Final Report. These include adding material on the global carbon budget and health effects from climate change in Section 9.1.4, the expansion of the risk assessment in Section 9.6.2, a revision of the "Risk Assessment Summary" in Section 9.9, and the addition of ***Recommendation 9.8***.

40 Skone et al. 2016; Littlefield et al. 2017. For example, the NETL report of Skone et al. 2016, which was prepared for the US Department of Energy, is a comprehensive and authoritative report that adopts results from many referenced sources.

transport and distribution systems (26%), episodic emissions from well completions (21%), and fuel combusted by processing compressors (12%). The results show that episodic or occasional activities in shale gas production such as well completions, workovers and liquids unloading[41] can be a large contributor (typically 25%) to total GHG emissions.[42] The total upstream emissions were 15.5 g CO_2e/MJ (90% confidence interval (**CI**) of 14 -18 g CO_2e /MJ)[43] for a representative US shale gasfield (the Appalachian field), using historical data before the introduction of reduced emissions completion regulations and strategies (see **Figure 9.1**). Methane accounted for 11.9 g CO_2e /MJ of these emissions, which is equivalent to a methane emission rate of 1.8% of the natural gas production, and they represent 77% of the total upstream emissions.

The implementation of new technologies and adoption of new practices will change the environmental burden of natural gas systems. For example, the US EPA introduced New Source Performance Standards (**NSPS**) rules in 2012 and 2016 that mandate reduced emissions during well completions and workovers and from production and processing equipment.[44] Consistent with these changes, the NETL conducted an evaluation of the next evolution of shale gas wells in the Appalachian field by adjusting the model parameters to reflect likely emission reduction technologies; for example, liquids unloading (100% use of plunger lifts compared with 55% previously), preferred practices such as increased flaring activity rather than venting for well completions (100% compared with 43–51% previously), and higher well estimated ultimate recoveries (**EURs**). This modelled well scenario produced GHG emissions of 12 g CO_2e/MJ, which are 23% lower than historical practices, and with a methane emission rate of 1.25% on a mass basis.[45] All emission reductions occurred at the extraction or production stage and were associated with methane reductions.

Variability between natural gas sources can lead to substantial differences in emissions. Conditions that lead to increased emissions are shale gas wells that have a low average EUR and those that do not capture or flare the gas emitted during well completions (that is, do not comply with the NSPS). Under these circumstances, the average upstream emission rate can be significantly (72%) higher.

41 A majority of gas wells (conventional and unconventional) must perform liquids unloading to enhance gas recovery; this becomes more likely as the age of the well increases. While several technologies can remove liquids from wells, plunger lifts are the most common, but their efficiency varies greatly depending on whether the gas is vented or recovered.

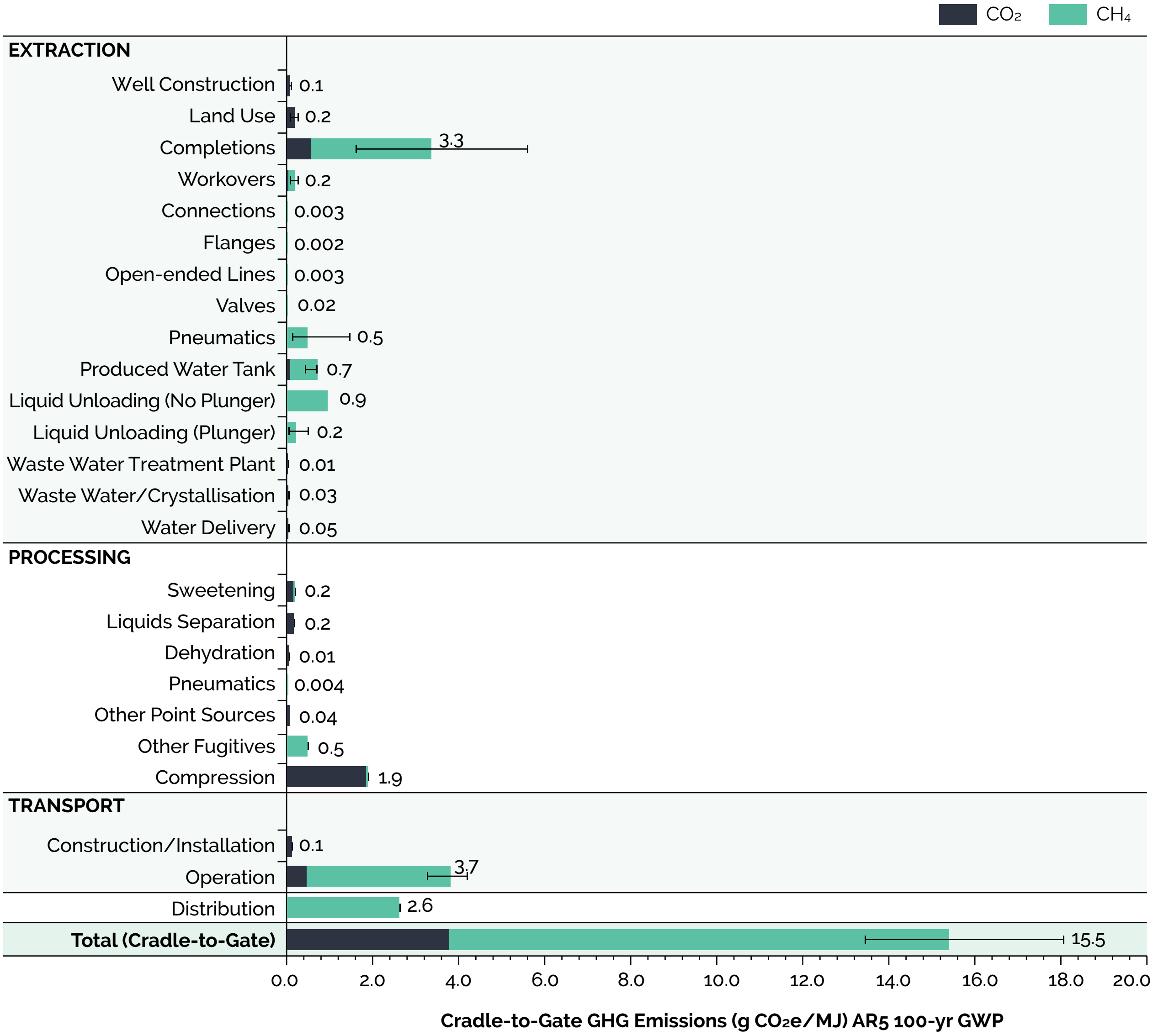
42 Skone et al. 2016, Table C-2.

43 The estimates of Skone, et. al. 2016 include consideration of approximately 25 different GHGs, including carbon dioxide, methane, butane, propane, nitrogen oxides and sulphur dioxide. The results are dominated by carbon dioxide and methane.

44 US EPA in 2012 published air pollution standards for VOCs and hazardous air pollutants, including sulphur dioxide from the oil and natural gas sector. These rules were designed to improve air quality and had the correlative benefit of reducing methane emissions. These rules required companies to reduce emissions from hydraulically fractured and re-fractured gas wells by employing reduced emissions completions; controlling emissions from storage vessels by 95%; using low or no bleed pneumatic controllers in the production segment; using no bleed controllers at gas plants; replacing reciprocating compressor seals on a regular basis; reducing wet seal centrifugal compressor emissions by 95%; and implementing more stringent leak detection and repair programs at gas plants (US EPA 2012); In 2016 the US EPA published additional NSPS that covered methane, VOCs and hazardous air pollutants. This included leak detection and repair programs at well sites; gathering and boosting stations and compressor stations; control of emissions from pneumatic pumps at well sites and gas processing plants; and control of emissions from compressors at compressor stations used for transmission and distribution (US EPA 2016c).

45 Skone et al. 2016.

Figure 9.1: Upstream GHG emissions for gas from a US Appalachian shale gasfield based on a methane GWP = 36. Source: Skone et al.[46]



9.4 Methane emissions

As noted above, methane emissions are the major contributor to upstream GHG emissions from shale gas operations. The key findings identified by the Panel are that:

- over recent years upstream methane emissions have been consistently reduced, so that current inventory estimates for Australia are about 0.7% and for the US, about 1.25%. These values underestimate field-based measurements, which range from 1.3–2.2% based on one comprehensive study. Further research is required to better understand the differences between these inventory and field-based estimates;
- emissions that are released during the shale gas exploration stage, such as venting during flowback, can be significant and they must be minimised;
- a large proportion of fugitive emissions come from a small number of high-emitting sources, but they also present opportunities for mitigation by applying industry best practices;
- methane emissions from a new gasfield in the NT (365 PJ/y) would be similar to the methane emissions from the enteric fermentation of the entire livestock herd in the NT and greater than the emissions from waste in the NT;

46 Skone et al. 2016, Figure 4-2, p 62.

- fugitive methane emissions from a new onshore shale gasfield in the NT (365 PJ/y) are estimated to be worth $62 million per year, indicating that there are environmental benefits and economic incentives for gas companies to reduce methane emissions;
- fugitive emissions from natural gas production in the NT are expected to be about 3% of Australia's Inventory methane emissions and 0.03% of the global anthropogenic methane emissions;
- based on global emissions, the consequential effect of fugitive methane emissions from any new onshore shale gasfield in the NT is assessed to be 'low;
- the risk of upstream fugitive methane emissions from a new shale gas industry in the NT, before any further mitigation, is assessed to be 'medium'; and
- because the assessed risk is 'medium', it is therefore necessary to mitigate this risk (see Chapter 4). One strategy is to introduce new standards and technologies as outlined in this Section. Further mitigation strategies are considered in Section 9.5.

9.4.1 Measured methane levels

Reviews of the literature[47] have reported methane emissions from natural gas production that vary by several orders of magnitude. For example, the Melbourne Energy Institute (**MEI**) quotes methane emissions ranging from 0.22 to 17% of total methane production.[48] The extreme values are bounded at the low end by component-level measurements at the exact point of emission ('bottom-up' techniques), and on the high end by continental measurements after atmospheric mixing ('top-down' techniques). Both approaches are subject to error. In particular, it is difficult, if not almost impossible, to distinguish between the many sources of emissions when considering the results from top down investigations. The high figure (17%) is not representative of average emissions from gasfield operations, because it represents only the highest value from a larger set of measurements within such a top-down study, some of which may have been further compromised by the presence of alternative sources of methane. The timeframe of each study is also important. Schwietzke et al.[49] noted that methane emissions from natural gas as a fraction of production have declined from approximately 8% to 2% over the past three decades. In the US, prior to 2012, the mixture of water and gas generated during shale gas well completions was often released directly to the environment (venting), which resulted in very large methane emissions. However, as previously noted, NSPS were introduced by the US EPA in 2012 and, starting in 2016,[50] have caused emission levels to fall by mandating reduced emission completions (**RECs**).[51] Reductions have also resulted from reduced compressor station emissions, increased use of plastic piping (which has lower fugitive emissions than other pipe materials), and upgrades at metering and regulating stations.[52] The US EPA inventories of methane emissions from US natural gas production show a reduction from 2.27% in 1990 to 1.25% of the dry production volume in 2015 when using a consistent methodology.[53] Both Schwietzke et al. and Brandt et al. suggest that the true emissions are 20 to 60% greater than these inventories,[54] suggesting a reduction from around 3.4% in 1990 to 1.9% in 2015. As noted previously, global fugitive emissions from natural gas production are estimated to be 35 Mt/y (over the decade 2003 to 2012), and this represents approximately 1.5% of current global natural gas production.[55]

A major recent study also noted that new data sources are necessary to reconcile the differences between bottom-up methods and other quantification approaches.[56] A synthesis of new methane emission data from a recent series of ground-based field measurements[57] was integrated with

47 For example, Brandt et al. 2014.
48 Lafleur et al. 2016.
49 Schwietzke et al. 2016, p 88.
50 US EPA 2012. It should be noted that the US EPA has stayed some elements of the NSPS to allow reconsideration after specific objections. These elements include the fugitive emissions requirements for low production sites and well-site pneumatic pump standards (see US EPA 2017).
51 Reduced emissions completions, also known as reduced flaring completions, is a term used to describe an alternate practice that captures gas produced during well completions and well workovers following hydraulic fracturing. Portable equipment is used to separate the gas from the solids and liquids produced during the high-rate flowback, and produce gas that can be delivered into the gathering pipeline. These assist in reducing methane, volatile organic compounds, and hazardous air pollutant emissions during well clean up and can eliminate or significantly reduce the need for flaring.
52 Lamb et al. 2015.
53 US EPA 2017a.
54 Brandt et al. 2014; Schwietzke et al. 2016.
55 Average global gas production was 2.2 Mt/y from 2003-2012; see BP 2016.
56 Littlefield et al. 2017.
57 Zavala-Araiza et al. 2015.

other data to estimate that 1.7% of methane is emitted (with a 95% CI of 1.3 - 2.2%) between extraction and delivery across the US natural gas supply chain, including both conventional and unconventional gas wells.[58] Littlefield et al. noted that, using data from basin-wide measurements, the total site-level emissions are higher than the sum of component emissions at production sites. This difference is referred to as 'unassigned' emissions. These emissions are not from a specific emission source, but comprise a small number of production sites with atypically high emission rates, production equipment that requires maintenance, intermittent well head maintenance events, or any combination thereof. The authors quantified these unassigned emissions as 0.3% (with a 90% CI of 0.1 - 0.5%) for gas produced for the Barnett Shale region in the US. The inclusion of unassigned emissions makes the bottom-up compilation of emission sources more complete, but it is a source of uncertainty that points to opportunities for further research.

Overall, this recent study concludes that 19% of all upstream methane emissions fall into this 'unassigned' or 'super emitter' category. The skewed nature of the original data supports the existence of a small share of emission sources that represent a large share of total emissions, and the analysis translates this variability to a national supply chain average. The top three contributors to these emissions are gathering systems, pneumatic controllers, and 'unassigned emissions'. Gathering facilities, a key connection between production and processing, are a significant methane emission source that has been omitted or undercounted in many studies to date.

Air measurements at natural gas production sites indicate that a large proportion of fugitive emissions come from a small number of high-emitting sources. For example, one study measured about 75,000 sources (such as well heads, valves, pipe welds and other sources within a natural gas production system and found that 58% of emissions came from 45 possible sources.[59] These few large leaks produce the majority of fugitive emissions and present opportunities for mitigation by applying industry world leading practices.[60]

9.4.2 Inventory levels

Australia reports its GHG emissions, including CO_2 and CH_4, through the National Greenhouse Gas Inventory[61] using a structure that is consistent with the IPCC Guidelines.[62] Most Australian corporations and facilities[63] are required to report their emissions through the National Greenhouse and Energy Reporting (**NGER**) scheme,[64] which provides the methodologies required for reporting. Similar to the US, the fugitive emissions reported from the oil and gas industry in Australia have declined as a per cent of production since 1990.

In many cases, the emissions reported through the NGER are based upon emission factors rather than direct measurement. In the National Inventory Report (**NIR**) 2015 published in May 2017,[65] new emission factors were introduced for the estimation of fugitive emissions from the gas supply chain. These methods bring Australia more into line with the methods developed by the US EPA and the NETL, which represents *"the largest and best dataset available globally"* and *"are expected to largely underpin a forthcoming update to the Intergovernmental Panel on Climate Change (IPCC) Guidelines for the preparation of national greenhouse gas inventories which will, in turn, become part of the international rules and guidance under the Paris Agreement on Climate Change".*[66]

Australian emission factors for well completions and well workovers[67] for hydraulic fracturing are now identical to that of the US EPA (36.8 tonnes of methane with hydraulic fracturing, reducing to 3.2 tonnes for a REC and 4.9 tonnes for a well completion with flaring), thereby reducing the estimates for these emissions from previous approaches. The emission factors for gathering and boosting stations and for processing plants have increased to be in line with the recent study by

58 Littlefield et al. 2017.
59 Brandt et al. 2014.
60 Zavala-Araiza et al. 2017.
61 Australian Department of the Environment and Energy 2017h.
62 IPCC Guidelines 1996.
63 Facilities with over 25kt of emissions, or producing more than 100 TJ of energy; corporate groups with over 50 kt of emissions or producing more than 200 TJ of energy.
64 Australian Department of the Environment and Energy 2017g.
65 Australian Department of the Environment and Energy 2017h.
66 Australian Department of the Environment and Energy 2017i, p 4.
67 The process of performing major maintenance or remedial treatments on an oil or gas well to achieve enhanced performance. This can include the re-simulation or replacement of the production tubing string.

Mitchell et al.[68], and those for transmission and storage systems have increased to be consistent with Zimmerle et al.[69] The existing Australian emission factor is retained for pipelines, based on the premise that Australian pipelines are of relatively recent vintage, have been built to high quality standards, and are well maintained.

General leakage of methane during the shale gas production phase also remains at 0.047 t CH_4/kt of processed natural gas (~0.0047%), based on the 2009 American Petroleum Institute Compendium[70] and a CSIRO study.[71] However, this factor is well below the value (0.073%) estimated by Littlefield et al.[72]. The CSIRO study was conducted across a limited dataset of 43 CSG wells, and the report notes that the values measured are lower than observed for the US shale gas industry. For example, they found the leak rate from Australian pneumatic devices to be 0.12 ± 0.18 g/min, while Allen et al.[73] measure a value of 5.9 ± 2.4 g/min and the American Petroleum Institute 2009 Compendium[74] uses 4.6 ± 0.66 g/min.

The upstream methane emissions reported in the 2015 National Greenhouse Gas Inventory (**NGGI**)[75] for the Australian natural gas industry are 266 kt, while the emissions of carbon dioxide are 78 kt (**Table 9.1**). This translates to total emissions of 6,735 kt CO_2e (based on a GWP of 25). The 2015 NGGI report also breaks down these emissions into those for exploration (including flaring during exploration and emissions from well completions and workovers), production, processing and transmission and storage (**Table 9.1**). However, emissions reported from these sectors do not add to the total. The difference is reported as "*Other*" in **Table 9.1**.

The NGGI reports flaring and venting emissions separately at processing facilities. The combined emissions are 63 kt of CH_4 and 6,841 kt CO_2 giving total emissions for venting and flaring of 8,406 kt CO_2e (based on a GWP of 25). The large CO_2 emissions are associated with the removal of carbon dioxide from the raw gas during the natural gas processing stage. These emissions may be measured directly by the operating facility, rather than emission factors being utilised. In 2015, the combined upstream, venting and flaring emissions were 329 kt CH_4 and 15,141 kt CO_2e.

68 Mitchell et al. 2015.
69 Zimmerle et al. 2015.
70 API 2009.
71 Day et al. 2014.
72 Littlefield et al. 2017.
73 Allen et al. 2014.
74 API 2009.
75 Australian Government NGGI; see also Australian Department of the Environment and Energy 2017h.

Table 9.1: Annual inventory emissions of CH_4 and CO_2 and their total (as CO_2e) from both conventional and unconventional natural gas production in Australia in 2014/2015. Source: Australian Government NGGI.[76]

	CH_4 emissions (kt)	CH_4 emissions as a proportion of gas production (%)[77]	CO_2 emissions (kt)	Equivalent CO_2 emissions[78] CO_2e (kt)
Natural gas				
Exploration	3.9	0.01%	49.8	148
Production	117.5	0.25%	18.5	2,955
Processing	24.4	0.05%	4.1	614
Transmission and storage	25.2	0.05%	0.6	631
Other[79]	95.3	0.21%	5.4	2,387
Total	266.3	0.57%	78.4	6,735
Addition for venting and flaring	62.6	0.14%	6,840.8	8,406
TOTAL	328.9	0.71%	6,919.2	15,141

As shown in **Table 9.1**, the inventory fugitive methane emission rate as a ratio of natural gas production is about 0.7%[80] when venting and flaring is included. This level of emission is below values reported by the US EPA for the US's mix of conventional and unconventional wells (1.25% in 2015).[81] In particular, in **Table 9.1** the emissions from gas processing are 0.04%, whereas the NIR report itself quotes the Mitchell et al.[82] report as 0.1%. Similarly, the NIR report quotes Zimmerle et al.[83] for losses from transmission and storage as 0.2%, whereas the analysis above gives 0.05% (**Table 9. 1**). Further research is required to explain these discrepancies.

However, as was noted in one submission,[84] the inventory methane leakage rate for Australia is broadly comparable with inventory estimates for the UK and for Canada, and significantly higher than that reported by Norway. The upstream GHG footprint of 15.1 Mt CO_2e (**Table 9.1**) is equivalent to 5.7 g CO2e/MJ, (based on a GWP of 25), which is well below the scientific studies outlined previously. For example, Littlefield et al.[85] gives 13.8 g CO e/MJ with a GWP of 36, for the US gas industry, including conventional and shale gas wells. Adjusting this upstream emission value by removing emissions associated with gas compression, and changing the GWP to 25, the revised upstream fugitive emissions are estimated to be 11.4 g CO2e/MJ. This is double the rate of 5.7 g CO_2e/MJ applicable in **Table 9.1**. Furthermore, from **Table 9.1**, the annual rate of equivalent CO_2 emissions (15,141 kt) expressed as a proportion of natural gas production (46.2Mt) is 0.33. The equivalent mass rate for US emissions as a proportion of natural gas production is 0.39.[86] It appears that the reason that the US inventory emission rate data is closer to the Australian inventory emission rate data is because Australia has higher venting and flaring rates (probably from lower quality gas), and this tends to balance the lower methane emissions.

As the Commonwealth Department of Environment and Energy[87] noted in its submission, it is recognised that this area (fugitive emissions) is one of the more difficult parts of the NGGI to estimate and that some caution is advisable in relation to the conclusions to be drawn from international comparisons. The NGGI is open to ongoing improvement as new methods and data emerge.

76 Australian Government NGGI.
77 Total natural gas production in Australia for 2015/2016 is 56 Mt based on data from Department of Industry, Innovation and Science 2017a. This converts to 46.2 Mt for a natural gas density of 0.67 kg/m^3.
78 CO_2e emissions are the combination of methane emissions, converted using a 100-year GWP of 25, and the CO2 emissions.
79 This is understood to be the 'distribution' component of upstream emissions.
80 0.71% = (0.329 Mt CH4 emissions)/(46.2 Mt CH4 production).
81 US EPA 2017a.
82 Mitchell et al. 2015.
83 Zimmerle et al. 2015.
84 Australian Department of Environment and Energy, submission 1242 (**DoEE submission 1242**).
85 Littlefield et al. 2017.
86 DoEE submission 1242.
87 DoEE submission 1242.

9.4.3 Comparison of methane emission sources

To place the estimated methane emissions from any new shale gas operation into perspective, it is useful to compare those emissions with the level of emissions from alternative methane sources. In Australia, the agricultural (including pastoral) sector is the dominant source for both methane and nitrous oxide emissions.[88]

Table 9.2: Comparison of methane emissions from various sources.

Source of emissions	Australia (Mt CH_4/y)	NT (Mt CH_4/y)
Enteric fermentation in livestock[89] (mostly cattle and sheep)	1.95[90]	n/a
Enteric fermentation in cattle	1.17-2.51[91]	0.08-0.18[92]
Solid waste to land and waste water handling	0.47[93]	0.005[94]
Fugitive emissions from natural gas production	0.80-1.35[95]	0.09-0.15[96]

Table 9.2 shows that methane emissions from any new onshore shale gasfield in the NT (0.09–0.15 Mt CH_4/y)[97] would be similar to the methane emissions from the enteric fermentation of livestock in the NT, and greater than the emissions from waste in the NT. There are substantial incentives for gas companies to reduce the amount of fugitive emissions. Assuming that fugitive emissions represent 1.7% of production (Section 9.4.1), a gasfield producing 365 PJ/y at a gas price of $10/GJ, the cost of these fugitive emissions represent $62 million per year (the cost would be greater if a price was imposed on carbon emissions). If a substantial part of these fugitive emissions were prevented, then gas companies would achieve increased sales and profits, and the environment would benefit from reduced methane emissions.

In the upstream phase of any shale gas operation, methane dominates the emissions (77%, see Section 9.3). Given that more control can be exercised over methane emissions in the upstream phase (compared to combustion of gas in the downstream phase), it is appropriate to initially focus any mitigation strategies on methane emissions during the upstream stage. This focus also serves to reduce GHG emissions over the full life cycle.

9.4.4 Risk assessment

Table 9.3 contains the results of an assessment of the risk (see Section 9.9 for details on environmental values and objectives for the risk assessment) associated with upstream methane emissions from a possible new shale gasfield in the NT producing 365 PJ/y, expressed as a proportion of global methane emissions. The risk assessment is based on consideration of global methane emissions as these are an important component of global GHG, and therefore, a contributor to global temperature rise. The Panel has assessed the risk associated from methane emissions over the upstream stage as 'medium'.

88 Australian Government NGGI. Enteric fermentation from livestock represents 47% of Australia's inventory methane emissions.
89 Australian Department of the Environment and Energy 2017k.
90 Assuming that all reported CO_2e emissions are methane, GWP=25 and data is applicable to 2016.
91 Based on methane emissions for cows of 45-97 kg/y (DeRamus et al. 2003) and the Australian cattle herd of 25.9 million (Colliers International 2016).
92 Based on the Northern Territory cattle herd being 7% of the Australian cattle herd (Colliers International 2016).
93 Assuming that all reported CO_2e emissions are methane, GWP =25 and data is applicable to 2016.
94 A pro rata allocation based on the NT population being 245,000 and the Australian population of 24,385,000 (ABS 2016).
95 Based on Australian natural gas production of 3,394 PJ in 2015/2016 (Department of Industry, Innovation and Science 2017a, p 57) and assumed methane fugitive emission rates of between 1.3 and 2.2% (Littlefield et al. 2017).
96 Based on NT natural gas, new field production rate of 365 PJ/y and methane fugitive emission rates of between 1.3 and 2.2% (Littlefield et al. 2017). No allowance has been made for other natural gas production in the NT.
97 The range of fugitive emissions for Australian natural gas production in **Table 9.2** are larger than the value in **Table 9.1** (0.33 Mt CH_4/y) because more representative methane emission rates are used compared to the inventory results used in **Table 9.1**.

Table 9.3: Risk assessment for upstream methane emissions for a new shale gasfield producing 365 PJ/y (1,000 TJ/day).

Component	Assessment	Reason
Likelihood	High	Methane emissions occur mostly on a continuous basis but with some episodic releases.
Consequences	Low	Upstream methane emissions (from a possible new shale gasfield) will contribute 0.03% to global anthropogenic methane emissions; as these emissions are < 0.1%, they are assessed as minor/moderate (**Table 4.4**).[98]
Risk	Medium	Based on the risk assessment matrix in Chapter 4.

Because the assessed risk is 'medium', it is necessary to consider how this risk can be mitigated. Based on the information presented in Section 9.3 and this section, the Panel has formed the view that the following mitigation measure must be introduced to reduce upstream methane emissions from any shale gas industry in the NT.

Recommendation 9.1

That to reduce the risk of upstream methane emissions from any onshore shale gas wells, the Government implement the US EPA New Source Performance Standards of 2012 and 2016.[99]

The application of these standards will also serve to achieve possible reductions in CO_2 emissions at the upstream stage. Additional strategies to reduce the level of methane emissions are considered in Section 9.5. It is important that the issues of methane emissions and risk, as given in this section, be considered in the broader context of GHG emissions; these are discussed in Section 9.8.

Flaring at a gas processing facility in Australia.

98 For a gasfield production of 1,000 TJ/day (365 PJ/y), and assuming the upstream gross fugitive methane emissions are 1.7% of production, Littlefield et al. 2017, this leakage represents 0.11 Mt methane/y (0.017x365= 6.2 PJ/y and converting using 55.5 MJ/kg). The Australian NGGI for methane emissions is 4.36 Mt CH_4/y (Australian Government NGGI; see also Australian Department of the Environment and Energy 2017h). The fugitive emissions from a new gasfield in the NT represent 3% (=0.11/4.36) of Australia's Inventory methane emissions. The annual global anthropogenic methane emissions are 329 Mt of CH_4 (= 558x0.59; refer to Section 9.1.2 for details). Accordingly, the fugitive emissions from any new gasfield in the NT represent 0.03% (=0.11/329) of the annual global anthropogenic methane emissions. At this level of contribution to anthropogenic global methane emissions (< 0.1%), the consequence for methane emissions from a gasfield is assessed as 'moderate/ minor' (**Table 4.4**), and therefore, the 'consequence' rating is assessed to be 'low': refer to Chapter 4.

99 US EPA 2016c.

9.5 Monitoring methane emissions

Given that the concentration of methane in the atmosphere is low, there are challenges in determining the methane levels that apply to a basin-wide shale gasfield. Consideration is given, therefore, to options for monitoring methane emissions, including coverage over different spatial dimensions. The key findings identified by the Panel are that:

- the accurate detection of methane concentrations, conversion of these emissions into a flow rates (fluxes), and assigning them to particular sources, is difficult and that further research is required. For this reason, the reporting of total facility-wide emissions for inventory purposes relies on using emission factor calculations and measurements;
- current inventory estimates underestimate basin-wide measurements of methane emissions and basin-wide methane measurements are not routinely undertaken;
- the assessed risk of non-detection of abnormal levels of fugitive methane emissions from a new shale gas industry in the NT, without any further mitigation, is 'medium'; and
- because the assessed risk is 'medium', it is necessary to mitigate this risk. Mitigation / strategies are identified, using basin-wide measurements of methane concentrations, to enable abnormal methane emissions (above background levels) to be detected and repaired quickly, before large releases of methane occur.

Baseline monitoring of methane levels in the soil and atmosphere in the vicinity of any new onshore shale gas development should be undertaken before any hydraulic fracturing associated with exploration commences. Other possible emission sources (including wetlands, landfills, sewage treatment facilities, and livestock, such as cattle and sheep) can mean that top-down measurements of fugitive emissions can substantially overestimate the emissions generated from gas extraction unless such a baseline is established. A study observed from space a hot spot of methane emissions in the Four Corners region of the US, but the authors were unable to determine whether this arose from oil, CSG, or coal mining activities due to a lack of baseline data.[100] In some cases, the opportunity to gather such baseline data has passed, as hydraulic fracturing associated with exploration has already commenced. In this case, baseline measurements should therefore begin before further activities occur. These measurements should continue for at least 12 months to capture potential seasonal variations and be repeated over the production life of the field.[101] Baseline measurements can also provide a reference point assisting to establish closure criteria for emission levels for a gasfield at the end life for any shale gas project.[102]

Natural methane seepage can lead to elevated methane concentrations in the ambient air and in the soil.[103] These natural methane seeps can also result in the bubbling of methane on the surface of dams and waterways, and oil films on the water surface.[104] As an example, the NSW Division of Resources and Energy sampled water bores throughout NSW between 1994 and 2004 (before CSG activities commenced). Of the 300 bores sampled, 90% emitted methane. The methane concentrations varied from 3 to 600,000 ppm (0.0003% to 60% methane).[105] In fact, the detection of such seeps is often used to identify potential drill sites for gas.[106] These background methane levels mean that images such as those shown in the film *Gasland*, where the water from a tap is ignited, need to be treated with extreme caution before attributing the source to unconventional gas operations. Similarly, it is well documented that the bubbling of methane from the Condamine River in Queensland has increased threefold since ongoing measurement began in early 2015, although it is now declining. There is no conclusive evidence that this increase is related to CSG activities. It may relate to the migratory emissions described by the MEI,[107] but it could also relate to changes in river water flows or natural changes in groundwater flows.[108]

100 Lafleur et al. 2016.
101 Saddler and Gotham 2013.
102 Commonwealth Scientific and Industrial Research Organisation, submission 450 (**CSIRO submission 450**).
103 Saddler and Gotham 2013.
104 Saddler and Gotham 2013.
105 NSW Bore Water Data Package.
106 Saddler and Gotham 2013.
107 Lafleur et al. 2016.
108 CSIRO 2016.

GISERA has undertaken detailed measurements of methane concentrations in the Surat Basin of Queensland over the last three years that provide an excellent reference for future monitoring programs.[109] The Panel notes that Santos is also planning a baseline methane monitoring/assessment in the Beetaloo Sub-basin.[110]

9.5.1 Measurement of methane concentrations

Methane concentrations in the atmosphere are very low (1.8 ppm), and therefore, any detection method requires high precision and accuracy. For example, in a survey of Queensland mines, the maximum methane peak concentration was only 2.0 ppm.[111] Analytical techniques for measuring methane include catalytic oxidation, flame ionisation, infrared absorption, Fourier Transform Infrared Spectroscopy, photoionisation,[112] and cavity ringdown laser absorption spectroscopy. Isotopic analysis can determine whether the gas is 'biogenic' (from rotting vegetation and wastewater treatment) or 'thermogenic' (from oil or gas deposits) in origin.[113]

9.5.2 Leak detection and repair

Small leaks of methane from equipment such as valves, pumps and compressors, and pressure relief devices can be detected using portable instruments that rely on any of the above methods.[114] This is often referred to as 'Method 21', reflecting the relevant US EPA test method. More significant leaks can be efficiently detected using Optical Gas Imaging (**OGI**), which adopts passive infrared sensing technology to provide a visual image of methane plumes across a broader footprint. Origin[115] notes that the accuracy in determining methane concentrations using OGI could be only as good as 10,000 ppm.[116] That is, OGI equipment is not capable of accurately measuring concentrations below this range. The NSPS regulations introduced by the US EPA[117] indicate that methane leaks need to be repaired if they exceed 500 ppm when measured with a portable meter (Method 21), or if they are detected as a visible plume by an OGI instrument. These regulations enforce semiannual monitoring and repair of fugitive emission components at well sites and quarterly monitoring and repair at compressor stations, using either approach. Equipment leaks at natural gas processing plants must be monitored and repaired using the Method 21 approach. Submissions from industry[118] indicate that it has a preference for the Queensland Government's Code of Practice[119] approach to leak detection and repair. DPIR has indicated to the Panel that it will adopt this practice, with some possible customisation.[120] This Code of Practice requires that petroleum production operators carry and use personal calibrated gas detectors, but that formal leak inspections are only conducted every five years. An above ground *"reportable leak"* is defined as one that, at a measurement distance of 150 mm immediately above (and downwind) of the source, gives a sustained reading for a 15-second duration of greater than 5,300 ppm. A *"reportable leak"* must be corrected within 48 hours. However, the timeframe for repair of smaller leaks is at the discretion of the operator.

Other submissions have highlighted the regulations established by the Colorado Department of Public Health and Environment[121] as world-leading practice. These require natural gas compressor stations to be inspected for leaks at a frequency between monthly and quarterly, depending upon the anticipated emissions level calculated using *"emission factors"*. Similarly, well production facilities must undergo *"audio, visual and olfactory"* inspections for leaks monthly and using instrumentation at frequencies between "one time" and monthly, again depending upon the anticipated emission rate. Leaks requiring repair are those with emissions greater than 500 ppm if detected with portable instrumentation, while any leak detected by an OGI camera or *"audio, visual and olfactory"* inspection must be repaired.

109 Day et al. 2013; Day et al. 2015; Etheridge et al. 2017.
110 Santos submission 168, p 110.
111 Williams et al. 1993.
112 Santos submission 420.
113 Sherwood et al. 2017.
114 See Method 21-Determination of Volatile Organic Compound Leaks: US EPA 2016c.
115 Origin submission 433.
116 As indicated by the US Code of Federal Regulations, Title 40, Chapter I, Subchapter C, Part 60.
117 US EPA 2016c.
118 Origin submission 433 and Santos submission 420.
119 Queensland DNRM 2017b.
120 DPIR submission 424.
121 Colorado RAQC 2014.

9.5.3 Localised measurements

Flux towers can be used to monitor methane concentrations (ppm) at fixed points across regions of approximately 1 km^2. These towers also use an eddy covariance method to estimate the flow rate (flux) of methane from the land surface to the atmosphere from high-frequency measurements of the fluctuations in wind speed and concentration. GISERA has recently installed two such systems, upstream and downstream respectively, in respect of CSG operations in the Surat Basin, Queensland.[122] Each system consists of two towers. The first samples air for analysis from a height of 10 m and also records meteorological data such as wind speed, direction and humidity. The second, installed about 150 metres downwind of the first, contains the eddy covariance equipment, which determines the vertical methane flow rate from the land surface. Concurrent concentration measurement of gases such as carbon monoxide, ozone, VOCs, CO_2 and nitrogen oxides and particulates can assist in identifying the methane sources.[123] The GISERA program uses five sites that are separate from the flux towers to record this data.[124] Data for NO_2, CO_2, ozone and particulates is reported online in real time for three of these sites and a range of other sites throughout Queensland.[125] An alternative approach is being developed by the University of Adelaide in conjunction with the South Australian Roundtable for Oil and Gas Working Group.[126] There, an array of four methane spectrometers are connected to an atmospheric monitor, with the air mass exchange with methane concentration used to calculate a total methane flux.[127]

The 'static flux chamber' (a non-flow-through, non-steady-state chamber) method can be used for localised flux measurements of methane emissions from the ground. Essentially, this device consists of a chamber that is placed over an area of soil, with the gas composition recorded in the head space. This gives a flux result, but only over a very limited surface area, typically 0.1 to 0.5 m^2.[128] This small area means that many replicate measurements are required for high levels of accuracy.[129]

9.5.4 Regional measurements

Fixing continuous monitoring equipment to a vehicle allows a wider, more regional, area to be sampled. However, such monitoring needs to be completed regularly and at varying wind conditions. Santos and Maher[130] used this approach around the Tara region in Queensland in 2012, while in recent work undertaken by GISERA, a vehicle carrying a methane analyser covered more than 7,000 km on public and private roads within a region of 350 km x 300 km in the Surat Basin.[131] GISERA found that a disadvantage of this approach was that surveys were restricted to existing roads, which limited coverage. Such a restriction is likely to be of even greater concern in the NT, where the road network is restricted.

Although more expensive, the use of aircraft has the advantage that measurements across a range of horizontal and vertical distances can be made, allowing better detection of plume behaviour. However, because methane is much lighter than air (relative density of 0.55), it is readily dissipated from the point of emission.[132] This means that atmospheric measurements taken even a short distance from the source (as little as 100 m) can soon return to background levels. GISERA used a diode laser sensor mounted under a helicopter to monitor emissions in the Surat Basin, but noted that the narrow range of the instrument meant that many passes of the aircraft were needed to adequately cover the survey area.[133] The use of drones that can fly closer to the surface and at lower cost may prove more effective. These are being trialled in Queensland for the CSG industry for monitoring infrastructure by an Advance Queensland funded project.[134]

Remote sensing from either aircraft or satellites can be effective to determine larger-scale variations in methane. Differential Absorption Infrared Remote Sensing provides point

122 Day et al. 2015.
123 Etheridge et al. 2017.
124 Lawson et al.2017.
125 Queensland DEHP 2017.
126 SA Roundtable for Oil and Gas 2017.
127 Kennedy et al. 2013.
128 Pihlatie et al. 2013.
129 Denmead 2008.
130 Santos and Maher 2012.
131 Day et al. 2015.
132 Saddler and Gotham 2013.
133 Day et al. 2015.
134 CSIRO submission 450.

measurements of 1 m in diameter using pulsed laser light, from an altitude of around 150 m.[135] A similar, laser-based, remote sensing method is being developed by the University of Adelaide and Macquarie University.[136] The 'Methane Airborne MAPper' can provide point measurements of footprint of 23 × 33 m^2 for an aircraft altitude of 1 km and a ground speed of 200 km/h.[137] At the other extreme, the absorption spectrometer on board the Envisat satellite had a spatial resolution ranging from 30 × 60 km to 30 × 240 km.[138] This approach was used successfully to show increased methane emissions from the Four Corners region of the US over the period 2003–2009.[139] Data from the same spectrometer was recently used by GISERA to examine historical methane emissions from the Surat Basin. However, in that case, the spectrometer was unable to identify local scale impacts; rather, only regional trends could be identified.

The techniques described above can only measure the concentration of methane at a given point in time and space. Conversion of this data into a volumetric flow rate or flux is more difficult. These measurements need to be used in conjunction with meteorological models of wind patterns. These techniques are complex and require sophisticated expertise.[140] In Australia, AUSPLUME[141] is one of the most well-known models of plume dispersion, but AERMOD[142] is now the method of choice for the Victorian Environment Protection Authority and is supported by the US EPA. Others such as CALPUFF[143] and TAPM[144] are also used. Given sufficient meteorological data, these models can relate a concentration measured at some distance from a source of methane leakage to the flow rate from that source. An alternative approach can be to use a tracer gas, which is a stable gas unrelated to the source of methane. This gas can be released at a known rate, from the same location as the methane source. Measurement of both the tracer and methane concentrations downwind can give an accurate determination of the methane flow rate as the ratio of both concentrations multiplied by the tracer rate.[145] Even when a flux can be determined, associating this flow to a particular emission source can add greater uncertainty, especially in the absence of good baseline data and when concentration measurements are made a long way downwind of the potential source.[146] As noted by Saddler and Gotham,[147] *"methodologies to differentiate methane from a variety of background anthropocentric and natural background sources are still at an experimental stage"*. Schwietzke et al.[148] point out that most vehicular-based and aircraft-based methane concentration measurements are carried out during the middle of the day, which is also when activities such as liquid unloading and equipment maintenance occurs. Any concentration measurements made during these hours need to consider whether the methane concentrations would be lower in the middle of the night, before simply translating the data to a 24-hour basis.

9.5.5 Facility-wide emissions

The NGER scheme requires all operating facilities to report facility-wide emissions through a combination of direct measurement and the use of emission factors. The Australian Government's 'safeguard mechanism',[149] which commenced on 1 July 2016, is designed to ensure that emissions reported through this scheme do not increase over time and applies to both existing and new facilities that have direct emissions of more than 0.1 Mt tonnes of carbon dioxide equivalence a year, as reported through the NGER scheme. There are currently 340 facilities listed on the Clean Energy Regulator website as meeting this requirement.[150] Businesses must use Australian carbon credit units to offset emissions above their baseline levels, as determined by the Clean Energy Regulator. It is likely that any new onshore shale gas production facilities developed in the NT will be covered by the safeguard mechanism.[151] Rather than specifying actions to be taken to reduce

135 Zirnig et al. 2004.
136 Henderson-Sapir et al. 2016.
137 Gerilowski et al. 2015.
138 Saddler and Gotham 2013.
139 Kort et al. 2014.
140 Saddler and Gotham 2013.
141 Victorian EPA 1986.
142 US EPA 2016b.
143 Exponent 2014.
144 Hurley 2008.
145 Day et al. 2015.
146 Day et al. 2015.
147 Saddler and Gotham 2013, p 23.
148 Schwietzke et al. 2017.
149 Australian Department of the Environment and Energy 2017j.
150 Clean Energy Regulator 2017.
151 DoEE submission 445.

emissions, the Mechanism uses financial incentives to encourage companies to find their own least cost and effective emission reduction approaches.[152]

9.5.6 Towards a code of practice

The ability to detect methane concentrations accurately, to convert these emissions into a flow rate in g/h, and to assign these emissions to a particular source is difficult. This means that the reporting of total facility-wide emissions to the NGER will continue to rely substantially on emissions factor calculations. However, there are methodologies that can be undertaken to give confidence to the public that methane emissions are being correctly reported and that 'super emitters' can be detected and repaired quickly before large releases of methane occur.

The Panel has developed an outline of a mandatory code of practice for monitoring methane concentrations, which is described below. This code is based on reviews of existing codes of practice and GISERA reports and submissions to the Inquiry, as described in the preceding Sections 9.5.1 to 9.5.5. It is as follows:

- baseline monitoring should be conducted at least six months prior to hydraulic fracturing in the exploration phase, or in areas where hydraulic fracturing has already commenced, at least a year prior to any hydraulic fracturing for the purpose of production to ensure that seasonal variations are captured. This baseline monitoring is likely to consist of a combination of:
    - regional scale measurements of methane concentrations (greater than 100 km^2) using remote sensing and/or gas monitoring from drones, vehicles or aircraft. At least three such regional-scale surveys across a year are needed to cover seasonal variations in the baseline period. At least one regional scale survey should provide an isotopic analysis to separate thermogenic from biogenic sources of methane because this will assist to identify the source of major methane emissions;
    - localised measurements (approximately 1 km^2) through the establishment of a small number of flux towers (that is, fixed atmospheric monitoring stations combined with eddy covariance), or methane spectrometry arrays (as proposed by the University of Adelaide) upstream and downstream of the proposed production site to measure methane concentration and localised methane flux. Measurement results should be made available in real time and online for the public to view; and
    - a number of monitoring stations should also be established to monitor concentrations of other relevant gases (CO_2, NO_x and particulates). Measurement results should again be made available publicly in real time and online for the public to view;
- once production commences, the localised measurements and monitoring stations should continue to provide continuous data of CH_4, CO_2, NO_x and particulate concentrations in an online, real-time, publicly available format. This is to ensure community confidence that these emissions do not deviate significantly from the baseline. Any statistically significant deviation from the seasonally adjusted, steady-state concentrations recorded by these monitoring stations should require the gas company to immediately investigate the source of the deviation using portable instrumentation and/or OGI analysis;
- the regional scale measurements (>100 km^2) recorded during the baseline period should be repeated within the first six months of full-scale production commencing, and then at least once every five years (it is highly desirable that these measurements occur more regularly), to ensure that 'super emitters', and other emissions not detected by the flux towers and monitoring stations, can be observed. Again, any statistically significant deviation from the baseline regional survey should require the gas company to immediately investigate the source of the deviation;
- the monitoring program described above, should be undertaken by an independent regulator, (see Chapter 14);[153]
- methane emissions during well completions, well workovers, from vents and from flares should be monitored. This is possible using relatively simple flow meters and sensors.[154]

152 Australian Petroleum Production and Exploration Association, submission 421 (**APPEA submission 421**).
153 EDO submission 456.
154 CSIRO submission 450.

This monitoring should be the responsibility of the gas company, with by a oversight from an independent regulator; for example, the Commonwealth Clean Energy Regulator and

- detection of leaks from compressor seals, valves, pumps and gathering stations should occur as part of a leak detection and repair program.[155] A formal site-wide leak inspection and repair program should be conducted that is consistent with the US EPA NSPS standards.[156] Specifically, monitoring and repair of fugitive emission components at well sites should be conducted twice per year, with quarterly monitoring and repair at compressor stations, using either the Method 21 approach or OGI approach. Equipment leaks at natural gas processing plants must be monitored (and repaired) using the Method 21 approach at least annually, if not more regularly. While the Queensland Government's Code of Practice[157] indicates a program with five-year intervals, the Panel considers that the more frequent timeframes outlined in the NSPS are needed to ensure that emissions not detected by the monitoring stations are minimised and that community confidence is maintained. The threshold for localised emissions that are reportable should follow the US EPA NSPS regulation of 500 ppm for Method 21 and the detection of a visual plume using the OGI approach. This leak inspection and repair program should be the responsibility of the operating gas company, but with auditing, as outlined above, by an independent regulator.

9.5.7 Risk assessment

Current inventory estimates underestimate basin-wide measurements of methane emissions, and basin-wide methane measurements are not routinely undertaken. Accordingly, abnormal levels of methane emissions may not be detected. The risk assessment given in **Table 9.3** for methane emissions from a producing gasfield is broadly relevant to the risk of non-detection of abnormal levels of methane emissions. As the assessed risk is 'medium', it is necessary to consider how this risk can be mitigated. The Panel has formed the view that a mitigation strategy based on basin-wide measurements of methane concentrations is a key strategy that will enable abnormal methane emissions (above background levels) to be detected and repaired quickly, before large releases of methane occur. Other detection strategies are also relevant. Accordingly, and consistent with the discussions above, the following recommendations are made.

Recommendation 9.2

That prior to the grant of any further exploration approvals, a code of practice be developed and implemented for the ongoing monitoring, detection and reporting of methane emissions from any onshore shale gasfields and wells.

Recommendation 9.3

That baseline monitoring of methane concentrations be undertaken for at least six months prior to the grant of any further exploration approvals. In areas where hydraulic fracturing has already occurred, the baseline monitoring should be undertaken at least a year prior to the grant of any production approvals.

Recommendation 9.4

That baseline and ongoing monitoring be the responsibility of the regulator and funded by the gas industry.

Recommendation 9.5

That all monitoring results must be made publicly available online on a continuous basis in real time.

Recommendation 9.6

That once emission concentration limits are exceeded, as soon as reasonably practicable the regulator must be notified, an investigation must be undertaken by the gas company to identify the source or sources of the emissions, and make-good provisions be carried out by the gas industry.

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155 CSIRO submission 450
156 US EPA 2016c.
157 Queensland DNRM 2017b.

The mitigation and assessment of risk associated with methane levels is further discussed in Section 9.9.1.

9.6 Life cycle GHG emissions from a new gasfield in the NT

Estimates are given for the quantities of life cycle GHG emissions for a new shale gasfield in the NT producing 73, 365 and 1,240 PJ/y respectively. These results are used in risk assessments by comparing the life cycle emissions from 365 and 1,240 PJ/y productions with Australian and global GHG emissions. The key findings identified by the Panel are that:

- GHG emissions from any new onshore shale gasfield in the NT producing 365 PJ/y would contribute around 4.5% of Australian GHG emissions, and on a global basis 0.05% of global GHG emissions;
- for gasfields producing 1,240 PJ/y (with LNG exports of 80% and domestic consumption of 20%), the Australian component of emissions is around 6.6% of Australian GHG emissions and 0.07% of global GHG emissions, and the total emissions (emitted in both Australia and overseas) is 0.17% of global GHG emissions; and
- the assessed the risk associated with life cycle GHG emissions is 'medium' for a gasfield producing 365 PJ/y; 'medium' for the Australian emission component associated with gasfields producing 1,240 PJ/y; and 'high' for the global emissions (both in Australia and overseas) associated with gasfields producing 1,240 PJ/y. These assessments represent unmitigated risk levels. The mitigation of these risk levels is considered in Section 9.9.

9.6.1 Quantity of GHG emissions

The life cycle GHG emissions estimates are based on production estimates[158] provided by industry where a potential shale gasfield is assumed to have production in the range of 800 - 1100 TJ/day (nominal 365 PJ/y) for a large gasfield development, or 100 - 220 TJ/day (nominal 73 PJ/y) for a small development. In addition, a further submission[159] provided a best estimate indicative later development scenario that equates to 3,400 TJ/day (1,240 PJ/y). In this later development scenario, it is assumed that 2,740 TJ/day is used for liquid natural gas (**LNG**) export and 660 TJ/day is used for domestic gas consumption. When gas is exported, there are additional upstream emissions in Australia associated with the conversion of gas to LNG, while emissions associated with transport, regasification and combustion occur in the importing country. Based on these three production scenarios, the estimated quantity of life cycle GHG emissions, which combine upstream GHG emissions with the downstream GHG emissions from the combustion of natural gas for end use application, are shown in **Table 9.4**. In the case of LNG, the emissions accounting is done for both Australian-only emissions and for combined Australian and overseas emissions. The data in **Table 9.4** represents the additional quantity of GHG emissions for given levels of any new shale gas production in the NT. They are applicable for the combustion of gas and apply irrespective of whether the gas is used for heating or electricity production. Further, the estimates in **Table 9.4** are total emissions and they do not take account of possible net emissions where gas may replace other fossil fuels.

158 Origin submission 153; Santos submission 168; Pangaea Resources Pty Ltd, submission 263 (**Pangaea submission 263**).
159 DPIR submission 281, pp 3-4.

Table 9.4: Quantity of life cycle GHG emissions and comparison to the total GHG footprint for Australia.

Total gas production PJ/y (TJ/day)	Location of emissions	Life cycle GHG emissions[160] per year Mt CO_2e/y	Proportion of Australia's emissions for 2015[161] %	Proportion of global emissions %
	Based on a 100-year GWP (= 36)			
365 (1,000)[162]	Australia	26.5	4.5	0.05
73 (200)	Australia	5.3	0.9	0.01
1,240 (3,400)[163]	Australia	38.9	6.6	0.07
1,240 (3,400)[164]	Australia and overseas[165]	98.8	n/a	0.17
	Based on a 20-year GWP (= 87)			
365 (1,000)	Australia	31.6	3.9	0.04
73 (200)	Australia	6.3	0.8	0.01
1,240 (3,400)	Australia	56.2	7.0	0.07
1,240 (3,400)	Australia and overseas	116.3	n/a	0.15

The quantity life cycle GHG emissions in Australia from a shale gasfield producing 365 PJ/y is estimated to be 4.5% as a proportion of Australia's GHG inventory emissions[166] for a 100-year GWP of 36 (after Australian inventory results for methane are converted from a GWP of 25 to 36). In the case of gasfields producing 1,240 PJ/y (where approximately 80% of the gas is used for LNG export and approximately 20% is used for domestic consumption), the quantity life cycle GHG emissions in Australia is estimated to be 6.6% of Australia's GHG inventory emissions for this 100-year GWP (=36). Similarly, the GHG emissions are estimated to be 0.05% of global emissions for a shale gasfield producing 365 PJ/y, and for gasfields producing 1,240 PJ/y, the Australian component of emissions is 0.07% of global GHG emissions and the total emissions (emitted in both Australia and overseas) is 0.17% of global GHG emissions (when adopting a similar correction to adjust emissions to a common GWP).

To provide context for the gas production data given in **Table 9.4**, if a new shale gasfield in the NT were producing 365 PJ/y, this would represent 7.5% of Australia's estimated gas production in 2017/ 2018.[167] This production level (365 PJ/y) is representative of 670 wells (Gale scenario over a 25-year period: see Appendix 16). The higher production of 1,240 PJ/y is representative of 6,250 wells (or 4,170 wells with a higher EUR per well).[168] This later production estimate is higher than the industry estimates of 1,000 to 1,200 wells over 25 years as noted in Section 6.5.1. The higher production estimate (1,240 PJ/y) is considered representative of a significant cumulative development over a number of gasfields.

160 The downstream emissions from combustion of natural gas was assumed to be 57 g CO_2e/MJ; Steen 2001. Domestic consumption of gas upstream emissions were assumed to be 15.5 g CO_2e/MJ (100-year GWP) or 29.5 g CO_2e/MJ (20-year GWP); Skone 2016, Table C-1 & C-2 applicable to the Appalachian shale gasfield. The life cycle emissions are then 72.5 g CO_2e/MJ (100-year GWP) and 86.5 g CO_2e/MJ (20-year GWP).

161 Australia's total emissions are taken from the NIR for 2015 (Australian Department of the Environment and Energy 2017h). Australia's national inventory total emissions for 2014/2015 were reported as 537.9 Mt CO2e/y. The methane emissions were converted to CO2e by the GWP shown in the Table above. The NO and other emissions are left with the same CO2e value as in NIR for 2014/2015.

162 The production scenarios of 73 and 365 PJ/y are assumed to be 100% Australian domestic consumption: see previous footnote for life cycle emissions.

163 For the production scenario of 1,240 PJ/y, it is assumed that 240 PJ/y is consumed in Australia and 1000 PJ/y is exported via LNG processing. The Australian domestic consumption component has both upstream and downstream emissions of 72.5 g CO_2e/MJ (100-year GWP), see footnote above. The Australian LNG component has only upstream emissions of 15.5 g CO_2e/MJ + 5.9 g CO_2e/MJ. The later component represents the emissions from LNG production (Hardisty et al. 2012).

164 The Australian domestic consumption component is estimated using 72.5 g CO_2e/MJ (100-year GWP): see footnote above. The Australian LNG component has upstream emissions = 21.4 g CO_2e/MJ (as noted previously), plus overseas emissions of 1.6 + 1.3 g CO_2e/MJ for LNG shipping and regasification (Hardisty et al. 2012) and natural gas combustion of 57 g CO_2e/MJ (Steen 2001). This gives total emissions, both locally and overseas, for the LNG stream = 81.3 g CO_2e/MJ (100-year GWP).

165 In this case, the overseas emissions amount to 98.8 – 38.9 = 59.9 Mt CO_2e/y. It is not appropriate to account for these overseas emissions against Australian emissions, but rather against the importing country's emission inventory.

166 These may be an overestimate since they are based on a comparison of life cycle emissions, that are based (in part) on comprehensive basin wide measurements, with inventory estimates. As shown in Section 9.4.2, basin wide measurements are double inventory estimates for fugitive methane emissions.

167 Department of Industry, Innovation and Science 2017a, Table 7.1.

168 DPIR submission 281.

The Australia Institute has estimated[169] that shale gas operations in the NT would emit much higher GHG emissions than estimated above by assuming the full exploitation of shale gas resources in the NT. The resource estimate used by The Australia Institute is what is defined in Section 6.1 as a "prospective resource". Prospective resources[170] are estimated volumes associated with undiscovered accumulations. These are clearly unreliable and are an overly optimistic gas estimate of what can be recovered commercially. Accordingly, The Australia Institute estimates of GHG emissions are, in the Panel's view, highly inflated.

Some submissions have noted also the possible extraction of shale oil resources.[171] Increased levels of shale gas and shale oil production will result in larger contributions to GHG emissions from shale gas operations in the NT and a faster erosion of the global carbon budget[172] (see Section 9.1.4). Nevertheless, the Panel has deemed the assumed levels of production (365 PJ/y or 1,240 PJ/y) are plausible and relevant for the purposes of conducting the risk assessment (see also Section 6.1).

9.6.2 Risk assessment

It is appropriate to focus the risk assessment of GHG emissions over the full life cycle (which considers both CO_2 and CH_4 emissions for both upstream and downstream phases as a ratio of the global GHG emissions because it is these emissions that are a major contributor to global warming. **Table 9.5** contains the risk assessments for life cycle GHG for a gasfield in the NT producing 365 PJ/y and gasfields producing 1,240 PJ/y. The Panel assessed the risks associated from GHG emissions over the full life cycle as 'medium' for a shale gasfield producing 365 PJ/y, 'medium' for the Australian emission component associated with gasfields producing 1,240 PJ/y and 'high' for the global emissions (both in Australia and overseas) associated with gasfields producing 1,240 PJ/y. These assessments represent mitigated risk levels. The mitigation of these risk levels is considered in Section 9.9.

169 The Australia Institute, submission 627. The Australia Institute have estimated GHG emissions of some 20 or 32 Gt CO2e from the exploitation of a 257,276 PJ prospective resource base in the NT.

170 Prospective resources represent quantities of petroleum which are estimated to be potentially recoverable from oil and gas deposits identified on the basis of indirect evidence but which have limited or no drilling. This class of resource represents a higher risk than contingent resources (and commercial reserves) since the risk of discovery is also added. For prospective resources to become classified as contingent resources, hydrocarbons must be discovered, the accumulations must be further evaluated and an estimate of quantities that would be recoverable under appropriate development projects prepared (Australian Energy Resources Assessment 2014).

171 T Forcey, submission 548 and Australian-German Climate and Energy College, submission 543.

172 T Forcey submission 548.

Table 9.5: Risk assessment to climate change for life cycle GHG emissions from possible new shale gasfield(s) in the NT.

A: Producing 365 PJ/y.

Risk assessment component	Assessment	Reason
Likelihood	High	Life cycle GHG emissions occur mostly on a continuous basis but with some episodic releases.
Consequences	Low	Life cycle GHG emissions) are 0.05% of global GHG emissions; these emissions are deemed assessed as minor/moderate (< 0.1%; see **Table 4.4**).[173]
Risk	Medium	Based on the risk assessment matrix in Chapter 4.

B. Producing 1,240 PJ/y, Australian emissions only.

Risk assessment component	Assessment	Reason
Likelihood	High	Life cycle GHG emissions occur mostly on a continuous basis but with some episodic releases.
Consequences	Low	Life cycle GHG emissions (from a new field) are 0.07% of global GHG emissions ; these are assessed as minor/moderate (<0.1%; see **Table 4.4**).
Risk	Medium	Based on the risk assessment matrix in Chapter 4.

C. Producing 1,240 PJ/y, global emissions.

Risk assessment component	Assessment	Reason
Likelihood	High	Life cycle GHG emissions occur mostly on a continuous basis but with some episodic releases.
Consequences	Medium	Life cycle GHG emissions (from new fields) are 0.17% of global GHG emissions; these are assessed as serious (<0.5%; see **Table 4.4**).
Risk	High	Based on the risk assessment matrix in Chapter 4.

9.7 Life cycle GHG emissions: technology comparisons for electricity production

Natural gas is used for heating purposes (domestic, commercial and industrial), electricity generation, and as a feedstock for the production of other materials. The focus in this Section is on the life cycle emissions produced from electricity generation by natural gas plants and other technologies. GHG emission results are presented in terms of the quantity of CO_2e per unit of electrical energy produced (MWh). The Panel's key findings are that:

- the downstream emissions from modern natural gas electric power generation plants represent 78% of the life cycle GHG emissions (and the upstream methane emissions represent 22% of the life cycle GHG emissions);
- the life cycle GHG emissions from shale gas-generated electricity are 50–60% of that from coal-generated electricity. Natural gas combined cycle gas turbine power plants[174] (**CCGT**) have a lower climate impact than supercritical pulverised coal power, provided methane emission rates are lower than 3.3%;
- the total life cycle GHG emissions from renewable energy sources are much lower (and generally less variable) than those from fossil fuels. For example, supercritical coal fired electricity releases about 20 times more GHG per megawatt-hour than solar electricity; and

173 For a gasfield production of 1,000 TJ/day (365 PJ/y), the gross life cycle GHG emissions (not allowing for any replacement of coal-fired electricity) is 26.5 Mt CO2e/y (**Table 9.4**) or approximately 5% of Australian GHG emissions (= 543.3 Mt CO2e/y). On a global basis, these represent 0.05% of global GHG emissions (= 26.5 Mt CO2e/y compared to 53.4 Gt CO2e/y). At this level of contribution to global GHG, the consequence for GHG emissions from a gasfield is assessed as 'minor/ moderate' (< 0.1%: see **Table 4.4**), and therefore, the consequence rating is considered to be 'low': see **Chapter 4**.

174 A combined-cycle power plant uses both a gas and a steam turbine together to produce up to 50% more electricity from the same fuel than a traditional simple open-cycle plant.

- in the short to medium term, the Australian National Electricity Market is likely to require higher levels of flexible, gas-fired generation, which can provide a reliable, low emissions substitute for ageing coal-fired generation, and can provide essential security services to rapidly respond to and complement variable renewable electricity generation.

9.7.1 Electricity production

The life cycle emissions of shale gas represent the combination of the downstream emissions with the upstream emissions in terms of CO_2e. Downstream emissions refer to final use of the natural gas for electricity production, which includes the operation of power plants and the transmission and distribution of electricity to the consumer. Skone et al. estimated that the life cycle emissions from CCGT are 497 kg CO_2e/MWh for 100-year GWP and 598 kg CO_2e/MWh for 20-year GWP.[175] Older style open-cycle gas turbine peaking plants have greater emissions.[176] Skone et al. also determined that the total life cycle GHG emissions for electricity generation are dominated by CO_2 from power generation. In the case of CCGT, the downstream power generation represents 78% of total life cycle GHG emissions and the upstream emissions account for about 22% of life cycle GHG emissions.

9.7.2 Comparison with coal

Natural gas-fired power has lower GHG emissions per unit of electricity than coal-fired power because of the relatively low carbon-to-energy intensity of natural gas[177] and the relatively high efficiency of natural gas power plants. However, upstream CH_4 emissions can reduce the life cycle GHG advantage of natural gas-fired power plants.

Heath et al. employed a process of harmonisation to normalise a wide range of results to a common set of units, while ensuring consistent system boundaries and sets of major activities throughout the production and use of shale gas.[178] Ten harmonised estimates of life cycle GHG emissions from the use of shale gas for electricity generation are compared with 215 harmonised estimates for conventional gas and coal power generation, all from the peer-reviewed literature.[179] Even with greater consistency after harmonisation, variability in results remained because of intrinsic differences between the study conditions. Therefore, the validity of comparing individual results from different authors is highly questionable. Nevertheless, Heath et al. found that the median of GHG life cycle emissions from shale gas generated electricity from CCGT plants was less than half those from coal-fired electricity generation. The median estimates for the life cycle emissions of shale and conventional CCGT plants after harmonisation were nearly identical: 465 kg CO_2e/MWh for shale, and 461 kg CO_2e/MWh, respectively. The median estimate for the life cycle emissions of coal-fired electricity generation after harmonisation was 980 kg CO_2e/MWh. This covers four coal combustion technologies and thermal efficiencies representative of modern plants.

Littlefield et al. determined that for electricity generation, the upstream methane emission rate would have to be greater than 4.4% of natural gas production for CCGT to be worse than supercritical, pulverised coal power generation for a 20-year GWP, or 10.0% for a 100-year GWP.[180] Use of an alternative procedure (Technology Warming Potential (**TWP**), that is independent of GWP timeframes) found that as long as CH_4 emission rates are lower than 3.3%, CCGT power plants have a lower climate impact (in terms of cumulative radiative forcing) than supercritical, pulverised coal power at all points in a time series.[181] **Table 9.6** provides estimates of the emissions from various forms of coal-fired and gas-fired electric power generation. Both forms of gas-fired generation represent substantial reductions on the average Australian National Electricity Market generation. Nevertheless, the life cycle emissions from new black coal-fired High Efficiency, Low Emission (**HELE**) generators can approach the emissions of open cycle gas turbines (**OCGT**).

175 Skone et al. 2016. p72.
176 An open cycle gas turbine plant uses only a gas turbine to produce electricity. This technology does not recover heat via a steam turbine and therefore has a lower efficiency and higher fuel use than CCGT. OCGT can respond quickly to changes in electricity demands, but modern CCGT plants can operate with a high degree of flexibility and fast response times.
177 US EIA 2017.
178 Heath et al. 2014.
179 Whitaker et al. 2012; Health et al. 2014.
180 Littlefield et al. 2016.
181 Littlefield et al. 2016.

Table 9.6: GHG emissions for various forms of electric power generation.

	GHG emissions, kg CO_2e/ MWh				
	Coal power generators			Gas power generators	
	Black coal supercritical HELE	Black coal ultra-supercritical HELE	Average National Electricity Market	Open cycle (OCGT)	Combined cycle (CCGT)
Downstream[182]	860	700	990	620	370
Upstream[183]	128	116	137	156	120
Life cycle	988	816	1127	776	490

As **Table 9.6** demonstrates, the best gas fired generation (CCGT) is approximately 60% as emission intensive as the most efficient coal fired plant (ultra-supercritical coal HELE generation) based on life cycle GHG emissions.

If natural gas is used to displace coal from electricity production in Australia, and the net unit CO_2e savings are in the order of 515 kg CO_2e/MWh of electricity[184] (see above) for 100-year GWP, there could be a reduction in Australia's GHG emissions of appromixately 1% from a 73 PJ/y production and 5% in the case of 365 PJ/y production.[185] However, it should be noted that the actual savings will be less than that estimated because not all of the gas supply will be used as a fuel for electricity generation. For example, gas may be used to supplement renewable energy sources and to assist with grid stability (where there are high levels of renewables); used to replace coal; exported as LNG (as considered previously); used for heating (domestic, commercial and industrial); and/or used as a feedstock chemical for industrial processes.

9.7.3 Comparison with renewable energy technologies

The National Renewable Energy Laboratory has carried out a comprehensive review of published GHG life cycle assessments of electricity-generation technologies. Approximately 2,165 references were collected, of which 296 passed screens for quality and relevance, and distributional information on the emissions was calculated based on the as-published data. The resultant data was published and the median emission results for a selection of renewable energy technologies are given in **Table 9.7**.

Table 9.7: Median GHG emissions for a selection of renewable energy technologies.[186]

Renewable energy technology	Life cycle GHG estimate kg CO_2e/ MWh	Renewable energy technology	Life cycle GHG estimate kg CO_2e/ MWh
Geothermal	45	Wind- onshore and offshore	12
Photovoltaic	46	Ocean energy	8
Concentrating solar thermal	22	Hydropower	4

The results in **Table 9.7** show that the total life cycle GHG emissions from renewables are much lower than those from fossil fuels. For example, the life cycle GHG emissions on a per megawatt-hour basis are about 22 times higher from supercritical coal fired electricity (**Table 9.6**) than from photovoltaic solar electricity.

It has also been claimed that it is cheaper to employ solar and wind power, and pumped hydro and batteries to provide baseload power and manage energy supply/demand fluctuations, which are the major functions of gas in the electricity system.[187] Estimates for the cost of producing

182 Figures are the estimated downstream emissions for new power stations (Finkel et.al. 2017, p 203) with the exception of the NEM; Based on data for the NEM (Brazzale 2016), the average emissions are 860 kg CO_2e/ MWh for black coal generators and 1250 kg CO_2e/ MWh for brown coal generators, and the combined average emissions (weighted on outputs) are 990 kg CO_2e/ MWh.

183 It has been estimated (Whitaker et al. 2012) that in the case of coal, upstream transmission and distribution accounts for some 5% to 10% of emissions and that coal-mine methane emissions yield a median estimate of 63 kg CO_2e/ MWh. Indicative estimates for the upstream emissions for OCGT (fleet peaking) and CCGT are 156 and 120 kg CO_2e/ MWh respectively, Skone et. al. 2016, Table C-4.

184 Heath et al. 2014.

185 Savings of 515 kg CO_2e/MWh of electricity, at 51% generation efficiency, converts to a savings of 72.9 g CO_2e/MJ of delivered gas. For example, a production of 73 PJ/y represents savings in emissions of 5.3 Mt CO_2e/y; this is approximately 1% of Australia's GHG emissions.

186 IPCC WG III 2012, p 190.

187 Climate Action Darwin, submission 446, p 9.

electricity in Australia for a range of technologies have recently been developed.[188] While these levelised cost of electricity (**LCOE**) results provide a different perspective, it is important to realise that investment decisions involve numerous other factors not reflected in the LCOE values.

9.7.4 Future electricity generation mix and the role of gas

In a recent review of the Australian National Electricity Market by Finkel et al., it was found that under a proposed Clean Energy Target (**CET**) policy setting, calibrated to achieve an emissions reduction target of 28% on 2005 levels by 2030, there is a need for a substantial change in the electricity-generation mix. Renewables are projected to have their proportion of generation increased from 28% in 2020 to 42% in 2030 and 70% in 2050; whereas, fossil fuels are projected to have their proportion of generation reduced from 72% in 2020 to 58% in 2030 and 30% in 2050. The proportion of gas generation will reduce from 6% in 2020 and 2030 to 4% in 2050.[189]

APPEA used recent research from the US and Europe to suggest that renewables and fast-reacting gas-fired power general technologies appear to be highly complementary and should be jointly installed to meet the goals of reduced emissions and stable supply.[190] However, concern has been raised about developing an overreliance on gas and renewables as an energy mix. For example, the Climate Council has observed that using existing gas-fired generators to complement wind and solar power, while scaling up a range of renewable energy technologies, energy storage and energy efficiency measures, can deliver a limited benefit, provided that the end goal is phasing out the use of all fossil fuels as quickly as possible.[191]

Since 2014, when gas-fired generation was contributing around 13% of electricity energy generation in the Australian National Energy Market, gas-fired generation output has been in decline due largely to higher gas prices, increases in variable renewable energy generation, and reduced electricity demand. As noted in the Finkel review,[192] access to a reliable and affordable gas supply is in the interest of all Australians given its direct use for heating, as a feedstock chemical for industrial processes, and as a fuel for electricity generation. Gas has an important role to play in supporting the continued deployment of renewable energy technologies. Rapid changes in power output from variable renewable energy generation need to be balanced with generation technology that has the ability to increase (ramp up) or decrease (ramp down) power output at the same time. Gas-fired generators have the ability to 'fast ramp'. Most of Australia's coal-fired generators, however, do not.

In the short to medium term, the Australian National Energy Market is likely to require higher levels of flexible, gas-fired generation, which can provide a reliable, low emissions substitute for ageing coal-fired generation, and essential security services to complement variable renewable electricity generation. Storage technologies, such as pumped hydro and batteries, will be able to play a role to support reliability as and when they are deployed at scale.[193] Over a longer timeframe, as Australia transitions to lower-emissions generation, natural gas may be replaced by zero emissions fuels such as hydrogen and biogas.

9.8 Methane emissions from post-production shale gas wells

Oil and gas wells can provide a potential pathway for subsurface migration and emissions of methane to the atmosphere (see Chapters 5 and 7). There are an estimated three million abandoned oil and gas wells throughout the US, with no regulatory requirement to monitor or account for their methane emissions in the national inventory.[194] Estimates are given in this Section for the quantity of methane emissions from plugged, unplugged and decommissioned wells. These results are used as the basis of a risk assessment based on comparing the emissions from 1,000 hypothetical decommissioned wells in the NT (should any onshore shale gas industry be established) with global methane emissions. The key findings are that:

- the evidence on methane emissions from decommissioned and abandoned gas wells is mixed. It is clear, however, that properly decommissioned wells (wells that have been

188 Finkel et al. 2017.
189 Finkel et al. 2017, p 93.
190 APPEA submission 215, p 8.
191 Climate Council, submission 458, p 5.
192 Finkel et al. 2017.
193 Finkel et al. 2017, p 109.
194 Kang et al. 2014. p 18173.

cut-off, sealed (plugged) and then buried under soil) have generally lower methane emissions than wells that have been not been properly (or at all) decommissioned and have been abandoned with well head infrastructure left above the surface;

- there is a need to improve the integrity performance of decommissioned wells over the long term, such as 1,000+ years, and that this needs further research;
- fugitive methane emissions from any onshore shale gas industry in the NT (for the case of 1,000 decommissioned wells) is estimated to represent 0.7% of Australia's inventory fugitive methane emissions and 0.005% of the global anthropogenic methane emissions from fossil fuels; and
- the assessed risk of fugitive methane emissions from decommissioned wells resulting from any new shale gas industry in the NT, without any further mitigation, is 'medium'.

The assessment of risk associated with methane levels is further discussed in Section 9.9.1

9.8.1 Quantity of emissions

Studies suggest that 4–9% of all wells drilled experience some form of gas leakage that is detectable at the surface.[195] The quality of the casing installations is considered the major potential pathway for fugitive gas seepage.[196] Any pathway outside the casing is of particular concern because it may lead to leakage from intermediate-depth gas zones, rather than from the deeper target reservoirs (see Chapter 5). Mitigation is possible. It is noted that hydraulic fracture stimulation a does not appear to be a significant risk of methane leakage, although problems can occur when stimulation induces a connection with legacy or offset wells that have not been plugged.[197] In another study,[198] it was noted that poor cementing may result in well integrity failure and potential leaks. This is influenced by three main factors: failure to bring the cement top high enough; failure to surround the casing completely with cement; and gas migration in the cement during cement setting. Direct measurements[199] of methane fluxes from 19 abandoned oil and gas wells in Pennsylvania were undertaken, with methane flow rates observed from all 19 wells and the mean well methane flow rate being 99 kg/y. Of the 19 measured wells, most were over half a century old, five (26%) were plugged and 14 (74%) were unplugged. The integrity of plugging was difficult to determine. Three out of the 19 measured wells were high emitters that had methane flow rates that were approximately three orders of magnitude larger than the median well flow rate of 0.5 kg/y. The maximum flow rate from a well was 753 kg/y. In this study, it was also found that methane flow rates from plugged wells were not always lower than methane flow rates at unplugged wells. Assuming the mean flow rate to be representative of all abandoned wells in Pennsylvania, it was estimated that the methane emissions from abandoned wells was 0.1–0.5 % of gross gas withdrawal in Pennsylvania. These measurements show that methane emissions from abandoned oil and gas wells can be significant.

In the UK, a study of 102 decommissioned wells (cut-off, sealed and then buried under 2 m of soil) from four onshore oil and gas basins reported that the mean methane flux at the soil surface was 15 ± 27 kg /well/y,[200] where the uncertainty is given as the standard deviation in the mean, with a 28% chance that any well would be a net sink of methane. In the case of one additional well that had not been decommissioned, the methane flux was 345 kg /y. The relative methane concentration above wells did not increase with age, and 40% of the most recent wells surveyed showed leaks, implying that leaks develop early (within a decade) in the post-production life of a decommissioned well.

In another study, direct measurement of methane emissions from 138 abandoned oil and gas wells found that nine (6.5%) wells had measurable methane emissions.[201] Only one of the 119 plugged wells was a positive source of methane, emitting 1.8 kg/y. By contrast, eight of the 19 unplugged wells were a positive source of methane, with an average methane emission rate of 209 kg/y. There was a skewed pattern of emissions, with a small proportion of measurements comprising the majority of emissions. The results indicate that plugging is essential for mitigation of methane emissions from abandoned wells. The majority of the wells had been drilled since the

195 Watson and Bachu 2009; Ingraffea et al. 2013.
196 Dusseault and Jackson 2014.
197 Dusseault and Jackson 2014.
198 NSW Chief Scientist and Engineer 2014.
199 Kang et al. 2014.
200 Boothroyd et al. 2016.
201 Townsend-Small et al. 2016.

1970s and 1980s, although a few had been drilled since the 1850s. It was found that abandoned wells made a small contribution (<1%) to regional methane emissions, and it was estimated that, when abandoned oil and gas wells were included, the US inventory would increase national CH_4 emissions from oil and gas activity by 1.9–4.3%.

A range of international industry experience and literature suggests that if the current methods prescribed in national and international codes and standards for petroleum well integrity (of which well abandonment/decommissioning is a component) are adopted, the risk of a petroleum well failing is considered to be low.[202] However, often these types of studies consider petroleum well integrity over a period of decades, with little research conducted on the potential longer-term impacts (over a 1,000+ year period). Some researchers have used simulations to determine the potential for degradation of the cement over the long term. One study considered cement seals over 1,000 years and concluded that cement would be able to isolate CO_2 and upper aquifers over the very long-term, while another study estimated cement plug degradation after 10,000 years and concluded that *"mechanical integrity of cement plugs and the quality of its placement probably is of more significance than chemical degradation of properly placed abandonment plugs"*.[203] These studies were conducted on wells intended for CO_2 storage. Shale gas in the Beetaloo Sub-basin contains very low levels of corrosive gases such as CO_2 and H_2S,[204] and therefore, the likelihood of chemical degradation is even lower.

A substantial proportion of petroleum wells in NSW are either suspended or abandoned. Current codes and standards may be adequate regarding abandonment of existing exploration or production wells, but were not in effect for historic petroleum wells (legacy wells). Like petroleum wells, mining or irrigation wells also have the potential to connect aquifers and emit fugitive emissions, including following abandonment, if their integrity is compromised. In Queensland, investigations are under way to locate, quantify the emissions, and remediate abandoned and legacy wells. For example, it has been noted that:

> *"during the Queensland GISERA greenhouse study in the Surat Basin, a number of legacy exploration boreholes were found to be leaking methane. Given the large number of such boreholes in Queensland, they represent a potentially significant source of methane in the region. As a result of that work, further research is currently under way in collaboration with the industry to locate and remediate leaking boreholes";[205] and*
>
> *"mobile ground surveys over a wide region between Chinchilla and Roma have surveyed approximately 1,000 abandoned boreholes sites. Downwind methane concentrations have been measured and local wind speed and direction data used to determine whether or not methane is leaking from the boreholes. Most of the boreholes examined are old coal exploration holes, but there have also be numerous plugged and abandoned CSG wells included in the dataset. So far, the majority of sites examined have shown no methane emissions. However, a handful of sites have shown some level of emission".[206]*

A recent review by the NSW Chief Scientist and Engineer on abandoned wells[207] noted that different jurisdictions regulate well abandonment in different ways. Some jurisdictions require companies to submit abandonment plans to the regulator for each project. These plans are then reviewed and approved in light of industry standards and field development plans. Other jurisdictions, such as NSW, Queensland and Alberta, have set up codes of practice, rules, or directives, governing well integrity and abandonment that must be adhered to by all companies. An overview of available oil well abandonment regulations for a selection of countries and jurisdictions found that a general distinction can be observed between European and non-European countries.[208] The main differences lie in the length requirements of the plugs near the deepest casing shoe. In Europe, the length of the cement plug is between 50 m and 100 m, and in evaluated non-European countries, the length of the plug is between 30 m and 60 m. The evaluated regulations primarily comprise prescriptive requirements for plugging and abandonment of oil and gas wells. In Colorado, all wells used for the injection of fluids must be pressure tested

202 NSW Chief Scientist and Engineer 2014.
203 APPEA submission 465, p 6.
204 DPIR submission 424, p 3.
205 GISERA 2016, p 8.
206 Etheridge et al. 2017, p 43.
207 NSW Chief Scientist and Engineer 2014.
208 IEA GHG 2009, Section 8.3.

at least once every five years for ongoing management of well integrity. In Alberta, a well bore integrity plan must include assessments of 3D hydraulic fracture propagation extent. In the UK, there is a recommendation for post-management monitoring to detect any well failure after abandonment.

The Queensland Department of Natural Resources and Mines has recently published a code of practice for the construction and abandonment of coal seam gas wells and associated bores.[209] This code includes principles and mandatory requirements based on industry good practice. While this comprehensive and prescriptive-based code is applicable to CSG wells, and not shale gas wells, it nevertheless specifies that cement plugs should be a minimum length of 30 m; whereas, European codes specify plugs to be 50 m to 100 m and do not include a requirement for ongoing monitoring of methane emissions post abandonment.

It is noted that research is being undertaken in Australia to develop cheaper and more effective measures to seal wells using bentonite (a clay).[210] Further, it is noted that under the NGER scheme, methods will be developed to account for decommissioned wells and wells where production has been temporarily suspended by considering empirical data. In addition, the results will be reported in the NIR.[211]

Based on the evidence above, methane emissions appear generally lower with plugged or decommissioned wells compared to unplugged wells. To further mitigate methane emissions, it is appropriate to require that all wells be decommissioned post production and that monitoring for possible leaks must be undertaken.

9.8.2 Risk assessment

Table 9.8 contains an assessment of the risk associated with methane emissions from decommissioned wells for a new shale gasfield in the NT, based on these emissions as a proportion of global GHG emissions. The Panel has assessed the risk associated from methane emissions from decommissioned wells as 'medium'.

Table 9.8: Risk assessment for methane emissions from 1,000 decommissioned wells in the NT.

Risk assessment component	Assessment	Reason
Likelihood	High	Methane emissions occur mostly on a continuous basis once leakage has commenced.
Consequences	Low	Methane emissions from decommissioned wells are 0.005% of net global anthropogenic methane emissions; as these emissions are < 0.1%, they are assessed as minor/moderate (**Table 4.4**).[212]
Risk	Medium	Based on the risk assessment matrix in Chapter 4.

Based on the findings contained in Chapter 5, and the discussion above, the Panel is of the view that to reduce fugitive emissions from post-production wells, all such wells must be decommissioned in accordance with world-leading practice. The Panel therefore repeats ***Recommendations 5.1*** and ***5.2***.

Because the assessed risk is 'medium', it is necessary to consider how this risk can be mitigated. The mitigation and assessment of risk associated with methane levels is further discussed in Section 9.9.1.

The number of decommissioned wells will increase during the production life of a gasfield and then remain essentially constant following the decommissioning of the gasfield. During the life of

209 Queensland DNRM 2017a.

210 UQ CCSG 2017.

211 Australian Department of the Environment and Energy 2017h.

212 Assuming that a gasfield in the NT will comprise 1,000 decommissioned wells and that the mean methane emissions from each well is 15 kg well/y (see Boothroyd 2014), then this mean leakage represents 0.015 Mt methane/y; this is about 10% of the methane emissions from a new gasfield. The Australian National GHG Inventory for methane emissions is 4.36 Mt CH_4/y (Australian Government NGGI; see also Australian Department of the Environment and Energy 2017h). The fugitive emissions from decommissioned wells in the NT represent 0.3% (=0.015/4.36) of Australia's Inventory methane emissions. The annual global anthropogenic methane emissions are 329 Mt of CH_4 (= 558x0.59; refer to Section 9.1.3 for details). Accordingly, the fugitive emissions from decommissioned wells in the NT represent 0.005% (=0.015/329) of the annual global anthropogenic methane emissions. At this level of contribution to global anthropogenic methane emissions, the consequence for methane emissions from decommissioned wells is assessed as 'minor/ moderate', therefore, the consequence rating is assessed to be 'low': see Chapter 4. During the decommissioned phase of a gasfield, emissions from decommissioned wells must be assessed as part of a new methane monitoring regime with possibly revised performance targets.

a gas production field, methane emissions from any decommissioned wells must be monitored (see Section 9.5). In the decommissioned phase of a gasfield, emissions from decommissioned wells must be monitored and levels above normal background levels should be investigated and remedial action taken if appropriate.

9.9 Risk assessment summary

The Panel has assessed the risks to climate change associated with life cycle GHG emissions, (including methane) and separately, the risks for methane emissions from possible new onshore shale gasfield(s) in the NT, namely:

- upstream methane emissions (Section 9.4);
- non-detection of abnormal levels of methane emission (Section 9.5);
- life cycle GHG emissions (Section 9.6); and
- methane emissions from 1,000 decommissioned wells (Section 9.8).

Given that the unmitigated risks were assessed to be either 'medium' or high, it is necessary to apply mitigation strategies that, first, achieve the environmental objective (namely, to "limit the emissions of methane and greenhouse gases to the atmosphere"),[213] and second (as outlined in Chapter 4), achieve a mitigated risk that is either 'low' and/or meets the acceptability criteria for methane and GHG emissions (refer to **Table 9.9**).

The decision on the extent of mitigation required to achieve an acceptable outcome was guided by the principles of ESD (Chapter 4), while nevertheless recognising:

- community concerns about the impacts associated with GHG emissions (including methane emissions);
- the community's expressed lack of trust with industry;
- the community's expressed lack of trust with the Government's ability to adequately regulate industry; and
- the lack of facility-wide measurements of methane levels.

Table 9.9: Environmental objective and acceptability criteria for GHG and methane emissions.

Environmental objective	Limit the emissions of methane and greenhouse gases to the atmosphere	
Theme	**Criterion**	**Measure of Acceptability**
Methane emissions	Minimise fugitive methane emissions	Set a methane concentration limit that is equivalent to methane emissions that are 1.7%[214] of dry production
GHG emissions	Minimise GHG emissions	Offset life cycle GHG emissions in Australia from shale gas produced in the NT to ensure no net GHG emissions

9.9.1 Methane emissions

The unmitigated risks associated with methane emissions were assessed as 'medium'. A number of recommendations were made to reduce methane emissions. Namely, that the NT's regulatory regime must limit the extent of methane emissions from any onshore shale gas industry's contribution to climate change through the introduction of the following methane mitigation measures:

- require the application of the US NSPS and related emission-reduction technologies to reduce fugitive emissions at the upstream stage of operations (see Sections 9.3 and 9.4 and ***Recommendation 9.1***);
- require baseline and ongoing monitoring and reporting of methane concentration[215] levels at any new gasfield (see Section 9.5 and ***Recommendations 9.2*** to ***9.6***); and

213 See Appendix 3, Risk assessment matrix.
214 This is based on the results of Littlefield et al. 2017.
215 It is acknowledged that measuring methane flux levels from a gasfield is difficult and the results unreliable. Therefore, measurement of methane concentrations is proposed.

require that all post-production wells be decommissioned in accordance with world-leading practice (see Section 9.8 and ***Recommendations 5.1*** and ***5.2***).

The implementation of these recommendations will mitigate the levels of methane emissions. Nevertheless, after mitigation, the assessed 'likelihood' will remain 'high' and, even with lower levels of methane, the 'consequences' are assessed to remain 'low'[216] (see **Table 4.4**). Accordingly, the mitigated methane risk remains 'medium' (**Table 4.2**).

There are also a number of supplementary risks that may prevent the achievement of lower levels of methane emissions. In **Table 9.10,** these risks are identified, together with the actions that can be taken to mitigate the risks.

Table 9.10: Mitigation of supplementary risks that may prevent lower levels of methane emission performance from being achieved.

Risk identification	Comment	Mitigation action
Regulations are not implemented.	Regulations are required for reduced emissions completions, compressor emissions and pneumatic controllers.	Ensure that world leading practice regulations are implemented that are known to achieve lower methane emissions.
Regulations may restrict the development or implementation of technologies that lower emissions.	Regulations may hinder the achievement of lower emissions.	Prescription-based regulation only, while achieving desirable outcomes, may restrict new technologies. There is a need to allow appropriate flexibility in the formulation of performance-based regulations.
Regulations are not fully complied with.	This may have the effect of allowing increased emissions.	Ensure that there are appropriate incentives for compliance and penalties for non-compliance.
Monitoring for compliance with regulations is not undertaken or is inadequate.	Monitoring by a regulatory authority may not occur because of lack of resources.	Ensure that there are appropriate requirements for monitoring regulatory compliance and that there are adequate resources.
Monitoring of both baseline emissions and emissions during production is not undertaken.	Monitoring emissions is a means of assuring compliance and to detect 'super emitters'.	Ensure that there are appropriate requirements for monitoring emissions.
Inadequate monitoring of both baseline emissions and emissions during production.	This may result in the inability or failure to detect abnormal emissions and lead to higher emissions..	Ensure that there are adequate resources to undertake monitoring and that this monitoring is undertaken by an independent organisation with the necessary expertise.
Failure of plant or equipment occurs during the lifetime of the well.	These are normally low likelihood events with consequences that can range from a minor to a catastrophic release of gas for a relatively short period over the life of a well.	These failure events can be mitigated by ensuring compliance with appropriate regulations, including undertaking rigorous risk assessment and ensuring that a formal leak detection and repair program is undertaken regularly.

The Panel has formed the view that to mitigate the supplementary risks identified in **Table 9.10**, the action measures identified in that Table should be introduced to further reduce fugitive methane emissions.

Recommendation 9.7

That the action framework outlined in Table 9.10 be implemented to lower fugitive methane emissions.

216 Mitigation of methane emissions can result in at least a 23% reduction in upstream GHG emissions (see Section 9.3). Nevertheless, with this reduction the resultant methane emissions remain at about 0.03% of global anthropogenic methane emissions. The consequences are deemed 'minor/ moderate' (<0.1%), and therefore, the consequence rating remains 'low'.

In summary, after the implementation of the mitigation measures contained in ***Recommendations 9.1*** to ***9.7***, methane emissions will be reduced to a level that is consistent with the achievement of the acceptability criterion for methane emissions given in **Table 9.9**. Nevertheless, the mitigated methane emission risk will remain 'medium'. The further mitigation of the risk of methane emissions is necessary and is considered in the broader context of mitigating GHG emissions as described in the following Section.

9.9.2 GHG emissions

After mitigation of methane emissions, the residual life cycle GHG emissions are reduced slightly but they remain significant.[217] These mitigated/residual life cycle GHG emissions have the same risk levels as previously assessed in Section 9.6.2, namely, either 'medium' or 'high'.[218] These are unacceptable risk levels (refer to Chapter 4). Accordingly, the Panel has determined that to meet the environmental objective (**Table 9.9**), the life cycle GHG emissions must have a 'low' risk (Chapter 4) and meet the acceptability criteria (**Table 9.9**). These objectives can be achieved by fully offsetting the life cycle GHG emissions, namely, that there is no net increase in life cycle GHG emissions in Australia from any onshore shale gas produced in the NT.

Recommendation 9.8

That the NT and Australian governments seek to ensure that there is no net increase in the life cycle GHG emissions emitted in Australia from any onshore shale gas produced in the NT.

The Panel recognises that while this recommendation may present a challenging task, it is based on the principles of ESD. It also reflects widespread and strongly held concerns that were articulated to the Panel regarding the impacts of increased GHG emissions. To achieve this outcome, the increase in life cycle GHG emissions in Australia from any onshore shale gas produced in the NT (see **Table 9.4**) must be fully offset. For example, 26.5 Mt CO_2e/y must be fully offset for a gasfield producing 365 PJ/y and 38.9 Mt CO_2e/y must be fully offset in Australia for a gasfield producing 1,240 PJ/y. In the latter case, the residual emissions of some 60 Mt CO_2e/y are emitted overseas, and they should therefore be offset overseas.[219]

There are various existing energy and climate change policies and commercial and public initiatives that support the reduction of GHG emissions and assist in meeting Australia's obligations under the Paris Agreement to limit global warming to less than 2°C. Accordingly, fully offsetting these additional GHG emissions (see **Table 9.4**) may require strengthening existing policies and/or the introduction of new policies and initiatives to meet Australia's international obligations. There are a variety of strategies that may either be expanded or new strategies be implemented to achieve this recommendation, including: early retirement of coal-burning power plants; fitting of carbon capture and storage to gas or coal-fired power stations; higher emission standards for fossil fuel-burning vehicles; increased uptake of electric vehicles; international offsets; carbon credit offsets in agriculture and savannah burning; formal offset policies and markets; increased deployment of renewable energy; and reductions in deforestation. Any decisions to adopt such strategies and the implementation of mechanisms required to fully offset of GHG emissions from any onshore shale gas produced in the NT are, however, beyond the scope of this Inquiry when regard is had to the Terms of Reference.

217 Mitigation of methane emissions can result in at least a 23% reduction in upstream GHG emissions (see Section 9.3). This reduction in upstream emissions translates to a reduction of 5% in life cycle GHG for a 100-year GWP. Accordingly, the mitigated life cycle GHG emissions are similar to the unmitigated GHG emissions. Therefore, there is no change in the assessed risk.

218 The Panel has assessed the risks associated with GHG emissions over the life cycle as: 'medium' for a gasfield producing 365 PJ/y; 'medium' for the Australian emissions associated with gasfields producing 1,240 PJ/y; and 'high' for global emissions (both in Australia and overseas) associated with gasfields producing 1,240 PJ/y.

219 The total NT GHG emissions in 2014/15 were 12.8 Mt CO_2e (inventory estimate: see Australian Department of the Environment and Energy 2017g). By comparison, the estimated emissions from a gasfield producing 365 PJ/y is 26.5 Mt CO_2e (**Table 9.4**). Clearly, any offset of GHG emissions from any onshore shale gas operations in the NT must also involve the Australian Government. The NT Government had a Climate Change Policy in 2009 (Climate Action Darwin, submission 1159) which set emissions reduction targets. The NT Government has recently released a *Roadmap to Renewables* report as part of achieving a 50% renewable energy target by 2030 (Langworthy et al. 2017).

9.10 Conclusion

The Panel is of the opinion that the collective application of methane mitigation measures (including the introduction of NSPS, methane monitoring and reporting, well decommissioning, and the mitigation measures in **Table 9.10)** will result in lower levels of methane emissions that will meet the acceptability criterion for methane emissions. Nevertheless, the residual risk (after mitigation of methane levels) of life cycle GHG emissions remains either 'medium' or 'high', and this is unacceptable. Accordingly, the life cycle GHG emissions must be reduced to a 'low' risk for the GHG emissions and it is necessary to meet the acceptability criterion. This can be achieved by ensuring that GHG emissions are fully offset and that there is no net increase in the life cycle GHG emissions emitted in Australia from any onshore shale gas produced in the NT. The Panel has formed the view that if there is a no net GHG emission increase, this would represent an acceptable outcome.