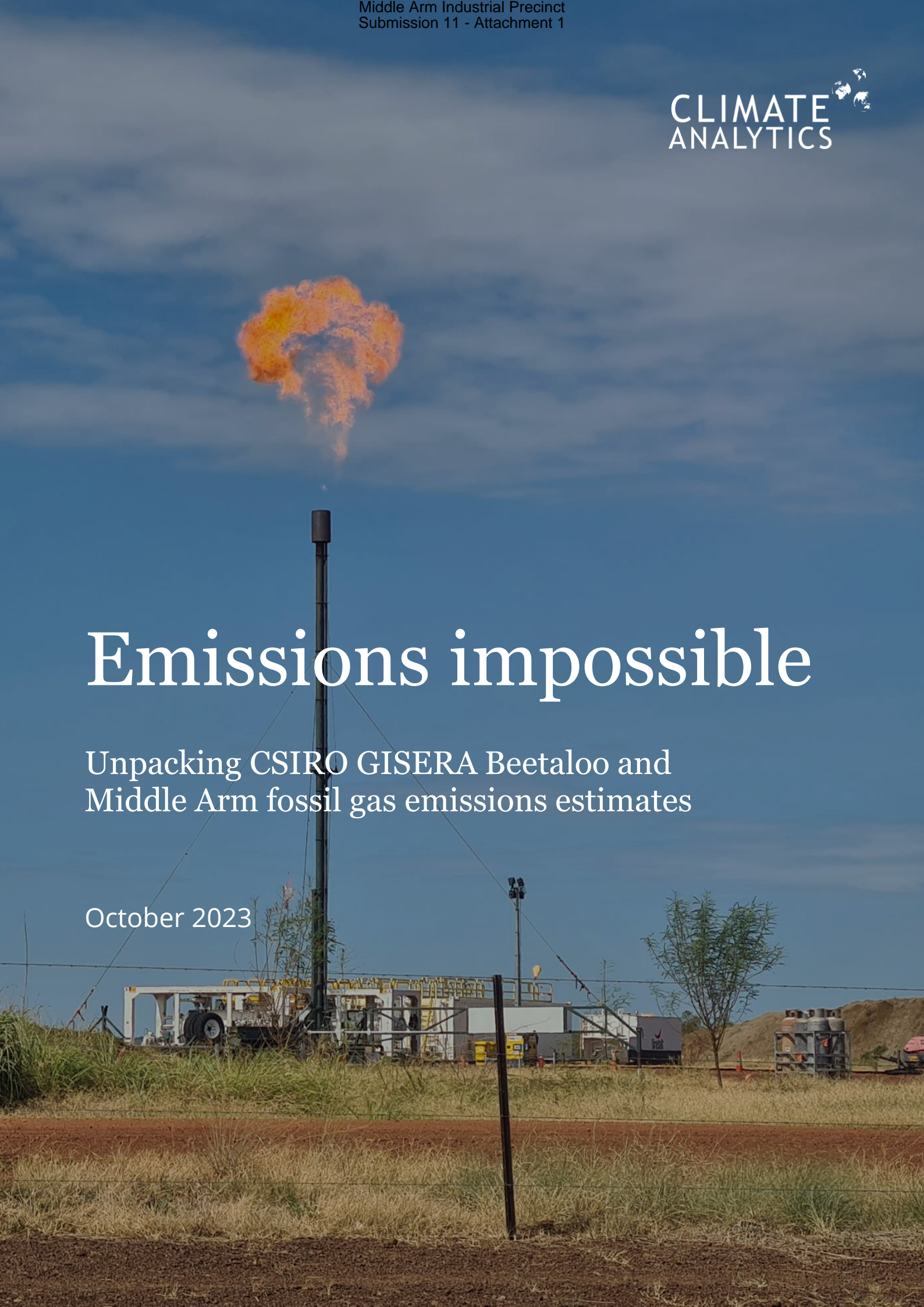


Emissions impossible

Unpacking CSIRO GISERA Beetaloo and
Middle Arm fossil gas emissions estimates

October 2023



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Key findings

This report provides an independent evaluation of the CSIRO and GISERA assessments of the potential greenhouse gas emissions that would result from the exploitation of the Beetaloo fossil shale gas reserves. This is in light of the Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory, specifically Recommendation 9.8, which states:

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

The Northern Territory Government has stated it has completed this action point. The GISERA report provided the basis for this statement.

We find the CSIRO GISERA report has:

- Underestimated emissions for the Beetaloo project and its associated LNG production facilities across the board, across all areas of the proposed project, from methane leakage on extraction to liquefaction emissions intensity. We estimate these emissions would add up to 11% of Australia's 2021 emissions, and that:
 - The methane loss rate is underestimated by at least 56%.
 - The upstream emissions intensity is underestimated by 44% to 110%.
 - LNG production emissions underestimated by 57% to 89%.
- Underestimated annual onshore emissions by up to 84% from the scenarios used.
- Underestimated the cumulative total emissions over 25 years, including those occurring overseas, by close to 1.5 times Australia's 2021 emissions.
- Focused on using offsets rather than real mitigation measures.
 - Failed to account for any of the scientific findings questioning the efficacy of using offsets for fossil CO₂ emissions.
 - Putting the emphasis on offsets, despite findings that offsets are not a viable alternative to cutting emissions.
- Overestimated the supply of offsets in Australia, by:
 - Using liberal assumptions for all the offsetting methods under the Emissions Reduction Fund.
 - Assuming a potential supply of offsets sufficient to offset Australia's 2021 emissions in their entirety.
- Assumed up to 42% of offsets would need to be sourced internationally, which is not possible under the recent Safeguard Mechanism regulations.

- Significantly exaggerated the viability of blue hydrogen and carbon, capture and storage, which would require injecting CO₂ into the Timor L'Este seabed to contain it for thousands of years.

Tamboran's Middle Arm emissions

Using updated emission estimates, we find that Tamboran Resources' plan to develop a 6.6 million tonnes per annum LNG plant at the Australian taxpayer funded Middle Arm gas precinct in the Northern Territory this decade would generate emissions equivalent to 2-3% of Australia's 2021 emissions. This figure translates to adding 6 to 8 million new cars to Australia's roads.

- Tamboran Resources' announced plan to expand capacity to 20 million tonnes per annum, would generate emissions equivalent to 10-13% of Australia's 2021 emissions, equivalent to having 30-38 million additional cars on Australia's roads.

Cumulatively, over the 25-years life of the project and including exported emissions, Tamboran Resources' plans to frack the Beetaloo and produce LNG would generate between 0.8 to 3.2 GtCO₂e, when the IPCC and the IEA make it clear that existing fossil fuel infrastructure set us on track to exceed the remaining 1.5°C compatible carbon budget.

- The emissions from Tamboran's plans are 8-51% of Australia's cumulative emissions from 2024 to 2050, if Australia's emissions were to decline consistently to become net-zero by 2050.

Executive Summary

The Beetaloo Basin, situated 500km from Darwin in the Northern Territory, contains technically recoverable fossil gas resources equivalent to 60 times Australia's current consumption. The prospect of fracking a pristine area has been the subject of considerable political and economic interest in recent years.

The exploitation of the Beetaloo Basin is deeply intertwined with, and potentially dependent on, the proposed development of the Middle Arm industrial precinct in Darwin. The project has been driven primarily by the Northern Territory Government. Despite officially referring to the project as the "Middle Arm Sustainable Development Precinct", official documents make it clear Middle Arm has been designed as a "gas demand centre" for gas fracked in the Northern Territory.

Fossil gas is one of the main drivers of climate change and is not a transition fuel. Analysis from multiple sources, including the IPCC, the IEA, and Climate Analytics, all show that there should be no new gas exploration if the world is to limit warming under 1.5°C.

The Middle Arm precinct will receive a total AUD [\\$1.5 billion package](#) from the Federal Government – effectively a taxpayer-funded fossil fuel subsidy which will pay for the port, roads, and pipelines needed to export fracked gas from the Beetaloo Basin.

In June 2023, Tamboran Resources announced plans to build an initial 6.6 million tonnes per annum (Mtpa) liquefied natural gas (LNG) plant at Middle Arm, with the aim to expand to 20 Mtpa LNG in the 2030s, using gas from fracking the Beetaloo Basin. The Northern Territory government has awarded Tamboran exclusive land rights at Middle Arm for this purpose.

A very large volume of greenhouse gas emissions would be released from the fracking of the Beetaloo Basin, from its extraction, processing and export at Middle Arm, to its ultimate burning.

Recommendation 9.8: nonet increase in lifecycle GHG emissions in Australia

It was this concern around emissions that led to *Recommendation 9.8* of the March 2018 report of the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory ordered by the NT Government, led by Hon Justice Rachel Pepper (the "Pepper Inquiry").

Both Federal and Northern Territory governments have committed to implementing Recommendation 9.8, which states, as per the Northern Territory and Federal governments' objectives, there should be no net increase in the lifecycle greenhouse gas (GHG) emissions emitted in Australia from onshore shale gas produced in the NT (Northern Territory Government, 2018a).

Following the Pepper Inquiry, in February 2023 the CSIRO Gas Industry Social and Environmental Research Alliance (CSIRO GISERA) released its long-overdue [report](#) on the mitigation and/or offsetting of the lifecycle greenhouse gas emissions of the exploitation of onshore shale gas in the Beetaloo Basin. The report was funded by the Federal and Northern Territory governments, and industry.

Recommendation 9.8 of the Pepper Inquiry has not been implemented, yet on May 2023, the Government of the Northern Territory announced it had met all the recommendations of the Pepper Inquiry. The CSIRO GISERA report provided the basis for the Northern Territory Government including Recommendation 9.8 in this statement.

Independent evaluation of CSIRO GISERA conclusions

The purpose of this report is to independently evaluate the assessments made by CSIRO GISERA of the greenhouse gas emissions from the exploitation of the Beetaloo fossil gas reserves, in light of the recent developments in the Northern Territory and as they apply to Recommendation 9.8.

We have stepped through the logic of the CSIRO GISERA report by first estimating the lifecycle emissions assessment of the emissions intensity at each step of the fossil gas production and processing phases. We then compile these results in gas use scenarios reflecting current developments to produce revised estimates of total emissions. Finally, we examined the so-called mitigation options.

CSIRO GISERA substantially underestimates the upstream emissions intensity of Beetaloo fossil gas

To assess CSIRO GISERA lifecycle emissions assessment results, we compared its outputs with other published large-scale studies, industry estimates and our own recalculations.

Upstream emissions are defined here as fossil gas production, processing, and transmission to the point of use in Darwin. Upstream emissions intensity is the greenhouse gas intensity of shale gas delivered to the point of downstream use, such as a liquefied natural gas (LNG) plant.

The CSIRO GISERA upstream emissions intensity estimates of 8.9 kgCO₂e/GJ are significantly lower than other estimates made for shale gas developments in Australia,

the United States, China, and the European Union. The Pepper inquiry estimated upstream emissions to be around 13.7 kgCO₂e/GJ when adjusted using the same GWP basis as CSIRO GISERA.

CSIRO GISERA upstream methane loss rate far too low

The main reason for the very low CSIRO GISERA upstream emissions intensity is the very low methane (CH₄) loss rate it assumed. This loss rate is critical to the overall lifecycle emissions from fossil gas production, but is not made clear anywhere in the report itself. Based on the figures in the CSIRO GISERA report we find the loss rate behind what is reported is likely in the range of 0.7-1%.

This compares with the Pepper inquiry, which estimated upstream emissions CH₄ losses to be almost twice the CSIRO GISERA report at around 1.8%. A recent state of the art review of estimates of upstream release of methane from shale gas production in the United States indicates a production volume weighted loss rate of 2.6% (with a range from 1-5.6%).

In the absence of detailed, independent, publicly available analysis for Australia we believe the average US upstream CH₄ loss rate observed from actual fracking activities using similar technologies is appropriate.

We find that adjusting the methane leakage rate to correspond with those found in existing shale gas fields around the world, including the one discussed in the Pepper Inquiry, results in a revision of the upstream emissions intensity of 56 to 150%, yielding a range of 12.3-19.8 kgCO₂e/MJ instead of 8.9 kgCO₂e/MJ reported by the CSIRO GISERA.

LNG emissions substantially underestimated

The total emissions intensity of LNG to the point of export is the sum of upstream emissions from fossil gas supplied to the LNG plant and LNG manufacturing emissions.

The CSIRO GISERA upstream emission factors for shale gas input to an LNG plant in Darwin is 0.54 tCO₂e/tLNG. We estimate the actual upstream emission intensity is more likely to be 0.97 tCO₂e/tLNG.

The CSIRO GISERA have used a substantially lower LNG liquefaction intensity than has been observed in Australia and abroad. The CSIRO GISERA estimates the emissions intensity associated with LNG liquefaction at approximately 0.21 tCO₂e/tLNG, 19% lower than the estimate provided in another recent CSIRO report. This report cited an intensity of 0.26 of tCO₂e/tLNG for liquefaction at the Queensland LNG plant, which is already at the low end of the range for an Australian LNG plant.

We find that the LNG liquefaction intensity calculated by the CSIRO GISERA is underestimated by at least half.

We estimate the LNG made with Beetaloo shale gas to have an emissions intensity of around 21.9 kgCO₂e/GJ (range 17.8-26.3 kgCO₂e/GJ) before shipping, which translates to about 1.2 tCO₂e/tLNG, nearly twice the intensity estimated by CSIRO GISERA. The shale gas from the Northern Territory would be the most carbon intensive LNG produced in Australia.

Due to the lack of clarity in the CSIRO GISERA report it is not possible to say to what level the raw shale gas is processed to remove CO₂ prior to arrival at the LNG liquefaction plant. To ensure our assumptions are conservative we assume that the gas processing intensity in CSIRO GISERA accounts for this. If it does not, then the total LNG intensity will be even higher than what we estimate above.

Table 1: Comparison of the domestic emissions intensity for LNG

Intensity		Upstream emissions	LNG liquefaction	Total domestic emissions intensity of LNG
CSIRO GISERA	kgCO ₂ e/GJ	8.90	3.5	12.4
CH ₄ loss 0.7 – 1.0%	tCO ₂ e/tLNG	0.54	0.21	0.75
Revision	kgCO ₂ e/GJ	16.0 12.3 – 19.8	5.9 5.5 – 6.6	21.90 17.8 – 26.3
CH ₄ loss 1.8% - 2.6 %	tCO ₂ e/tLNG	0.97	0.33	1.21
Difference (%)		56% - 150%	57 – 89%	44 – 113%

Note: based on the literature and own estimates.

Scenarios underestimate emissions

Our evaluation of the emissions consequences of the use of gas in the CSIRO GISERA scenarios indicates that the total emissions from each of them is significantly underestimated.

The low emission intensities described above are a substantial part of this underestimation. However, for individual use cases involving LNG production CSIRO GISERA also does not appear to have accounted for the 10% loss of fossil gas in the manufacturing process.

The CSIRO GISERA report found that the total lifetime (cumulative) onshore emissions for the period 2025-2050 were in the range of 164 – 827 Mt CO₂e, with annual onshore emissions in the range of 6.5 – 33 MtCO₂e/year, depending on the development scenario.

Our evaluation shows that the CSIRO GISERA has likely systematically underestimated the intensity and magnitude of greenhouse gas emissions from the different gas production scenarios for both upstream and downstream emissions. CSIRO GISERA emissions are too low by 21-84%: the actual emissions estimates, we find, would more likely be in the range of 9 – 49 MtCO₂e per year, and 230 MtCO₂ – 1.2 GtCO₂e over the 25-year lifetime of the project.

A large proportion of the emissions generated by the fracking of the Beetaloo Basin will be emitted overseas. Including exported emissions, 700 MtCO₂e – 2.3 GtCO₂e will be emitted over the 25-year life of the project, between 50 to 70% of the total emissions from the project.

The Tamboran first stage LNG plant development at 6.6 Mtpa LNG is consistent with scenario 1 or 5 of the CSIRO GISERA report and 20 Mtpa LNG is consistent with scenario 5.

The five scenarios outlined in the CSIRO GISERA report run counter to Australia's decarbonisation efforts, as they all involve significant new fossil gas and LNG production. As the International Energy Agency (IEA) has shown in its Net Zero road map (NZE), no new fossil gas resources are needed and hence the Beetaloo development would not be aligned with the Paris Agreement's goal of limiting global mean temperature increase to 1.5C.

Blue hydrogen exaggerated

The CSIRO GISERA report emphasises the production of blue hydrogen, which involves the production of hydrogen from fossil gas with the CO₂ captured and stored underground.

Far from being advantageous, it is likely to be more costly than green hydrogen within the next seven to ten years, while the claimed costs and scale of CCS storage are underestimated. The climate benefits of blue hydrogen are also controversial.

The proposed CCS project at Middle Arm involves constructing a pipeline into the territorial waters of Timor L'Este and ensuring that carbon dioxide remains permanently isolated from the atmosphere under the seabed for thousands of years.

However, achieving this goal has not been accomplished in practice. The Federal Government is currently attempting to pass the Environment Protection (Sea Dumping) Amendment (Using New Technologies to Fight Climate Change) Bill 2023 in parliament to enable the project to move forward.

Mitigation and offsetting

For mitigation of the greenhouse gases, the CSIRO GISERA has focused on offsetting using domestic and international offsets.

At no point does CSIRO GISERA question nor discuss the scientific efficacy of offsetting fossil CO₂ emissions, although it is well known that there are serious questions in relation to the scientific basis of this.

The CSIRO GISERA have used the most optimistic availability of offsets to be found in the scientific literature, which are unlikely to be realisable in practice, and which, if realised, would consume very large areas of land in Australia.

In order to evaluate the possibility of offsetting emissions from the Beetaloo project, the CSIRO GISERA report examines the potential for land-based carbon sequestration in Australia.

Upon reverse-engineering the offset potential calculated by the CSIRO GISERA, it becomes evident that they have made the most optimistic assumption at every stage of the process.

Based on the assumptions taken by CSIRO GISERA, 163 MtCO₂e of land-based sequestration annually are both technically and economically viable at current ACCU prices, enough to entirely offset the Safeguard Mechanism emissions.

Under the assumptions used by CSIRO GISERA, at 85\$ per tCO₂e, a carbon price lower than in the European Union, there would be enough technical and economic annual offsetting potential available to make Australia net zero. In other words, they could offset the entirety of Australia's 2021 emissions.

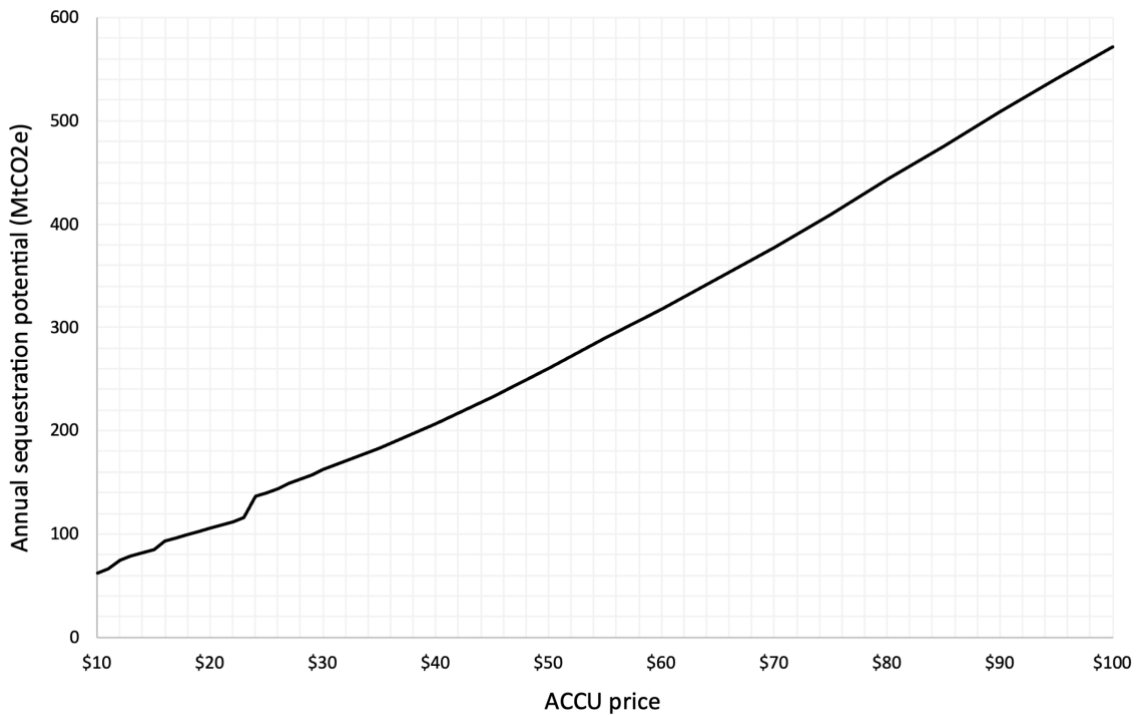


Figure 1: Cumulative annual sequestration economic and technical potential available in Australia vs carbon price

Derived according to the assumptions used by the CSIRO GISERA (Source: CSIRO GISERA, 2023).

In a large-scale development scenario, 42% of the abatement would need to be sourced from international offsets obtained overseas. At present, making use of international offsets in Australia to satisfy the Safeguard Mechanism baselines is not possible. Lifting this restriction would raise several crucial questions regarding the credibility of international offsets.

Carbon capture & storage

The inclusion of CCS as a mitigation option for the Beetaloo also rests on shaky assumptions. There are currently no CCS projects for the Beetaloo that have reached a stage of firm proposal or progress. Meanwhile, the Bayu-Undan depleted field in the Timor L'Este seabed is being put forth as a potential location for CO₂ storage for emissions from the Middle Arm area.

Although the CSIRO GISERA assumes a capture rate of 90%, no commercially operational facility has achieved anything like such a capture rate. Furthermore, CCS infrastructure has been underwhelming, consistently failing to meet its commitments despite the billions poured into it. The shortcomings of CCS raise additional concerns about the viability of blue hydrogen production at the Middle Arm precinct.

How else might Australian offsets and CCS be used rather than abating onshore shale gas?

We find the theoretical framework of the CSIRO GISERA report to be highly problematic. Assuming the deployment of mitigation options, a systematic implementation of carbon capture and storage infrastructure, and unlimited access to domestic and international offsets, any conceivable project can theoretically be rendered net-zero.

While the CSIRO GISERA publication's nature, scope, and goals are clearly defined, it is important to acknowledge that its results could be exploited by advocates of fracking in the Northern Territory. This underscores the need for increased transparency and scrutiny, as these efforts could minimise the substantial environmental impact of a project that is clearly incompatible with global efforts to rapidly cut emissions.

The CSIRO GISERA report ends with the following words:

"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" (GISERA, 2023).

The same could be said of the political will, human capital and financial resources channelled toward an anachronistic exploitation of the Beetaloo Basin.

Introduction

Fracking (hydraulic fracturing) in Australia is mainly confined to coal seam gas extraction in Queensland. Several states like Victoria, South Australia, and Tasmania have implemented moratoria, bans, or strict regulations on fracking (Government of South Australia, 2022; Premier of Victoria, 2021; Tasmanian Government, 2018).

The Northern Territory too had a moratorium on hydraulic fracturing. This changed in recent years so that the Beetaloo Basin, a 2.8 million hectares region located only 500 kilometres away from Darwin and claimed to hold more than 1,000 times domestic Australian gas consumption (Government of the Northern Territory, 2023b) is on the brink of being opened up for this destructive activity.

Apart from the environmental damage that fracking would cause, fossil gas is one of the main drivers of climate change and is not a transition fuel. Analysis from multiple sources, including the IPCC, the IEA, and Climate Analytics, all show that there should be no new gas exploration if the world is to limit warming under 1.5°C (IPCC, 2023; IEA, 2021; Climate Analytics, 2023a).

Very large volumes of greenhouse gas emissions would be released from the fracking of the Beetaloo Basin. It was this concern that led the 2018 report of the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory to include the recommendation, known as Recommendation 9.8, that:

“The NT and Australian governments seek to ensure that there is no net increase in the lifecycle GHG emissions emitted in Australia from any onshore shale gas produced in the NT” (Northern Territory Government, 2018a).

To respond to the concerns around the meeting of Recommendation 9.8, the CSIRO GISERA started a project aiming at providing a comprehensive analysis of the climate-related factors associated with fracking in the Beetaloo Basin. The final report of their investigation is divided into three primary sections. The first section presents several supply and demand scenarios. The second section estimates the lifecycle emissions associated with the development. Lastly, the report examines various mitigation options and evaluates their potential effectiveness in meeting Recommendation 9.8.

In this report, we evaluate the main conclusions of CSIRO GISERA. This evaluation follows the report's organisation and seeks to assess its assumptions and findings considering recent developments in the Northern Territory.

Background

2018 Independent Scientific Inquiry into Hydraulic Fracturing

In 2016, the then Chief Minister of the NT announced a moratorium on the fracturing of onshore shale gas, with the release of the terms of reference of what would become the Independent Scientific Inquiry into Hydraulic Fracturing in the Territory, led by Hon Justice Rachel Pepper (Northern Territory Government, 2018a).

This work, commonly referred to as the Pepper Inquiry, aimed at investigating the risks associated with hydraulic fracking in the Northern Territory along with their potential mitigation. The Pepper Inquiry was yet another instance in the long line of government-ordered investigations into fracking in the NT, after the 2012 Hunter Report, the 2014 and 2015 Hawke Report and, finally, the 2016 Hunter Report (Northern Territory Government, 2018a).

The years-long campaign to reinstate fracking in the Northern Territory took a dramatic turn in 2018 with the release of the Pepper Inquiry report. It concluded that the risks of fracking could be reduced to acceptable levels if 135 recommendations were implemented by the Northern Territory, including Recommendation 9.8.

Subsequently, the NT Government lifted the fracking moratorium, asserting that it embraced the report's conclusions and was committed to enacting the recommendations. Deputy Chief Minister Nicole Manison has said the gas will give the Territory "the opportunity to decarbonise", a talking point from the fossil fuel industry also used by government officials, despite having been debunked on multiple occasions (Climate Analytics, 2023a; Cox, 2023a).

In 2018, a poll ordered by the Australia Institute showed that 58% of Solomon electors were not trusting the Government and gas companies to implement all the recommendations of the Inquiry, echoing its findings that *"for a significant majority of the people participating in the Inquiry, the overwhelming consensus was that hydraulic fracturing for onshore shale gas in the NT is not safe, is not trusted and is not wanted"* (Australia Institute, 2018a; Northern Territory Government, 2018b).

Engagement of CSIRO GISERA

The Gas Industry Social and Environmental Research Alliance (GISERA) is an alliance between the CSIRO, the industry, and the government to conduct research on the various impacts of the exploitation of gas in Australia. Gas industry executives oversee the research undertaken by the alliance, which led the Australia Institute to call out potential conflicts of interest (Australia Institute, 2018b).

The CSIRO GISERA was tasked in 2020 with leading research on the Beetaloo sub-Basin in regard to Recommendation 9.8 (GISERA, 2020).

The aim of their final delivery, a report, was to determine whether domestic emissions from Beetaloo's gas can be mitigated, making exploitation of the Basin compliant with Recommendation 9.8 of the Pepper Inquiry (GISERA, 2023).

About 68% of the funding of the report came from the Federal Government, 25% from the CSIRO, 4% from the Northern Territory Government, and the rest from the gas industry (GISERA, 2020).

The report was published a year behind schedule in February 2023, with the conclusion that *"from an engineering perspective, the majority of GHG emissions can be mitigated or physically abated with options available in Australia [...]"* (GISERA, 2023).

While the report only attempts to see if emissions from Beetaloo's gas could be mitigated in accordance with Recommendation 9.8, its finding was seen in the media as a green light from the CSIRO to the exploitation of the Beetaloo Basin (ABC, 2023a; Australian Resources, 2023).

The blurring of boundaries between CSIRO and the fossil gas industry-dominated GISERA could be seen as a conduit for "science-washing" by an industry eager to boost its public image and social legitimacy, and more significantly, dependent on the results of this research to continue its expansion. Its results are mostly reported in the media as being from the CSIRO (Australian Resources, 2023).

Acceleration of developments in 2023

Along with the release of the CSIRO GISERA work, the timeline of the developments at the Beetaloo has been accelerating in the first few months of 2023.

In April 2023, the Federal Senate released a report of an Inquiry into Oil and Gas Exploration and Production in the Beetaloo Basin, which comprises 14 recommendations, including that the Australian Government *"strongly assist the Northern Territory Government to create a regulatory framework that will enable the Territory to fully implement Recommendation 9.8 of the Pepper Inquiry prior to shale gas production in the Beetaloo, and ensure that supporting frameworks and materials are developed expeditiously and made available to all 'new entrants' in the Beetaloo, to support the net zero Scope 1 emissions requirement"* (Senate, 2023).

Documents from late 2022 released under FOI indicate that the NT government was aware of its inability to meet recommendation 9.8 (Cox, 2023a; Environmental Defenders Office, 2023).

Yet, in May 2023, the Northern Territory government declared it had satisfied all of the Pepper Inquiry's recommendations, an announcement welcomed by the industry (Government of the Northern Territory, 2023a; Tamboran Resources, 2023a). This decision effectively permits fracking in the Beetaloo.

In a letter to the Chief Minister of the Northern Territory published the same month, Dr David Ritchie, responsible for overseeing the implementation of the recommendations from the Pepper Inquiry, explained that *"despite the Commonwealth agreeing to "work with the Territory to support its implementation of recommendation 9.8 using available technology and policies", there has been no progress on the crux of this recommendation, that is: to develop a system that would allow the public to see how a specific reduction in GHG elsewhere in the Australian economy is directly attributed to offset GHG emitted in Australia from production and consumption of shale gas produced in the NT"* (Ritchie, 2023)

Recommendation 9.8 suggests that emissions occurring overseas should be offset overseas. It states that *"the increase in life cycle GHG emissions in Australia from any onshore shale gas produced in the NT (see Table 9.4) must be fully offset. For example, [...] 38.9 Mt CO₂e/y must be fully offset in Australia for a gas field producing 1,240 PJ/y. In the latter case, the residual emissions of some 60 Mt CO₂e/y are emitted overseas, and they should therefore be offset overseas"* (Northern Territory Government, 2018). So far, no government has taken steps to ensure this happens, and there is no existing framework or mechanism in place to do so.

Middle Arm and Beetaloo fracking

In parallel, the Northern Territory has accelerated the development of the Middle Arm industrial precinct. The development will source gas from the Beetaloo (see dedicated discussion in the Scenario section).

The Middle Arm Sustainable Development Precinct aims to shape the area into a "globally competitive, sustainable precinct with a focus on low emission". In contrast to the government's narrative, its establishment primarily centres on increasing the demand for Beetaloo gas obtained through fracking, all the while advancing infrastructure like ports, roads, and pipelines to facilitate the extraction process.

The project includes heavy petrochemical manufacturing industries, gas processing facilities and gas export infrastructure. In order to justify the 'sustainable' moniker, press releases have mentioned possible renewable hydrogen generation, carbon capture and storage, and critical minerals processing (Land Development Corporation, 2022). Middle Arm already hosts Santos' Darwin LNG plant and the Ichthys onshore plant.

Behind this green facade, the Northern Territory Government is not shy of calling the Middle Arm precinct a “new gas demand centre” in a submission to the Federal Government for the “Growing advanced manufacturing in the Northern Territory’s Middle Arm Industrial Precinct” (ABC, 2022b). In a document submitted to Infrastructure Australia and retrieved by ABC thanks to a Freedom of Information demand, the Northern Territory Government argues that the *“Beetaloo Sub-Basin onshore gas presents an opportunity for long term agreements to be put in place at price points that will make manufacturing cost effective”* (Infrastructure Australia, 2020).

Such long-term price agreements would lock in gas demand, at a time when fossil gas needs to be phased-out on a global level.

It is clear this project has been designed to create gas demand and drive gas-fired petrochemical manufacturing, with Infrastructure Australia documents saying, *“the potential recovery of fossil gas liquids from the onshore Beetaloo Sub Basin project means there is also an opportunity for future production of ethane-based products such as plastics, paints, polymers and rubbers as well as the production of liquid fuels”* (Infrastructure Australia, 2020).

In 2023, an executive from Tamboran Resources argued to the Environment and Communications References Committee that *“the gas that will be extracted from the Beetaloo will be necessary for a full range of industrial purposes at the Middle Arm Sustainable Development Precinct”* (Senate, 2023).

The Middle Arm Industrial Precinct and the Beetaloo gas Basin are in symbiosis in what sounds like circular reasoning. The gas supply from the sub-Basin is required for the operation of the precinct, and the precinct would generate local demand for the gas from the sub-Basin, making it viable.

The Federal Government allocated \$2.6 billion from the \$7.1 billion Energy Security and Regional Development Plan for infrastructure projects in the NT, of which \$1.5 billion are targeted towards the Middle Arm precinct in what has been called a taxpayer funded fossil fuel subsidy (Lock The Gate, 2023).

The Senate Inquiry into Oil and Gas Exploration and Production in the Beetaloo Basin released in April 2023 has called for an inquiry into Middle Arm (Senate, 2023). The Government rejected twice the recommendation arguing that it was too early, as the project had not received its environmental and administrative approvals. This led commenters to ask why the government was channelling hundreds of millions with “no strings attached” to the project (The Monthly, 2023; Tom Swann, 2023). Finally, a Senate Inquiry was established in September 2023 (ABC, 2023).

While Deloitte conducted economic modelling of the project, the Department of Infrastructure refused to release it, saying it would not be in the public interest to do so (ABC, 2022b). The IEEFA has identified 12 risks associated with the development of Middle Arm which render the project flawed and its business model unviable (IEEFA, 2023).

In June 2023, the Northern Territory awarded five parcels of land for 12 months in the Middle Arm precinct, to give prospective developers the confidence to build their proposals. Two parcels were allocated to Total Eren and Fortescue Future Industries for green hydrogen production projects. Two other parcels were granted to companies planning to process critical minerals and produce material for batteries (RenewEconomy, 2023).

Although four of the five parcels allocated are linked to clean industries, the last one was awarded to Tamboran Resources to build an LNG plant with a nameplate capacity of 6.6 Mtpa per year. The facility would source its gas from the Beetaloo Basin, which Tamboran is also exploring (RenewEconomy, 2023).

This distribution of parcels in the Middle Arm precinct highlights the awkward positioning of the development. Most of the companies that received parcels are embracing the climate transition. Tivan, which plans to develop a critical mineral processing facility, [dissociated itself](#) from the gas industry planning to frack the Beetaloo. Yet Tamboran doubles down on fossil fuels, possibly to artificially create a market for the Northern Territory's gas as other private stakeholders are increasingly looking elsewhere.

Tamboran Resources plans on building a large diameter pipeline linking the Beetaloo to the East Coast gas markets, with a capacity of around 183 PJ per year. In June 2023, it selected APA Group for building the pipeline (Tamboran Resources, 2023).

Concerns regarding the financial impact of the offsetting task

The implementation of recommendation 9.8 calls for the offsetting of the scope 2 and scope 3 emissions of the gas extracted from the Northern Territory. In April 2022, the Federal Government and the Northern Territory signed the Commonwealth-Northern Territory Bilateral Energy and Emissions Reduction Agreement, pledging to collaborate to ensure the execution of recommendation 9.8 (Federal Government & Northern Territory Government, 2022).

The Safeguard Mechanism mandates that the scope 1 emissions linked with any onshore gas exploitation in the Northern Territory must be net zero right from the start of operation. However, it does not address the scope 2 and scope 3 emissions emanating from the use of the gas. In practice, most if not all the scope 1 emissions related to shale gas in the NT will have to be offset.

The Commonwealth Bank has evaluated the Safeguard Mechanism requirements for offsetting emissions from gas projects in the Northern Territory and found that they could impose a significant financial burden on the responsible entities (Commonwealth Bank of Australia, 2023).

The committee supervising the Senate Inquiry into Oil and Gas Exploration and Production in the Beetaloo Basin recommended the development of a national strategy to offset all scope 2 and scope 3 emissions connected to shale gas extraction in the Northern Territory. During the hearings, the former Chief Executive of the Australian Petroleum Production & Exploration Association, declared that gas producers should not be held responsible for the climate impact of the gas extracted from the Beetaloo Basin (Senate, 2023).

Also during the hearings, a representative of the Northern Territory's Department of Environment, Parks and Water Security stated that *"the Northern Territory government has been pretty clear that it's not paying for the cost of offsetting [the emissions resulting from the domestic consumption of Beetaloo gas that occurs outside the NT]"*, and that *"the cost of managing emissions—whether it's avoiding, mitigating or offsetting—will rest with the industry itself"* (Senate, 2023).

Federal Climate Change Minister Chris Bowen has suggested that the offsetting of emissions from gas projects in the Northern Territory should involve the implementation of policies in other Australian jurisdictions. The basis for such contributions, as he stated, would depend on "where the gas is sent, where the scope two and three emissions occur." (ABC, 2023b). As per media reports, during a meeting of the country's Energy Ministers in July 2023, Minister Bowen put forth a proposal for other states to regulate how gas consumers would bear the cost of offsetting the emissions resulting from the extraction of shale gas in the Northern Territory (The Guardian, 2023). The final meeting communiqué includes the mention that "Ministers noted the Northern Territory and the Commonwealth would undertake work to consider the management of indirect (scope 3) emissions in Australia from any onshore shale gas developments in the NT, including in the Beetaloo Basin, and report back to the Energy and Climate Change Ministerial Council" (Department of Climate Change, 2023c)

The allocation of financial responsibility for the offsetting task may curtail the attractiveness of the gas from the Northern Territory compared to other domestic gas sources that do not require supplementary offsetting expenses. The financial burden of offset costs domestically can further prompt producers to prioritise exporting their gas overseas as LNG.

Scenarios for fossil gas use

To estimate the likely scale of emissions relevant to the implementation of Recommendation 9.8, we first evaluate the CSIRO GISERA scenarios and provide alternate cases based on recent development proposals for the Beetaloo Basin. Based on the revised and assessed lifecycle emission analysis to be developed in the subsequent section of this report we will use two of the original CSIRO GISERA scenarios and two current development options to compare and evaluate the original emission estimates.

CSIRO GISERA Scenarios

CSIRO GISERA studies five scenarios of development for the Beetaloo. Four of these scenarios assume an output of 365 petajoules per year but differ in the final use of the gas. The last scenario, more ambitious, hypothesise a large-scale development with an output of 1130 PJ/year.

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 <i>Scientific Inquiry</i> 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 <i>Scientific Inquiry</i> 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 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 <i>Scientific Inquiry</i> 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 <i>Scientific Inquiry</i> 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

Figure 2: Scenarios included in the CSIRO GISERA report.

Source: CSIRO GISERA, 2023

LNG Production


The authors mention that an indicative LNG train with a nameplate capacity of 4.5 Mtpa of LNG per year processes 241 PJ of gas. Using this conversion factor, scenario 1 implies a production of 6 Mtpa of LNG per year. Scenario 2 to 4, with a smaller amount of gas targeted towards LNG exports, implies the production of 3.7 Mtpa – slightly higher than the Darwin LNG plant production capacity.

Finally, Scenario 5 implies a production capacity of 13.5 Mtpa, the capacity of some of the largest plants in Australia. In comparison, in 2021, Australia exported 77.4 Mt of liquefied fossil gas (Department of Climate Change, 2022b).

The announcement of Tamboran’s project to build an LNG plant with a nameplate capacity of 6.6 million tonnes per year at the Middle Arms precinct can be perceived as an endorsement of the Beetaloo development under either scenario 1 or 5.

The use of Beetaloo's gas for LNG production appears to be misaligned with global developments, as Australia’s LNG importers are pursuing ambitious goals to decarbonise their power sectors and achieve net-zero emissions. The Australian Industry Energy Transitions Initiative has estimated a one-third decline in the country’s LNG exports between 2020 and 2030, based on the net-zero emission scenarios of the International Energy Agency (Australian Industry Energy Transitions Initiative, 2023).

It should be noted that 365 PJ per year was the highest production scenario in the ACIL Allen 2017 report, which was referenced in the Pepper Inquiry (ACIL Allen, 2017). The group gave their Gale scenario a subjective probability of going ahead of “low” in case of a full lift of the fracking moratorium. However, using this scenario as a minimum or a baseline in the CSIRO GISERA report was “the consensus of industry, government and CSIRO researchers” (GISERA, 2023).



INDUSTRY DEVELOPMENT SCENARIO	Production Profile	Production Cost Regime	POLICY SCENARIO PROBABILITY MATRIX		
			PERMANENT MORATORIUM	PARTIAL LIFT	FULL LIFT
BASELINE	Nil Shale Production	N/A	CERTAIN	MODERATE	LOW
SHALE CALM	Exploration occurs Failure to commercialise	N/A	ZERO	VERY HIGH	VERY HIGH
SHALE BREEZE	Scenario 1 Target production: 36PJ per annum	High cost	ZERO	MODERATE	HIGH
SHALE WIND	Scenario 2 Target production: 150PJ per annum	Moderate cost	ZERO	LOW	MODERATE
SHALE GALE	Scenario 3 Target production: 365PJ per annum	Low cost	ZERO	VERY LOW	LOW

Figure 3: Probability matrix for the exploitation of the Beetaloo Basin

Source: ACIL Allen, 2017

The assumed domestic gas supply consumption is at 45 PJ per year for all scenarios. Fossil gas consumption in the Northern Territories was 106 PJ in 2022, mostly in the mining and power sector. These sectors account respectively for 58% and 41% of the consumption (Department of Climate Change, 2022a). Voluntary production data provided to the AEMO show that the NT will experience a supply shortfall starting 2032 with committed supply, and 2033 with committed, anticipated and uncertain supply (AEMO, 2023).

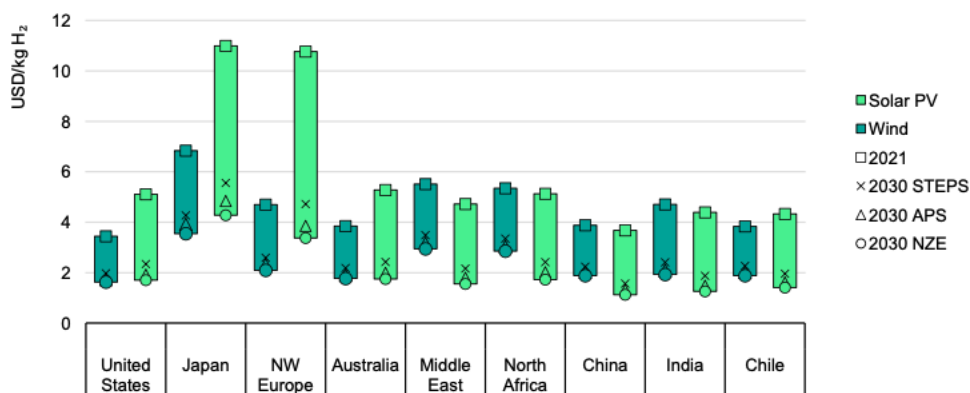
It is unclear whether gas from the Beetaloo is included in the estimate from the AEMO, however, the market operator expects the supply gap in the Northern Territory to exceed 10 PJ by 2035 even after accounting for anticipated and uncertain supply.

Blue hydrogen

Scenario 4 assumes that 120 PJ per year of Beetaloo’s gas would be consumed for “blue” hydrogen production. The term "blue" hydrogen refers to hydrogen produced from fossil gas, where CO₂ emissions from the process are captured and stored. Most of the hydrogen consumed worldwide is generated through methane reforming without carbon capture, which is commonly known as "grey" hydrogen.

The viability of “blue” hydrogen is problematic. It relies on uncertain carbon capture, a technology that still must prove it can be scaled cost-efficiently. It is also far from zero emissions, taking into consideration fugitive emissions and incomplete carbon capture. Its financial soundness is dependent on gas prices, which have experienced significant volatility since Russia’s invasion of Ukraine. More than 75% of the levelised cost of blue hydrogen production can be attributed to gas prices (IEA, 2023a).

Australia has a huge opportunity for the generation of renewable-based hydrogen thanks to its photovoltaic and wind energy potential. The discussion of hydrogen production cost per production route included outdated data. The production cost for renewable hydrogen is already on track to reach nearly \$2 per kilogram by 2030, even in scenarios that do not put the world on track for net zero (IEA, 2023a). These cost projections also do not account for carbon costs. Australia already has one of the lowest levelised costs of hydrogen produced from renewable energy sources in the world (IEA, 2023a).



IEA. CC BY 4.0.

Note: STEPS = Stated Policies Scenario; APS = Announced Pledges Scenario; NZE = Net Zero Emissions by 2050 Scenario; NW Europe = North-West Europe. Wind includes both offshore and onshore wind. The capital cost for an installed electrolyser system is assumed at USD 1240-1500/kWe for electrolyser in 2021, USD 460-570/kWe in STEPS 2030, USD 340-390/kWe in APS 2030, USD 270-320/kWe in NZE Scenario by 2030.

Figure 4: Levelised cost of hydrogen from renewable electricity by region and scenario, 2021 and 2030.

Source: IEA, 2023

Although initial documents released under FOI suggested that the Middle Arm precinct would utilise Beetaloo gas to produce blue hydrogen, the two parcels earmarked for hydrogen production would be dedicated to renewable-based hydrogen production (ABC, 2023c).

In its 2023/24 budget, the government announced it will create a Guarantee of Origin scheme to certify low-carbon products, including hydrogen (Department of the Treasury, 2023). While the details of the mechanism to be implemented are yet to be unveiled, it is likely that it will create a further incentive for hydrogen consumers to source hydrogen generated thanks to renewables to decarbonise their activities instead of blue hydrogen. Additional discussion on blue hydrogen is available in the section on mitigation options.

The scenarios outlined in the CSIRO GISERA report align with the industry submissions made to the Pepper Inquiry. These scenarios depict a Beetaloo Basin development that will fulfil needs that do not exist and are improbable to emerge in the future.

Methanol and ammonia

Two of the scenarios envision the use of Beetaloo's gas for methanol and ammonia production, assuming the Middle Arm industrial precinct and Hexagon's Pedirka Hydrogen Project come online.

The authors acknowledge that the outflow of Beetaloo's gas to methanol and/or ammonia production they consider in the report exceeds the consumption from these facilities and is purely indicative. Under scenarios 3 and 5, 120 PJ per year are going to methanol and ammonia production, while plans from the Northern Territory government have a total demand of 32.5 PJ per year.

Scenarios evaluated with the current LNG proposal at Middle Arm

To conduct an effective comparison of the CSIRO GSIRO emission estimates and account for the information deficit that hinders a comprehensive comparison of each scenario, we have selected Scenario 1 and 5 to focus on. These two scenarios have a focus on the production of LNG.

To better align with the latest developments occurring in the Northern Territory, these scenarios have also been updated to include the recently disclosed 6.6 million tonnes per annum LNG plant of Tamboran Resources (Tamboran Resources, 2023b). The company has mentioned the possibility to expand the capacity of the plant to up to 20 million tonnes per annum (Tamboran Resources, 2023c).

A summary of the scenarios we consider is included in Table 1, see dedicated section for more details.

Table 2: Evaluation scenarios including new LNG proposals.

PJ/yr	Output	Domestic gas supply	Refinery products	LNG exports for	Methanol and ammonia	Hydrogen
Scenario 1	365	45		320		
Scenario 1b. (Tamboran 6.6 Mtpa LNG)	446	45		401 ¹		
Scenario 5	1130	45	120	725	120	120
Scenario 5b. (Tamboran 20 Mtpa LNG)	1622	45	120	1217 ²	120	120

¹ For an output of 365 PJ (6.6 million tonnes of LNG).

² For an output of 1106 PJ (20 million tonnes of LNG).

Review of lifecycle assessment

The process of lifecycle assessment seeks to estimate the emissions associated with gas extraction from the Beetaloo Basin, from its production to its combustion.

The lifecycle of fossil gas is commonly broken down into two segments. Upstream emissions refer to the greenhouse gas emissions that are produced during the extraction, processing, and transportation of fossil gas from the source to the point of use. Downstream emissions from fossil gas are emissions that are produced during the combustion of fossil gas, usually for energy production, such as in power plants, industrial processes, and residential and commercial heating.

The estimation of lifecycle emissions relies on assumptions regarding the global warming potential (GWP) of various gases. GWP is a metric that measures the amount of heat that a greenhouse gas traps in the atmosphere relative to carbon dioxide over a specific period, usually 100 years. Methane, which constitutes the primary component of fossil gas, has a much higher GWP than CO₂. The CSIRO GISERA uses a 100-year CH₄ GWP of 30.5.

The CSIRO GISERA report's lifecycle analysis is based on a study entitled *Lifecycle Carbon Footprint Study of Onshore Shale Gas in the Northern Territory*, prepared by the company LifeCycles (Grant, 2023). It is explained in the CSIRO GISERA report that:

"The lifecycle carbon footprint assessment (CFP) was conducted by LifeCycles Pty Ltd. This section is an abridged version of the full CFP report [...] For the full suite of assumptions, inventory inputs and all results including the sensitivity analysis, we refer the reader to that report."

Despite being referred to multiple times in the report, the lifecycle assessment study was not publicly available until September 2023, more than six months after the release of the CSIRO GISERA report.³

As seen with the confidential Deloitte report, the Government's initial rejection of an investigation into the Middle Arm precinct, the multiple documents only released thanks to FOIs, and the lifecycle assessment study published months after the main report, lack of transparency permeates every aspect of the Beetaloo development and its ramifications.

³ Director and founder of LifeCycles Tim Grant kindly confirmed to Climate Analytics that the lifecycle assessment was not public as of August 2023 in an email communication.

Lifecycle emissions estimates

The upstream lifecycle emissions of the shale gas delivered at Darwin are calculated to be 8.85 kgCO₂e per GJ with the model used in the lifecycle assessment. The breakdown is shown in Figure 5.

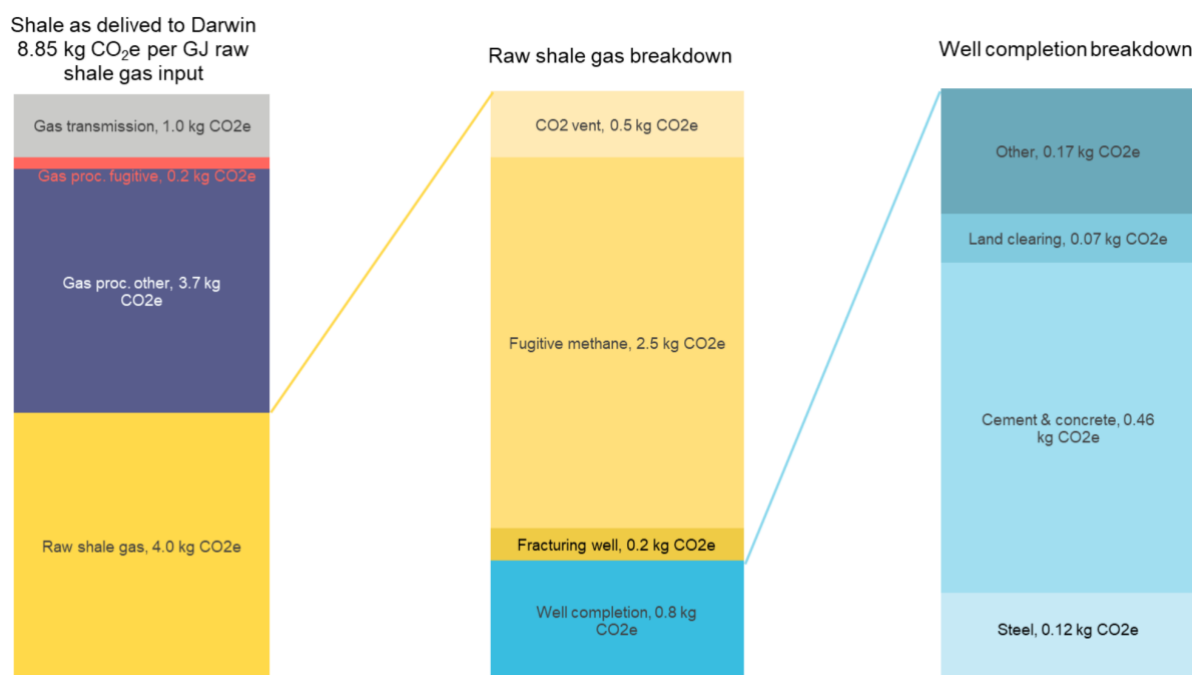


Figure 5: Upstream emissions from one GJ of gas from the Beetaloo sub-Basin, delivered to Darwin.

Source: CSIRO GISERA, 2023.

Without accounting for the emissions caused by distribution to Darwin, Beetaloo's gas has an upstream carbon intensity of 7.9 kgCO₂e per GJ.

Table 15 of the report also outlines the intensities of different gas uses, measured in ktCO₂e per PJ of shale gas input. Specifically, the domestic emission intensity of one PJ of shale gas input converted into LNG is 13.3 gCO₂e/MJ, which includes the upstream emissions assumed at 8.85 gCO₂e/MJ.

Table 3: Emission intensities for different applications of fossil gas

Table 15 Climate change impact intensities for different gas uses (kt CO₂e/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
H₂ 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

Source: Table 15 from the CSIRO GISERA report, detailing the carbon intensity of the different processes and use of the gas extracted from the Northern Territory in the lifecycle carbon footprint (CFP) study.

The calculated upstream emissions are lower than those presented in the Pepper Inquiry. The Pepper Inquiry does not evaluate the emissions from the Beetaloo, but instead incorporates those of a "representative US shale gas field" at 15.5 kgCO₂e per GJ, and 9.1 kgCO₂e per GJ before transport and distribution (Northern Territory Government, 2018a). Accounting for the difference in GWP, the intensity of the gas cited in the Pepper Inquiry is 13.7 kgCO₂e per GJ.

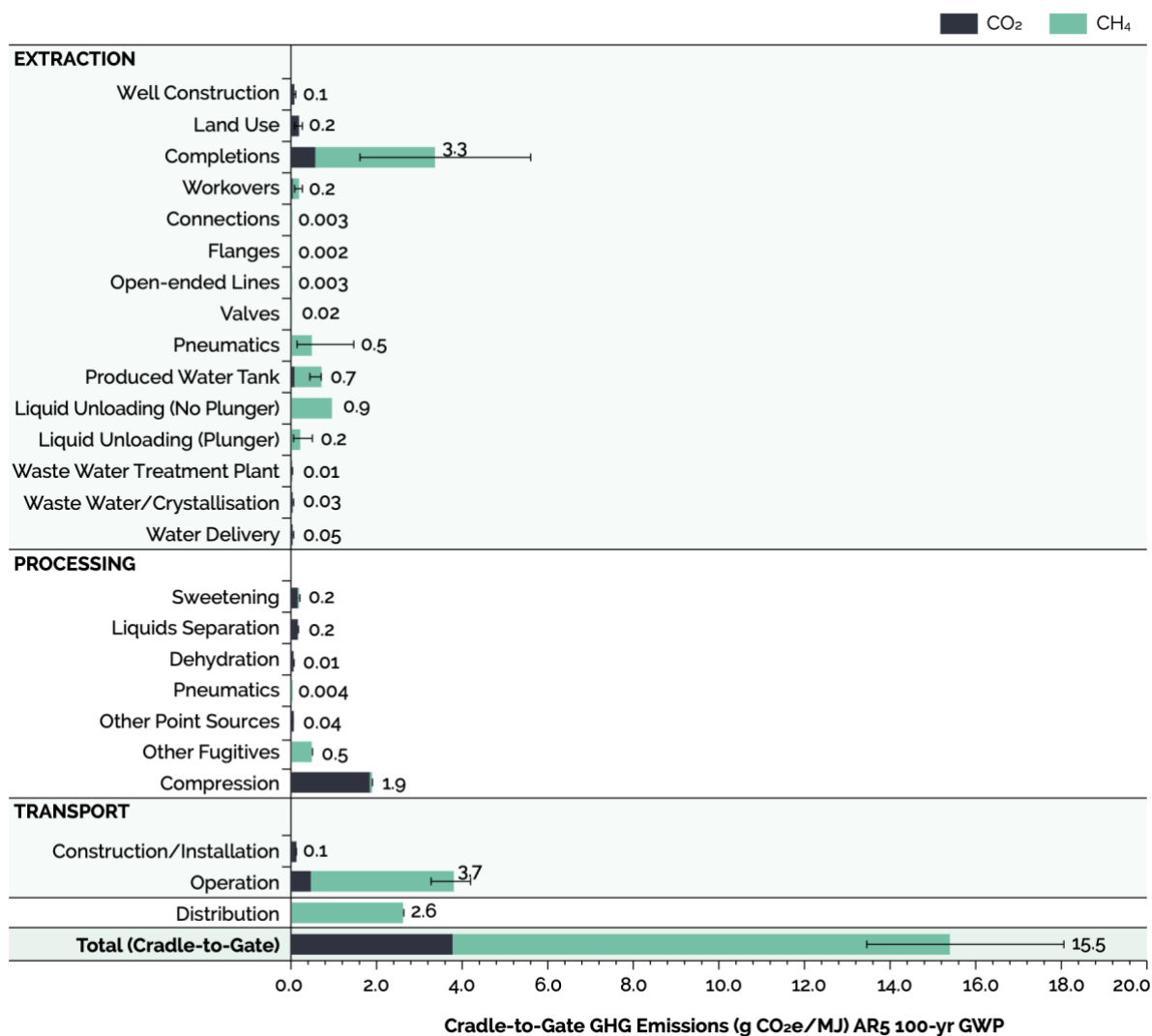


Figure 6: Upstream emissions from one MJ of gas from an Appalachian onshore shale gas field.

Source: Figure 9.1, Pepper Inquiry (Northern Territory Government, 2018a).

Similarly, Reputex applies an emissions factor of 13 gCO₂e/MJ with a lower GWP of 28. They find emissions significantly higher than the CSIRO GISERA, even after adjusting for the difference in GWP. A comparison of the emissions estimates between the CSIRO GISERA, the Pepper Inquiry and Reputex can be found in Annex A.

The reservoir CO₂ content of Beetaloo is based on Origin Energy's estimate of 0.9% for the Kyalla well, and 4% for the Velkerri well. Tamboran plans to commercialise gas with a CO₂ reservoir content of around 3% (Senate, 2023).

Methane leakage rate

The leakage rate, which is employed to model fugitive emissions, is a critical assumption in this lifecycle analysis. Fugitive emissions refer to the inadvertent release of greenhouse gases, mainly methane, into the atmosphere during the production, transportation, and distribution phases. As noted in the CSIRO GISERA report, there is substantial variability in fugitive emissions across shale gas projects.

It is mentioned that the emissions from shale well completion in the lifecycle assessment have been calculated using the values from Burnham, Han et al. (2012). Burnham, Han et al. (2012) estimated the total lifecycle leakage rate of shale gas from well completion to distribution at 0.71%-5.23%, with a mean value of 2.01% (Burnham et al., 2012).

Unlike in the Pepper Inquiry, the gas-by-gas breakdown of the emissions is not presented, and only 2.7 kgCO₂e per GJ is declared to be strictly methane.

To obtain an estimate of the total methane emissions from the fields, we assumed a usual range of methane emissions at each stage of the process, in line with the illustrative shale gas field exploitation presented in the Pepper Inquiry.

We assumed that methane emissions from gas processing may vary between 10% and 40% of processing-related emissions. We also considered that methane can account for between 50% and 100% of total transmission emissions and 0% to 100% of emissions from the fracturing of the well.

These ranges are on the conservative side compared to the findings presented in the Pepper Inquiry. According to the inquiry, methane accounts for 22% of the emissions related to processing and over 80% of the emissions related to transport and distribution.

Implementing this approach results in the following upstream intensity range, along with the gas breakdown for two scenarios – one in which CH₄ methane leaks are high, and the other in which they are low.

Table 4: Gas breakdown of the upstream emissions estimates by the CSIRO GISERA, with assumptions.

Upstream intensity 3.2% of the gas used in processes and transmission					
gCO ₂ e/MJ	CH ₄ - Low Case	CH ₄ - High Case	CO ₂ - Low Case	CO ₂ - High Case	Total
EXTRACTION					
Well Construction	0	0	0.8	0.8	0.8
	0%	100%			
Fracturing wells	0.0	0.2	0.2	0.0	0.2
Fugitive methane	2.5	2.5	0.0	0.0	2.5
CO ₂ venting	0.0	0.0	0.5	0.5	0.5
Total	2.5	2.7	1.5	1.3	4.0
PROCESSING					
	10%	40%			
Gas processing	0.4	1.5	3.3	2.2	3.7
Fugitive from gas processing	0.2	0.2	0.0	0.0	0.2
Total		1.7		2.2	3.9
TRANSPORT					
	50%	100%			
Distribution to Darwin	0.5	1	0.5	0	1
Total	0.5	1		0	1
Total (Cradle-to-Gate)	3.6	5.4	5.3	3.5	8.9

This gives a methane emissions intensity of 3.6 to 5.4 kgCO₂e/GJ. The same approach for the indicative field included in the Pepper Inquiry yields the following results.

Table 5: Gas breakdown of the upstream emissions estimates included in the Pepper Inquiry.

Pepper Inquiry Converted from a GWP of 36			
gCO ₂ e/MJ	CH ₄	CO ₂	Total
EXTRACTION			
Well Construction	0	0.1	0.1
Land Use	0	0.2	0.2
Completions	2.7	0.6	3.3
Workovers	0.2	0	0.2
Connections	0	0.003	0.003
Flanges	0	0.002	0.002
Open-ended Lines	0	0.003	0.003
Valves	0	0.02	0.02
Pneumatics	0.5	0	0.5
Produced Water Tank	0.6	0.1	0.7
Liquid Unloading (No Plunger)	0.9	0	0.9
Liquid Unloading (Plunger)	0.2	0	0.2
Waste Water Treatment Plant	0.01	0	0.01
Waste Water/Crystallisation	0.03	0	0.03
Water Delivery	0.05	0	0.05
Total	5.19	1.028	6.218
PROCESSING			
Sweetening	0	0.2	0.2
Liquids Separation	0	0.2	0.2
Dehydration	0	0.01	0.01
Pneumatics	0.004	0	0.004
Other Point Sources	0	0.04	0.04
Other Fugitives	0.5	0	0.5
Compression	0.1	1.8	1.9
Total	0.604	2.25	2.854
TRANSPORT			
Construction/ Installation	0	0.1	0.1
Operation	3.3	0.4	3.7
Distribution	2.6	0	2.6
Distribution (to Darwin) ⁴	1	0	1
Total	5.9	0.5	6.4
Total (to Darwin)	4.3	0.5	4.8
Total (Cradle-to-Gate)	11.7	3.8	15.5
Total (Cradle-to-Gate, delivery to Darwin)	10.1	3.8	13.9

⁴ In the field referenced in the Pepper Inquiry, distribution emissions are much higher than for an exploitation of shale gas from the Northern Territory. To harmonise assumption, we provide both the original breakdown as included in the independent inquiry, and the distribution intensity of 1 kgCO₂e/GJ included in the CSIRO GISERA report.

In their study, Howarth et al. (2021) present shale gas production and upstream methane emission data from various significant shale-gas-producing fields in 2015. Their paper includes top-down estimates for upstream methane emissions from different natural gas systems, which enables the establishment of a relationship between the methane leakage rate and upstream emissions.

By applying the relationship determined by Howarth et al. (2021), we find that the CSIRO GISERA study assumes a methane leakage rate of 0.65% to 1.0%. It is, at best, consistent with the lower limit of the range found by Burnham, Han et al. (2012), and suggests that the lowest values from the 2012 study have been picked, instead of the average.

The authors note that “there is an expectation with new shale wells that emissions control will be vastly improved based on the greater emphasis on GHG emission reduction” (GISERA, 2023). Although there are certainly substantial opportunities to mitigate methane emissions, sometimes at no net expense, uncertain future enhancements cannot dictate the assumptions regarding methane releases (IEA, 2023b).

In comparison, the methane leakage rate of 1.8% of lifetime production assumed by the Pepper Inquiry has been labelled as “extremely optimistic” by Professor Ian Lowe (Lowe, 2019).

Reputex notes that estimates of emissions from hydraulic fracking range between 1.8-17% - the lower bound being the Pepper Inquiry estimates (Reputex, 2021). The consulting firm suggests that alternative assumptions could be appropriate. They suggest using emission factors from Littlefield et al., cited as a “larger and more precise U.S. lifecycle modelling” (sic) study.

In 2019, building on previous work from the National Energy Technology Laboratory, Littlefield et al. found an upstream emissions factor of 19.9 gCO₂e/MJ with a 95% mean confidence interval of 13.1 to 28.7 g CO₂e/MJ – well higher than the estimate from the CSIRO GISERA (Littlefield et al., 2019).

Alvarez et al. (2018) found that fugitive emissions from the oil and gas industry supply chain account for 2.3% of the total gas production in the United States. This estimate is 60% higher than the figures provided by the U.S. Environmental Protection Agency (EPA) of ±1.5%, with the most significant difference observed in the production segment. However, these numbers do not include emissions produced during well drilling or flowbacks (Alvarez et al., 2018).

The Alvarez et al. (2018) study used a bottom-up approach to estimate methane releases, which has been criticised for its potential to underestimate emissions. This method relies on on-site measurements that are limited in time and location, which may not capture the full extent of unintended emissions (R. Howarth & Jacobson, 2021).

The EPA has faced scrutiny for its use of non-peer-reviewed and outdated data in its bottom-up models to estimate methane emissions. Aerial and satellite studies have corroborated concerns that these estimates may underestimate fugitive emissions (R. Howarth & Jacobson, 2021).

Similarly, the International Energy Agency estimates that Australia's methane emissions from the energy sector are 63% higher than what was reported to the United Nations Framework Convention on Climate Change (IEA, 2023c):

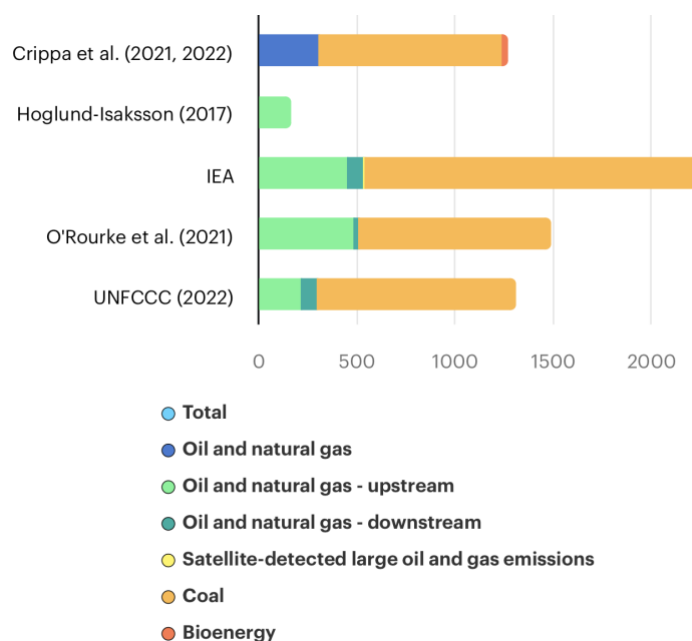


Figure 7: Australia's methane emissions estimates from the energy sector from various sources.

Source: IEA, 2023.

Research conducted in British Columbia, Canada, using an airborne study, has found that methane emissions are 1.6 to 2.2 times higher than US Federal inventories, even with conservative assumptions. This discovery confirms earlier findings that Canadian oil and gas operation methane emissions estimates were also underreported (Chan et al., 2020; Johnson et al., 2017; Tyner & Johnson, 2021).

An independent study in the Permian Basin, where methane emissions are known to be higher than average, found that emissions from upstream and midstream sources are 6.5 times larger than EPA estimates (Chen et al., 2022).

A comprehensive review of multiple works on US shale gas projects found that the aggregate upstream methane leakage rate ranges from 2.3% to 4.3%, not including distribution to end users (R. W. Howarth, 2021). When this factor is considered, the leakage rate rises from 3.6% to 7.9%. It is important to note that the latter range is based on studies conducted in urban centres.

This discussion is critical. One of the main arguments for developing fossil gas assets in Australia is to displace coal-fired power generation. In the Pepper Inquiry, we can read that:

"If fossil gas is used to displace coal from electricity production in Australia, and the net unit CO₂e savings are in the order of 515 kgCO₂e /MWh of electricity [...], 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" (Northern Territory Government, 2018a)

However, as noted in another report by the CSIRO, there is a widespread agreement that when fugitive emissions from upstream operations surpass 3% of total production, the climate advantages of fossil gas replacing coal are nullified (Schandl et al., 2019).

It could be argued that to accurately assess the climate impact of fossil gas power generation, we should compare it with renewables rather than coal.

The Pepper Inquiry notes that "there are substantial incentives for gas companies to reduce the amount of fugitive emissions". Yet, fugitive emissions have only increased since 2015 to reach 12 MtCO₂e in 2020, and are forecasted by the government to further rise to 15 MtCO₂e per year by 2030 (Department of Climate Change, 2022b).

A summary of the comparison of various upstream emissions intensities with different methane leakage rate can be found on the next page.

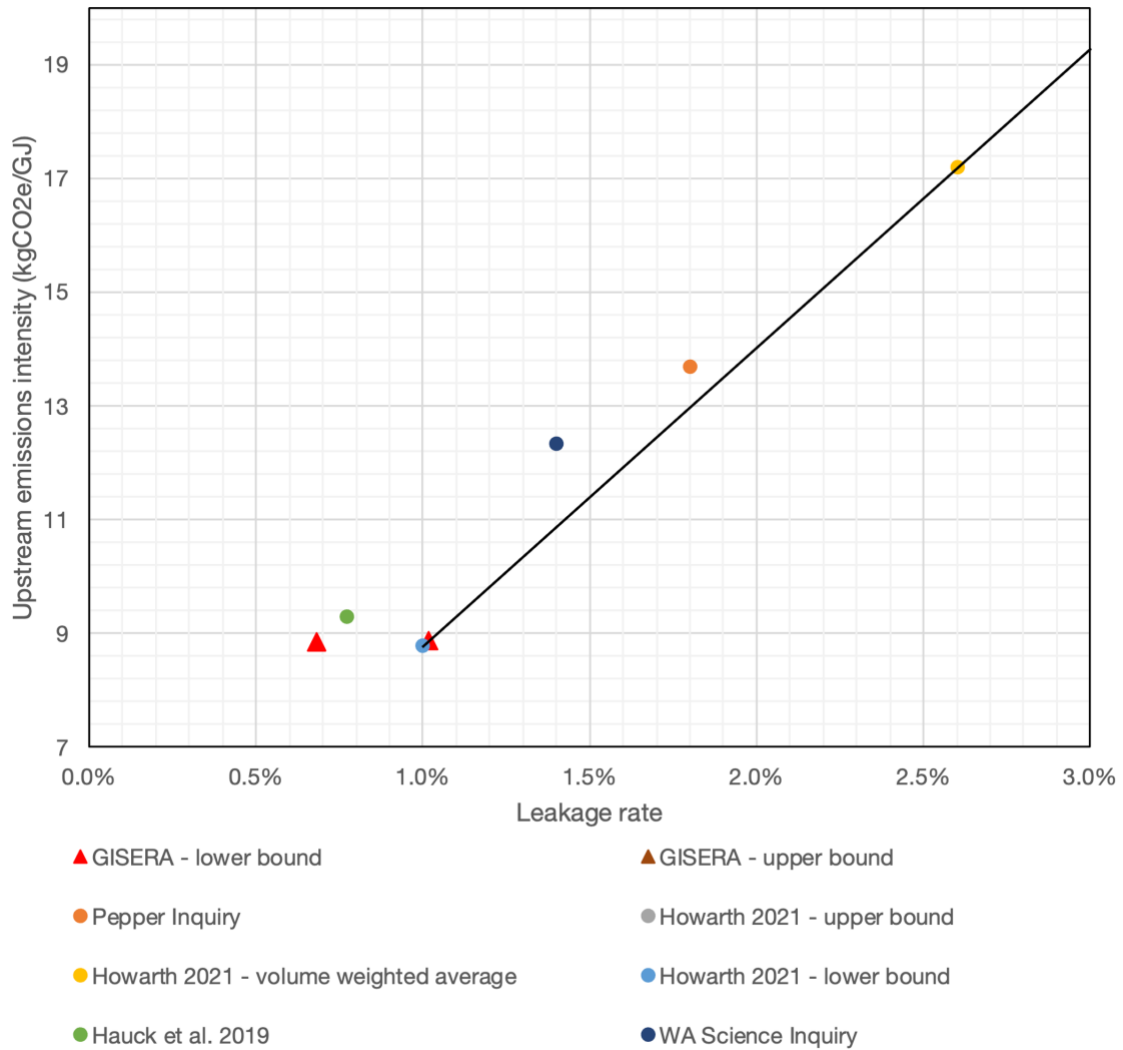


Figure 8: Comparison of the upstream intensity per leakage rate from different sources.

Sources: CSIRO GISERA (2023), Pepper Inquiry (2019), Hauck et al. (2019), Howarth (2021), WA Science Inquiry (2018).

Methane fugitives are not the only emissions that are associated with shale gas extraction and processing. Various studies, like the one from Littlefield and their colleagues, compile lifecycle emissions of shale and unconventional gas sources in different regions. Without a clear definition of the methane leakage rate assumed in the study, we can only compare the upstream lifecycle assessment of Beetaloo gas emissions with other studies.

A comparison between the upstream emissions estimates from the CSIRO GISERA and the existing literature reveals that they are much lower than most gas supplies in China, as well as shale gas fields in the US and Europe, even without accounting for transport and transmission emissions (Gan et al., 2020; Hauck et al., 2019; Weber & Clavin, 2012). In the lifecycle assessment underlying the CSIRO GISERA report, it is assumed that the end market for LNG produced from Beetaloo's gas is China's power sector (Grant, 2023). A visual comparison with these studies, covering gas fields from all around the world, can be seen below.

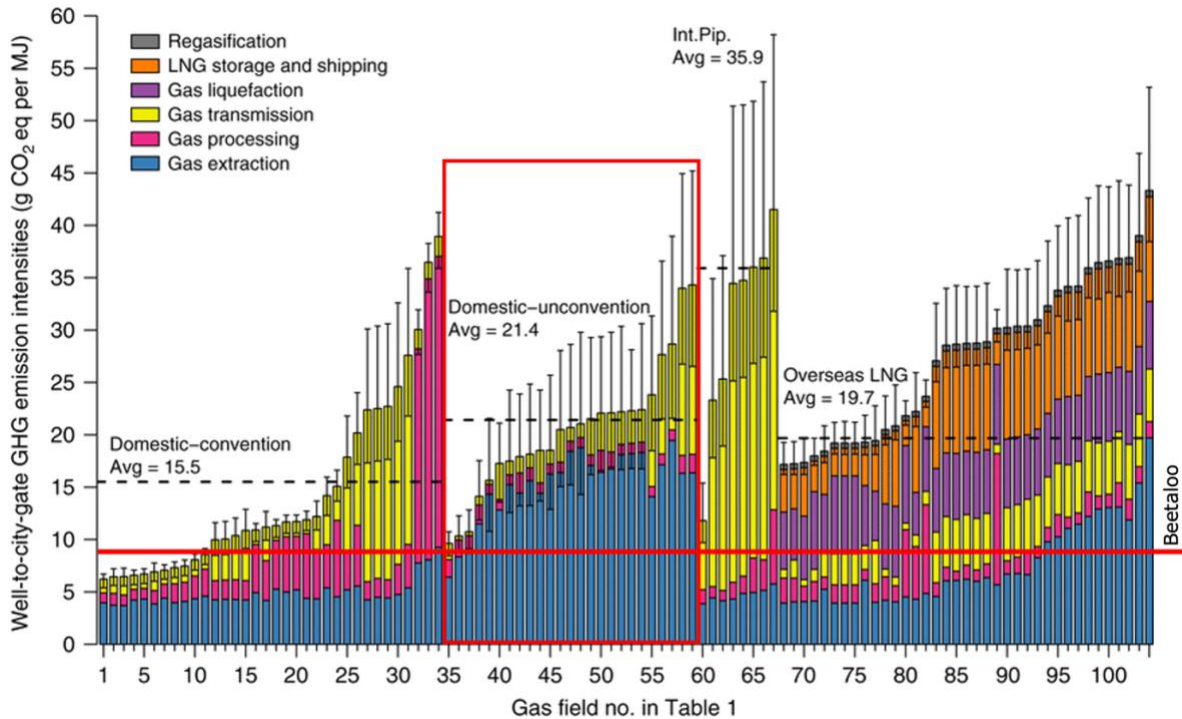


Figure 9: Well-to-city-gate carbon intensity of China's fossil gas supply per field in 2016.

The red box contains emissions from domestic unconventional gas sources. Gan et al. use a methane GWP of 28, compared to 30.5 in the CSIRO GISERA report (Source: Gan et al., 2020).

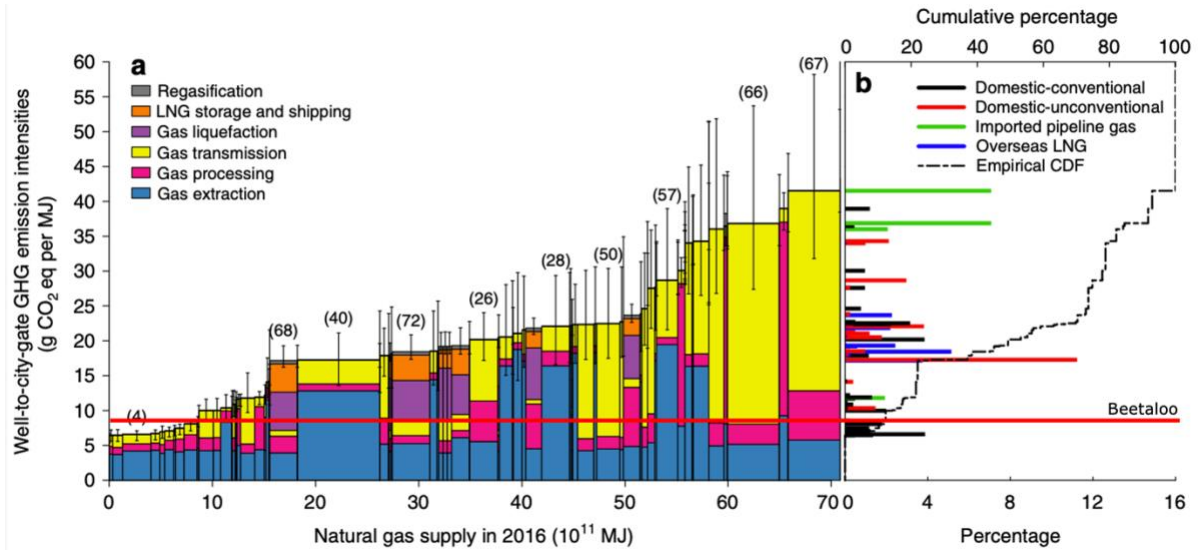


Figure 10: Well-to-city-gate carbon intensity supply curve of China's fossil gas supply in 2016.

The authors note that: "Bars with numbers in parentheses on top are the top 10 gas fields with the largest supply in 2016. The numbers in parentheses are their corresponding gas field numbers [...]. Error bars represent the 90% CI of the estimates with Monte Carlo simulation of uncertain parameter inputs [...]. B: Empirical probability mass function and empirical cumulative probability function (CDF)" (Source: Gan et al., 2020).

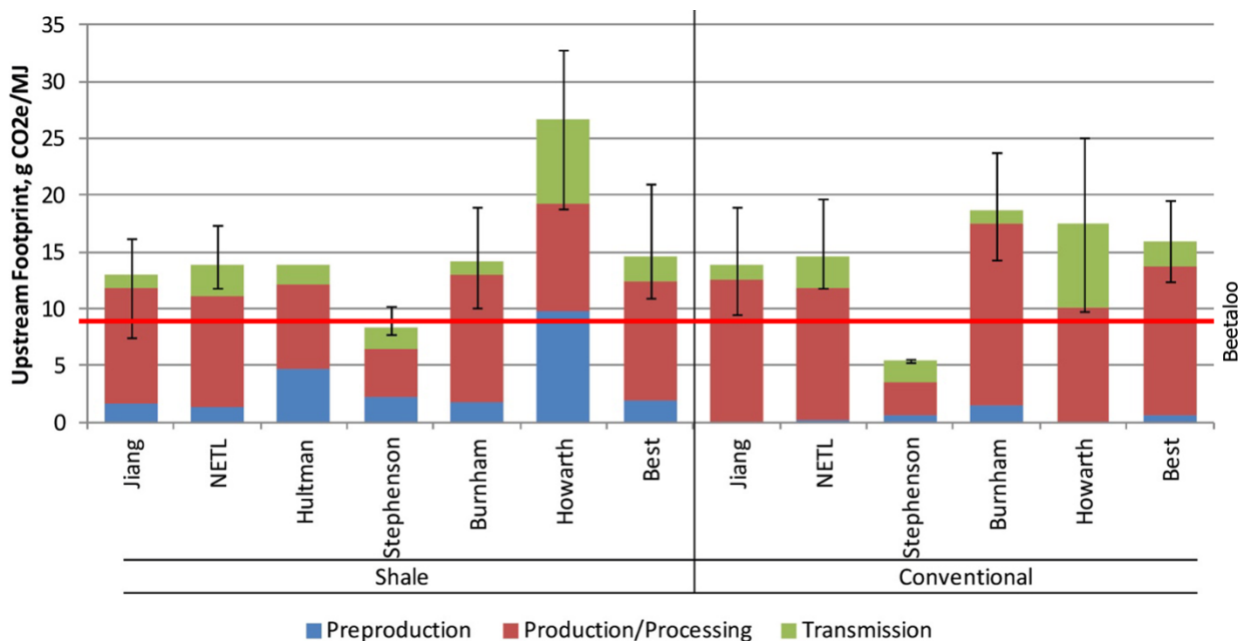


Figure 11: Upstream emissions intensity estimates for various studies of shale and conventional gas emissions in the United States at a methane GWP of 25, compared with the intensity of the gas produced from the Beetaloo according to the CSIRO GISERA.

The authors note that not all the studies referenced in their paper use the same boundaries. (Source: Weber & Clavin, 2012).

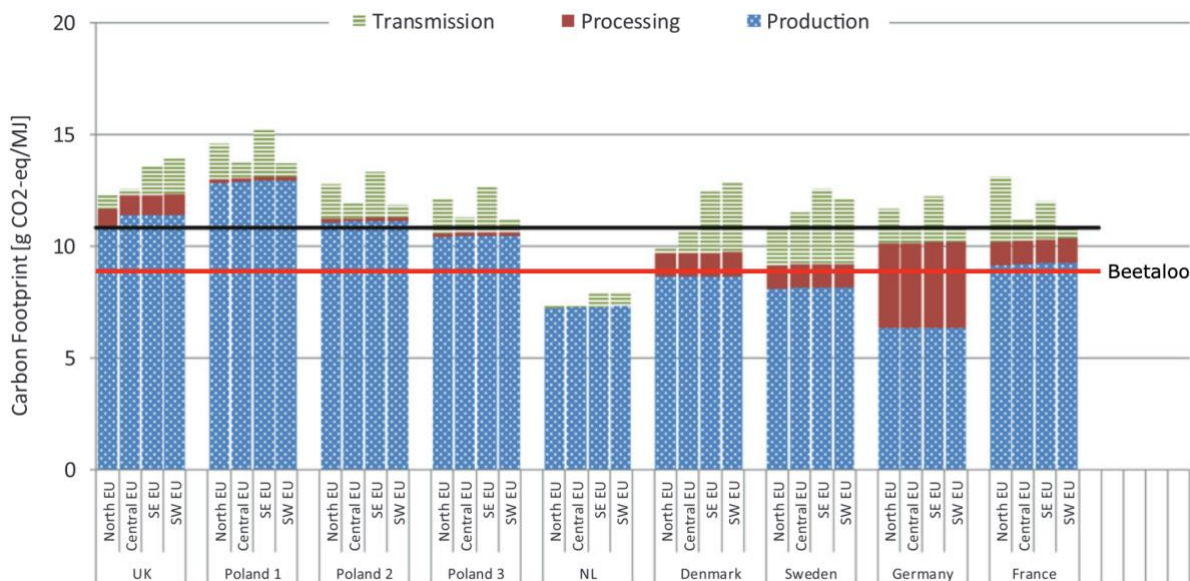


Figure 12: Upstream emissions intensity estimates from shale gas delivered to European countries, with a methane GWP of 30.

The black line is the consumption-weighted average intensity of conventional gas of all European regions (Source: Hauck et al., 2019).

Extraction emissions are typically higher for unconventional gas than for gas from conventional sources. The average extraction-associated emissions for domestic shale gas in China (before processing) are estimated at 19.1 gCO₂e per MJ, close to five times higher than the CSIRO GISERA extraction emissions estimates for the Beetaloo (see Figure 9).

Conventional gas extraction-related emissions in China are only 4.8 gCO₂e per MJ – values similar in range to the estimate for shale gas in the Northern Territory at 4.0 gCO₂e per MJ (Gan et al., 2020). Until at least 2021, the US EPA assumed no difference in emissions between shale and conventional gas in their emissions estimates, an assumption that has been challenged over time with more granular measuring and modelling (R. W. Howarth, 2021).

The processes of acid removal, dehydration, and phase separation during gas processing generate emissions. Fields with high impurities, such as CO₂ or H₂S, tend to have higher emissions as more extraction is necessary to produce the same volume of gas. The liquids-rich gas extracted from the Kyalla well site has a methane content of 65% of methane, which is relatively low (GISERA, 2023). The gas extracted from the Kyalla well site also contains ethane (19%), propane and butane (11%), condensates (3%) and levels of CO₂ lower than 1%.

Despite not being explicitly mentioned in the CSIRO GISERA report, we have previously estimated that the emissions estimates use a methane leakage comprised between 0.65% and 1%.

Howarth et al. (2021) provide methane emissions and leakage rate values for major shale gas fields in the United States. Additionally, it is possible to estimate Beetaloo's gas emissions by applying chemical factors and GWPs to the composition of the gas extracted.

With its low methane content, the Kyalla well is not representative of a typical shale gas well. We instead used the more representative composition of the flow from the Valhalla well in Western Australia, of "87% methane, 5.5% ethane, 2.7% propane and low inert gases" (Bennett Resources, 2020).

We are taking into account Tamboran Resources' statement that the reservoir CO₂ content is 3% (Senate, 2023). As for the Kyalla well, while fugitive emissions estimates can be established using the composition of the Valhalla well, its accuracy in representing the gas that will be extracted from the field during commercial operations cannot be guaranteed.

To ensure comparability with the findings from the CSIRO GISERA, we have maintained a methane 100-year time horizon GWP of 30.5. We have adopted a cautious approach by only considering the direct global warming potentials for ethane, propane, and butane over a 100-year time horizon, as per Hodnebrog et al. (2018). The direct GWPs for these non-methane volatile compounds are 0.39, 0.018, and 0.0055, respectively. Factoring in indirect effects, the adjusted GWPs stand at 10.2, 9.5, and 6.5, respectively (Hodnebrog et al., 2018).

Thanks to the curves derived from Howarth et al. (2021) and from the gas composition, we can scale the results from the CSIRO GISERA at various leakage rates.

At a methane leakage rate of 1.8%, the rate reported in the Pepper Inquiry, we find an upstream emissions intensity ranging between 12.3 and 15.3 kgCO₂e/GJ. The lower end of this range is based on the composition of the Valhalla field with low methane emissions, while the upper end is derived from the harmonization of the high methane case with the Howarth et al. (2021) findings.

These findings confirm that the reason for the CSIRO GISERA's low upstream emissions intensity is the assumption of a low methane leakage rate, as the emissions align with the results described in the Pepper Inquiry after correcting this factor (Northern Territory Government, 2018a).

By employing both the findings by Howarth et al. (2021), and the recalculation using the content of the gas, we identified an upstream emissions intensity range of 12.3 kgCO₂e/GJ to 19.8 kgCO₂e/GJ for methane leakage rates comprised between 1.8% and 2.6%.⁵

At a more liberal leakage rate assumption of 3.6%, the upstream intensity can reach as high as 25 kgCO₂e/GJ. These estimates are 1.4 to close to 3 times higher than the estimate from the CSIRO GISERA.

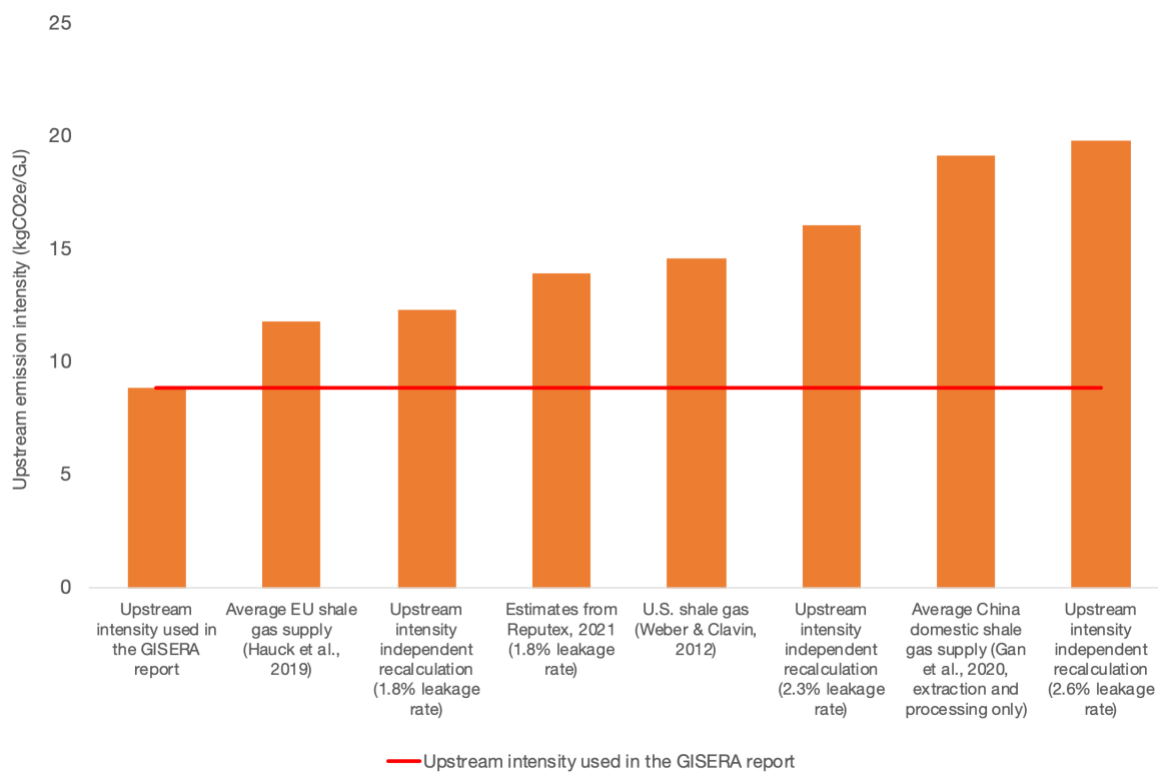


Figure 13: Upstream emissions intensity comparison, including delivery to Darwin for shale gas in the Northern Territory, before GWP conversion.

The studies cited use different methane GWPs. Hauck et al., 2019, assume a methane GWP of 30. Weber & Clavin, 2012, use a methane GWP of 25. Gan et al, 2020, use a methane GWP of 28. Their estimate does not include distribution emissions. The estimates from Reputex were adjusted for GWP assuming that lifecycle emissions are 77% methane, as presented in the Pepper Inquiry. In comparison, the CSIRO GISERA report uses a methane GWP of 30.5.

⁵ 1.8% is the methane leakage rate referred to in the Pepper Inquiry. 2.3% is methane leakage rate found by Alvarez et al. (2018), and 2.6% the volume weighted average methane leakage rate found by Howarth et al. (2021). It should be noted that Howarth et al. (2011) find a lower bound for total methane leakage rate of 3.6% (R. W. Howarth et al., 2011).

Transferring foreign shale gas studies to the Australian context requires careful consideration. Unfortunately, as pointed out in the CSIRO GISERA report, no emissions studies have been conducted for fracking in Australia (GISERA, 2023). Notwithstanding, there is no evidence to justify the report's use of an exceptionally low methane leakage rate.

Transmission emissions

The emissions related to the delivery to Darwin are estimated at 1.0 kgCO₂e/GJ by the CSIRO GISERA.

The research conducted by Gan et al. (2020), which was mentioned earlier, employs a pipeline leakage rate of 0.003 grams of methane per kilogram of fossil gas per kilometre, obtained from various sources including Brandt et al. (2014), Alvarez et al. (2018), and the National Energy Technology Laboratory.

Assuming 500 kilometres between the fracking area and Darwin and using the pipeline leakage rate from Gan et al. (2020) for the gas supplied to China from domestic and overseas sources, we find the same result as the CSIRO GISERA for the transmission emissions.

Our calculations do not consider the emissions generated during the transport and distribution of Beetaloo's gas to the East Coast, as outlined in Tamboran's pipeline proposal. Burning Beetaloo's gas in the East Coast instead of Darwin would lead to additional emissions from domestic gas consumption.

LNG Production

To be exported outside of Australia, fossil gas is compressed and liquefied before being sent overseas on tankers. The report mentions that "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 ktCO₂e/PJ) GHG emissions footprint from all CSG-LNG production", from which the CSIRO GISERA appears to have derived the manufacturing intensity of 3.5 gCO₂e/MJ (26% of the total intensity in the scope of the abatement task) (GISERA, 2023).

This estimate is extremely low.

Gan et al. (2020) find that emissions from gas liquefaction vary from 4.1 to 7.6 gCO₂eq/MJ. The ambient temperature significantly impacts this range, as cooler temperatures enhance the energy efficiency of the liquefaction process. According to Gan and colleagues, the Snohvit LNG plant in Norway, located 140 kilometres off the coast of Hammerfest, the northernmost city in the world, has the lowest liquefaction emissions intensity in their sample at 4.1 gCO₂eq/MJ.

Nonetheless, the CSIRO GISERA still reports a lower liquefaction emissions intensity for the LNG produced at Darwin, despite the 25-degree Celsius difference in annual daily mean temperature between Hammerfest and the capital of the NT.

The range from Gan et al. are cited in a report on LNG emissions prepared by the CSIRO and published in June 2022 (CSIRO, 2022).

Five studies on the intensity of LNG exported from Queensland found a liquefaction intensity ranging between 4.72 to 6.2 gCO₂e/MJ, with a methane GWP of 28. The 4.72 gCO₂e/MJ value comes from a CSIRO GISERA report evaluating the lifecycle emissions of a coal seam gas to LNG project published in 2019, a study cited in the report on fracking in the Northern Territory (GISERA, 2023; Schandl et al., 2019). They found an LNG liquefaction carbon intensity of 0.26 tCO₂e/tLNG. The Pepper Inquiry cite Hardisty et al., 2012, which found an emission factor of 5.9 gCO₂e/MJ with a methane GWP of 21 (Hardisty et al., 2012). Reputex also used this value in their report on the Beetaloo.

The range of liquefaction emission intensity range is wider for WA's LNG: 3.76 to 7.6 gCO₂e/MJ, as compiled by the CSIRO. It should be noted that the lower bound of this range comes from a study published in 2010 when, according to the CSIRO, "most projects were only projected", and that the inputs were "based on many assumptions" (CSIRO, 2022). The production-weighted average of the liquefaction stage of Australian LNG, as estimated from the environmental approval stages of all the WA and NT plants, falls within the range of 0.30 to 0.40 tCO₂e/tLNG, as confirmed by the CSIRO study on the lifecycle emissions of Australian LNG (CSIRO, 2022).

The values included in Table 6 do not include the self-consumption of the plant, as the inputs and outputs are matching. In the same way, annual and cumulative emissions suggest that 320 PJ of shale gas are produced for LNG, and that 320 PJ of LNG leave the port of Darwin. In 2021, the Australian LNG production reached 77.4 Mt. According to the 2022 Energy Update, of the 4,747 PJ of gas supplied to LNG facilities during the year, 4,314 PJ was exported as LNG, while the remaining 433 PJ was consumed at the plants. It gives a rate of 55.7 PJ per MtLNG, marginally higher than the average for the years 2017 to 2021, which stands at 55.3 PJ per MtLNG (Department of Climate Change, 2022a).

Upon examination, it becomes evident that the proposed value of 3.5 gCO₂e/MJ for the emissions linked to the liquefaction of gas from the Beetaloo field falls well below both international estimates and the limited available data for Australia.

Based on the range provided by the international study by Gan et al. (2020), the emissions associated with LNG manufacturing should be revised by 17% to 117%. To retain conservative assumptions, we use the range of LNG plants in Australia, excluding CSG. This implies a 57% to 89% upward revision of the values used in the CSIRO GISERA report, and an LNG liquefaction intensity of 0.33 tCO₂e/tLNG.

Domestic consumption

Across all scenarios, 45 PJ of gas from the Northern Territory is expected to be combusted in Australia. In scenario 1, where the gas is utilised directly, the combustion process leads to the emission of 54.7 MtCO₂e over a 25-year period, or 2.19 MtCO₂e annually. This results in an assumed emission factor of 49 kgCO₂e per GJ.

The calculated emission factor of 49 kgCO₂e per GJ is 5% lower than the value from the National Greenhouse Accounts Factor workbook for fossil gas distributed via a pipeline, of 51.5 kgCO₂e per GJ (Department of Climate Change, 2023a).

Although relatively small in absolute terms compared to the other discrepancies outlined above, this difference is significant, as the emissions stemming from direct gas utilisation in Australia account for one-third of the abatement task in Scenario 1.

Table 6: Emission intensities for different applications of fossil gas

	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
H₂ 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

Source: CSIRO GISERA, 2023.

Compiling our results, we can recalculate the emission intensity of the gas from the Beetaloo using:

- Upstream emissions intensity ranges from 12.3 to 19.8 kgCO₂e/GJ, according to the recalculation using both the findings from Howarth et al. (2021) and the chemical composition of an indicative unconventional shale well in Australia.
- LNG liquefaction emissions range from 5.5 to 6.6 kgCO₂e/GJ, which corresponds to the range of liquefaction emissions for LNG plants in Western Australia and the Northern Territory. This falls conservatively into the range of Gan et al. (2020), of 4.1 to 7.1 kgCO₂e/GJ.

- Domestic direct gas consumption emission intensity is estimated to be 51.5 kgCO₂e/GJ, according to the National Greenhouse Accounts Factor workbook.
- Shipping and regasification emissions intensity of respectively 1.0 and 3.4 kgCO₂e/GJ, the range for Australian LNG supplied to China as per Gan et al. (2020).⁶
- LNG combustion emission factor of 56.5 kgCO₂e/GJ, calculated with the carbon content of fossil gas.
- For non-direct gas combustion and LNG applications, estimates from the CSIRO GISERA have been retained. Additional investigations would be necessary to determine the accuracy of these estimates for other usage scenarios.

Table 7: Comparison of the domestic emissions intensity for LNG

Intensity		Upstream emissions	LNG liquefaction	Total domestic emissions intensity of LNG
CSIRO GISERA	kgCO ₂ e/GJ	8.90	3.5	12.4
CH ₄ loss 0.7 - 1.0%	tCO ₂ e/tLNG	0.54	0.21	0.75
Revision	kgCO ₂ e/GJ	16.0 12.3 - 19.8	5.9 5.5 - 6.6	21.90 17.8 - 26.3
CH ₄ loss 1.8% - 2.6%	tCO ₂ e/tLNG	0.97	0.33	1.21
Difference (%)		56% - 150%	57 - 89%	44 - 113%

Notes: See the list of assumptions for more details.

⁶ The liquefaction, shipping and regasification intensity found by the CSIRO GISERA is at least 51% lower than the values found by Gan et al. (2020) for Australian LNG, and 37% lower than the results from Schandl et al. (2019).

Table 8: Comparison of the domestic emissions intensity for gas consumption in Australia

	Upstream emissions	Distribution	Use	Total
CSIRO GISERA (kgCO ₂ e/GJ)	7.9	1.5	47.1	57.5
Revised (kgCO ₂ e/GJ)	12.3 - 19.8	1.5	51.5	65.3 - 72.8
Difference (%)	56 - 150%	0%	9%	14 - 27%

The revised LNG intensity ranges from 61% to 134% higher than the estimates from the CSIRO GISERA. Additionally, the emissions intensity of the gas consumed in Australia is underestimated by 16% to 26%.

Recalculated onshore and global emissions from Beetaloo

Thanks to these revised intensity ranges, we can calculate the annual and cumulative emissions of the gas produced in the Beetaloo for each of the scenarios selected.

Scenario 1 was proposed during the preparation of the Pepper Inquiry and does not accurately mirror the current development plans in the Northern Territory, indicating that it may not be appropriate for present-day use. In 2023, Tamboran Resources announced plans to develop an LNG facility of an annual capacity of 6.6 Mtpa near Darwin, that would source its gas from the Beetaloo sub-Basin (Tamboran Resources, 2023b). For comparison purposes, we estimated its emissions using the factors from the CSIRO analysis. In the same way, a variant of scenario 5 that factors in an expansion of Tamboran’s LNG plant to a nameplate capacity of 20 Mtpa has been included.

Tables 7 to 10 show the emissions for scenarios 1 and 5 of the GISERA, and the emissions for synthetic scenarios where a 6.6 or a 20 Mtpa LNG plant is built in the Northern Territory (scenarios 1b and 5b).

As discussed earlier in this report, it appears that the CSIRO GISERA did not take into account the self-consumption of gas from the LNG plants in their analysis. This is evident from the fact that from the results of the lifecycle emissions analysis. in scenario 1, 320 PJ of gas are produced in the Beetaloo, 320 PJ of gas is transferred, and 320 PJ of gas is burnt as LNG.

Using an energy intensity of 55.3 PJ/MtLNG, and accounting for the 10.0% of gas used for LNG plants' self-consumption, Tamboran's facility would consume 401 PJ per year to output 365 PJ LNG. With a domestic consumption of 45 PJ, like in scenario 1, this brings the total production to 446 PJ per year. The same approach was used in the case of the construction of a 20 Mtpa plant.

To ensure comparability, we maintained the approach of not considering losses occurring at the plant in the recalculation of the emissions from the CSIRO GISERA scenario (scenarios 1 & 5).

However, it is important to recognise that the actual LNG output is expected to be lower than the raw gas input. This factor was considered in our calculations for the synthetic scenarios, which examine the impact of the operation of new 6.6 or 20 Mtpa LNG plants in the Northern Territory (scenarios 1b and 5b).

It should be noted that these recalculations only include revisions to emissions factors for natural gas and LNG. The climate impact of hydrogen, ammonia, methanol, and refinery products, which are all produced in scenario 5, was not investigated and therefore not revised.

Table 9: Comparison of annual emissions estimates for the CSIRO GISERA scenarios (MtCO₂e per year) and cumulative emissions estimates (MtCO₂e).⁷

Annual Emissions	Gas production	Transmission	Manufacturing	Domestic use	Total domestic	% of 2021	% of 2030	Total overseas	Global total (range)	
									Min	Max
Scenario 1 CSIRO GISERA Estimates	2.9	0.3	1.1	2.2	6.5	1.4%	1.9%	15.1	21.7	21.7
Scenario 1 Independent estimate	4.5 - 7.2	0.3	1.8 - 2.2	2.3	9.0 - 12.1	1.9% - 2.6%	2.6% - 3.4%	19.5	28.5	31.5
Scenario 5 CSIRO GISERA Estimates	8.5	1.0	14.5	9.1	33.1	7.1%	9.4%	34.3	67.4	67.4
Scenario 5 Independent estimate	13.9 - 22.3	1.0	16.0 - 16.8	9.3	40.1 - 49.3	8.6% - 10.6%	11.4% - 14.1%	44.2	84.3	93.5

Cumulative emissions	Gas production	Transmission	Manufacturing	Domestic use	Total domestic	% of 2021	% of 2030	Total overseas	Global total (range)	
									Min	Max
Scenario 1 CSIRO GISERA Estimates	73	9	9	55	164	35%	46.7%	378	542	542
Scenario 1 Climate Analytics estimate	113 - 180	9	46 - 54	58	225 - 302	48% - 65%	64% - 86%	487	712	789
Scenario 5 CSIRO GISERA Estimates	213	24	363	228	827	178%	236%	857	1684	1684
Scenario 5 Climate Analytics estimate	349 - 558	24	399 - 419	232	1003 - 1233	216% - 265%	286% - 352%	1104	2107	2337

⁷ Calculations of the emissions of the CSIRO GISERA's scenarios 1 and 5 do not take into account the self-consumption of gas for the LNG manufacturing process.

Table 10: Comparison of annual and cumulative emissions estimates for synthetic scenarios (building of a 6.6/20 million tonnes per annum LNG plant, MtCO₂e per year and MtCO₂e).⁸

Annual Emissions	Gas production	Transmission	Manufacturing	Domestic use	Total domestic	% of 2021	% of 2030	Total overseas	Global total (range)	
									Min	Max
Scenario 1b. - Tamboran 6.6 Mtpa LNG GISERA estimates	3.5	0.4	1.4	2.1	7.5	1.6%	2.1%	17.4	24.9	32.3
Scenario 1b. - Tamboran 6.6 Mtpa Climate Analytics estimates	5.5 - 8.9	0.4	2.1 - 2.5	2.3	10.4 - 14.1	2% - 3%	4.0%	22.4	32.8	46.9
Scenario 5b. - Tamboran 20 Mtpa LNG GISERA estimates	12.8	1.4	15.8	9.1	39.1	8.4%	11.1%	52.0	91.1	130.2
Scenario 5b. - Tamboran 20 Mtpa LNG Climate analytics estimates	19.9 - 31.9	1.4	18.0 - 19.2	9.3	48.6 - 61.8	10% - 13%	17.6%	67.0	115.6	177.5

Cumulative emissions	Gas production	Transmission	Manufacturing	Domestic use	Total domestic	% of 2021	% of 2030	Total overseas	Min	Max
Scenario 1b. - Tamboran 6.6 Mtpa Climate Analytics estimates	139 - 222	11	52 - 62	58	259 - 353	56% - 76%	74% - 101%	560	820	913
Scenario 5b. - Tamboran 20 Mtpa LNG GISERA estimates	319	36	396	227	977	210%	279%	1301	2278	2278
Scenario 5b. - Tamboran 20 Mtpa LNG Climate Analytics estimates	498 - 798	36	451 - 481	232	1216 - 1546	262% - 333%	347% - 441%	1675	2891	3221

⁸ For these synthetic scenarios, we included the self-consumption of gas for LNG liquefaction both in the calculations using the CSIRO GISERA factors and in the independent recalculations.

Our analysis indicates that domestic emissions resulting from the development in scenario 1 would fall within the range of 9 to 12 MtCO₂e, as opposed to the 7 MtCO₂e estimated by the emissions intensities from the CSIRO GISERA report. Domestic emissions from a development in line with scenario 5 would range between 40 to 49 MtCO₂e per year, compared to 33 as per the CSIRO GISERA.

Domestic emissions from the exploitation of shale gas in the Northern Territory are underestimated by 21% to 84%.

The emissions linked to the gas extracted in the Northern Territory would mostly occur overseas during the combustion of the exported LNG. As these emissions are beyond the responsibility of Australian stakeholders, they are not considered in the abatement tasks.

The lifecycle greenhouse gas emissions resulting from Tamboran's current development plans, in line with the CSIRO GISERA scenario 1 (scenario 1b), would amount to between 33 and 47 million MtCO₂e annually, accounting for 7 and 10% of Australia's 2021 total emissions.⁹ Over the 25-year lifetime of the project, this represents between one and a half to two times Australia's 2021 emissions.

For comparison purposes, the average emissions intensity of a new passenger car or a new light SUV in Australia in 2021 was 146.5 gCO₂ per kilometre (National Transport Commission, 2022). In the 2019-2020 period, a passenger vehicles travelled an average of 11,100 kilometres (Australian Bureau of Statistics, 2020). As a result, the domestic emissions generated in scenario 1b would be equivalent to putting approximately 6-8 million new cars or light SUVs on the roads of Australia. Alternatively, if the development of a 20 Mtpa plant were to occur, it could generate emissions equivalent to adding 30-38 million new cars to the country's roads.

A larger scale development of the Beetaloo sub-Basin would generate significantly higher emissions. An exploitation of the Basin following the lines of the fifth scenario included in the CSIRO GISERA analysis, with the building of a 20 Mtpa LNG plant (scenario 5b), would generate domestic emissions of 49 to 62 MtCO₂e per year, compared to 39 using the CSIRO GISERA's emission factors. Over the course of 25 years, including overseas emissions, this would release up to 2.9 to 3.2 GtCO₂e in the atmosphere (2.3 using the emissions factors from the CSIRO GISERA), six to seven years' worth of Australia's current emissions levels.

The complete set of results is available in Tables 9 and 10.

⁹ The summary of the assumptions used is available in Annex B.

Mitigating emissions from the Beetaloo

The purpose of the CSIRO GISERA report is to assess to what extent it is possible to mitigate and offset emissions from the gas produced in the Beetaloo. Mitigation refers to the implementation of actual measures to reduce emissions, such as the electrification of processes coupled with the rollout of renewable capacities and should be prioritised over offsetting.

Offsetting potential

The CSIRO GISERA report takes the stance that emissions not abatable thanks to state-of-the-art – if not unproven – approaches will be offset, to conform with recommendation 9.8 of the Pepper Inquiry. This would create an enormous pressure on the Australian Carbon Credit Units (ACCUs) market and on Australia’s environment as most of these offsets would be linked to the land sector.

It also assumes that ACCUs have full integrity, an assumption that has been questioned by researchers. Yet, offsets are instrumental to make fracking the Beetaloo Basin compliant with Recommendation 9.8 of the Pepper Inquiry. In scenarios with a production of 365 PJ per year, between 59 and 83% of the abatement comes from domestic offsets. The share decreases to 34% in the large-scale development scenario, where most carbon credits are obtained overseas.

The CSIRO GISERA bases these high levels of offset use on previous works from the CSIRO. In 2020, the research agency assessed the carbon sequestration potential in the land sector beyond abatement already locked in, at different price levels (Roxburgh et al., 2020).¹⁰ The report from Roxburgh et al. (2020) offers an overview of the possible supply of ACCUs linked to land use by modelling the technical and economic feasibility of the different ERF land-based methods. 65% of ACCUs generated since the start of the scheme came from the land sector.

The numbers provided by the studies from the CSIRO do not represent the realisable sequestration potential. The figures obtained by Roxburgh et al. (2020), and later by Fitch, Battaglia, Lenton, et al. (2022) do not consider trade-offs resulting from competition with other sectors, social license, and extreme events such as drought and bushfires. There can be a significant difference between the technical, economic, and realisable potentials, as emphasised by Fitch et al (2022).

¹⁰ Roxburgh et al. (2020) considered abatement contracted as of May 17, 2020. The Emissions Reduction Fund contract register (ERF, 2023) provides the data for abatement contracted up until February 2023. The total annual abatement contracted between May 2020 and February 2023, including from non-land-related projects, is 3.1 million ACCUs (Emissions Reduction Fund, 2023).

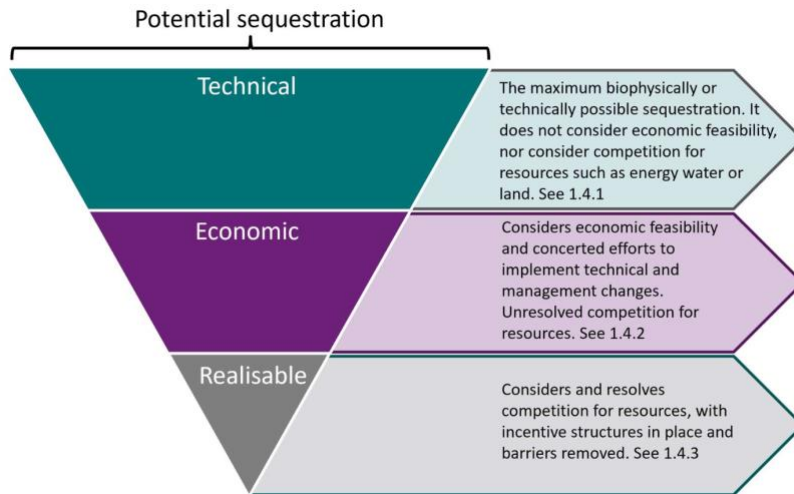


Figure 14: Difference between technical, economic, and realisable potential for sequestration

Source: Fitch et al, 2022

The Roxburgh et al. (2020) study uses multiple method-specific assumptions. A key variable present in almost all methodology assessments is the hurdle rate. A higher hurdle rate may indicate a greater level of risk, which may require a more significant return on investment to be considered worthwhile. Increasing the hurdle rate constrains the potential, as only more financially viable projects are considered feasible. As in the example shown below, lower hurdle rates are associated with higher sequestration potential. For most methods, both sequestration values at years 10 and 25 are provided.

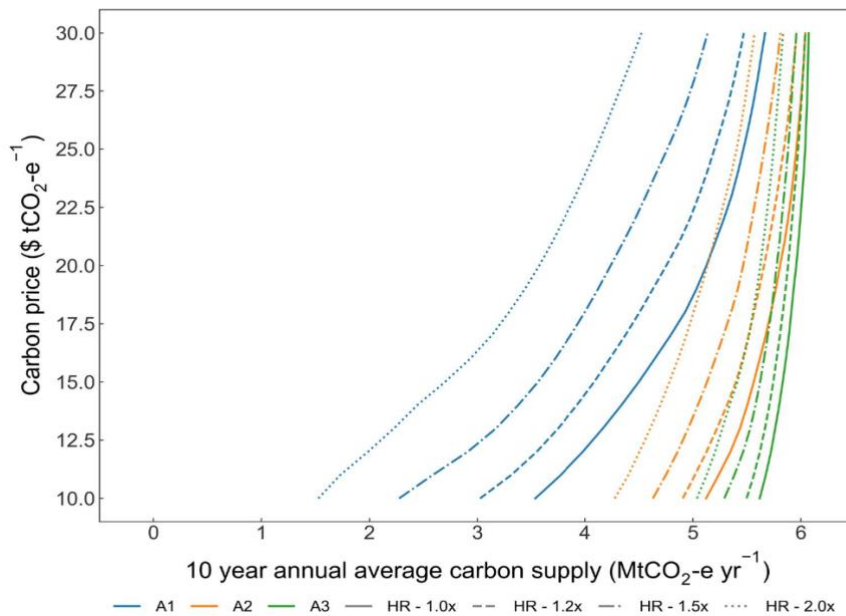


Figure 15: Example of annualised technical and economic potential sequestration curve.

Native Forest from Managed Regrowth method (Source: Roxburgh (2020)).

The offsetting potentials they derive from the CSIRO works are summarised in Table 13 of the report.

Table 11: Annual abatement potential and abatement density per carbon price and method

ERF methodology	Carbon price = \$15/t		Carbon price = \$30/t	
	Abatement/ha (t CO ₂ e /year)	Total abatement (Mt CO ₂ e/ year)	Abatement/ha (t CO ₂ e /year)	Total abatement (Mt CO ₂ e/ 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.

Source: CSIRO GISERA, 2023

All the values from Table 11 that have been cited above, except for the numbers for the Plantation Forestry and Measurement-based methods for new farm forestry plantations, are taken from Roxburgh et al. (2020). These numbers are included in Fitch et al. (2022). The authors of the latter report mention that “modelling of economic sequestration for Farm Forestry (without project area constraint) has not yet been undertaken”. Only technical sequestration has been considered.

The CSIRO GISERA prioritises assumptions that provide the highest potential whenever possible. For all methods, the values used correspond to a hurdle rate of 1.0. This implies that the offset provider expects to earn a return that is equal to the cost of capital, and therefore, the investment is deemed risk-free.

The annualised sequestration values are calculated based on the sequestration at year 25, which is significantly higher than the value for sequestration at year 10, as indicated in the same report. Regarding methods that involve clearing, such as the native forest from managed regrowth methodology, the highest clearing rate of \$300 per hectare is chosen.

As a consequence of these choices, the resulting offset supply potential is remarkably high. According to the CSIRO GISERA, land-based sequestration has the potential to mitigate up to 163 MtCO₂e per year, at a price point of \$30 per tonne. Such sequestration potential is sufficient to offset the entire Safeguard Mechanism emissions. For contextual reference, at the time of writing, the ACCU price stood at \$37 (Jarden, 2023).

By tracing the numbers presented in Figure 11 to their respective sources in the reports from Roxburgh et al. (2020) and Fitch et al. (2022), we can deduce the assumed yearly sequestration at each price point. The supply curve derived using the CSIRO GISERA assumptions regarding offset potential supply shows their liberal stances.

At the \$75 price mark, which triggers the Safeguard Mechanism containment measure, land-based offsetting projects with over 400 MtCO₂e of sequestration per year are deemed technically and economically feasible. This level of sequestration represents over 85% of Australia's 2021 emissions (Department of Climate Change, 2023b). At 90\$ per tCO₂e, a carbon price lower than in the European Union, there would be enough technical and economic annual offsetting potential available to make Australia net zero.¹¹

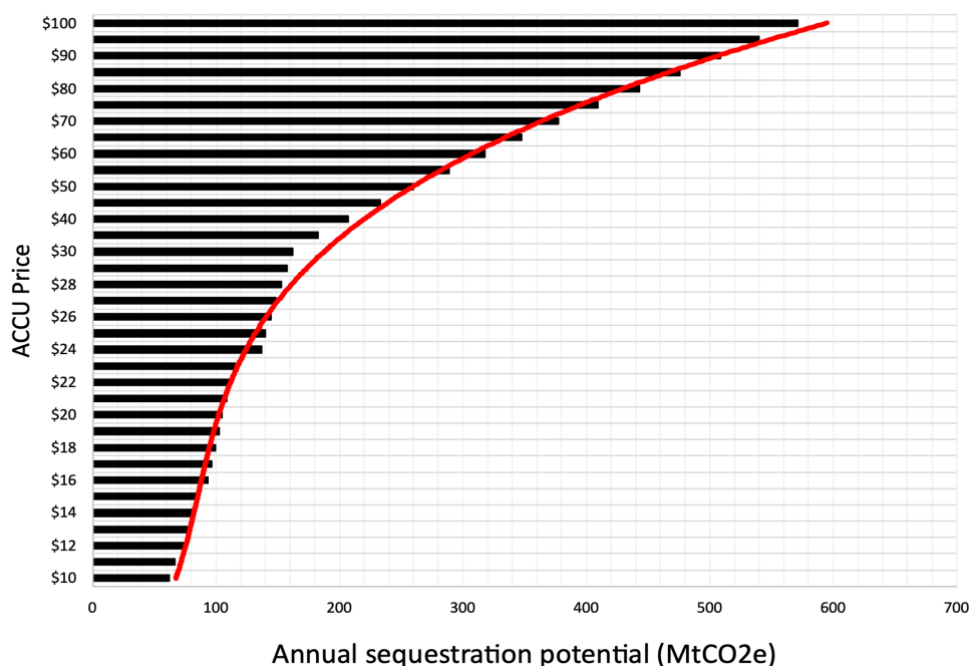


Figure 16: Supply curve of annual technical and economic sequestration potential available in Australia.

Source: CSIRO GISERA, 2023.

¹¹ The discrepancy occurring at an offsetting price of \$24 per tonne of CO₂e is due to a jump in estimates of sequestration from conversion of annual pasture to perennial pasture activity in Roxburgh et al. (2022).

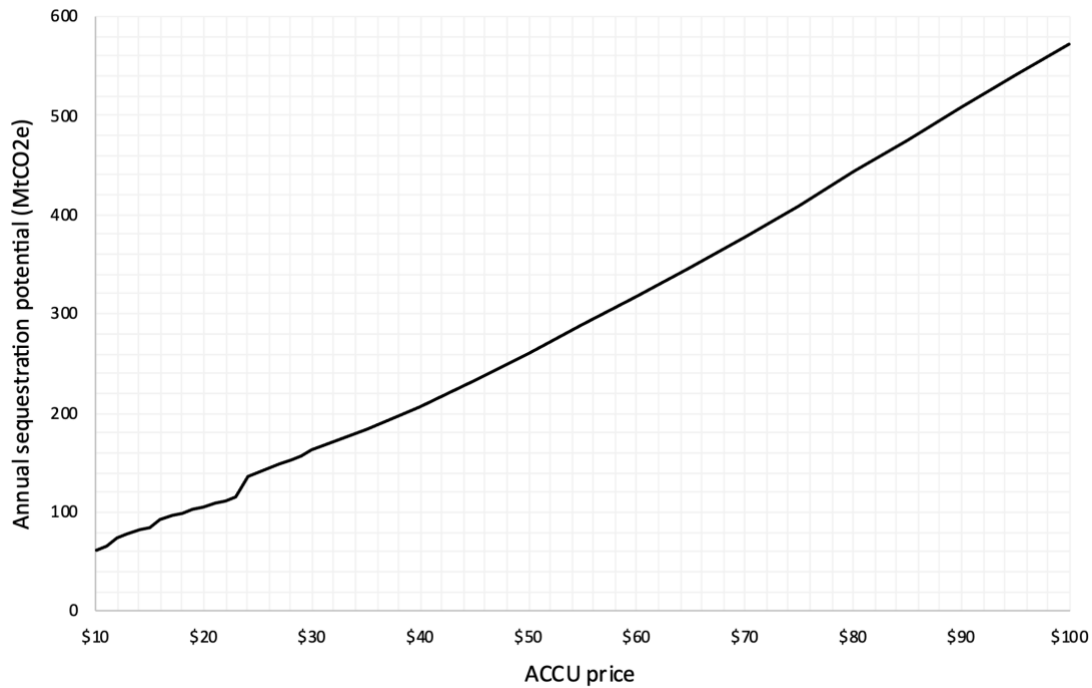


Figure 17: Cumulative annual sequestration economic and technical potential available in Australia per ACCU price.

Source: CSIRO GISERA, 2023.

To what extent the issues with current offsetting methodologies explain these figures is subject to further investigations.

Australia’s current climate policies still rely extensively on land sequestration. In the “with additional measures” scenario of the 2022 Projections, which includes the Safeguard Mechanism reform and the national 82% renewable target, Australia’s emissions decrease by 41% in 2030 compared to their 2005 levels including land use, land-use change and forestry (LULUCF) but by only 35% excluding LULUCF (Department of Climate Change, 2022b)

Researchers from the Australian National University have raised concerns about the integrity of Australian offsets since 2020. Their study of the implications of the Chubb review estimates the number of high-risk ACCUs from existing human-induced regeneration projects, landfill gas and avoided deforestation projects flowing to the market at 61 MtCO₂e between 2023 and 2030.

Another paper, published in June 2023, confirms that the vast majority of human-induced regeneration projects, one of the most widely used offsetting methodology, are likely to have been significantly over-credited (Macintosh et al., 2023b). The same month, the Government announced it will launch a full audit of 1,000 offset sites (Minister for the Environment, 2023). Restricting market participants from using low-integrity offsets

would tighten supply and put upward pressure on ACCU prices, altering the viability of offsetting emissions from shale gas extraction in the Northern Territory (Macintosh et al., 2023a).

At present, the total volume of ACCUs held by the ERF and not cancelled or relinquished add up to about 113.4 MtCO₂e, with an average purchase cost of about \$14.5/tCO₂e (ERF, 2023). The average price of an ACCU released under a fixed delivery contract was \$11.8/tCO₂e as of the third quarter of 2022.

Offset use

Once the available potential was determined, the CSIRO GISERA assumed that 10% of the potential available at \$30 per tonne of CO₂e and 30% of available offsets from fire management in the Northern Territory, would be utilised to offset Beetaloo's emissions.

10% of the potential available at \$30/tCO₂e represents 16 MtCO₂e per year, more than 40% of the net annual emissions reduction target of the Safeguard Mechanism between now and 2030. This is conveniently sufficient to offset the emissions of the 4 scenarios where the gas production from the Beetaloo sits at 365 PJ per year.

In comparison, the 2021 Long-Term Emission Reduction plan states that 27 MtCO₂e per year of sequestration will be generated in 2050 thanks to land-based methods, assuming a carbon price of \$25/tCO₂e and including sequestration from the HIR method (CSIRO GISERA, 2023).

Setting an upper bound on the use of offsets is legitimate, as the economic and technical potentials derived from the CSIRO studies do not equate to realisable potential. However, it does not accurately represent the decision that Beetaloo's developers will have to make.

Given the GISERA's assumption of an abundant supply of affordable ACCUs, the question arises whether gas producers would find it profitable to invest in actual mitigation measures, such as deploying more rigorous methane monitoring systems or adopting low-bleed pneumatic controllers. Should the cost of purchasing offsets be more economically sound than that of implementing on-site abatement measures, then gas producers would be likely to choose the former. The abatement hierarchy – avoid, reduce, offset – is not mandatory for gas producers.

Recent industrial activities across Australia, coupled with the Safeguard Mechanism reform, have brought attention to the issue at hand. The developers of the Perdaman urea plant in Western Australia, for example, have outlined several mitigation options in their environmental assessment, which includes the construction of a desalination plant. However, the document fails to specify the implementation timeline or confirm whether these options will be carried out at all. At present, most of the plant's abatement targets

are expected to be attained through offset acquisition (Climate Analytics, 2023b). Professor Chubb, who led the independent review of Australia’s offsetting scheme, explained to The Australian that “offsets can’t be a device which big emitters use not to [...] do something about reducing emissions” (The Australian, 2022).

Overall, between 59 and 83% of the abatement from the Beetaloo comes from domestic offsets in the scenarios where 365 PJ per year are produced. This share decreases to 34% in the large-scale development scenario, where a massive amount of emissions is compensated with international offsets.

A total of 4.8 to 11.2 MtCO₂e of domestic offsets would be consumed to compensate the lifecycle emissions from the gas from the Beetaloo. In comparison, the government anticipates Safeguard Mechanism facilities to use 9 MtCO₂e worth of ACCUs between 2021 and 2030 (Department of Climate Change, 2022b).

If we exclude offsets from the human-induced regeneration methodology, offset use ranges between 51-71% for scenarios where production is 365 PJ/yr, and 24% for the large-scale production scenario, without taking into consideration potential substitutions.

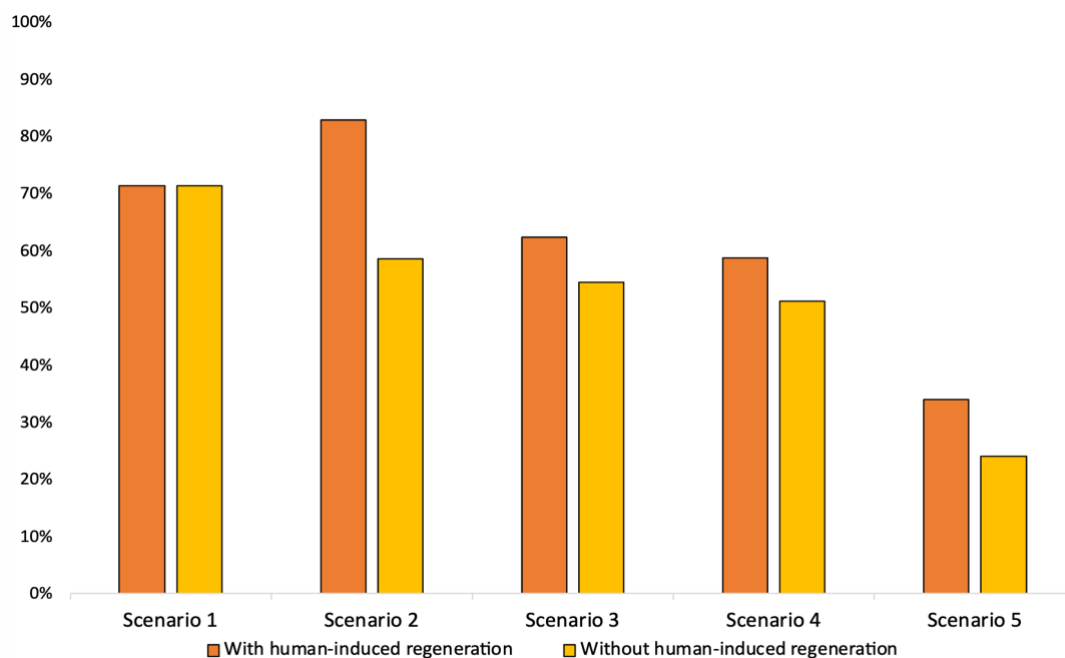


Figure 18: Share of abatement coming from domestic offset per scenario.

Source: CSIRO GISERA, 2023.

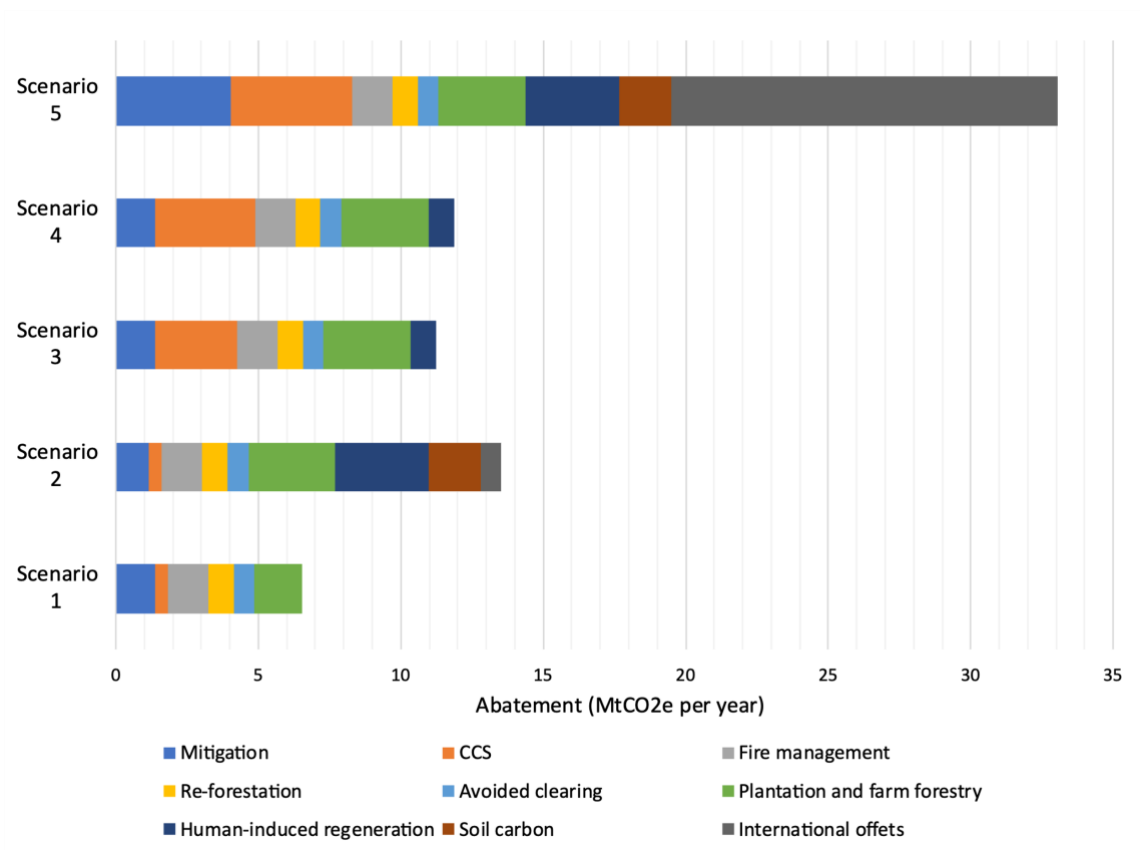


Figure 19: Annual abatement per source

Source: CSIRO GISERA, 2023.

Offset land use

As a result of the varying density of abatement between methods, the area required to offset the emissions of the gas extracted in the NT varies significantly depending on the scenario.

Using the abatement per hectare included in the report, the area required in Australia for the offsets assumed to go towards mitigating the impact of gas from the Beetaloo sub-Basin ranges from 0.2 million to 2.9 million hectares.¹²

The upper bound is skewed upward by the low density of the measurement of soil carbon sequestration in agricultural systems and human-induced regeneration of native forest

¹² By taking the average density of abatement at the \$15/tCO₂e and \$30/tCO₂e mark, like the authors for the total annual abatement. Without taking into account savanna fire management sequestration and emissions avoidance.

methods, two offsetting methods that are predominant in scenarios 2 and 5 (see figure 19).

International offsets

As the CSIRO GISERA note, *"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"*.

As of now, Australian companies cannot make use of carbon credits issued abroad to meet their Safeguard Mechanism baselines. The fifth scenario of the CSIRO GISERA report suggests that extensive utilization of internationally issued offsets would be required to execute a large-scale development plan for the Beetaloo Basin.

Approximately 42% (13.6 MtCO₂e) of the abatement resulting from this scenario would need to be sourced overseas, almost as much as the annual emissions from all the new projects assumed to come online in the Safeguard Mechanism in 2030 by the government. With the restriction on the use of international offsets, at the moment, achieving such abatement is impossible.

This situation could change soon. The Safeguard Mechanism submission by the Australian Petroleum Production and Exploration Association (APPEA), a lobby group that represents the Australian oil and gas industry, called for the government to allow access to international offset (ABC, 2022a). The Federal Government suggested they could be allowed if they were sufficient guarantees of their integrity (ABC, 2022a).

Australia has been pushing the Indo-Pacific carbon offset scheme, designed in collaboration with the industry and launched at the COP26 in 2021, which would allow emissions occurring in Australia to be offset in neighbouring countries (Department of Climate Change, 2023d).

There are significant integrity risks for international carbon credits. Mechanisms for enabling the use of credits issued abroad require a robust accounting system (Schneider & La Hoz Theuer, 2019). Experience shows that disparate transparency, lack of standardisation and country risks make it challenging to guarantee unit quality (Australian Banking Association, 2022; Schneider & La Hoz Theuer, 2019).

Carbon capture and storage (CCS)

Carbon capture and storage technology involves capturing CO₂, either pre or post-combustion, and injecting it into geological reservoirs. The technology has primarily been employed in enhanced oil recovery, a process that entails injecting pressurised CO₂ into

oil reservoirs to extract more oil, ultimately leading to an increase in greenhouse gas emissions.

The use of carbon capture and storage technology is a way for fossil producers to prolongate their activities. CCS was a crucial aspect of the Coalition's climate policy, and was named among its priorities area as part of the Technology Investment Roadmap (Climate Action Tracker, 2022). The Moomba facility, designed by Santos for sequestering carbon dioxide from onshore gas extraction, is, in essence, rebranded enhanced oil recovery infrastructure (Australia Institute, 2021).

CCS is a proposed solution for mitigating the emissions from the Beetaloo Basin, and its potential is investigated by the CSIRO GISERA. The proposed CCS project at Middle Arm Point involves constructing a pipeline into the territorial waters of Timor Leste and ensuring that carbon dioxide remains permanently isolated from the atmosphere under the seabed for an extended period. However, achieving this goal has not been accomplished in practice. The federal government is currently attempting to pass a bill in parliament to enable the project to move forward. (Cox, 2023b).

The most suitable area for deploying carbon capture and storage infrastructure in the Northern Territory would be near Darwin. The developers of the Middle Arms precinct plan to store CO₂ in the Petrel sub-Basin, 180 km west of Darwin, or/and in the soon-to-be-depleted Bayu-Undan field 500 km away from the side (Northern Territory Government, 2021).

Although the CSIRO GISERA study concentrates on technical feasibility, the introduction of CCS would impose a substantial financial burden on the project's viability. The cost of CCS is influenced by factors such as the sink's distance from the CO₂ source and the storage type. Carbon dioxide storage in saline aquifers is significantly more costly than in depleted reservoirs. The capital expenses are significant and would affect the project's viability, which is already being challenged by Recommendation 9.8 of the Pepper Inquiry.

Data is scarce on the cost of CCS in Australia. The latest data points are from 2015, when a report from the Australia Power Generation Technology found lifecycle costs varying widely from \$5/tCO₂ to \$790/tCO₂ (Fitch et al., 2022). The Global CCS Institute compiled the following indicative prices for carbon sequestration (Kearns, 2021). These prices were cited in a CSIRO study of the potential for carbon sequestration in Australia and are used by the CSIRO GISERA (Fitch et al., 2022; CSIRO GISERA, 2023):

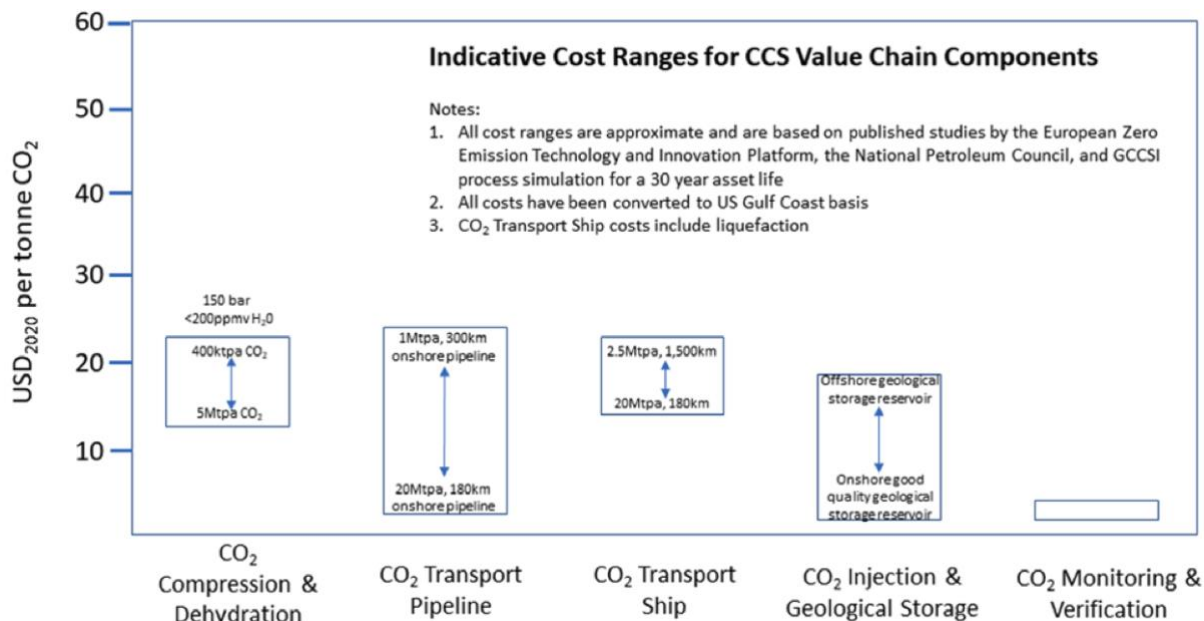
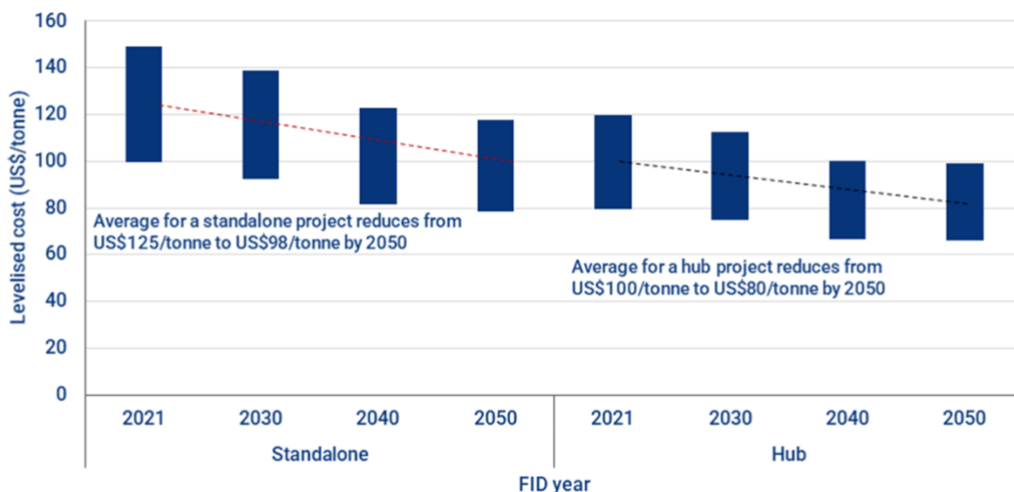


Figure 20: Cost range for CCS value chain

Source: Kearns, 2021.

Wood Mackenzie found CCS levelised costs well above current ACCU prices, even when industries cooperate to form a hub like is planned for the Middle Arms precinct (Evans, 2021).

CCS levelised costs: multi-user hubs versus standalone projects



*Hub means a CO₂ transportation and storage service, which is developed and operated separately to the capture projects. Hubs will receive CO₂ from multiple sources from potentially multiple industries. The cost to use a hub for transportation and storage will be opex, on a per tonne basis, similar to an offtake arrangement in LNG or oil and gas production. Example of hubs in development are Northern Lights (Norway), East Coast Cluster (UK) and Alberta Carbon Grid (Canada)

Source: Wood Mackenzie

Figure 21: Levelised CCS costs: hubs vs standalone projects

Source: Wood Mackenzie, 2021.

The options available to sequester downstream emissions from Beetaloo's shale gas are of varying maturity. Although there is operating but inadequate CCS infrastructure for mitigating fossil gas processing emissions, the use of this technology for decarbonising power generation is still in its early stages of development.

The separation of raw gas and carbon dioxide is a crucial element of gas processing, making CCS implementation a low hanging fruit for this specific use case. However, carbon capture is a challenging, energy-intensive, and unprofitable process when CO₂ concentration is low, such as in the exhaust gas of coal and gas power plants. The IEA provides a cost of carbon capture varying from \$40-\$340 USD/tCO₂ for streams with low CO₂ concentration, and \$15-\$80 USD/tCO₂ for processes with high concentration, such as the synthesis of hydrogen, ethylene oxide, or ammonia (IEA, 2019). Almost 90% of the proposed CCS capacity intended for the power sector has failed to materialise (IEEFA, 2022b).

According to the CSIRO GISERA, none of the post combustion capture infrastructures discussed in the report captures more than 30% of the emissions from their power plants. However, they estimate that the deployment of post-combustion capture could result in emissions reductions of up to 0.46 MtCO₂e per year, while requiring expensive retrofitting of existing gas-fired power plants. The CSIRO GISERA provides a price range for CCS for fossil gas-fired combined cycles of \$86-\$222 per tonne – between 2 and 6 times the current ACCU price.

Throughout their discussions of CCS, beyond power generation, the CSIRO GISERA assumes a uniform carbon capture rate of 90%.

Such an assumption is common in the literature, yet it is still generous. The IEA reports that no plants using technologies for capture rates above 90% are operating at present (Brandl et al., 2021; IEA, 2023a).

Moreover, existing CCS facilities are not performing up to their disclosed capacities. According to the Institute for Energy Economics and Financial Analysis, ten of the 13 flagship projects they reviewed, which represent nine tenths of the total carbon capture capacity in their sample, are either underperforming or failing. Most of them fall significantly short of expectations, leading to the conclusion that “the 90% emission reduction target generally claimed by the industry has been unreachable in practice” (IEEFA, 2022b). Supplementary research confirms these results and finds that most CCS facilities underperform by up to 30% relative to their nameplate capacity (Zhang et al., 2022).

This discussion has implications for the production of hydrogen, where the use of CCS is often touted as a game-changer. Recent documents by the Northern Territory

government obtained by the Environment Centre NT thanks to a FOI show that all of the three scenarios for the development of the Middle Arm precinct include CCS, and two of them the production of blue hydrogen (ABC, 2023c).

Lower capture rates can negate the emissions reductions from the production of blue hydrogen. At a 60% capture rate, burning hydrogen produced from fossil gas with CO₂ capture is only 17% less emissive than directly burning fossil gas (IEA, 2023a). Coincidentally, as of 2022, the two operational blue hydrogen commercial plants capturing more than 1 MtCO₂ per year have a historical effective capture rate ranging from less than 50% to almost 70%, well below their pledges and after having been heavily subsidised (IEEFA, 2022a).

The CSIRO GISERA assumes a 47% reduction of emissions from the production of blue hydrogen thanks to CCS, from 12.1 kgCO₂e/kgH₂ to 6.4 kgCO₂e/kgH₂. This is consistent with recent lifecycle assessments of the emission intensity of hydrogen from the IEA (IEA, 2023a). In comparison, hydrogen produced with solar and onshore wind has lifecycle emissions of a few grams of CO₂e per kilogram of hydrogen.

Methane leakage rates have a substantial influence on the emissions associated with blue hydrogen throughout its lifecycle. According to the first peer-reviewed attempt to account for fugitives in the lifecycle assessment of blue hydrogen emissions, assuming a methane leak rate of 3.5% and considering 20-year global warming potentials, blue hydrogen is only 9-12% less carbon-intensive than grey hydrogen.

The lifecycle emissions of blue hydrogen also surpass those of direct fossil gas combustion by 20%. Importantly, this finding remains valid even at a 1.54% leaking rate, which is lower than the one considered in the Pepper Inquiry (R. Howarth & Jacobson, 2021). For this study, the authors assumed that the capture rate was 85% and that the carbon dioxide was stored underground permanently.

These findings challenge the narrative that exploiting the Beetaloo to develop the Middle Arm precinct will, according to Minister for Infrastructure Catherine King, contribute to “setting up our economy for a sustainable future” (House of Representatives, 2022).

Conclusion

Our findings suggest that the estimations of the emissions from the exploitation of shale gas in the Northern Territory are underestimated, and that the mitigation potential - through mitigation measures or through offsetting - are overestimated.

Evaluating the cost impact of purchasing offsets on the viability of exploiting the Beetaloo sub-Basin is beyond the scope of the CSIRO GISERA report but warrants attention.

Findings from Reputex and the Commonwealth Bank demonstrate that the cost of satisfying the stipulations of Recommendation 9.8 of the Pepper Inquiry could act as a deterrent for project developers (Commonwealth Bank of Australia, 2023; Reputex, 2021). Estimates of supply cost for gas from the NT cited by the IEEFA find that it is not competitive compared to other sources, by a large margin (IEEFA, 2023; Qenos, 2021). It is still unclear as to who will be responsible for offsetting the emissions related to shale gas sourced from the Northern Territory (ABC, 2023b; Senate, 2023).

Beyond a pragmatic assessment of the investigation from the CSIRO GISERA, theoretical considerations make the purpose of the report problematic. Assuming the deployment of mitigation options, systematic implementation of carbon capture and storage infrastructure, and unlimited access to domestic and international offsets, any conceivable project can be rendered net-zero on paper.

Annex A: Comparison of lifecycle analyses

This annex provides the lifecycle emissions estimates from the CSIRO GISERA, the Pepper Inquiry and Reputex. The Reputex report uses the emissions factors from the Pepper Inquiry, with a lower GWP.

Table 12: Annualised emissions from the exploitation of the Beetaloo sub-Basin

Scenario	Gas production	Transmission	Manufacturing	Domestic use	Oversea use	Total
Sc. 1 (Domestic gas and LNG)	2.9	0.3	1.1	2.2	15.1	21.8
Sc. 2 (Domestic gas, LNG & refinery)	2.4	0.2	1.8	9.1	9.4	23.0
Sc. 3 (Domestic gas, LNG & chemicals)	2.9	0.3	5.8	2.2	9.4	20.7
Sc. 4 (Domestic gas, LNG & hydrogen)	2.9	0.3	6.5	2.2	9.4	21.3
Sc. 5	8.5	1.0	14.5	9.1	34.2	67.3

Note that these emissions were annualised from the 25-year life calculations. They do not reflect the ramp-up of production and emissions. Source: CSIRO GISERA.

Table 13: Annualised emissions from the exploitation of the Beetaloo sub-Basin

	Upstream (Mt p.a.)	Conversion to LNG (Mt p.a.)	Transport (Mt p.a.)	Regasification (Mt p.a.)	Combustion (Mt p.a.)	Full production lifecycle emissions (Mt p.a.)	Total lifecycle emissions (Cumulative Mt over 20-years)
High scenario (Australia and overseas)	16	6	2	1	64	89	1,358
Use of gas in Australia (660 TJ/day)	16	6			12	34	523
Mid scenario (use of gas in Australia)	5				19	24	368
Low scenario (use of gas in Australia)	1				4	5	59

Source: Reputex, 2021.

Table 14: Estimated emissions from the exploitation of the Beetaloo sub-Basin, based on the emissions from an American shale gas field.

Total gas production TJ/day	Location of emissions	Life cycle GHG emissions ¹⁶⁰ per year Mt CO ₂ e/y	Proportion of Australia's emissions for 2015 ¹⁶¹ %	Proportion of global emissions %
	Based on a 100-year GWP (= 36)			
365 (1,000) ¹⁶²	Australia	26.5	45	0.05
73 (200)	Australia	5.3	0.9	0.01
1,240 (3,400) ¹⁶³	Australia	38.9	6.6	0.07
1,240 (3,400) ¹⁶⁴	Australia and overseas ¹⁶⁵	98.8	n/a	0.17
	Based on a 20-year GWP (= 87)			
365 (1,000)	Australia	31.6	3.9	0.04
73 (200)	Australia	6.3	0.8	0.01
1,240 (3,400)	Australia	56.2	7.0	0.07
1,240 (3,400)	Australia and overseas	116.3	n/a	0.15

Source: Pepper Inquiry, 2018.

Annex B: Summary of assumptions

Table 15: Summary of assumptions used for the independent recalculations.

Gas breakdown	Range of methane emissions as part of the total emissions (%)
Well fracturing	0-100% ¹³
Gas processing	10-40% ¹⁴
Transmission	50-100% ¹⁵

gCO ₂ e/MJ	CSIRO/GISERA	Revised factors
Gas production and processing	7.9	12.3 – 19.8 ¹⁶
LNG liquefaction	3.5	5.6 – 6.6 ¹⁷
LNG Shipping	Outside of scope (0.9 gCO ₂ e/MJ for shipping)	3.4 ¹⁸
LNG Regasification		1.0 ¹⁹
Combustion of LNG	46.4	56.5 ²⁰
Combustion of gas distributed through pipeline	47.1	51.5 ²¹

¹³ In the indicative field mentioned in the Pepper Inquiry, methane represents 82% of the emissions related to well construction.

¹⁴ In the indicative field mentioned in the Pepper Inquiry, methane accounts for 22% of the emissions related to gas processing.

¹⁵ In the indicative field mentioned in the Pepper Inquiry, methane amounts for over 90% of the emissions related to transport and distribution.

¹⁶ Value based on recalculation for a range of methane leakage rate, using the methane leakage rate and emissions from Howarth (2021) and recalculation using the flow from an unconventional gas well in WA. These results are in line with values reported in the Pepper Inquiry report on the Beetaloo, as well as with the emission intensity from shale gas in the United States, Europe and China (see literature review).

¹⁷ This range corresponds to the liquefaction emissions detailed by gas producers in Western Australia and in the Northern Territory, as specified in the Environmental Impact Statements of their projects. This falls conservatively into the range provided by Gan et al. (2020) for gas supplied to China of 4.1-7.6 gCO₂e/MJ, which includes LNG imported from Australian plants.

¹⁸ Data from Gal et al. (2020) for LNG shipped to China from the Gorgon and Jansz-Lo. In 2021-22, 30% of Australia's LNG was exported to China. 81% of Australia's LNG was exported to China, Japan and Korea (Department of Industry, Science and Resources, 2023).

¹⁹ Same as footnote 16.

²⁰ Value based on the carbon content of fossil gas.

²¹ Emission factor from consumption of natural gas distributed in a pipeline in the Australian National Greenhouse Accounts Factors.

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