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Mitigation and Offsets of Australian Life Cycle Greenhouse Gas Emissions of Onshore Shale Gas in the Northern Territory

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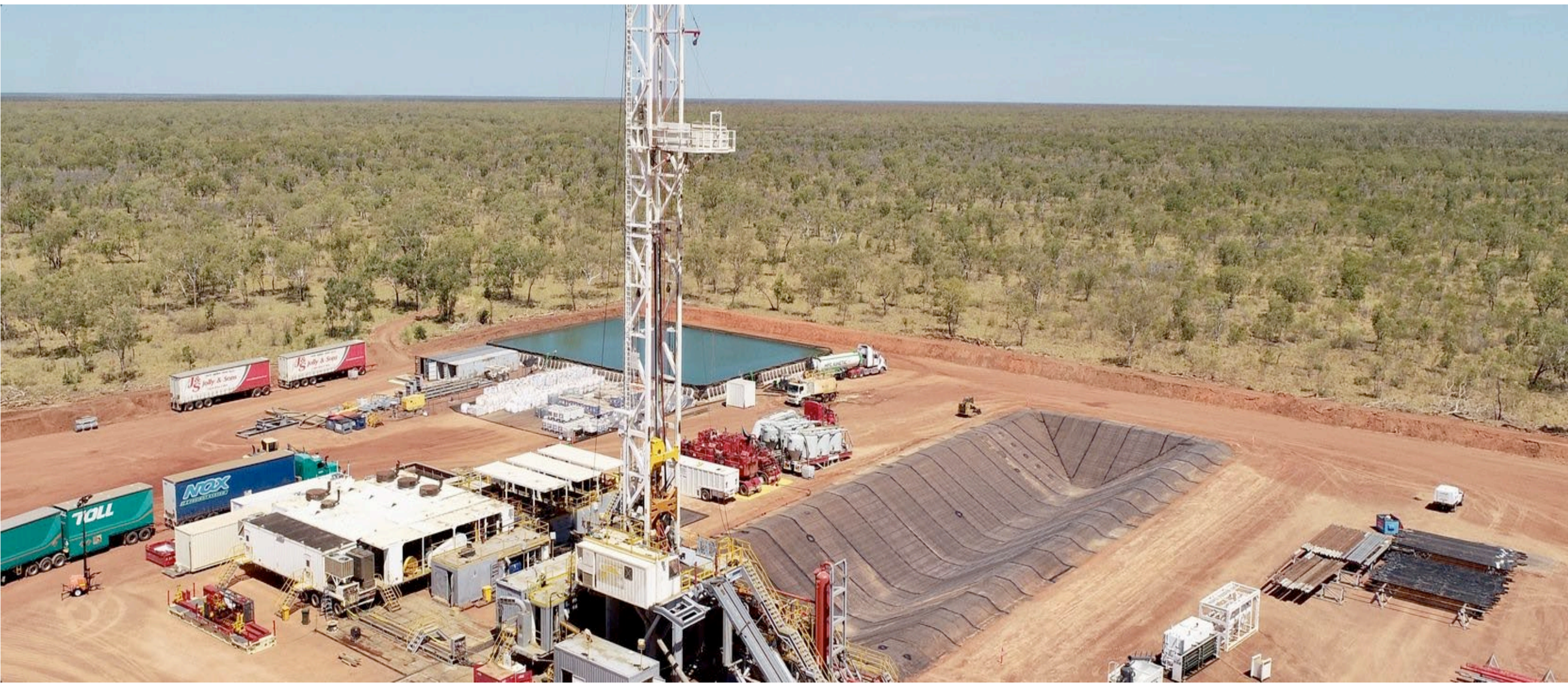

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Acronyms used in this report

AET	Avoided Emissions Technology
ATR	Autothermal reformer
AUSLCI	Australian life cycle inventory
ACCU	Australian Carbon Credit Unit (1 tonne CO_2e)
BBL	Billion barrels of oil (6004.3PJ)
BECCS	Bioenergy with carbon capture and storage
CCS	Carbon capture and storage
CCU	Carbon capture and utilisation
CFP	Life cycle carbon footprint
CH_4	Methane
CO_2	Carbon dioxide
CO_2e	CO_2 equivalent global warming potential
COP	Conference of the Parties to the United Nations Framework Convention on Climate Change
DPIR	Northern Territory Department of Primary Industry and Resources now known as the Department of Industry Tourism and Trade
ERF	Emissions Reduction Fund
EUR	Estimated ultimate recovery
GHG	Greenhouse gas
GJ	Gigajoule = 10^9 joules
GTP	Global temperature potential
GWP	Global Warming Potential
H_2	Hydrogen gas
HHV	Higher heating value
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
kt	Kilotonne = 10^3 tonnes
LCA	Life cycle assessment
LDAR	Leak detection and repair
LNG	Liquid natural gas
LPG	Liquid Petroleum gas
MEA	Monoethanolamine
MEE-MVR	multiple-effect evaporation with mechanical vapour recompression
MJ	Megajoule = 10^6 joules
Mt	Megatonne = 10^6 tonnes
MTPA	Megatonnes per annum
NET	Negative Emissions Technology
NGCC	Natural Gas Combined Cycle
NGER	National Greenhouse and Energy Reporting Scheme
NT	Northern Territory
PCC	Post Consumption Capture
PJ	Petajoule = 10^{15} joules
REC	Reduced emission completion
SMR	Steam methane reforming
SNG	Synthetic natural gas
TCF	Trillion cubic feet (1094.1PJ)
UK	United Kingdom
US	United States
USEPA	United States Environmental Protection Agency
VOC	Volatile organic compounds
WA	Western Australia

Acknowledgments

We acknowledge that this research is conducted on, and is about, Aboriginal land. We also refer to the presumed use of that land for extracting natural gas but do not presume that Indigenous Land Councils and other representative organisations consent to the activities referred to herein.

This research has been funded through CSIRO's Gas Industry Social and Environmental Research Alliance (GISERA) with contributions from the Australian Government's Department of Industry, Science and Resources. GISERA is a collaboration between CSIRO, Commonwealth, state and territory governments and industry established to undertake research on the impacts of onshore gas exploration and development on the environment, and the socioeconomic costs and benefits. For information about GISERA's governance structure, projects and research findings visit https://gisera.csiro.au.

It was important for the project team to consult with government, industry, Indigenous Land Councils, those in the Indigenous carbon abatement industry, scientific peers and other stakeholders to share perspectives and understanding on the material issues of new onshore shale gas in the Northern Territory, and the offset options.

We would specifically like to acknowledge the useful input and conversations with Professor David Allen from the University of Texas, and Garry Cook, Linda Stalker, Dimitri Lafleur, Maartje Sevenster, Andrew Reeson, Steve Roxburgh, Allison Hortle and Andrew Ross from CSIRO.

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The life-cycle greenhouse gas emissions assessment was independently reviewed by Andrew Moore, Principal Sustainability Scientist at Life Cycle Logic, Associate Professor Wahidul Biswas Sustainable Engineering Group Curtin University, and Associate Professor Ahmed Barifcani Department of Chemical Engineering Curtin University.

Executive Summary

This research assessed the Australian life-cycle greenhouse gas (GHG) emissions of potential onshore shale gas projects in the Northern Territory (NT) using a set of plausible production scenarios from 2025-2050. Subsequently, we assessed options for mitigating or offsetting these scenarios' respective contribution to climate change, measured in 100-year global warming potential (GWP) – various sensitivities were explored including impacts for 20-year GWP.

Part of the context of this study is Recommendation 9.8 of the *Scientific Inquiry into Hydraulic Fracturing in the Northern Territory* (2018),: "*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*."

Four scenarios considered gas production of 365PJ/year and one scenario 1130PJ/year, with a variety of use cases for the produced gas (see Table ES1). All scenarios assumed that the source of gas would be shale gas from the onshore Beetaloo Sub-basin and that extracted gas would be processed before being transported by pipeline to Darwin for further processing and use. The total *lifetime* emissions to be abated according to Recommendation 9.8, ranged from 164 – 826Mt CO_2e (*annual* emissions range: 6.6 – 33Mt CO_2e/year).

The scope of our life-cycle assessment (LCA) included upstream shale gas extraction activities, and downstream transformation of gas to basic chemicals, hydrogen, LNG and direct Australian consumption. Although we have calculated, and present, emissions from the consumption of exported gas for global context, this was not in scope to be offset.

Table ES1: Annual GHG emissions from scenarios of onshore shale gas production and consumption that would need to be offset under Recommendation 9.8 Measures are in 100-year GWP Mt CO_2e/year.

	Gas production	Transmission	Manufacturing	Domestic use	Total annual emissions
Sc1 Domestic gas use & LNG export (365PJ/year)	2.9	0.3	1.1	2.2	**6.6**
Sc2 Domestic gas use & LNG & refinery (365PJ/year)	2.4	0.2	1.7	9.1	**13.5**
Sc3 Domestic gas use & LNG & chemicals (365PJ/year)	2.9	0.3	5.8	2.2	**11.2**
Sc4 Domestic gas use & LNG & hydrogen (365PJ/year)	2.9	0.3	6.5	2.2	**11.9**
Sc5 All (1130PJ/year)	8.5	1.0	14.5	9.1	**33.0**

These are results from our scenarios but for any actual development, the emissions intensities of production and consumption are useful parameters to extract from this research (see Figure ES1).

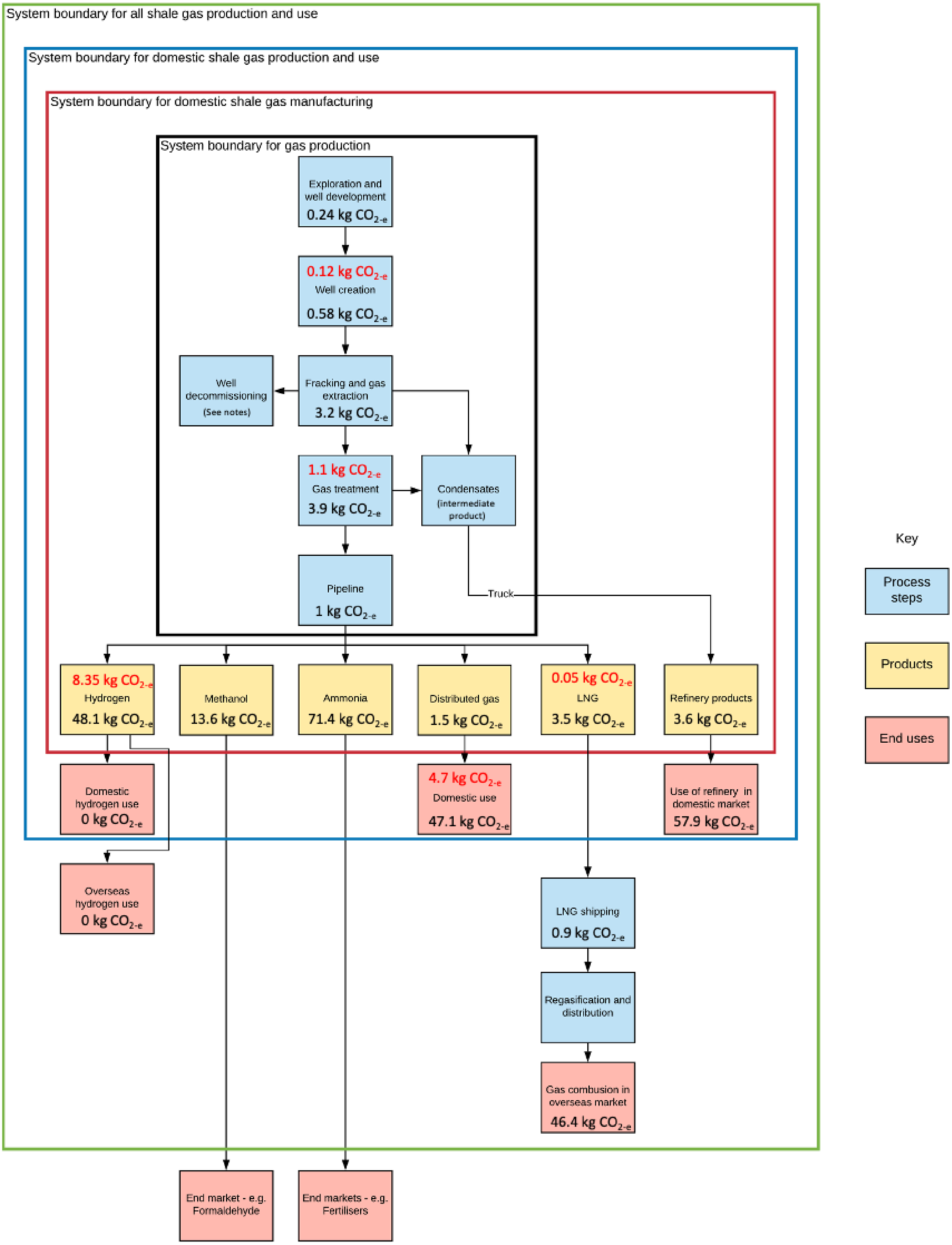


Figure ES1: 100-year GWP emissions intensities (black) and mitigation (red) in kg CO_2e for 1GJ shale gas

We applied a hierarchy in seeking ways to abate GHG emissions, starting with avoidance or mitigation, followed by the capture and sequestration of GHG emissions before seeking offset options for any residual emissions. For offsets, local options were considered before national offsets with international offsets given the lowest priority.

The mix of mitigation or offset options deployed for each scenario depended on scale and availability over the lifetime of the gas development, technical feasibility, indicative cost and a priority for local, well-governed schemes. As for the production scenarios, the mitigation and offset options considered are also scenarios constrained by current knowledge.

The conclusion of our work is that, from an engineering perspective, the majority of GHG emissions can be mitigated or physically abated with options available in Australia for the four scenarios of 365PJ/year production. A cost–benefit or other economic analysis was not undertaken.

The LCA study identified potentially 1.38Mt CO_2-e/year could be mitigated in the upstream production and processing of onshore shale gas. This involves operational practices to reduce emissions and investment in renewable energy to power compression, gas treatment and other processes that would otherwise be powered by diesel, grid electricity or off-take gas. Carbon Capture and Storage (CCS) options were limited to activities in Darwin where concentrated CO_2 streams and access to storage made this abatement option technically viable.

Combining the mitigation activities during production in the NT, potential CCS based out of Darwin, and savannah fire management in Northern Australia, more than 7Mt/year (+/- 5%) of mitigation and abatement could be implemented in that region based on our assumptions.

Land-based offsets available elsewhere in Australia were applied to remaining emissions. Between 79-156Mt/year of land-based offsets are available elsewhere in Australia, enough to offset *all* the life-cycle emissions from *all* scenarios. But we have assumed that 10% of that could be available for an onshore shale gas project. The assumed proportion of land-based offsets that our scenarios of NT onshore shale gas consume, was a deciding factor in how many residual emissions needed to be accounted for with international offsets (see for example Figures ES2 - ES4). Based on these assumptions, the majority of GHG emissions can be mitigated or physically abated with options available in Australia for the four scenarios of 365PJ/year production.

It is important to note the limits of the Australian land-based offset resource. According to our analysis of available land-based offsets with respect to increasing carbon prices, annual supply becomes inelastic towards $AUS100/t CO_2e. The maximum possible national, annual abatement lies somewhere between 150-180Mt CO_2e/year (Fitch et al. 2022) and this needs to be considered in the context of socioeconomic impacts or dynamics, for example, competition with land for food production. For perspective, Australia's current national GHG emissions, which are around 500Mt CO_2e/year.

If we had assumed onshore shale gas from the NT absorbed a larger fraction of the supply of Australian land-based or other offsets, this could perturb the domestic carbon market and drive up the price for a tonne of CO_2e abatement. Such a dynamic market analysis was out of scope for the present project, but our assumptions apply a precautionary principle.

Figure ES2: life-cycle GHG emissions and mitigation or offset implementation for a scenario that assumed 365 PJ/year of NT onshore shale gas would be used as: 45PJ/year in domestic consumption and; the remainder for LNG export.

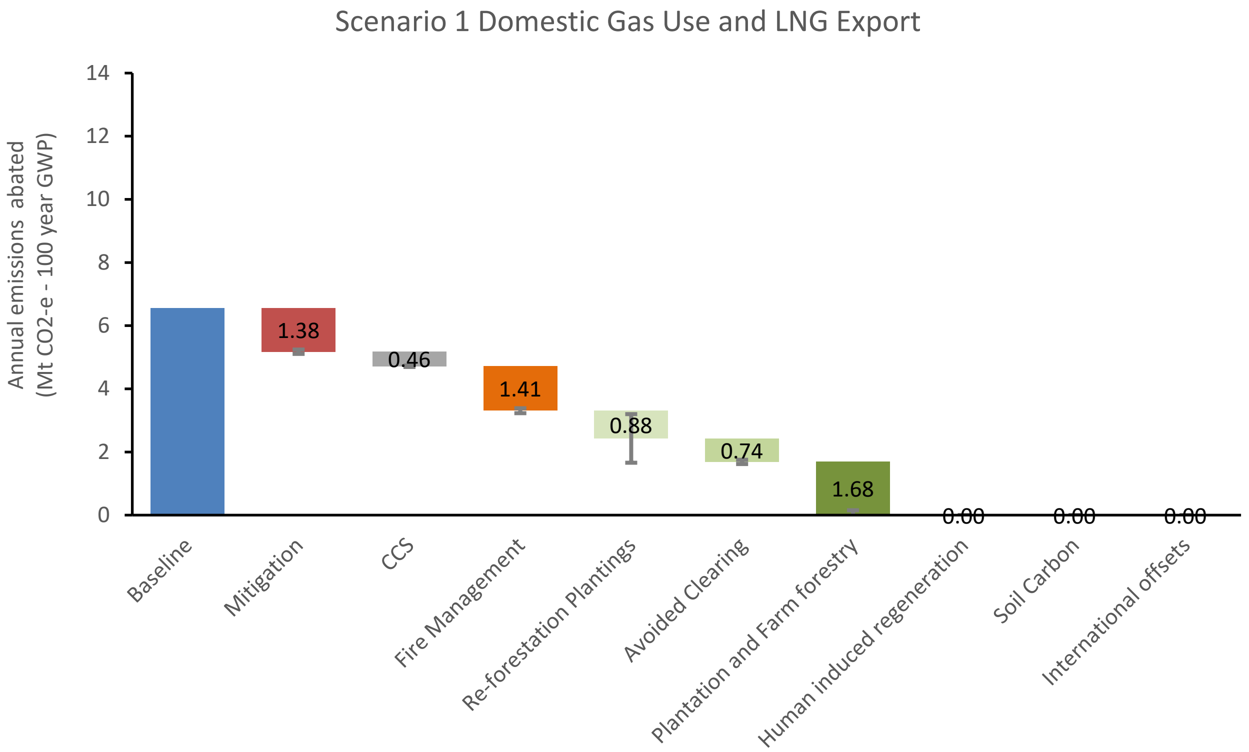


Figure ES3: life-cycle GHG emissions and mitigation or offset implementation for a scenario that assumed 365 PJ/year of NT onshore shale gas would be used as: 45PJ/year in domestic consumption; 120PJ/year in hydrogen production and; the remainder for LNG export.

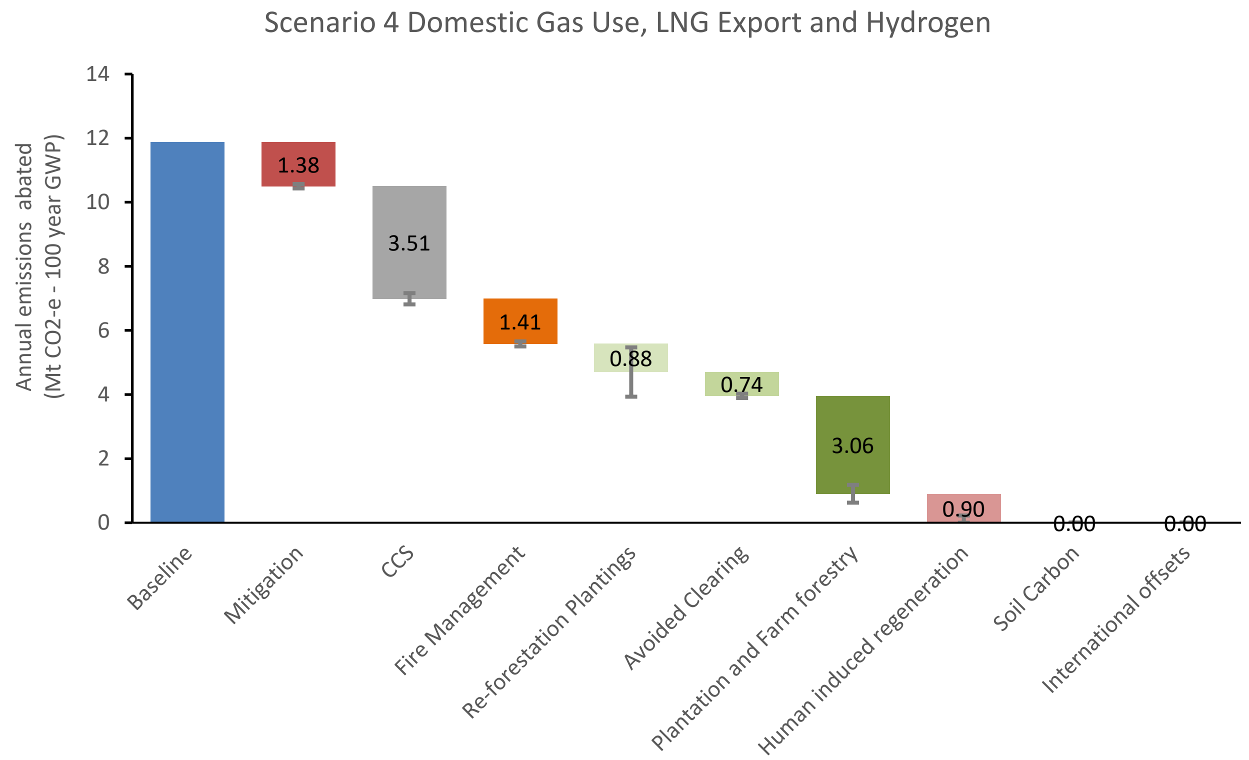
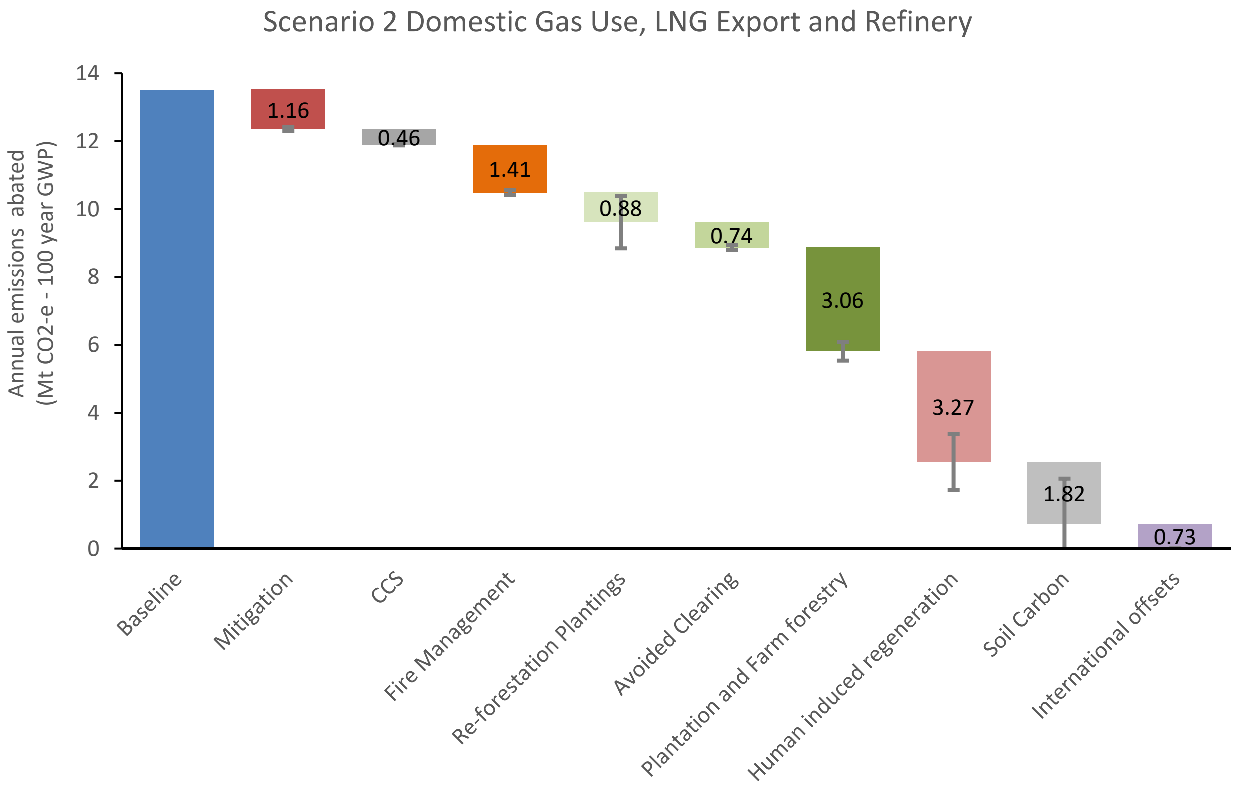


Figure ES4: life-cycle GHG emissions and mitigation or offset implementation for a scenario that assumed 365 PJ/year of NT onshore shale gas would be used as: 45PJ/year in domestic consumption; 120PJ/year in liquids needing refining and; the remainder for LNG export.



It is possible that overall responsibility for emissions and their abatement might be shared across producers and consumers in different jurisdictions, for example, through NT shale gas substituting for more emissions-intensive coal-powered electricity. Such cross-jurisdictional arrangements are unknown to the authors and outside the scope of this work to assess. Cross-government involvement is implied in Chapter 9 of *The Scientific Inquiry.* The Australian Federal Government, that regulates GHG emissions-intensive industries, could work with state and territory governments that have their own abatement targets and rules.

This research is ambivalent about the outcome with respect to approval of gas development. The main purpose here was to provide a rigorous and transparent assessment of a number of scenarios for the potential emissions impact and feasible means to mitigate or offset these, which may inform the decision-making process. The approval of any actual gas development would have to consider these and any other criteria that are a matter for the regulator.

1 Introduction

There are concerns in the community and government that the life cycle greenhouse gas (GHG) emissions from any new onshore shale gas project could challenge Australia's commitment to reduce emissions in line with COP 21 Paris Agreements (Parra et al. 2019; Climate Council of Australia 2019; Witt et al. 2018). Concurrently, the Northern Territory (NT) Government's gas strategy five-point plan[1] has the aims of: supporting the development of onshore gas; establishing gas based processing and manufacturing; and expanding the LNG hub in Darwin.

Achieving both aims is somewhat addressed by Recommendation 9.8 of the *Scientific Inquiry into Hydraulic Fracturing in the Northern Territory* (2018), which requires: "*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.*" There are also policy developments to limit Australia's emissions, such as the Safeguard Mechanism[2] and the NT's Large Emitters Policy[3], which will apply to gas developments. The present report provides a quantitative analysis of the life cycle GHG emissions, and what measures can be taken to mitigate or abate them, in scenarios of onshore shale gas extraction. This can inform the decision-making process around the response to recommendations.

The term "carbon offset" as used in this report refers to using carbon credits which have accrued to an activity deemed to reduce CO_2e emission, to reduce (in a net accounting sense) CO_2e emissions from another activity. "*The key concept is that offset credits are used to convey a net climate benefit from one entity to another*"[4].

Crucially, the emitting activity may take place in a totally unrelated activity and industry. The carbon credits used come from the use of Negative Emissions Technologies (NET), and also potentially from the Avoided Emissions Technologies (AET) described in (Fitch et al. 2022).

Conceptually simple examples include the use of carbon credits from biomass-capture dependent schemes. Reafforestation / greening projects, of the type referred to in Greening Australia are perhaps the oldest and more widely used activities here[5]. Carbon credits accrued by accredited reafforestation projects are traded, and can be bought by industries totally removed from this activity (e.g. by an airline), to compensate for their CO_2e emitting activities. The deliberate growing and stewardship of native forests for this purpose is a form of NET, however, other land-use based schemes, such as avoided land clearing, fit better as AET.

A variety of other activities do, or potentially will, create recognised carbon credits which can be used to offset CO_2-e emissions. The range of technologies which might generate carbon credits is extensive, and the methods and rules around recognition of carbon credits complex and evolving. For a further detail on both in the Australian context, refer to Fitch et al (2022).

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[1] https://business.nt.gov.au/publications/strategies/northern-territory-gas-strategy

[2] https://www.cleanenergyregulator.gov.au/NGER/The-safeguard-mechanism

[3] https://depws.nt.gov.au/environment-information/large-emitters-policy/large-emitters-policy

[4] https://www.offsetguide.org/understanding-carbon-offsets/what-is-a-carbon-offset/.

[5] https://www.greeningaustralia.org.au/carbon-offsetting/

1.1 Background

According to the Australian Petroleum Production and Exploration Association (APPEA), "unconventional" gas reservoirs include coal seams, shale, and tight sandstone formations[6]. There is some prior experience in assessing life-cycle emissions intensities from Australian unconventional gas extraction and downstream operations (Schandl et al. 2019), though that work referred to coal seam gas (CSG).

Hydraulic fracturing technology has been applied to the extraction of unconventional gas and liquids from tight sands in more than 900 fracture stimulated wells in the Cooper Basin in South Australia[7]. However, tight sands are not the same as shale: wells are vertical and typically have small fracture stimulations relative to shale gas. Onshore shale is the predominant type of unconventional gas reservoir we assess in this report, but there are no prior Australian studies specifically on this source of gas.

There has been more experience, and assessment, of onshore shale gas production overseas, notably in North America. In North America there is a different regulatory stance towards fugitives, noting that in some oil and gas plays, large quantities of 'associated gas' may be vented or flared in accessing the more valuable oil[8]. This is not universal and there are best practice industry standards[9], however, any translation of the North American experience to Australia is confounded by the technical, economic, regulatory and environmental context and geological features of shale gas projects there. Thus, there is a need for an original Australian life-cycle carbon footprint assessment, albeit relating to *scenarios* of potential onshore shale gas projects rather than existing operations.

An extension to prior research, and the impact, or problem-orientated literature (Allen et al. 2013; Alvarez et al. 2018), is the exploration of options for mitigating emissions in addition to the survey of carbon offset options.

For example, Alvarez et al (2018) conducted an emissions survey of multiple onshore wells in US natural gas supply chains and found that largest contribution to GHG emissions came from a small number of production wells that are referred to as "super emitters." They concluded that "*substantial emission reductions are feasible through rapid detection of the root causes of high emissions and deployment of less failure-prone systems*." (Alvarez et al. 2018). In a more recent review Nisbet et al. (2020) looked at general geophysical methods to reduce methane emissions and also promoted broad and frequent maintenance schedules for onshore gas to deal with leaks and other failures.

Before any consideration of carbon offsets, we looked at mitigation options for industry including use of renewal energy in the field, less error prone equipment and maintenance schedules to identify and rectify high emissions sources.

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[6] http://www.appea.com.au/wp-content/uploads/2017/02/Final-APPEA-Report-to-CoAG-Unconventional-Gas-in-Australia-2016.pdf

[7] https://www.petroleum.sa.gov.au/__data/assets/pdf_file/0007/274642/DEM002_The_Facts_-_Natural_Gas.pdf

[8] See for example https://www.nytimes.com/2019/10/16/climate/natural-gas-flaring-exxon-bp.html

[9] https://methaneguidingprinciples.org/best-practice-toolkit/

1.2 Purpose of this research

This project assessed feasible options to mitigate and offset life cycle GHG emissions emitted in Australia associated with scenarios of onshore shale gas extraction in the NT. Specifically, we have quantified technical options[10] for mitigating and offsetting Australian GHG emissions from production, and Australian consumption, of onshore shale gas extracted from the NT's Beetaloo Sub-basin. This responds to Recommendation 9.8 of the *Scientific Inquiry into Hydraulic Fracturing in the Northern Territory* (Scientific Inquiry into Hydraulic Fracturing in the Northern Territory 2018), hereafter referred to as the "*Scientific Inquiry*."

1.3 Project components of the project

The project was composed of five parts that were developed sequentially, seeking input from various stakeholders and an internal Technical Reference Group.

1.3.1 Scope

A scoping exercise was undertaken to define the elements and limits of this research, and also to inform, and seek feedback from, industry, government and community stakeholders. This interaction was considerably attenuated due to the COVID 19 pandemic, but a workshop was convened that included several Indigenous Land Councils, the Indigenous Carbon Industry Network, the NT Government and representatives from the gas industry. See Section 2.

1.3.2 Scenarios

Without existing onshore shale gas projects to refer to, we developed a set of high-level indicative scenarios of production and use of onshore shale gas. At an aggregate quantitative level, these were consistent with submissions from industry to the *Scientific Inquiry* and scenarios of production used in the *Scientific Inquiry's* report. The scenarios were disaggregated by different potential end-uses of the gas (and liquids) expected from the Beetaloo: gas for domestic consumption, LNG, blue hydrogen, methanol and refinery products. Each scenario isolated one end-use disposition with one scenario looking at a combination of all potential products and end-uses of the onshore shale gas. See Section 3.

1.3.3 Life-cycle carbon footprint

GHG emissions were calculated using a life cycle carbon footprint assessment[11] (CFP) conducted according to the ISO 14044 Standard. The CFP included upstream and downstream processes in the production of gas and the different end-uses. See Section 4.

[10] This research is predominantly a technical economic assessment. However, it should be noted some GHG offsets options may have socio-technical costs or benefits that warrant deeper examination.

[11] A life cycle assessment (LCA) is broader in the number and variety of impacts considered than just climate change.

1.3.4 Greenhouse gas mitigation and offset options

The project looked at contemporary mitigation activities for industry to reduce emissions in operations based on recent literature (Alvarez et al. 2018) and the effect of electrification of equipment and use of renewable power. We also investigated land-based offset options such as: re-forestation; avoided de-forestation, and; Indigenous fire management in Northern Australia. We have also investigated geological options for carbon capture and storage (CCS), and scenarios of developing hydrogen and basic chemical production in the NT that represent alternative gas end-products. See Section 5.

1.3.5 Synthesis of emissions from scenarios and abatement options

In this exercise, we combine the magnitude of the emissions bill for each scenario, with the different mitigation and abatement options available. This synthesis presents results on how the requirements of Recommendation 9.8 from the *Scientific Inquiry* could be met, for each scenario. See Section 6.

1.4 Intended outputs and use of this research

One goal of this research was to estimate the potential life cycle GHG emissions from a number of development scenarios for onshore shale gas from the NT Beetaloo Sub-basin. Those results are intended to help identify and quantify strategies that might be used to offset or mitigate the respective emissions.

The audience for the study is intended to be a range of stakeholders including Aboriginal and Torres Strait Land Councils, the NT Government, Australian Government, environmental groups and representatives of the gas industry and the carbon offset industry.

We have assessed carbon mitigation and offset options over a 25-year lifetime of onshore gas production scenarios. This assessment looked at technical feasibility and tractability of the carbon accounting but not a cost–benefit analysis. In prioritising carbon offset arrangements, we had an explicit preference for schemes in Australia or its coastal waters, particularly any domestic options that engaged with the NT Aboriginal Carbon Industry Strategy[12]. This is related to a desire to identify options that return value (employment, income, regional development) back into the Australian economy.

Although this research responds to the preconditions laid out in Recommendation 9.8 of the *Scientific Inquiry*, the outputs of this research are not on a path to approval for onshore gas development in the NT. The investigation here may inform such a process, but this research is about scenarios of onshore shale gas extraction, not an actual onshore shale gas development.

The determination of approval for new gas development would need to consider more exact plans, many more variables and dimensions of impact than GHG emissions, and these would be evaluated in a regulatory approval process evaluating trade-offs across multiple criteria including

[12] https://denr.nt.gov.au/__data/assets/pdf_file/0006/584439/Aboriginal-Carbon-Industry-Strategy_A4_Digital.pdf

social and economic impacts and benefits. These features are not in the scope of the present work.

2 Scope

Prior to commencing this research, we undertook a scoping exercise that presented key stakeholders with the conceptual and physical scope of the research, and indicative information on location and scale of possible onshore shale gas production in the NT, and other background information on GHG emissions from onshore shale gas.

The ‘conceptual scope’ defines what processes are included within Australian onshore shale gas production and consumption and what accounting definitions respond to the recommendations of the *Scientific Inquiry*. The ‘physical scope’ includes the scale of the gas production scenarios, geography, infrastructure needs, and the assumed “lifetime” period when we are considering the total life cycle of gas extraction and use.

The accounting definitions for GHG emissions followed those developed by the World Business Council for Sustainable Development and the World Resources Institute[13]:

- Scope 1 refers to all direct emissions from upstream shale production and downstream processing of gas, and any other emissions from direct consumption of shale gas.
- Scope 2 relates to embodied GHG emissions associated with the consumption of secondary energy such as grid electricity or heat. Here that is specifically NT grid electricity that is largely gas-fired.
- Scope 3 includes all other GHG emissions, for example, emissions embodied in the cement used to construct wells.

2.1 Summary of scoping exercise

The purpose of this preliminary exercise was twofold. Firstly, to make various key stakeholders aware of this research, and secondly to get their engagement and perspective on production and consumption scenarios, mitigation options, how many GHG emissions could be offset by the carbon industry in Northern Australia, and priority for offset options including the Indigenous management of Country (such as fire management, revegetation and coastal).

In November 2020, we convened a face-to-face roundtable held in Darwin. It was attended by representatives from Aboriginal and Torres Strait Islander Land Councils, the Indigenous Carbon Industry Network, the gas industry and senior officers from the NT Government.

All stakeholders had the opportunity to review the initial scoping material and provide feedback on all details including the production scenarios. This meeting was conducted according to CSIRO’s standards for ethical research. Further review was obtained from: the NT Department of Business Trade and Innovation; the project Technical Reference Group and; CSIRO Colleagues in Bioregional Assessment.

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[13] https://www.wri.org/initiatives/greenhouse-gas-protocol

2.1.1 Production scenarios

The consensus of industry, government and CSIRO's Bioregional Assessment[14] was that a valid baseline scenario would be the "GALE Scenario" defined by ACIL Allen[15] in their submission for the *Scientific Inquiry*. These were also the scenarios used by the *Scientific Inquiry* in their environmental impact risk assessment (See Chapter 9 p229*)*. This choice aligns with submissions from gas industry to the Scientific Inquiry and will also enable cross comparison with other analyses, outside of the present work, using the same scenario (e.g. cost–benefit, return on investment or non-GHG impact assessments)

Practically this assumes an extraction rate of 365PJ/year but a key metric of interest was the emissions intensity per petajoule of gas. It was also recommended we investigate a scenario of over 1000 PJ/year to explore if there are economies of scale in reducing that intensity.

2.1.2 Consumption scenarios

At the time of writing, the price of an Australia Carbon Credit Unit (ACCU) was $AUS20-30/tonne CO_2e. It was the consensus of participants that domestic consumption would be much less than 200PJ/year in every production scenario. Otherwise, the cost of offsetting Australian emissions from consumption of NT gas would be prohibitive (approximately $AUS200-300 million /year without accounting for future increases in price)[16].

We had further conversations with the NT Department of Business Trade and Innovation who have corroborated the potential for industrial use of methane in plans for industrial development of methanol and ammonia plant, and possible development of hydrogen production from gas at Darwin's Middle Arm Industrial zone. This suggests a level of non-combustion consumption of methane from onshore shale gas, potentially coupled with CCS.

2.1.3 Mitigation and offset scenarios

From industry feedback there was the suggestion of staging the approach to mitigation and offset of GHG emissions following these steps:

1. minimise emissions through equipment and process design
2. eliminate scope 2 emissions through renewable energy/low-carbon electricity sources
3. choose end-uses of gas that could reduce consumption emissions or allow capture (see also non-combustion options in Consumption scenarios)
4. offset residual GHG emissions

Feedback confirmed the priority for carbon offsets sourced from projects in the NT over projects elsewhere in Australia, and both were preferred over offsets from overseas projects. However, the

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[14] Geological and Bioregional Assessment Program Resource development: Driver node description for the Beetaloo GBA region

[15] https://frackinginquiry.nt.gov.au/inquiry-reports?a=456790

[16] 200PJ is approximately 3.73Mt of CH_4. When combusted, this produces ~10Mt CO2/year @$AUS20-30/tonne = $AUS200-300 million/year

insights from Indigenous Land Councils and the Indigenous Carbon Industry Network were that *available* land-based GHG emission offsets in the NT could be limited because:

- over the next 5 years they are expecting much larger demand from a variety of emissions-intensive industries for example airlines
- there are existing contracts to use Indigenous fire management and other land-based carbon offsets, so new requirements from onshore shale gas would compete for ACCUs within the existing market
- there is less opportunity for new land-based or coastal offsets because of the relatively intact (and arid) environmental condition of much of NT

2.2 Conceptual Scope

It was important to define what is meant by the processes included in 'Australian onshore shale gas production and consumption' in order to ensure this work aligned with, and responded to, the recommendations of the *Scientific Inquiry,* and to provide clarity to stakeholders. This also establishes some of the system bounds for the life cycle carbon footprint assessment (CFP) that was based primarily on ISO14067 International Standard *Greenhouse Gases – Carbon Footprint of Products – Requirements and Guidelines for Quantification* (ISO 2018). The CFP study also used guidance from the *International Standard on Life Cycle Assessment* (ISO 2020).

The scenarios and CFP included scope 2 emissions associated with any grid electricity used, GHG emissions from in the field electricity generation, and scope 1 emissions from other combustion (e.g. to support compression), scheduled emissions (e.g. flaring, venting), and any unplanned fugitive GHG emissions (leaks) [17]. These were based on:

- overall expected total production and domestic consumption of onshore shale gas and any potential hydrocarbon liquids
- an estimated number of wells, including drilling, well completion, maintenance, decommissioning, well plugging and abandonment
- gathering lines and compression or boosting of gas and condensates
- energy and emissions for gas processing and flaring
- energy and emissions relating to any water treatment facilities
- mid-stream distribution and boosting (pipeline transport)
- liquefaction and storage for export from current or anticipated NT Darwin capacity

The creation of LNG for export is a value-adding activity undertaken by industry operating in Australia and governed and regulated by the Australian Government. As such it was included in the scope of 'Australian production' although the product is destined for export. The shipping, regassification and consumption of LNG *outside* of Australia was explicitly excluded from the scope

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[17] in the gas industry "fugitive emissions" are sometimes considered as only minor leaks, separate from flaring and venting. We refer to all emissions from venting, flaring and leaks as "fugitive" – see also Part 3.3. and specifically Division 3.3.9A of the *National Greenhouse and Energy Reporting (Measurement) Determination 2008* updated July 2021 (Commonwealth of Australia 2021), and further notes in Section 4.3

of this work in accordance with the territorial approach of the 2006 *IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) and refinements up to 2019[18]. Refer also to section 4.3 for a high-level summary of processes included in scope.

For the life-cycle carbon footprint, a more exact description of the system boundary is in Section 4.1.2 and Figure 4.

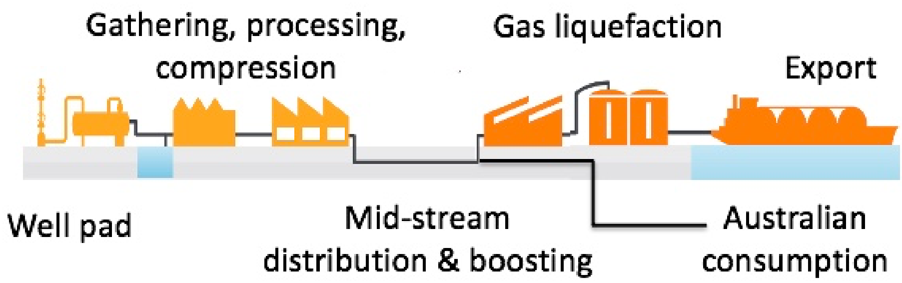

Figure 1 Pictorial system scope of the study including production and consumption activity in Australia up to the point of export, but not including foreign consumption of natural gas. 'Upstream' processes occur before transport by pipeline to the Gas Liquefaction, which is referred to as 'Downstream' processes.

2.3 Physical Scope

The area referred to as the Beetaloo Sub-basin is shown in Figure 2. According to Falcon Oil and Gas (2020) there is a technically recoverable resource of 93,900PJ (89TCF). This is the maximum possible quantity of gas we consider available for extraction noting that it is highly uncertain how much of this is economic. In 2021, Geoscience Australia reported that less than 10% of this (7,423PJ) have been identified in Beetaloo as 2C contingent resources[19]. This is consistent with the 6.6TCF 2C contingent resources reported in the Geological and Bioregional Assessment: Stage 2 Baseline Analysis for Beetaloo[20].

[18] https://www.ipcc.ch/report/2019-refinement-to-the-2006-ipcc-guidelines-for-national-greenhouse-gas-inventories/

[19] https://www.ga.gov.au/digital-publication/aecr2021/gas (Table 3). Contingent resources are defined by the international Petroleum Resources Management System as estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable

[20] https://www.bioregionalassessments.gov.au/assessments/geological-and-bioregional-assessment-program/beetaloo-sub-basin/beetaloo-gba-region-stage-two-report

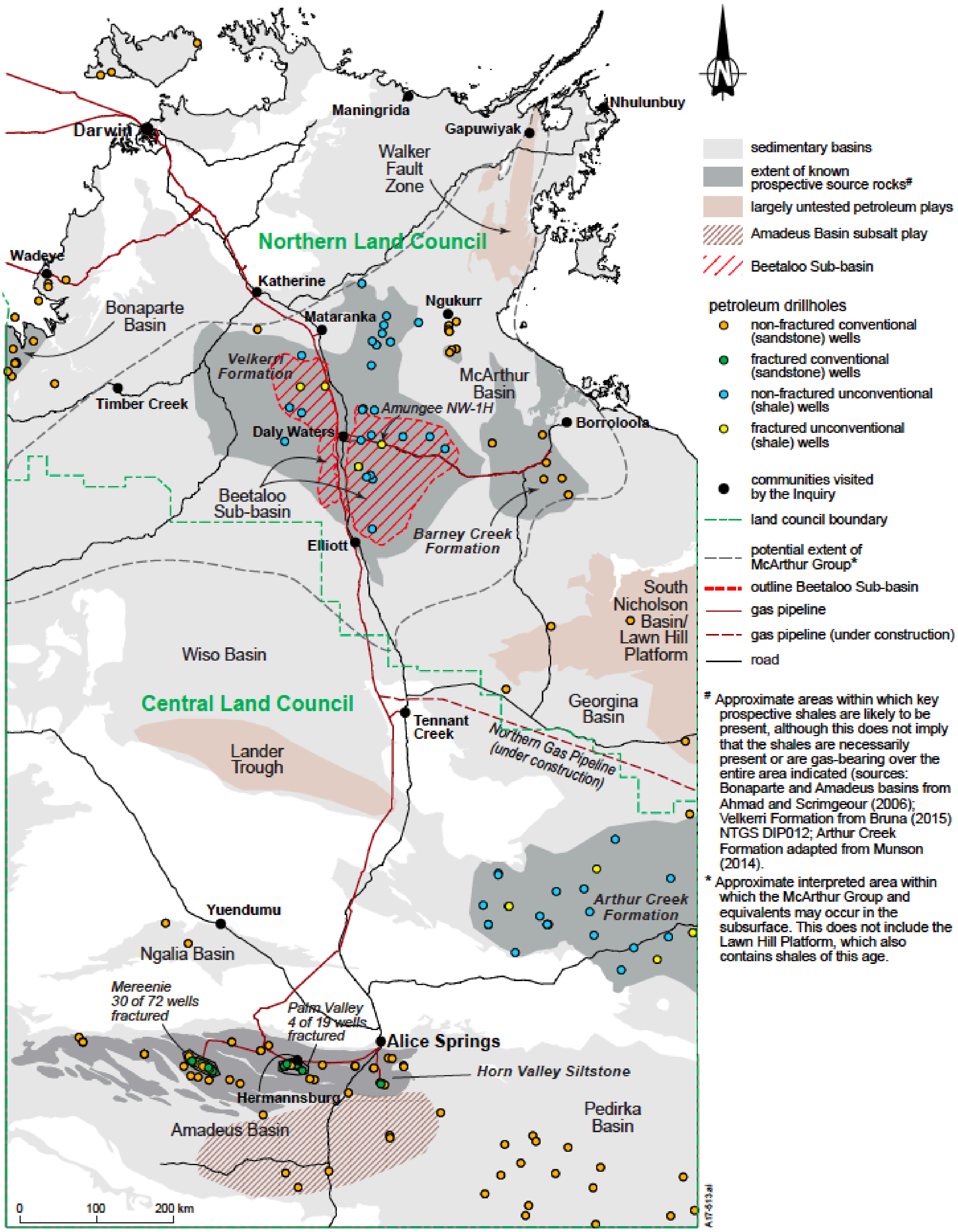

Figure 2 location and boundary of the Beetaloo Sub-basin from Chapter 6 of the *Scientific Inquiry into Hydraulic Fracturing in the Northern Territory – Final Report* (2018), © The Northern Territory of Australia.

The source of gas to be extracted is determined in part by the type of "play." In gas/oil development a "play" represents a group of petroleum accumulations that occur in the same region and are controlled by the same set of geological circumstances (Satter and Iqbal 2016).

According to Côté, Richards et al. (2018) five different unconventional play types have been identified within the Beetaloo Sub-basin that have the potential to bring hydrocarbons to market within a time frame of five to ten years:

- dry gas hosted in the Velkerri Formation shales
- liquids-rich gas hosted in the Velkerri Formation shales
- liquids-rich gas hosted in the Kyalla Formation shales
- the hybrid Kyalla Formation play (including tight sands adjacent to the organic-rich shale intervals)
- tight gas, condensate and potentially volatile oil within the Hayfield Sandstone member of the Hayfield Mudstone in the overlying Neoproterozoic units.

An estimate of the potential yield of petroleum products and liquids-rich gas plays has been made using the data on the respective resource quantities published by the US Department of Energy (2015). Table 1 shows that the risked recoverable gas in the Beetaloo Sub-basin is 22.2TCF for Velkerri Shale and 21.5TCF for Kyalla Shale, which sums to a total of 46,106PJ of total recoverable gas in the Beetaloo Sub-basin. Table 2 shows that the recoverable petroleum resources are 1.39bbl and 3.26bbl for Velkerri Shale and Kyalla Shale respectively, which adds up to 28,400PJ of recoverable petroleum products. This suggests that in the liquids-rich scenarios it is not unreasonable to assume approximately at least one-third of the energy products to be liquids.

Table 1 Gas resources in the Beetaloo Sub-basin.

	Velkerri Shale			Kyalla Shale		
Gas phase	Associated gas	Wet gas*	Dry gas^	Associated gas	Wet gas	Dry gas
Risk gas in place (TCF)	9.6	32.7	52	23.5	44.5	32.5
Risked recoverable (TCF)	1	8.2	13	2.3	11.1	8.1

* Natural gas that typically contains <85% methane and more ethane and other complex hydrocarbons

^ Natural gas that occurs in the absence of condensate or liquid hydrocarbons.

Table 2 Petroleum resources in the Beetaloo Sub-basin.

	Velkerri Shale		Kyalla Shale	
Oil phase	Oil	Condensate	Oil	Condensate
Risked oil in place (BBL)	22.1	5.7	54.4	10.7
Risked recoverable (BBL)	1.11	0.28	2.72	0.54

Source: (U.S. Department of Energy 2015)**, TCF = 1 trillion cubic feet = 1094.1PJ**

Given the uncertainty in reserves, the total quantity of gas *extracted* over the study period was not based on reserves, but rather assumed rates of extraction at levels which, in the estimation of the *Scientific Inquiry*, are suitable for an environmental impact risk assessment (See Chapter 9 p229 of the *Scientific Inquiry into Hydraulic Fracturing in the Northern Territory.* 2018). Even with the range of estimated reserves, they can support a rate of extraction suggested in feedback from the scoping exercise (365PJ/year).

The study period was from 2025-2050 (25 years) as an assumed duration of an onshore shale gas project at Beetaloo. This is also the duration suggested by gas industry in Section 7.3.1.4 of the *Scientific Inquiry.* A project life of 25 years (including 5 years of exploration) was used in the Geological Bioregional Assessment[21] and a previous 'cradle to grave' study of WA shale gas field assumed 20 year lifetime (Bista et al. 2017).

2.4 Upstream Gas Production

The extraction process for shale gas involves vertical and horizontal drilling to access gas trapped in shale sediments, which are between approximately 1,500 to 3,000 metres below ground (see Figure 3). To access the gas, the layers need to be fractured with high-pressure liquid, which contains mostly water and a small amount of sand and chemicals.

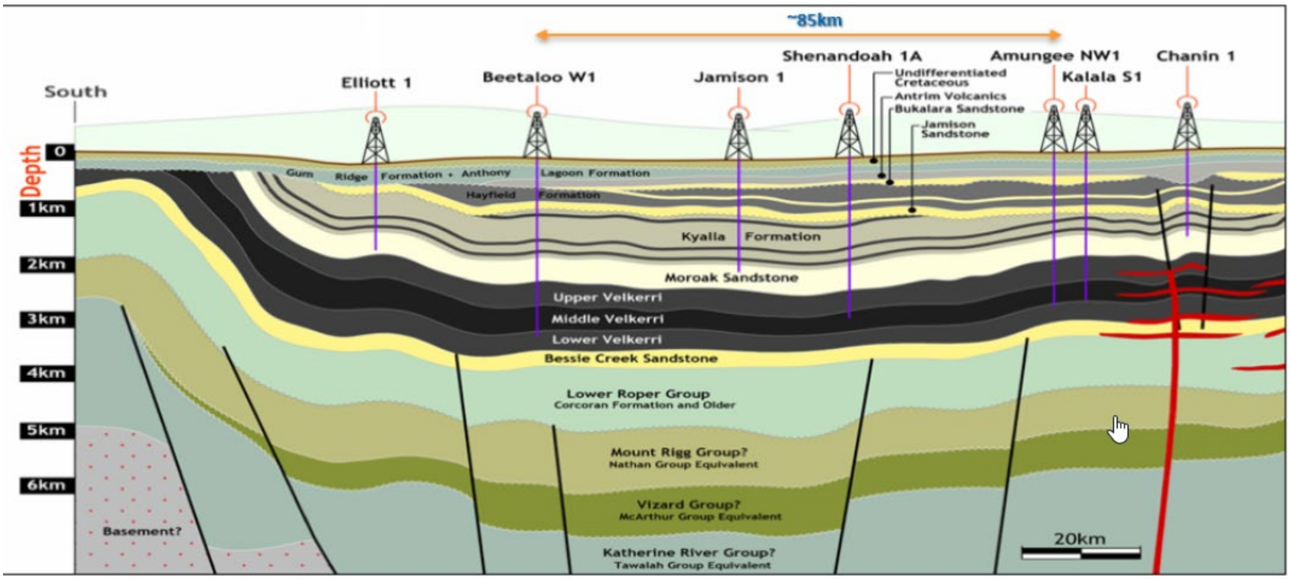

Figure 3 Representation of drilling depth and geological layers for Beetaloo Sub-basin (Source (Côté et al. 2018)**)**

The main material inputs are steel and cement lining for the well construction to avoid contamination of other layers, including groundwater and the water itself with the sand and chemical additives. The production process involves bringing gas and or oil and condensates[22], and water that is released from the stimulation process to the surface (flowback).

Upstream gas production includes the extraction of the raw resource at the well, the gathering lines, de-hydration of the gas and gas and water treatment. Liquids-rich gas plays will also have gas

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[21] https://gba-explorer.bioregionalassessments.gov.au/bee/items/item/9/0

[22] Natural-gas condensate, also called natural gas liquid, is a low-density mixture of hydrocarbon liquids that are present as gaseous components in the raw natural gas produced from many natural gas fields. At lower temperatures they condense to liquid form while methane remains gaseous.

processing for ethane and propane and processing of condensates. It is at this stage where much of the equipment and activity that involves fugitive emissions occurs, and the emissions from flaring. For a new gas development, evolving technology is reducing these emissions.

As the rate and volume of scheduled (engineered) and other fugitive emissions relate to the annual production rate and volume, the quantity of annual GHG emissions will be closely connected to the scenarios of upstream gas production.

From recent observations in Canada, the ratio of total methane leakage to total production, decreases as a function of increasing gas production (Ravikumar et al. 2020)[23]. To be included in this research, production scenarios were informed by several factors:

- engineering technical feasibility
- the capacity of existing, planned or new infrastructure, for example, installation of gas processing capacity and pipelines
- how many tons of carbon offsets would be required and how soon they could be used by available realistic means to compensate for emissions from production.

2.5 Downstream LNG Production

The downstream processes include the compression and liquefaction leading to LNG production, which was assumed to be entirely for export markets. The location of this activity would be at facilities putatively considered to be near Darwin[24]. Capacity for LNG production is modular and related to the number of 'trains' in place that are each assumed to handle approximately 4.5Mt/year of gas (241PJ/year)

As an example, a (16-year-old) facility at Wickham Point, Darwin, is currently supplying gas from the Bayu-Undan gas project off the coast of the NT in the Australia Timor-Leste Joint Petroleum Development Area. Its single production train can use up to 225PJ per year of gas feed for LNG sales (ACIL Allen Consulting 2017).

Depending on any increase in export flows of LNG in scenarios, we anticipated a proportional increase in the number of trains (refer to Table 3). Emissions associated with the downstream LNG production were calculated based on emissions intensities for a given volume of gas liquefied, and annual export volume flows.

In previous work on CSG to LNG, we found that the consumption of gas in the processes of compression and liquefaction resulted in 34% of the total (10.30 kt CO_2e/PJ) GHG emissions footprint from all CSG-LNG production (Schandl et al. 2019). We would consider these emissions to be in scope as this is a production activity located in Australia and a process under the control of operations and regulation in Australia.

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[23] This may also be a function of age of plant. Input from industry suggests that newer plant is often more efficient and larger than their predecessor.

[24] https://cmc.nt.gov.au/advancing-industry/northern-territory-gas-strategy

3 Scenarios of Production and Consumption

Currently, there is no onshore shale gas production in the Beetaloo Sub-basin. We have used a scenario analysis to represent potential gas extraction, manufacture and consumption, coupled with technical calculations on the GHG implications of those scenarios. The purpose of this scenario analysis was to ask, “what is reasonably plausible” rather than to ask, “what is probable.” The former is a technique usefully employed by extractive industries for several decades (Schoemaker 1993). The latter might feed into actuarial or risk calculations, which were not the aim here.

The main product in the following scenarios of NT onshore shale gas is an energy commodity functionally equivalent to natural gas, which is typically greater than 90% methane with small components of other hydrocarbons. The variety of possible domestic gas end-use processes and their efficiencies, prohibits a complete and detailed analysis of all consumption paths.

After gas treatment, contaminants have been removed from the extracted gas and further products can be: distributed gas; gas for industrial feedstocks for processes such as ammonia, methanol and hydrogen production and; after compression and refrigeration, as LNG. In Table 3 there are four scenarios of different gas end-uses for the same output of gas from Beetaloo.

As part of the *Scientific Inquiry,* overall scale of production was modelled with three scenarios referred to as “Breeze,” “Wind” and “Gale.” Each represented increasing levels of production, with breeze the lowest level and gale the highest level. The scenarios explored in this work are based on “Gale.” Note, that two other scenarios were modelled for the economic analysis in the *Scientific Inquiry* but did not include any production from the Beetaloo Sub-basin.

A fifth scenario has been created to demonstrate a compound effect. These scenarios have been constructed to highlight the separate emissions intensities corresponding to the different gas products. GHG emissions intensity was measured in kilotonnes of CO_2e per petajoule of natural gas used in an end product (in terms of kt CO_2e/PJ).

It is readily acknowledged that other factors are involved in any real production activity that may be approved, including access to water, lands and social licence to operate. In this research we were only simulating technical features of production.

Table 3 scenarios of annual production and consumption of onshore shale gas and liquids – colouration used to show different gas products in assumptions.

Scenario name	Output (PJ/year)	Domestic gas supply (PJ/year)	Refinery products (PJ/year)	LNG for export (PJ/year)	Methanol and ammonia (PJ/year)	Hydrogen (PJ/year)	Source comment
Sc1 Dom. gas & LNG	365[25]	45[26]		320			Production level based on "Gale" scenario from ACIL Allen (2017) and the *Scientific Inquiry* assuming dry gas extraction only with some supply to domestic gas market and balance to LNG production for export.
Sc2 Dom. gas, LNG & refinery	365	45	120[27]	200			Production level based on "Gale" scenario from ACIL Allen (2017) and the *Scientific Inquiry* assuming high liquids gas extraction with some supply to domestic gas market assuming one-third of extracted energy as liquids process to petroleum products and the and balance to LNG production for export.
Sc3 Dom. gas, LNG & chemicals	365	45		200	120[28]		Production level based on "Gale" scenario from ACIL Allen (2017) and the *Scientific Inquiry* assuming dry gas extraction only with some supply to domestic gas market, one-third to methanol and ammonia manufacture and the balance to LNG production for export.
Sc4 Dom. gas, LNG & hydrogen	365	45		200		120	Production level based on "Gale" scenario from ACIL Allen (2017) and the *Scientific Inquiry* assuming dry gas extraction only with some supply to domestic gas market, one-third to hydrogen manufacture and the balance to LNG production for export.
Sc5 All	1130[29]	45	120	725[30]	120	120	Requires 3X ~4.5MTPA LNG capacity. 2 LNG plants already operational in NT and although the potential expansion is a multibillion-dollar investment, this would appear to be a prospect (https://theterritory.com.au/invest/key-sectors/oil-and-gas). The main difference in emissions were expected from increasing scale of production, and additional construction

[25] 1000 TJ/d is also the cumulative output expected from submissions by Origin, Santos and Pangea to the *Scientific Inquiry* (see Table 6.2 in that report) using their lower bounds of 'high potential' development. Upper bounds would amount to 1600TJ/d

[26] The NT directly consumes about 110PJ of gas/year (https://www.energy.gov.au/publications/australian-energy-update-2021 -see Table F). There's also the proximity to the Northern Pipeline https://www.energymagazine.com.au/jemena-to-extend-northern-gas-pipeline-with-mou/ suggesting domestic uptake of Beetaloo gas elsewhere in Australia. This depends on economics of domestic vs LNG export markets, which is not analysed here.

[27] See comment on proportion of methane and other hydrocarbons in Beetaloo gas from Origin Energy here: https://originbeetaloo.com.au/origin-back-on-the-ground-in-the-beetaloo/

[28] Consistent with planned new industrial chemical plant planned for Middle Arm, Darwin https://industry.nt.gov.au/news/2019/september/start-of-gas-manufacturing-industry-in-nt

[29] This is close to the 1240PJ/year scenario used in the *Scientific Enquiry* Table 9.4 (3400TJ/d).

[30] increased production would mostly be for export through LNG

3.1 Domestic Consumption of Natural Gas

Our interpretation of Recommendation 9.8 of the *Scientific Inquiry* is that there are net-zero GHG emissions from *Australian* consumption of onshore shale gas produced in the NT. One measure of potential Australian consumption of shale gas from Beetaloo is that needed to maintain output to current domestic markets.

The scenarios of domestic consumption of natural gas in Table 3 (and subsequent emissions) were based on the profile of direct natural gas consumption in the NT. In 2019-20, the consumption of natural gas in NT was 445 GJ/person or 109PJ/year. About 63PJ is used by mining and 44PJ used for electricity generation, noting that 86% of electricity generated in the NT is from gas[31].

There are also potential changes in domestic demand on the east Coast of Australia enabled by new infrastructure connections and other planned developments, such as the Northern Pipeline. These scenarios are not included in this analysis.

We propose that the scenario Beetaloo could supply non-mining annual domestic gas used in the NT is quantitatively reasonable. Emissions from Australian (NT) consumption of natural gas from Beetaloo are likely to be more than 75% of the total emissions needing to be offset (Clark et al. 2011; Hardisty et al. 2012; Skone et al. 2011).

3.2 Refinery Products

There are limited reports available regarding the non-methane components of the hydrocarbon resources in the Beetaloo Sub-basin. We assume that non-methane products would be sold as refinery products. According to 2021 reports from Origin Energy[32] the composition of initial flows taken from the Kyalla well site near Daly Waters in the Beetaloo Basin was: "*65 per cent methane, 19 per cent ethane, 11 per cent propane and butane, and 3 per cent condensates, combined with low CO_2 levels of less than 1 per cent*." Kyalla is the first exploration well to successfully flow liquids-rich gas from the shale formation of the same name. Whether or not this particular well is characteristic of the play is unknown, but it was reasonable to create a scenario where approximately a third of production could be non-methane.

3.3 Hydrogen Gas

One potential equivalent energy source for distributed consumption is "blue" hydrogen derived from steam methane reforming (SMR) or auto-thermal reforming (ATR) processes that convert methane to hydrogen (see also Section 5.4).

Unlike "green" hydrogen that is produced without CO_2 emissions, blue hydrogen produces CO_2 and therefore requires emissions offsetting technologies, such as CCS. The fourth scenario of

[31] https://www.energy.gov.au/publications/australian-energy-statistics-state-and-territory

[32] https://originbeetaloo.com.au/origin-back-on-the-ground-in-the-beetaloo/

domestic consumption, LNG and Hydrogen production assumes 120PJ of methane could be diverted to produce blue hydrogen given: a) the proximity to highly suitable geological CO_2 storage that could handle the scale of production (see Section 5.5), b) the extant potential for exporting blue hydrogen[33], and c) to enable a comparison with other scenarios where 120PJ of shale gas is used for other products.

An illustrative case within this scenario might be a pilot SMR plant supplying hydrogen for stationary or transport energy use, or for blending with natural gas to substitute for pure methane consumption in the NT. Potentially there is the more advanced scenario of switching electricity generation in the NT entirely to variable renewables supported by blue hydrogen from SMR coupled with CCS.

Blended hydrogen and natural gas as a fuel source is well-understood and there is no need for changes to pipeline or distribution infrastructure (Melaina et al. 2013). In the production of hydrogen by SMR there is the need for carbon capture in the process with a connection (pipeline) to geological or other long-term storage (see Section 5.5). Otherwise, the CO_2 by-product of SMR, would be vented and require offsetting through some other means.

3.4 Methanol and ammonia

The NT Government has explicit plans to enlarge the industrial site at Middle Arm, Darwin[34]. This includes the manufacture of basic chemicals from natural gas feedstock. A 350,000 tonne methanol plant is at an advanced stage of planning[35], which would require approximately 175,000 tonnes (10PJ) of natural gas per year.

Ammonia is already planned to be produced in conjunction with blue hydrogen from onshore gas in the Pedirka Basin, NT (located near Alice Springs)[36]. The expected capacity is reported to be 1 million tonnes of ammonia per year, which would require approximately 420,000 tonnes (22.5 PJ) of natural gas per year.

The absolute flows of Beetaloo shale gas to methanol or ammonia production in the scenarios of Table 3 are indicative and exceed the above use cases of gas. The important outputs from the CFP are the emissions *intensities* from methanol and ammonia production for output flows that are within the same order of magnitude.

3.5 Export Consumption

It is assumed in the production scenarios of Table 3 that the dominant market for onshore shale gas will be international LNG sales. This overseas end-use is out of the scope of the response to Recommendation 9.8 of the *Scientific Inquiry*, but we have explored such calculations as part of the life-cycle carbon footprint assessment, assuming that the gas is ultimately combusted.

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[33] https://www.upstreamonline.com/hydrogen/worlds-first-shipment-of-liquefied-hydrogen-set-to-leave-australia-for-japan/2-1-1149448

[34] https://invest.nt.gov.au/investment-opportunities/middle-arm-sustainable-development-precinct

[35] https://industry.nt.gov.au/news/2019/september/start-of-gas-manufacturing-industry-in-nt

[36] https://www.ammoniaenergy.org/articles/blue-ammonia-in-the-northern-territory-wyoming/

4 Life-Cycle Carbon Footprint Assessment

The life cycle carbon footprint assessment (CFP) was conducted by Lifecycles Pty Ltd. This section is an abridged version of the full CFP report: *Life Cycle Carbon Footprint Study of Onshore Shale Gas in the Northern Territory* (Grant 2022). The CFP consists of all GHGs from the various stages of development of the onshore Beetaloo Sub-basin gas field. Emissions for the different development scenarios in Table 3 were calculated using an assessment according to the ISO 14044 Standard (ISO 2006). For the full suite of assumptions, inventory inputs and all results including the sensitivity analysis, we refer the reader to that report.

4.1 Scope

4.1.1 Functional unit

While the 'product' considered in this CFP was predominately natural gas, the investigation also aimed to estimate the requirements for offsetting the emissions from the project. The different scenarios being assessed had very different quantities of product, which made a common quantitative reference, such as 1PJ of gas, impractical. What was common between all scenarios was that they represent the total production from the NT Beetaloo Sub-basin *between 2025 and 2050.*

Therefore, the functional unit used for this assessment was: *"the product supply and use of all proposed shale gas products from the NT Beetaloo Sub-basin between 2025 and 2050."*

4.1.2 System boundary

The system boundary in a CFP describes which unit processes are included in the calculation and the outer limits of the scope. There were several possible system boundaries of interest which could have been drawn.

- Emission from the production of shale gas produced in the NT (not including its use)
- Emission from production of shale gas and other products made from shale gas in the NT
- Emission from production of shale gas and its products and Australian use of these gases
- Emission from production of shale gas, and its production and all use regardless of location

Rather than set one of these boundaries as the correct one, all four boundaries were reported against in the results. Figure 4 shows the system boundary for the CFP with four concentric boundaries working outwards from the shale gas production boundary, the domestic shale gas manufacturing boundary, the domestic shale gas manufacturing and consumption boundary and finally a full system boundary, which included both domestic and overseas emissions from extraction right through to consumption.

The inner-most system boundary (in black in Figure 4) includes all GHG emissions from upstream operations that begin with the production of the gas:

- an expected number of wells, including stages of exploration, construction, drilling, well completion and maintenance
- gathering lines and new pipeline infrastructure
- energy and emissions for the gas treatment and water treatment facilities
- compression and pipeline transport.

The system boundary for domestic shale gas production *and manufacturing* (second most inner boundary in red in Figure 4) includes impacts from the prior boundary and also:

- liquefaction and storage for export from current or anticipated Darwin capacity
- production of associated liquid fuels from condensate co-produced with the shale gas
- production of basic chemicals and hydrogen in the NT.

The system boundary for domestic shale gas production *and use* (third most inner boundary in blue in Figure 4) includes impacts from prior boundaries and includes emissions from the

- final consumption of the gas in Australia (specific to the set of scenarios)
- Australian consumption of liquid fuels from refinery in the NT
- use of hydrogen in Australia

The outermost system boundary for *all* shale gas production and use (green in Figure 4) includes impacts from all prior boundaries and includes emissions from the:

- transport of LNG from shale gas to overseas markets
- regassification and consumption of LNG from shale gas in overseas markets.

The various offset options come after the LCA assessment of GHG emissions and are outside the scope of the CFP. The scenarios of converting methane to blue hydrogen (with CCS) is considered part of the domestic consumption of natural gas, and would be in scope for the CFP. SMR is an established process already in use around Australia to make ammonia[37]. There are well-cited previous LCA examinations of SMR (Spath and Mann 2001)

[37] https://www.cefc.com.au/media/nhnhwlxu/australian-hydrogen-market-study.pdf

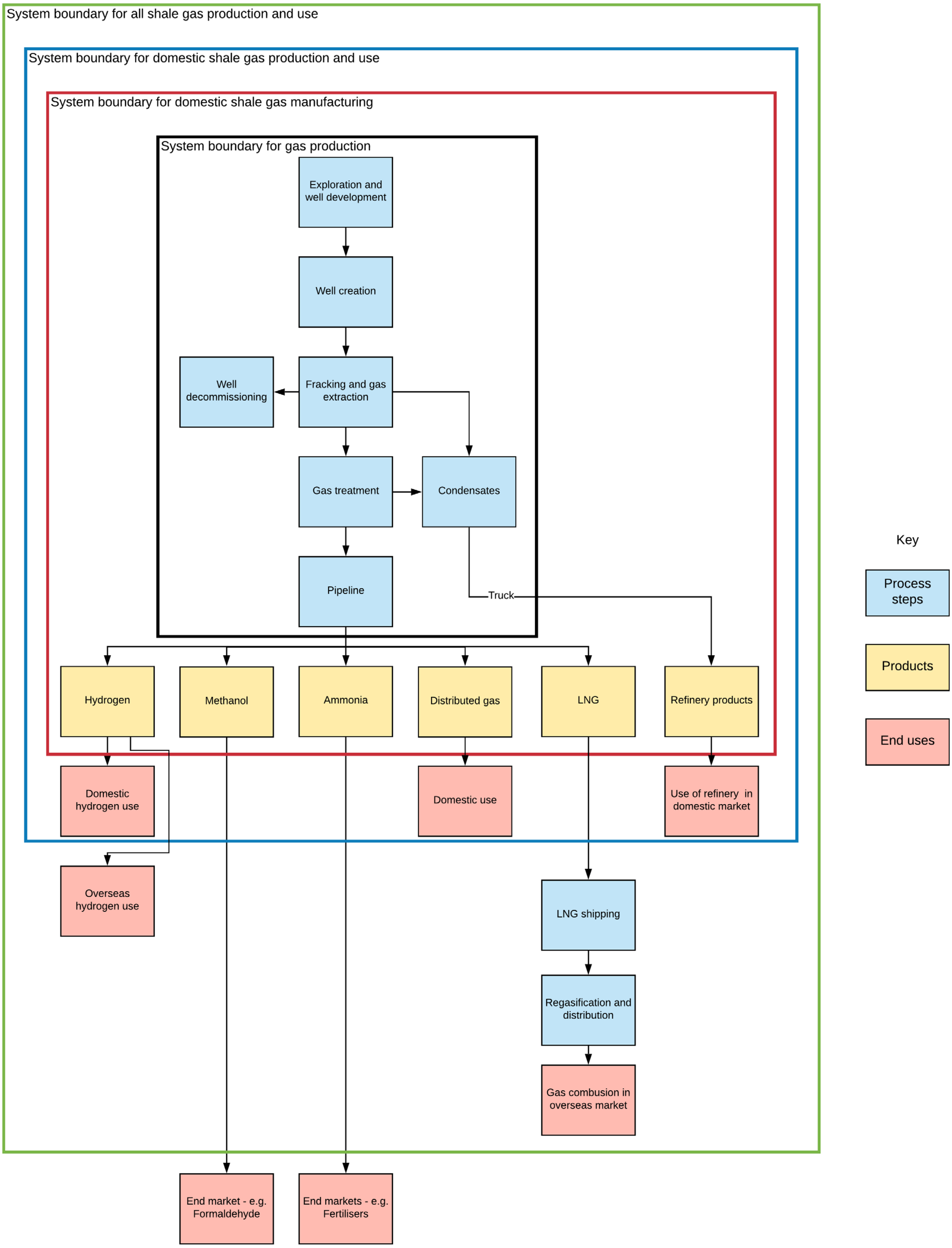

Figure 4 System boundaries for the CFP analysis

4.2 Methods

4.2.1 Approach to data sources and modelling

The calculation of a CFP is an accounting exercise that, in this case, determines all the emissions associated with extraction and use of onshore shale gas. For accounting purposes an *attributional* LCA modelling approach is recommended (European Commission Joint Research Centre and Institute for Environment and Sustainability 2010).

For attributional modelling, the most appropriate data source is from actual inputs to the process being studied, however, this is not always available or practical. There is no LCA precedent for onshore shale gas in Australia. A report has been produced recently (McConnell and Grant 2020) outlining system boundaries in common with the present study (similar processes and timelines) although their subject was offshore gas production.

We take an environmentally conservative stance: unless specified otherwise, we use upper values for emissions intensity ranges observed in other studies. See Grant (2022) for the hierarchy of data source selection.

Calculations used the SimaPro™ software and the databases residing within this software (AUSLCI version 2017, Ecoinvent version 3.7 and any other database as specified with version date).

4.2.2 Multifunctionality and foreground data

Multifunctionality occurs when a single process or group of processes produces more than one usable output, or "co-product" defined as "*any of two or more products coming from the same unit process or product system*" ISO 14040 (2006). The CFP identifies impacts associated with a discrete product or system, so it is necessary to separate the impacts of co-products arising from multifunction processes. Table 4 describes the co-products in the foreground system of this LCA, and the allocation approach used according to the ISO 14044 LCA standard.

Table 4 Co-production in the CFP foreground and allocation used.

Process	Determining product	Co-product	Allocation approach
Gas extraction at well	Raw natural gas	Condensate for refinery processing	Energy allocation used as both products represent raw input to energy supply chains
Gas processing	LNG	LPG	Energy allocation
Petroleum refining	Diesel, petrol & aviation kerosene	LPG, fuel oil	Energy allocation

Foreground data for specific emissions were sourced from national and international GHG emission reports including:

- The emissions factors in the National Greenhouse Account Factors notably Sections 2.4.2.6 - 2.4.2.9. (Australian Government Department of Industry, Science 2021).
- National Greenhouse Inventory Reports, Section 3.9 generally and specifically Section 3.1 on CCS (Australian Government Department of Industry Science Energy and Resources 2021).
- Methods on natural gas production used in the National Greenhouse and Energy Reporting (NGER) Scheme (Commonwealth of Australia 2021).
- IPCC Guidelines Volume 2 Chapter 4.2 (IPCC 2006) with 2019 refinements (IPCC 2019).
- The Australian Life Cycle Inventory (AUSLCI) databases (ALCAS 2020).
- The Ecoinvent life cycle inventory database V3.7 (Weidema et al. 2019).
- Industry reports and experts, engineering information.
- Where no Australian data is available, international data specific to shale gas production operations (Omara et al. 2018; Hajny et al. 2019; Skone et al. 2011; Ravikumar et al. 2020).

The background data from the AUSLCI database and Ecoinvent contain multifunctionality and by default this is dealt with through economic allocation and in some instances physical allocation.

4.2.3 Impact assessment categories

GHG emissions are the only indicators assessed in this study. These have, however, been assessed using multiple methods:

- 100-year GWP used by the Australian government in the NGER and Climate Active programs[38]
- 20-year GWP, which focuses on the cumulative impact of GHGs assessed over 20 years (Frischknecht and Jolliet 2016)
- Global Temperature Potential (GTP) 100 values, which measure the longer-term impacts of climate change by estimating the instantaneous impact in 100 years' time rather than the cumulative impact over the next 100 years (Frischknecht and Jolliet 2016).

In this study we used the current values published in the National Greenhouse Factors, which are based on the IPCC 5th Assessment Report. There has been a recent 6th Assessment Report that has a slightly lower GWP value for methane over 100-year GWP (from 30.5 to 29.8). The Life Cycle Initiative Global Guidance of Life Cycle Impact Assessment recommends two alternative metrics in addition to the GWP 100 (Table 5)

Table 5 Characterisation factors for different climate change metrics.

	GWP 100	GWP 20	GTP 100

[38] http://www.cleanenergyregulator.gov.au/NGER/About-the-National-Greenhouse-and-Energy-Reporting-scheme/global-warming-potentials

Carbon dioxide	1	1	1
Methane (fossil)	30.5	85.4	13
Nitrous oxide	265	264	297

4.2.4 Sensitivity analysis

The sensitivity analysis was driven in part by examination of the most critical data points in the study (refer to Section 4.4.4 of the CFP report, Grant (2022)). The sensitivity analyses were undertaken on variables relating to the type and scale of production such as: fugitive emissions from wells, pipelines and LNG processing equipment; number of wells required; onsite mitigation such as electrification and renewable energy supply to equipment.

4.2.5 Uncertainty

Foreground data of the study have uncertainty estimates based on published ranges provided with the data. In the absence of ranges, uncertainty was estimated based on the data quality assessment was based on the pedigree matrix uncertainty estimation approach outlined in Muller, Lesage et al. (2016). Scenarios were analysed using Monte Carlo simulation to determine how the uncertainty of the input data propagated through to uncertainty in the final results presented as a mean value and 95% confidence limits of the climate change impacts.

4.3 Inventory and main assumptions

The following is a high-level overview of key components in the inventory. For a complete description, please refer to Section 3 of Grant (2022).

4.3.1 Well establishment and completion

Wells are constructed through drilling and lining with steel and cement. We assumed the energy and water required to drill and complete these wells, and the amount of construction material was proportional to total length of the well. Construction materials and construction energy intensities were sourced from Bista et al. (2019).

Typical well depth was estimated based on the locations of the different shale formations (refer to Section 2.4). For Velkerri the vertical depth is estimated to be 2,500m, while for Kyalla the vertical depth is estimated to be 1,500m. For both formations the horizontal drilling distance is 2,500m, which is similar to the value used in Bista et al. (2019).

4.3.2 Well pads

A well pad is the surface installation where wells are located. Well pads consist of between 1 to 16 wells and the infrastructure used in drilling and fracturing the wells, as well as tanks and/or ponds for managing waste water and water treatment (Jiang et al. 2011).

Section 7.3.1.4 of the *Scientific Inquiry* suggests that the gas industry's 25-year development scenario of between 1,000 and 1,200 wells is associated with around 150 well pads. From this it is assumed that the number of wells per well pad will range from 6 to 8, and we estimate each well pad occupies an area of 2 hectares that will need to be cleared of vegetation. These numbers are broadly consistent with CSIRO's Bioregional Assessment of Beetaloo's[39] assumptions although their estimate of cleared area around each well pad is 4 hectares.

Although we do not assess landscape impacts, this was prominent in the operational concerns and protection of country issues raised by the Central Land Council in their submission[40] to the *Scientific Inquiry*. The number and distribution of well pads is important and leads to a high variation in the additional land area needed for access roads.

4.3.3 Hydraulic fracturing fluid

Clark et al. (2013) estimate of *life-cycle* water use in onshore shale gas extraction is between 13 and 37 L /GJ gas based on US conditions. The same authors use a range of 1.4-33.4ML per *fracturing stage*. Again, referring to Australian conditions and Australian industry, the range was estimated as 1- 2ML per fracturing stage, from which we take the upper limit for this work.

The *Scientific Inquiry* cites US data (USEPA 2016) that typical water-based hydraulic fracturing fluid is 90% to 97% water, 1% to 10% proppant, and 1% or less of chemical additives. The proppant is most likely to be quartz sand (in 98% of cases), so for this study sand will be taken as the proppant.

The water recovered from fracturing can be treated and reused. Jiang et al. (2011) estimate water reuse to be between 30% and 60% of total input water. Water is assumed to be sourced from groundwater at a depth of 80m based on bore depths reported in Fulton and Knapton (2015). See Grant (2022) for details on energy requirements.

4.3.4 Energy use in fracturing operations

Stephenson, Valle et al. (2011) estimate 2 hours of water injection per fracturing event, at 6MW. Jiang, Michael Griffin et al. (2011) estimate the pumping power to be 25MW, with an operation time of between 10 and 30 hours for a multistage fracturing operation.

A 2 hour interval per fracturing event has been assumed with the larger power value, which translates to 25.5 MW, or 51 MWh for each fracturing event. This is the hydraulic energy requirement, so assuming a pumping efficiency of 75% and diesel motor efficiency of 45%, the diesel requirement in GJ is 51 MWh/0.75/0.45*3.6 GJ/MWh = 544GJ of diesel.

Jiang, Michael Griffin et al. (2011) estimate that the average lateral length of a well is 4,000m, so the energy use values are divided by 4,000 to derive an energy use per metre of lateral well based on the assumption that volume of fracturing fluid and energy would be proportional to the lateral length of the well. The resulting energy use per metre of lateral well length is therefore 544/4000 = 0.136 GJ/m. Assuming that 10 to 30 hours represents the uncertainty, the low and high values

[39] https://www.bioregionalassessments.gov.au/assessments/geological-and-bioregional-assessment-program/beetaloo-gba-region.

[40] https://www.clc.org.au/wp-content/uploads/2021/03/CLC-2017-Submission-to-Scientific-Inquiry-into-Hydraulic-Fracturing-in-the-NT.pdf

are 0.068 GJ/m and 0.204 GJ/m respectively. See Grant (2022) for the conversion of energy requirements into emissions.

4.3.5 Wastewater treatment

Wastewater (flowback from hydraulic fracturing, produced water and residual drilling fluids) is likely to be more saline than, for example, in Queensland CSG. Evaporation rather than reverse osmosis treatment is assumed, requiring less energy but more land. Caballero, Labarta et al. (2020) provide data on options for primary and secondary wastewater treatment of fracturing fluid. For this study, only primary treatment is assumed. Refer to Grant (2022) for numerate details.

4.3.6 Gas processing

Gas processing involves removal of moisture and separation of any liquid fractions including C3 and C4 hydrocarbons to liquified petroleum gas (LPG) and heavier fractions to condensate. Energy use input assumptions for gas processing are presented in Table 6 and is based on the Ecoinvent inventory.

Table 6 Data for energy use in gas processing (assumes gas density of 0.702 kg/m^3).

Energy input	Unit		Source/comment
Electricity	kWh/t	65	Ecoinvent data listed as 0.0457kWh of electricity.
Energy from natural gas	GJ/t	2.96	Ecoinvent data 2.08MJ of energy from natural gas per m^3 of gas.

4.3.7 Fugitives

Shale gas projects have been established in North America since the 2000s, and there has been much discussion on the range of fugitive emissions reported as between 2-17% of production there (Howarth et al. 2011) and referred to in Lafleur et al (2016).

There are analyses that argue the contrary point of view (Hultman et al. 2011; Skone et al. 2011) or that observe lower fugitive emission rates (< 1% production) even when considering fugitive losses from gathering and processing of gas (Marchese et al. 2015). Hence, the level of fugitive emissions is an important, and contested, variable that was essential to include in the sensitivity analysis.

It is important to note, in translating from US studies to Australian contexts, that a large fraction of methane fugitive emissions are ‘associated gas’: a by-product of accessing higher value hydrocarbon liquids. The associated gas may be unregulated in different jurisdictions. In onshore petroleum and natural gas production in the US, in 2019, ‘associated gas’ emissions were approximately 24 million tons CO_2e/year out of a total of 117 million tons CO_2e/year[41] (100-year GWP). Unregulated associated gas does not occur in Australia.

Furthermore, 'fugitive emissions' may be accounted for differently in different jurisdictions. In the United States EPA definition[42], fugitive emissions are leakages and categorically separated from vented gas and combustion, which are considered deliberate releases, and combustion respectively. In the Australian inventory, all three categories are considered to be fugitive releases except where gas is combusted in engines, in which case it is counted as energy usage (Day et al. 2012)[43].

Because of the variety of contexts and accounting methods in the literature, we sought data or Australian standards on fugitive emissions for the key processes of: well completion; venting; leakages; flaring and other combustion in production.

Stephenson, Valle et al. (2011) provide a shale gas estimate of methane fugitives from well completions as 0.45% of gas produced, with a low value of 0.09% and a high value of 1.94%. Burnham, Han et al. (2012) provide a similar mean value for shale gas well completions with fugitives at 0.46% of gas produced, with a low value of 0.006% and a high value of 2.75%.

There is an expectation with new shale wells that emissions control will be vastly improved based on the greater emphasis on GHG emission reduction. For this reason, the values from Burnham, Han et al. (2012) have been used in this CFP.

As mentioned in Section 3.2, onshore shale gas fracturing yields a mix of gases including a small fraction of carbon dioxide which is vented to the atmosphere. See Table 7 for assumptions about the CO_2 content of Beetaloo shale gas.

Table 7 Carbon dioxide content assumptions from shale gas production.

Well source	CO_2 content mol%	Source/comment
Kyalla	0.91%	Origin Energy Ltd estimate (Kernke 2021)
Velkerri	4.0%	Origin Energy Ltd estimate (Kernke 2021)

Any pipeline transmission emissions including leakages are taken from the National Inventory Report (2021) and fugitives from gas processing have been calculated according to the same report assuming an energy density for gas produced of 50.16PJ/Mt. Refer to tables in Grant (Grant 2022) for further detail on the input assumptions and inventory for the CFP.

A note on flaring

Flaring during operations is mainly used in emergency situations. For initial production and well testing, there is a short period of flaring needed to remove water from the well after hydraulic

[41] https://www.epa.gov/sites/default/files/2020-11/documents/subpart_w_2019_industrial_profile.pdf

[42] https://www.epa.gov/natural-gas-star-program/primary-sources-methane-emissions

[43] See also the National Greenhouse and Energy Reporting legislation https://www.legislation.gov.au/Details/F2017C00508

fracturing (flowback). The NT Government's *Code of Practice: Onshore Petroleum Activities in the Northern Territory*[44] requires a green completion and the use of a separator to capture gas.

The effect of operator judgement and the assumption that the initial production rates of fugitive emissions apply to the entire flowback period, results in the wide disparity in reported fugitive emissions (Howarth et al. 2011; Burnham et al. 2012). In practice, the flowback initially brings up mostly sand and fluids, and as the sand and water are removed from the well, the gas concentration increases. At a sufficiently high enough pressure, operators cease venting and direct the gas to the gathering lines. Burnham, Han et al. (2012) refer to practices in the US but we can use their rate of 0.469 kt CO_2/PJ to estimate the scale of the emissions from flaring.

If we apply this excessively, not just for initial production and testing, but for the entire production scenario flow of 365PJ over 25 years, this amounts to just less than 4.3 Mt of CO_2. This would be a considerable overestimate but it is still less than 2% of the total life cycle emissions relevant to the offset task, (see results in section 4.4) and less than 1% of the total life cycle emissions including overseas use of onshore shale gas. Given the uncertainties involved in estimating GHG emissions specifically from flaring, and its diminutive importance, it is excluded from the calculations of the life cycle CFP. It might also be noted that in the current Emissions Reduction Fund Methods, credit is given to flared combustion of captured emissions that would otherwise have been vented or leaked to the atmosphere[45].

4.4 Results

The CFP calculated results with respect to the different GWP and GTP of Table 5. In the following we present the GWP 100 results only, to avoid triplication of content here. The effect of using GWP 20 is 10-13% more total emissions, depending on the scenario, whereas using the GTP 100 reduces calculated total emissions by 4% across scenarios, compared to GWP 100 - refer to Section 4 of Grant (2022).

Note that the CFP study does not resolve a temporal dimension as to when production and consumption happens (or at what level) over the study period. See the discussion section for commentary on temporal issues of mitigating or offsetting GHG emissions.

4.4.1 Shale gas production

Figure 5 shows the GHG results for 1GJ of raw shale gas input delivered to Darwin via high-pressure pipeline, noting that 3.2% of this gas is utilised in processes and transmission. The total GHG emissions result is 8.85kg CO_2e/GJ. Raw gas production impact (4.0kg CO_2e), gas processing makes up 3.9kg CO_2e of which 0.2kg CO_2e are from fugitive methane emissions from processing. Transmission of gas to Darwin is also 1kg CO_2e. Raw gas impacts are made up of CO_2 venting (0.5kg CO_2), methane fugitives (2.5kg CO_2e), with the remainder being the impact of creating the wells

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[44] https://denr.nt.gov.au/onshore-gas/onshore-gas-in-the-northern-territory/code-of-practice-onshore-petroleum-activities-in-the-nt.

[45] http://www.cleanenergyregulator.gov.au/ERF/Pages/Choosing%20a%20project%20type/Opportunities%20for%20industry/Mining,%20oil%20and%20gas/Oil-and-gas-fugitives.aspx

including diesel and electricity for well drilling and construction. The main impacts of well completions are cement and concrete contributions at 0.46kg CO_2e.

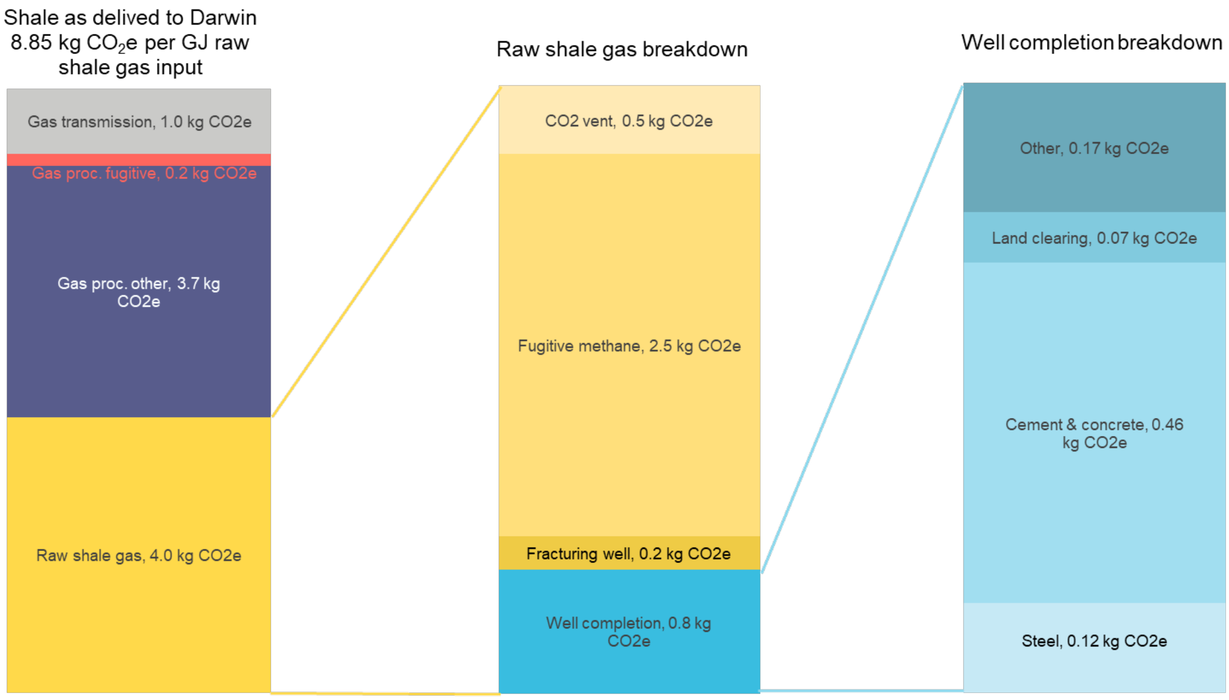


Figure 5 100-year GWP climate change impacts for 1GJ shale gas delivered to Darwin.

4.4.2 Shale gas utilisation scenarios

The different production and utilisation scenarios for shale gas from Beetaloo Sub-basin were shown earlier in Table 3. The emission intensities for these can be found in Grant (2022) and results from these scenarios in relation to process stages are shown in Table 8 and Figure 6.

Table 8 Greenhouse gas emissions by scenario in Mt CO_2e over 25-year life.

	Gas production	Transmission	Manufacturing	Domestic use	Overseas use	Total
Sc1 Dom. gas & LNG	72.1	8.7	28.2	54.7	377.8	541.5
Sc2 Dom. gas, LNG & refinery	60.5	5.8	43.4	228.5	236.1	574.4
Sc3 Dom. gas, LNG & chemicals	72.1	8.7	145.1	54.7	236.1	516.8
Sc4 Dom. gas, LNG & hydrogen	72.1	8.7	161.9	54.7	236.1	533.5
Sc5 All	211.6	24.1	361.5	228.5	855.9	1,681.6

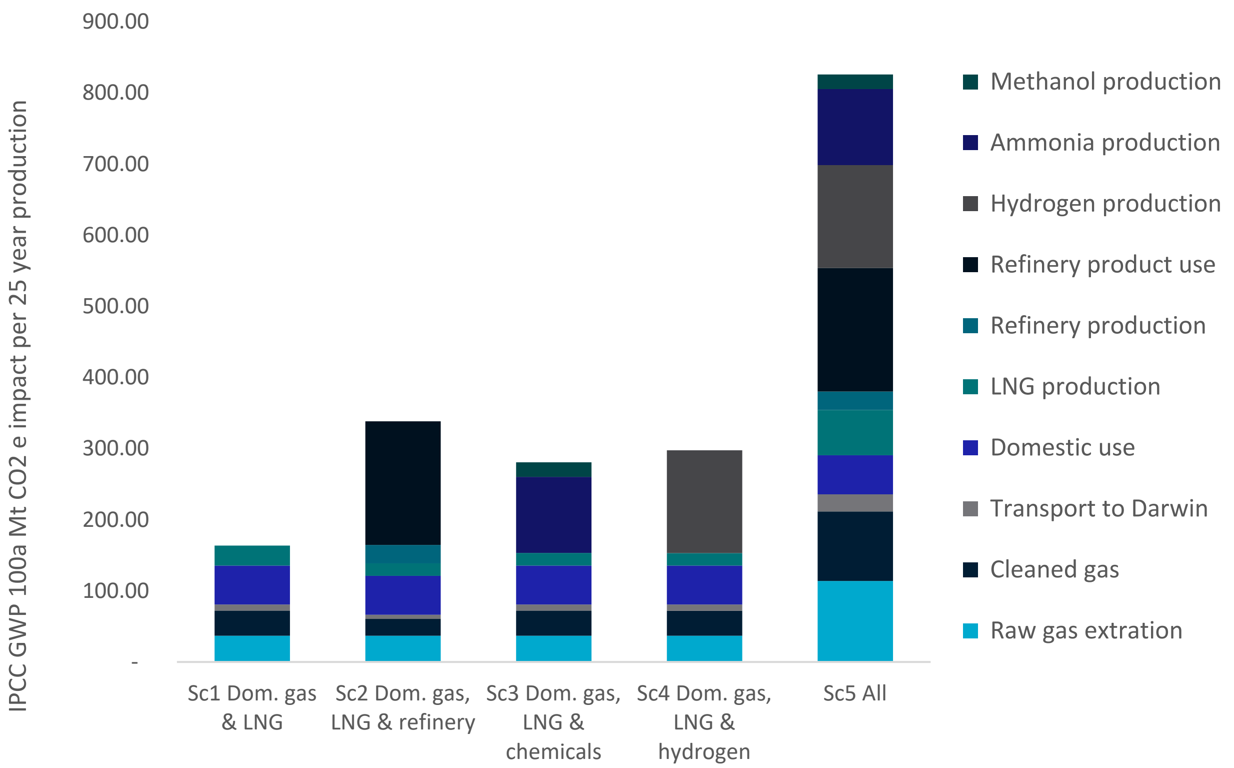


Figure 6 Greenhouse gas emission by scenario in Mt CO_2e over 25-year life excluding overseas use of LNG. Refer to system boundary 3 in Table 9. When annualised over 25 years these represent the annual emissions bill to be mitigated or offset – see text for discussion on uncertainty

A sensitivity analysis was conducted to look at 10% increase in the default values for parameters of – see Section 4.4.4 of Grant (2022). Fugitive methane and energy use in gas processing were the two most sensitive parameters, increasing GHG emissions of processed gas by 3.1% and 4.3%, respectively. The effect of either of these impacts on the final emission total is between 0.44% and 0.64% depending on which scenario is being assessed.

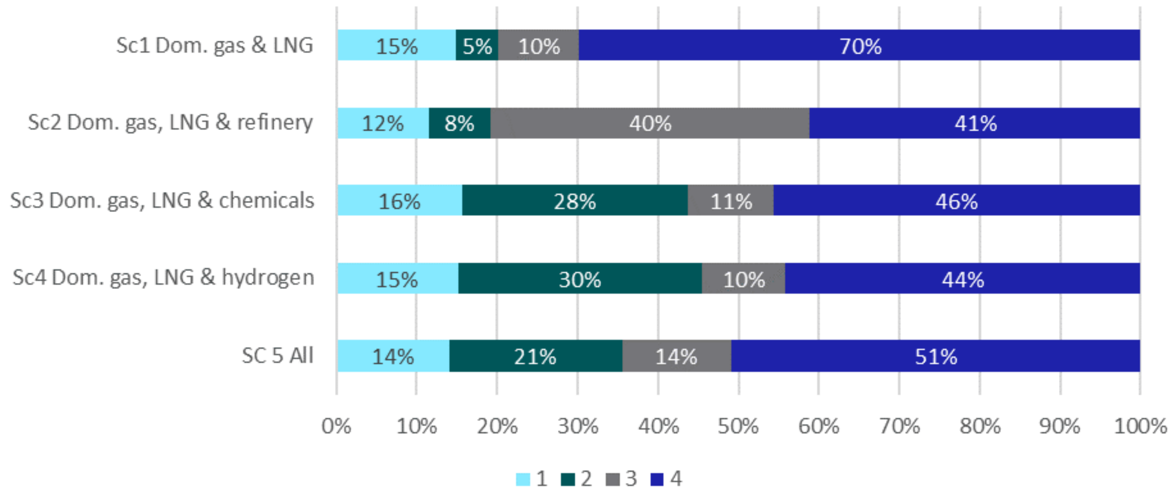
An uncertainty analysis was undertaken using Monte Carlo simulation, which runs the LCA model many times while randomly setting each input parameter to a value within its specified distribution – see Section 4.5 of Grant (2022). This results in a probability distribution for the overall output results of the CFP. The ninety-fifth upper and lower percentiles are used in Table 9, which shows the results for all scenarios using four different boundary conditions outlined in the system boundary section (refer to Figure 4).

1. Production of shale gas produced in the NT (not including its use)
2. Production of shale gas and other products made from shale gas in the NT
3. Production of shale gas and its products and domestic (in Australia) use of these products
4. Production of shale gas, and its production and all its uses regardless of location

The large volume of shale gas destined to overseas use via LNG production and export was not in scope but the fourth system boundary described (all gas production, manufacturing and use globally) adds to between 41% and 70% emissions depending on the scenario (see Table 9).

Table 9 Greenhouse gas emission by scenario in Mt CO_2e over 25-year life for four different system boundaries and percentage of emissions added by each expansion of the boundary.

	1 Shale gas production	2 Shale gas production and product manufacturing	3 Shale gas production, manufacturing and domestic use	4 Shale gas production, manufacturing and use globally	Uncertainty from Monte Carlo simulations (95th percentile interval)
Sc1 Dom. gas & LNG	81	109	164	541	+12%/-6%
Sc2 Dom. gas, LNG & refinery	66	110	338	574	+8%/-8%
Sc3 Dom. gas, LNG & chemicals	81	226	281	517	+12%/-7%
Sc4 Dom. gas, LNG & hydrogen	81	243	297	534	+10%/-6%
Sc5 All	236	597	826	1,682	+9%/-8%



5 Options for Mitigating and Offsetting Emissions

There is a putatively understood hierarchy in seeking ways to abate GHG emissions. Some emissions can be avoided or mitigated, and this reduces the task of capturing and sequestering GHG emissions. Both of these should be attempted before seeking offset options for any residual emissions.

5.1 Scope

It was noted in Chapter 9 (p232) of *The Scientific Inquiry* (2018):

"*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 515kg CO_2e/MWh of electricity … for 100-year GWP, there could be a reduction in Australia's GHG emissions of approximately 1% from a 73 PJ/year production and 5% in the case of 365 PJ/year production.*"

The potential for gas to substitute for coal-fired electricity generation is indeed a way to reduce emissions that would otherwise occur. However, we are not aware of any collaboration between any of Australia's jurisdictions to use gas in this way, let alone plans to use 365PJ/year of onshore shale gas.

There is an argument that the use of gas in this way would be a *consumer* choice of government or industry in different jurisdictions. That some fraction, or the entirety, of NT shale gas substitutes for coal-fired electricity generation elsewhere cannot be included in scope for similar reasons as to why *consumption* of exported gas is not included in the total GHG emissions liability. The responsibility for offsets is defined for production and Australian consumption of onshore shale gas from NT. Therefore those offsets should occur regardless of the end-use of that gas.

A hypothetical thought experiment is illustrative. If, hypothetically, through some consumption of natural gas from the NT, this involved an activity that *increased* GHG emissions, these additional emissions would not be attributable back to the NT or the producer. Likewise, if another consumer chooses to use the gas to decommission emissions-intensive activities, and *reduce* GHG emissions, this is also not wholly credited to the NT or the producer of onshore shale gas from the Beetaloo Sub-basin.

It is possible that overall responsibility for emissions and their abatement might be shared across producers and consumers in different jurisdictions. Scenarios of such an arrangement are unknown to the authors and outside the scope of this work although the *Scientific Inquiry* implies this through the involvement of the Australian Government (Chapter 9, Footnote 219). Crediting and trading of emissions reductions through proposed changes to the Australian Government's Safeguard Mechanism may facilitate such arrangements[46].

GHG emissions offsets, or 'carbon offsets' are accounting mechanisms to counteract emissions produced in one activity or location, with another activity that reduces emissions. For example, GHG emissions may be offset by tree planting, CCS or by enabling a switch to cleaner fuels. Carbon

[46] https://consult.dcceew.gov.au/safeguard-mechanism-reform-consultation-paper

offset markets can be complex and, since the COP 21 Paris Agreement, there has been greater scrutiny on the governance and efficacy of carbon offsets (Blum and Lövbrand 2019). This is why we first look for offset options in the NT or elsewhere in Australia: so that government agencies tasked with ensuring net-zero emissions from onshore shale gas in the NT are more proximal to any offset schemes required.

We investigated feasible options for mitigating and offsetting scenarios of GHG emissions from onshore shale gas development in the NT. Commentary on feasibility is given against: maturity of technology; demonstrated effectiveness; application at scale; continuity over lifetime of gas project (25 years); quality of governance and; indicative cost.

We did not enter into cost and benefit analyses, which would be the subject of another, separate and substantial analysis, but the costs of mitigation or abatement options are a key factor. We do comment on the approximate offset costs in comparison to anticipated carbon prices.

In Australia, the spot price of ACCUs in late 2022 was just over AUS\$30/tCO_2e, compared to around AUS\$16-\$17/tCO_2e in 2020, and at the beginning of 2021[47]. This range is used in the estimations of available land-based offsets in Section 5.3, but for companies with investment exposure to long-lived assets, many are planning for a long-term international carbon price around \$US50/tCO_2e [48,49,50].

Offset options are not confined to the NT, nor even Northern Australia[51] but we looked to prioritise offset options that would naturally be sensitive to the NT Offset Principles (Northern Territory Government 2020). Offset options that were considered included:

- Indigenous fire management
- human induced regeneration of land and coastal habitats, particularly in Northern Australia
- re-forestation or carbon plantings in Australia
- carbon farming and sequestration in soil
- reducing land clearing and deforestation
- accelerated weathering/mineral carbonation/reactive minerology
- forest carbon management (extending timber rotations, optimising tree stocking levels, breeding selectively for faster-growing tree stocks, enhancing growth)
- geological CCS.

It will be understood that, in general, the higher the carbon price, the more options become available but also the greater incentive to not need offsets in the first place. First, we look at the options for mitigation.

[47] http://www.cleanenergyregulator.gov.au/Infohub/Markets/Pages/qcmr/september-quarter-2021/ACCU-Market-trading.aspx

[48] https://www.oecd.org/tax/tax-policy/tax-policy-and-climate-change-imf-oecd-g20-report-april-2021.pdf

[49] https://hbr.org/2021/10/carbon-might-be-your-companys-biggest-financial-liability

[50] shadow pricing around \$US50/tonne https://www.c2es.org/wp-content/uploads/2017/09/business-pricing-carbon.pdf

[51] we define Northern Australia to be north of the 26th parallel line of latitude (also the Northern Territory and South Australia border).

5.2 Mitigation in production

There are a number of options for minimising GHG emissions from the upstream production of onshore shale gas, for example in the electrification of equipment, improved maintenance schedules, leak detection and repair (Campey et al. 2017; Nisbet et al. 2020) [52].

We know from the US experience that as a general rule of thumb, 4-5% of leaks in upstream production are responsible for 40-50% of fugitive methane (Brandt et al. 2016; Zimmerle et al. 2015; Lamb et al. 2015) and a similar result was found in an earlier 'bottom up' CSIRO study (Day et al. 2014). Thus, a significant part of the mitigation of GHGs in shale gas production will be about minimising scheduled emissions for example in venting, emissions from well completions and work-overs, and in the rapid and accurate detection and rectification of fugitive leaks.

From our consultations with Australian gas industry (Baynes 2021; Kernke 2021), it may be that domestic practices are ahead of the current US pollution control standards (United States EPA 2020)[53] and guidelines for Reduced Emissions Completions (RECs)[54] for hydraulically fractured gas wells.

When asked about practices such as: RECs, field turndown automation, flare avoidance, low emissions pneumatic controllers, higher frequency maintenance schedules and leak detection and repair (LDAR), the response from Australian industry was that these are 'business as usual.' There was also the comment that the electrification of equipment meant that gas as a direct power source for wells was becoming outdated.

5.2.1 Leak detection and repair (LDAR)

In a recent (and useful) review of methane detection technologies and protocols, Fox et al (2019) acknowledge that although there are diverse and mature technical capabilities in this area, practical leak detection is confounded by false positives, scheduled emissions and the equally diverse contexts where natural gas extraction occurs, for example, near cattle feedlots.

Although not a panacea, Fox et al (2019) introduce a hybrid, tiered approach to LDAR called a comprehensive monitoring program. Here, a screening technology (satellites, aircraft or unmanned aerial vehicles with sensors) is used to rapidly identify high-emitting sites, to direct close-range source identification at the level of the well. The latter stages often involving on the ground checking and monitoring of many hundreds of individual components.

To further complicate the LDAR task, even a tiered approach could be confounded by the temporal sophistication of methane emissions. Allen et al (2017) measured and modelled methane at 20,000 wells over the Barnett Shale play in the US, at hourly intervals, and found that emissions are highly intermittent, and intermittent sources accounted for 14–30% of the mean emissions for methane.

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[52] See also https://methaneguidingprinciples.org/

[53] Note recent changes https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-issues-final-policy-and-technical

[54] https://www.epa.gov/natural-gas-star-program/reduced-emission-completions-hydraulically-fractured-natural-gas-wells

Over the long-term, Cardoso-Saldaña and Allen (2020) found approximately half of the *absolute* methane emissions from gas wells over a 10 year period occur in the first year. However, the specific sources of methane fugitives change over time. Although well production declines, the intensity of fugitive methane emissions *relative to production*, increases over 10 years.

Accounting for temporal features of fugitive or other emissions is important in diagnosing leaks and other failure modes. We spoke directly with the author of both the aforementioned papers (also a seminal publication of methane emissions in US gas (Allen et al. 2013)), Prof. David Allen from the University of Texas. He recommended several innovations that included:

- **continuous monitoring** – static measurements may over- or under-state methane emissions because of the intermittency of engineered and fugitive methane emissions
- **a 'digital twin' of the gas field** – an open-source dataset with high spatial and temporal resolution
- **modelling of methane emissions** – using the digital twin database to distinguish and anticipate different types of temporal emissions.

Combined, these can aid in the modelling and measurement of dispersion to compare with higher-level screening data. Operational emissions have characteristic regularity in form and duration, therefore the above can also be used with signal processing to better detect leaks.

We do not comment on the cost or practicality of this advice though there would certainly be environmental dividends to a more sophisticated approach to LDAR and this could form part of the technical governance requirements of gas development in the Beetaloo Sub-basin.

5.2.2 Equipment and processes

Another finding of Cardoso-Saldaña and Allen (2020) was that the sources of emissions change markedly over time. Over a decade of operation, the contribution to methane emissions from pneumatic controllers and chemical injection pumps rises from < 2% initially, to more than 60% of the total per year (compared to leaks, which contribute about 10% after 10 years).

Methane is vented from pneumatic devices driven by natural gas produced onsite, so preventing or reducing emissions can also often have economic benefits. Some 15% of the total global emissions of methane from oil and gas operations, could be saved if using best practice approaches for pneumatic controllers and pumps[55].

In November 2021, the US EPA proposed new source performance standards (NSPS) for reducing methane emissions in the oil and natural gas industry[56]. At the time of writing, they have only just finished the consultation period and are not finalised but several reforms are worth noting:

- Larger sites where > 3 tonnes CH_4 emissions/year occur will be subject to quarterly monitoring.

[55] https://methaneguidingprinciples.org/best-practice-guides/pneumatic-devices/

[56] https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-proposes-new-source-performance

- All new and existing compressor stations to be monitored; flaring equipment, and storage vessels will be inspected and any leaks fixed at least every 3 months.
- Pneumatic controllers are used extensively and are currently unregulated. These will become regulated and all new and existing pneumatic controllers and pumps in production, processing and transmission and storage facilities are to have zero methane and VOC emissions.

According to the American Petroleum Industry Compendium (2021) Table 6-29, there are significant reductions in methane emissions possible in the choice of low-bleed pneumatic controllers and especially in efforts to rectify malfunctions (see a selected extraction in Table 10).

Table 10 Methane Emission Factors (tonnes CH_4/controller-year) for different pneumatic controllers under different functional operating status. Source (American Petroleum Institute 2021)**.**

Methane Emission Factors (tonnes CH_4/controller-year)	
Low-bleed Pneumatic Controllers (functioning)	0.093
Low-bleed Pneumatic Controllers (malfunctioning)	4.66
Intermittent Vent Pneumatic Controllers (functioning)	0.39
Intermittent Vent Pneumatic Controllers (malfunctioning)	2.21
Average Pneumatic Controller (functioning)	0.68
Average Pneumatic Controller (malfunctioning)	2.61
High-bleed Pneumatic Controller (functioning)	2.64

5.2.3 Electrification with renewable energy

Currently, the majority of equipment around gas wells are electric, though the source of the electricity is mostly from gas or diesel – as assumed in the CFP. Sources of energy for compression are variable. The industry preference is for electric but they also report there are gas driven compressors where it is more energy-efficient to run a gas compressor rather than a gas-powered generation unit that drives electric drive compressor[57].

One of the sensitivities explored in the CFP was the effect of substituting renewable energy sources for gas or diesel at different stages of production. Electrification with renewable energy was tested in four parts of the production chain:

1. replacing diesel energy used in fracturing (pumping)
2. replacing genset gas electricity generators at gas processing plants

[57] notes from personal communication with Chad Wilson at Santos Ltd

3. replacing gas compressors at gas processing
4. replacing gas compressors at LNG manufacture.

All replacements were undertaken using solar electricity, open field installation using average generation from solar energy inputs to the grid mix. In reality, the production of energy from solar will not match the timing of demands from the shale gas operations which typically run 24 hours per day. This may be resolved through trading electricity credits or power storage, but this was not investigated in this sensitivity.

The efficiency of electric motors and compressors were assumed to be similar to gas compressors and diesel genset. This likely overestimated electricity demand as electric motors tend to be more efficient than gas compressors and diesel generation sets.

Table 11 shows the results of the sensitivity analysis for shale as delivered to Darwin. It shows the influence of renewable energy is most significant at the gas processing stage where it leads to a 26.7% reduction in the overall footprint. If solar energy is implemented at all four points of the production chain the total impact on production-related emissions is a reduction of 47%.

Table 12 shows the influence of renewable energy use at processing on scenario 5. The total reduction for scenario 5 with solar energy replacements at all four points in the supply chain is 7.9%.

Table 11 Sensitivity result for 1 kg of LNG at the port when implementing renewable energy at different parts of shale gas and LNG production chain.

	kg CO_2e/ kg of LNG	% reduction
Baseline	0.722	
Solar replacing diesel at well head	0.582	19.5%
Solar replacing gas genset at processing	0.713	1.3%
Solar replacing gas compressor at gas processing	0.530	26.7%
Solar replacing compressor at LNG	0.713	1.3%
All solar options in production chain	0.382	47.1%

Table 12 Sensitivity result Mt CO_2e for scenario 5 over 25 years implementing renewable energy at different parts of shale gas and LNG production chain.

	Mt CO_2e	% reduction
Baseline	1,681.5	
Solar replacing diesel at well head	1,613.5	4.0%
Solar replacing gas genset at processing	1,677.25	0.3%
Solar replacing gas compressor at gas processing	1,621.75	3.6%
Solar replacing compressor at LNG	1,677	0.3%
All solar	1,548.75	7.9%

We summarise the mitigation opportunities with reference to the feasibility criteria.

5.2.4 Maturity of technology or demonstrated effectiveness

Renewable power for continuous industrial processes is technically feasible with storage or back up. Technologies such as solar PV and wind power are demonstrated and particularly suited to remote northern areas of Australia with excellent solar access[58]. The concomitant technology of battery storage is available or back up could be in the form of the existing gas-powered technology, which would reduce emissions but not eliminate them. The effectiveness of LDAR relies on rigorous procedures and established technology. Requirements for measurement equipment, and frequency of testing in the NT Government's *Code of Practice: Onshore Petroleum Activities in the Northern Territory*[59] refers to the US EPA Best Practice Guide[60] Method 21 *Determination of Volatile Organic Compound Leaks* that has been in operation since 2014.

5.2.5 Scale

A number of the practices and processes suggested above, and the renewable power options, are modular and able to be scaled through repeated replication rather than requiring a large singular investment in infrastructure for example in large-scale solar farms. Renewable power for the liquefaction process could be more challenging given the related electricity load of such a facility.

5.2.6 Longevity

An average lifetime of 25-30 years for solar panel modules is commonly used in recent literature (Gürtürk 2019; Heath et al. 2020) and for wind turbines 20-40 years (depending on component maintenance). This at least matches the expected lifetime of gas production from Beetaloo onshore shale gas assumed in this study. Continuous monitoring and maintenance of components such as pneumatic controllers and chemical injection pumps could be expected over the lifetime of wells (~10 years).

5.2.7 Quality of governance

Within the NGER Scheme[61] there are standards for scope 1 and 2 GHG accounting that would enable a rigorous estimation of the effect of any mitigation interventions. In Australia, emissions from pneumatic controllers and chemical injection pumps are covered in NGER (Measurement) Determination 2008, Subsections 3.3.9A.4 and 3.3.9A.5 (Commonwealth of Australia 2021). Apart from established GHG emissions accounting and reporting, there are also existing national schemes to encourage installation of renewable energy power[62].

[58] See https://industry.nt.gov.au/reforms/renewable-energy and https://territoryrenewableenergy.nt.gov.au/

[59] https://denr.nt.gov.au/onshore-gas/onshore-gas-in-the-northern-territory/code-of-practice-onshore-petroleum-activities-in-the-nt.

[60] https://www.epa.gov/sites/default/files/2014-02/documents/ldarguide.pdf

[61] http://www.cleanenergyregulator.gov.au/NGER

[62] https://www.dcceew.gov.au/energy/renewable/target-scheme

5.2.8 Indicative cost and market

Every state and territory jurisdiction in Australia has a target of net-zero carbon by 2050. All else being equal, this indicates the demand for offsets, the price of carbon and the value of mitigating emissions, will rise. At the same time the cost of renewable energy technology has fallen to a level where CSIRO's Chief Energy Economist, Paul Graham states:

"*Even taking into account [these extra] system integration costs, solar photovoltaics (PV) and wind continue to be the cheapest new sources of electricity for any expected share of renewables in the grid — anywhere from 50 per cent to 100 per cent. This is projected to continue to be the case throughout the projection period to 2050.*" (Graham et al. 2021)

Using Table 11, we can do a simple calculation of the tons of CO_2e that *could be* mitigated with renewable power, in the production of 200 PJ (~3.7Mt CO_2e/year) of LNG from the scenarios. Compared to the baseline (2.7 Mt CO_2e/year), this is a saving of 1.3 Mt CO_2e/year or ~32Mt Mt CO_2e for the scenario lifetime of the Beetaloo gas project. If this had to be offset with ACCUs at current prices, this mitigation would *avoid* a cost of $AUS950 million.

For reference, the regulatory impact analysis for the proposed US NSPS (United States EPA 2021) found that the effect would be to save 920 Mt CO_2e (nearly double Australia's national GHG account) and have a net benefit of nearly $US50 billion[63].

5.3 Land-based opportunities for carbon abatement

Land-based emission offsets are derived from interventions in Agriculture, Forestry, and other Land Uses (AFOLU) to reduce GHG emissions or enhance carbon removal. AFOLU offsets are generated through the protection, restoration and management of land ecosystems; emission reduction and carbon sequestration from agricultural activities; and bioenergy generation (Roe et al. 2021). Around one-quarter of Nationally Declared Contributions (NDC) rely on AFOLU emission reductions (Grassi et al. 2017). As part of the Paris agreement, Australia has committed to reduce its total GHG emissions by 43% below 2005 levels by 2030. The Emissions Reduction Fund (ERF) administered by the Clean Energy Regulator, is the main federal mechanism to achieve such a target. The ERF incentivises the reduction or avoidance of emissions or the development of projects to offset carbon emissions by Australian businesses, farmers, councils and other entities. Where these projects meet the requirements set by the Clean Energy Regulator (CER), the projects result in ACCUs that the government or other entities can purchase to achieve committed GHG emissions reduction goals. As of 2021, the ERF reported around 103 million ACCUs issued to 1,048 projects, with 66% of those credits issued to vegetation, agriculture, and savanna burning projects[64]. Between July 2014 and June 2021, the ERF has delivered around 11.6 Mt CO_2e per year at an average price of approximately $12.6/t CO_2e abated[65]. Fitch et al (2022) provides an up-to-date summary of land-based offsets as a component of Australia's carbon sequestration potential.

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[63] See p31 here https://www.epa.gov/system/files/documents/2021-11/epas-proposed-oil-and-gas-rules.presentation-11.2.2021.pdf

[64] http://www.cleanenergyregulator.gov.au/maps/Pages/erf-projects/index.html

[65] http://www.cleanenergyregulator.gov.au/ERF/project-and-contracts-registers/carbon-abatement-contract-register

5.3.1 Maturity of technology or demonstrated effectiveness

From January 2012 to December 2020, around 97.1 million ACCUs have been issued to ERF projects. Average issuance per year from 2016-17 to 2020-21 has been 14.2 million ACCUs. Currently, land-based projects in the ERF deliver around 11 Mt CO_2e offset per year. Four technologies account for around 95% of those offsets: 1) Human Induced Regeneration, 2) avoided deforestation, 3) savanna fire management, and 4) native forests from managed regrowth (Figure 7).

Human Induced Regeneration (HIR). HIR projects require the removal of land clearing pressures, improved livestock grazing management, feral animal control and weed management to allow natural regrowth of native vegetation. Net carbon increases in plant biomass and soil carbon are used to estimate the amount of ACCUs that a project could receive. HIR projects require implementation in non-forest land[66] with active management that prevents vegetation regrowth for example grazing, and with potential to achieve natural vegetation regeneration. This type of project has been primarily implemented in marginal land where the opportunity costs of alternative land uses are low. HIR projects require a permanence of 25 or 100 years and are currently able to claim credits for 25 years. HIR currently accounts for 50% of the total ERF contracted emission reductions, and 60% of the total land-based (Fitch et al 2022) (see also Figure 7).

Avoided deforestation. This ERF methodology is focused on the protection of native forests that would be converted to cropland or grassland if conservation incentives were not available. Above and below grown forest carbon sinks are used to estimate the number of ACCUs that this type of projects can receive. Land contracted to deliver carbon offsets from avoided deforestation requires to be in such a status for 25 or 100 years. The crediting period of this type of projects is 15 years. Avoided deforestation generates around three Mt CO_2e offset per year.

Savanna fire management. This type of projects generates carbon offsets by implementing strategic burning to reduce emissions from fires in the high-intensity late dry season. ACCUS are obtained for demonstrated reductions in the non-CO_2 GHGs methane and nitrous oxide. There are no permanence constraints associated with this methodology. Another source of abatement for savanna fire management is through increases in soil carbon stocks due to the positive impact of fire management. However, this subcategory requires a permanence of either 25 or 100 years and have a crediting period of 25 years (Fitch et al 2022). Savanna burning projects currently offset around 0.8Mt CO_2e per year.

Native forest from managed regrowth. Under this method, net carbon gains in above and below ground biomass derived from avoiding clearing of native vegetation regrowth and supporting regeneration of native vegetation are used to generate ACCUs. The permanence and crediting period are similar to other ERF methods, that is 25 or 100 years for permanence and 25 for crediting. Native forests from managed regrowth each offset around 0.7Mt CO_2e per year.

[66] Deforested land over at least ten years qualifies for this ERF methodology.

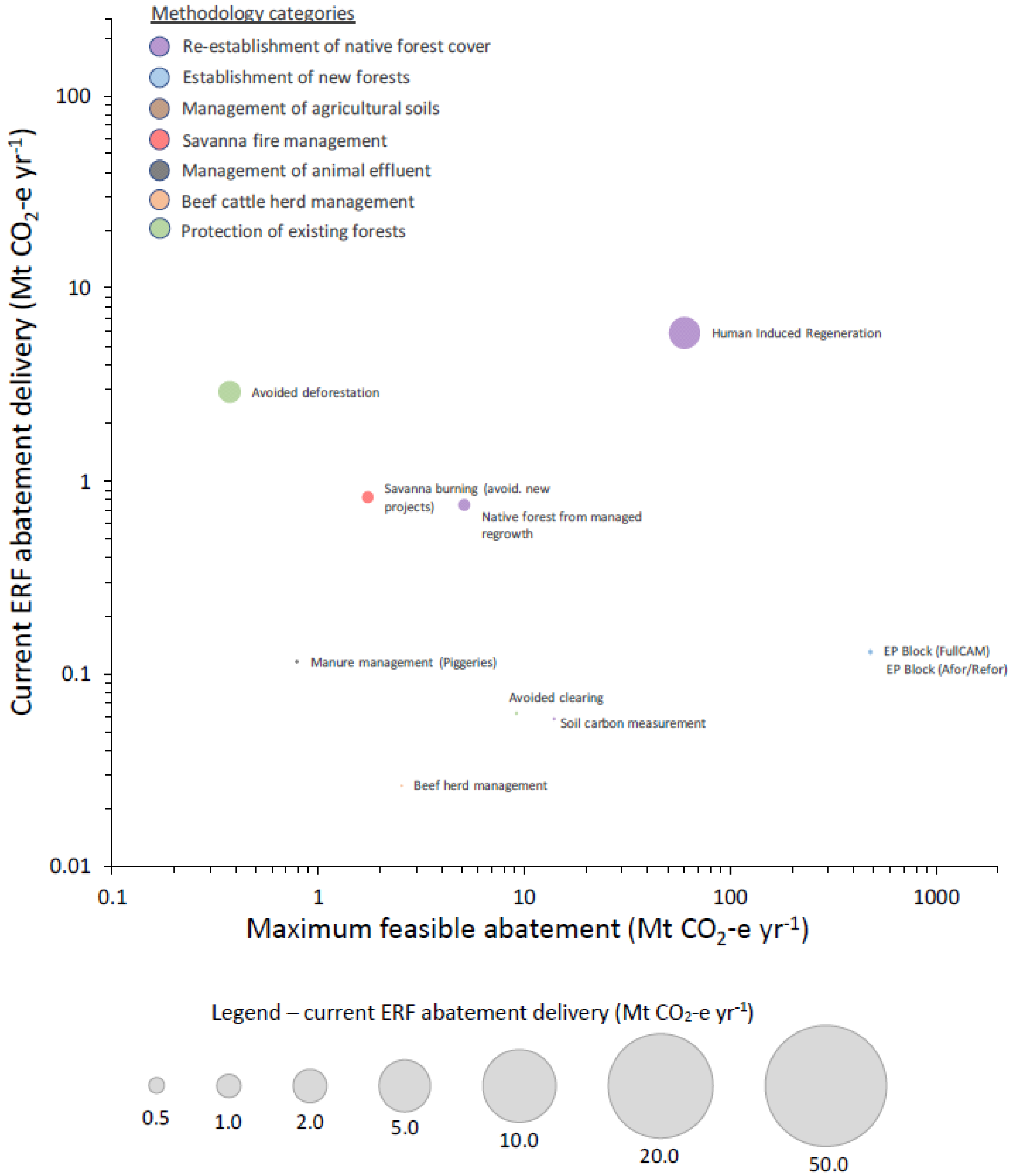

Figure 7 Maximum feasible abatement and current abatement delivery under ERF contracts. Bubble size is proportional to delivered abatement. EP block means Environmental Plantings. Source: Roxburgh et al. (2020)**.**

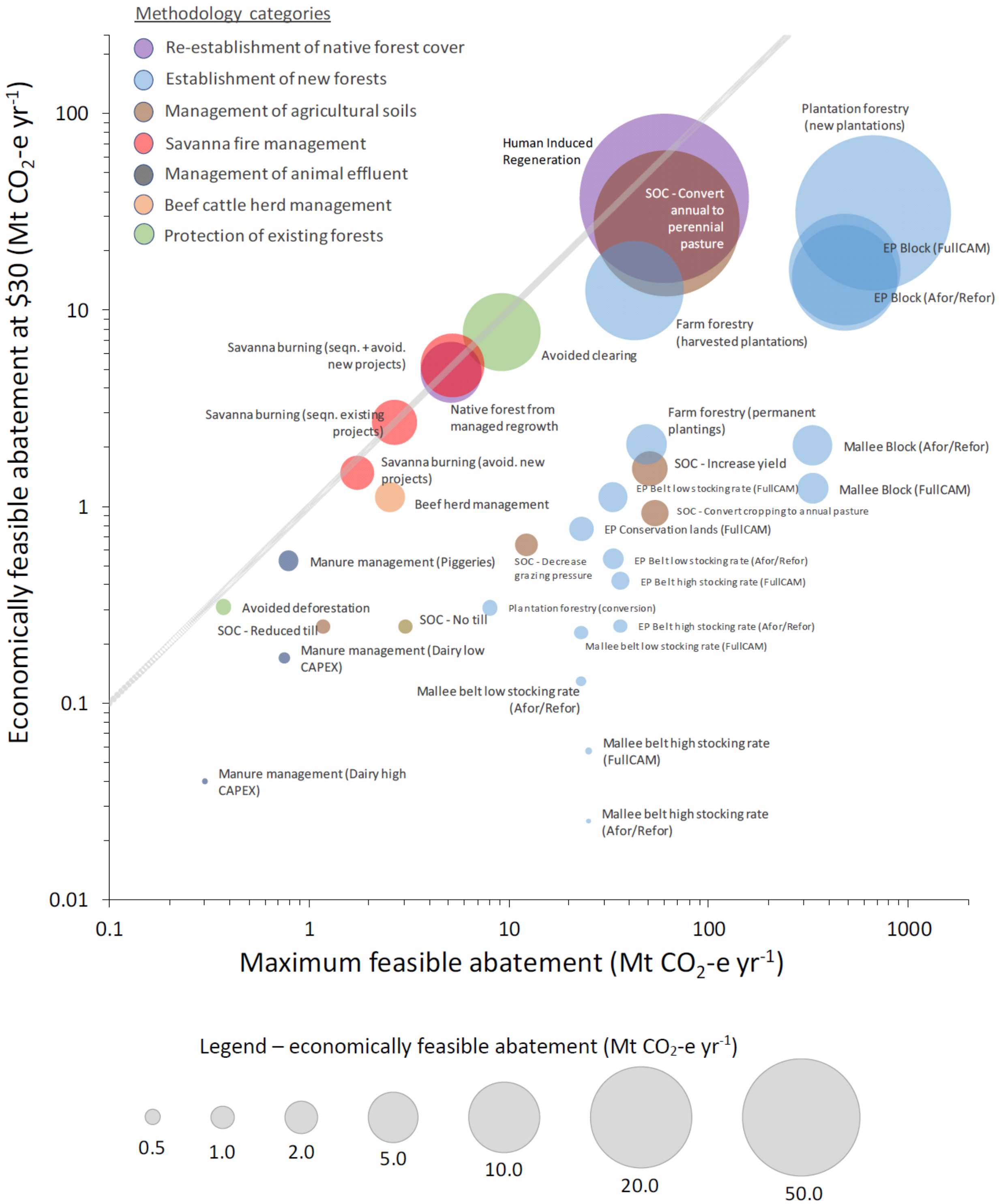

Figure 8 Maximum feasible abatement and economically feasible abatement at a carbon price of $30 t CO_2e^{-1}. Bubble size is proportional to delivered abatement. The diagonal line indicates a one-to-one relationship between maximum and economically feasible abatement. EP block means Environmental Plantings. Source: Roxburgh et al. (2020).

Other ERF methodologies currently in use account for less than 5% of the annual land-based offsets. However, the establishment of new forest for carbon faming has the biophysical potential to achieve large levels of emission abatement (Figure 7). However, such abatement potential is constrained by economic, infrastructure, political and social factors. Figure 8 shows the maximum feasible abatement and economically feasible abatement at $30 dollars per year for all the land-based methodologies covered in the ERF (Fitch et al 2022). While plantation forestry has potential to offset around 600 Mt CO_2e per year, at a carbon offset price of $30/t CO_2e, only around 10% of such potential could be economically feasible.

In addition to the land-based options covered by the ERF, there is evidence to suggest regeneration of coastal mangrove and seagrass habitats can sequester large amounts of organic carbon – "blue carbon" – at a much higher intensity per-hectare than on land (Doughty et al. 2016; Saderne et al. 2019; Macreadie et al. 2017). Achieving carbon offsets through blue carbon is the subject of strategic recommendations in the Carbon Market Institute's *Carbon Farming Industry Roadmap* (2017), although it has not had so much uptake in Northern Australia where mangroves ecosystems are mostly intact. There is some industry support though the localised capacity to sequester carbon and cost of blue carbon schemes can vary widely (Vanderklift et al. 2018). Development of blue carbon methodologies for inclusion in the ERF are ongoing, as well as an assessment of the potential of Australian coastal ecosystems to contribute to emission reduction targets[67]. However, further quantitative research would be needed to include this in the scope of offset options.

Bioenergy with CCS (BECCS) is another technology that could contribute to long-term carbon emission reduction goals. Pour, Webley, and Cook (Pour et al. 2018) estimate potential emissions reductions in Australia of around 25 Mt CO_2e per year by 2050. The authors modelled the use of organic waste from municipal, agricultural and forestry sectors to produce energy and store derived carbon emissions. BECCS would be price competitive with coal-fired power at a carbon price of around $60. Dedicated use of energy crops/trees could increase the abatement potential of BECCS. However, more research is needed to estimate the potential implications of land clearing to grow bioenergy crops, the compromise in reduced land to grow food, loss of carbon from soil, and proper consideration of emissions through the BECCS value chain. Some of these effects could negate the carbon sequestration gain (Harper et al. 2018).

5.3.2 Scale

While the biophysical potential for generating land-based emissions offsets is relatively large in the country, the feasible abatement potential is limited by economic and technical conditions. At a carbon price of $15 per tonne, the total land-based options available in the ERF could offset approximately 86 Mt CO_2e per year (i.e. approximately 18% of Australian yearly emissions). Increasing the price to $30 results in an economically feasible annual abatement from 163 Mt CO_2e (i.e. approximately 34% of the Australia's annual emissions) – refer to Table 13.

In Northern Australia, most emission offset projects operate under the *Savanna Fire Management Sequestration and Emissions Avoidance* ERF methodology. Avoiding high-intensity, late-season fires through low-intensity, cool weather burning involves a considerable amount of ecological knowledge and participation of Aboriginal and Torres Strait Islander people. There are currently 80 contracts in Western Australia, Queensland and the NT for this form of abatement[68], which have reduced emissions by approximately 9.9Mt CO_2e since inception. Around one-fifth of such offsets

[67] https://www.csiro.au/en/news/news-releases/2021/estimating-australias-blue-carbon-potential

[68] http://www.cleanenergyregulator.gov.au/maps/Pages/erf-projects/index.html

have been generated by the West Arnhem Land Fire Abatement (WALFA) in partnership with the Darwin LNG (DLNG) project since 2006[69].

Table 13. Feasible CO_2e abatement potential per year (total and per-hectare) at carbon prices of $15 and $30 per tonne data from Fitch et al (2022). As in that report, Plantation Forestry is considered over a technically feasible area of 1Mha.

ERF methodology	Carbon price = $15/t		Carbon price = $30/t	
	Abatement/ha (t CO2e /year)	Total abatement (Mt CO_2e/ year)	Abatement/ha (t CO_2e /year)	Total abatement (Mt CO_2e/ year)
1. Human-induced regeneration of native forest	1.8	26.1	1.7	39.2
2. Native forests from managed Regrowth	2.4	4.4	2.4	4.8
3. Re-forestation by environmental or Mallee plantings	94.6	1.5	71.5	16.0
4. Re-forestation and afforestation	102.8	1.4	79.1	14.5
5. Plantation forestry	29.3	29.3	31.8	31.8
6. Measurement based methods for new farm forestry plantations	11.9	4.3	14.2	12.5
7. Avoided clearing of native Regrowth	6.5	7.1	6.6	7.7
8. Measurement of soil carbon sequestration in agricultural systems	3.4	5.8	1.6	30.7
9. Savanna fire management sequestration and emissions avoidance	0.08	6.1	0.08	6.2
Totals *		86		163

Source: Abatement estimates consider a crediting period of 25 years. Based on Fitch et al (2022). Totals may not match summation over rows due to rounding.

Heckbert et al. (2012) estimated that savanna fire management was economically viable at a price of $23/t CO_2e on 51 M ha of land in Northern Australia, potentially abating 1.6 Mt CO_2e /year. If the carbon price were $40 t CO_2e, this would practically make economic the entire area of land eligible for abatement of emissions through fire management. Roxburgh et al. (2020) estimate that around 57 M ha of land could be used in Northern Australia for projects focused on avoiding emissions and sequestration. According to Fitch et al's (2022) analysis, carbon offsets derived from savanna fire management are economically viable at carbon prices of $4-5t/$CO_2e$. However, the total abatement potential is around 5.2Mt CO_2e/year, which could be reached at a price of around $16/t CO_2e (Figure 9). There are some calculations[70] that fire management could increase carbon

[69] https://www.appea.com.au/wp-content/uploads/2020/08/Industry-Action-on-Emissions-Reduction-1.pdf

[70] https://theconversation.com/savanna-burning-carbon-pays-for-conservation-in-northern-australia-12185

stocks (sequestration) in long-lived woody biomass such as mulga, to the effect of an additional 0.22 t CO_2e/ha/year, where this species occurs in the landscape (Burrows 2014). We estimate the total sequestration potential to be 6.2Mt CO_2e/year, which agrees with Fitch et al (2022).

Other ERF methods are unlikely to provide significant opportunities for carbon offset projects in the NT. There are limited revegetation opportunities as there has been very little land clearing compared to other states and territories. Hence, there would be very few opportunities for carbon offsets via revegetation. However, mine site revegetation (e.g., Ranger uranium mine) has probably been the space where the most amount of work has been done on recreating savanna ecosystems in the NT. There is also a forestry industry in the NT (mahogany timber) that manages to grow sufficient biomass to make a profit, although rates of tree growth in savannas (native or non-native species) are much lower than areas on the east coast with more fertile soils and more even rainfall (Richards, 2021 personal communication).

Over 25 years, HIR could offset around 820Mt CO_2e at a price of \$30/t CO_2e, that is around 39Mt CO_2e per year (Figure 9 and Table 13). Managed regrowth of native forests could offset around 118Mt CO_2e during the same period (4.8 Mt CO_2e per year). Invariant to higher carbon prices, there appears to be a limit of economically feasible offsets for savanna fire management and avoided deforestation of between 5 to 6.2Mt CO_2e (see Figure 9).

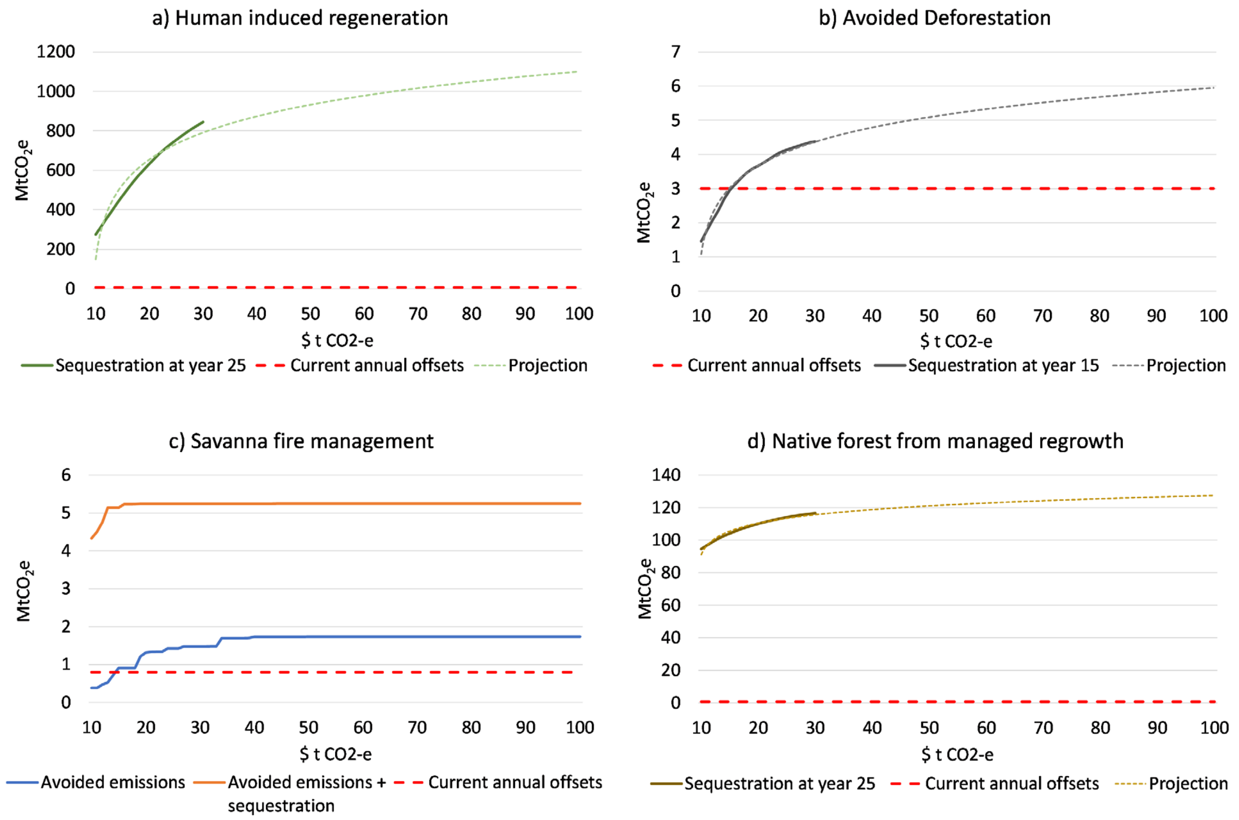

Figure 9 Estimated CO_2e abatement for offset prices from \$10 to \$100 after 25 years.

5.3.3 Longevity

The crediting period for ERF projects is 15 years for avoiding deforestation and 25 years for other land-based methods unrelated to animal management. Given the long-term nature of ERF contracts, existing and potential land-based carbon abatement options could provide a mechanism to offset emissions derived from the production and consumption of shale gas in the NT. Modelling for Australia's long-term emissions reduction plan estimates that the Australian Government's purchase of ACCUs under the ERF will reduce over time as offsets are sold to private entities[71]. Even with limited government incentives in place, domestic and international demand for carbon offsets could result in long-term supply of emission abatement options. However, the viability and sustainability of large-scale carbon farming requires maintaining a social licence to operate in regional areas impacted by emission abatement projects. Adequate accounting and remediation of environmental and economic impacts for example water use, displacement of agricultural land could also facilitate the uptake and longevity of offsets supply (Brinsmead et al. 2019).

5.3.4 Indicative cost and market

Supply of ACCUs was 16% higher in 2021 than in 2019. In contrast, annual demand remained practically stable during such a period (Figure 10). These trends contributed to an increase in the inventory of ACCUs which by December 2021 reached offsets equivalent to around 13Mt CO_2e that is the equivalent of one year of ACCUs supply was not sold. Around 50% of unsold ACCUs were held by project managers, intermediaries held around 18% of the balance, and business and government enterprises owned around 17% of available offsets.

ACCUs spot prices have increased substantially in recent months, going from around $17 in June 2021 to a high of $55 by February 8, 2022 and fell back to just over $30 in late 2022[72]. However, such high prices may reflect short term market dynamics and have been based on relatively small transactions[73]. Australia's long-term emissions reduction plan[74] assumes a carbon price of $25/t CO_2e by 2050 to generate around 27Mt CO_2e of land sector offsets. Such a level of offset production from industrial and transportation projects was estimated at a cost of $62/t CO_2e.

In 2019, ACCUs representing around 0.48Mt CO_2e were cancelled that is the offsets were claimed. Cancellation volumes increased 76% in 2020. Around half of the cancellations in those years were part of emission offsets as part of the Climate Active collaboration between the Australian Government and Australian businesses to promote voluntary climate action (Table 14).

[71] https://www.dcceew.gov.au/climate-change/publications/australias-long-term-emissions-reduction-plan

[72] https://coremarkets.co/resources/market-prices

[73] http://www.cleanenergyregulator.gov.au/Infohub/Markets/quarterly-carbon-market-reports/quarterly-carbon-market-report-%E2%80%93-september-quarter-2021

[74] https://www.industry.gov.au/sites/default/files/October%202021/document/australias-long-term-emissions-reduction-plan.pdf

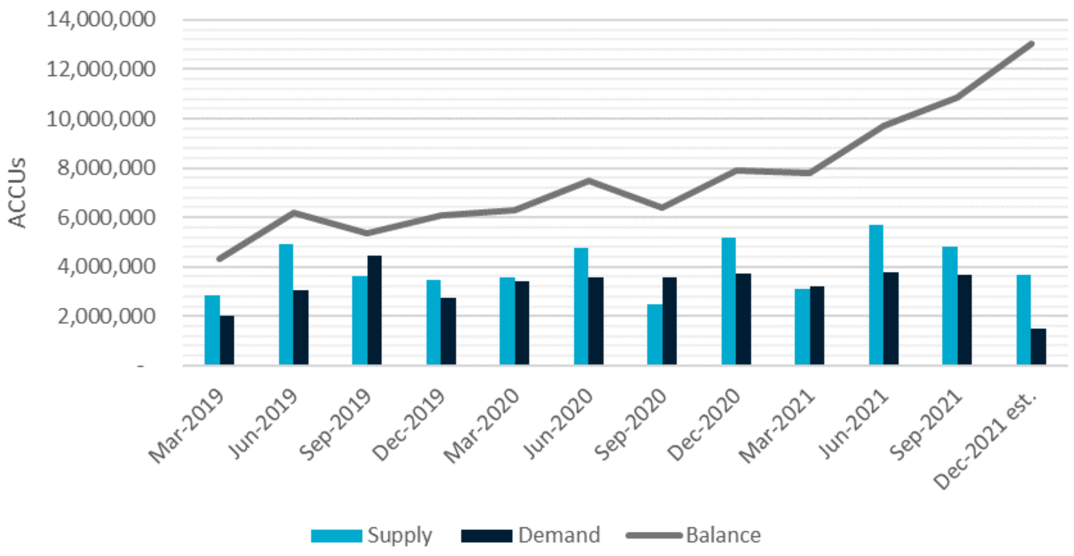

Figure 10 Supply, demand and balance of ACCUs. Source: Based on data from the Clean Energy Regulator Quarterly Carbon Market Report[75].

Table 14 Voluntary private and state and territory government demand for ACCUs by reason for cancellation

	Climate Active*	State and territory	Desalination	Other	Total
	ACCUs cancellation volume				
2019	215,475	110,672	27,955	122,776	476,878
2020	447,026	119,752	80,005	194,174	840,957
	ACCUs cancellation %				
2019	45%	23%	6%	26%	
2020	53%	14%	10%	23%	

Notes: Based on data from the Clean Energy Regulator Quarterly Carbon Market Report. Climate Active is a collaboration between the Australian Government and Australian businesses to promote voluntary climate action in the form of emission abatement.

[75] http://www.cleanenergyregulator.gov.au/Infohub/Markets/quarterly-carbon-market-reports/quarterly-carbon-market-report-%E2%80%93-september-quarter-2021

5.4 Alternative gas products: hydrogen and basic chemicals

The use of natural gas in the Australian chemicals industry is worth some $38billion/year to the economy[76].The natural gas industry and NT Government can support new connections to the emerging Australian hydrogen industry (Bruce et al. 2018). The potential for reducing emissions comes through producing hydrogen from using natural gas in SMR coupled with CCS or carbon capture and utilisation (CCU). Hydrogen produced from methane, coupled with CCS is known as 'blue hydrogen' compared with 'grey hydrogen' also made from fossil fuels but releasing CO_2 by-product to the air, and 'green hydrogen' that is obtained from hydrolysis powered by renewable energy sources, such as wind or solar. There is considerable potential for future use of hydrogen is as an energy carrier and fuel, in addition to its use as a chemical feedstock (Bruce et al. 2018).

SMR is the process of converting methane to a synthesis gas consisting of CO, CO_2 and H_2 using steam as a reactant. The typical example of such a reactor is shown in Figure 11. Ideally, 1 tonne of H_2 results from an input of 4.5 tonnes of water and 2 tonnes of methane gas[77]. In practice, there are mass and heat transfer inefficiencies and coke deposition during the process. Without carbon capture, 1 tonne of H_2 requires an input of 3.8 tonnes of methane, and *with* carbon capture, this rises to 5.3 tonnes because of the additional energy required (Khojasteh Salkuyeh et al. 2017), which was the value assumed in our calculations.

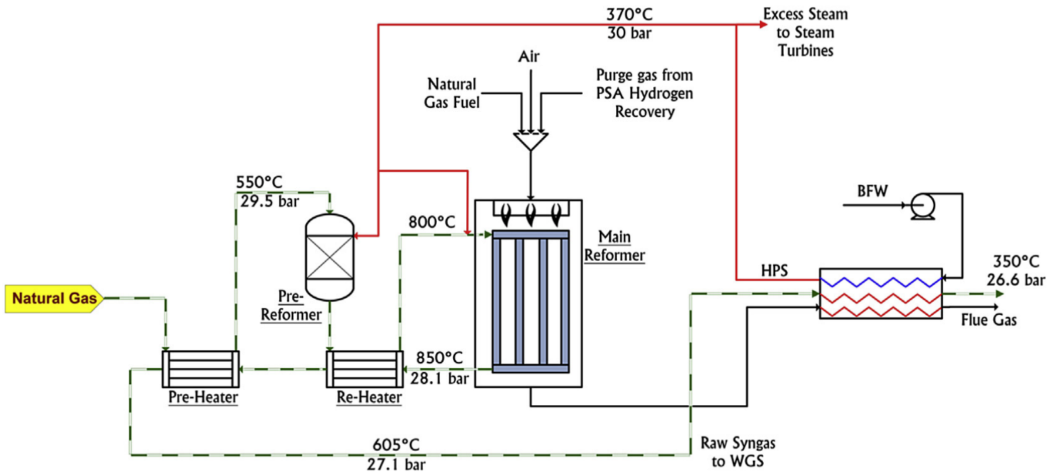

Figure 11 Schematic flow diagram of the SMR process from (Khojasteh Salkuyeh et al. 2017)

Other products of SMR feed into processing and manufacturing industries, for example, use of syngas for manufacturing fertilisers or basic chemicals such as methanol used in making paint and plastics (see Figure 12 on the next page). The use of methane in this way allows more control over flows for CCS in a contained, chemical engineering process.

The loss of methane in the controlled SMR process is negligible and the process involves high temperatures (700–1,000°C) and water inputs as steam. The typical thermal and electrical energy inputs are estimated to be 567kWh/tonne of H_2 and 316kWh/t H_2, respectively (Spath and Mann

[76] https://chemistryaustralia.org.au/news-events/statement_economic_benefits_of_gas_based_manufacturing_16_November_2020

[77] From the stoichiometry of the SMR and water shift reaction: https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming

2001). The emissions of a typical SMR plant are around 9 to 11kg CO_2e per kg of H_2 (Khojasteh Salkuyeh et al. 2017).

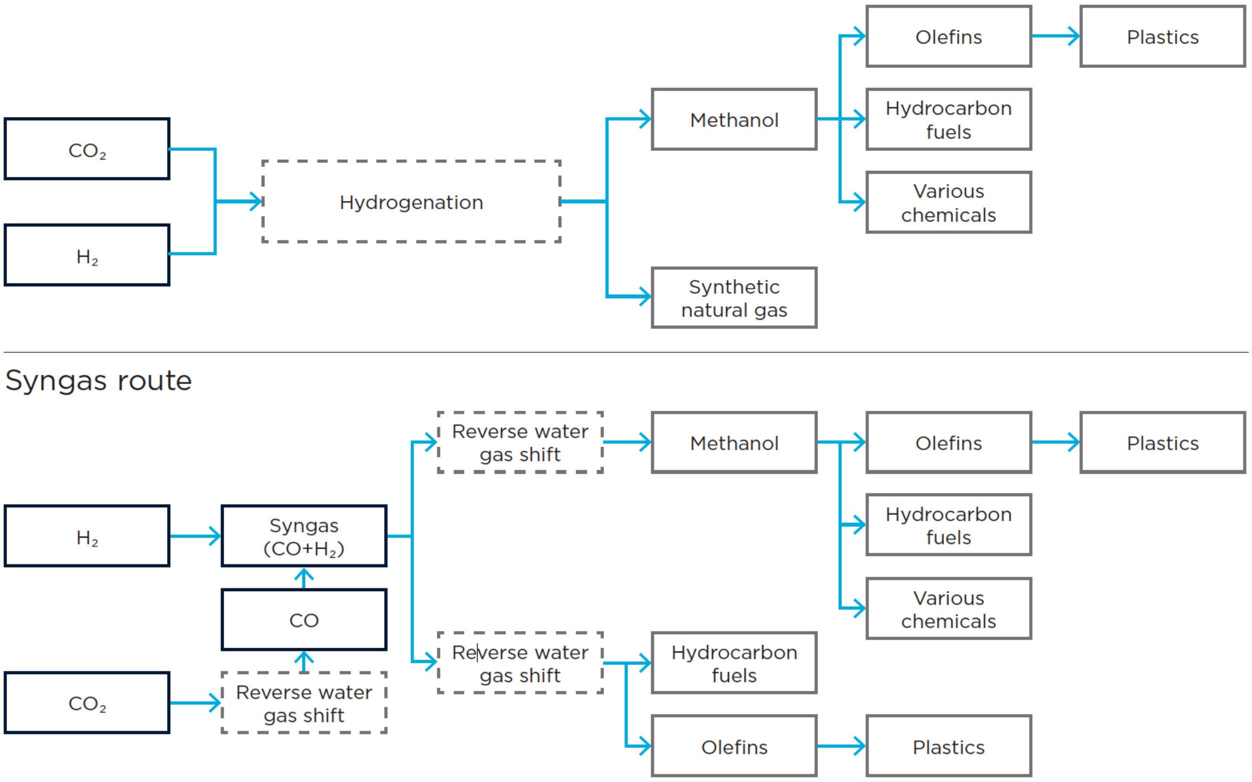

Figure 12 outputs of the SMR of natural gas can be transformed into basic chemicals through various processes

5.4.1 Maturity of technology and demonstrated effectiveness

SMR is currently the most widely used method for hydrogen production worldwide, responsible for nearly half of global production of approximately 90Mt H_2/year in 2020 (IEA 2021). Although 60% of global hydrogen production comes from natural gas, only 0.7% is coupled to CCS, which is important in this context for making 'blue' hydrogen.

There are variations of SMR and alternative processes. Autothermal Reforming (ATR) is a combination of SMR and combustion of the fuel (methane), where steam is added to the oxidation process[78]. The heat from the oxidation component supplies the energy required for the steam reforming and ATR involves less carbon/soot formation. ATR has relatively higher hydrogen yield and provides more flexibility in terms of process conditions, start-up time, and complex feedstock utilisation than SMR (Voitic et al. 2018). It is expected that this process will play an important role in future fuel processing industries though the production cost of ATR systems is higher than that of SMR because of the high purity oxygen consumed in the reaction.

[78] https://www.csiro.au/en/work-with-us/ip-commercialisation/hydrogen-technology-marketplace/autothermal-reforming-dry-or-steam

Methane pyrolysis[79] requires slightly higher temperatures (750-1200°C) and is a 'dry' process whereby the hydrogen is stripped from the methane leaving hydrogen gas and carbon as products. This can reduce the issue of CO_2 emissions but for every 100PJ of hydrogen produced, this results in approximately 3 million tons of solid carbon, which presents other resource management issues or opportunities. In Australia there is at least one company pursuing this technology though, at the time of writing, this was at the commercial pilot plant stage[80].

As part of the life-cycle CFP assessment, we looked at the emissions intensity of alternative gas products derived from gas, measured in GWP 100-year kg CO_2/GJ of gas input. Table 15 and Figure 13 show the impact profiles for the use of shale gas to alternative gas product destinations.

Of the six destinations we looked at for onshore shale gas, five of them involved the complete release of carbon embodied in the shale gas at some point in the production chain (assuming no CCS). For this reason, total emissions from those five destinations were relatively similar, ranging between 57 and 80kg CO_2e/GJ. The higher impacts of refinery products were due to the higher emission factor from diesel in use as well as the impacts of refinery production. Note the refinery production model is based on conventional crude oil inputs and may be lower when refining shale gas liquids. The scenario for methanol holds some of the carbon in the final product. Depending on the ultimate use of the methanol this may eventually be released to the environment.

Ammonia production had the highest impact due to energy inputs in the ammonia production process as well as the release of CO_2, which is liberated in that process. Note that in some circumstances this CO_2 is captured and used in urea production, however, this is only temporary storage as the carbon dioxide would be released when urea is placed on farms as a fertiliser (see Section 11.4 of the IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006)). Although it is possible to use methane to produce ammonia, it would defy the purpose of seeking less emissions-intensive uses for the shale gas. "Blue ammonia" coupled with CCS requires yet more energy[81].

[79] https://www.energy.gov/sites/default/files/2021-09/h2-shot-summit-panel2-methane-pyrolysis.pdf

[80] https://hazergroup.com.au/announcement/burrard-hazer-hydrogen-project-announcement/

[81] https://royalsociety.org/-/media/policy/projects/green-ammonia/green-ammonia-policy-briefing.pdf

Table 15 Climate change impact intensities for different gas uses (kt CO_2e/PJ shale gas input) from the CFP study (no CCS assumed).

	Raw gas extraction	Cleaned gas	Delivery to Darwin	Distribution/ shipping	Manufacture	Use	Total
Domestic use	4.0	3.9	1.0	1.5	-	47.1	57.5
LNG	4.0	3.9	1.0	0.9	3.5	46.4	59.6
H_2 SMR	4.0	3.9	1.0	-	48.1	-	57.0
Refinery	4.0	3.9	1.1	-	3.6	57.9	70.6
Methanol	4.0	3.9	1.0	-	13.6	-	22.5
Ammonia	4.0	3.9	1.0	-	71.4	-	80.2

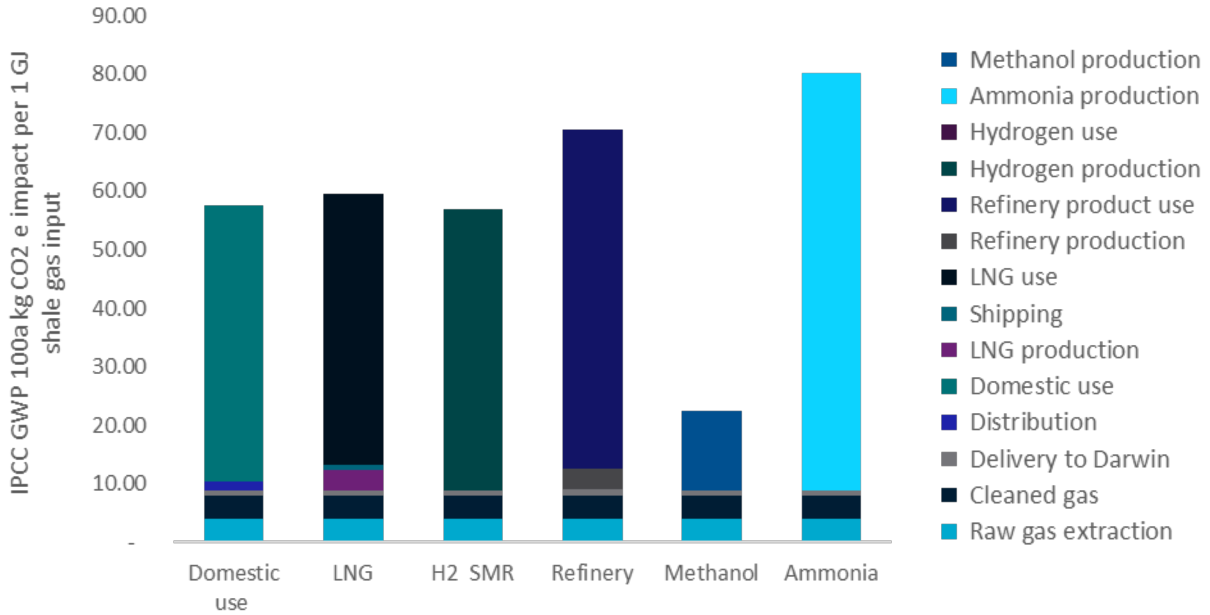

Figure 13 Comparison of 100-year GWP (kg CO_2e) climate change impact per 1 GJ shale gas input for different products.

The hydrogen production process was assumed to be SMR and results in Table 15 and Figure 13 do not include CCS. The reduction in GHG emissions intensity for hydrogen production *with* CCS can be seen in Figure 14.

Carbon capture was assumed to use monoethanolamine (MEA) and to be 90% effective, and no storage or utilisation impacts were included in the calculation. The energy data for carbon capture were taken from Salkuyeh, Saville and McLean (2017). The practicality of carbon storage and utilisation *after* capture, are discussed in more detail in Section 5.5.

Note that CCS is not a zero-emissions process itself. Figure 14 shows the impacts without carbon capture are 12.1kg CO_2e per kg H_2, and with carbon capture it is 6.4kg CO_2e per kg H_2. Although all

CO_2 emissions from the SMR reaction itself are captured, other life-cycle GHG emissions mean that there is only a 47% reduction in overall carbon footprint of hydrogen production.

For our scenario of hydrogen production, using 120PJ/year of shale gas as input (output of approx. 420,000 tonnes/year of H_2), the aggregate carbon footprint was 2.7 Mt CO_2e /year compared to the 6.2 Mt CO_2e /year from combusting 120PJ of shale gas.

From the LCA inventory used in the CFP calculations, 0.5 tonne of shale gas was required to produce 1 tonne of methanol. If 60PJ/year of shale gas (approx. 1.12Mt CH_4/year) were used to produce this basic chemical, the aggregate carbon footprint would also be 1.35Mt CO_2e /year.

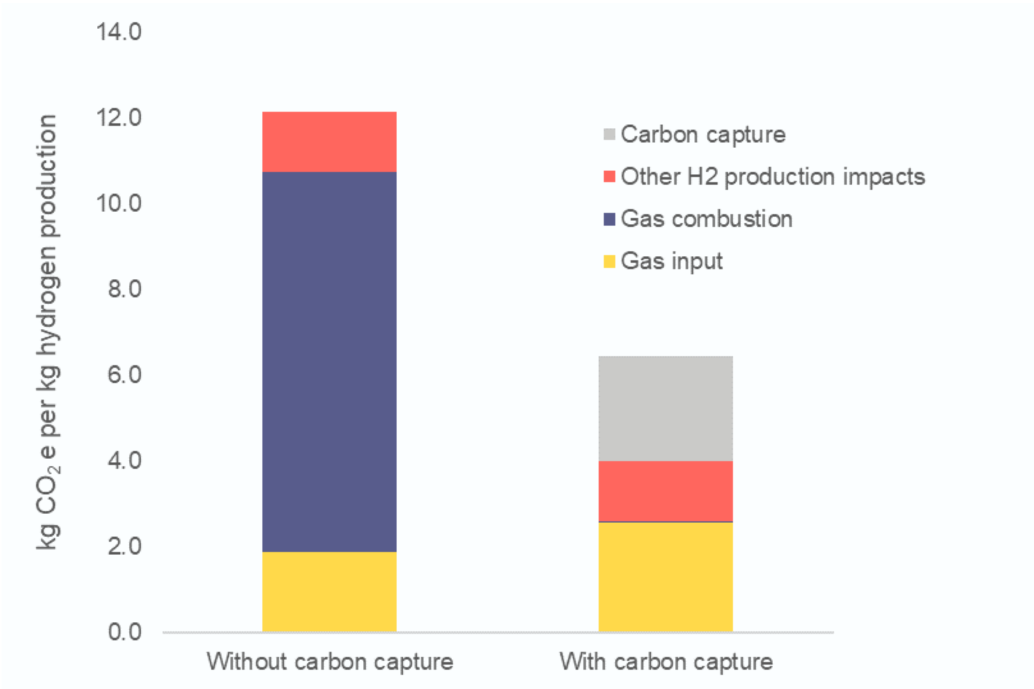

Figure 14 Impact difference between hydrogen production with and without carbon capture and storage.

5.4.2 Scale

SMR is an established process with commercial application at scale[82]. In fact, blue hydrogen production from SMR must be built at scale (i.e. > 500 tonnes/day) to offset the capital cost of the generation plant and accompanying CO_2 storage reservoir (Bruce et al. 2018). There are several international, and a few Australian hydrogen projects that use a fossil fuel source with CCS – refer to Table 16.

The assumed production of 450kt H_2/year in our scenarios is validated by existing projects where annual output of H_2 is the same order of magnitude, and especially for planned projects using natural gas with CCS that are a multiple of 5-8 times the size (see Table 16).

[82] https://www.energy.gov/eere/fuelcells/fact-month-may-2018-10-million-metric-tons-hydrogen-produced-annually-united-states

From our discussions with industry (Baynes 2021), a reasonable production *capacity* for an ATR process would be 1,500 tonnes H_2/day (0.55Mt/year). Noting that capacity is not the same as actual annual output.

As an example of a basic chemical, global methanol production in 2020 was just over 100Mt/year[83]. Analysis from the International Renewable Energy Agency (IRENA) and the Methanol Institute (2021) has predicted that global methanol production could grow to 500Mt/year by 2050.

Table 16 List of current of planned hydrogen production projects using CCS, from Hayward et al. (2020)

Project name	Country	Start date	Fuel	Estimated H_2 production (kt/year)	Estimated zero-carbon H_2 production (kt/year)
Port Arthur	US	2013	Natural gas	120	100
Wabash CarbonSAFE[1]	US	2023	Coal	105	80
HyDEMO	Norway	2025	Natural gas	220	130
H21 North of England	England	2028	Natural gas	3,200	3,010
H2morrow	Norway/Germany	2030	Natural gas	2,600	190
HESC	Australia	2030	Brown coal	280	255

Currently there are no operating methanol plants in Australia. There are, however, some proposed projects, which could transition to renewable methanol with scale-up of renewable hydrogen and CO_2 capture. Examples from p59 of Srinivasan et al. (2021).

- Wesfarmers, Coogee Chemicals and Mitsubishi announced in 2018 a prefeasibility study into a large-scale methanol plant in Burrup Peninsula, Western Australia producing 1.8Mt of methanol per annum, with a goal of bringing the plant online by the mid-2020s, if the companies decide to proceed.
- Coogee Chemicals announced in 2019 plans to conduct a feasibility study for a $500 million, 350,000t/per year methanol plant in Darwin.
- ABEL Energy announced in 2020 to explore development of Australia's first renewable methanol plant located in Bell Bay, Tasmania. The plant targets 60,000 tonnes of methanol per year with first production planned for 2023.

[83] Methanol Market Services Asia (2020) *Methanol price and supply/demand*. Viewed 3 May 2022, https://www.methanol.org/methanol-price-supply-demand/

The scenario of 60PJ of shale gas being directed to the production of ~2Mt methanol/year is at the outer edge of the scale of these projects but within the realms of possibility.

5.4.3 Longevity

Generally, industrial chemical plants such as SMR and methanol hydration are long-term investments. In a recent report for the Federal Department of Industry, Science Energy and Resources, the expected economic lifetime of SMR, ATR plant and also renewable technologies such as proton exchange membranes and alkaline electrolysis, was 25 years (Hayward et al. 2020). Blue hydrogen will also depend on the longevity of carbon storage options, discussed in section 5.5.

5.4.4 Quality of governance

Natural gas production, transport and transformation into other energy forms is regulated by the Australian Energy Regulator and, more locally, natural gas production and manufacture of derivatives, like methanol, would be regulated by the NT EPA.

The key enabler for blue hydrogen from fossil fuels in Australia is the certification of CCS as a valid means of sequestering CO_2. This came into effect in December 2021 as a 'methodology' in the Australian Government's Emission Reduction Fund[84].

Policy support for the Australian hydrogen industry is substantial with support for the rollout and development of regional hydrogen hubs across Australia[85,86]. The NT Government is developing the Middle Arm Sustainable Development Precinct and include hydrogen as one of the targeted sectors [87], and explicit support for gas manufacturing in the Darwin Export Hub area[88].

Although Australian hydrogen export is at a nascent stage, the Federal Guarantee of Origin Scheme[89] is also useful in certifying the provenance of blue or green hydrogen for export and the veracity of low- or zero-carbon claims. The scheme is intended to support a future trade in clean hydrogen by informing customers about the:

- emissions associated with the hydrogen they buy
- source and type of technology used in its manufacture.

5.4.5 Indicative cost and market

Low-carbon hydrogen (blue hydrogen) from shale gas with CCS has the potential to enter the market with only about 10 to 20 per cent higher costs than those of conventional 'grey' hydrogen (with no emissions abatement). This can initially provide low-carbon hydrogen at scale and,

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[84] http://www.cleanenergyregulator.gov.au/ERF/Choosing-a-project-type/Opportunities-for-industry/carbon-capture-and-storage-method

[85] https://www.dcceew.gov.au/energy/hydrogen

[86] https://research.csiro.au/hyresource/regional-hydrogen-hubs-program/

[87] https://invest.nt.gov.au/investment-opportunities/middle-arm-sustainable-development-precinct

[88] https://invest.nt.gov.au/key-sectors/energy

[89] https://www.cleanenergyregulator.gov.au/Infohub/Markets/guarantee-of-origin

according to the Hydrogen Council (2020): "*in cases where [natural gas] is most cheaply and easily available, … make hydrogen applications financially viable much sooner*." It may be expected that 'blue' hydrogen with CCS would become increasingly uncompetitive compared with other low-carbon hydrogen production methods[90] as the per unit cost of renewable electricity decreases (Graham et al. 2021; Advisian 2021), and the price of CO_2 emissions offsets likely increases towards 2050[91].

According to S&P Global (2020) the cost of making hydrogen using SMR with CCS is $US1.40/kg H_2 compared to current costs of green renewable hydrogen at $US4.42/kg H_2. Similarly, in Europe where planned hydrogen production is expected to equal half of global capacity by 2028, the current cost of making blue hydrogen has been estimated[92] at €2.00/kg H_2 whereas the production costs for green hydrogen are €2.50-5.50/kg H_2.

According to a CSIRO study of levelised cost of hydrogen to 2050 (Hayward et al. 2020), Australian production costs of blue hydrogen with 'off-grid' gas and CCS are already at or near the target level of $AUS2/ kg H_2, whereas green hydrogen currently is costed at $AUS4.75/kg H_2. With various improvements from economies of scale and learning-by-doing, green hydrogen could be competitive (below $2/kg H_2) by around 2040 – refer to Figure 15.

The market for blue hydrogen projects of the scale we are referring to is a hydrogen export industry, which is an explicit intent in developing hydrogen and gas hubs in Australia's north. Between Korea and Japan alone there is expected to be a demand greater than 15Mt H_2 per year by 2050. There has been a recent demonstration of Australian hydrogen exports, albeit hydrogen produced from the gasification of coal[93].

Blue hydrogen may be used in the production of other basic chemicals, such as methanol. In this case, hydrogen production is a major cost driver, accounting for approximately 60% of the total levelised cost of methanol production (Srinivasan et al. 2021). If blue hydrogen can be used at $AUS2/kg, then the levelised cost is $AUS582/tonne of methanol. If the cost of hydrogen input to methanol production were $AUS4.30/kg then the levelised cost is $AUS1396/tonne of methanol. For comparison, since the mid-1990s, methanol has had an average contract price that has fluctuated between approximately $AUS290 to $AUS580 per tonne (Srinivasan et al. 2021; IRENA and the Methanol Institute 2021).

[90] https://www.strategyand.pwc.com/m1/en/reports/2020/the-dawn-of-green-hydrogen.html

[91] https://www.afr.com/policy/energy-and-climate/carbon-offset-credits-set-to-soar-on-net-zero-ambitions-20220110-p59n7n

[92] IEA (2019) Hydrogen report (page 42), and based on IEA assumed natural gas prices for the EU of 22 €/MWh, electricity prices between 35-87 €//MWh, and capacity costs of €600/kW quoted in https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf

[93] https://www.hydrogenenergysupplychain.com/

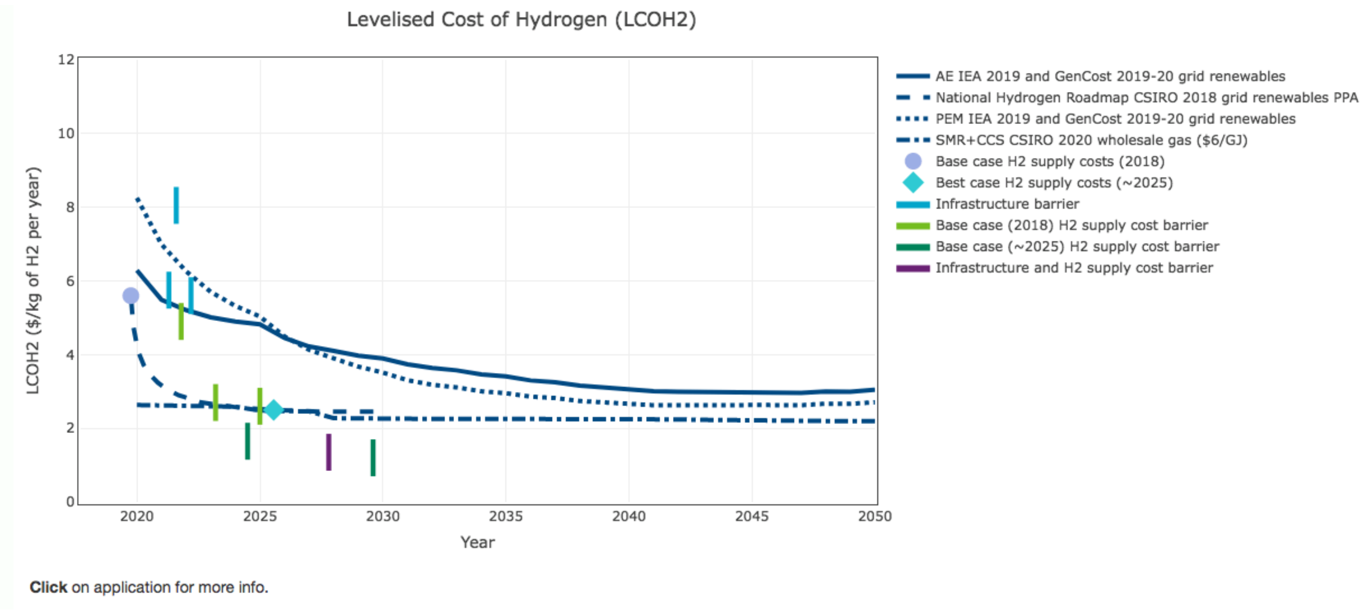

Figure 15 Levelised cost of hydrogen production through various technologies over time. The current cheapest way to make 'blue' hydrogen is SMR with CCS shown by the dot-dash blue line. Taken from https://research.csiro.au/hylearning/tools-and-resources/H_2-cost-comparison/ (viewed 22 June 2022), based on Figure 9 of the CSIRO report: *Towards H2 under 2: Costs and barriers to low emission hydrogen production* (Hayward et al. 2020).

5.5 Carbon capture use and storage

CCS covers a range of processes and technologies, some of which are at an early stage of development, but some have been implemented effectively at large, production scale. The differences between existing and prospective CCS technologies, and the range of possible end-uses for CO_2 arising from onshore shale gas in the NT, combine to give a multiplicity of potential CCS options. This needs a much more detailed analysis than we can provide here, and indeed, there is a dedicated project (CSIRO 2021), which is specifically about the viability of a large-scale Low Emission Carbon Capture Utilisation and Storage (CCUS) Hub, based on Darwin's Middle Arm. See also Fitch et al. (2022) for a more detailed discussion of geological storage of CO_2.

Captured CO_2 can be used for a number of different applications, some of which may result in permanent storage, others may have application for emissions avoidance technologies, such as low emissions fuels using CO_2 captured from air combined with hydrogen generated by electrolysis from water. Permanent solutions include geological storage.

In 2021 the CER developed a methodology for enabling projects using geological storage of captured CO_2 to generate ACCUs. The first of these projects to be registered under the new methodology is the Moomba project in the Cooper Basin, operated by Santos. The Moomba project is scheduled to begin injection in 2024. Several direct air capture[94] projects utilising geological storage are in development at the same site.

In the following we provide a global overview of the current status of CCS technologies (excluding any biological or land use management-based options discussed in Section 5.3) and some considerations in assessing whether and where a CCS technology may be significant in the NT onshore shale gas context.

Current global CCS of CO_2 is nearly 40Mt/year (Turan et al. 2021). CCS technologies currently deployed in a production setting, at scale, mainly involve capturing CO_2 from an extracted natural gas stream, and injecting that CO_2 into a geological formation for long-term storage or sequestration. CCS technology is well established in situations where the CO_2 has found a subsequent economically beneficial use for enhanced oil recovery (EOR). Here, CCS becomes a form of CCUS. EOR usage has a long record of deployment at scale in North America, and its continuing dominance of CCS globally is apparent in Figure 17, though there has been an increase in dedicated geological sequestration of GHGs in the last 3 years.

The geological formations suitable for storage are either depleted former petroleum or gas reservoirs, or saline aquifers. Saline aquifers are deep sandstone reservoirs which contain non-potable salty water and no hydrocarbons. Saline aquifers are large, porous and permeable containers, vertically sealed by low permeable mudstones which prevent vertical migration. The ultimate suitability of such formations will depend on detailed geological and geochemical analysis specific to each individual site.

According to a Geoscience Australia report quoted in Fitch et al (2022) there is an estimate storage capacity of "*227Gt for saline aquifers and 6.5Gt for depleted oil and gas reservoirs, for a total of*

[94] Direct air capture refers to the extraction or removal of carbon dioxide from air using an engineered device and the provision of the carbon dioxide product at the required purity to a storage facility (Fitch et al 2022).

233.5Gt. An estimate for feasible sequestration for 2035 can be provided by summing projects under development which is 24Mt per year at a cost of between $14 to $35 per tonne."

Figure 16 shows the location of the Beetaloo Sub-basin (in red) relative to sedimentary basins assessed by Geoscience Australia for their broad potential as CO_2 sequestration. Immediately to the west of Darwin is the Boneparte basin that is rated as "highly suitable" by Geoscience Australia and separately by CSIRO (Stalker et al. 2020), which may connect with the NT Low Emission Hub mentioned above.

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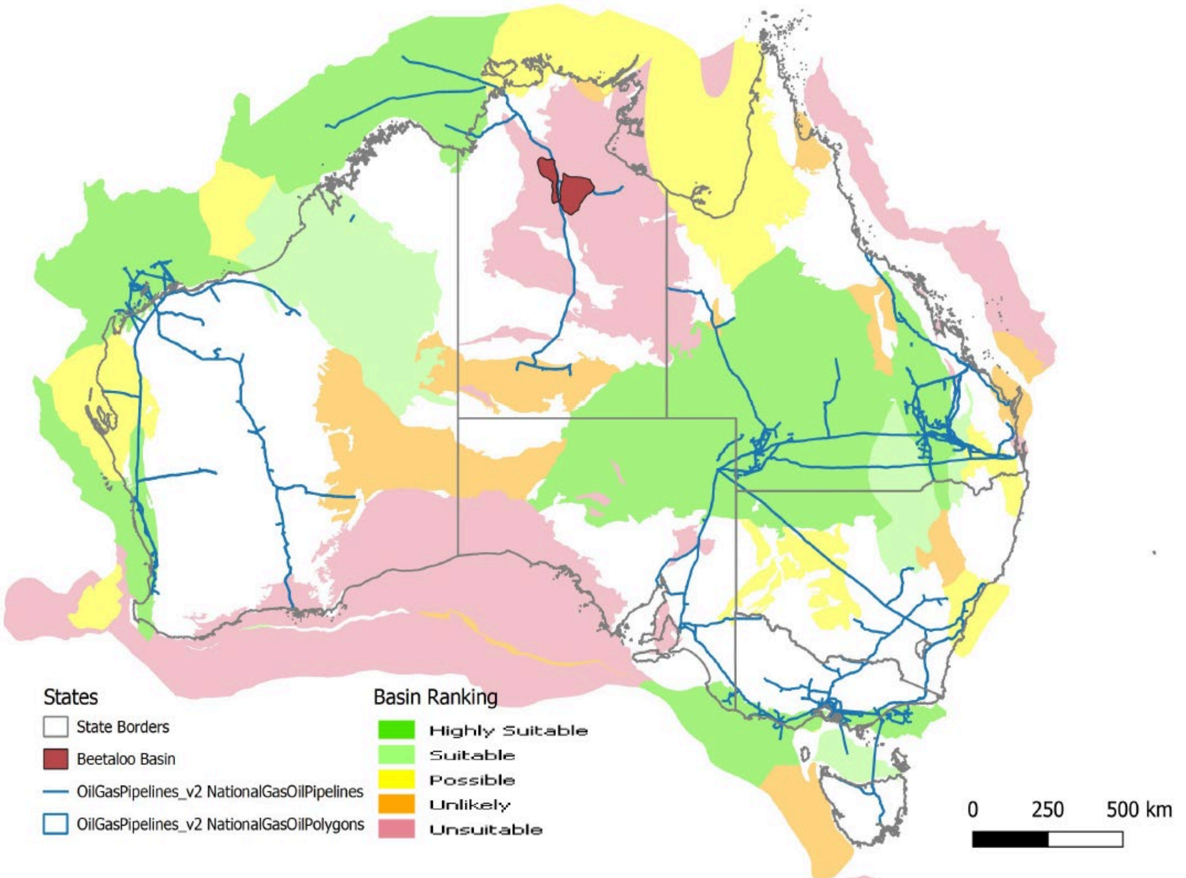

Figure 16 location of basins for CCS relative to Beetaloo Sub Basin (in red) and existing oil and gas pipelines (blue). Data from Geoscience Australia (2017, 2022)

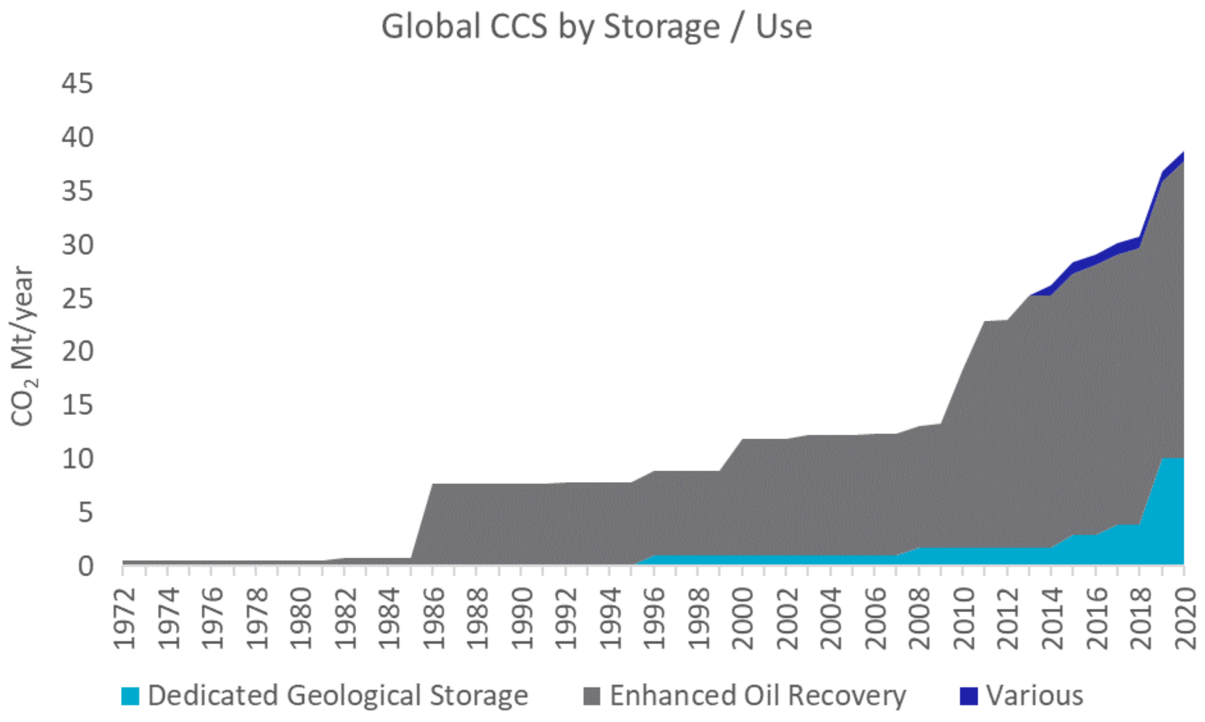

Figure 17 Operational CCS/CCUS by storage type or use. Data sourced from Appendix 5.1 of (Turan et al. 2021)**. Suspended or decommissioned CCS facilities excluded.**

5.5.1 Concentrated CO_2 streams from onshore shale gas end-use available for CCS

Here we estimate the CO_2 *potentially available* for CCS from different onshore shale gas end-use scenarios. This requires CO_2 capture technology to provide a source of CO_2 at the appropriate rates, volumes and composition required for each particular end-use or manufacture in Table 15, for the different scenarios in Table 3. This is a simplistic calculation as few technologies are greater than 90% efficient in CO_2 capture, and there are inherent losses in any industrial process. The purpose here is to derive first-order estimates of potentially available CO_2 flows. The potential for geological CCS is moderated by the proximity and flow capacity of existing or planned capture operations.

Table 17 Direct CO_2 emissions amenable to CCS associated with different scenario use streams (Mt CO_2/year)

Scenario name	Domestic combustion[1]	Refinery products[2]	LNG for export[3]	Methanol [4]	Ammonia [5]	Hydrogen [6]	Total
Sc1 Dom. gas & LNG	2.12	-	1.12	-	-	-	**3.24**
Sc2 Dom. gas, LNG & refinery	2.12	-	0.70	-	-	-	**2.82**
Sc3 Dom. gas, LNG & chemicals	2.12	-	0.70	-	2.72	-	**5.54**
Sc4 Dom. gas, LNG & hydrogen	2.12	-	0.70	-	-	5.77	**8.59**
Sc5 All	2.12	-	2.54	-	2.72	5.77	**13.15**

1. Assumes 45PJ of gas is used in utility powerplants or other direct combustion in large-scale industrial applications amenable to post combustion capture from large, concentrated, exhaust streams. Capture expected to be zero for residential and commercial cooking, heating etc.
2. Not assessed: unclear what concentrated CO_2 streams would be produced.
3. According to Table 14 in Grant (2022), the main direct CO_2 emissions are from combustion in the liquefaction and storage process, or flaring of waste natural gas. This does not include any downstream use, or combustion, of exported LNG.
4. Methanol production assumed to have no direct CO_2 emissions to air.
5. Ammonia production involves approximately 1.46t CO_2 per 0.6t raw gas input with 60PJ of methane corresponding to 1.12Mt of raw gas input (at 53.6GJ/t).
6. Note that over 90% of natural gas used in SMR is combusted (see Table 15 in Grant (2022)).

5.5.2 Maturity of technology or demonstrated effectiveness

CCS of CO_2 from natural gas extraction, processing and liquids refining

CO_2 removal is a routine component of natural gas processing. Long-term expertise developed from decades of CO_2 transport, injection and monitoring in EOR fields are applicable to geological storage and demonstrates the maturity of the technology. Large-scale geological sequestration of CO_2 stripped from extracted natural gas has been deployed as part of the Gorgon project in WA[95], designed to store 3.4 - 4Mt CO_2e/year in a deep saline geological formation (technical challenges have limited storage rates during the start-up of this project).

Given the low CO_2 content expected for gas extracted from Beetaloo[96], the capture of CO_2 from natural gas processing is likely to be of limited relevance to NT onshore shale gas. The capacity to directly reduce CO_2 from refinery production also appears to be very limited. This is due to a

[95] https://www.dmp.wa.gov.au/Petroleum/Gorgon-CO2-injection-project-1600.aspx

[96] CO2 content of 3% is cited in (Tamboran Resources 2021), and 0.9% at Kyalla for a liquids rich prospect – see https://resourcingtheterritory.nt.gov.au/oil-and-gas/onshore-exploration.

combination of the concentration of GHGs in the final products and their end usage, and the lack of (identified) consistently large CO_2 capture points in the refinery processes.

CCUS in hydrogen and basic chemical production

Other than natural gas processing, more than 10Mt/year of *captured* CO_2 is used as industrial feedstocks globally – see Figure 19. Data in Turan (2021) indicates total global operational CCS of around 3.8 Mt of CO_2/year from global hydrogen production in 2020[97]. This was split between three projects, all in North America and mainly from SMR. The oldest of these was commissioned in 2013. It is understood that CCS following a process of converting natural gas to hydrogen is the premise of Santos' planned operations at Moomba where it is expected that 1.7Mt CO_2/year can be stored through CCS[98]. Although it uses coal as feedstock, the Hydrogen Energy Supply Chain project uses geological sequestration and, when commercial aims to "reduce global emissions by 1.8Mt/year"[99].

There are various technologies that utilise captured CO_2 in industrial chemicals production (see Figure 18 and Figure 19), including the use of CO_2 as an input to manufacture of basic chemicals, building materials and liquid fuels. However, many of these delay the release of CO_2 rather than permenanently sequestering it. Uses such as building materials may provide long-term storage but are currently not proven at scale and have not been considered further.

[97] If the hydrogen in syngas for fertilizer and synthetic natural gas operations is included as hydrogen production, the figure for current operational CCS from hydrogen production arguably more than doubles to 7.9 Mtpa.

[98] https://www.santos.com/wp-content/uploads/2022/02/Fact-sheet_Hydrogen.pdf and https://www.afr.com/companies/energy/santos-books-co2-disposal-capacity-20220208-p59ums

[99] https://www.hydrogenenergysupplychain.com/report-successful-completion-of-the-hesc-pilot-project/

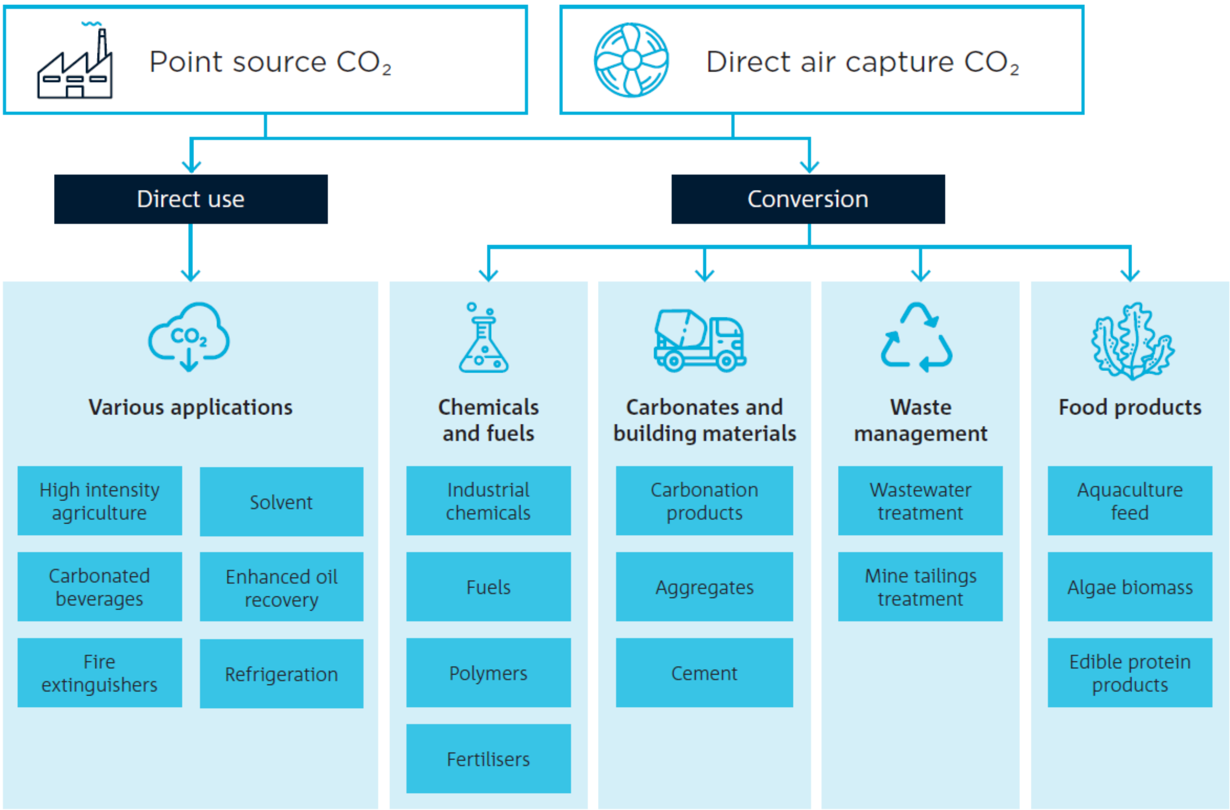

Figure 18 Various paths of CO_2 utilisation after capture and enrichment (Srinivasan et al. 2021)

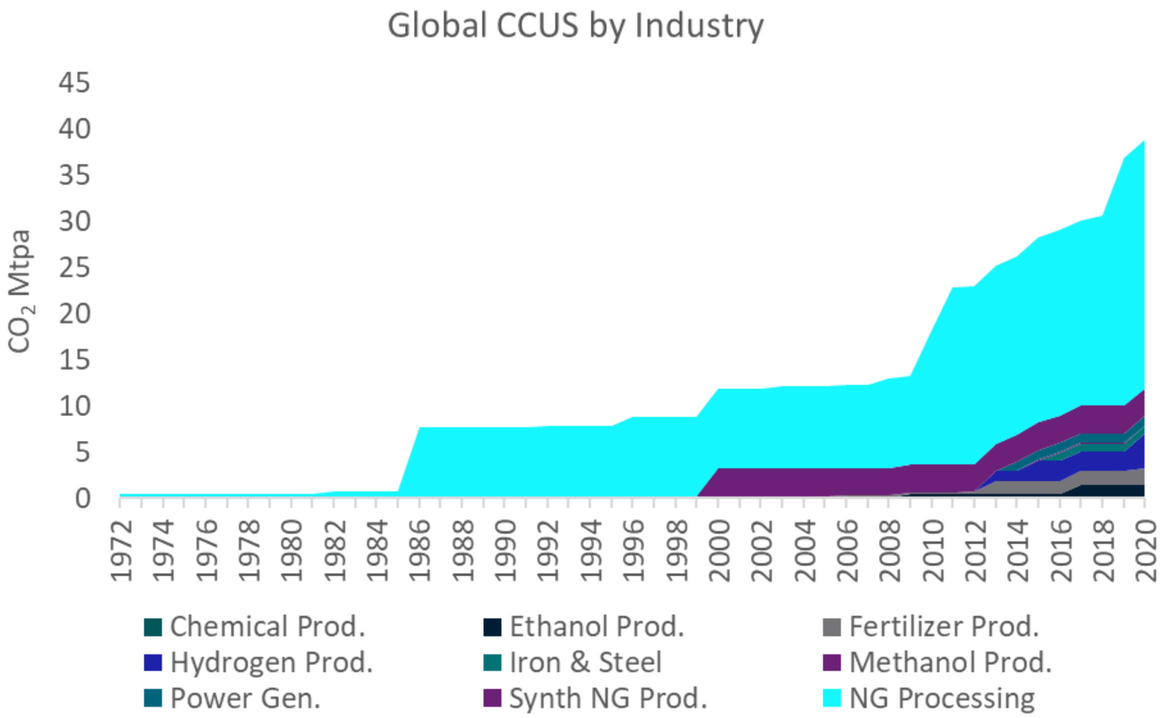

Figure 19 Operational CCS/CCUS by industrial facility type. Data sourced from Appendix 5.1 of (Turan et al. 2021)**. Suspended or decommissioned CCS facilities excluded.**

CCUS from post combustion of natural gas

A currently operational CCS post combustion capture (PCC) project from power production has a capacity of one Mt CO_2/year. The power plant (Boundary Dam 3 in Canada) is coal-fired, and so not directly analogous to use of Beetaloo gas for domestic power generation. It is, however, of interest as the only example of PCC connected to a currently operational CCS from a fossil fuel power plant given in Turan (2021).

While PCC for CCS projects are relatively recent and have limited development, Abu-Zahra et al. (2016) makes clear that PCC of CO_2 for subsequent commercial use of CO_2 is long established, giving examples going back to the 1970s. That work lists five main technology families for CO_2 capture from gas streams more generally: absorption, membrane technology, adsorption, cryogenic technique and chemical looping. They then expand on four examples of different proprietary absorption PCC technologies which had been commercially deployed at the time of their writing. These include the Shell-Cansolv aqueous amine-based capture system deployed at Boundary Dam, which is designed to attain up to 90% capture of CO_2 from the exhaust stream. The other three commercially deployed systems described had demonstrated CO_2 capture rates for single installations to over 100kt/year, and in at least one case had been used on a gas rather than coal-fired power station.

Solvent based technologies were also assumed for carbon capture in the LCA (see Section 5.4.1). Operational plants are listed in (Turan et al. 2021) and solvent based technologies and pathways for further development are discussed in detail in (Oko et al. 2017). Table 18 provides an indication of how variants on solvent technology have been used in large-scale capture in the most important applications.

Table 18 Solvent technology deployed in large-scale carbon capture

CO_2 Capture context	Status
Capture of CO_2 content from natural gas processing / conditioning / LNG	Commercially deployed at scale > 5Mtpa for 30+ years (Shute Creek, since 1986). Amine solvent based. More recently non-amine solvent based SELEXOL, > 5Mt CO_2/year scale (Century Plant, since 2010)
Post combustion capture (PCC) of CO_2 from power stations	Single commercially deployed example at scale of 1 Mt CO_2/year (Boundary Dam, since 2014). Second > 1Mt/year installation at Petra Nova (suspended operations). Both amine solvent based
Capture of CO_2 from production of hydrogen / syngas	Commercially deployed at scale of 3Mt CO_2/year (Great Plains Synfuels, since 2000). Methanol solvent based (Rectisol process)

Any portion of NT onshore shale gas used for utility scale electricity generation should produce relatively large and concentrated CO_2 streams. These would potentially be amenable to similar capture technologies to that already demonstrated at one Mtpa scale at the Boundary Dam 3 (coal-fired) power station in Canada. It is important to note that no PCC operation we have discussed captures more than 30% of the emissions from their corresponding fossil fuel power station. This informs the later assumptions we make about potential PCC from domestic use of onshore shale gas.

Domestic use of gas in smaller scale applications, for example most other industrial, commercial and residential domestic uses, generally have no demonstrated, ready to deploy options for direct capture at scale, and so should probably be assumed to require offsetting.

Mineral carbonation

Mineral carbonation is a form of geological storage of CO_2 that involves the reaction of CO_2 with basic minerals to form solid carbonates, a process that occurs in nature as rock weathering (Fitch et al. 2022). It is particularly effective with ultra-mafic rocks. The industry is at an extremely early start-up stage[100]. In alignment with the assessment of Fitch et al (2022) that feasibility of these projects to abate GHG emissions is unknown mineral carbonation is not used as an option in the Synthesis Section.

5.5.3 Scale

Geological CO_2 storage is typically available in natural-gas-rich regions, as depleted oil and gas fields make good storage areas. The main parameters that decide the feasibility of a formation for CCS are containment, capacity, and injectability (Fitch et al 2022). Deep geological formations are the main mode of storage for new projects planned for Australia in the near term, listed in Turan (2021) and include WA's north-west shelf, Bass Strait and north-eastern South Australia where Moomba is located (Figure 16). It may be possible that CCS at these locations capture and sequester CO_2 in excess of the emissions of local industrial processes, for example, through direct air capture. The estimate from the Fitch et al (2022) is that there could be an available flow rate of 24Mt /year in 2035 and > 50Mt /year at 2050. These figures are for projects around Australia (onshore and offshore), and we select only geological storage that would be available to emissions from processing, manufacture and use of onshore shale gas in the NT (see next section).

The Petrel Sub-basin, part of the Bonaparte Basin, immediately to the west of Darwin is rated as highly suitable and there is pre-existing pipeline infrastructure. The reservoirs have a large maximum CO_2 storage capacity of 15,900 Mt (Consoli et al. 2014) though not all of that is necessarily viable to access (Stalker et al. 2020).

The main scale constraint is the possible flow rate, which is determined by infrastructure such as pipelines), rather than the stock of geological space to store CO_2. From conversations with industry (Baynes 2021), we understand that the Bayu Undan capacity is rated to be commercially viable for at least 265Mt, which translates approximately to 10Mt CO_2/year flow capacity over at least the 25 year accounting lifetime that is used for assessing carbon credit schemes. There are offshore gas projects in Northern Australia, with gas processing at Darwin, which may expect to use 5.5Mt/year[101] of that flow rate capacity before any would become available for emissions

[100] See for example https://www.mineralcarbonation.com/

[101] This figure is an aggregate derived from several separate conversations with industry sources.

from a new onshore shale gas project. This may be dependent on the conditions of "newness" in the CCS methodology of the ERF – see Section 5.5.5.

Additional storage capacity may become available through time. The Australian Government has recently awarded assessment permits for offshore areas for CO_2 storage through an acreage release, including an area in the Bonaparte Basin[102]. Further acreage releases are planned.

5.5.4 Longevity

The longevity of CO_2 storage is comparable to the time scales for accumulation of hydrocarbons and is of the order of millions of years (Fitch et al, 2022). The Intergovernmental Panel on Climate Change (2005) suggests that a successful project would retain 99% of stored CO_2 for at least a thousand years. This is supported by further research of natural accumulations of CO_2 (Fitch et al 2022).

The longevity of capture infrastructure will be consistent with that of gas processing plant, SMR, PCC technologies.

5.5.5 Quality of governance

CCS has recently been added as a method for emissions abatement under the ERF in Australia and there are specifications in the NGER (Measurement) Determination 2008 – revised July 2021 (Commonwealth of Australia 2021).

The CCS method requires that any CO_2 captured and stored is derived from a new GHG source, whether that will:

- Involve GHGs generated from an industrial process, which would be a new GHG capture point. For GHGs extracted from a hydrocarbon field, this will be a new hydrocarbon field.
- Be undertaken under either the Offshore Petroleum and Greenhouse Gas Storage Act 2006 or a law or legislative framework that meets the criteria to be a recognised law of a State or Territory, as set out in the CCS method.

The Gorgon CCS project has now stored over 15Mt of CO_2. The WA State Government requires annual reporting from Chevron but there was no condition of capturing and storing carbon that prevented extraction and sale of LNG.

5.5.6 Indicative cost and market

CO_2 separation from raw natural gas streams, either prior to direct sale or processing into LNG, is often a routine and necessary processing step, along with the separation of other acid gases, notably H_2S. Given this, the boundary at which "capture" costs should be attributable to CCS, prior to transport and storage, may not be clear cut. Notwithstanding this, one range estimate for the capture cost from natural gas processing can be inferred from a study of levelised cost of CCS

[102] https://www.industry.gov.au/news/2021-offshore-greenhouse-gas-storage-acreage-release-assessment-permits-awarded

across countries, and in US energy and carbon-intensive industries. The lowest cost applications for CCS include natural gas processing (Irlam 2017).

Using Table 1 from Irlam (2017), total CCS cost of $US21.50 per tonne, and subtracting their transport and storage estimates of $US7 to $US12 per tonne, gives a capture cost of $US9.5 to $US14.5/t CO_2, for the USA. Assuming that capture costs scale proportionally with total CCS costs for different regions and technologies, this translates to a corresponding estimate for Australia in the range: $US12 to $US18/t CO_2. One industry source has said that once CO_2 is in the dense phase, the actual cost to get that gas into the ground is ~$AUS 5-10/tonne including the cost of construction and decommission. Total cost per tonne of CO_2 once you have dehydrated it and got to a pressure of 50Mpa is more like the $AUS30/tonne, which is similar to "full life cycle" costs quoted for the Moomba CCS project[103]. The CarbonNet Project estimates that the total cost to compress, transport CO_2 from industries in the Latrobe Valley to offshore storage sites in Bass Strait is between $AUS30 to $AUS50 per tonne of CO_2 for sectors where CO_2 is separated as part of business as usual (Filby and Harkin 2019).

For PCC from power stations, the separation of CO_2 from exhaust gases into a concentrated CO_2 stream is typically a step that is only performed to avoid emitting CO_2, so the additional process costs are entirely attributable to CCS. There was only one large-scale deployment of PCC on a power station operational at the time of writing (Boundary Dam) with costs of capture in the range of $US105-$US115/t CO_2 (GCCSI 2019). A newer large-scale PCC deployment (Petra Nova) with a cost of capture in the range $US62 - $US72/t CO_2, was operational, but subsequently suspended. Both of these operations are in North America, with the cost structures that entails. The lower costs of Petra Nova are broadly comparable to the range of $US43 - $US76/t CO_2 for PCC from a super-critical coal power generator and $US31 - $US82/t CO_2 for natural gas-fired combined cycle (NGCC) plant calculated from data in Irlam (2017)[104]. Scaling proportionally for Australia, the NGCC cost range would be $US57 - $US147/t CO_2.

Costs of CO_2 capture from five different options applied to SMR production of hydrogen were calculated in Collodi et al. (2017). The options covered were expected to capture 50% - 90% of the CO_2 generated in the process. The costs per tonne of CO_2 captured range from 37 - 60 Euros per tonne[105]. This equates to around $US42 - $US68 at the average exchange rate at 2017. There are no costs given directly for SMR (Irlam 2017), however, costs for capture from fertiliser production (less transport and storage) would lie in the range $US12 - $US19 (in USA). This much lower range may indicate cheaper capture of CO_2 from syngas via the ATR route.

Separate to the *process* costs of different CCS options, are the transport costs, and specifically the capital expenditure (capex) of building pipelines to connect sources of CO_2 with CCS injection and

[103] Actual quote "*We forecast a full lifecycle cost of less than US$24 per tonne of CO2 including cash costs in operation of US$6-8 per tonne of CO2, with first injection targeted for 2024*" from https://www.santos.com/news/santos-announces-fid-on-moomba-carbon-capture-and-storage-project/

[104] The lower estimates in the ranges derived here from Irlam (2017) take the lower total CCS cost of later plants and subtract their upper transport and storage component ($US11), while the upper estimate takes "first of a kind" plant cost and subtracts the lower transport and storage component ($US7)

[105] This capture cost is inferred from values in Collodi et al's table 6 for CO2 Emission Avoidance costs, less their figure in table 2 of 10 Euros per tonne for the Transport and Storage component. It can also be inferred from Collodi et al's table 6 that the entire CCS process would add between 18%-45% to the levelized cost of H_2 produced, at a CO_2 price of zero.

storage facilities. The costs will depend on the proximity of the injection facility to the source, and the pipe diameter required for the volume of CO_2 to be transported.

The costs and indicative market for mineral carbonation have not been considered (see section 5.5.2).

5.6 International Schemes

We have to consider the possibility that the collective carbon mitigation and abatement options presented earlier may not be sufficient to offset the life cycle GHG emissions from the scenarios of onshore shale gas. There are a number of international offset schemes that we understand are now approved within the Federal Climate Active Scheme (consequent of a review[106]). These include: the United Nations (UN) Clean Development Mechanism (now the Sustainable Development Mechanism); the Verified Carbon Standard or Verra and; the Gold Standard schemes.

UN Clean Development Mechanism[107]

The UN Clean Development Mechanism (CDM) was developed under Article 12 of the Kyoto Protocol in 1997, and allowed trading of carbon credits from 2006. It was the first global, environmental investment and credit scheme to provide standardised, emissions offsets, and has a governance structure within the United Nations Framework Convention on Climate Change (UNFCCC) that covers methodologies and accreditation. It is being super ceded by the 'Sustainable Development Mechanism' under the 26th UN Climate Change Conference of the Parties (COP26) Paris Agreement.

A country with an emission reduction or emission-limitation commitment under the Kyoto Protocol (Annex B Party) could implement a project in developing countries that reduced CO_2 emissions. These projects could be renewable energy projects and could earn saleable certified emission reduction (CER) credits, each equivalent to one tonne of CO_2e. A CDM project activity could be, for example, a rural electrification project using solar panels or the installation of more energy-efficient boilers. A CDM project must provide emission reductions additional to what would otherwise have occurred.

Based on observations of over-supply and estimations to 2020[108], the cost per tonne of CO_2e abated for CERs from CDM projects ranged between $AUS2-$AUS10 with a midpoint around $AUS5/t. Historically, the CER market has been prone to instability[109], and may remain so, though in the present, post-Paris-Agreement era, there may be a heightened global demand for CERs.

[106] https://www.climatechangeauthority.gov.au/sites/default/files/2022-03/Review%20of%20international%20offsets%20consultation%20paper.pdf

[107] https://cdm.unfccc.int/index.html see also the more recent Climate Neutral Now Initiative https://unfccc.int/climate-action/climate-neutral-now

[108] https://www.climatechangeauthority.gov.au/reviews/using-international-units-help-meet-australias-emissions-reduction-targets/availability-and

[109] https://voxeu.org/article/collapse-clean-development-mechanism

Existing CDM projects can transfer to the Sustainable Development Mechanism by 2025, subject to meeting the criteria for new methodologies, and can only be credited to countries' targets in the period to 2030. CERs already issued under the CDM may continue to be used towards countries' targets, provided the project was registered after 2012 and certain other conditions are met. However, the CDM will cease to register, renew or issue CERs for post-2020 emissions reduction activities.

Verified Carbon Standard (VCS)[110]

Verra claims to be the World's largest voluntary offset program and within the VCS Program, Verra's role is to administer, develop and provide operational oversight. Once certified against the (VCS) Program's rules and requirements, project developers can be issued tradable GHG credits for one tonne CO_2e abated, referred to as a Verified Carbon Unit (VCU). VCUs can then be sold on the open market and retired by individuals or companies as a means to offset their own emissions.

New large-scale renewable energy projects are no longer eligible under voluntary offset standards administered by Verra (or Gold Standard), except where carbon finance is required. VCS projects can include small-medium scale renewable energy (such as wind and hydro-electric projects), and forestry (including the avoidance of deforestation). Validated and certified emission reductions are issued with one VCU representing one metric tonne of GHG emissions reduced or removed from the atmosphere.

Validation of a carbon offset project is through auditors known as validation/verification bodies (VVBs) that are mostly private companies. There are currently about 20 VVBs over 5 continents.

Contrary to the trend prior to 2018, in the last two years demand has outstripped supply of VCUs[111], and the historical price range of $US3 - $US5/tonne CO_2e, is unlikely to persist and could be between $US20 - $US50/t CO_2e by 2030 (World Bank Group 2020).

Gold Standard[112]

Gold Standard is a not-for-profit organisation established in 2003 by the World Wide Fund for Nature Inc (WWF) and other international NGOs and now headquartered in Geneva, Switzerland. Their governance structure includes financial and strategic oversight by a board, a secretariat that sets standards and several technical groups focused on credible measures of impact. Gold Standard has two senior advisers based in Australia, and at least one Australian project has been certified with Gold Standard[113].

Gold Standard advocates for prices of carbon credit to more closely mirror the true social cost of carbon and the economic value provided in additional impacts. While all Gold Standard-certified projects include emissions reduction, they also use a value-driven model to set a price for carbon

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[110] https://verra.org/project/vcs-program/

[111] https://www.mycarbon.co.uk/blog/should-carbon-be-new-gold

[112] https://www.goldstandard.org

[113] https://www.goldstandard.org/blog-item/first-australian-project-earns-gold-standard-certification

credits to truly account for the full environmental, social and economic impacts of a specific project. Current cost/tonne of CO_2e abated vary greatly because clients of Gold Standard may choose to support socioeconomic outcomes as part of their offset value price. Their minimum price is calculated based on the Fairtrade carbon credit pricing model[114] at between €8 and €13/t CO_2e.

[114] https://www.fairtrade.net/standard/minimum-price-info

6 Synthesis and Discussion

Given the range of offset options, each with a different ability to abate GHG emissions in different ways, there is a need to synthesise these with corresponding shale gas production and consumption scenarios. Based on input from stakeholders in the scoping exercise, some qualitative aspects of offset options were used to determine their inclusion as a matter of priority.

We do not have a view on the temporal nature of what offsets might be available when, or in what quantities. Given the existing market for Australian land-based and other offsets, it would be difficult to provide such options, of at least 6.6Mt CO_2-e/year, for a potential onshore shale gas project in the NT starting in the next two years. On the other hand, there is usually a ramp up period to production, and mitigation and CCS options could be available from the start. To the extent that annual emissions associated with any of our scenarios exceed the potential to mitigate or offset those emissions in Australia, one option is to use international offsets early in a gas project. Another option would be to commit to more mitigation and/or offsets later.

6.1 Priority

In terms of the jurisdictions where new gas development and GHG emissions would occur, these will appear on the account for the NT (certainly those due to production activities). It is also the NT that will experience any environmental disturbance or other disruptions from new gas developments.

More broadly, the in-scope GHG emissions from production *and Australian consumption* are a national responsibility according to methods in international emissions accounting – refer to IPCC Guidelines Volume 1.1 (IPCC 2006) with 2019 refinements (IPCC 2019).

As noted earlier, the quantity of emissions from a development of shale gas resources in the Beetaloo Sub-basin is large and it would be expected that the total cost or value of abatement would also be substantial. In the first place, it is in the interests of the NT to develop the carbon market in the Territory and cycle the expense of offsetting GHGs from any production of new gas resources back into the local economy.

This is related to another consideration in prioritising offset options: quality of governance and the degree of regulatory control, consistent metrics and management of GHG offsets. In Australia there is the ERF, ACCU, the National Carbon Offset Standard, The Carbon Market Institute, The Indigenous Carbon Industry Network, and Climate Active[115] among other institutions.

Therefore, in this report we prioritise offset activities initially available in the NT and Northern Australia. If the NT could not provide enough annual GHG emission offsets alone, then the next level of priority would be options from elsewhere in Australia. Only after all domestic options have been exhausted are international offset options considered.

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[115] https://www.climateactive.org.au/

Some land-based offset options could have co-benefits to domestic communities and business, and sustainable environmental management. Thus, another level of prioritisation concurs with the *Northern Territory Offset Principles* (Northern Territory Government 2020):

"…*outcomes must generally be delivered in the Territory and be designed to deliver environmental, and wherever possible social, benefits in the affected region and to the communities impacted*."

There is a priority, across all scenarios, to include offset options in Northern Australia that engage Aboriginal and Torres Strait Islander peoples. Although the available abatement may be small, savanna fire management is considered in all scenarios.

Of lowest priority are the international offsets, where payment for GHG emissions abatement effectively represents an imported service to Australia unless a particular project, under an international scheme, is actually based in Australia.

6.2 Annualised offset requirements and implementation

In Table 8 we showed the results of the CFP for the 25-year lifetime GHG emissions for the different scenarios (based on 100-year GWP). To synthesise these results with possible offset options, we looked at the annualised version of these results (Table 19). Subsequently, we first applied the mitigation potential of Table 11 and Table 12 to the different production stages of the scenarios. Of the remaining emissions bill, we then applied the offset options of Section 5, according to the scope and priorities outlined above. A further priority was given to the use of CCS ahead of land-based or other offsets as it links more closely with the technical production of basic chemicals, hydrogen and possibly gas-powered electricity. The CCS options discussed in Section 5.5 are also largely being developed by the gas industry that would also be responsible for any development of onshore shale gas (the quantities of Table 19 are less than those found in Table 9.4 of the *Scientific Inquiry* (p228) for similar production scenarios of 365PJ/year. The scenarios in the *Scientific Inquiry* assumed all the shale gas was consumed in Australia – no LNG exports).

Without definite data on future supply *and* demand of offsets, key assumptions were made regarding the possible use of land-based offsets and CCS available in Australia for the specific abatement of emissions from NT onshore shale gas.

There is a high degree of uncertainty also in the availability or cost of obtaining Australian offsets due to issues of land access, social licence to operate, future carbon pricing and possible future legislative changes. The complex interaction and effect of these influences cannot be prospectively quantified. Consequently, we use estimates of how much (per cent) of the available mitigation and offset options could actually apply to emissions from NT onshore shale gas.

We assume that 10% of the annual feasible potentially available land-based offsets at a carbon price of $AUS30/tonne CO_2e in Table 13, could be used, and 30% of *additionally* available offsets from fire management in Northern Australia (30% of (6.16Mt/year – 1.46Mt/year) = 1.41Mt/year).

Furthermore, we assume that *up to* 4.25Mt CO_2/year is available through CCS but only for direct, captured CO_2 emissions in PCC, hydrogen or basic chemical production. This figure is based on half of the available flow of 14Mt CO_2/year less the use of CCS by other industry discussed in Section 5.5.3.. There is certainly more potential geological CCS capacity and the availability and regulation of Australian CCS is a highly dynamic space, with CCS offset methods having changed during the writing of this report. Notwithstanding this, the emissions that could be captured in scenarios 1-4 do not exceed 4.25Mt CO_2/year.

Given the examples and costs of PCC in Section 5.5.6, we assume only 20% of the 45PJ used in domestic consumption, could have PCC associated with CO_2 emissions from natural gas-powered electricity (approximately 20% of 2.3Mt CO_2e/year). This implicitly assumes some retrofitting and PCC attached to any replacement gas-powered electricity generators. For perspective, in the North American example of a facility built with PCC, this figure is 30%.

Table 19 Annualised GHG emissions for scenarios and different stages of onshore shale gas production and consumption in Australia, and total annual offset requirement. All measures in Mt CO_2e/year

	Gas production	Transmission	Manufacturing	Domestic use	Total annual emissions
Sc1 Dom. gas & LNG	2.9	0.3	1.1	2.2	**6.6**
Sc2 Dom. gas, LNG & refinery	2.4	0.2	1.7	9.1	**13.5**
Sc3 Dom. gas, LNG & chemicals	2.9	0.3	5.8	2.2	**11.2**
Sc4 Dom. gas, LNG & hydrogen	2.9	0.3	6.5	2.2	**11.9**
Sc5 All	8.5	1.0	14.5	9.1	**33.0**

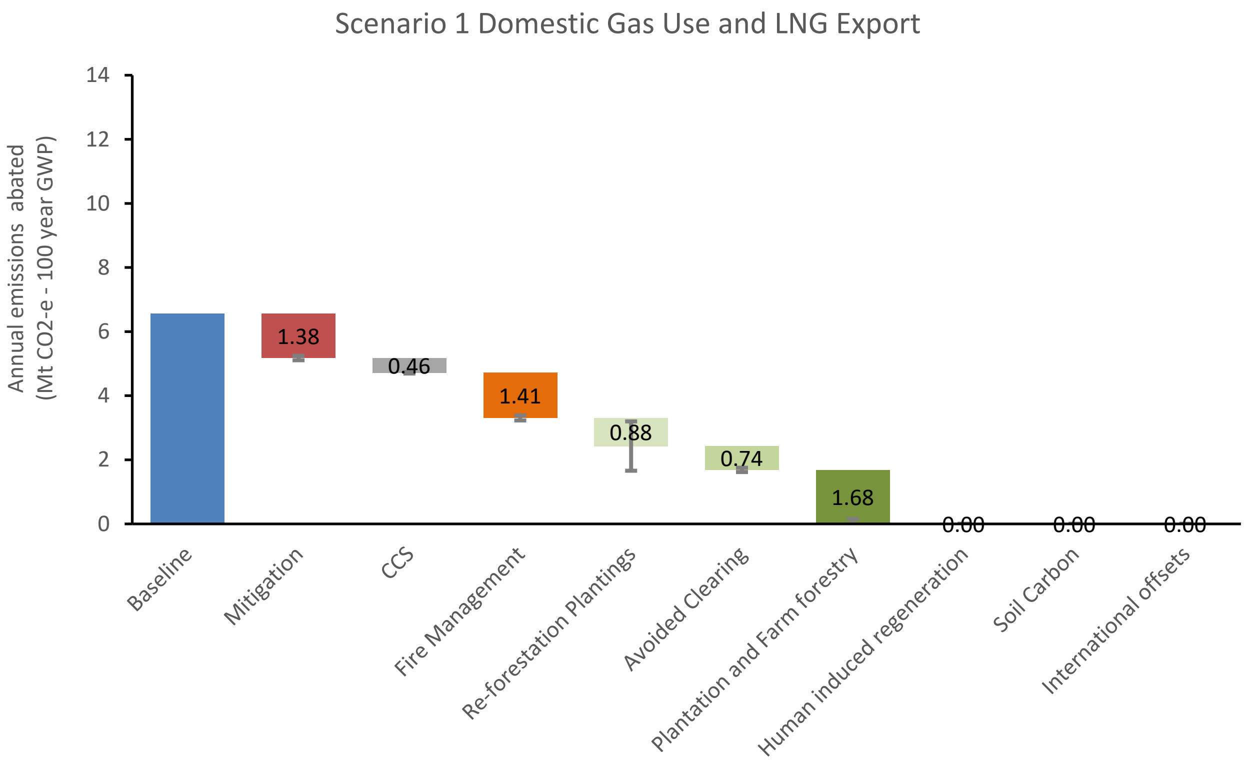
Table 20 scenarios of annual life-cycle GHG emissions with application of options to completely offset the 100-year global warming impact- based on a carbon price of \$AUS30/t CO_2e, assumed values, uptake or physical limits discussed in the text.

Scenario name	Baseline (100-year Mt CO_2e/year)	Mitigation (Mt CO_2e/year)	Carbon capture and Storage (Mt CO_2e/year)	Fire management (Mt CO_2e/year)	Re-forestation: avoided clearing & managed regrowth (Mt CO_2e/year)	Avoided clearing (Mt CO_2e/year)	Plantation and Farm forestry (Mt CO_2e/year)	Human-Induced regeneration (Mt CO_2e/year)	Soil carbon (Mt CO_2e/year)	International offsets (Mt CO_2e/year)
Notes	Annualised Results from Table 8	Solar power implemente d as in Table 11 and Table 12	Assumes up to 4.25Mt/year for capture from PCC, SMR and basic chemicals	30% of additional 4.54Mt/year abatement & sequestration [116]	Assumes 10% of annual new available offsets nationally	Assumes 10% of annual new available offsets nationally	Assumes 10% of annual new available offsets nationally	Assumes 10% of annual new available offsets nationally	Assumes 10% of annual new available offsets nationally	Remainder of offset bill
Sc1 Dom. gas & LNG	**6.6**	-1.38	-0.46	-1.41	-0.88	-0.74	-1.68	0.00	0.00	0.00
Sc2 Dom. gas, LNG & refinery	**13.5**	-1.16	-0.46	-1.41	-0.88	-0.74	-3.06	-3.27	-1.82	-0.73
Sc3 Dom. gas, LNG & chemicals	**11.2**	-1.38	-2.89	-1.41	-0.88	-0.74	-3.06	-0.88	0.00	0.00
Sc4 Dom. gas, LNG & hydrogen	**11.9**	-1.38	-3.51	-1.41	-0.88	-0.74	-3.06	-0.90	0.00	0.00
Sc5 All	**33.0**	-4.05	-4.25	-1.41	-0.88	-0.74	-3.06	-3.27	-1.82	-13.56

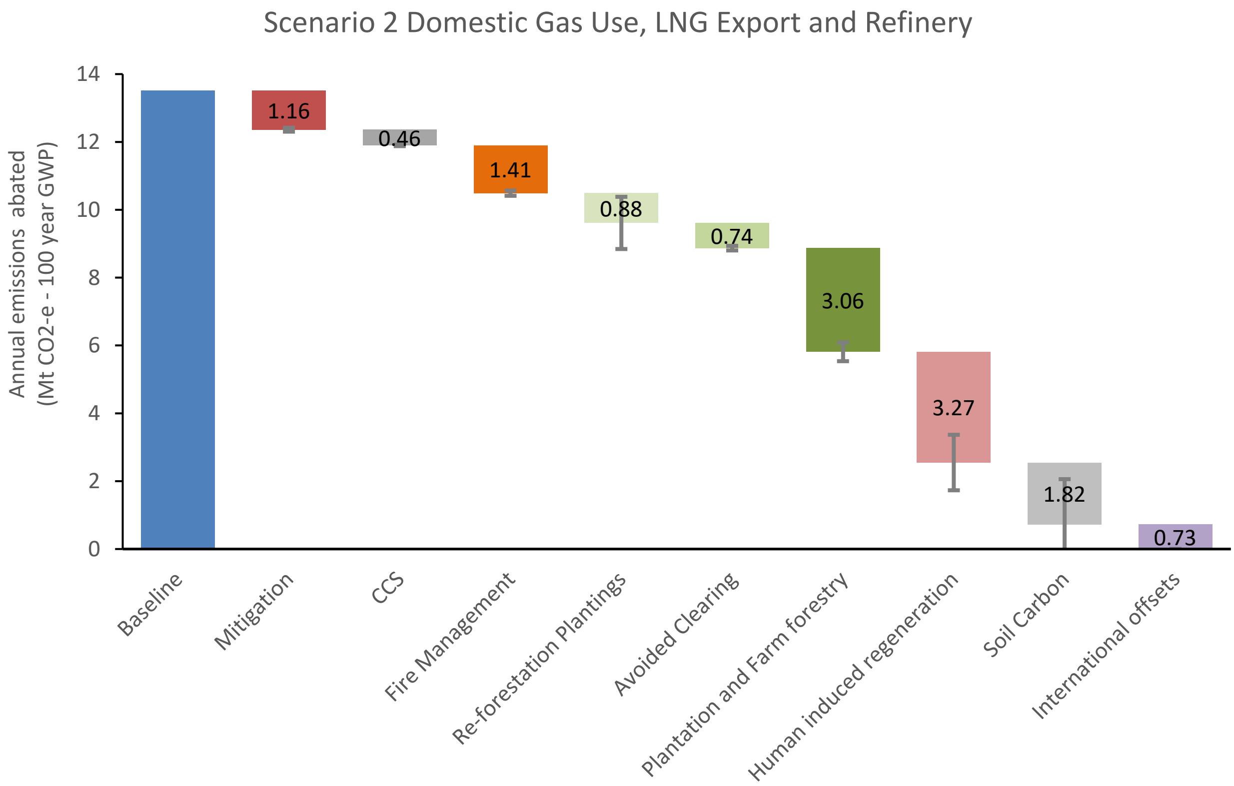
[116] Includes additional 0.22 tCO2-e/ha/year sequestration in carbon stocks, such as woody biomass like mulga (Burrows 2014).

Figure 20 life-cycle annual GHG emissions for all scenarios (a-e) with application of options to completely offset the 100-year global warming impact

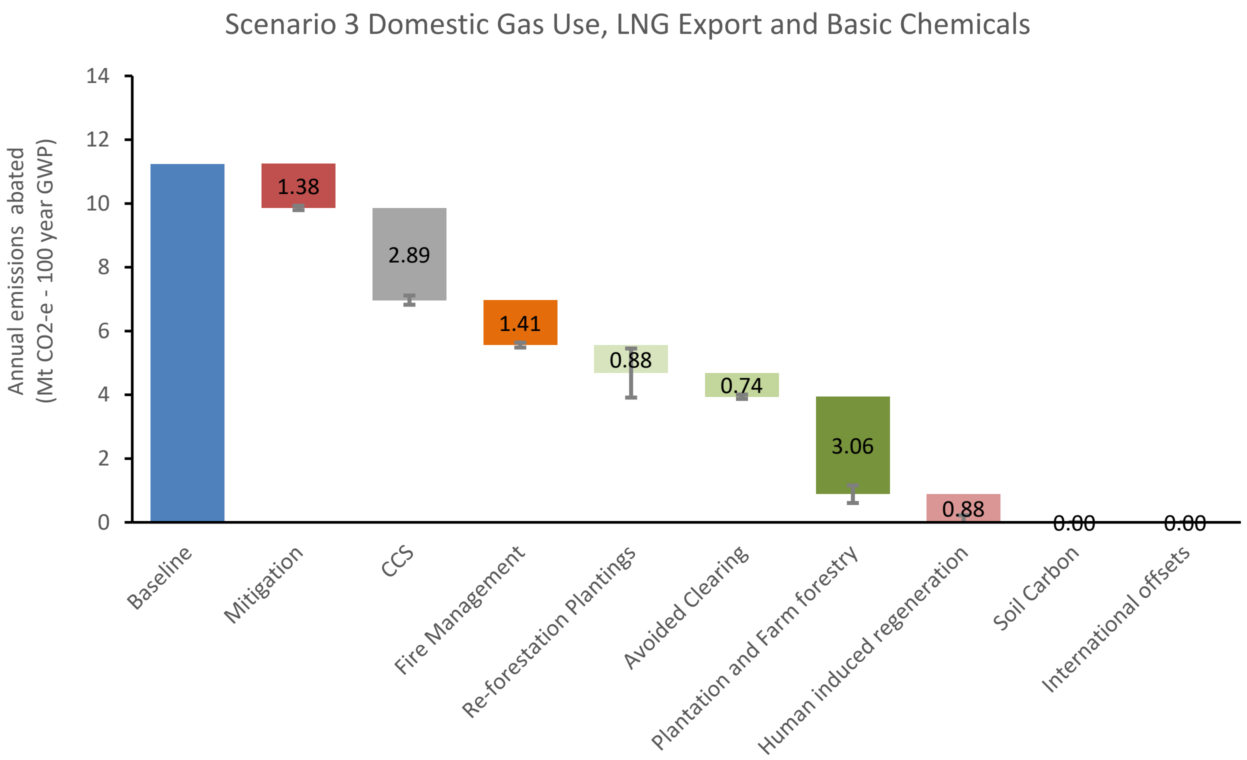
a)



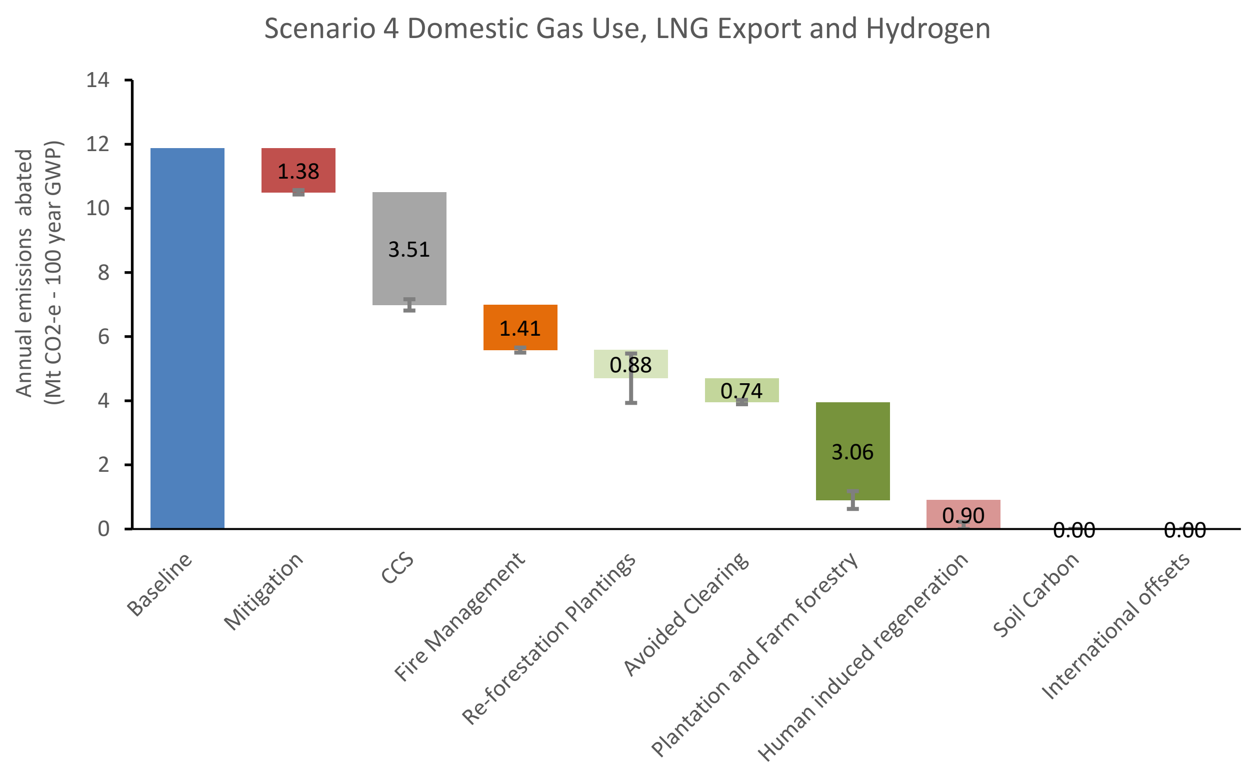
b)



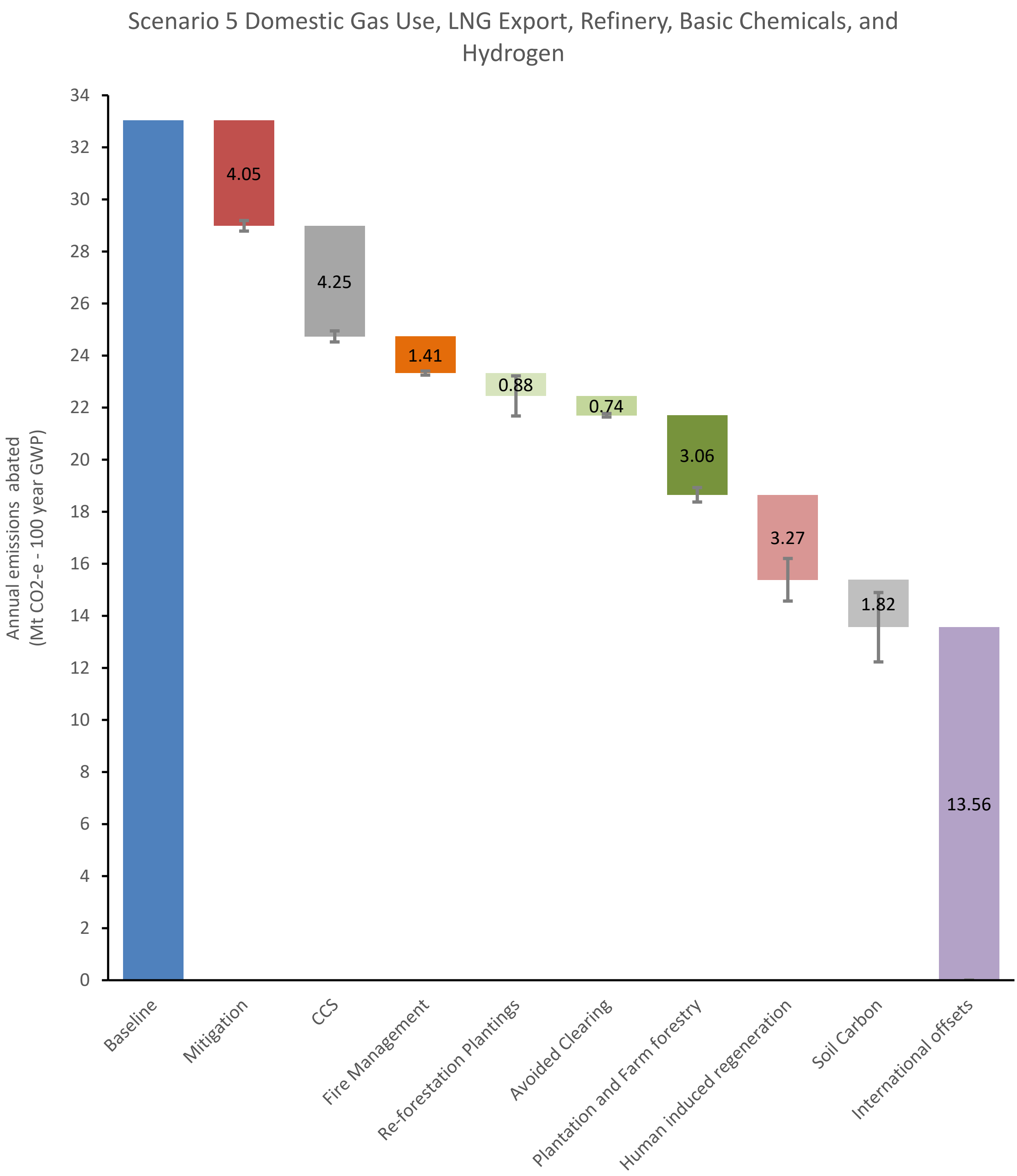
c)


Scenario 3 Domestic Gas Use, LNG Export and Basic Chemicals
Annual emissions abated
(Mt CO2-e - 100 year GWP)
14
12
10
8
6
4
2
0
1.38
2.89
1.41
0.88
0.74
3.06
0.88
0.00
0.00
Baseline
Mitigation
CCS
Fire Management
Re-forestation Plantings
Avoided Clearing
Plantation and Farm forestry
Human induced regeneration
Soil Carbon
International offsets

d)


Scenario 4 Domestic Gas Use, LNG Export and Hydrogen
Annual emissions abated
(Mt CO2-e - 100 year GWP)
14
12
10
8
6
4
2
0
1.38
3.51
1.41
0.88
0.74
3.06
0.90
0.00
0.00
Baseline
Mitigation
CCS
Fire Management
Re-forestation Plantings
Avoided Clearing
Plantation and Farm forestry
Human induced regeneration
Soil Carbon
International offsets

e)



6.3 Discussion

For the four scenarios of 365PJ/year production, the majority of GHG emissions can be abated with offsets available in Australia. If we include the mitigation activities during production in the NT, the CCS based out of Darwin, and savannah fire management offsets in Northern Australia, more than 7Mt CO_2e/year (+/- 5%) of mitigation and abatement could be sourced from that region.

Between 79-156Mt of land-based offsets are available elsewhere in Australia, enough to offset *all* the life-cycle emissions from *all* scenarios. But we have assumed in Section 6.2, that 10% of that could be available for an onshore shale gas project. The assumed proportion of land-based offsets that our scenarios of NT onshore shale gas consume, was a deciding factor in how many residual emissions needed to be accounted for with international offsets. If onshore shale gas from the NT were to absorb a larger fraction of the supply of Australian land-based or other offsets, it could perturb the domestic carbon market and drive up the price for a tonne of CO_2e abatement. Such a dynamic market analysis was out of scope for the present project, but would be a worthwhile sensitivity investigation.

For three scenarios of 365PJ/year of onshore shale gas, no international offsets were needed. In this case, gas was largely flowing to LNG exports. In the scenarios where the total CFP was larger, the need for international offsets was greater. This was not a linear relationship because of the physical limit of Australian offset options.

Mitigation and CCS are less significant in scenarios where we have anticipated a refinement of liquids from the shale gas (see Figure 20 b) and e)). It is to be acknowledged that the assumed refinery processes from the CFP are from oil refining, and this may lead to an over-estimation of the GHG emissions to offset.

CCS is used in a greater proportion of offsets where industrial chemical reactions occur to enable controlled capture of CO_2 from SMR, methanol or ammonia production. How much CCS flow capacity could actually become available would depend heavily on the development of CCS technology at unprecedented scale. There is also the likely competition onshore shale gas would face with other emissions-intensive activities, for use of CCS abatement.

Domestic CCS could also have the potential to reduce emissions associated with domestic use and hydrogen production. SMR and pyrolysis operate at high temperatures and consume natural gas in the process of transforming it. It is not known whether substituting in a renewable power or heat source is technically feasible but that could reduce emissions and lead to a more effective use of gas in manufacturing other chemical products.

The potential to impact the total emissions of exported LNG depend on the mode of final use and CCS arrangements in the importing country. We assume no Australian producer, consumer or government has control over this, though an important concept in mitigating downstream scope 3 emissions is 'Extended Producer Responsibility.' This would entail selecting gas consumers who, themselves, are seeking to offset their carbon footprint or who are using LNG in production with carbon capture or without combustion

We should acknowledge that there is an unexplored opportunity cost absent in this report: how else might we use Australian land-based offsets and CCS rather than abating the impact of onshore shale gas, which would otherwise maintain or add to cumulative GHG emissions. As we have deferred any cost–benefit analysis, we also leave any analysis of opportunity cost to a further study.

7 Conclusion

The key objective of this project was to seek feasible mitigation and options to offset life cycle GHG emissions, emitted in Australia, corresponding to scenarios of onshore shale gas extraction in the NT. These scenarios explicitly reference the potential development of the Beetaloo Sub-basin. This report contains a set of scenarios of production, and domestic (Australian) consumption in accordance with the 'life cycle' scope of Recommendation 9.8 from the *Scientific Inquiry into Hydraulic Fracturing in the Northern Territory* (2018). As for GHG emissions, the mitigation and offset options considered are also scenarios constrained by current knowledge of available technologies and their maturity, scale, longevity, governance and indicative costs.

We defined the conceptual and physical scopes to include upstream gas extraction activities, downstream transformation of gas to LNG or other gas products, and any domestic consumption, but not emissions from the consumption of exported LNG. This set the system boundary for a life-cycle carbon footprint (CFP) assessment of GHG emissions according to the ISO 14044 Standard.

The levels of methane and other fugitive emissions in production of gas is a valid question but one that is poorly informed by LCA studies from operations in other countries where fugitive emissions have been less regulated or not regulated at all, and especially for projects where natural gas may be an 'associated gas' by-product from extracting hydrocarbon liquids.

We have been guided by research from other regions where onshore shale gas has been developed and, aware of Australian regulatory standards, we have assumed lower values in the range of internationally observed shale gas fugitive emissions.

Otherwise, the LCA study has taken engineering parameters and information from: The AUSLCI databases; the Ecoinvent life cycle inventory database V3.7; National Greenhouse Account Factors; National Greenhouse Inventory Reports; methods on natural gas production used in the NGER Scheme; the IPCC Guidelines Volume 2 Chapter 4.2 with 2019 refinements and; industry reports and experts.

The LCA study calculated the CFP for the production, supply and use of all proposed shale gas products from the NT Beetaloo Sub-basin between 2025 and 2050. Four scenarios looked at a production level of 365PJ of shale gas per year, each differentiated by separate end-uses of gas in: LNG, refinery products, basic chemicals and hydrogen production. A compound scenario considered a 'high' production of 1,130PJ/year that incorporated all of these end-uses and 725PJ/year of LNG exports. Total lifetime emissions relevant to the lifetime mitigation and offset task specified in Recommendation 9.8 for the first four scenarios had a range of 164-338 Mt CO_2e with 826Mt CO_2e for the high production scenario.

Results indicate that the GHG emissions intensity for the scenario with liquids-rich gas that needs refining may make it more difficult to offset than for dry gas scenarios. Our assumptions about the liquids component of the resource are consistent with recent industry reports on the results of exploratory drilling in the Kyalla Shale within the Beetaloo Sub-basin. Production of hydrogen and basic chemicals from shale gas enables the use of CCS but both processes involve higher carbon footprints than LNG production.

These emissions impacts were annualised and compared to available mitigation, CCS, land-based and international offset options. Offset options were prioritised to cycle the cost and value of offsetting emissions back into the Australian economy and preferably the northern Australian economy. Some offsets may have local socioeconomic benefit additional to their immediate environmental effect.

There are many dimensions to the sustainability questions of development of onshore shale gas in the NT. We have been conscious to limit our scope to being primarily an engineering study though we have assessed offsets on aspects of technical development and effectiveness, scale, longevity, quality of governance and indicative cost of mitigation and abatement options.

Before considering any offsets, the LCA study identified potentially 1.38Mt CO_2e/year could be mitigated in the upstream production and manufacture of onshore shale gas.

Although substantial, ultimately, the amount of annual Australian land-based emissions offsets available is physically limited (regardless of a price on carbon).

CCS is at a nascent stage of development in Australia, though there are depleted basins close to Darwin that are rated as 'highly suitable' by Geoscience Australia, and they have the advantage of pre-existing pipeline infrastructure. In the scenarios considered CCS connects most effectively with the production of basic chemicals and hydrogen from shale gas, which we have assumed to be part of the Clean Hydrogen Industrial Hub or Low Emission CCUS Hub planned for the Darwin industrial area.

Synthesising the CFP results and offset options we find that GHG emissions from the lowest impact scenarios were able to be completely mitigated or offset within Australia. All other scenarios required international offsets to some degree. For three of the four production scenarios of 365PJ/year, all emissions could be mitigated or offset with Australian options. The exception was the scenario of co-production of liquids involving refining. For the 'high' production scenario 13.56Mt CO_2e/year of GHG emissions needed to be offset overseas.

Australian offsets presented here are a valuable resource for the future environmental security of Australia, just as the fossil fuel resources in the Beetaloo could be to an economic future. There are finite offset resources and there will be competition from others who also require them. These market aspects have not been explored, nor the opportunity costs of interest to policy makers.

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