



Australia's National
Science Agency

Northern Territory Low Emissions Carbon Capture Storage and Utilisation Hub

Suggested Business Model and Execution Plans – Task 14 Report

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Foreword

Transitioning the global energy system while rapidly reducing emissions to net zero by 2050 is a vast and complex global challenge.

Modelling of a range of emissions pathways and decarbonisation scenarios from the Intergovernmental Panel on Climate Change (IPCC) (2023), International Energy Agency IEA (2024) and Net Zero Australia NZA (2024) shows that to meet net zero greenhouse gas emissions targets by 2050, a wide range of emissions reduction technologies will be required to decarbonise existing and future industries globally IPCC (2023).

These organisations identify that emissions elimination from hard-to-abate and high-emissions industries will require the use of carbon capture and storage (CCS) alongside other abatement strategies, such as electrification, underpinned by power generation from renewable energy sources such as photovoltaics and wind.

Globally, there is considerable effort to identify industrial hubs and clusters where common user infrastructure can enable rapid decarbonisation of existing industries and enable future low-emissions industrial development.

Australia has an opportunity to create new low-carbon growth industries and jobs in these areas, but lacks the infrastructure, skills base and business models to realise this. The transition to net zero will have a disproportionate impact on regional communities, particularly those reliant on industries in transition, but it may also create economic opportunities through a wide range of new industries and jobs suited to regional areas.

The Commonwealth Scientific and Industrial Research Organisation (CSIRO) is working to identify decarbonisation and transition pathways for existing and potential future industries that may be established in the Northern Territory by developing a Low Emissions Hub concept in the Darwin region.

CSIRO has established a portfolio of projects to explore and evaluate a range of approaches and technologies to quantify and achieve the required emissions reductions. This includes research into the Northern Territory's renewable energy potential, hydrogen demand, generation and storage capacity, and carbon capture utilisation and storage (CCUS) potential. CSIRO is working collaboratively with industry and governments to understand their needs, drivers and strategic directions so that our research is informed and relevant. This includes establishing appropriate pathways and partnerships to understand and incorporate the perspectives of First Nations peoples.

A key activity is the research into a business case project (CSIRO 2024; Ross et al. 2022) that aims to enhance understanding of the viability of a CCUS hub centred on the Middle Arm of Darwin Harbour.

The work has three elements comprising 15 tasks:

1. analysing macroeconomic drivers, Northern Territory and regional emissions, low-emissions product markets, identifying key learnings from other low-emissions hubs being developed globally, and cross-sector coupling opportunities (Tasks 0–5)

2. completing CCUS hub technical definition and technical risk reduction studies, including detailed studies on the infrastructure requirements for a CCUS hub, renewable power requirements for existing and potential future industries, and road-mapping for CO₂ utilisation industries that could be established to produce low or net zero products (e.g. zero-emission chemical feedstocks) (Tasks 6–9)
3. creating a business case to appreciate the scale of investment required to develop a Low Emissions Hub and the economic returns from doing so; this will lead to suggested business models and routes for their execution (Tasks 10–14).

The CCUS business case project will involve research that is based on possible industrial development scenarios, models of future potential emissions, market demand, enabling technologies and costs. The project is intended to provide an understanding of possible future outcomes. Industry development will be determined by the investment decisions of individual industry proponents, framed by government policies and regulation, and constrained by the development trajectories of enabling technologies as part of the energy and emissions transition.

On completion of this research, the outcomes of the CCUS business case project will be made publicly available.

This report comprises Task 14 of the Northern Territory CCUS business case project and summarises the outcomes of the project to date. It presents the business case for the Northern Territory CCUS hub and the next steps required for its development.

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Although CSIRO has sought feedback from government and industry on the technical content of the report, CSIRO has sole discretion on including such feedback.

Northern Territory Low Emissions Carbon Capture Utilisation and Storage Hub business case project

The Northern Territory Low Emissions Carbon Capture Utilisation and Storage Hub business case project is a result of a collaborative approach between CSIRO, government and industry to develop a business case to assess the viability of a large-scale low-emissions carbon capture utilisation and storage hub outside Darwin.

The project includes inputs from the wider Northern Territory Low Emissions Hub (NT LEH) collaboration group, whose current members include the Northern Territory Government, Xodus, INPEX, Santos, Woodside Energy, Eni, Total Energies, Tamboran Resources and SK E&S.



Abbreviations

ACCU	Australian Carbon Credit Unit
ACoE	Average cost of electricity
ACoH	Average cost of hydrogen
AGRU	Acid gas removal unit
APS	Announced Pledges scenario – IEA
ARENA	Australian Renewable Energy Agency
ASU	Air separation units
ATR	Autothermal reforming (of methane)
bar	Unit of pressure called a bar (defined as 100,000 Pascals)
barg	Unit of pressure measurement bar gauge
bbl	Barrel (42 US gallons/ 159 litres)
CapEx	Capital expenditure
CBAM	Carbon border adjustment mechanism
CCfD	Carbon Contracts for Difference
CCS	Carbon capture and storage
CCUS	Carbon capture utilisation and storage
CCU	Carbon capture and utilisation
CCTS	Carbon capture transport and storage
CEFC	Clean Energy Finance Corporation
CER	Clean Energy Regulator
CfD	Contract for Difference
CO ₂ -e	Carbon Dioxide-equivalent
COVID-19	Coronavirus disease 2019
CRC	Cooperative Research Centre
CSIRO	Commonwealth Scientific and Industrial Research Organisation
Cth	Commonwealth Government
DAC	Direct air capture
DLPE	Department of Lands, Planning and Environment
DITT	Department of Industry, Tourism and Trade
DKIS	Darwin Katherine interconnected system
DLI	Northern Territory Department of Logistics and Infrastructure
DLNG	Darwin liquefied natural gas project

DTBAR	Department of Trade, Business and Asian Relations (formally DITT)
EU	European Union
EPBC	Environment Protection and Biodiversity Conservation Act 1999
ETS	Emissions Trading Scheme
FEED	Front-end engineering design
FID	Final investment decision
FMA	Future Made in Australia Act 2024
GDP	Gross domestic product
Gj	Gigajoule (10^9 Joules)
GO	Guarantee of Origin Scheme
GSP	Gross state product
Gt	Giga tonnes (10^9 tonnes)
Gtpa	Giga tonnes (10^9 tonnes) per annum
GW	Gigawatt (10^9 watts)
HVAC	High-voltage alternating current
HVDC	High-voltage direct current
IEA	International Energy Agency
IIP	Infrastructure Investment Program
JV	Joint Venture
ILNG	Ichthys liquefied natural gas project
IMF	International Monetary Fund
IPCC	Intergovernmental Panel on Climate Change
km	Kilometre
LAES	Liquid air energy storage
LCO ₂	Liquified CO ₂
LEH	Low Emissions Hub
LPG	Liquid petroleum gas
LNG	Liquefied natural gas
LULUCF	Land Use, Land Use Change and Forestry
m ³	Cubic metres
MASDP	Middle Arm Sustainable Development Precinct
Mt	Million tonnes
Mtpa	Million tonnes per annum (10^6 tonnes per year)
MTO	Methanol-to-olefin

MW	Megawatt (10 ⁶ watts)
MWh	Megawatt (10 ⁶ watts) hour
NAIF	Northern Australia Infrastructure Facility
NDC	National Determined Contributions
NGERS	National Greenhouse and Energy Reporting Scheme
NOCs	National Oil Companies
NOPTA	National Offshore Petroleum Titles Administrator
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
NPP	New policy proposal
NRFC	National Reconstruction Fund Corporation
NT	Northern Territory
NTEPA	Northern Territory Environment Protection Authority
NTLEH	Northern Territory Low Emissions Hub
NTG	Northern Territory Government
NZA	Net Zero Australia
NZE	Net Zero Emissions by 2050 scenario - IEA
OD	Outside diameter
OpEx	Operating expenditure
OPGGs	Offshore Petroleum and Greenhouse Gas Storage Act 2006
PJ	Petajoule
PRF	Powering the Regions Fund
PSA	Pressure swing adsorption
PV	Photovoltaic
REZ	Renewable energy zone
SAM	Serviceable available market
SDS	Sustainable Development scenario - IEA
SGM	Safeguard Mechanism
SMC	Safeguard mechanism credits
SOM	Serviceable obtainable market
STEPS	Stated Policies scenario (IEA)
TAM	Total addressable market
tcf	Trillion cubic feet
TJ	Terajoule (10 ¹² Joules)

TWh	Terawatt (10^{12} watt) hours
US	United States of America
VRE	Variable renewable energy
WTO	World Trade Organization

CHEMICAL COMPOUNDS

CH ₄	Methane
CO ₂	Carbon dioxide
CO ₂ -e	Carbon dioxide equivalent
H ₂	Hydrogen
HFCs	Hydrofluorocarbons
NF ₃	Nitrogen trifluoride
NO _x	Nitrogen oxides
N ₂ O	Nitrous oxide
PFCs	Perfluorocarbons
TEG	Triethylene glycol
SF ₆	Sulphur hexafluoride

Summary

The Northern Territory CCUS Business Case has examined whether a large-scale carbon capture, utilisation and storage hub in the Darwin region can be feasibly developed. The project was delivered through a series of technical, economic and policy studies that collectively built a picture of the opportunities and challenges associated with establishing a CCUS hub at the Middle Arm Sustainable Development Precinct (MASDP) in Darwin.

The Northern Territory offers distinct advantages for CCUS development. It has existing CO₂ capture from the Darwin liquefied natural gas (LNG) and Ichthys LNG facilities; significant geological storage potential in the offshore Bonaparte Basin; exceptional solar resources for renewable electricity and significant natural gas chemical feedstocks that could underpin future low-emission industries. The MASDP itself is a largely greenfield industrial precinct, allowing shared infrastructure and circular economy- principles to be embedded from the outset. Its proximity to major Asian economies also positions the Northern Territory (NT) as a potential low emission product supplier and regional CO₂ storage provider.

At the outset of the project a collaborative vision was developed with industry and government outlining a staged pathway for hub development. In the Base Case, expected between 2025 and 2027, CO₂ captured at the two LNG plants would be compressed and transported for storage in the depleted Bayu-Undan field, enabling around five million tonnes per annum (Mtpa) of CO₂ to be stored. The Near Future vision, extending to 2030, adds CO₂ import terminals, a CO₂ gathering network for MASDP industries, and a second offshore pipeline to the Petrel Sub-Basin, lifting storage capacity to around 15 Mtpa. By 2040, the Far Future vision envisages a fully integrated low-emission industrial hub with expanded CO₂ imports, additional industrial capture, and a third storage site, enabling more than 25 Mtpa of CO₂ to be stored.

The Northern Territory economy is heavily reliant on resource extraction and exposed to global commodity cycles. Achieving the Territory's growth ambition will require significant private investment at a time of heightened global uncertainty. Realising low-emission industrial development will depend on how effectively risks can be reduced to enable investment. Emissions modelling indicates strong potential demand for CCUS from MASDP industries, with scenarios ranging from 5 to 25 Mtpa. Without new industrial development, however, CCUS demand would decline after 2043 as natural gas production falls, reducing the local need for the development of large-scale CCUS infrastructure.

However, the Northern Territories key trading partners — such as Japan, China, Taiwan, Singapore and South Korea — could generate substantial demand for CO₂ shipping to the NT, with demand forecast to increase from around 3 Mtpa in 2030 to more than 70 Mtpa by 2050. Levelised costs of CO₂ shipping between Japan and the Northern Territory are estimated between \$224 to \$122 per tonne for volumes of 1-6 Mtpa respectively, with the construction of buffer storage at the import terminal being a major cost driver.

Low-emissions products such as hydrogen, ammonia, methanol and synthetic fuels represent an opportunity for Northern Territory industrial growth (and CO₂ use) and diversification, as global demand for these products grows under net-zero scenarios. However, these products currently struggle to compete with conventional alternatives, which benefit from decades of optimisation and low-cost inputs. Shared CCUS and hydrogen infrastructure, along with targeted policy support, could assist to closing this price gap between these low-emission and unabated products, as could innovation and scale.

There are opportunities for sector coupling within the MASDP, enabling industries to share heat, energy and feedstocks. A near-term hydrogen generation pathway based on methane reforming could transition over time to electrolysis-based hydrogen and direct air capture. Power system modelling shows that renewable electricity costs vary widely depending on load profiles and the share of gas generation, with hydrogen production costs highly sensitive to electrolyser efficiency and renewable resource quality. Further work is needed to understand wind resources in the NT and identify low-cost storage options.

The concept design for the CCUS hub within the MASDP outlines a system capable of handling around 9 Mtpa of CO₂ from MASDP industries, with the CO₂ conditioned and then delivered to a central compression facility before being transported to a tie-in point for offshore storage pipelines. The design also includes the development of a CO₂ import facility with an additional 6 Mtpa capacity. Geological storage is not considered a major risk given the scale and quality of the Territory's offshore basins. The total capital cost for the MASDP CO₂ capture, gather and terminal system is estimated at around \$7.4 billion, with capture facilities accounting for more than 70% of the costs, the majority of which would be embedded as a product separation cost. MASDP CO₂ pipelines, compression and the liquid CO₂ import terminal represent 28% of the total costs, which can be phased as CCUS demand grows.

Policy analysis undertaken to identify what policies are applicable to CCUS hub development revealed gaps in Australia's CCUS and hydrogen policy frameworks. While carbon pricing mechanisms such as ACCUs and Safeguard Mechanism Credits exist, they are insufficient to bridge the cost gap for low-emissions products or to incentivise large-scale CCUS investment. Analysis indicates a national CCUS strategy could help to clarify the role of hubs in industrial decarbonisation. International experience shows that mechanisms such as Contracts-for-Difference (CFD), along with dedicated delivery agencies like Norway's Gassnova or the UK's Low Carbon Contracts Company, can provide the stability and risk-sharing mechanisms needed to unlock investment. To this end the business case recommends the use of a CFD mechanism to reduce price uncertainty and risk for CO₂ capture and a phased CCUS infrastructure development within MASDP, which minimises cost whilst retaining future growth potential. The suggested mechanism for the initial phase of the CCUS hub development is through a shared equity model between industry and government, using current legislation for fiscal policy and funding. Based on concept design first phase capital costs for the CO₂ gather and LCO₂ import terminal would be \$786 M. Future phases of development, once derisked, could then access concessional and conventional funding.

Overall, the business case concludes that the Northern Territory has the geological resources, industrial foundations and strategic location to support the phased development of a major CCUS hub. Realising this potential will depend on coordinated low-emissions industrial development at

the MASDP, strong policy support, investment certainty, and the maturation of regional CO₂ shipping markets. To realise this future requires rapid action before future development options are removed. With the right settings, the NT could become a significant regional centre for low-emission industry and carbon management.

1 Purpose of the CCUS business case

Transitioning the global energy system while simultaneously reducing emissions to net zero by 2050 is a vast and complex global challenge. Globally, considerable effort is being undertaken to identify industrial hubs and clusters where common user infrastructure can enable rapid decarbonisation of existing industries as well as enable future low-emissions industrial development. These hubs and clusters often contemplate carbon capture utilisation and storage (CCUS) as one of a range of decarbonisation technologies to be deployed. The investment decisions for CCUS projects as part of low-emissions industrial hubs are predicated on clearly articulated business cases.

A clear, well-developed business case supported by detailed reports and technoeconomic models can facilitate the development of and upcoming investment decisions in CCUS projects worldwide (e.g., Teesside Net Zero project¹ and Project Longship²). This CSIRO Northern Territory CCUS Business Case project is aimed at investigating the business case for large-scale CCUS in the Northern Territory. The outputs of the project are intended to enable evaluation of the financial and commercial viability of the development of a CCUS hub and allow progression to more detailed pre-front-end engineering design (FEED) and FEED studies and provide a possible blueprint for future phased CCUS hub development.

NT CCUS business case project activities

This business case project is delivered as a series of task reports, with this report comprising the final summary report and business case.

At the commencement of the study CSIRO, supported by Xodus, undertook vision setting with key industrial and government stakeholders to understand the scope of the potential CO₂ hub development and inform the direction of the subsequent tasks (Task 0; Ross et al., 2023).

The subsequent project tasks were divided into three parts:

Part 1 tasks assess macroeconomics (Task 1; Rogers et al., 2024a), emissions (Tasks 1 and 2; Rogers et al., 2024a; 2024b), markets for CO₂ (Tasks 2 and 3; Rogers et al., 2024b; Joodi et al., 2024a), and low-emissions products (Task 3; Joodi et al., 2024a), as well as best-practice hub examples and learnings (Task 4; Stalker et al., 2024). Principally, this part of the project aimed to develop an appreciation of the Northern Territory and regional demand drivers for an NT CCUS hub.

Part 2 tasks focus on the CCUS hub technical definition and technical risk reduction studies, including: The identification of possible sector coupling opportunities for existing and future Middle Arm Sustainable Development Precinct (MASDP; see box below) industries, which could enhance industrial efficiencies and reduce emissions (Task 5; Czaplá et al., 2024).

¹ Teesside Collective which became Net Zero Teesside <https://www.netzeroteesside.co.uk/>

² Project Longship. <https://ccsnorway.com/>

- the concept-level design and costing of the NT CCUS hub (Task 6; Joodi et al., 2024b)
- a power systems study to understand system costs for the implementation of large-scale renewable power into the MASDP (Task 7; Green et al., 2024)
- a CO₂ shipping study to assess the costs and required scale of CO₂ shipping into the MASDP (Task 8, Toccock et al., 2024)
- a Carbon Capture and Utilisation (CCU) roadmap to identify uses of the CO₂ made available within the hub (Task 9; Banfield et al., 2023).

Part 3 tasks focus on the NT Low Emissions Hub (LEH) economic model, business case and execution plan, including:

- the exploration of policy and legislative settings and the importance of community engagement (Tasks 10 and 11; Toccock et al., 2025)
- economic modelling of the MASDP and CCUS infrastructure to identify barriers and opportunities in their development (Tasks 12 and 13; Rogers et al., 2026)
- a business case and execution plan for the NT CCUS hub that will allow assessment of the next steps of CCUS hub development (Task 14; this report).

These previous task reports are referenced throughout this report so that the reader can easily find further detailed supporting information.

Why the Northern Territory?

The Northern Territory, and specifically the Darwin area, was chosen by CSIRO as it presents unique opportunities for the development of a CCUS hub in Australia (Figure 1). The CCUS hub will be located within a largely greenfield industrial development area in the Middle Arm of Darwin Harbour, known as the MASDP (see box below). The development of a greenfield industrial precinct provides an opportunity to consider future low-emissions industry infrastructure requirements, needs and how efficiencies can be realised through the inclusion of circular economy and industrial ecosystem design principles.

The Middle Arm already has captured emissions, from the Darwin and Ichthys liquefied natural gas (LNG) plants, which represent foundational CCUS hub customers. These plants are supplied by large gas reserves, and production is expected to continue for some time, likely supported by additional natural gas developments both on- and offshore. In the near term, this gas will be a key feedstock for Middle Arm industries.

The region contains many gigatons (Gt) of potential CO₂ storage resources in the offshore Bonaparte Basin, with estimates ranging from 6 to more than 15 Gt (Consoli et al., 2014; Johnstone and Stalker, 2022). Onshore CO₂ storage potential has also been identified but remains only lightly investigated Talukder et al. (2024). The region additionally has some of the world's highest levels of solar irradiance, making it well suited to photovoltaic renewable electricity generation, and wind resources are also being explored.

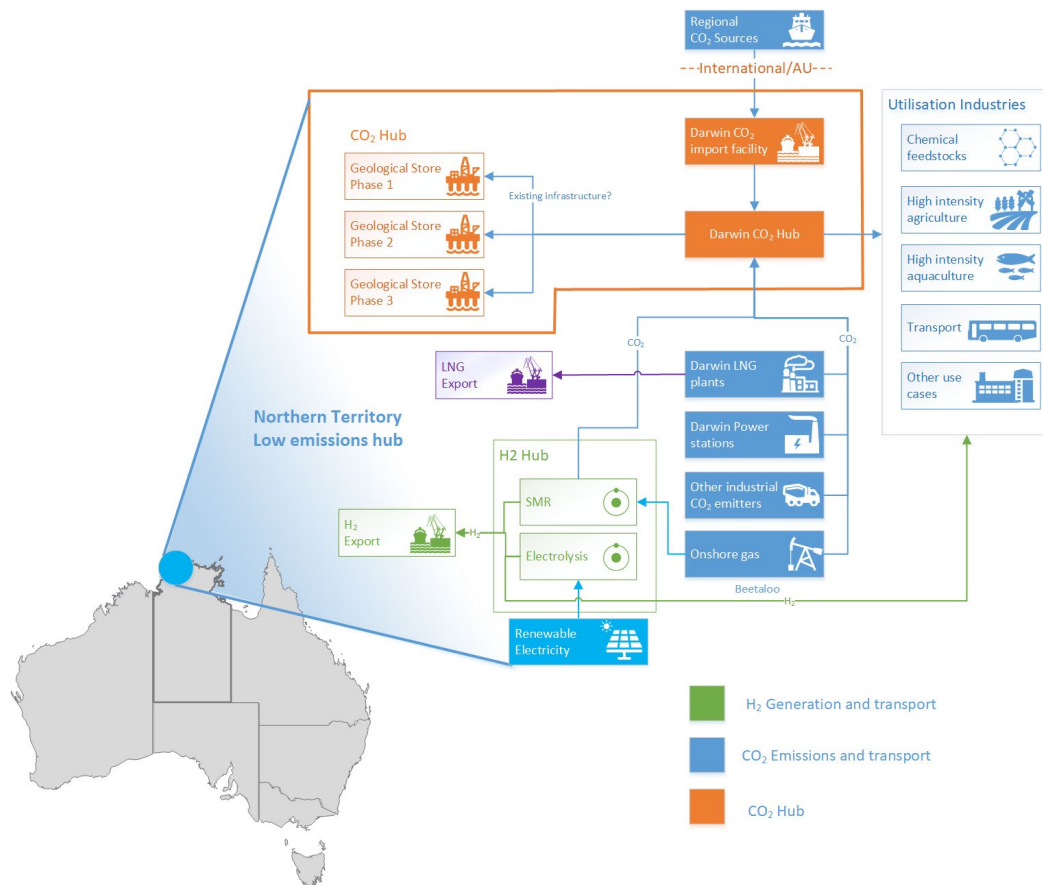


Figure 1: Concept of NT low emission hub

Critical to the development of CCUS hubs, and low-emissions industrial hubs more generally, is the necessity of close collaborations between potential participants, the development of a shared vision of the final desired outcomes, and consideration of how risks and costs can be shared or mitigated. As such, one of the first tasks of this project was to develop a vision of how a low-emission hub might be developed in the Darwin region and understand the role of a CCUS hub within it. This collaborative vision development (Table 1) was undertaken by industry and government and details of which are contained within Ross et al. (2024). It is important to note that this task of the CCUS Business Case project was conducted in quarters three and four of 2021 and as such is a product based on information and understandings available at that time.

Middle Arm Sustainable Development Precinct

The Middle Arm Sustainable Development Precinct (MASDP) is a proposed industrial precinct to be situated on the Middle Arm of the Darwin Harbour, directly to the south of Darwin city (Figure 2). Currently, industrial development on the Middle Arm includes the Darwin LNG (DLNG), Ichthys LNG (ILNG) and Channel Island and Weddel power stations. Much of the remainder of the Middle Arm is assigned for greenfield development, meaning that it is a new industrial precinct in which master planning of shared infrastructure can occur from the outset.

The Northern Territory Department of Logistics and Infrastructure (DLI) has defined the possible makeup of future industries that could be situated in the MASDP in its Balanced Scenario. This scenario uses the widest range of industries that are envisaged to be

established in the MASDP and includes the production of LNG, hydrogen (from methane reforming and electrolysis), methanol, ammonia (one option based on hydrogen production from methane reforming, and another on hydrogen production from electrolysis), urea, ethylene, CCUS and critical minerals processing (e.g. lithium, vanadium) (Figure 3).

The actual industrial mix that could be established in the MASDP, and therefore the CCUS demand, may not match the exact composition of industries in the Balanced Scenario. However, it offers a way to align with other modelling and design activities that the Northern Territory Government is pursuing, and therefore this scenario has been chosen for the whole of the CCUS business case project.

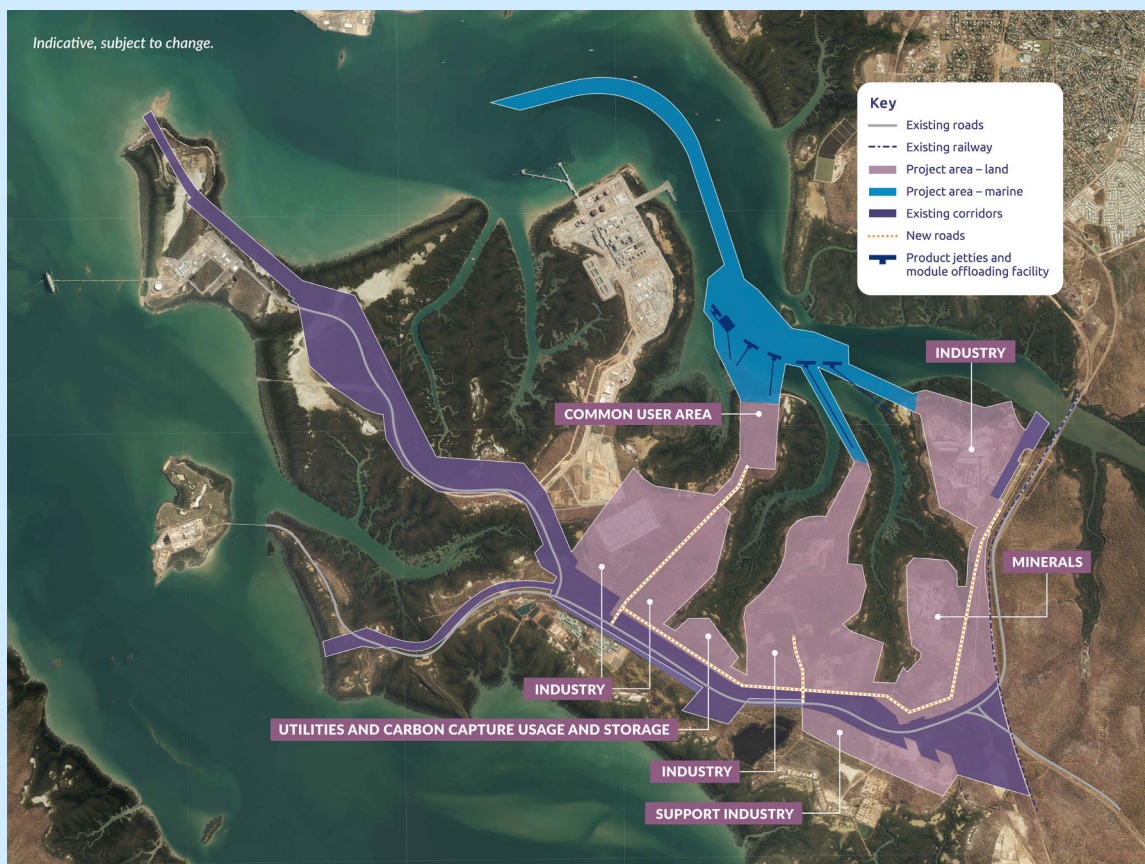


Figure 2: A map of the Middle Arm Sustainable Development Precinct
Source: NTG (2024a)

Potential Middle Arm Industry Types	Inputs	Outputs	Typical uses
Liquid Natural Gas LNG			
Gas to Liquid GTL			
Blue Hydrogen H ₂			
Green Hydrogen H ₂			
Hydrogen H ₂ - Green NH ₃			
Ammonia			
Urea			
Methanol			
Ethane			
Mineral Processing 1			
Mineral Processing 2			
Carbon Capture, Utilisation & Storage CCUS			
Advanced Manufacturing			

Figure 3: The Balanced Scenario: potential industries, their inputs and outputs, and typical uses
Source: NTG (2024a)

Low Emissions Hub vision

The vision for the LEH comprises Base, Near-Future and Far-Future cases.

Base Case

The Base Case (Table 1 and Figure 4), anticipated to be undertaken between 2025 and 2027, comprises gathering existing captured reservoir CO₂ from both the ILNG and DLNG facilities through a high-pressure CO₂ interconnector. It is anticipated that CO₂ compression will occur close to/or on the ILNG and DLNG sites, and this CO₂ will be transported through the existing Bayu-Undan pipeline and be injected into the depleted Bayu-Undan gas field³. It is anticipated that the Barossa field will enter production to back fill the DLNG facility’s LNG capacity over this period. This Base Case contemplates the storage of over 5 Mtpa of CO₂.

³ Acknowledging that Bayu-Undan has been delayed from the original vision.

Table 1: Proposed Collaborative Vision of Success

Proposed Collaborative Vision of Success	
Near Future	Far Future
As part of the base case between 2025 and 2030 the two existing LNG plants are connected and exporting CO ₂ to a single storage site with sufficient capacity in the pipelines for continued capacity growth and additional users.	By 2040 the LEH is operating on renewable energy is economically sustainable, and is capturing/storing all major sources of CO ₂ in Darwin, including from new low-carbon industries that have been established by access to the Hub. These new industries include CO ₂ imports and hydrogen.

Near-Future Case

The Near Future Case (Table 1), anticipated to be undertaken between 2027 and 2030, includes all the elements described in the Base Case with the addition of two CO₂ importation facilities: one situated at the DLNG jetty and a second, common user facility, situated within the MASDP port facility. Within the MASDP a medium-pressure CO₂ gathering pipeline system will be constructed to allow MASDP industries to access the CO₂ transport and storage system. This CO₂ will be further compressed to high pressure either within the MASDP or close to the current Ichthys pipeline shore crossing. Due to the increases in anticipated CO₂ volumes, a second CO₂ offshore pipeline is included, leading to a Petrel Sub-basin CO₂ sequestration site. During this period, it is anticipated that the Verus (formerly Evans Shoal) field⁴ will be brought into production through the DLNG facility and gas produced from the Beetaloo Basin will be piped to the MASDP. This Near-Future Case contemplates the storage of approximately 15 Mtpa of CO₂.

Far-Future Case

The Far-Future Case (Table 1 and Figure 5), anticipated to be undertaken by 2040 includes all the elements described for the previous two cases. In this case greater volumes of CO₂ are provided into the CO₂ gather and transport system through additional industrial CO₂ inputs from the MASDP and further imports of CO₂ via shipping. The greater volumes of CO₂ require a third CO₂ storage location, either in the Petrel Sub-basin through an additional offshore CO₂ pipeline or an onshore storage location notionally identified in the Beetaloo Basin. This Far-Future Case contemplates the storage of over 25 Mtpa of CO₂.

⁴ It is noted that the Verus JV has not made any decision on utilisation of a DLNG Train 2 expansion and is considering other development concepts.”

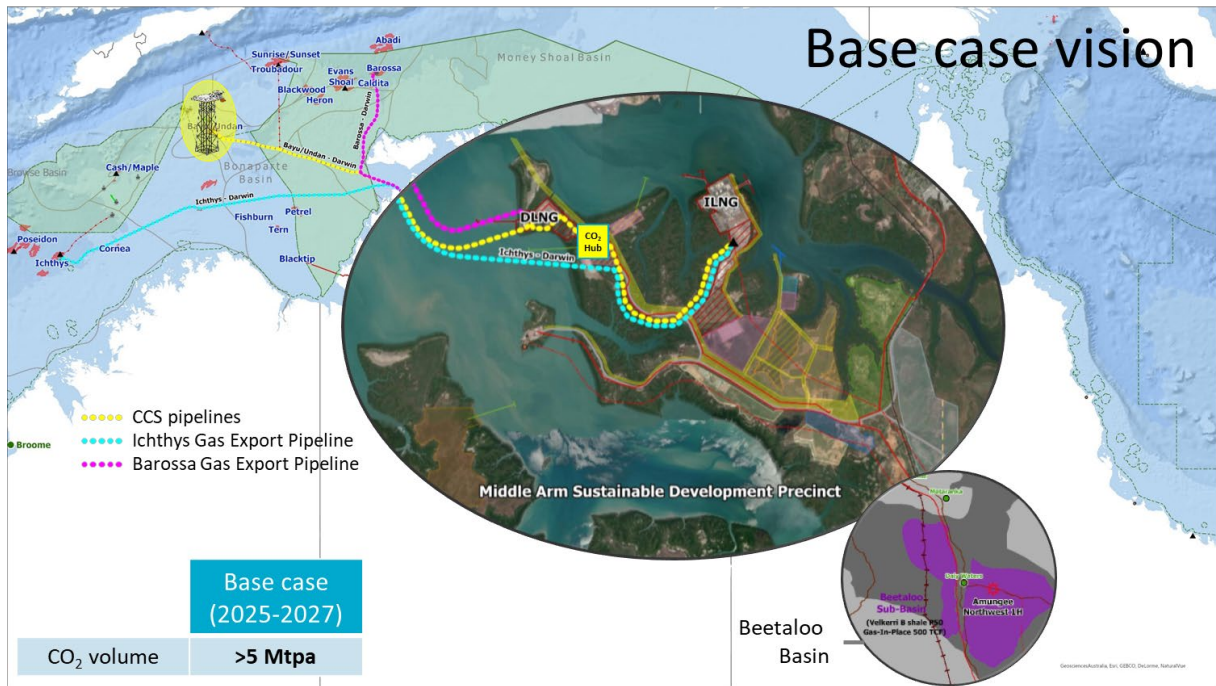


Figure 4: NT low emission hub Base Case (2025-2027)

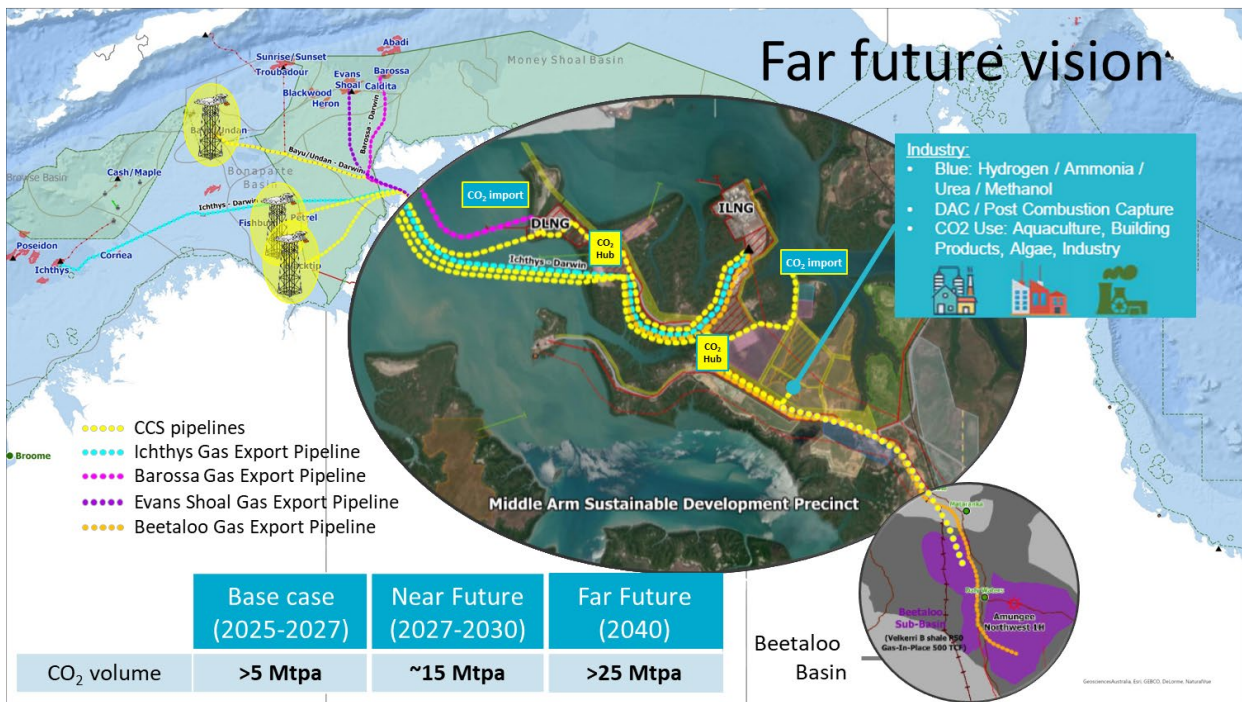


Figure 5: NT low emission hub Far-Future Case (2040)

This future vision has been used to develop an understanding of the steps required for CCUS hub realisation and has provided context for CSIRO’s research delivery within the CCUS Business Case project. The subsequent sections of this report summarise key findings from the CCUS Business case project and the factors that will define the NT CCUS hub development.

2 Northern Territory and regional economies and outlook

Northern Territory economic snapshot

The Northern Territory is a small open economy strategically located on the doorstep of Asia. The economy relies on a small population (~1% of Australia's population), sparsely distributed over a large area that is remote from other population centres across the rest of the country (Australian Bureau of Statistics (ABS), 2021). Its growth has historically relied on private investment in major projects and net exports, which are influenced by macroeconomic conditions such as the strength of the Australian dollar and energy prices. The economy is dominated by natural resource production, a large public sector and sizeable defence force establishments. Resource extraction (including mineral mining and onshore and offshore oil and gas) accounts for 28% of the gross state product (GSP) and is the single largest sector of the economy (Figure 6). The Territory has a wide range of minerals and hydrocarbon resources which have historically contributed to its economic growth.

In the year to September 2025 the value of the Northern Territory's exports was \$13.0 billion (NTG, 2025). 72.4% of these exports were energy (LNG and petroleum), with 16.2% being metalliferous ores and metal scrap. Exports were dominated by five jurisdictions within the region: Japan (\$5.3 billion) China (\$2.7 billion), Taiwan (\$1.6 billion), South Korea (\$1 billion) and Singapore (\$552 million). The demographics, industrial structures and energy mixes of these countries will influence their future reliance on the Northern Territory for energy and energy-transition products.

Northern Territory: drivers of economic growth

Since the GSP began being reported in 1990 (Figure 6), the Northern Territory economy has grown by more than \$28 billion, at a compound annual growth rate of 6.2% (although it has slowed over the period and the average for the last 10 years is 3.7% per year). Growth through the period has been supported by investment in a succession of major projects in the mining sector (including hydrocarbons), with the added generation of investment in the broader economy (Australian Government, 2023). Additional investment in the public sector and defence force operations has also contributed to economic growth.

Historically, economic performance has been characterised by periods of high economic growth due to large private capital investment and associated phases of construction (e.g. the development of the Darwin and Ichthys LNG projects) and periods of slower economic growth when economic performance is determined more by the growth rate in private and public consumption.

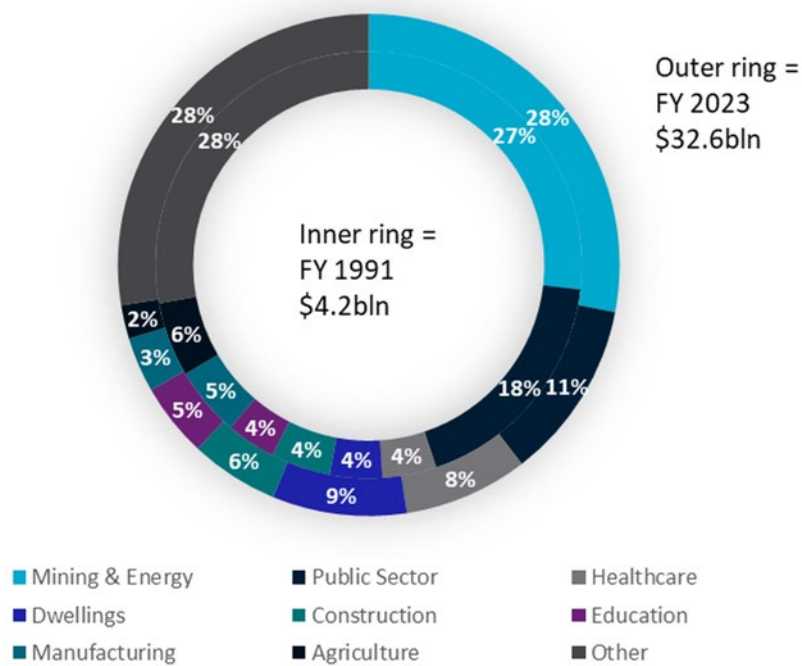


Figure 6: Northern Territory industrial sector composition, by percentage of GSP, 1990–2023
Source: ABS (2023)

Northern Territory: growth aspiration

The Northern Territory Government has an ambitious strategy to grow the economy in future decades. This strategy includes diversifying the industrial base with the aim to have more sustainable growth in GSP. This includes a desire to grow the GSP to \$40 billion by 2030, increase the population to 300,000 and reach net zero by 2050.

To reach a \$40 billion economy by 2030, the Territory needs to achieve compound annual growth of 5.6% per year. This is significantly above the average growth of 3.7% per year since 2014, which includes investment in the Darwin and Ichthys LNG projects, the Montara oil field development and the Groote Eylandt magnesium expansion project.

Growth in private and public expenditure is traditionally stable and ordinarily would be expected to add around \$4–5 billion to GSP by 2030 based on historical trends. This leaves a gap of ~\$10 billion per year in public and private investment or net exports if the government is to meet its stated objective.

To meet the other objectives of net zero emissions (NZE) by 2050 and diversify the industrial sector, the type of investment will be equally important as the quantum. Investment in low-emissions technologies such as hydrogen generation from renewable electricity, minerals processing and CCS in the MASDP has the potential to provide this diversification and help the Territory to deliver on its other strategic objectives.

Australian economic outlook

Following the significant world-wide economic impact from the COVID-19 pandemic, the Australian economy has recovered. Domestic demand remains strong, with exports from mining outputs, rural produce, energy and services supporting growth. Imports have also recovered, limiting the economic impact obtained from gains from exports, though as of November 2025 Australia still has a positive balance on goods (ABS, 2026a).

As domestic demand has strengthened following the Australian economy's recovery from COVID-19, rising energy prices together with disruptions to global supply chains have led to broad-based price pressures building across the economy. In the 12 months to September 2022, the consumer price index increased by 7.3%, employment recovered strongly with low levels of unemployment and high labour market participation, but the labour market remained tight. As a result, wage growth began to accelerate and the Reserve Bank of Australia tightened the Australian cash rate rapidly from mid-2022. The result of this tightening of the cash rate and fiscal measures implemented by the Australian Government in 2022 and 2023 has been a slowing of the economy, and in the 12 months to January 2026 the consumer price index increased to 3.8% (ABS, 2026b).

As of December 2025, Australia's economy grew by 2.6% (ABS, 2026c), slightly exceeding the IMF forecast (Figure 7). This is in line with the previous long-run real GDP growth rate of at least 2% per annum (Commonwealth of Australia, 2023).

Strong domestic conditions are likely to support the Northern Territory economy in the near to medium term. Key concerns though are likely to centre around the impact of rising interest rates on private investment after a period of very low lending costs and the potential for labour shortages.

Southeast Asian regional economic outlook

Forecast economic growth in the East and South-East Asian region is generally accepted to be around 5% in the medium term (Figure 7). The region did suffer significant setbacks with reductions in GDP in many economies due to the COVID-19 pandemic, with recovery from its effects ongoing and the added impact of the current military conflicts and global geopolitical and trade uncertainties. The region's economic and developmental progress is likely to be slower than expected before these setbacks.

Economic factors affecting growth and development include natural resources, capital formation, technological progress, entrepreneurship, human resource development, population growth and social overheads.

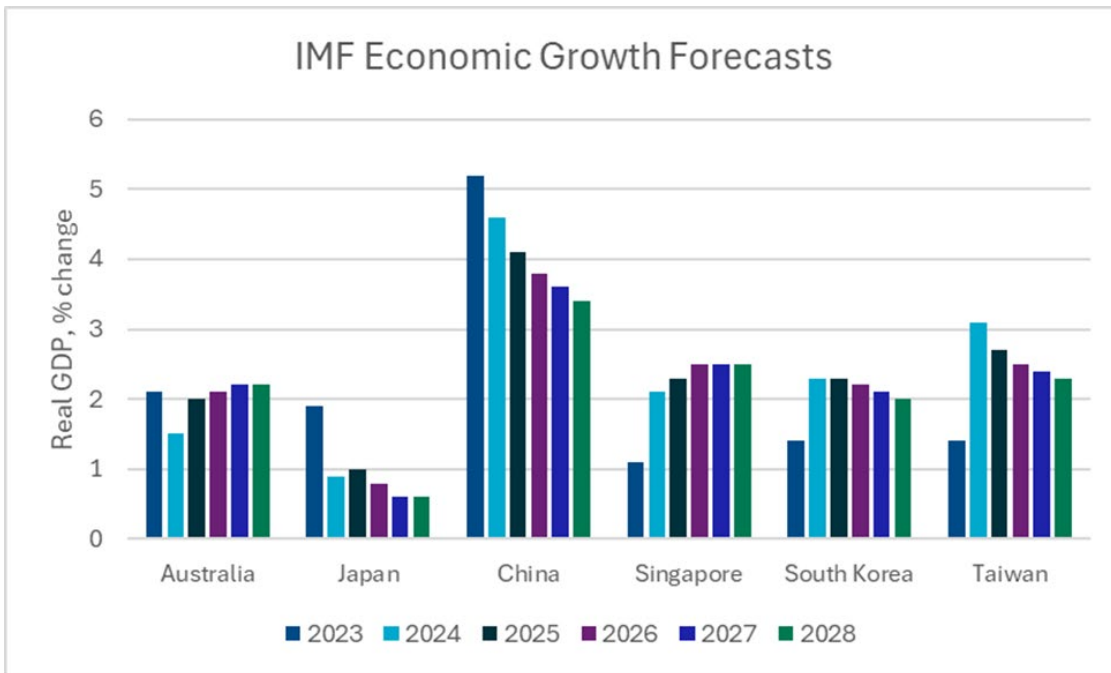


Figure 7: Comparison of economic growth forecasts for Australia and our regional trading partners
Source: International Monetary Fund (IMF) (2024)

Southeast Asian regional demographic shifts

Between 2024 and 2050 the Asia-Pacific region’s demography is expected to be characterised by declining population, rising prosperity and significant ageing. The population decline, both in total terms and in the working-age group, has already started in some of the countries (e.g. South Korea) and is expected to accelerate by 2050 with the exception of India, Indonesia and Malaysia, which at present are still enjoying a growing working-group population, but this is expected to stabilise or even turn into a declining trend by 2050.

Southeast Asia: regional middle-class growth

Globally, the majority of middle-class growth is expected to be in the Asia-Pacific region (Kharas, 2017) (Figure 8). China’s middle-class population is expected to continue to grow, although at a slowing rate, following its population peak, which is likely to have an impact on consumer spending patterns. India is expected to be the second-largest consumer market by 2030, but it is likely that the total size of the Indian middle class will remain smaller than China’s. Malaysia and Indonesia are also undergoing significant economic development as a result of middle-class growth (Kharas, 2017). In contrast, it is expected that the middle-class growth in the fully developed Asian economies, such as South Korea and Japan, will slow and their consumption patterns will likely follow the pattern observed in other developed economies (Ministry for Primary Industries, 2019).

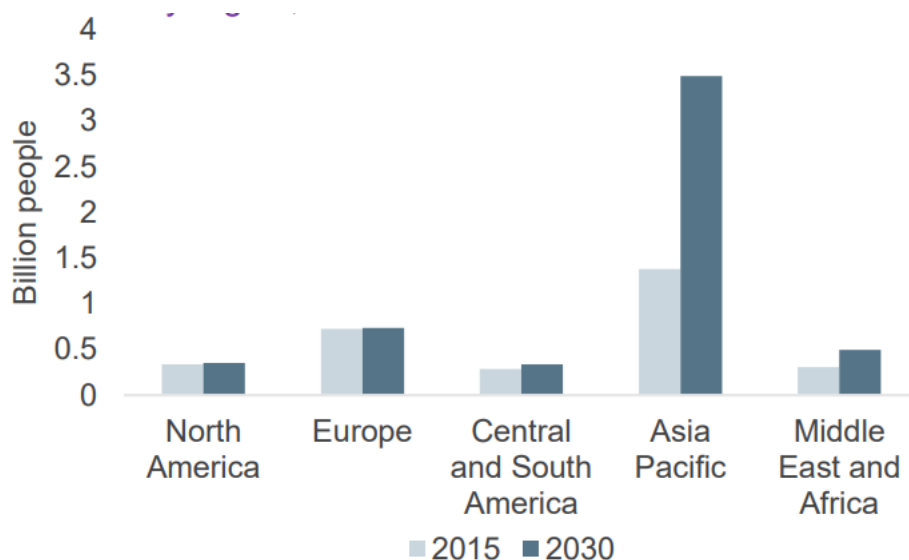


Figure 8: Forecast size of the global middle class, by region
Source: Kharas (2017)

Southeast Asia: the ageing population

Ageing is a major demographic change that will impact the region. However, the Asian Development Bank has analysed the consumption patterns of several developing Asian economies and those elsewhere in the world (Estrada et al., 2011): its findings indicate that there is no significant correlation between old-age dependency and consumption over time in 10 major Asian economies. The findings are also supported by other studies (Lee and Mason, 2011). Although demographic changes in the region are expected to be substantial, these results may suggest that population ageing in developing Asia, especially in economies in the early stages of ageing, may not materially impact consumption and domestic demand.

Global economic outlook

The Northern Territory's economy is relatively small and reliant on global economic, commodity and geopolitical conditions for exports and private investment. As such, it is important to understand not only the Australian and Asia-Pacific region but also factors affecting global trends.

After a long period of stable global economic conditions, characterised by low inflation, low interest rates, strong growth and a cooperative geopolitical environment, the global economic outlook has deteriorated in recent years due in part to the COVID-19 pandemic and associated disruptions to demand and global supply chains. In addition, the geopolitical environment has deteriorated with the United Kingdom (UK) leaving the European Union (EU), various countries having trade disputes with China, and the outbreak of hostilities between Russia and Ukraine, and Israel and Palestine. There is also significant geopolitical uncertainty associated with the policies arising from the Trump administration in the United States (US) and the impact of tariffs on global trade. Rising global inflation has led to a rapid increase in interest rates across the globe as central banks seek to rein in inflation and restore price stability, and while these rates are beginning to decline they are still high compared with recent decades. This has an impact on the cost of capital, and debt servicing especially for projects where returns may be small.

Risks to the global outlook in the near term remain weighted to the downside. A sharp deceleration in global growth is more likely than a rapid improvement as central banks continue to maintain existing monetary policy settings, the Russian invasion of Ukraine continues to disrupt global energy supplies, China (the world's second-largest economy) battles the residual effects of opening its economy after COVID-19 lockdowns, and food security becomes a global concern as reduced gas supplies and potash exports from Russia and Belarus threaten the global availability of fertiliser. These and other factors (such as increasing levels of protectionism and tariffs, fragmentation of globalisation and rapidly accelerating regional geopolitical tensions) lead to greater economic uncertainty, which will also be reflected in increased costs of lending or higher requirements for investment certainty by financial institutions. Global economic growth is forecast to be around 3% in the short term, with advanced economy forecast growth around 1.7% this is the lowest level in over a decade.

The Northern Territory's economy is relatively well placed to navigate the current challenging global economic outlook. Reduced Russian gas supplies into Europe mean that demand is likely to remain strong for the Territory's key export LNG at potentially elevated prices. Demand for minerals, particularly manganese (a key input into electric car batteries), also remains strong. Rising fertiliser prices may negatively impact the agriculture industry in the near term, although agriculture represents a relatively small part of the Territory economy (<5%).

Longer term, the key challenge to economic growth will be how countries can support growth in their economies while maintaining living standards as they incur the expense of seeking targets of NZE by 2050.

Key points

- The Northern Territory is a small open economy strategically located on the doorstep of Asia.
- The economy is reliant on global economic, commodity and geopolitical conditions for exports and private investment.
- Resource extraction (including mineral mining and on- and offshore oil and gas) accounts for 28% of the GSP and is the single largest sector of the economy.
- While this is a key strength of the Territory's economy, the lack of economic diversification leaves the economy exposed to global commodity prices.
- Forecast economic growth in the East and South-East Asian region is generally accepted to be around 5% in the medium term which could have a positive impact on the Territory's export industries.
- However, to reach a \$40 billion economy by 2030, the Territory needs to achieve compound annual growth of 5.6% per year.
- This will need to occur during a period of higher interest rates and greater global economic uncertainty, which will flow on to increased costs of lending and higher requirements for investment certainty by financial institutions.

3 Northern Territory and regional emissions

Northern Territory emissions

Greenhouse gas emissions reduction targets

In June 2022, Australia lodged an updated Nationally Determined Contribution (NDC) commitment with the United Nations Framework Convention on Climate Change. Australia committed to achieve net zero emissions by 2050 and reduce greenhouse gas emissions to 43% below 2005 levels by 2030. The Australian Government has recently announced its third NDC pledge to reduce greenhouse gas emissions by 62-70% from 2005 levels by 2035 (DCCEEW, 2025a). Activities in the Northern Territory contributed to 3% of Australia's total greenhouse emissions in 2022–23.

Individual states and territories have also made commitments to reach net zero by 2050 or earlier.

The Northern Territory Government announced in June 2025 that it will not implement an interim emissions reduction target for 2030 and has scrapped the previous government target for 50% of electricity consumption to be sourced from renewable energy by 2030. The 2024 Northern Territory Budget committed resources to 'facilitate the transition to a 50% renewable energy target by 2030, net zero emissions by 2050, and meet increasing demand for large-scale solar power' (NTG, 2024b).

Greenhouse gas emissions

Northern Territory CO₂-e emissions for the 2022–23 year were reported as 23.6 Mtpa⁵ originating from five sectors: energy; industrial processes and product use; agriculture; land use, land use change and forestry (LULUCF); and waste (DCCEEW, 2024a).

Historically these emissions were dominated by agriculture and land use, but the energy sector has become the dominant contributor over the past two decades. The growth in greenhouse gas emissions from this sector coincides with the commissioning of the DLNG project in 2006 and ILNG project in 2018.

Point source emissions

Of the Northern Territory's total greenhouse gas emissions, the National Greenhouse and Energy Reporting Scheme (NGERS) data show that 9.2 Mtpa of CO₂-e were reported for the year 2022–23, of which 7.3 Mtpa were from the safeguard emitters⁶ and 1.2 Mtpa CO₂-e from 'designated generation facilities' (Clean Energy Regulator, 2025). Note that the NGERS explicitly excludes the agriculture and land use, land use change and forestry (LULUCF) sector. Major point sources of greenhouse emissions in the Northern Territory are from the production of LNG, offshore oil and gas operations, mining, and power stations. Of the NGERS reported emissions sources, CSIRO estimates that 82% are located within 50 km of the Darwin Port; 7% are produced from offshore

⁵ included carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), sulfur hexafluoride (SF₆) and nitrogen trifluoride (NF₃)

⁶ Under the NGERS safeguard facilities (emitters with over 100,000 tons per annum CO₂-e) and electricity generation facilities are required to report their CO₂-e emissions.

oil and gas operations; and the remaining 11% are located in regional areas – principally associated with mining operations and remote power generation (Figure 9).

The point-source CO₂-e emissions around Darwin (Figure 9), a large proportion of which are already processed and concentrated, the proposed location of the MASDP and any developed port’s ability to locate infrastructure for the import of international CO₂ cargo, make Darwin an ideal location for the development of a low-emissions CCUS hub.

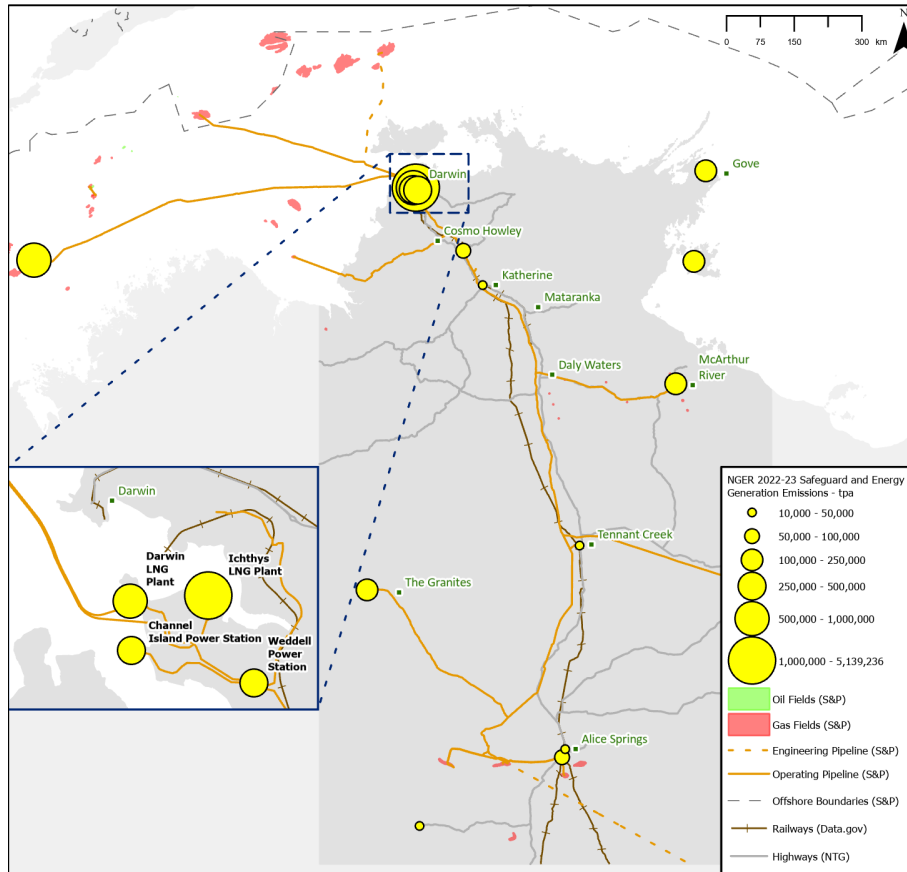


Figure 9: A map of point-source emissions and the distance of these emissions from existing pipeline and port infrastructure

Source: Based on NGRS, S&P Global Edin Database, Company Reports

Emissions model development

This business case project developed an emissions forecast model to understand the demand for avoidance and abatement solutions for existing and future Northern Territory CO₂ point-source emissions (Rogers et al., 2024a). In determining this demand emissions projections have been generated using:

- publicly reported emissions data from current Northern Territory industries and designated generation facilities
- predicted emissions obtained from environmental plans, websites and data services
- new industry projections using data obtained from reports and analogies
- MASDP Balanced Scenario emissions projections.

See the method workflow included in Figure 10.

Resultant emissions data are presented by emissions type rather than by industry and include:

- acid gas removal unit (AGRU) emissions – emissions generated from the separation of CO₂ from natural gas and other products (e.g. methane-derived hydrogen)
- turbines – open and combined cycle gas turbines
- reciprocating engines – stationary reciprocating engines for the purpose of electricity generation
- industrial process flaring – emissions generated during the burning of flammable waste products during operations
- furnaces and boilers – emissions generated by furnace and boiler operations
- production emissions – process emissions not included in the categories above, including fugitive emissions of methane and CO₂.
- offshore emissions associated with offshore natural gas production (constituting several sources of emissions e.g. gas turbine operations, flaring and fugitive emissions of methane and other greenhouse gases)⁷.

The emissions forecasts do not include individual industry proponents' emissions reduction strategies, nor do they consider the marginal cost of abatement. The purpose, as described above, is to provide an understanding of the quantum of requirement for avoidance and abatement technologies and survey possible future emissions reduction outcomes through their use. Offsets have not been considered for any of the scenarios explored; it is assumed that residual emissions could be managed through offsets, but this topic is outside the scope of the business case project.

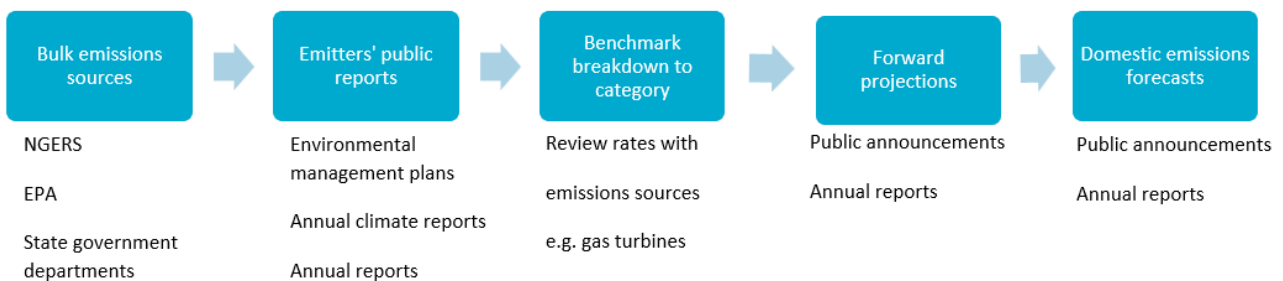


Figure 10: CSIRO emissions database workflow

Emissions scenarios

Forecasts of emissions and avoidance and abatement alternatives are evaluated for two scenarios:

Base Scenario (Status Quo): Anchored on current industrial (principally energy and mining) and electricity generation activities to end of life for these facilities. It assumes that no new industrial and electricity generation projects will be developed in the Northern Territory outside the projects for which final investment decisions (FIDs) have already been taken (e.g. the Barossa gas field developed via the DLNG – even though this gas field has taken FID and will require CCS to manage its reservoir CO₂; Bayu-Undan CCS was targeting FID in 2025, therefore, it has not been included as

⁷ It is assumed that these emissions will be much more difficult to avoid and abate.

it will be applied in the avoidance and abatement options below). In the Base Scenario, the MASDP is not developed.

Reference Scenario: Assumes development of the Balanced Scenario industries and includes natural gas developments in the Beetaloo Basin (onshore) and Verus field (offshore), Bonaparte CCS developments, as well as the Barossa and Caldita gas fields and Bayu-Undan CCS developments.⁸ The Reference Scenario industrial development is based on the timeline presented in Figure 11. The development timeline is one possible development outcome and will be subject to change if the industries are established.

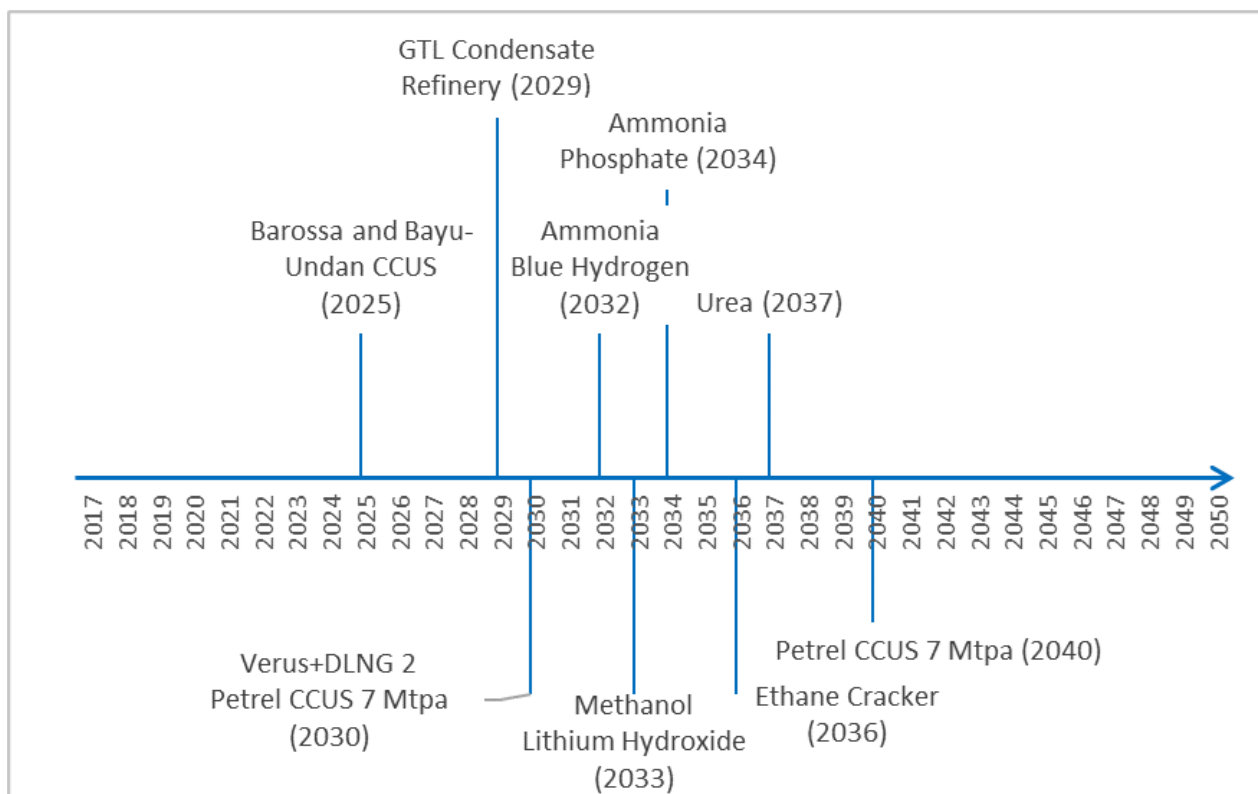


Figure 11: Reference Scenario industrial development timeline
Source: NT-Department of Logistics and Infrastructure

Avoidance and abatement options

Avoidance and abatement of Northern Territory emissions will be undertaken by a combination of methods including renewable electrification, hydrogen fuel substitution and CCS.

In the emissions avoidance and abatement models developed below the following assumptions were used in addressing each emissions category:

- For AGRU emissions, only CO₂ capture was determined as a suitable abatement technology.

⁸ The reference scenario was developed before 2025. At the time of writing, the Bayu-Undan CCS project has not yet reached final investment decision. The Bonaparte CCS project is expected to reach final investment decision in 2027, while the Barossa gas field is operational.

- For gas turbine emissions, appropriate technologies for emissions reduction were determined to be renewable electrification, hydrogen fuel substitution and CO₂ capture. The exception to this assumption was for gas turbines situated in remote areas away from Darwin, such as mine sites and remote communities. In these cases, only renewable electrification was determined to be a realistic pathway to emissions reduction.
- For reciprocating engine emissions, only renewable electrification was considered as a realistic pathway to emissions reduction.
- Industrial process flaring was assumed not to be addressable through electrification, hydrogen fuel substitution or CCS. This is considered to be a conservative assumption, as industries seek to minimise flaring operations.
- For furnaces and boilers, assumed pathways to reduce emissions were fuel substitution using hydrogen and/or capture of CO₂ emissions.
- Production emissions were determined to be suitable for CO₂ capture only within the Middle Arm, while other process emissions generated remotely were determined not to be suitable for avoidance and abatement. This is a conservative assumption as it would be expected that individual industries and sites would work towards reduction of these emissions.

Other emissions reduction drivers that are not considered in this report include the impact of increased efficiency, which is discussed separately in the Task 5 report (Czapla et al., 2024).

Emissions forecasts

A combination of emissions reduction approaches is required as no single emissions reduction technology can achieve rapid decarbonisation of point-source emissions in the Northern Territory. The ultimate mix of approaches will be determined by a combination of technical and economic feasibility and stakeholder buy-in.

Emission reduction technologies have been applied for the Base and Reference scenarios, beginning with electrification, followed by hydrogen fuel substitution before finally CCUS is applied to any residual emissions.

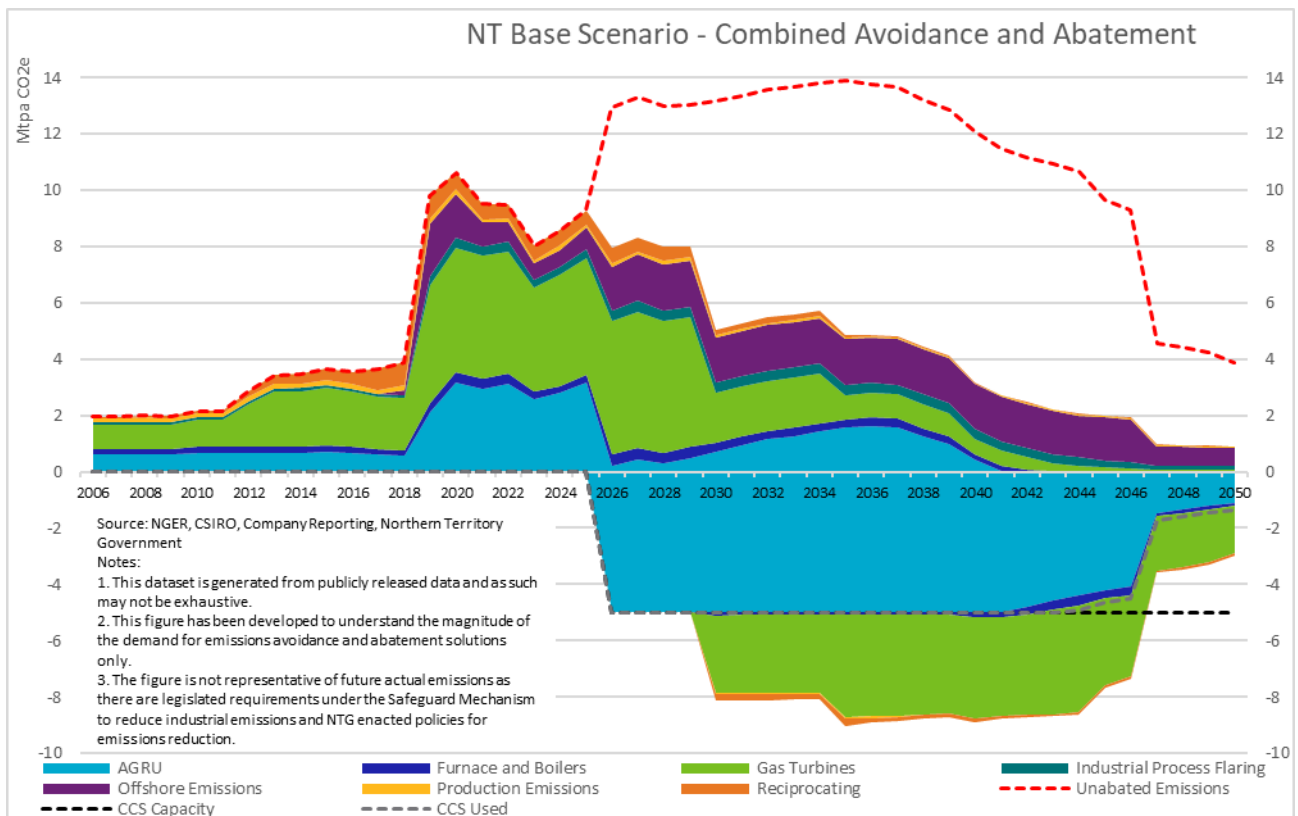


Figure 12: Emissions outlook with all abatement options – Base Scenario
Source: see Rogers et al. (2024a)

Base Scenario (Status Quo): The combination of avoidance and abatement emissions reduction technologies leads to a decreasing emissions trajectory through to 2050, when residual emissions comprise less than 1 Mtpa CO₂-e, almost exclusively associated with offshore gas production (Figure 12). For this model, all 5 Mtpa of potentially available CO₂ storage⁹ is used through to 2043, after which there is a strong decline in the volumes of CO₂ for storage, and demand for emissions reduction from the use of renewable energy and hydrogen declines due to falling natural gas production.

Reference Scenario: In the combined avoidance and abatement model, net emissions are dramatically reduced, after peaking at 12.9 Mtpa CO₂-e in 2037. Between 2024 and 2050 (apart from the years 2036–38), point-source emissions are below 10 Mtpa CO₂-e with emissions steadily declining to just over 5 Mtpa CO₂-e from 2038 to 2050 (Figure 13). The uplift in emissions in 2036–38 could, in principle, be mitigated through either delayed industrial development or earlier development of the CCS capacity. The residual emissions in 2050 comprise process and offshore emissions. In this model, CO₂ storage capacity is fully used through to 2040 and after this period significant residual CO₂ capacity is available.

⁹ In the assessment of the potential impact of CCS on both Base and Reference scenario emissions, 5 Mtpa CO₂-e emissions reduction through CO₂ storage is made available in 2026. For the Reference Scenario this capacity is augmented by an additional 10 Mtpa CO₂ in 2030 and a further 10 Mtpa CO₂ in 2040 (totalling 25 Mtpa CO₂ storage capacity, as per the Task 0 report (Ross et al., 2023).

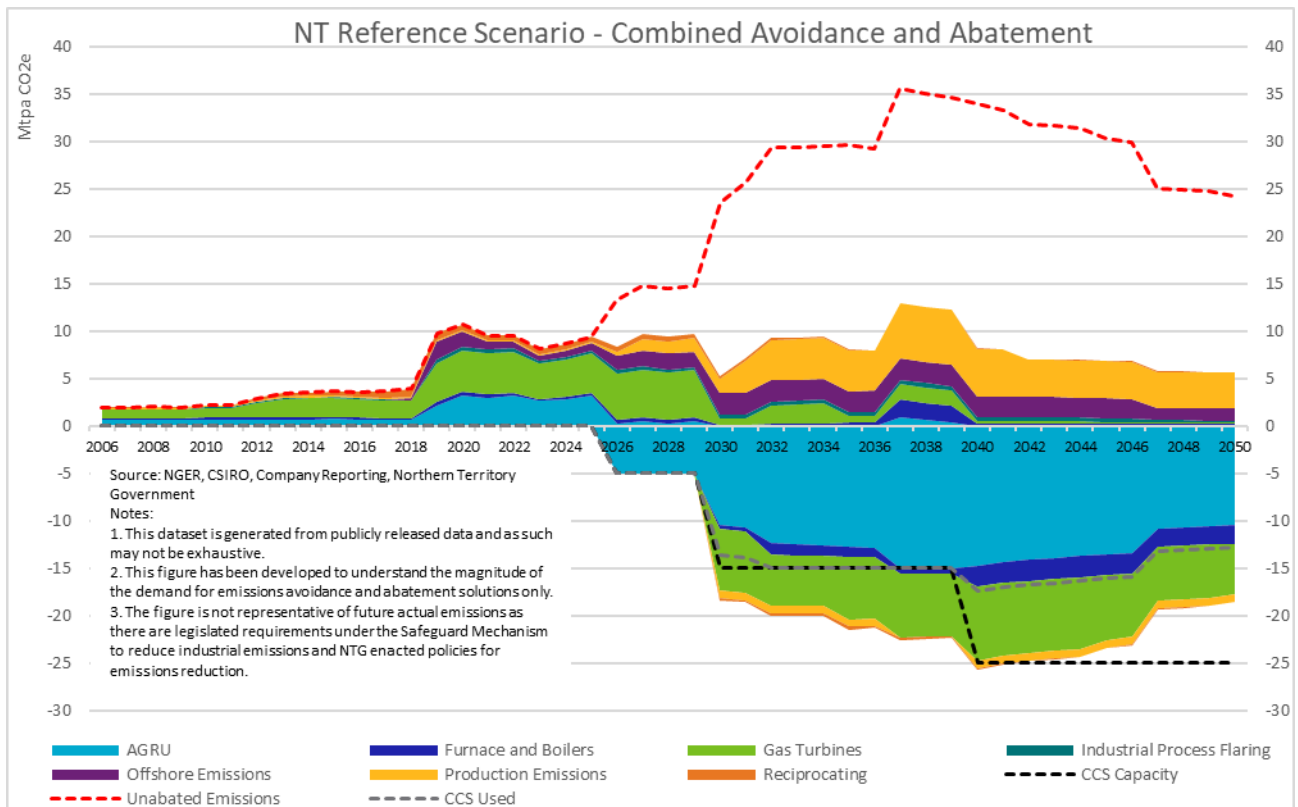


Figure 13: Emissions outlook with all abatement options – Reference Scenario

Source: see Rogers et al. (2024a)

These forecasts for emissions reduction have shown there is strong potential demand for renewable electrification, fuel substitution and CCS from MASDP industries both in the base case and reference scenarios. The range of CCS demand varies from 5 Mtpa to 25 Mtpa between the scenarios and shows how that even with no further development of the MASDP the demand for large scale CCS will be strong.

Regional emissions reduction commitments

To provide further understanding of the CO₂ market that may be accessible for the Northern Territory regional emissions reduction commitments and pathways have been analysed.

Countries in the region have made NDCs reflecting their climate action plans under the Paris Agreement. Across the region there is growing ambition through these stated policies to make significant reductions to greenhouse gas emissions. Examples of NDC commitments are included for reference below:

- China is targeting peak carbon emissions by 2030 and to reach carbon neutrality by 2060, (IEA, 2026a).
- Japan has made a commitment to reach 46% emissions reduction by 2030 (vs 2013), 60% emissions reduction by 2035, 73% emissions reduction by 2040 and carbon neutrality by 2050 (Government of Japan, 2025)

- South Korea has pledged to reduce greenhouse gas emissions by 40% by 2030 compared with 2018 levels and to reach carbon neutrality by 2050 (Republic of Korea, 2025).
- Singapore's emissions are expected to peak before 2030 and the country has pledged to reduce emissions to 45–50 Mt CO₂-e by 2035 (from 58.6 Mt CO₂-e in 2022) with a 2050 net zero target (Singapore Government, 2025).
- India has a target to reduce emissions intensity in relation to gross domestic product (GDP) by 47% by 2030 with a long-term goal of reaching net zero by 2070 (Government of India, 2026).
- Indonesia has a target to conditionally reduce emissions by 43.20% relative to 2019 levels (Republic of Indonesia, 2025).
- Malaysia has a target of a 45% reduction in carbon intensity against GDP by 2030 compared with 2005 levels and seeks to achieve net zero by 2050 (Malaysian Government, 2021).
- Thailand has a target of reducing greenhouse gas emissions by 47% compared to 2019 levels, with a goal of net zero by 2050 (Thailand Government, 2025).

These NDCs and the policies that underpin them (See section 7) will drive the development of new low-emissions industries and the decarbonisation of existing industries.

Point-source emissions

The elimination of point-source emissions will be critical to emissions reduction across the region, as in 2022 the emissions stood at ~10 Gtpa (Figure 14). China represents 65% of these emissions and India 13% (Rogers et al., 2024b). 55% of the region's point-source emissions come from coal-fired power generation, while the production of iron, steel and cement and gas-fired power generation represent a further 40% of emissions (Figure 14). It is important to note that the Northern Territory's key trading partners (Japan, China, Taiwan, Singapore and South Korea) together account for 76% of emissions in the region.

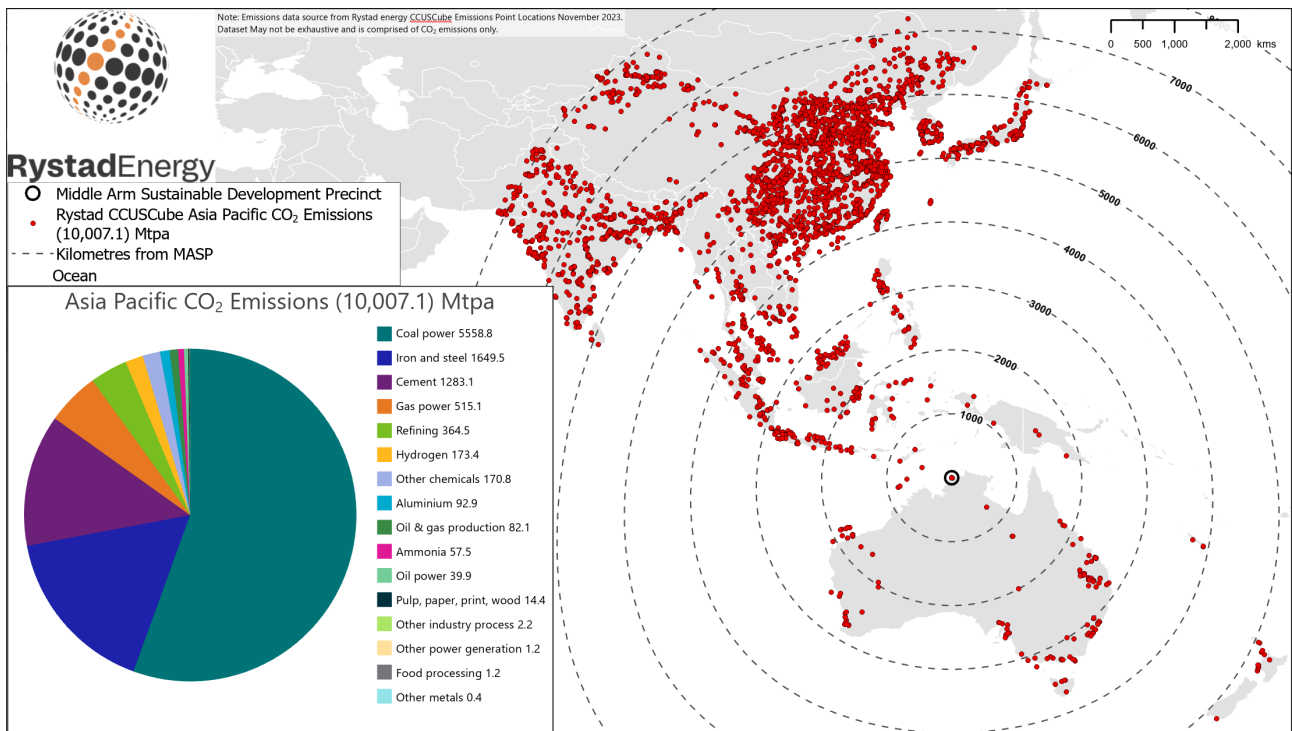


Figure 14: Regional CO₂ point-source emissions plotted with reference to Darwin; pie chart shows distribution of emissions by industry

Source: Adapted from Rystad Energy (2024)

The need for CO₂ shipping

As in the Northern Territory, a range of avoidance and abatement approaches will need to be taken in each of these countries to manage emissions, including efficiency measures, renewable electrification, fuel substitution and CCS (see low-emissions product demand projections in section 4).

However, in jurisdictions where CO₂ storage is not available, the opportunity to transport captured CO₂ to the Northern Territory CCUS hub via liquid CO₂ shipping may be considered.

As an example, Singapore's emissions were 58.6 Mt of CO₂-e in 2022 (National Climate Change Secretariat (NCCS), 2024), of which 28.8 Mtpa come from point-source emissions, predominantly from gas power generation and refining (Rogers et al., 2024b). As a small nation covering just 728 km² it is recognised that Singapore does not have the natural resources, land area and climatic conditions for large-scale renewable energy installation and so will need to both import renewable electricity and export captured CO₂ to other jurisdictions.

As well as assisting decarbonisation of regional partner countries, CO₂ shipping is seen as a way of increasing the capacity for CO₂ storage projects, since greater volumes of CO₂ can reduce the unit cost of CO₂ storage. For CCUS hubs, having CO₂ import-export terminals provides some contingency for periods when local CO₂ storage may not be possible (e.g. during periodic maintenance), allowing the export of CO₂ to alternative CO₂ storage projects. This approach is part of the business model being considered by many of the CCUS projects around the North Sea (Stalker et al., 2024).

For long distances, shipping is a lower-cost alternative compared with pipelines, which require large upfront capital expenditure (Jakobsen et al., 2013; Smith et al., 2021). Given the significant potential geological CO₂ storage resources in the basins offshore of the Northern Territory (Johnstone and Stalker, 2022) there is the possibility for CO₂ emitted overseas or within other parts of Australia to be stored there, along with CO₂ that has been captured from existing LNG and future MASDP facilities operating in Darwin.

CO₂ market analysis

To establish an understanding of the potential CO₂ shipping market across the region point-source emissions have been filtered using a CO₂ market estimation method similar to that employed by the Northern Lights project to estimate their market potential. This method estimates the total addressable market (TAM), serviceable available market (SAM) and serviceable obtainable market (SOM) for the Northern Territory's top five trading partners from the Southeast Asian region (described in more detail in the box below). The market is estimated for both 2030 and 2050 to enable comparison of potential long-term demand, noting that realising this demand depends in part on sufficient policy alignment between Australia and its trading partners.

CO₂ market estimation method

Total addressable market (TAM): Estimated using the 2022 CO₂ emissions from the Northern Territory's key trading partners (Japan, China, Taiwan, Singapore and South Korea). These emissions were filtered to those within 50 km of a port with a depth of 13 m or more. Note that no projection of emissions growth was included in the total addressable market assessment as a conservative approach to estimating the market potential.

Serviceable available market (SAM): The total amount of CO₂ emissions that might be captured was calculated using the numbers from the total addressable market estimation multiplied by the level of CO₂ capture forecast to be installed and abating emissions in the years 2030 and 2050 for each sector. Factors estimating the level of CO₂ capture forecast for various sectors were sourced from the IEA's *Net Zero Roadmap: A Global Pathway to Keep the 1.5 °C Goal in Reach* (IEA, 2023a). Further details of the estimation method are included in Rogers et al. (2024b).

Serviceable obtainable market (SOM): The potential volumes of CO₂ available for the Northern Territory CCUS hub were estimated by multiplying the serviceable available market by an arbitrary figure of 5% (i.e. assuming 20 CCUS hubs equally share in servicing the CO₂ storage demand for the Territory's five key trading partner jurisdictions) to represent the volume of CO₂ that could be imported to Darwin.

This approach to market size estimation has inherent uncertainties and gross assumptions (as detailed above). However, the purpose is to provide an estimating basis to help understand the size of potential future CO₂ markets in the region.

It is anticipated that the volumes of CO₂ available in the market are significantly underestimated using the approach above as the estimates do not incorporate:

- economic growth and any resultant growth in unabated emissions

- other countries beyond the Northern Territory's five key trading partners
- ports with a depth of less than 13 m
- gather pipelines for CO₂ beyond 50 km from a port.

When the 2022 CO₂ emissions of ~10 Gt for the Asia-Pacific region (inclusive of Australia) are filtered from emissions of the Northern Territory's key trading partners (Japan, China, Taiwan, Singapore and South Korea), this results in 7.6 Gt of point-source CO₂ emissions. Of these CO₂ emissions, ~2,265 Mt are within 50 km of a port with a depth of 13 m or more, representing the TAM. A SAM of ~64 Mt is estimated by 2030, of which ~3 Mt of CO₂ are estimated as a SOM for the Northern Territory CCUS hub (Figure 15). Using the same 2022 total addressable market data, the total serviceable market in 2050 is estimated to be ~1,449 Mt of CO₂. This is based on increased CO₂ capture requirements by industry sectors to meet net zero requirements. Of this total serviceable market, ~72 Mt are estimated as a serviceable obtainable market (Figure 16). While several assumptions are made in these estimations, they show the likely strong demand for CO₂ shipping in the future within the region.

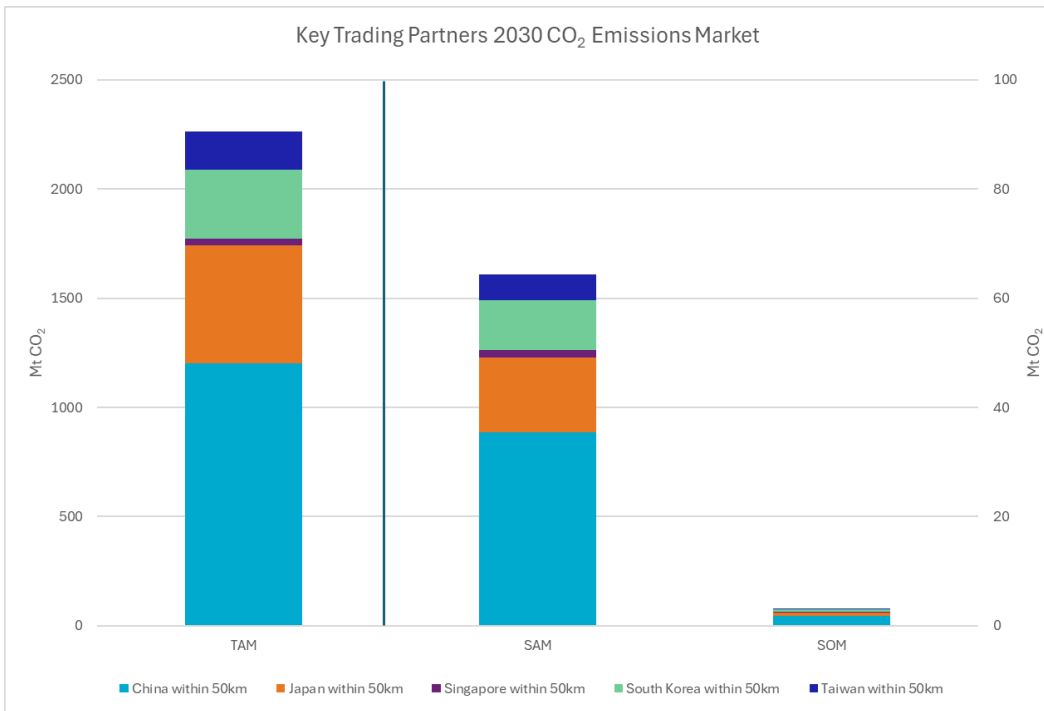


Figure 15: 2030 CO₂ market estimate

TAM = total addressable market, SAM = serviceable available market, SOM = serviceable obtainable market

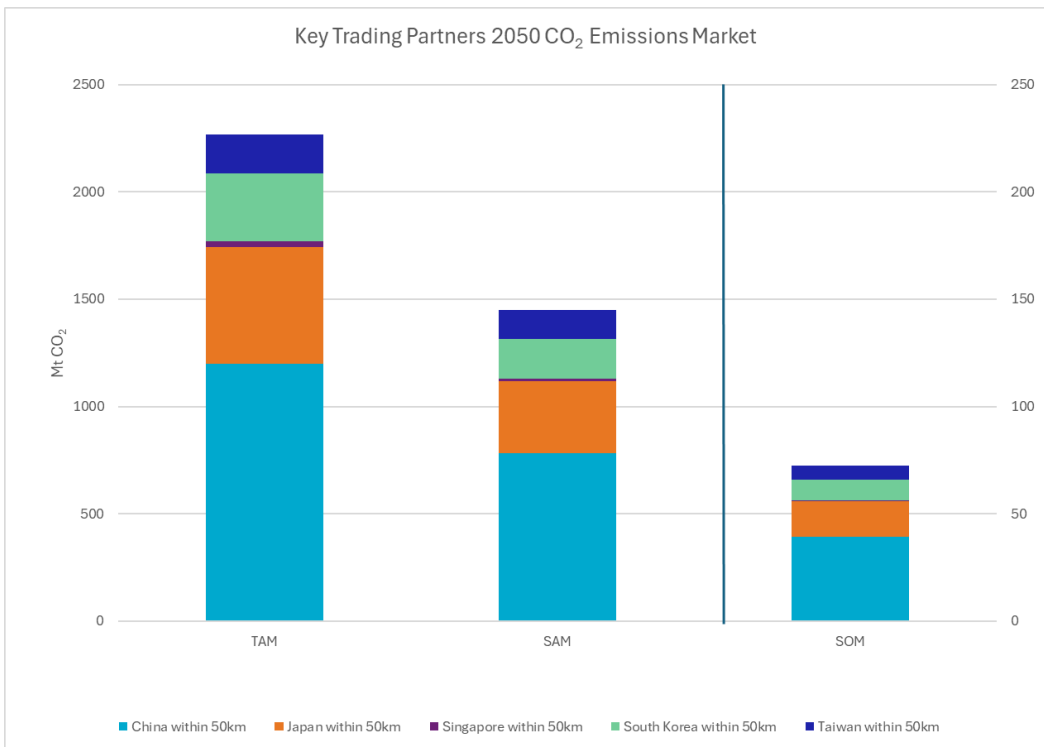


Figure 16: 2050 CO₂ market estimate

TAM = total addressable market, SAM = serviceable available market, SOM = serviceable obtainable market

The carbon capture transport and storage value chain

The carbon capture transport and storage (CCTS) value chain is often described in terms of three key components. The first component involves point-source carbon capture – for example, emissions associated with power generation, resource extraction or industrial processes. Second, the captured CO₂ is either compressed or liquefied before being transported. Finally, once the CO₂ has been transported, it is either used or stored permanently within deep geological formations.

For this project a combined logistics and techno-economic model was developed to estimate the levelised cost of shipping CO₂ from the Port of Kawasaki in Japan to the Port of Darwin (a one-way distance of 6,231 km). The modelling involved two steps:

1. calculating the number of ships required to transport a desired volume of CO₂ each year
2. calculating the levelised costs, using the logistic model outputs.

The detailed description of the model can be found in Tocock et al. (2024).

The various equations used to estimate the costs for each component of the value chain build upon the work described in Element Energy (2018), with formulas and results from other studies used as a robustness check. In addition, cost estimates from recent Northern Territory Government reports (Royal HaskoningDHV, 2021; GHD, 2023) – for example, the costs of constructing an import terminal within the Middle Arm – have also been used.

The model was constructed assuming low-pressure, low-temperature transport conditions (see the box below) and includes the export terminal, shipping and import terminal components. The model includes three different vessel cargo sizes of 40,000 m³, 60,000 m³ and 80,000 m³. Capture and storage components and costs were not included in the model (Figure 17).

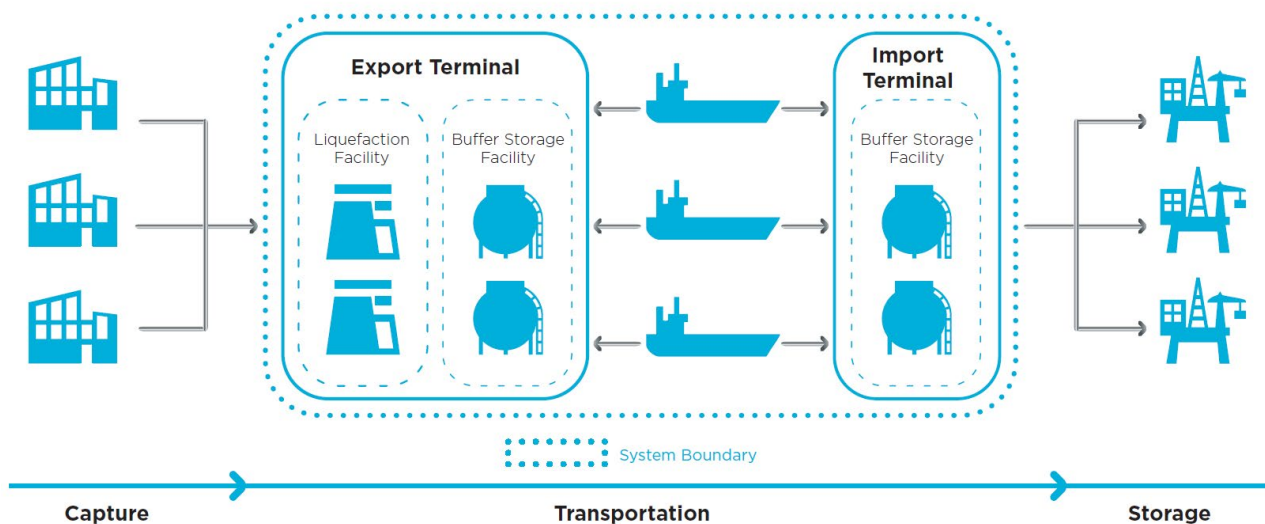


Figure 17: Overview of the CCTS value chain

Modes of CO₂ transport via ship

Currently there are three modes of transport that vary according to the temperature and pressure of the stored CO₂. Often it is assumed that CO₂ will be transported in its liquid state due to its higher volumetric density. However, there is no clear consensus as to what pressure/temperature range above the triple point (-56.6°C, 4.17 barg) CO₂ should be transported at. Below are the three ranges often discussed Orchard et al. (2021):

1. low pressure (5–10 bar between -50° and -40°C)
2. medium pressure (15–20 bar between -30° and -20°C)
3. elevated pressure (35–50 bar between 0° and 15°C).

Each of the proposed pressure ranges has its relative merits. Currently, food-grade CO₂ is transported at medium pressure and uses mature technologies (Al Baroudi et al., 2021). Storing CO₂ at a low pressure results in relatively higher volumetric densities and uses similar technologies as for liquid petroleum gas (LPG) transportation. High-pressure transportation results in lower energy requirements but it means that the CO₂ is transported at the lowest volumetric density.

There are also drawbacks that relate to the risk of dry-ice (solid CO₂) formation, the cost of materials for tank construction, and the relative technological maturity for handling CO₂ at the proposed pressures.

Based on a review of the literature, transporting CO₂ at a low pressure appears to be the most cost-effective option over longer distances and is therefore the pressure used in the techno-economic model presented below. However, as research continues and more demonstration projects reach completion, the optimal temperature/pressure combination may change.

Costs of CO₂ shipping

Using the results from the logistics model, the levelised cost of transportation for the three ship sizes across the different annual volumes of CO₂ is reported in Figure 18. When considering annual volumes between 1 and 6 Mtpa, the levelised cost of shipping CO₂ was estimated to range from \$122 to \$224 per tonne. Achieving the lower end of this cost range requires using the largest ships modelled and leveraging economies of scale by spreading the fixed infrastructure costs over larger CO₂ volumes.

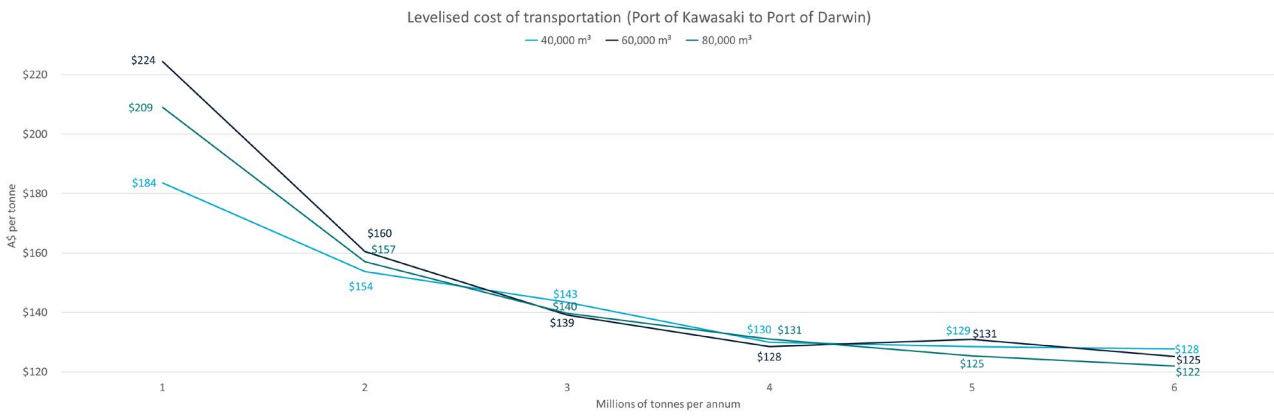


Figure 18: Levelised cost of transportation in A\$ per tonne

One of the most significant factors in the technoeconomic model is the cost associated with the import terminal’s buffer storage facility. As noted in GHD’s (2023) report, significant cost savings could be realised if the number of onsite storage vessels was reduced, leading to lower capital expenditure (CapEx). Currently it is assumed that the LCO₂ is unloaded from the site to the buffer storage facility and then progressively converted to a dense state before being transferred to an export tie-in pipeline. Greater conversion capacities and associated downstream capacities could reduce the amount of buffer storage required.

Determining both the desired pressure/temperature and the tolerance of impurities will be critical for derisking the value chain and evaluating alternative methods to lower costs. Agreeing on a common set of standards could also help decide tolerances for impurities within the CO₂ stream.

The reported CO₂ shipping costs represent only one part of the three-part value chain associated with CCS. To determine the total cost of CCTS, the costs of capture and storage must also be considered. Policymakers across multiple jurisdictions will need to compare this aggregate cost with alternative decarbonisation methods (if they are available in their jurisdictions) to identify the most effective allocation of government funds for achieving least-cost emissions reductions.

Key points

- Australia is committed to achieve NZE by 2050 and to reduce greenhouse gas emissions to 43% below 2005 levels by 2030 and 62-70% by 2035.
- Forecast models of emissions reduction have shown there is strong potential demand for renewable electrification, fuel substitution and CCS from MASDP industries both in the Base and Reference scenarios.
- The range of CCS demand varies from 5 Mtpa to 25 Mtpa between the scenarios and shows that, even with no further development of MASDP industries, the demand for large-scale CCS will be strong.
- For the Base scenario, after 2043 there is a strong decline in the volume of CO₂ for storage due to falling natural gas production (and lack of other emitting industries in the MASDP). As such, if this scenario were realised there would be no incentive to build CCS infrastructure at scale.
- Across the Asia-Pacific region there is growing ambition through stated policies to make significant reductions in greenhouse gas emissions. In jurisdictions where CO₂ storage is not available, the opportunity to transport captured CO₂ to the Northern Territory CCUS hub via liquid CO₂ shipping may be considered.
- Estimates of the CO₂ import market from the Northern Territory's five largest trading partners (Japan, China, Taiwan, Singapore and South Korea) are ~3 Mt by 2030 rising to ~72 Mt by 2050.
- As well as assisting in the decarbonisation of regional partner countries, CO₂ shipping is seen as a way of reducing the unit cost of CO₂ storage within importing countries, which would benefit industries within the Northern Territory.
- This is due to increases in transport and storage not scaling linearly with increasing CO₂ volumes.
- The costs of CO₂ shipping were modelled to include export terminal, shipping with three vessel cargo sizes of 40,000 m³, 60,000 m³ and 80,000 m³ and import terminal components.
- When considering annual volumes between 1 and 6 Mtpa, the levelised cost of shipping CO₂ was estimated to range from \$122 to \$224 per tonne.
- One of the most significant factors in the techno-economic model is the cost associated with the import terminal's buffer storage facility.
- Determining both the desired pressure/temperature and the tolerance of impurities will be critical for derisking the value chain and evaluating alternative methods to lower costs.
- While there are significant uncertainties about the development of new industries in the MASDP and the market's ability to bear the costs of CO₂ shipping, the studies have shown that there is significant market potential for CO₂ hub development in the Northern Territory at a scale much greater than currently operating CCUS projects.

4 Demand for low-emissions products

To understand the types of industries that may be established in the MASDP and the Northern Territory it is critical to understand the current and future demand for low-emissions products and identify their key drivers in local and overseas markets. This will help inform CCUS demand for the NT CCUS hub (as well as the demand for other emissions avoidance and abatement technologies).

What are low-emissions products?

Low-emissions products are designed to minimise the release of greenhouse gases over their lifecycle by incorporating principles of a circular economy, energy efficiency, use of renewably sourced electricity, and carbon management practices including process substitution and CCUS. Low-emissions products range from fuels such as low-emissions hydrogen and methanol to manufactured goods based on recycling of plastics and building materials that incorporate captured CO₂ in their manufacture. The intent of these products is to provide low-emissions alternatives to existing products, particularly where alternatives may be currently unfeasible (e.g. sustainable aviation and marine fuels).

The NT CCUS business case project focuses on hydrogen and hydrogen derivatives (e.g. ammonia, urea) and chemical feedstocks, since these are most relevant to opportunities for decarbonising and expanding existing industries based around LNG in Darwin and serving major export markets in the region. In addition, low-emissions fuels and derivative chemical products can serve the decarbonisation needs of the largest-emitting industrial sectors of the Northern Territory's five key trading partners (Japan, China, Taiwan, Singapore and South Korea).

Key emissions sectors which will drive low emissions product demand

Five key emitting sectors are the focus in understanding low-emissions product demand from the Northern Territory's key trading partners (See section 3 and Joodi et al., 2024b). These sectors are electricity generation, iron and steel, cement, primary chemicals and aviation.

Electricity generation

The electricity generation sector is the largest contributor to the point-source emissions and requires rapid emissions reduction to meet net zero goals. This will occur through the retirement of existing high-emissions assets and substitution with low-emissions capacity (e.g. renewable electricity generation from wind solar and hydro); prioritisation of lower-emitting technologies; low emissions fuel blending; and retrofitting current plants to capture emissions. This may also include new-build facilities with capture incorporated in the design from initiation.

With coal-fired power plants having an average life span of 40–50 years, the region's facilities with an average age of 13 years (Figure 19) are early in their lifespan and likely candidates for retrofit solutions, including carbon capture and ammonia/biomass co-firing Joodi et al. (2024b). Co-firing of coal-fired power plants with ammonia has been trialled and is moving into operation, and co-firing with hydrogen or ammonia in natural gas-fired power plants is also being developed. Current natural gas infrastructure can use an approximately 10% hydrogen blend without any upgrading

due to the higher burning temperature of hydrogen and potential for the production of nitrogen oxides (NOx).

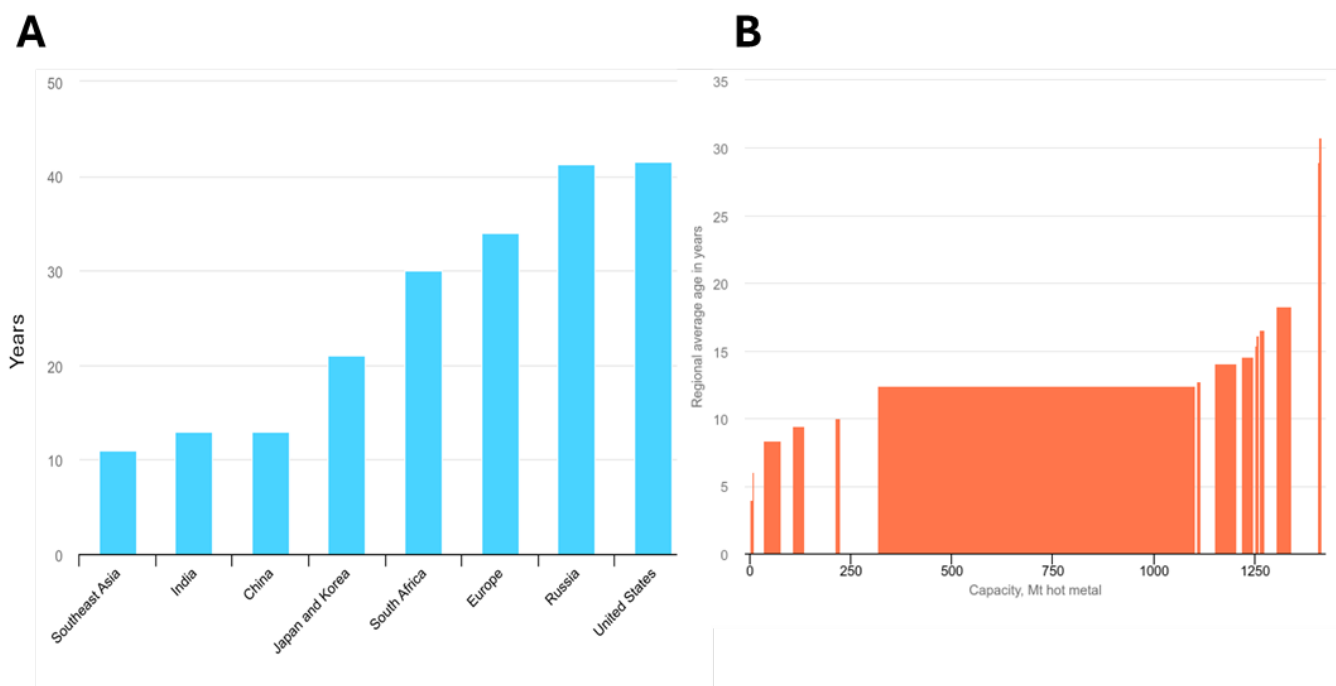


Figure 19: A: Average age of existing coal-fired power plants worldwide. B: Age profile of Asia-Pacific production capacity for the steel sector (blast furnaces and DRI furnaces)
Sources: IEA (2021a)

Iron and steel

Iron and steel production currently accounts for nearly 8% of global emissions and the global blast furnace fleet is relatively young, with an average age of 13 years, compared with an expected useful life of 40+ years IEA (2020). Most of the youngest iron and steel plants are located in the Asia-Pacific region (IEA 2020; see Figure 19) and these plants are not due for replacement for several decades. Methods to reduce emissions from this sector will include using higher grades of iron ore (or undertaking beneficiation processing of ores in supplier countries to reduce direct iron and steel-making emissions), using greater proportions of scrap metal, and pursuing energy efficiency and waste heat recovery, electrification, alternative fuels (including natural gas, hydrogen and ammonia), and CCUS.

Cement

Although there have been major energy efficiency improvements in the cement industry, the industry's direct emissions still account for 6.4–8.0% of total global emissions of CO₂ (Bashmakov and Nilsson, 2020). The sector's emissions can be divided into energy-related emissions (one-third of the total) and process-related emissions (the remaining two-thirds, largely from calcining (IEA, 2023b)).

Currently, multiple technologies are being developed to decarbonise the cement industry, including near-term efficiency improvements, CCUS, the use of clinker from non-carbonate sources to avoid calcining, supplementary/alternative cementitious materials, alternative binding materials, and fuel substitution IEA (2023a). CCUS is the most advanced technology and can

achieve >90% emissions reduction, targeting both the emissions from fossil fuel combustion and the CO₂ gas released when limestone is calcined.

Primary chemicals

The chemicals sector is the largest industrial consumer of hydrocarbons from which thousands of products are derived. However, since the hydrocarbon inputs are in the form of feedstock, rather than fuel, the sector is only the third-largest CO₂ emitter (IEA, 2023a). Most of the value chains included in the chemical sector are derived from only seven primary chemicals:

- ammonia
- methanol
- the high-value chemicals of ethylene, propylene, benzene, toluene and mixed xylenes.

Production of primary chemicals accounts for two-thirds of energy consumption in the sector. The remaining third is divided across the manufacture of thousands of different products.

No single decarbonisation method can deliver the decarbonisation level required under the NZE by 2050 scenario. Electrolytic hydrogen production, CCUS and direct electrification of thermally activated processes are the key technologies to align the sector's emissions with NZE (IEA, 2021b), see the role of CCU in the Northern Territory section).

Aviation

Emissions from the aviation sector are among the most difficult to avoid, due to the industry's need for energy-dense fuels Bergero et al. (2023) and lack of practical alternatives to kerosene in jet and turboprop engines.

Sustainable aviation fuels are the most promising option to achieve the deep decarbonisation required in the aviation industry. These range from biojet kerosene (a kerosene substitute produced from biomass) to synthetic kerosene produced from hydrogen and (ideally captured) CO₂ via Fischer-Tropsch synthesis (see Banfield et al., 2023). Under current regulations, these alternative fuels can be blended with conventional fuels at concentrations of up to 50%. Tests are in progress to run aircraft on only sustainable aviation fuels.

Why low-emissions products and not other emissions reduction pathways?

There are several routes to decarbonise the sectors identified above, and each of these routes has unique challenges. For recently constructed industrial plants it is likely that operators will seek to identify opportunities to decarbonise through fuel substitution, as this represents the least capital-intensive route to attain emissions reduction, while allowing operating companies to service existing debt repayments. For industrial plants due for maintenance, operators may take the opportunity to retrofit these assets with emissions reduction technologies, which may include electrification of parts of their process, changes to enable fuel substitution, or CO₂ capture facilities. If suitable policies are in place new industrial plants are likely to implement best-practice emissions reduction technologies or, at a minimum, be built with sufficient flexibility for implementation of emissions reduction approaches (e.g. gas turbines capable of pure hydrogen firing).

While it is often suggested that new industrial plants could be offshored to countries with abundant renewable energy and feedstocks, such as Australia, this argument overlooks the significant employment and economic benefits these industries provide to their host countries. These countries are also the very sources from which Australia would seek capital investment. Careful consideration is therefore needed when identifying the types of low-emission products that could be manufactured in the Northern Territory. These products should support emission-reduction pathways for industries in key trading partner countries while also fostering new industrial development within the Northern Territory.

Low-emissions product demand

Global demand for low emission products

Using the IEA NZE 2050 forecast data, global demand for low-emissions products will grow strongly to meet emissions reduction targets.

Globally, in the NZE by 2050 scenario across all industrial sectors, the demand for low-emissions hydrogen is forecast to be 70 Mt in 2030 and 420 Mt in 2050, the majority of which is expected to be produced through electrolysis, with the rest produced from the methane thermochemical sources equipped with CCUS. As a subset of this demand, the electricity generation sector demand is expected to grow from negligible amounts in 2022 to 14 Mt in 2030 and 42 Mt in 2050.

Around 200 Mt of ammonia are currently produced worldwide each year, only 10% of which is traded on the international market. Under the NZE by 2050 scenario, global annual ammonia demand is expected to grow to 204 Mt by 2030 and 228 Mt by 2050.

Under the NZE by 2050 scenario, emissions from the chemical sector will need to drop by 21% by 2030 and 96% by 2050, so there will be strong demand for low-emissions methanol feedstocks for the chemicals industry in the region. Total global demand for methanol is expected to grow rapidly through to 2050, from 100 Mtpa to 500 Mtpa.

Currently, the aviation sector consumes approximately 280 Mt (11,000 PJ) of oil-based fuels (International Air Transport Association (IATA), 2024; IEA, 2023c). Under the NZE by 2050 scenario, the annual demand for sustainable aviation fuels reaches 11,700 PJ in 2030 and 11,900 PJ in 2050 (IEA, 2023d).

Method used to estimate demand

Low-emissions product demand for the electricity generation, iron and steel, cement, primary chemicals and sustainable aviation fuels sectors for the Northern Territory's five key trading partners has been estimated using four IEA scenarios:

- Stated Policies scenario (STEPS)(IEA, 2023c)
- Announced Pledges scenario (APS) (IEA, 2023c)
- NZE by 2050 scenario (IEA, 2023c)
- Sustainable Development scenario (SDS), which has been excluded in recent IEA reports (IEA, 2024c).

In this analysis, the size of CCUS demand has also been estimated and this provides a comparator to the approach used to estimate CCUS demand in the Task 2 report by Rogers et al. (2024b).

The IEA does not share country-level details on the specified products (personal communication with the IEA, 24 July 2024). Therefore, to assess the potential market size for the low-emissions products within the industrial sectors of the five key trading partners, simplified estimates of regional demand for these products and services were developed.

The estimation method principally relies on the officially reported, most recent activity indicators (electricity generation, steel, cement and chemicals production, and billions of passenger kilometres for air travel) for each country as the starting point. These indicators were then forecast up to 2050. Where country-level forecast growth rates for the indicators are available, they were used in the analysis. Otherwise, it was assumed that their growth follows the global average forecast trends. A similar approach was taken for estimating the low-emissions products adoption rate to meet the decarbonisation targets.

Low-emissions product demand from the Northern Territory's key trading partners

For all forecast estimates there is strong demand for hydrogen, ammonia, sustainable aviation fuels, methanol (as a feedstock for chemicals manufacture) and CCUS from the five key trading partners (Table 2). These estimates of demand for low-emissions products do not include demand from other countries within the region, so are therefore conservative.

Table 2: Simplified projection of low-emissions product demand from the Northern Territory's five key trading partners

		2030				2050			
		STEPS	APS	SDS ^{*2021}	NZE	STEPS	APS	SDS ^{*2021}	NZE
Hydrogen and hydrogen-based Fuels (Mt H ₂ Eq.)	Electricity generation	1	2	2	8	4	14	19	12
	Steel	0		2	3	0		42	39
	Cement	0			0.3	0			2.1
Primary Chemical Feedstock (Mt)	Ammonia*	62.4		58.9	58.9	73.2		65.8	65.8
	Methanol	88Mt @ 2022 in the trading partners countries Global Demand: >100Mt 2024 - Projected to increase up to 500Mt by 2050 **.							
Sustainable Aviation Fuel (PJ)	Bio Fuel	137	229		309	444	1,038		1,004
	Hydrogen	0	0		0	9.3	102		278
	Synthetic Kerosene	3.5	7.0		29	0.0	636		1,128
CCUS (Mt CO ₂) by Sector	Electricity generation	2	14	150	106	15	345	820	342
	Steel	0		10	17	0		192	249
	Cement	0		131	86	0		596	665
	Primary Chemicals	0			15	0			102

* SDS scenario assumes savings in ammonia demand in the chemical feedstock, mainly due to fertiliser use efficiency and plastic recycling (IEA, 2024c).

** Global demand is projected to increase dramatically from 100Mt to 500Mt due to more adaptation in the transportation sector, as well as the growth in methanol-to-olefin (MTO) route as an alternative to the traditional production of ethylene and propylene through petrochemical routes, MTO share increased from almost 0% percent in 2010 to 25% of global consumption in 2020 (International Renewable Energy Agency and Methanol Institute, 2021).

Using the NZE by 2050 scenario, hydrogen and hydrogen derivatives for the five key trading partners represent 57% of total forecast global demand in 2030 and 28.5 % of global forecast demand in 2050 (summing to 8 and 12 Mt hydrogen, respectively). The NZE by 2050 scenario is the most aggressive emissions reduction scenario used for demand estimates. However, while the Announced Pledges scenario and the Sustainable Development scenario have lower gross demand estimates in 2030, they exceed the NZE demand estimates in 2050, representing lower levels of implementation of alternative technologies (Table 2).

Even just considering the electricity generation, steel and cement sectors for the five key trading partners, the hydrogen demand estimates presented here represent 16% of the total global market by 2030 and 12.6% of the market by 2050. There will be additional demand in these

jurisdictions from other sectors, including the aviation, other transport and primary chemicals sectors (Table 2).

For the five key trading partners, low-emissions ammonia demand estimates represent about 29% of global demand in both 2030 and 2050. The Stated Policies scenario (and the Sustainable Development scenario) demand estimates exceed the NZE-derived estimates of demand, reflective of the drivers and policies enacted for ammonia use, particularly by Japan and the Republic of Korea.

Specific demand estimates cannot be ascertained for methanol and high-value chemicals due to insufficient data availability. It is known, however, that most current global methanol demand comes from the five key trading partners

Approximately 20% of the global aviation fuel demand will be derived from the five key trading partners in both 2030 and 2050. The gross Stated Policies scenario and Announced Pledges scenario demand forecasts are somewhat lower than the NZE by 2050 scenario in 2030 but have higher demand in 2050.

The estimated CCUS demand differs from that determined in the Task 2 report (Rogers et al., 2024b) for 2030 as different estimation methods have been used. However, using this method there is significant forecast demand for CCUS in the electricity generation, iron and steel, cement and primary chemicals sectors in all but the Stated Policies scenario in 2030 and 2050.

The estimates of low-emissions product demand will be driven by China due to the size of its economy and associated emissions, but there are also important demand contributions from the other trading partners. While some of the demand for low-emissions products will be met by the countries themselves, there will be significant opportunity for the Northern Territory to export low-emissions products.

The role of CCU in the Northern Territory

The development of a hub with shared CCUS and hydrogen production infrastructure can support the deployment and scale-up of CO₂ utilisation opportunities. As part of the CCUS business case CSIRO assessed the opportunities for CCU in the production of low-emissions products in the NT (Banfield et al., 2023). This consultative assessment identified five CCU products that could be manufactured in the Territory and then undertook a technoeconomic assessment of their cost and possible pathways to implementation.

Methanol



CO₂-derived methanol is a precursor to downstream products, such as plastics and textiles, as well as a standalone fuel. CO₂-derived methanol production could be a short-term opportunity for the NT because of its diversity in downstream uses and potential for hybrid production using both renewable hydrogen and methane.

Jet Fuel



The aviation industry has demonstrated interest in decarbonising via sustainable aviation fuels, including CO₂-derived jet fuel. The local military sector in the NT may be willing to pay the premium associated with CO₂-derived jet fuel to support domestic fuel security and decarbonisation targets.

Urea



Urea is the most widely used nitrogen-based fertiliser and demand is projected to continue to grow. Conventional urea production is a mature application of CO₂ utilisation but a significant contributor to global emissions. Renewable hydrogen and direct air capture (DAC)-sourced CO₂ could enable the production of renewable urea in the long-term. In the medium term, the NT could consider manufacturing hybrid urea (using both natural gas and renewable hydrogen inputs) while the availability and affordability of renewable inputs improve.

Methane



CO₂-derived methane production can offer a low to zero emission alternative to natural gas. Customers may be willing to pay a significant premium for methane derived from DAC or recycled CO₂, where alternative solutions (such as hydrogen, ammonia or electrification) are economically or technically unsuitable. If this is the case, the NT will be well placed to meet this demand due to its well-established LNG infrastructure, trade links, and gas processing expertise.

Mineral carbonates



CO₂-derived mineral carbonates can create negative-emissions products when coupled with DAC. High-level analysis suggests that the suitable mineral feedstocks such as mafic/ultramafic rock formations are present in the NT. However, waste from current mining operations is not expected to be suitable for carbonation. New mining projects may create opportunities for mineral carbonation in the NT.

CCU product costs

CO₂ utilisation opportunities are comparatively expensive, but cost reductions are expected as the relevant technologies mature. Most CO₂ utilisation applications are not yet commercially mature and are not cost competitive with conventional products. However, it may be possible to charge a premium for these products if they support customers' emissions abatement objectives.

Technoeconomic models for five CO₂ utilisation products were used to calculate the levelised cost of production under the Base-Case and Best-Case scenarios. The levelised cost of production calculates the lifetime costs of production per tonne of product. To compare the potential commercial feasibility of the five products, the levelised cost of production results have been normalised using a historic sale price (Figure 20). A ratio of 1 indicates that the CO₂ utilisation product has potential to break-even (with no profit margin) at a mid-range historic price.

Under the Base-Case scenario, all CO₂ utilisation products would need to charge a premium to break-even on production costs. Balancing the sustainability and affordability of CO₂ and other input requirements will be critical to attracting customers for CO₂-derived products. All modelled products have significant cost-reduction potential under the best-case scenario, due to improvements in technology, feedstock affordability, and economies of scale. With a low-cost CO₂ source, mineral carbonates and urea may achieve a break-even price without needing to charge a premium.

The economic feasibility of all CO₂-derived products will also depend on a variety of other factors, including their ability to charge a premium for CO₂ abatement and the cost of competing low-emissions products.

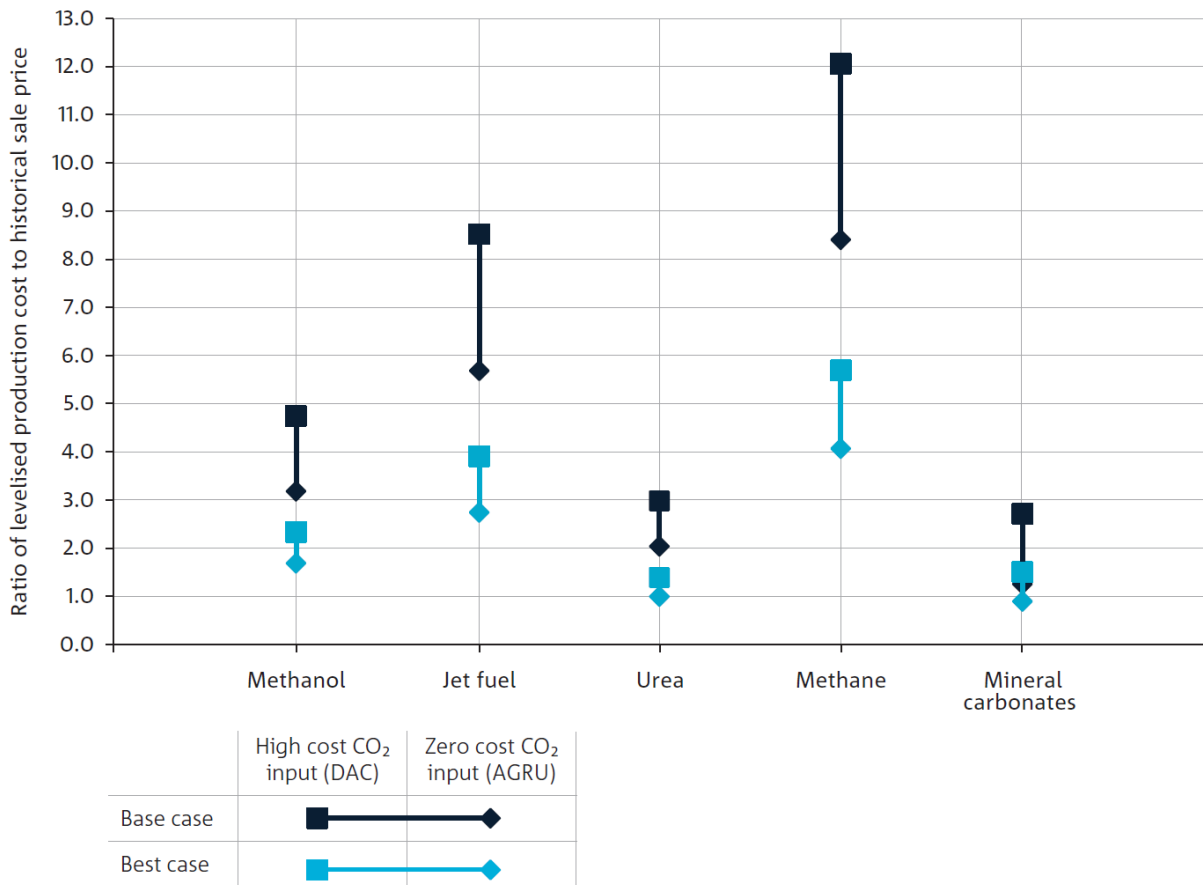


Figure 20: Best-Case and Base-Case levelised cost of production for five prioritised opportunities as a ratio of conventional sale price.

This above figure shows the best and base case levelised costs of production for CO₂-derived products expressed as a ratio to historic sale prices for their conventionally produced equivalent. Two different CO₂ feedstocks are shown, acid gas removal unit (AGRU) and direct air capture (DAC), which shows the impact of different CO₂ costs on levelised cost of production. AGRUs are used for liquefied natural gas (LNG) processes and are a source of near zero-cost CO₂. DAC technologies are emerging and have not reached commercial scale globally, producing CO₂ at a higher cost.

The scale-up of CO₂ utilisation

The deployment plan for the Northern Territory describes an indicative scale-up pathway for these five products in the context of expanded CO₂ capture and storage (Figure 21). Methanol has the greatest scale-up potential in the short term. Other opportunities including jet fuel and urea production reach demonstration scale in the medium term. Methane and mineral carbonates could also reach demonstration scale in the medium term if the right customers and mineral feedstocks can be identified.

		Short term (by 2030)	Medium term (2030-2040)	Long term (beyond 2040)
CO ₂ UTILISATION	CO ₂ CAPTURE	Existing industrial emissions (primarily LNG processing)	Existing industrial emissions + Point source + Demonstration scale DAC	Existing industrial emissions + Point source + Commercial scale DAC
	METHANOL	Demonstration scale	Commercial scale, potential for hybrid production	Commercial scale for local downstream manufacturing and export
	JET FUEL	Pilot scale	Demonstration scale for local defence and airport industry	Commercial scale for export
	UREA		Demonstration scale, potential for hybrid production	Commercial scale, potential for fully renewable urea
	METHANE		Demonstration scale, if suitable customers are identified	Commercial scale for export
	MINERAL CARBONATES		Demonstration scale, if appropriate mineral feedstocks are identified	Commercial scale
	CO ₂ STORAGE	Geological storage	Geological storage	Geological storage

Figure 21. Integrated plan for deployment and scale-up of CCU in the NT

Commercial-scale CO₂ utilisation will require significant volumes of CO₂, renewable hydrogen and renewable electricity (Figure 22). This will require multiple orders of increase in the scale of production of these inputs. To enable full abatement potential for CO₂ utilisation products, it is assumed that:

- sources of CO₂ will transition over time, with the existing LNG industry providing short-term sources of CO₂ in the Territory, sustainable sources of CO₂ (such as DAC) can be used as they scale up and reach commercial competitiveness
- the electricity required in the MASDP will be provided entirely by renewable sources in the long term, supported by energy storage solutions, and upgraded transmission and distribution networks
- Large-scale renewable hydrogen production in the medium to long term, will be enabled by renewable electricity, naturally occurring hydrogen or low-emissions hydrogen produced from natural gas may act as transitional sources
- Access to land, water, natural gas and export infrastructure are also key requirements for scale-up CO₂ utilisation opportunities.

The development of these inputs and related infrastructure may be relatively low-risk investments for the Territory, as carbon capture, renewable electricity and hydrogen are all expected to be increasingly required, even if CO₂ utilisation opportunities do not reach maturity. This can de-risk investment for CO₂ utilisation proponents in the medium to long term.

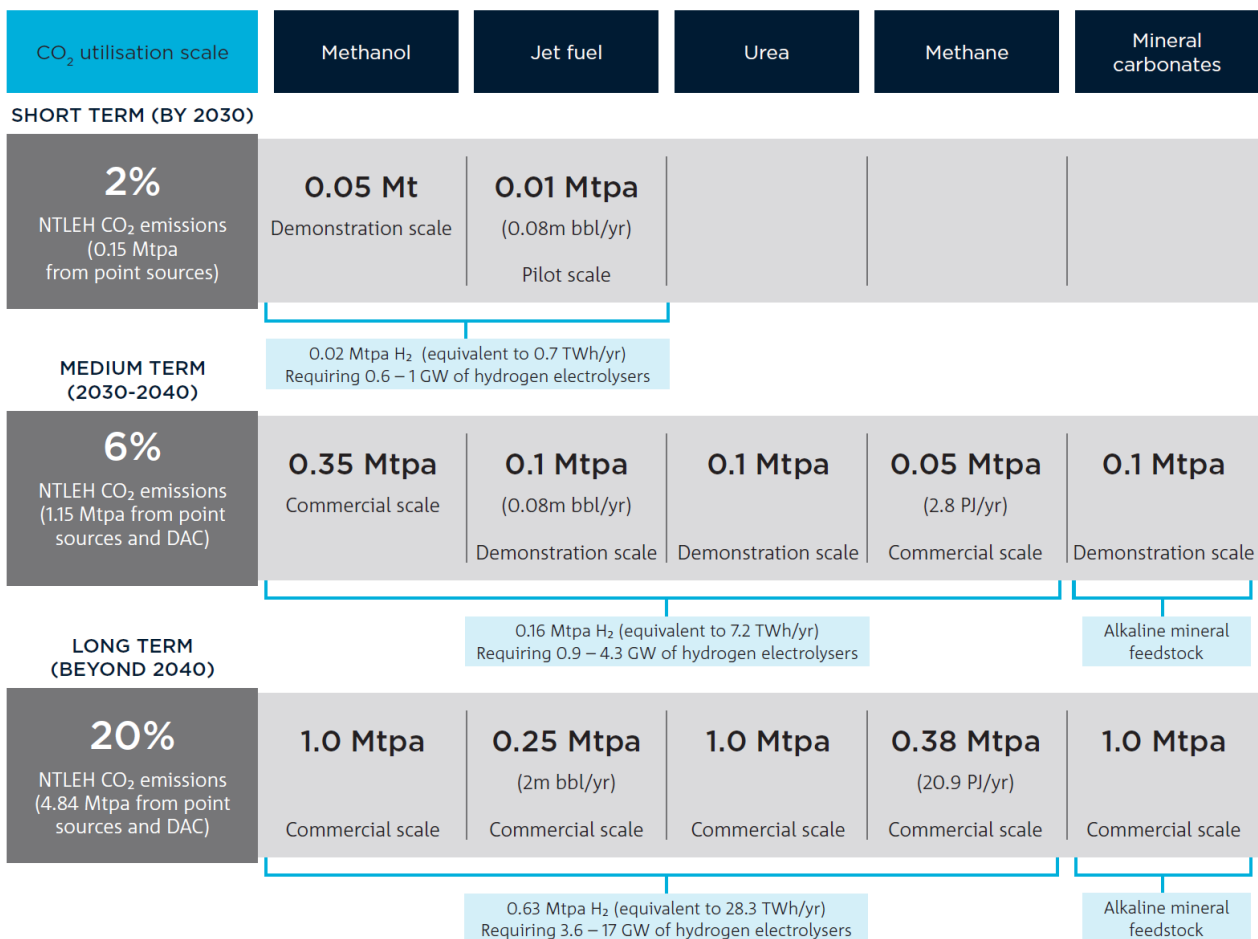


Figure 22: Cumulative CO₂ and hydrogen demand

The electrolyser scale varies to account for the different capacity factors modelled for electricity supply (19% and 90%). NTLEH = Northern Territory low emission hub, bbl = Barrel. See Banfield et al. (2022).

Developing a hub with shared CCUS and hydrogen production infrastructure can support the deployment and scale-up of CO₂ utilisation opportunities. The hub model could also enable the deployment and scale-up of CO₂ utilisation opportunities by:

- Strategically planning hub activities to identify synergies and efficiencies between CCUS, renewable hydrogen, low-emissions manufacturing and other industrial developments.
- Enabling research, development and demonstration into CO₂ utilisation and related technologies, such as DAC, hydrogen electrolysis and novel utilisation technologies, to reduce utilisation costs.

Stimulating low-emissions product demand

While the demand estimates for low-emissions products are large, even in the Stated Policies scenario, further policies and mechanisms are required to meet the Announced Pledges and NZE by 2050 scenarios. Low-emissions intensity products are typically not able to compete on price alone, as incumbent products are made using technologies that have benefited from many decades of optimisation and process improvement, use low-cost inputs, and have not needed to consider resultant process or product use emissions.

As such, the uptake of low-emissions products requires the closing of the price gap due to relative differences in emissions-intensity through the use of a variety of policy levers. This includes carbon pricing and markets; tax incentives, grants, low-interest financing and offtake agreements that support investments in enabling technologies and its associated infrastructure (e.g. renewable electricity generation and transmission infrastructure).

Some of the more pertinent universal and sector-specific demand drivers (electricity generation, iron and steel, cement, primary chemicals and sustainable aviation fuel) are briefly reviewed here, with greater detail provided in Joodi et al. (2024a) and in section 7.

Carbon price and market forecasts

Critical to driving low-emissions product demand is a carbon price that increases the cost of products with high embedded emissions or that generate emissions through their use. Forecast carbon prices from the IPCC forecasts required to meet global warming thresholds, the European Emissions Trading Scheme (ETS) and regional carbon markets, including the Australian carbon credit unit (ACCU) market, show a significant range in forecast carbon prices.

The forecast EU ETS prices fall between the IPCC C1 1.5°C (Figure 23) and C3 2°C (Figure 24) scenario median prices:

- US\$262 (A\$393) in 2030 and US\$756 (A\$1,135) in 2050 for C1 1.5°C
- US\$75 (A\$112) in 2030 and US\$285 (A\$428) in 2050 for C3 2°C.

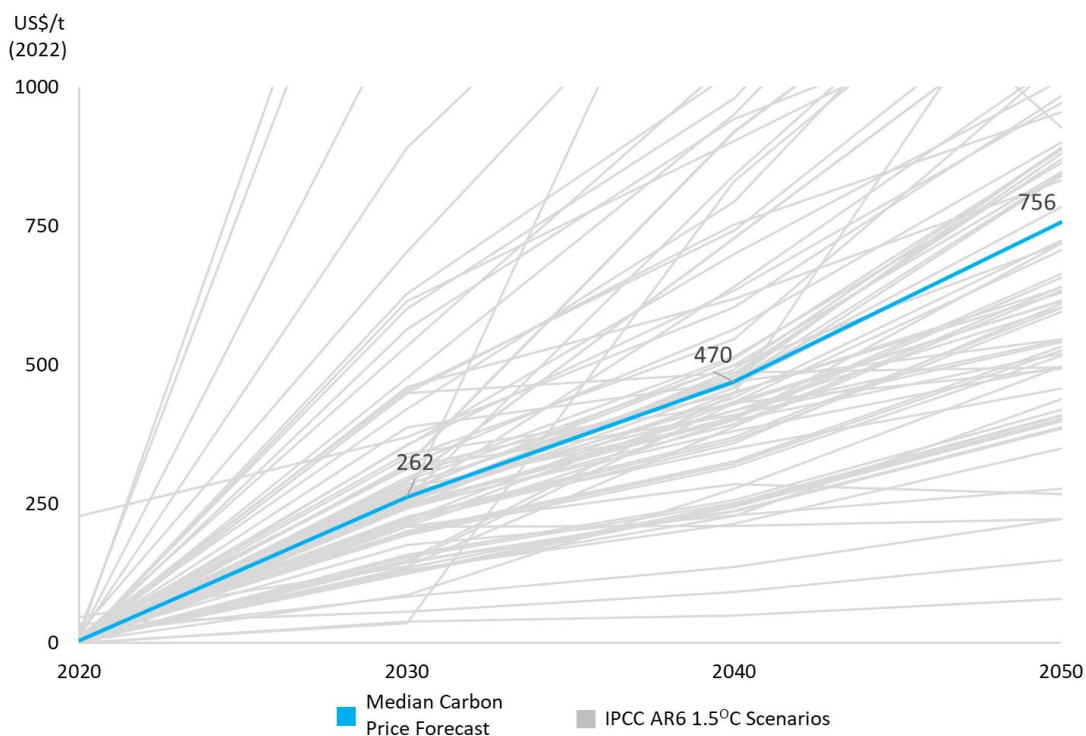


Figure 23: Global carbon median price outlook, C1 1.5°C pathway, all prices have been inflated from 2010 to 2022 US\$ (Federal Reserve Bank of St Louis, 2024)

Source: IPCC (2023)

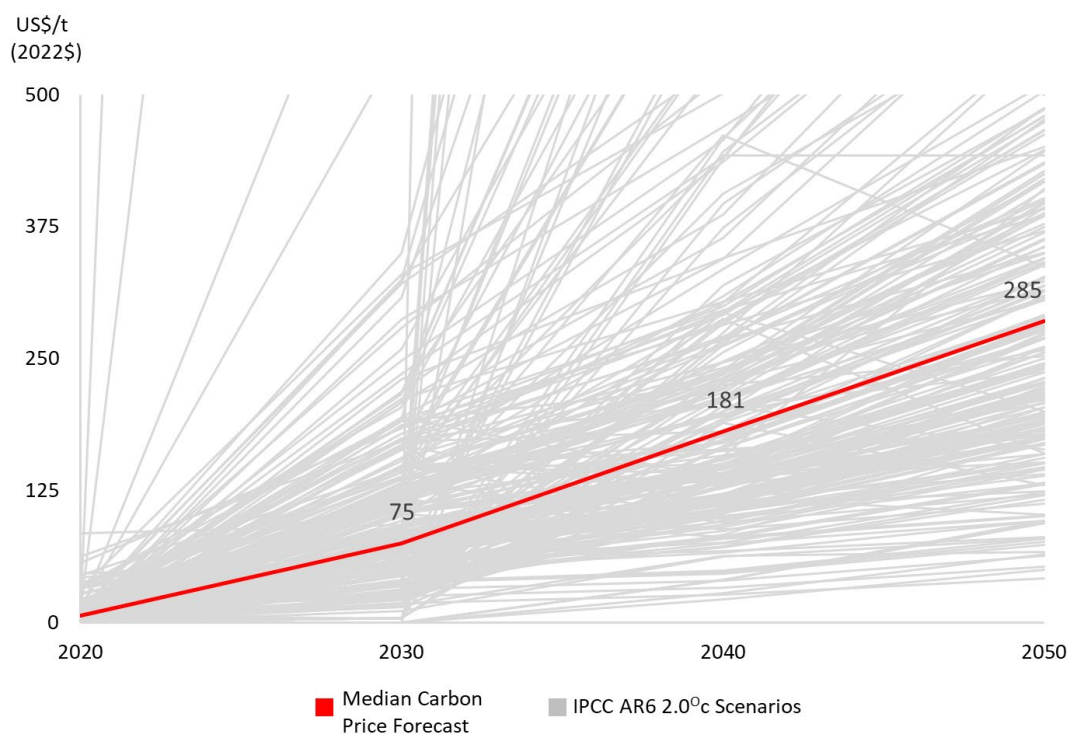


Figure 24: Global carbon median price outlook, C3 2.0°C pathway all prices have been inflated from 2010 to 2022 US\$ (Federal Reserve Bank of St Louis, 2024)
 Source: IPCC (2023)

While Australia does not have an official carbon price or ETS, legislative mechanisms have been implemented that broadly achieve a similar outcome. Australia’s carbon market involves the trading of several market-based instruments, including ACCUs, large-scale generation certificates and small-scale technology certificates. Each instrument is designed to reduce domestic emissions through incentivising projects that reduce emissions (ACCUs) or incentivising renewable energy generation technologies (large-scale generation certificates and small-scale technology certificates).¹⁰

There is a wide range of ACCU price forecasts from industry and the banking sector, a selection of which are shown in Figure 25. These forecasts all show increasing ACCU costs towards the ACCU price cap associated with the Safeguard Mechanism (see section 7). It is interesting to note that since the data were collated for the ACCU voluntary market, it has not followed the lowest growth forecast in ACCU price with current spot market prices as of February 2026 being \$37.06 (Clean Energy Regulator, 2026).

Forecast upper-bound ACCU prices are broadly in line with the C3 2.0°C scenario median prices. The Southeast Asian carbon markets, with the exception of Singapore (which more closely follows the IPCC C3 2.0°C scenario), have carbon prices that are unlikely to stimulate demand for low-emissions products alone or to meet IPCC carbon price requirements. However, the development

¹⁰ For the rest of this report the analysis focuses on the price of ACCUs, as the price of large-scale generation certificates and small-scale technology certificates is linked to the renewable energy target, which as of August 2024 is set to be phased out in 2030 (Clean Energy Regulator, 2024).

of carbon tax and ETS legislation across the region will allow those countries to increase their emissions reduction ambitions over time to drive towards their NDC targets (Rogers et al., 2024b).

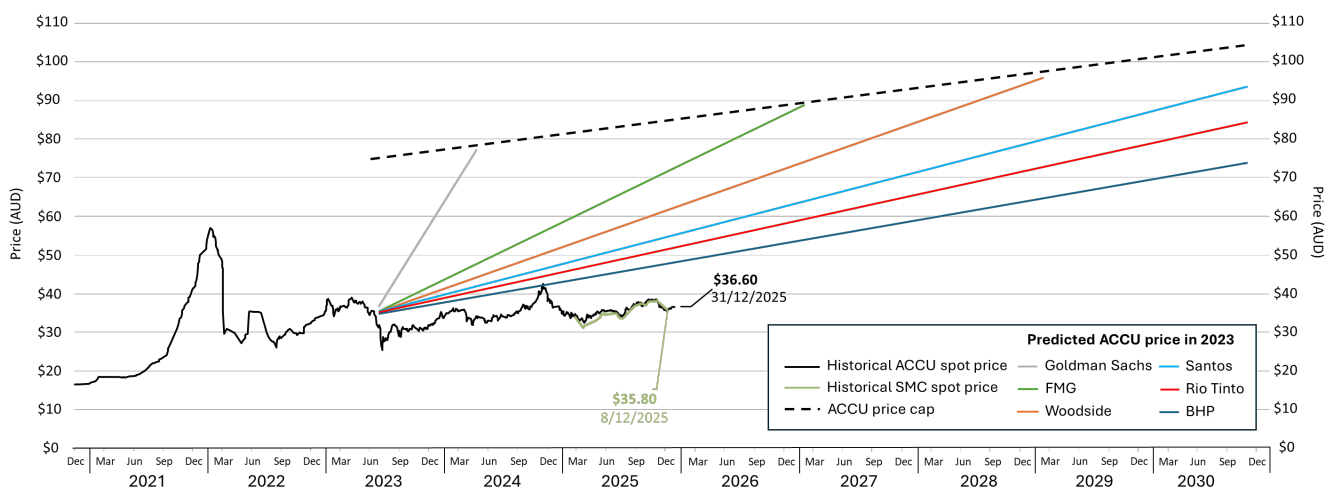


Figure 25: 2023 ACCU price outlook versus historical ACCU and SMC spot prices

Source: Adapted from AgTech (2023) and Clean Energy Regulator Q4 2025 QCMR workbook (CER, 2026)

Carbon border adjustment mechanisms

In April 2023 the carbon border adjustment mechanism (CBAM) was approved by the European Commission, with the mechanism coming into effect from 1 January 2026. In the EU, CBAM importers will be required to purchase and surrender allowances, and the free allocation of permits for domestic producers will be progressively phased out by 2034 (European Parliament, 2023).

Several countries are also considering implementing their own CBAM, including the UK, the US, Canada and Australia (a trigger is present within the Safeguard Mechanism legislation to implement a CBAM). This is in part to address their own country-specific risks of carbon leakage; however, there are revenue implications for countries that have not implemented their own carbon pricing regime. Once the CBAM is in effect, the EU will be collecting tariff revenues that can be used to enable other decarbonisation policies.

There is a possibility that the European CBAM may breach World Trade Organization (WTO) trade rules (Leonelli, 2022; Zhong and Pei, 2024). While a number of countries have raised trade concerns to the WTO related to the European CBAM (including China, Japan and the Republic of Korea), as of September 2024 no country had lodged a dispute with the organisation (WTO, 2024).

The implementation of CBAM mechanisms in key consumer markets is likely to stimulate demand for low-emissions products and decarbonisation of industrial processes, especially in markets and jurisdictions that have high reliance on the export of manufactured goods. This impact will be felt in the Asia-Pacific region due to its large manufacturing sector.

Green premiums

As part of the shift towards low-carbon economies, companies are also beginning to invest in technologies that reduce the embedded emissions of their products. Often these investments result in higher production costs that are either absorbed by the firm or passed on to consumers. The ability to pass on these costs is in part determined by a consumer's willingness to pay for low-emissions products, often referred to as a 'green premium'.

Previous research has identified that consumers will pay a green premium for products such as buildings (Dwaikat and Ali, 2016), electricity (MacDonald and Eyre, 2018), organic products (Aschemann-Witzel & Zielke, 2017) and bonds (MacAskill et al., 2021). However, how the level of premium impacts on final product cost needs to be carefully considered (e.g. low-emissions steel costs as part of the overall cost of a vehicle). Changing consumer preferences reflecting stronger pro-environmental values and increasing eco-literacy may reduce the aversion to paying more for green products, assuming the products are credibly 'green' (von Flüe et al., 2023; Wei et al., 2018).

Key points

- Low-emissions products are designed to minimise the release of greenhouse gases over their lifecycle by incorporating principles of a circular economy, energy efficiency, use of renewably sourced electricity and carbon management practices including process substitution and CCUS.
- In this business case project the focus is on hydrogen and hydrogen derivatives (e.g. ammonia, urea) and chemical feedstocks, the MASDP, the Northern Territory and major export markets in the region.
- Low-emissions product demand from the electricity generation, iron and steel, cement, primary chemicals and aviation sectors of the Territory's five top trading partners was studied.
- There are several routes to decarbonise these sectors, each route having unique challenges.
- Many of the industrial assets in these sectors were built over the last two decades and as such have several decades of remaining useful life.
- Although it is often argued that new industrial plants should be located in countries with abundant renewable energy and feedstocks, such as Australia, this viewpoint overlooks the significant employment and economic benefits these industries provide to their existing host countries. These same countries are also key sources of capital investment for Australia. It is therefore important to carefully consider which low-emission products could be manufactured in the Northern Territory in a way that both supports emission-reduction pathways for Australia's major trading partners and fosters new industry development within the Territory.
- IEA NZE 2050 forecast data show that global demand for low-emissions products will grow strongly to meet emissions reduction targets.
- Using four IEA emissions reduction scenarios, low-emissions product demand across the sectors for the NT's five key trading partners has been estimated.
- This demand has been shown to be significant, but the relative timing of this demand varies between emissions reduction scenarios and makes market forecasts uncertain.

- The utilisation of CO₂ from the CCUS hub could be one part of the low-emissions product opportunity with CO₂ used in the production of methanol, jet fuel, urea and synthetic methane.
- Low-emissions intensity products are typically not able to compete on price alone as incumbent products are produced using technologies that have benefited from many decades of optimisation and process improvement, use low-cost inputs, and have not needed to consider resultant process or product use emissions.
- The development of shared CCUS and hydrogen production infrastructure can support the deployment and scale-up of CO₂ utilisation opportunities.
- Enabling research, development and demonstration in CO₂ utilisation and related technologies, such as DAC, hydrogen electrolysis, and novel utilisation technologies, could reduce future CO₂ utilisation costs.
- The uptake of low-emissions products requires the closing of a 'price gap' through the use of a variety of policy levers.
- This includes carbon pricing and markets; tax incentives, grants, low-interest financing (see section 7) and offtake agreements that support investments in enabling technologies and their associated infrastructure (e.g. renewable electricity generation and transmission infrastructure).

5 The NT Low Emissions Hub

While this project has focused on the CCUS business case for a Northern Territory Low Emissions Hub, the interconnected nature of such a hub has made it essential to also consider the effects of sector coupling, renewable electrification (power systems) and hydrogen production opportunities, alongside the development of the CCUS hub.

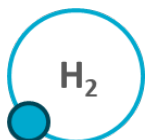
As described in section 3, the application of a portfolio of emissions avoidance and abatement options will be required to both realise Northern Territory emissions reductions and future manufacturing opportunities in the MASDP.

Opportunities for sector coupling

Realising net zero within industrial sectors will require large-scale deployment of renewable energy, low-emissions fuel substitution and significant increases in process efficiency (IEA, 2023e). Substantial efficiencies can, in principle, be gained through the coupling of industrial processes by harnessing industrial symbiosis opportunities across different sectors. Czapla et al. (2024) focused on a high-level technical review of technologies and approaches that could be employed to realise cross-sector coupling in existing and future potential industries within the MASDP as associated with the Balanced Scenario (see Section 1).

Synthesis routes were considered as an integrated system (i.e. not separate processes) and process technologies were considered for both their utility for sector coupling in the near term and their adaptability for changing feedstock and sector coupling benefits over the long term.

Hydrogen



Sector coupling opportunities across hydrogen-generation technologies include the use of 'waste' oxygen from electrolysis as an input feedstock for autothermal reforming (ATR) of methane. There are opportunities to use waste heat to drive endothermic reactions and in CO₂ capture material regeneration. In the case of methane reforming, waste CO₂ can also be used to synthesise downstream products of urea and methanol. There are also potential opportunities for the recycling of waste heat in combination with heat pumps in the generation of power through both methane reforming and electrolysis pathways.

Cryogenic air separation



Cryogenic air separation is important in several processes: oxygen can be used in ATR and other chemical processes, while nitrogen is required in combination with hydrogen for ammonia and urea production. In addition, atmospheric CO₂, water and noble gases produced can be sequestered or used for other processes or to generate additional revenue streams.

Cryogenic air separation is a significant industrial process that can be scaled up to process thousands of tonnes of air per day and accordingly involves the use of large amounts of electrical power and the transfer of large amounts of heat.

There are clear synergies between the compression trains and chiller systems used for air separation units (ASU) and other processes requiring cooling. For example, when liquefying hydrogen for storage or transportation, the type of cooling used in an ASU may be used in a preliminary stage. Alternatively, if lower-grade cooling is needed for refrigeration (e.g. for meat packing, or transportation of goods), 'waste cold' could be used, which would mean that much of the energy requirement for chillers may be reduced.

Oversized ASUs required for gas separation for other processes can provide the appropriate volumes of cryogenic gases for expansion to generate power (liquid air energy storage, LAES).

Ammonia and urea synthesis



In the production of ammonia and urea, aside from sector coupling opportunities for power-to-hydrogen, and efficiency improvements in the nitrogen production chain by more integrated process cooling systems, sector coupling opportunities can also be achieved through incorporation of biowaste to generate nitrogen compounds such as urea and nitric acid derived from black liquor gasification of waste wood pulp (Ribeiro Domingos et al., 2024).



Methanol synthesis

In methanol synthesis, the relatively low heat process requirements potentially allow waste heat from other processes to be used or heat to be generated from renewable electricity or solar thermal sources.

DAC



Thermal energy for desorption of capture materials represents 80% of energy requirements for DAC. Waste heat could dramatically reduce the operational costs of DAC technologies where heating requirements are low. At the same time, the processes supplying the waste heat may benefit from reduced cooling requirements. The energy to drive fans is another major cost component of DAC. There is an opportunity to leverage air flows from other industrial processes such as cooling towers. Alternatively, the coupling could be focused on the power generation side of a major hub development close to renewable infrastructure combined with electrical energy storage (e.g. batteries).

Mineral processing of critical energy metals



In the review of mineral (lithium ore) processing pathways, there are limited sector coupling opportunities beyond the use of electricity and hydrogen for high heating requirements associated with the processing of lithium ores.

Integrated sector coupling and industrial transition pathways

Review of industrial processes identified technologies that can be used to create a low-emissions production hub for the synthesis of ammonia, urea, methanol and derivatives. Two possible integrated processes are presented, representing (1) near-term integrated industrial development (Figure 26) and (2) the medium-to-long-term process (Figure 27), adapting the first integrated process to take advantage of future technology developments and reductions in costs. The core of an integrated process is the production of hydrogen, which is the key building block for downstream products.

The near-term integrated industrial development (Figure 26) envisages an ATR hydrogen generation plant fed by oxygen (from the ASU), methane and steam feedstocks, with resultant CO₂ captured for storage through pressure swing adsorption (PSA) for storage or further downstream use. Hydrogen would then be used for the synthesis of ammonia (using nitrogen from the ASU) and methanol, also using CO₂ from hydrogen generation. Methanol could be used in the manufacture of further derivatives. The ammonia plant could use some of the generated CO₂ for synthesis of urea. Assumed in the integrated industrial development would be the reuse of heat and cold energy across the system.

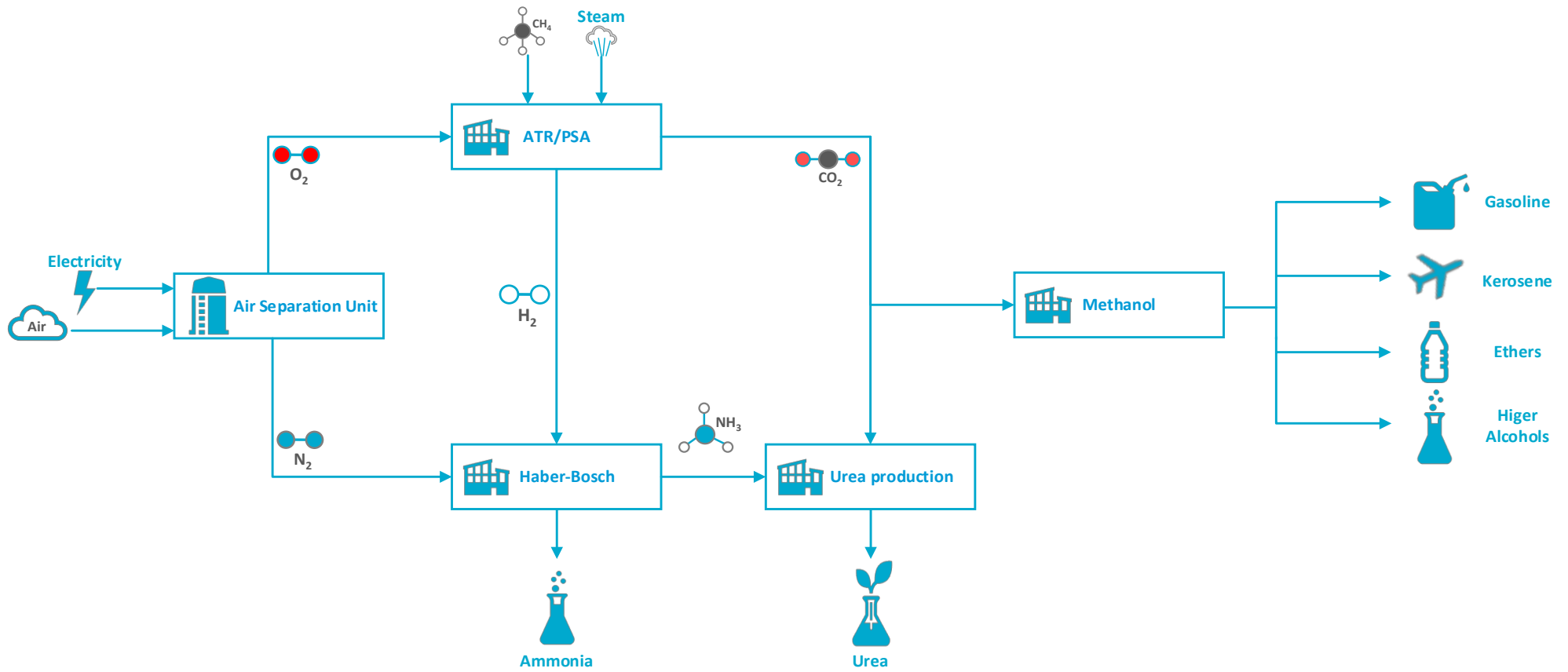


Figure 26: Illustrative diagram of the integrated process blocks that can be developed in the hub in the near term

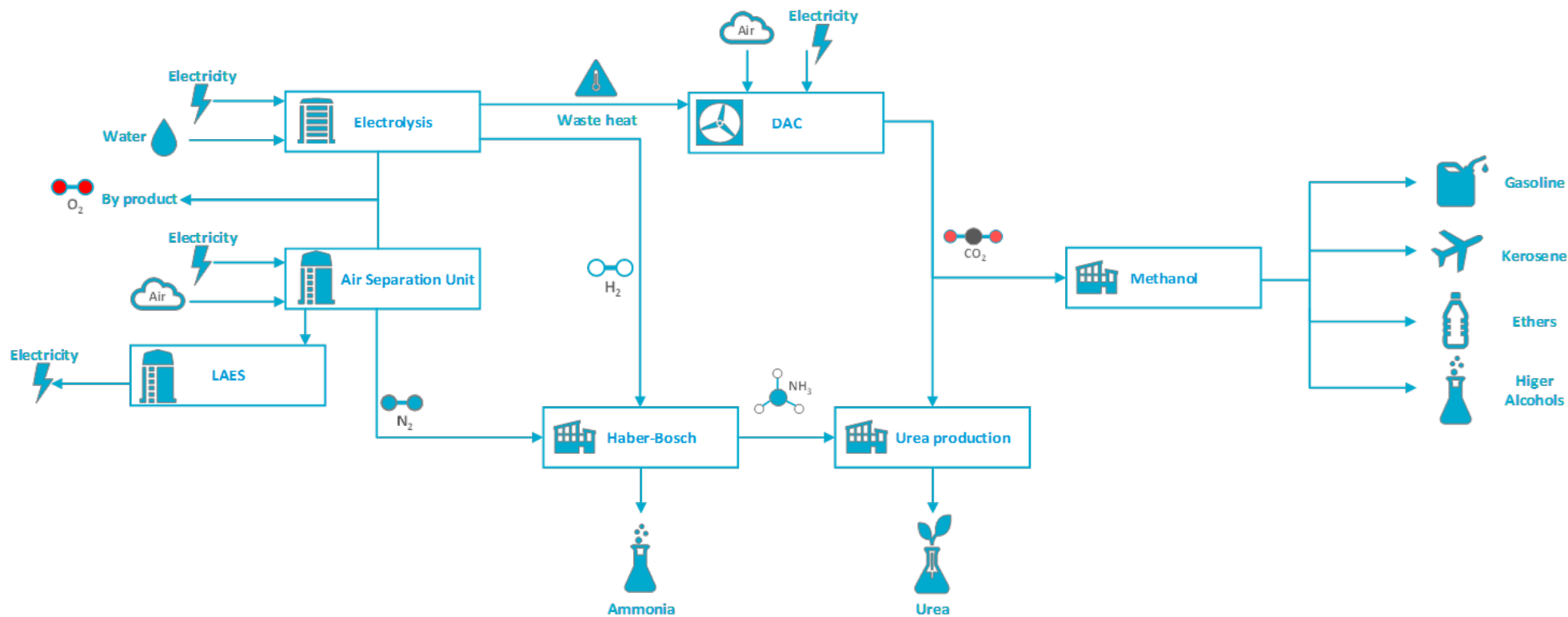


Figure 27: Illustrative diagram of an integrated process block that can be developed once lower-cost hydrogen and DAC are demonstrated

The medium-to-long term integrated process (Figure 27) envisages progressive additions to incorporate the production of hydrogen through electrolysis and DAC for CO₂ capture exchanging or augmenting the prior ATR. All other components of the system would be retained, with the ASU continuing to supply nitrogen to the ammonia plant but now also using nitrogen as a liquid air energy storage medium. While this integrated approach has some promise, more detailed investigations are required to assess the viability of such a system.

Barriers to sector coupling

The key technical barrier to sector coupling success is efficient energy management. Storage is at the nexus of sector coupling between electricity, industry and transport Sterner and Stadler (2019) and for the industries discussed in this business case, reuse and storage of heat are important, as well as transferring and exchanging heat efficiently.

To be able to realise sector coupling it is important that technological and financial risks can be managed and shared. In other jurisdictions mechanisms have been implemented that allow greater investment certainty and so enable industries to invest in higher-risk technologies. In Australia, the Australian Renewable Energy Agency (ARENA) funding for projects is one example of how government investment can enable the uptake of new technologies, although this funding is often constrained to a single sector.

Enabling cross-sector coupling and the operation of shared systems requires significant technical expertise and ongoing maintenance and upgrades by a skilled workforce. Plans should not be overly complex or ambitious in their goals, and common standards and language should be adopted among industries. In addition, existing regulations may not fully support and may even hinder, industrial symbiosis, requiring adjustments or new policies to facilitate better integration. There may also be legal and contractual issues, or disputes over information sharing and intellectual property. Careful consideration is required to understand how to remove unnecessary barriers to sector coupling.

Aligning the interests of multiple stakeholders and managing complex agreements can be time-consuming and difficult. A central body with proper governance could be established to plan for success and to operate efficiently and responsibly once launched. The foundation industry participants, together with their commercial partners (for finance and material supply), energy and service providers and the state or territory government, would typically be the key stakeholders whose vision must be aligned.

Power systems analysis

The Balanced Scenario includes energy-intensive industries such as renewable hydrogen generation, lithium processing, LNG, methanol, ethylene, ammonia, urea synthesis and the operation of a CCUS hub. These components of the MASDP have significant electricity and hydrogen demands. A least-cost electrical power generation model was developed to explore options to meet both the electrical and hydrogen production demand required by the potential MASDP industries (Green et al., 2024).

Assumptions

- Industrial electrical demand from the MASDP is likely to be much larger than the entirety of the Darwin-Katherine Interconnected System (DKIS) demand and as such the energy infrastructure for the MASDP is considered as a separate network to the existing DKIS.
- The electrical load from all MASDP industries, except electrolysis-based hydrogen production, is presented as an aggregated constant load of 0.78 GW.
- For electrolysis-based hydrogen production, the model assumes 110,000 t of hydrogen per year, representing about half the annual electrical load (of just under 13 TWh). Since there is considerable flexibility in electrolyser operation, this was assumed to be a variable load with the model able to determine the optimal electrolyser capacity factor.
- Four defined Renewable Energy Zones (REZs) were nominated. These REZs have associated distances from the Middle Arm that are approximate representations for the purposes of estimating the cost to build transmission and/or a pipeline to link them to the Middle Arm in a new electrical and/or hydrogen gas network.
- Assumed transmission options available to the model include lower-power (500 MW) high-voltage alternating current (HVAC) to connect the three capacity-constrained and closer REZs to the Middle Arm, and two high-power (2,500 or 5,500 MW) high-voltage direct current (HVDC) costing options for connecting Powell Creek to the Middle Arm. These high-power HVDC transmission options are further constrained in the model to have a minimum 90% capacity factor to reflect an expected requirement on the economic viability of such a project.
- Renewable electricity generation is constrained to the REZs, while new natural-gas-based electricity generation is constrained to the Middle Arm, as this is the location of both existing and new LNG production and it already has an incoming gas supply pipeline. The transmission routes do not consider current or future easement restrictions and take the shortest path.

Key questions

Given an approximate 50/50 mix of flat and variable electrical load in the MASDP Balanced Scenario, the probability that industrial customers requiring a variable load may be expecting different pricing for electricity than customers requiring a constant load, the constraints on individual system component utilisation (i.e. the HVDC transmission link to Powell Creek) and the general uncertainty in how to best size electrolysers, the study focused on answering three key questions:

1. How does the relative makeup of load type (flat versus variable) impact the least-cost solution for electrical power generation infrastructure and range for the average cost of electricity (ACoE)?
2. How does the constraint on gas generation impact the total cost of the system and the resulting ACoE without CCS?

3. What does the above imply for electrolysis-based hydrogen production in terms of the choice of power system infrastructure, electrolyser sizing and the production cost of hydrogen?

The power systems model

Based on these three key questions, a least-cost optimisation model was developed, while such models are useful in providing consistent infrastructure configurations and cost estimates, and for rapidly assessing how different choices in future scenarios impact the entire system configuration, they are only one part of the broader activity of developing an actionable plan for an industrial hub. By necessity, the model employed here contains limited detail on individual proponents, and takes a high-level, 'perfect coordination' view, whereas the reality of the individual aspects may be quite different due to their individual costs, access to land, competitive advantage or other aspects relevant to them.

As there is uncertainty associated with future gas and technology costs, model realisations have been conducted in 2025 and 2028 technology years and gas prices have been modelled at \$10.4/GJ in 2025 and \$8/GJ in 2028 for the base price, and \$15.5/GJ in 2025 and \$12.1/GJ in 2028 for a 1.5x higher priced sensitivity.

Typically, it would be expected that generation mix and ACoE would vary strongly with load type, and as such the model is applied to a purely constant load, a 50/50 flat/variable load mix and a purely variable load (for each of the above model realisations). To remove the complication of electrolyser and hydrogen infrastructure in answering questions 1 and 2, for those the variable load is not associated with any particular process but is directly associated with the production of hydrogen for question 3.

Results

The model results are organised into three categories aligned to the three key questions.

Question 1: How does the relative makeup of load type (flat versus variable) impact the least-cost solution for electrical power generation infrastructure and range for the ACoE?

With no constraint on gas generation, the model does not build battery storage or onshore wind, even at the higher end of gas prices (Table 3). The 90% utilisation constraint on the HVDC transmission from Powell Creek to Middle Arm, which requires battery storage to meet demand, means that without a gas generation constraint, the model does not use the Powell Creek REZ.

For the constant load model realisation, gas price is the driver of whether solar photovoltaic (PV) is built. Even though the ACoE from solar PV (with transmission) is significantly lower (approximately \$91/MWh compared with \$106/MWh for gas at \$10.4/GJ), the model does not choose solar until the savings in MWh cost offset the capital investment in the panels – this happens at the higher \$15.5/GJ and \$12.1/GJ gas prices. For those higher gas price cases, the model chooses to fully use the solar PV capacity at the closer REZs.

For models where only constant loads are allowed, the 50/50 mix and purely variable load model realisations at all gas fuel prices (considered here) and both 2025 and 2028 technology costs, 14% of the generation is supplied by solar PV in the REZs, with the cost for gas generation being

\$88/MWh for \$8/GJ in 2028 and \$81/MWh for solar (slightly higher at \$84/MWh in Koolpinyah). The capacity limits at the three closer REZs mean that variable renewable energy (VRE) is able to meet only 14% of total demand, so even when the variable fraction of the load is higher, there is no capacity to meet that demand with VRE (without using Powell Creek – which it does not do due to the transmission utilisation constraint).

Question 2: How does the constraint on gas generation impact the total cost of the system and the resulting ACoE without CCS?

This question was tested using the same three load types, technology years and gas price variances as above, with four constraints on the fraction of annual generation from gas, unconstrained (100%), 50%, 10% and 0% (i.e. renewable electricity only).

For a constant load, the ACoE rises sharply (about 1.8x) when increasing from 90% renewables to 100%, driven by the cost of battery storage. There is little difference between the 50/50 load mix and a purely variable load due to the 90% utilisation constraint on the HVDC transmission link to Powell Creek. The addition of onshore wind reduces the ACoE by approximately 15% when a constraint on gas generation is present. For a constant load, the spilled VRE energy is large (50%) for the 100% renewable fraction, and for the 90% renewable fraction the gas generation capacity factor is low (25%).

Table 3: ACoE versus load type and VRE fraction.

Minimum and maximum are over the range of results for the four combinations of technology cost year and wholesale gas price considered in Section 3.1 of Green et al. (2024), and with the lower HVDC costing. The coloured shading of the cells is only to help guide the eye as to where the significant variations occur.

\$/MWh	VRE Only		Gas <= 10%		Gas <= 50%		Gas <= 100%	
	Min.	Max.	Min.	Max.	Min.	Max.	Min.	Max.
Constant load, no wind	367	422	203	240	135	181	94	150
50/50 load, no wind	195	225	176	209	128	173	93	150
Variable load, no wind	187	219	176	209	128	173	93	146
Constant load, with wind	316	367	174	207	120	162	94	150
50/50 load, with wind	162	188	150	178	109	150	93	146
Variable load, with wind	162	188	150	178	109	150	93	146

Consistency with GenCost Estimates of levelized cost of energy

This business case project uses the capital and operating costs of generation technologies published in the CSIRO’s GenCost report (Graham et al., 2024). However, the costs of high variable renewable share electricity presented here are generally higher than those that are published in GenCost for three key reasons.

1. the Northern Territory has a cost premium for infrastructure investment relative to the more populous states

2. industrial load curves are flatter than the load curves that are found in larger mixed-customer grids, and flatter demand creates a higher requirement for capacity to maintain constant supply
3. the Middle Arm project represents investment in mostly new standalone infrastructure, whereas the GenCost modelling of renewable integration costs is in the context of adding to existing grids.

Question 3: What does the above imply for electrolysis-based hydrogen production in terms of the choice of power system infrastructure, electrolyser sizing and the production cost of hydrogen?

In examining this question, variable loads were assigned to electrolysis-based hydrogen production and the average cost of hydrogen (ACoH) was derived as well as the impact that hydrogen production has on system design and the ACoE.

The least cost of ACoH varies from \$7/kg to \$9/kg at the 50% and 100% renewable fractions, respectively. At the 90% renewable fraction, the ACoH is near \$8.2/kg with a corresponding ACoE of \$146/MWh. For the low (50%) renewable fraction, the optimal electrolyser capacity factor is near 90%, while for the high (90% and 100%) renewable fractions it is near 60%. The latter result is mostly driven by the 90% capacity factor constraint on the HVDC link to Powell Creek. The ACoH is most sensitive to the alkaline electrolysis efficiency (followed by the renewable fraction and wind capacity correction factor). The ACoE is most sensitive to the renewable fraction (followed by the wind capacity correction factor and the discount rate). A hydrogen pipeline from Koolpinyah to Middle Arm is chosen by the model as a least-cost option.

Conclusions

The range of costs produced results from the range in the allowable fraction of gas-based generation, the type of electrical load (flat versus variable) and model inputs such as the wholesale price of gas and the technology cost year. The modelling additionally investigates which aspects of energy infrastructure the cost of supply is most sensitive to, such as the incorporation of wind generation, as well as the interdependence of power generation and electrolysis-based hydrogen production.

This report provides a range of estimates for the average cost of supply for electricity and hydrogen to meet the demand required by the potential MASDP industries. The ACoE ranges from \$93/MWh when no constraint is applied to the renewable fraction, to \$176–209/MWh for a 50/50 mix of flat and variables loads and a 90% renewable fraction. The cost is most sensitive to the renewable fraction, followed by the capacity factor of onshore wind – which, when included, can decrease the cost of electricity by approximately 15%. Increasing the renewable fraction from 90% to 100% nearly doubles the cost of electricity, driven by the cost of battery storage.

ACoH at the 90% renewable fraction is near \$8.2/kg, with a corresponding ACoE of \$146/MWh and an optimal 67% electrolyser capacity factor. The cost of hydrogen supply is most sensitive to the assumed electrolyser efficiency, followed also by the renewable fraction and the onshore wind capacity factor. The optimal electrolyser capacity factor is driven mostly by the 90% capacity factor constraint on the HVDC link to the large REZ at Powell Creek.

Key needs for the future deployment of renewable electricity in the Northern Territory are the development of a greater understanding of the potential wind resources in the REZs and the identification of low-cost energy storage technologies. Other estimates of hydrogen generation costs are included in the Darwin clean hydrogen hub – Market development study (see the box below).

Darwin clean hydrogen hub – Market development study

Alongside the work undertaken in this Northern Territory CCUS business case project INPEX, led a Regional Hydrogen Hub Grant Program project entitled “Darwin clean hydrogen hub - Market development study” (Jimenez et al., 2024).

The purpose of this study was to evaluate the technical feasibility, economic viability, and potential timeline for developing a clean hydrogen and hydrogen derivatives market in the Northern Territory. The study identified both domestic and export market potential, assessed the levelised cost of hydrogen supply across different sectors, and estimated economic market demand.

It also explored the potential growth of the hydrogen market in Darwin under various policy support scenarios, providing insights into the economic feasibility and competitiveness of Northern Territory’s hydrogen as an alternative fuel. Additionally, it assessed Darwin and the Territory’s current capabilities to produce and distribute hydrogen, including physical resources, business and workforce capability, and infrastructure.

The results of the study are instructive and provide greater clarity on options for hydrogen industry development in the Northern Territory.

The results are awaiting final public release by the Department of Climate Change, Energy the Environment and Water.

CCUS hub concept-level design

The concept-level design of a CCUS hub requires an understanding of the inclusions of sources and sinks of CO₂, as well as the connective infrastructure, shared infrastructure needs and high-level costs. This section provides a summary of the findings in Joodi et al. (2024b) which describe these components of the NT CCUS hub. This design assumes the development of the MASDP and as with the rest of this study uses the Balanced Scenario, which represents the widest mix of industries anticipated in the MASDP development.

In the delivery of the Joodi et al. (2024b) report, CSIRO has drawn heavily on work undertaken by the Northern Territory Government, in particular the DLI and two studies undertaken on its behalf by (GHD and Wood Group, 2023; 2024). This has been supplemented with work undertaken by INPEX and Santos and publicly available information. Where possible, CSIRO has provided additional inputs to build a more comprehensive understanding of the CCUS hub. There are also elements of the CCUS hub design and costing that CSIRO does not have access to, due to their commercial sensitivity, and these are noted in Joodi et al. (2024b).

CCUS hub system components

For each of the industries contemplated within the MASDP Balanced Scenario, the maximum volume of CO₂ required for transport and storage has been assessed. This assessment identified a maximum industry projected capacity requirement of around 9.1 Mtpa of CO₂.

CO₂ capture for each industry is assumed to occur within its respective facilities, and across the industries it has been estimated that pre-combustion sources will account for 60% of emissions and post-combustion sources for 40%, once the precinct is fully developed. It is assumed that industrial proponents will predominantly use amine capture (used for cost estimations below), but it will ultimately be the decision of the industrial proponents to determine their preferred capture technology.

It is important to note that the GHD and Wood Group (2023) study does not specify how each capture plant is configured. Understanding the configuration of the capture systems and the relative proportion of each capture system that is an unavoidable cost (i.e. an embedded cost as part of the industrial process) will be key to understanding the complexity in the design and additional sizing of MASDP industry capture systems. Once captured, CO₂ will undergo gas conditioning steps (e.g. dehydration) to meet specifications and enable its transport within the hub.

The design also requires each industrial supplier of CO₂ to compress its CO₂ to provide it at 8.5 barg to a centralised high-pressure compression facility (Figure 28). The compression process was modelled by GHD and Wood Group (2023) using a two-stage centrifugal machine, while dehydration was modelled with triethylene glycol (TEG). Following dehydration, the CO₂ will undergo final filtration to protect the pipeline against TEG carryover, before continuous online moisture analysis and custody transfer metering.

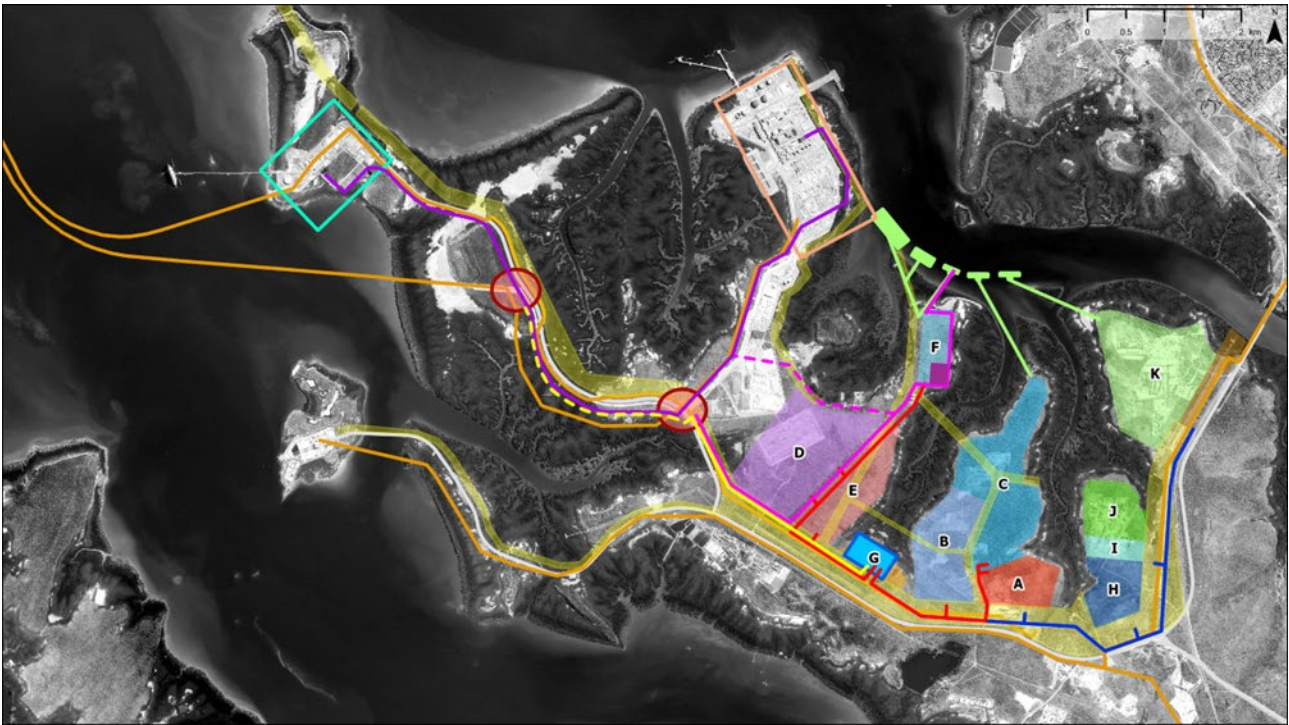


Figure 28: The NT CCUS hub

The MASDP header pipelines are shown in red and blue. The centralised high pressure compression hub is in area G. The MASDP hub CO₂ export pipeline is shown in yellow with an alternative export pipeline route shown as a dashed yellow line. Tie-in points into the CO₂ interface pipeline are shown as orange circles. The LCO₂ receiving and storage terminal location is shown as a purple box within common user facility in area F and associated transfer and export pipelines lines are shown as magenta lines; Orange lines represent natural gas pipelines

Source: adapted from GHD and Wood Group (2023)

The header pipeline, which will take the CO₂ from each industry to the centralised high-pressure compression facility, has western and eastern branches: the western branch will have a pipeline OD of 800 mm and the eastern branch will have outside diameters of 400 mm and 800 mm, reflective of the CO₂ transport capacity requirements of the industries of the MASDP. The design allows flexibility in the development within the header pipeline system for a phased development.

A medium-pressure design and a high-pressure design were considered for the centralised CO₂ compression facility. The preference is for high-pressure export as it enables more efficient integration with the downstream facilities. On arrival at the centralised high-pressure compression facility, CO₂ will be compressed to 180 barg using a three-stage compressor. The MASDP compression system is configured into three trains, each rated at 25 MW and providing one-third of the total capacity.

The dense-phase CO₂ fluid will then be pumped into the 600 mm export pipeline to be transported ~4 km to the INPEX Access Road Junction tie-in point and the third-party downstream CO₂ storage/sequestration system (MASDP CCUS hub battery limit). This tie-in point is one of two possible options, with a second point contemplated in the vicinity of the Ichthys gas pipeline shore-crossing easement close to the DLNG facility. This location is ~7.4 km from the compression facility.

LCO₂ receiving and storage terminal

An LCO₂ receiving and storage terminal has been defined by GHD and Wood Group (2024). The inclusion of a CO₂ import (and, in principle, export) terminal allows importation of additional CO₂ volumes to lower the unit cost of CO₂ storage, maximise CCUS system capacities and reduce regional emissions.

The LCO₂ import terminal was designed to receive CO₂, pump it and then export it to the designated tie-in point for downstream export to the CO₂ storage/sequestration sites. The LCO₂ import terminal is designed to share Berth 3 of the proposed MASDP port facility with ammonia and ethylene export activities (Figure 28). It is assumed that the facility will have at least 346 operational days each year (GHD and Wood Group, 2024) and be able to accept 40,000 m³ to 80,000 m³ ships as the facility's capacity increases. Delivered CO₂ is assumed to have a purity level of 99.9%, reflecting the higher specification requirements associated with liquid-phase CO₂ conditions at 7 barg and -48°C.

LCO₂ terminal processing capacity

A key design requirement was the infrastructure's flexibility to accommodate an initial processing capacity between 0.5 and 1 Mtpa. The system is designed to expand progressively to 5 Mtpa (or 6 Mtpa) to align with forecast growth in demand. Modelling suggests that an optimal limit for a 40,000 m³ cargo size is 3 Mtpa. This critical consideration has established an initial maximum importation rate of 3 Mtpa as the base case. Future vessel size growth up to 80,000 m³ allows for expansion of the facility to 5–6 Mtpa. For these models, berth utilisation ranges from a minimum of 4% to a maximum of 22%, with offloading taking approximately 12 hours for both the 40,000 m³ vessels and, with an upgrade to the loading arms, the 80,000 m³ vessels. The concept design also focuses on a single expansion phase from 3 Mtpa to 6 Mtpa, rather than multiple smaller brownfield expansions to incrementally boost throughput capacity.

LCO₂ terminal storage capacity

The design contemplates CO₂ offload in a liquid phase through two lines to the storage tanks located in the CO₂ receiving facility. A vapour balance line is required to facilitate the transfer of CO₂ gas back to the import vessel, allowing the vessel to completely empty its tanks. Loading operations occur only when the vessel is berthed, making the loading intermittent. Process design of the facility incorporates a keep-cold loop on the import offloading lines and a boil-off-gas recovery system.

Onshore buffer storage is a crucial aspect of the design process, as it directly impacts the system's flexibility to respond to fluctuations in vessel arrivals. Sufficient buffer storage mitigates the challenges posed by the arrival of two vessels within a short period of time and reduces vessel demurrage by offering extra capacity for the cargo of the second ship. It was recommended that the buffer storage volume be set at 150% of the cargo size.

This storage of LCO₂ will occur in the common user facility within the MASDP, with the storage facilities expected to cover an area of 6 hectares in the southern section (Figure 28). The common user facility will also handle various hydrocarbons for export, module and material imports, potential bunker fuel storage, and other related activities. As such, it is desirable to design the LCO₂ operations to be as simple as possible to minimise brownfield work.

The LCO₂ storage conditions were assumed to be 7.5 barg, while the design temperature is -60°C. The concept design study evaluated three types of storage tanks: Horton spheres, horizontal bullets and vertical cylinders. Horton spheres were selected, as horizontal cylinders have a substantial land footprint and vertical cylinders require extensive interconnected piping and maintenance.

LCO₂ terminal CO₂ export

The imported LCO₂ is expected to be exported in the supercritical or dense phase from the CO₂ compression facility through a pipeline to the offshore export pipeline tie-in point (Figure 28). However, alternative options were considered as part of the concept design.

Based on the outcomes of this options screening study, a base-case option and an alternative option were selected:

- In the base case, CO₂ is exported in a dense phase (150 barg, 5°C) directly from the common user facility to the specified tie-in location at the INPEX Access Road Junction via pipeline. The fluid travels from the heaters at the common user facility storage facility through a custody metering skid and into a 4.5 km DN 450 dense-phase pipeline.
- In the alternative option, CO₂ is transferred in a gas phase from the common user facility to a compression and export facility in Area G, where it is compressed and exported in a dense phase to the nominated tie-in location at the INPEX Access Road Junction.

In the base case, the treatment process includes pumping the CO₂ to the required export pressure of 150 barg and subsequently heating the compressed fluid from its storage temperature to approximately 5°C. In this system, a booster pump withdraws LCO₂ from storage and raises the pressure from 7 barg to 35 barg. The pressure is then further increased to 150 barg by the export pumps. This two-stage pumping process is essential because the pumping conditions of the liquid are close to its bubble point. The condition of the exported CO₂, which is supercritical at 150 barg, will be set by the downstream operator.

In the alternative option, the LCO₂ is initially pumped to 35 barg and then vaporised into gas at the common user facility. A gas pipeline transports this vaporised CO₂ to Area G, where it is compressed to a supercritical state (150 barg) and exported through another pipeline to the nominated tie-in point.

In both, the base-case and the alternative export pipeline options, the pressure of the LCO₂ is increased to 35 barg using booster pumps designed as 3 x 50% units. Two pumps are required to transfer 3 Mtpa. These pumps will be equipped with variable-frequency motor drives. Using a single pump, the system capacity can be reduced to 1.5 Mtpa. By reducing the speed of the running pump, it is possible to achieve lower rates.

In the base case, variable-speed reciprocating export pumps are responsible for compressing the LCO₂ to a supercritical state. Positive-displacement type pumps have been selected for exporting the CO₂, as there is no correlation between flow rate and pressure in this type of pump, and they can maintain low throughputs. The minimum operational capacity is determined by the performance of the booster pumps, which will be specified in the detailed design stage.

It should be noted that no technical showstoppers were identified for systems within the MASDP precinct in the GHD and Wood Group (2023) studies and global examples of each element of the system have been identified to establish the technical and cost bases.

Integration of export pipelines

The Darwin and Ichthys LNG facilities already capture CO₂ as part of the requirement to remove CO₂ from the natural gas coming from offshore reservoirs. Upgrade works will occur at these facilities for CO₂ gas conditioning (e.g. dehydration of CO₂) and compressor installation. It is envisaged that CO₂ will be exported from each of these facilities in a dense phase at the required pressure for transport to the offshore storage facilities.

The CO₂ exported from these facilities is expected to enter a common export pipeline interface, which will permit CO₂ to be exported to both the Bayu-Undan depleted field and the Bonaparte CCS saline aquifer storage/sequestration site.

The design of this system is currently underway and a schematic process flow diagram of the pipeline interface system has been provided by INPEX (Figure 29). This interface system includes a tie-in point at the INPEX Access Road Junction, the approximate proposed tie-in location for the LCO₂ export terminal pipeline (Figure 30). A Bonaparte CCS tie-in point is envisaged close to the easement associated with the existing Ichthys gas import pipeline (Figure 30). This location provides a pass-through tie-in point for a second MASDP CO₂ pipeline associated with CO₂ exported from the centralised MASDP compression facility.

It is assumed that, without the Bonaparte CCS interface, the pipeline interface system will have sufficient capacity to manage existing and future CO₂ volumes from the Darwin and Ichthys LNG facilities and the CO₂ import terminal. Additional interface pipeline capacity will be incorporated through the pipeline to the Bonaparte CCS site.

The offshore CO₂ export pipeline from the Santos facility is expected to reuse the existing Bayu-Undan natural gas import pipeline and therefore will not require new shore crossings or pipelines. The offshore CO₂ export pipeline for the Bonaparte CCS is envisaged to use the same shore crossing easement corridor as the existing Ichthys pipeline, with this new pipeline following the route of the Ichthys pipeline to the offshore storage location in the Petrel Sub-basin.

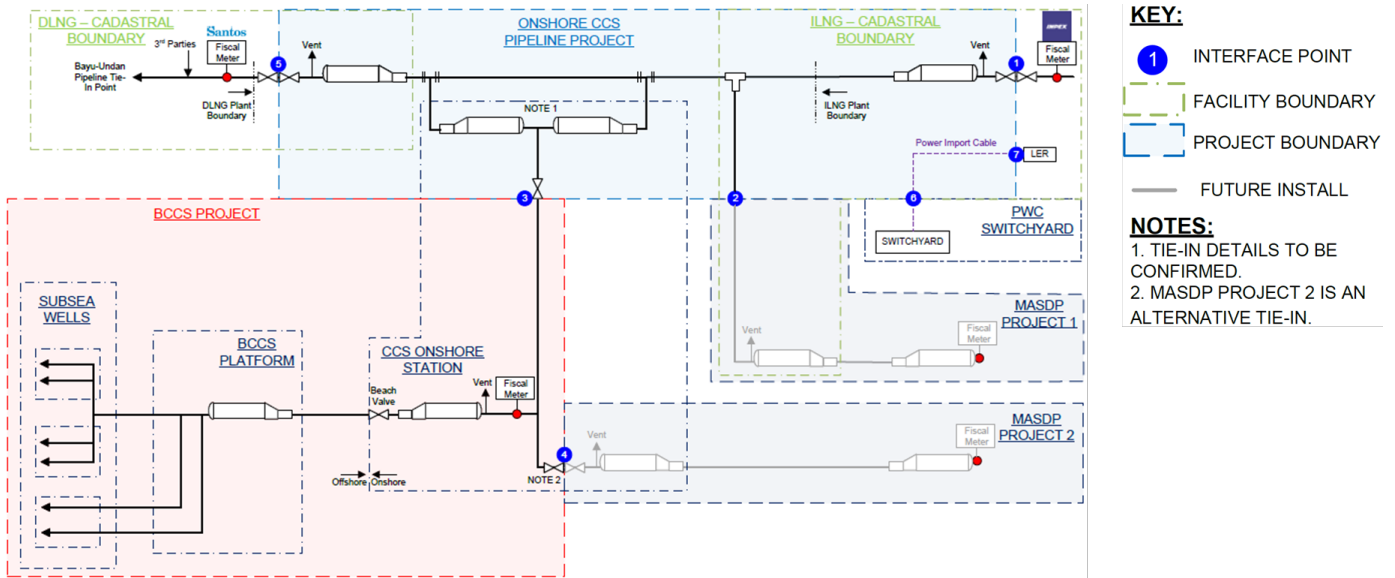


Figure 29: Pipeline interface system schematic
Source: INPEX

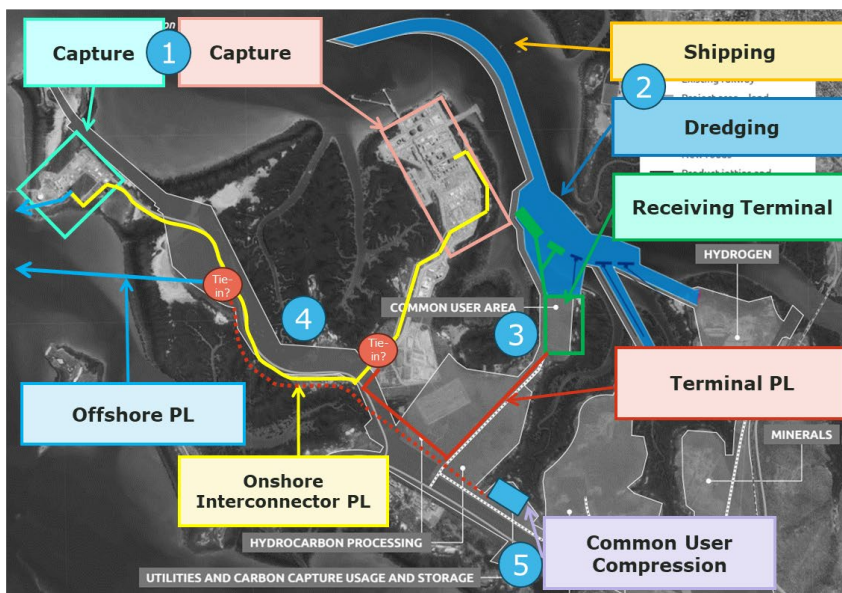


Figure 30: Onshore DLNG and ILNG CO₂ pipeline infrastructure map
PL = Pipeline

CO₂ storage options

Geological storage capacity is not considered a major risk for the NT CCUS hub, as some of the most prospective geological storage basins in Australia are situated offshore of the Northern Territory. Two offshore geological storage areas are being actively studied in the vicinity of Darwin:

- to the north of Darwin, the Bayu-Undan gas field could be transitioned from producing hydrocarbons to storing CO₂

- to the west of Darwin, two greenhouse gas permits have been awarded for assessment in the Northern Territory and Western Australia sectors of the Petrel Sub-basin of the Bonaparte Basin.

In addition to these active offshore geological storage projects the Northern Territory Geological Survey and CSIRO have collaborated on the identification of possible geological storage options in selected onshore basins in the Northern Territory (Talukder et al., 2024). This study has identified the onshore Bonaparte Basin (close to the Wadeye gas processing facility) and the Beetaloo Basin as having potential storage prospectivity warranting further investigation.

The two offshore potential geological storage areas are briefly described below.

Bayu-Undan CCS project

The Bayu-Undan gas field in the Timor Sea (in the jurisdiction of Timor-Leste) has been in production since 2004 and has reached the end of its field life. The Bayu-Undan CCS project entered the FEED phase in the second quarter of 2022 to use the depleted gas reservoir for CO₂ storage. The schematic in Figure 31 illustrates the proposed Bayu-Undan CCS project (Santos, 2022; Wilson, 2022). The project is designed around reuse of existing infrastructure such as the export pipeline, offshore platform and wells, but will need additional facilities for CO₂ capture and compression. The subsurface is well understood: the reservoir is a structural trap with an extensive aquifer providing pressure support. With high permeability and historical gas injection proving injectivity, it is expected to store up to 10 Mtpa of CO₂ for more than 20 years.

Initially ~2.3 Mtpa of CO₂ is intended to be injected from the Barossa field (Wilson, 2022). The operator, Santos, announced on 3 May 2023 that four non-binding memoranda of understanding have been signed for proposed storage of CO₂ emissions by third parties at Bayu-Undan (Santos, 2023). These agreements are with potential upstream gas and LNG projects offshore of the Northern Territory and Darwin and with an energy and industrial conglomerate in South Korea. While the parties have not been named, should all four memoranda be converted to binding agreements they indicate that demand for storage at Bayu-Undan will be in excess of 10 Mtpa (Santos, 2023).

Progress on the project will be determined by a number of factors including the outcome of bilateral negotiations between Australia and Timor-Leste to allow for the export of CO₂ from Australia to Timor-Leste for offshore sequestration under international law; NT legislative amendments; commercial considerations and Timor-Leste's CCS regulatory regime.

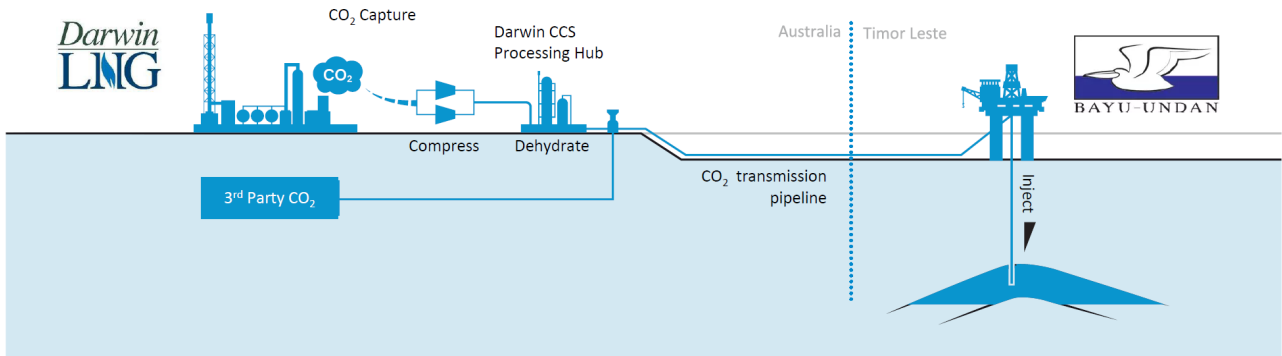


Figure 31: Bayu-Undan CCS project
Source: Santos (2022)

Petrel Sub-basin

Two greenhouse gas storage permits have been issued in the Petrel Sub-basin (see Figure 32; Department of Industry Science and Resources (DISR), 2021). Following many years of studies, Geoscience Australia reported storage resources of 15.9 Gt (300 tcf) in two saline reservoir-seal pairs in the eastern Petrel Sub-basin (Consoli et al., 2014).

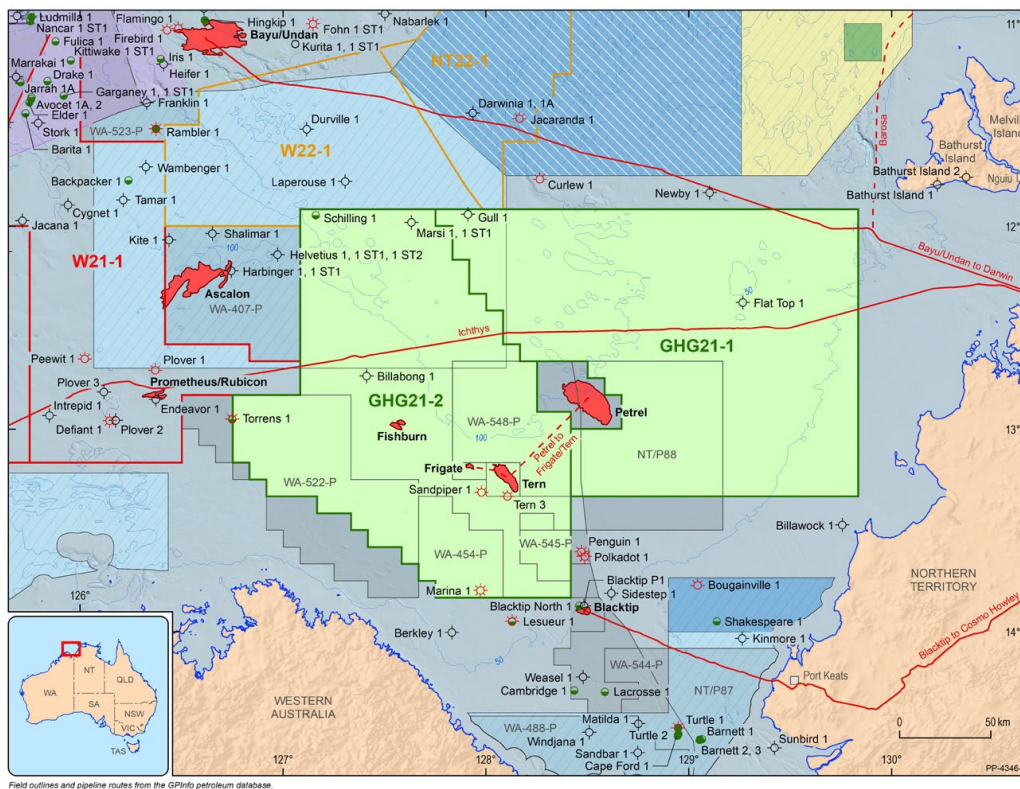


Figure 32: 2021 greenhouse gas permits acreage release, Petrel Sub-basin
Source: DISR (2021).

Figure 33 shows the locations within the permits mapped as suitable by Geoscience Australia. Investigations by Shell, Eni and CSIRO, supported by funding from the Australian Government and reported by Johnstone and Stalker (2022), have provided further geological appraisal and derisking for CO₂ storage in the eastern part of the Petrel Sub-basin.

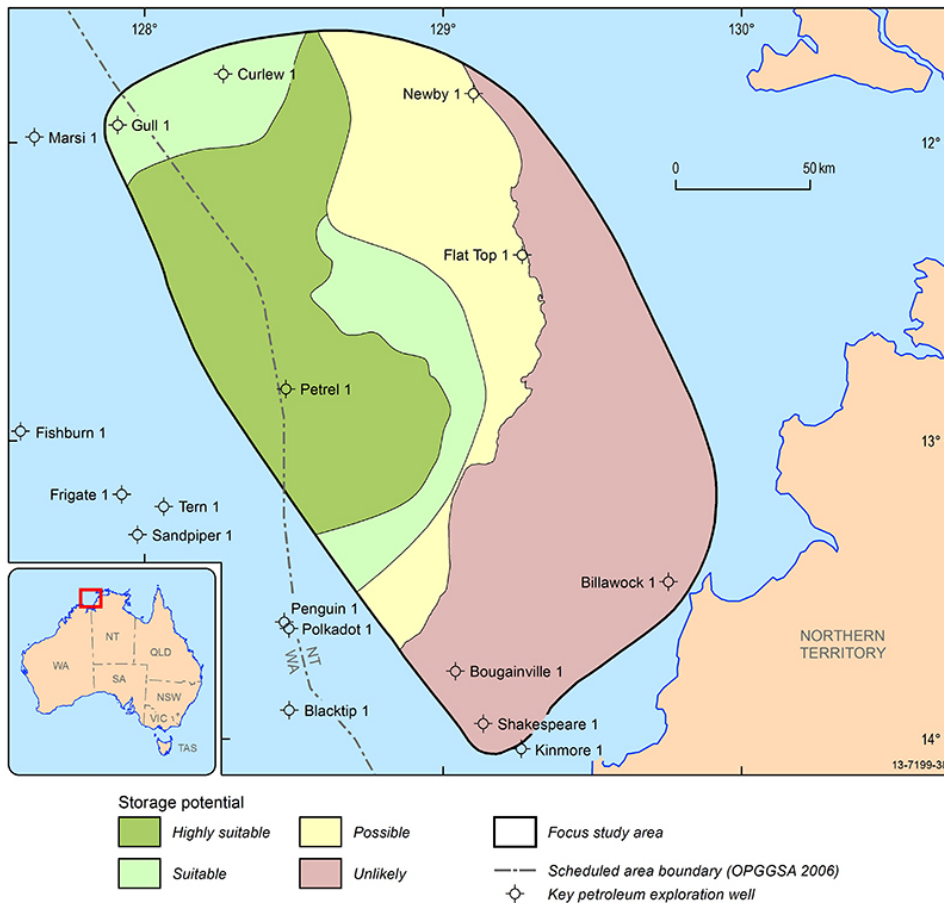


Figure 33: CCS suitable locations determined by Geoscience Australia for the eastern Petrel Sub-basin
 Source: Consoli et al. (2014)

A geological storage exploration and appraisal work program in the Petrel Sub-basin is underway to assess the viability of this highly prospective storage resource. In Permit G-7-AP (mapped as GHG21-1 in Figure 32) INPEX, operator of the Bonaparte CCS project, has drilled two wells and the appraisal work program is well advanced. Within this permit there are plans to inject into the Plover saline aquifer at a depth of ~2000 m. The project proposes to start injecting CO₂ at a rate of 2 Mtpa from the Ichthys onshore processing facility, with potential expansion to 7 Mtpa.

In the western sector of the basin a second permit, G-11-AP (mapped as GHG21-2 in Figure 32), was awarded in 2022 to a joint venture operated by Santos. The work plan for the permit also contemplates the drilling of an appraisal well that, if successful, will increase the annual storage capacity in the basin.

The geological risks of offshore storage are anticipated to be manageable as the storage areas have had significant prior geological investigation. Critical to the costs of storage will be:

- Injectivity, which determines the number of wells required for injection of a given volume of CO₂
- Pipeline capacity and CO₂ offtake to justify investment in that capacity, with larger volumes reducing unit costs
- the establishment of bilateral instruments between Australia and partner countries to allow for the export of CO₂ for offshore sequestration in Timor-Leste waters or for the sequestration of imported CO₂ in offshore Australia.

- Staging of geological storage site development to manage investment returns.

CCU offtake

While CCU options have not been explicitly planned for in the design of the NT CCUS hub, offtake of CO₂ within the MADSP medium-pressure CO₂ gather system could be simply achieved with a connection to the gather pipelines. For the offtake industries there will need to be suitable metering and inspection infrastructure, as with suppliers of CO₂ into the system. Optionality should be retained within the design for this to occur. To enable net zero product development (e.g. e-methanol) and negative emissions, the hub gather pipelines should also be planned for additional tie-in points for negative-emissions sources (e.g. DAC).

CCUS system indicative costs

The indicative costs of the MASDP CCUS system have been developed by the NT-DLI in its CCUS hub studies (GHD and Wood Group, 2023) and include estimates of both capital and operating costs. For clarity, the costs represent class 5 cost estimates only, are subject to large uncertainties and require a much more detailed study for being defined more accurately. They do not include estimates of the costs of the Darwin and Ichthys LNG facilities, nor do they include costs for the pipeline interface system or offshore/storage components. However, it can be assumed that these costs will be significant.

It is assumed by CSIRO that in the GHD and Wood Group (2023) study each industry generates its own products separately. While this approach reduces risk for individual proponents, it does not contemplate efficiencies that may be gained through sector coupling (see Czaplá et al., 2024), and therefore the number of emissions locations and the estimated capital infrastructure costs may be conservative if sector coupling can be implemented.

The largest component of costs for the CCUS hub development is associated with capital equipment. When the costs are collated across the base option capture, compression, LCO₂ and CO₂ export line elements of the CCUS system, they total ~\$7.4 billion (Table 4 and Figure 34). More than 70% of these costs are associated with industry capture facility costs and a further 8% are associated with the conditioning and first-stage compression within the battery limits of these facilities. Consolidated operational costs, derived as a proportion of capital costs, are \$360–\$373 million per year as an average 5% of total CapEx costs assuming full Balanced Scenario development, noting that most of these operating costs are associated with the CO₂ capture plants (Table 5).

The costs of capture for each industry identified in the GHD and Wood Group (2023) study are assumed to be the costs of all capture facilities for each industry. Many of these costs may be unavoidable or embedded process costs for the industries (e.g. separation of CO₂ from hydrogen in steam methane reforming, or the use of AGRU systems in LNG production), whereas in industries such as spodumene processing for lithium hydroxide, CO₂ capture would represent an additional cost to normal process operations.

This is an important consideration, as the cost of capture is either a cost factored into standard operations or an additional cost to industries. The additional capture costs represent a major

uncertainty in understanding the extra costs that would be encountered by industry through the implementation of CCUS in the MASDP.

The MASDP header pipelines, compression and CO₂ export pipelines represent less than 8% of total costs, and the LCO₂ import and export pipeline elements of the system represent 12–13% of the total costs.

Table 4: Capital costs of the MASDP CCUS system assuming full Balanced Scenario development

Item	Total costs (\$'000s)
MASDP CO ₂ capture facilities (industries) ¹	\$5,283,228
MASDP CO ₂ compression (industries)	\$620,042
MASDP collection header pipeline	\$95,169
MASDP CO ₂ compression hub (including buildings)	\$443,175
MASDP CO ₂ export pipeline ²	\$28,660
LCO ₂ import facility 3 Mtpa (base option)	\$478,677
LCO ₂ import facility increment to 5 Mtpa (base option) ³	\$366,483
Subtotal (base option)	\$7,315,434
LCO ₂ import facility 3 Mtpa (alternative option)	\$555,832
LCO ₂ import facility increment to 5 Mtpa (alternative option) ³	\$435,317
Subtotal (alternative option)	\$7,461,423

¹Total cost of CO₂ capture without discount for CO₂ capture costs realised as part of the processes.

²Assumes 4 km export pipeline only (see tie-in facility discussion above).

³Note that expanding the LCO₂ import capacity to 6 Mtpa is estimated to cost \$10 million.

Table 5: Operating costs of the MASDP CCUS system assuming full Balanced Scenario development, average of ~5% of total CapEx costs

Item	Total costs (\$'000s) per year
MASDP CO ₂ capture facilities (industries) ¹	\$324,000
MASDP CO ₂ compression (industries) ¹	
MASDP collection header pipeline	
MASDP CO ₂ compression hub (inc. buildings)	
MASDP CO ₂ export pipeline ²	
LCO ₂ import facility 3 Mtpa (base option)	\$21,000
LCO ₂ import facility increment to 5 Mtpa (base option)	\$15,000
Subtotal (base option)	\$360,000
LCO ₂ import facility 3 Mtpa (alternative option)	\$28,300
LCO ₂ import facility increment to 5 Mtpa (alternative option)	\$20,800
Subtotal (alternative option)	\$373,100

¹Total cost of CO₂ capture without discount for CO₂ capture costs realised as part of the processes.

²Assumes 4 km export pipeline only (see tie-in facility discussion above).

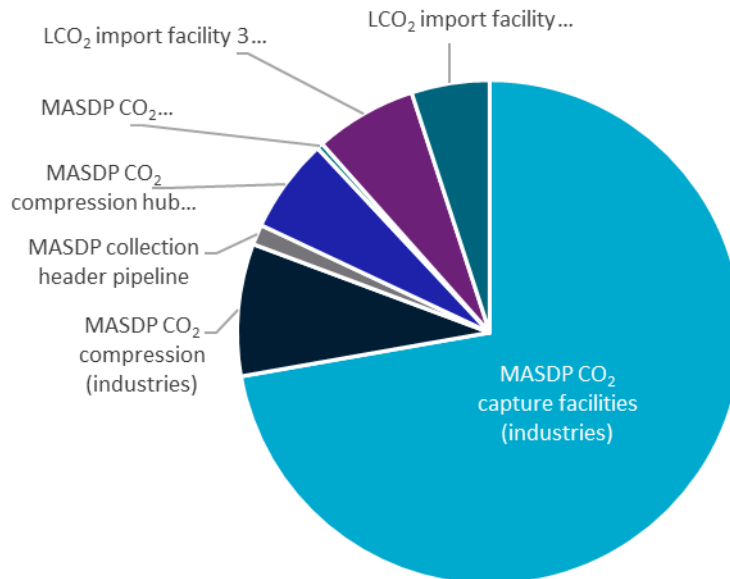


Figure 34: Proportional capital cost breakdown for the MASDP CCUS system assuming full Balanced Scenario development, using the base option LCO₂ import facility costs

It is assumed that MASDP developments will not occur simultaneously. As each industry is developed, it will incur the costs associated with its CO₂ capture, conditioning and low-pressure compression systems. Phased development of the MASDP will also enable phased development of the associated CCUS header pipeline and compression and export systems. In addition, the costs of the terminal receiving and storing LCO₂ can be phased.

Table 6 and Figure 35 illustrate the potential phased capital cost development options for the CCUS hub, excluding the costs of industry capture, conditioning and low-pressure compression. The lowest-cost development option contemplates installation of the 800 mm OD header pipeline and one compression train (CSIRO estimates this as 47% of the total costs of the compression facility). This would facilitate compression to the dense phase and transport of up to 3 Mtpa of CO₂ at a total estimated cost of \$307 million. Where CO₂ was not immediately available, these costs could, in principle, be minimised further by installing the header pipelines and completing early work on the compression station without procuring the compressor.

Table 6: Phased MASDP CCUS hub development capital cost options

Item (\$'000s)	800 mm OD headers 1 train compression	All headers 2 train compression	All headers 3 train compression	All headers 3 train compression LCO ₂ 3 Mtpa	All headers 3 train compression LCO ₂ 5 Mtpa
Collection headers (Areas B, C, D and E) 800 mm OD	\$65,509	\$65,509	\$65,509	\$65,509	\$65,509
Collection headers (Areas A, H and I) 400 mm OD	\$ -	\$29,834	\$29,834	\$29,834	\$29,834
CCUS export pipeline	\$28,660	\$28,660	\$28,660	\$28,660	\$28,660
Compression facility	\$202,497 ¹	\$317,350 ²	\$432,202	\$432,202	\$432,202
CCUS hub buildings	\$10,973	\$10,973	\$10,973	\$10,973	\$10,973
LCO ₂ import facility 3 Mtpa (base option)	\$ -	\$ -	\$ -	\$478,677	\$478,677
LCO ₂ import facility 5 Mtpa (base option) ³	\$ -	\$ -	\$ -	\$ -	\$366,483
Total (\$'000s)	\$307,639	\$452,326	\$567,178	\$1,045,855	\$1,412,338
CO ₂ capacity	3 Mtpa	6 Mtpa	9 Mtpa	12 Mtpa	14 Mtpa

¹CSIRO estimate of 47% of total compression facility cost.

²CSIRO estimate of 73% of total compression facility cost.

³To expand the LCO₂ import capacity to 6 Mtpa is estimated to cost \$10 million.

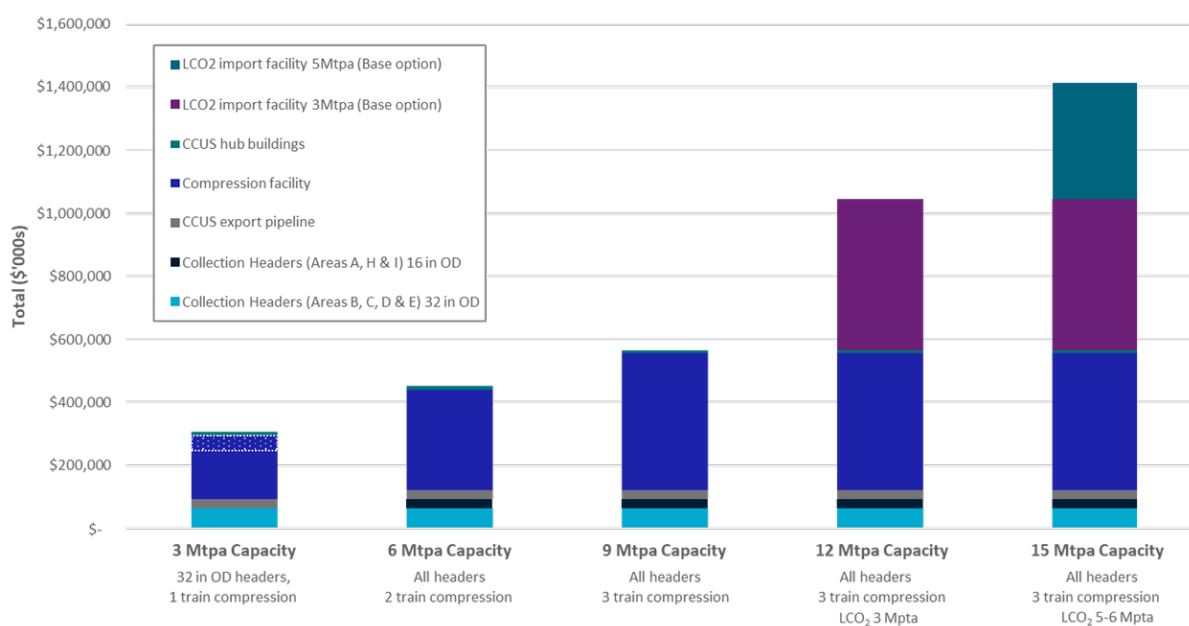


Figure 35: Phased MASDP CCUS hub development capital cost options

Note: As these are concept design costs, they are subject to significant uncertainty

NT CCUS hub key considerations

Concept-level designs and costings have inherent uncertainties as they represent the initial design before commencing more-intensive analyses where risks and costs are evaluated in more detail. The report should be considered in this context, providing a high-level basis for a future detailed design. As this design matures and becomes more detailed, it will evolve.

While the total system (i.e. including the offshore and Darwin and Ichthys LNG facilities) costs and detailed designs are not available at this time, design and development work is progressing collaboratively across all components of the NT LEH CCUS system. The interface pipeline systems, offshore pipelines and subsurface storage systems are being designed to carry and store the volumes of CO₂ that may be available from the MASDP CCUS system and imported via a LCO₂ receiving and storage terminal. Within the two GHD and Wood Group (2023; 2024) studies no technical showstoppers have been identified for systems within the MASDP and global examples of each element of the system have been identified to establish the technical and cost basis. The cost estimates include both capital costs and operating costs derived as a proportion of the capital costs.

Nearly three-quarters of the estimated capital costs of the MASDP CCUS system are associated with capture facilities. What proportion of these costs are embedded costs within the industry processes, versus additional costs, is a critical consideration in the overall development of the CCUS system. The capital costs of gas conditioning and low-pressure compression within the battery limits (the footprint of each MASDP industry) represent an additional cost beyond 'unabated' operations (over and above any capture costs). Further investigation of the models regarding who would own and operate these facilities is warranted.

The capital costs of the MASDP CCUS hub (header pipelines, compression facility and export pipeline) represent (at \$567 million; Table 6) less than 8% of the total MASDP CCUS system cost assuming full development of the Balanced Scenario. The capital costs of the full development of the LCO₂ (base option, 5 Mtpa) receiving and storage terminal taken from the GHD and Wood Group (2024) study are \$845 million.

Within both the GHD and Wood Group (2023; 2024) studies, options and flexibility in the design of the MASDP precinct CCUS system and LCO₂ receiving and storage terminal have been identified. These have flow-on effects for the costs associated with development of the precinct. CSIRO has used these options to explore phased development costs associated with the MASDP CCUS hub (header pipelines, compression facility and export pipeline to the INPEX/Santos pipelines) and the LCO₂ receiving and storage terminal. The least cost of the development providing up to 3 Mtpa of capacity is estimated at \$307 million. Further reduction in costs could be achieved through installation of the header pipelines and early works on the compression station being completed without the compressor procurement occurring (\$47 million further cost reduction).

Key points

Sector coupling

- Review of the MASDP balanced scenario industries has identified technologies that can be used to create a low-emissions production hub for the synthesis of ammonia, urea, methanol and derivatives.
- A near-term integrated industrial development option has been provided that enables the development of low emissions industries using methane as a chemical feedstock but will allow the transition to electrolysis derived hydrogen and CO₂ captured by DAC feedstocks.
- Realising sector coupling efficiencies will require: efficient energy management between industries in particular the reuse and storage and exchange of heat; the management and sharing of technological and financial risk to allow greater investment certainty; a central body with proper governance could be established to plan for success and to operate efficiently and responsibly once launched.

Power systems analysis

- A least-cost electrical power generation model was developed to explore options to meet both the electrical and hydrogen production demand required by the potential MASDP industries (Green et al. (2024)).
- ACoE costs vary from \$422 MWh to \$93 MWh depending on load type (constant to variable) and the proportion of gas generation (0-100%). Optimal costs for a significant proportion of renewable electricity generation include 50/50 loads with wind generation \$178-\$93 (Gas<=10% - <=50%).
- Major considerations for the levelised cost of energy are HVDC transmission costs from Powell Creek (and associated battery firming) and the capacity of the REZs in the vicinity of Darwin.
- Assuming that electrolysis-derived hydrogen generation uses variable loads, the least cost of ACoH varies from \$7/kg to \$9/kg at the 50% and 100% renewable fractions, respectively.
- The ACoH is most sensitive to the alkaline electrolysis efficiency (followed by the renewable fraction and wind capacity correction factor).
- Future deployment of renewable electricity in the Northern Territory requires a greater understanding of the potential wind resources in the REZs and the identification of low-cost energy storage technologies.

CCUS hub concept design

- The concept-level design of the NT CCUS hub includes the sources and sinks of CO₂, as well as the connective infrastructure, shared infrastructure needs and high-level costs.
- The maximum industry CCS projected capacity requirement is around 9.1 Mtpa of CO₂. with pre-combustion sources accounting for 60% of emissions and post-combustion sources for 40%.
- Once captured, CO₂ will undergo gas conditioning steps (e.g. dehydration) to meet specifications and enable its transport within the hub.
- The design also requires each industrial supplier of CO₂ to compress its CO₂ to provide it at 8.5 barg through a header pipeline to a centralised high-pressure compression facility
- CCU and negative-emissions options should be retained in the CCUS hub through additional tie-in points.

- On arrival at the centralised high-pressure compression facility CO₂ will be compressed to a dense phase and then piped to the DLNG and ILNG CO₂ pipeline tie-in point.
- As well as the CO₂ gather system for MASDP industries, an LCO₂ import terminal has been designed to accommodate an initial processing capacity of between 0.5 and 1 Mtpa (3 Mtpa phase 1 capacity) and to expand to a 6 Mtpa capacity (phase 2).
- The Darwin and Ichthys LNG facilities already capture CO₂ from natural gas from the offshore reservoirs.
- The CO₂ exported from these facilities is expected to enter a common export pipeline interface, which will permit CO₂ to be exported to both the Bayu-Undan depleted field CO₂ sequestration site and the Bonaparte CCS saline aquifer sequestration site.
- This pipeline interface system includes tie-in points for MASDP industry and LCO₂ import terminal CO₂
- Geological storage capacity is not considered as a major risk to the NT CCUS hub, as some of the most prospective geological storage basins in Australia are situated offshore of the Northern Territory. These areas include the depleted Bayu-Undan and the Northern Territory and Western Australian sectors of the Petrel Sub-basin of the Bonaparte Basin.
- Capital across the base option capture, compression, LCO₂ and CO₂ export line elements of the CCUS system totals ~\$7.4 billion.
- More than 70% of these costs are associated with industry capture facilities. The MASDP header pipelines, compression and CO₂ export pipelines represent less than 8% of total costs, and the LCO₂ import terminal and export pipeline represent 12–13% of total costs.
- Phased development of the MASDP will also enable phased development of the associated CCUS header pipeline and compression and export systems. In addition, the costs of the LCO₂ receiving and storage terminal can be phased.
- Compression to the dense phase and transport of up to 3 Mtpa of CO₂ can be achieved at a total estimated cost of \$307 million and the phase 1 3 Mtpa LCO₂ terminal cost is \$479 million.

6 Economics

The feasibility of a large-scale CCUS hub at Middle Arm requires a high-level understanding of the financial and commercial viability of the industries that may use it. Building on sections of this report that have assessed the broader economic benefits to the Northern Territory and Australia, this section focuses on the technoeconomic analysis of the Northern Territory Government's Balanced Scenario industries (Figure 3, Rogers et al., 2024c). This analysis is structured around two components: cash-flow and sensitivity analysis, and the evaluation of the impacts of potential policy measures and incentives.

The cashflow analysis performed in this report included several stages, specifically:

1. Estimation of cost and production profile for each product
2. Inclusion of additional costs such as development costs
3. Development of economic assumptions, for example market prices for each product
4. Calculation of levelised cost and other financial metrics for each product
5. Sensitivity analysis for each product.

The first two stages relied on modelling performed by Xodus to create a base set of feasible production profiles within Middle Arm as well as their associated costs (Xodus, 2023). These costs are based on Class 4 cost estimates, which have an indicative accuracy range of –30 per cent to +50 per cent. Where possible inputs from the other parts of the project are used either directly in the economic modelling or as a comparator to the model inputs and results. Additional economic assumptions were applied to account for key inputs, including product market prices, electricity prices, CO₂ processing costs, and a carbon price applied to unabated emissions.

This analysis is explicitly focussed on models of the Balanced Scenario industries at the scales identified by the Northern Territory Government. It does not assess proposed projects by industries, nor has CSIRO or its collaborator Xodus sought input from these proponents. As such this analysis should **not** be used to assess the viability of projects proposed by industry in the Northern Territory.

Levelised cost of production

The range of levelised costs for each of the products generated by balanced scenario MASDP industries analysed are presented in Table 7. Almost all products, when assessed against current market prices, show a significant price gap, particularly those intended to substitute for unabated conventional products i.e. low-emissions products.

Table 7 Summary levelised cost ranges by product

Product	Levelised Cost (Currency/Unit)
Onshore Liquefied Natural Gas (LNG)	US\$8.50 – \$11.00/MMBtu
Offshore LNG	US\$11.00 – \$13.50/MMBTU
Domestic Gas	A\$12.50 – \$14.50/GJ
Hydrocarbon-based Hydrogen	A\$3.50 – \$4.50/kg
Water-Based Hydrogen	US\$16.00 – \$18.50/kg
Hydrocarbon-based Ammonia	US\$1450 - \$1600/t
Water-Based Ammonia	US\$2400 - \$2600/t
Methanol	US\$700 - \$750/t (Integrated) and US\$630 - \$660/t (Domestic Gas)
Urea	US\$920 - \$960/t (Integrated) and US\$1050 - \$1100/t (Domestic Gas)
Gas-to-Liquids	US\$175 - \$190/bbl

Sensitivity Analysis

Sensitivity analysis was undertaken for each product to identify the key factors influencing levelised costs. Examples of factors assessed in the sensitivity analysis include:

- Commodity prices (high and low forecasts),
- CO₂ / emissions cost (high and low forecasts),
- Capital and operating expenses (+/-20%),
- Volume/capacity (where applicable and forecasts provided),
- Processing costs (range included where applicable), and
- CO₂ transport and storage fees (high and low range)

Tax rates are not included in the sensitivity analysis but are considered separately in relation to how variation in these rates impact on industry development. The full set of results can be found in the Task 12 report (Rogers et al., 2026c); however, Figures 36, 37, and 38, provide example sensitivity results for key factors influencing the levelised cost as a percentage of net present value (NPV) for offshore and onshore gas production as well as renewable hydrogen production.

Offshore gas production, LNG backfill

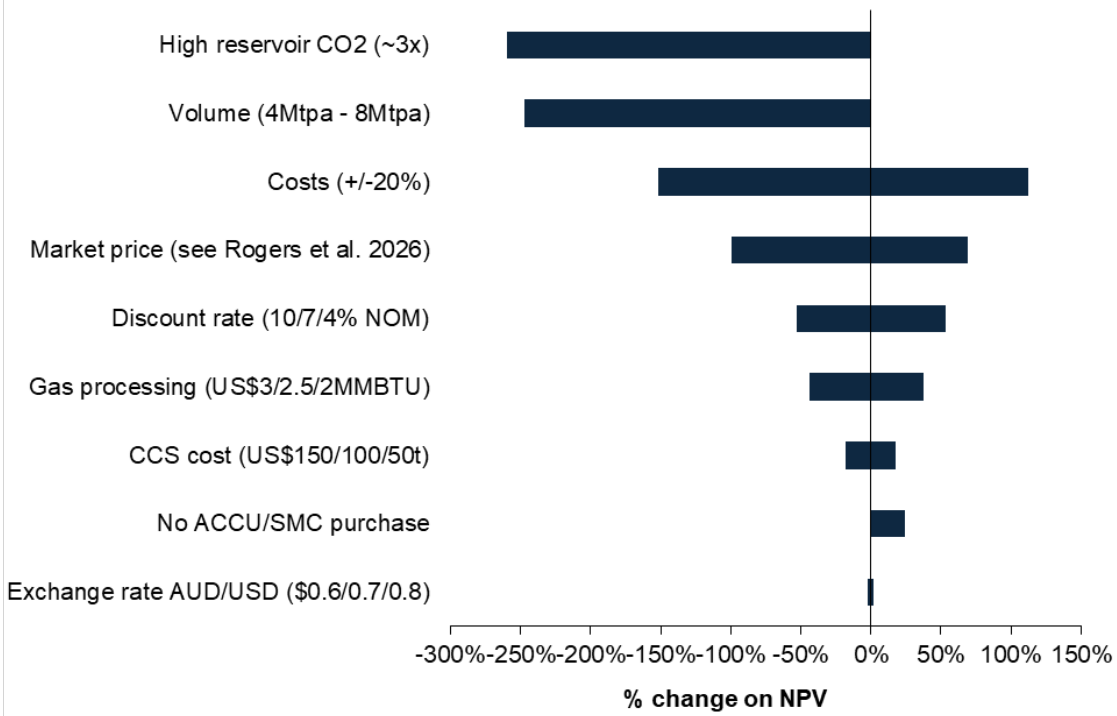


Figure 36: Tornado for sensitivity analysis of offshore LNG production. Note that initial NPV may be negative or positive

Onshore gas production, new LNG

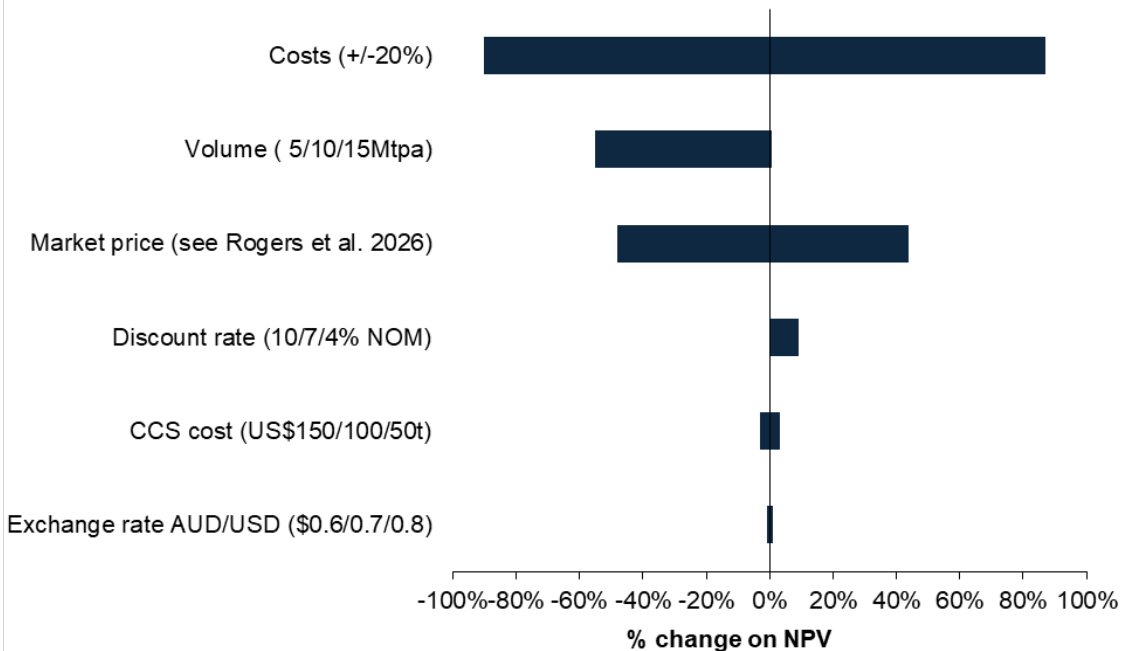


Figure 37: Tornado for sensitivity analysis of onshore LNG production with new LNG facility construction. Note that initial NPV may be negative or positive

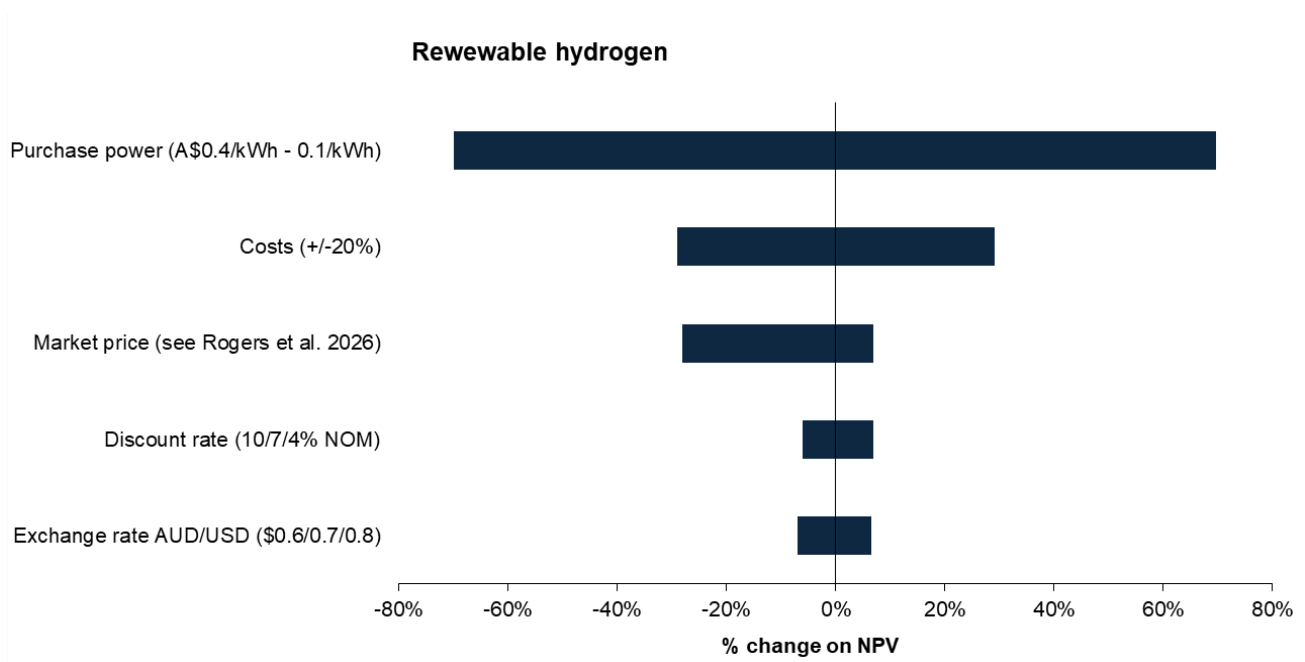


Figure 38: Tornado for sensitivity analysis of renewable hydrogen production. Note that initial NPV may be negative or positive

The analysis shows a high dependency in all cases on both costs (CapEx and OpEx) and commodity price. The cost of CCS for gas production is not as material as these other factors. In the case of renewable hydrogen, electricity is the key factor impacting NPV. Noting that the range in electricity costs are reflective of the lower LCoE estimates developed in the power systems study (Green et al., 2024). Consideration of policies that may affect these sensitivities are included in the possible models that could be used to incentivise hub development.

Macro-Economics

To assess the economic and employment opportunities of the Balanced Scenario for the MASDP, a high-level macroeconomic analysis was undertaken. Given the scale of the MASDP, the development is expected to have a significantly disproportionate impact on regional growth, employment, and income, consistent with outcomes observed in previous large-scale developments (Rogers et al., 2024a).

A review of the relevant literature, combined with assumptions derived from comparable projects, was undertaken to estimate employment levels and other anticipated economic benefits associated with each industry considered (Rogers et al., 2026c). A summary of this analysis is presented in Table 8 and indicates that a substantial workforce would be required in the Northern Territory if any of the proposed developments proceed. If all developments were to go ahead, the construction workforce is estimated at 46,539 with ongoing workforce demand estimated at approximately 10,000 additional workers including 3,278 direct employees and 7,211 within the wider economy. The economic boost of that ongoing employment to the Northern Territory is estimated at \$26 million per annum. The large numbers of construction workers and skilled workers required to build, operate and support the facilities would point to a need for sequential development of industries, to allow sustainable growth in the Northern Territory workforce and control costs.

Table 8: Summary of the Reference Development macro-economic benefits

	Capacity	CapEx (ex abandonment) US\$MM RT 2025	OpEx (per year inc. CCS) US\$MM RT 2025	Construction workforce	Operating workforce	Employment multiplier	Income boost
5 Mtpa greenfields LNG facility	5 Mtpa	31,440	766	5,513	379	834	3.03
1 x tieback 5 Mtpa LNG production (offshore platform)**	5 Mtpa	10,300	1,030				
Domestic gas*		3,120	256	2,340	230	507	1.84
Hydrogen (integrated water based)	0.2 Mtpa	16,315	307	12,236	276	608	2.21
Ammonia (water based)	0.5 Mtpa	11,335	225	8,501	203	446	1.62
Urea	2.15 Mtpa	10,661	1315	7,996	1184	2,604	9.47
Methanol	1.5 Mtpa	8,268	262	6,201	236	519	1.89
Condensate Refinery + Ethylene		5,002	855	3,752	770	1,693	6.16
Summary	-	96,441	5,016	46,539	3,278	7,211	-

*domestic gas is not in the balanced scenario but included for potential effects. ** utilising existing LNG trains for processing so no additional impact on ongoing employment

Potential cost reductions and policy Levers

Assessment of the key levers that could support the economic viability of the proposed developments was also undertaken. These levers vary depending on the specific products under consideration and the existing policy environment. Water-based hydrogen production provides one example where current incentives are available; however, these measures are insufficient to reduce the levelised cost of hydrogen below prevailing market prices with further reduction in costs required, including the cost of electricity.

Figure 39 illustrates how a range of factors could contribute to narrowing the cost gap relative to current market price of \$5/kg H₂. In considering this market price it is assumed that the hydrogen is used within the MASDP. The analysis commenced with a 25 per cent reduction in costs, reflecting the fact that current estimates are, at best, Class 4 and subject to significant uncertainty. It is anticipated that efficiencies will be realised as more projects of this nature are developed. In addition, further project definition and increased co-location of developments within the MASDP are expected to reduce both mobilisation costs and the ongoing costs of operating in this location.

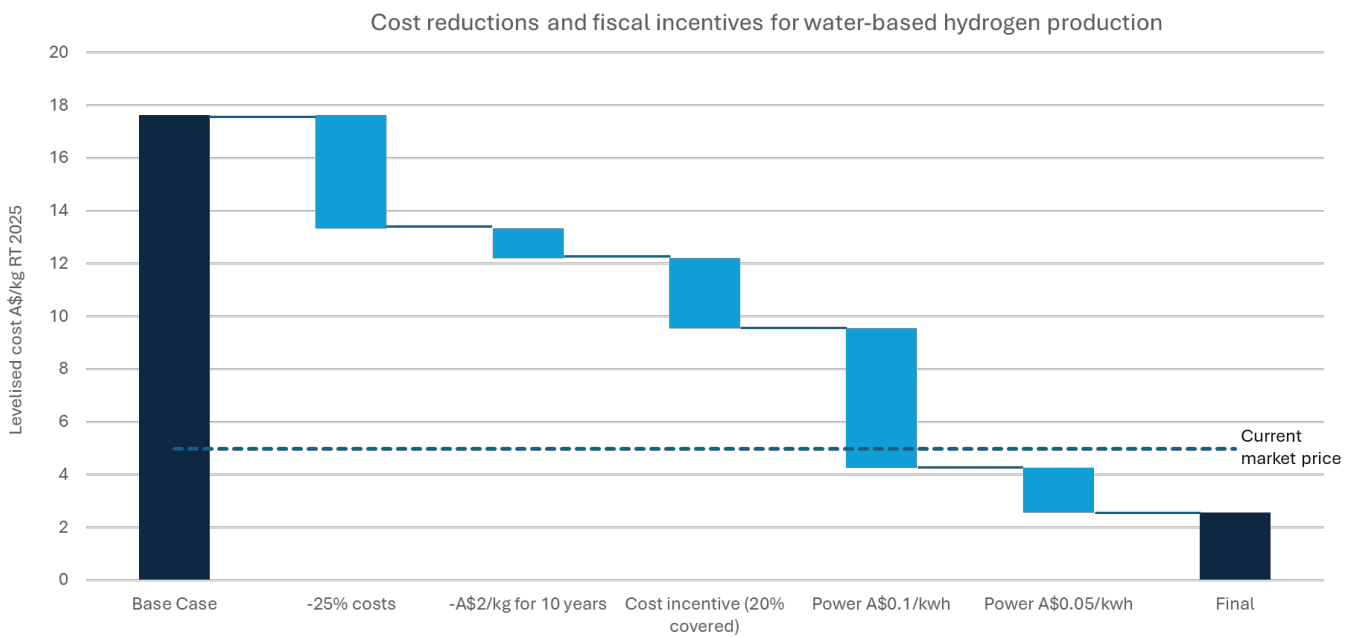


Figure 39: Analysis of water-based hydrogen fiscal levers

Current incentives include the Hydrogen Production Tax Incentive (HPTI), which provides a refundable tax offset of \$2 per kilogram of renewable hydrogen produced for up to 10 years, applicable between 1 July 2027 and 30 June 2040 and is also applied. An additional cost incentive equivalent to a 20 per cent reduction in costs was applied, which could represent other government direct funding (e.g. hydrogen hubs). Eligibility for capital support could include criteria such as support for green products, early-stage technologies, or additional recognition for developments achieving net-zero outcomes.

The development also incorporates the provision of dedicated renewable power to supply the facility, with an estimated electricity cost of approximately \$0.15/kWh. If, instead, power was supplied by an external provider able to benefit from economies of scale and potential subsidies, the cost of electricity generation could be reduced to a range of approximately \$0.05 - \$0.10/kWh. The optimistic sensitivities for the ACoE power systems model showed that the lower numbers could be possible (Green et al., 2024).

Taken together, these cost reductions and fiscal incentives have the potential to reduce the levelised cost of hydrogen to below current market prices. However, this analysis does not suggest that all cost reductions and incentives could be implemented simultaneously.

The market for unabated hydrogen is likely to become increasingly exposed to carbon pricing over time, effectively increasing the costs of the unabated hydrogen. Future analysis could therefore examine the optimal combination of fiscal incentives required to facilitate substitution towards water-based hydrogen under scenarios where carbon prices are more widely and consistently applied (see Jimenez et al., 2024; Joodie et al., 2024a).

Key points

- Technoeconomic analysis of Northern Territory Government's Balanced Scenario MASDP industries is structured around two components: cash-flow and sensitivity analysis.
- Class 4 cost estimates were developed with an indicative accuracy range of –30 per cent to +50 per cent.
- Levelised costs for each of the products show a price gap between cost of production and current market prices, particularly those intended to substitute for unabated products.
- If the industries are developed there will be significant employment opportunities generated in the Northern Territory. However, developments will need to be staged to manage workforce availability and costs.
- Sensitivity analysis shows the high sensitivity to OpEx and CapEx, and commodity price. The cost of CCS is not as material a sensitivity.
- To address cost uncertainty requires more detailed cost estimates, a reduction in costs through the realisation of lower mobilisation costs and project efficiencies and increases in commodity market price.
- Lower feedstock costs (natural gas and renewable electricity) can further bridge the price gap along with targeted policies for the development of low-emissions industries.

7 Australian and international policy

There is a clear price gap between the cost of producing low-emissions products in the Northern Territory and the prices of unabated products currently achievable in the market. However, there are carbon pricing mechanisms (see carbon price forecasts in section 4; and ACCUS and SMCs, outlined below) in place in many of the regional jurisdictions that over time will reduce the differential between unabated and abated products. This drives the robust demand forecasts for both low-emissions products and CO₂ removal services. There are also strong community expectations with respect to standards of living (and employment opportunities) and the need to rapidly reduce greenhouse gas emissions. For the Northern Territory, the opportunity to diversify their employment and income base is a priority to safeguard these community expectations.

The degree to which industry and governments pre-invest to secure early access to these emerging markets-while delivering economic benefits (not penalties caused by delay) and reducing emissions is at the core of industrial decarbonisation policy. These policy choices directly shape the NT infrastructure needs, including renewable energy provision, water access, and CO₂ removal capabilities.

As part of this business case project, CSIRO has reviewed CCUS and related policies both within Australia and internationally to identify policy strategies that could enable the acceleration of new industry development in the Northern Territory and maximise the benefits and long-term financial sustainability of MASDP industries.

Australian government policy

Policy levers

A wide range of policy levers can be used by governments to enact policy objectives, including the development of high-level strategies, legislation, regulations, financing, incentivisation, support for technology development, innovative practices and public engagement (Figure 40).

Development of a CCUS hub and associated industries should be guided by an assessment of the costs and benefits of CO₂ sequestration relative to alternative decarbonisation options. These approaches also need to be evaluated against the status quo of doing nothing or deferring till later.

Several criteria need to be fulfilled to enable investment in the necessary infrastructure for a CCUS hub, including:

1. A clear economic incentive
2. Regulatory and legislative mechanisms to make CCUS, hydrogen and low-emissions product manufacture a feasible alternative
3. Clear demonstration of how technical challenges can be overcome
4. Social licence from the community and the narrative behind the need be well articulated and understood.

The more consistently and broadly all the tools are applied, the higher the chance of an increase in successful deployment. Thus, measures to implement policies that enable low emissions hub developments need to be thoroughly defined and integrated.

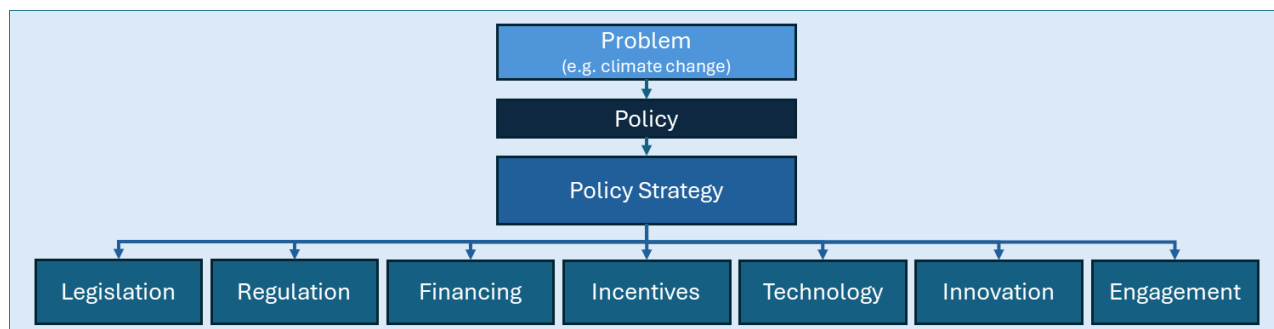


Figure 40: Policy levers and tools

Source: Althaus et al. (2022)

Australian Government emissions reduction policy landscape

In 2016 and 2022 Australia submitted its NDCs, which include two targets:

1. a reduction in greenhouse gas emissions to at least 43% below 2005 levels by 2030
2. a target of NZE by 2050 DISR (2024)

The Australian Government has recently announced its third NDC pledge to reduce greenhouse gas emissions by 62-70% from 2005 levels by 2035 (DCCEEW, 2025)

The Australian Government has implemented a wide range of policies to drive emissions reduction across all sectors of the economy. Of particular relevance for the existing and potential MASDP industries are the following policy categories:

1. the development of emissions reduction targets and reporting, and the ongoing development of emissions reduction strategies that will inform policy development
2. the development of a net zero and associated sectorial emissions reduction plans (DCCEEW, 2025; see blue box below)
3. the introduction of carbon pricing through the ACCU and SMC schemes
4. the regulation of offshore CCS
5. financing for hydrogen industries and manufacturing
6. past and current grants for CCUS hubs and hydrogen, projects and technology development
7. incentives to produce 'renewable' hydrogen.

A comparative study of the policy frameworks implemented at the Commonwealth and Territory government level for CCUS and hydrogen was undertaken in Tock et al. (2025) and identified the significant differences between the policy frameworks that have been implemented for each of these emissions reduction technologies (Figure 41). For both emissions reduction technologies there are gaps in policy frameworks at both government levels that, if filled, would provide a more comprehensive framework that could more effectively support their implementation.

Australia's Net Zero Plan

Australia's Net Zero Plan is designed to set a national pathway to net zero by 2050 with an interim 2035 target of 62–70% reduction on 2005 levels (DCCEEW, 2025). It frames the transition as an economic opportunity—scaling renewables, electrification, low-carbon fuels, innovation and carbon removals—while protecting communities, First Nations interests and energy security. The Plan is structured around five decarbonisation priorities:

Clean electricity across the economy (rapid rollout of firmed renewables, transmission, storage).

Electrification and energy performance (homes, buildings, vehicles, industry).

Expanding clean fuels (renewable hydrogen, low carbon liquid fuels, biomethane).

Accelerating new technologies (R&D, demonstration, scaleup).

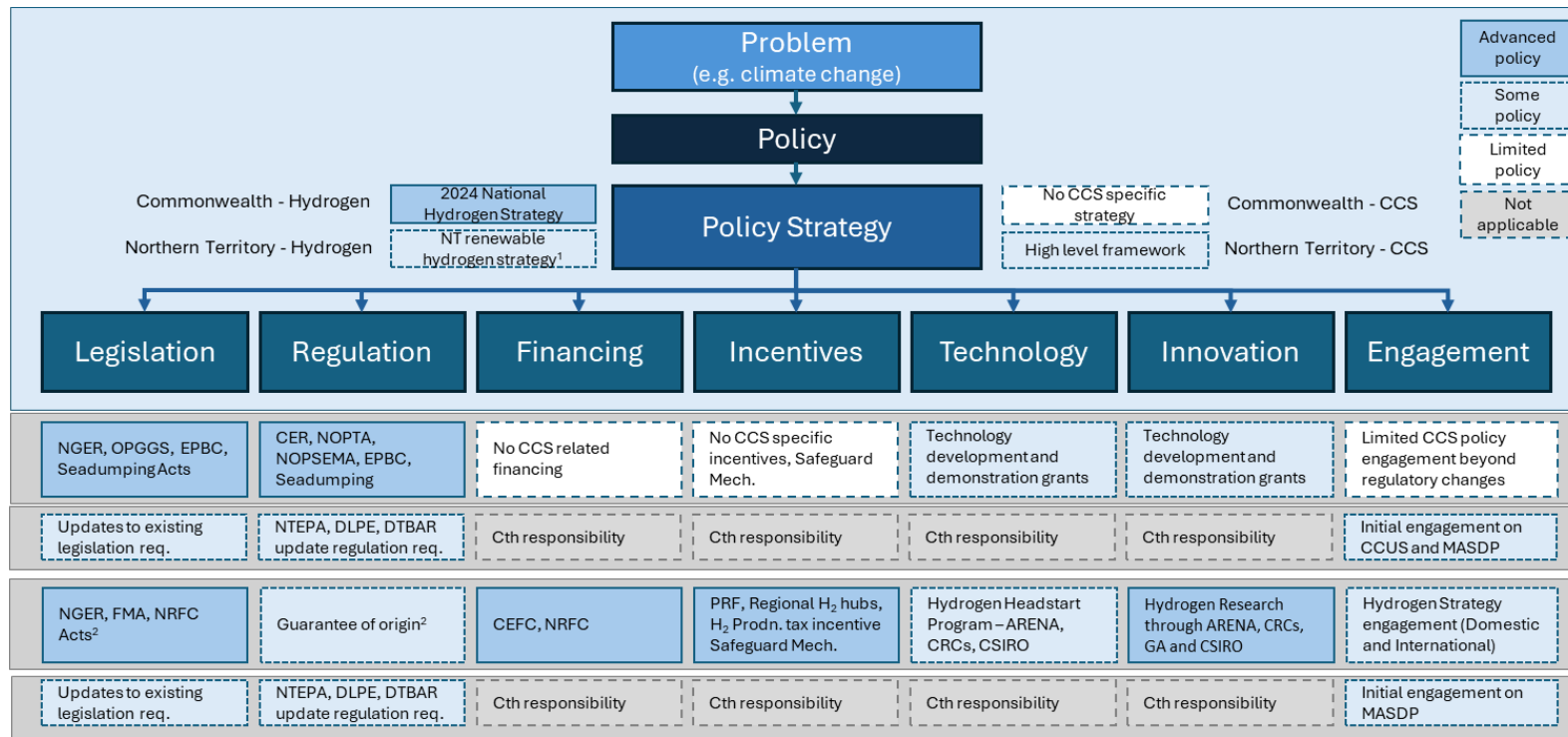
Scaling carbon removals (land-based and engineered CDR).

These decarbonisation priorities are accompanied by six sectoral decarbonisation plans across: electricity and energy, industry, resources, built environment, agriculture and land, transport). Together these plans will guide policy, investment and regulatory reform.

The Plan identifies carbon dioxide removal technologies as a key carbon management technology required to reduce emissions from hard-to-abate industry and balance residual emissions in the economy. It treats CDR as part of a portfolio of land emissions reduction technologies and notes the current cost barriers to CDR deployment.

The Plan notes that transboundary CCS has the potential to realise economies of scale needed to make carbon management technologies such as CCS a more accessible decarbonisation option for Australian industries and hard-to-abate sectors.

The Resource Sector Plan envisages a progressive role for CCS, with expansion in the near term (to 2030), growing application to 2035, and sustained use through to 2050.



NGER = National Greenhouse and Energy Reporting Act; OPGGS = Offshore Petroleum and Greenhouse Gas Storage Act 2006, EPBC = Environment Protection and Biodiversity Conservation Act 1999; CER = Clean Energy Regulator; NOPTA = National Offshore Petroleum Titles Administrator; NOPSEMA = National Offshore Petroleum Safety and Environmental Management Authority; NTEPA = Northern Territory Environment Protection Authority; DLPE = Department of Lands, Planning and Environment; DTBAR = Department of Trade, Business and Asian Relations; FMA = Future Made in Australia Act 2024; NRFC = National Reconstruction Fund Corporation; CEFC = Clean Energy Finance Corporation; PRF = Powering the Regions Fund; ARENA = Australian Renewable Energy Agency; GA = Geoscience Australia. Note: Some of the legislation could also be classified as creating or enabling incentives and innovation.

¹ Includes master plan and framework for the future and hydrogen supply chain (<https://territoryrenewableenergy.nt.gov.au/strategies-and-plans/hydrogen>).

² Other Acts and Regulations are applicable for the regulation of activities associated with the production, transport and use of hydrogen (<https://www.dcceew.gov.au/energy/hydrogen/regulatory-lists>).

Figure 41: CCS and hydrogen policy framework comparison

Contrasts between CCUS and hydrogen policy

One of the key differences between CCUS and hydrogen policy is the articulation of a National Hydrogen Strategy (DCCEEW, 2024b). The 2024 National Hydrogen Strategy, and its 2019 precursor (Australia's National Hydrogen Strategy), articulate the vision and policy levers required to enable the development of low-emissions and subsequently renewable electricity-derived hydrogen. They provide clarity to stakeholders on government priorities and as such serve as an important engagement tool for a broad cohort of stakeholders.

A similar strategy could be developed for CCUS (both at the Commonwealth and Territory level), especially as, like hydrogen, the application of CCUS cuts across industrial sectors and regions. If undertaken this will provide clarity on government priorities, including the role of CCUS hubs in decarbonisation of Australian industry. The inclusion of CCUS in decarbonisation strategies in other jurisdictions (see the examples below and those in Stalker et al., 2024) has provided certainty and direction for industry, investors and the community. Feedback from proponents, government representatives and other stakeholders to CSIRO during elicitation discussions in the UK and Europe was that while strategies should evolve, they should also provide long-term certainty (Stalker et al., 2024). This reduces investment risks in projects with high upfront capital expenditure and long return periods, while indicating government support behind the technology deployment, cohort of proponents for designated project locations.

For both hydrogen and CCUS emissions reduction technologies there are several legislative instruments in place, although the purpose of each is somewhat different. While there are opportunities for optimisation, Australia's CCS regulations are some of the most well-developed globally (Havercroft and Raji, 2023), with the majority of CCS regulations in place already. In contrast, hydrogen is governed by existing regulatory frameworks, with applicability varying according to project-specific characteristics (DCCEEW, 2025c).

Financing and incentive regimes have been developed for renewable electricity-derived hydrogen to provide the 'market pull' through low-cost financing, grants and production incentives and through the Safeguard Mechanism, an emissions disincentive. Apart from the Safeguard Mechanism creating a disincentive for ongoing emissions, and the potential to generate and sell credits following investment in abatement technologies, these systems are primarily absent for CCUS. The absence of 'market pull' through financing mechanisms and incentives does not allow the pricing gap to be bridged between the cost of ACCUs (the mechanism by which safeguard facilities can offset their emissions) and the cost of investing in CCUS technology implementation. For both hydrogen and CCUS, there are granting mechanisms designed to assist technology developers to demonstrate technologies at the pilot scale.

Northern Territory CCUS regulation

Currently there are no regulations in place in the Northern Territory to allow the transport and sequestration of CO₂.

Development of the NT CCUS hub requires the creation or amendment of NT legislation to permit the transport of CO₂ in pipelines. Work is underway to amend or develop legislation to enable CCUS to occur. Other state-based legislation and regulations have already been implemented that could form the basis of the design of this legislation and regulations.

Existing financial and incentive mechanisms to support CCUS hub development

While there are gaps in policy in Australia to support the development of a Northern Territory CCUS hub, there are mechanisms through existing policies and legislation that could be used to support its development and the industries that will use it.

These policies fall broadly into three categories:

- Policies and legislation applicable to most industries in the MASDP balanced scenario
- Specific MASDP industry-related policies and mechanisms
- NT low emissions hub infrastructure policies and mechanisms

Policies and legislation applicable to most industries in the MASDP

National Greenhouse and Energy Reporting (NGER) Act

The NGER Act describes a national framework for reporting greenhouse gas emissions, energy production and energy consumption by companies within Australia. Two thresholds exist to determine whether a company must report greenhouse gas emissions under the Act. A company operating a facility that surpasses any of the following thresholds within a financial year must report annually to the Clean Energy Regulator (CER): emitting 25,000 tonnes or more of CO_{2-e}, producing 100 TJ of energy or consuming 100 TJ of energy. For a corporate group the thresholds are doubled, but if a group triggers facility-level thresholds, the reporting requirements only apply to those facilities.

Several legislative instruments have been developed including procedures for reporting and measuring emissions or energy production/consumption, the requirement for third-party validation of reported figures and how the Safeguard Mechanism applies to specific facilities.

The NGER scheme requires emissions reporting but does not include any requirements to reduce emissions, with compliance only relating to the reporting of necessary information. It is likely that most facilities in the MASDP would come under these NGER reporting requirements.

The Safeguard Mechanism

Many of the proposed industries within the MASDP balanced scenario would also come under the safeguard mechanism. The currently operating LNG facilities on the Middle Arm are already subject to the mechanism and new industrial facilities would need to be built to comply with it and demonstrate low-emissions intensity.

The Safeguard Mechanism, administered by the CER, is one of the Australian Government's key decarbonisation policies and covers facilities with direct scope 1 emissions of more than 100,000 tonnes of CO_{2-e} per year. It covers the largest-emitting facilities in the mining, oil and gas, manufacturing, transport, construction and waste sectors. There were 219 covered facilities in 2023-24. Collectively, these facilities accounted for 44.89% of Australia's scope 1 emissions in the 2023-24 reporting period.¹¹

In 2023 the Safeguard Mechanism Act was amended to include an objective that the total net covered emissions budget for all facilities equalled 1,233 Mt CO_{2-e} for the period 1 July 2020 to 30 June 2030. A further net emissions objective of 100 Mt CO_{2-e} was set for all covered facilities for the financial year beginning 1 July 2029 and net zero by the financial year ending 30 June 2049. For gross emissions, the 5-year rolling average safeguard emissions for each financial year that begins after 30 June 2024 must be lower than the past 5-year rolling average safeguard emissions for that financial year.

For each facility that is covered by the mechanism, a baseline emissions intensity is determined that sets the maximum net emissions for that facility (known as a baseline). The minimum baseline is 100,000 tonnes, but this is adjusted each year based on the actual production at a facility. The baseline number assigned for most facilities declines at a fixed rate, equal to 4.9% per annum until 2030.

In addition, the emissions intensity factor used to calculate the baseline transitions over time from facility-specific factors to industry-average factors. This transition aims to incentivise production, where the relative emissions intensity is lowest, rather than individual facilities that use relatively older, more emissions-intensive technologies driving innovation and investment. New shale gas extraction facilities have had their baseline emissions set to zero, necessitating that net zero emissions must be achieved once gas production commences (CER, 2025b).

Facilities can reduce net emissions by investing in emissions reduction technologies, purchasing ACCUs, applying for variations in their baseline emissions or purchasing Safeguard Mechanism Credits (SMC). One SMC represents one tonne of CO_{2-e} and credits are generated whenever a facility reports actual emissions below its baseline. The credits can be banked for future years (until 2030) or sold to safeguard facilities that have exceeded their baseline emissions in a reporting year. Penalties for noncompliance with the scheme still apply if facilities exceed their baseline emissions in a given year.

The mechanism includes a cost-containment measure to provide certainty to safeguard facilities as to the price of carbon. ACCU offsets can be purchased from the government at a fixed price of \$79.20 in 2024-25, adjusted for inflation + 2% each year. Facilities cannot purchase international credits to meet their obligations under the Safeguard Mechanism. Finally, as part of the reforms the mechanism is scheduled to be reviewed in the 2026-27 financial year. This is to ensure that the mechanism is working as intended to reduce Australia's emissions in line with its NDCs.

¹¹ 2022-23 emissions reported by safeguard facilities totalled 136 Mt CO_{2-e} (CER, 2025c) and total scope 1 emissions for Australia were 303 Mt CO_{2-e}.

Within the Safeguard Mechanism 2023 amendments modest incentives were included for facilities to invest in at-source emissions reduction, as was support for emissions-intensive, trade-exposed industries.

ACCU scheme

One way for Safeguard Mechanism facilities to meet their emissions reduction targets is through the purchase of ACCUs. While the ACCU price remains low, this is likely to be a preferred option for facilities where the cost of the implementation of emissions reduction technology is higher than the forecast ACCU price. Several methods exist to create carbon credits, each representing one tonne of CO₂-e. Currently, there are 14 approved methods to generate these credits, categorised into the following sectors: agriculture, energy efficiency, landfill and waste, mining, oil and gas, transport, and vegetation (DCCEEW, 2026). These credits can be sold to firms that are seeking to offset their own emissions. ACCU Scheme participants with an existing carbon abatement contract can also sell ACCUs from their project to the Australian government.

The differential between the market ACCU price, the fixed Safeguard ACCU price and the SMC market price is an important consideration in how and when facilities will implement emissions reduction technologies and as described in section 6 is a cost factor (and possible income revenue stream – e.g. SMC generation when below baseline) when considering the development of new industrial facilities.

Specific MASDP industries-related policies and mechanisms

The MASDP balanced scenario contemplates the continued production of LNG (see the box on future gas strategy below), as well as the development of hydrogen (both from reforming of methane and electrolysis), methanol, ammonia, urea, ethylene, and critical minerals processing (e.g. lithium, vanadium) industries.

Depending on the technology used for the production some of these industries could be eligible for incentives through existing legislation, financing and granting mechanisms. This is particularly the case for renewable electricity generation, and products derived from this electricity, such as hydrogen and derivatives. This funding has been made available to help bridge the gap in production costs between incumbent unabated technologies and these technologies.

There is funding support for some industries that may establish within the MASDP, e.g. through the Australian Government's Future Made in Australia (FMA) agenda (Figure 42; Toccock et al., 2025), which is designed to drive investment in industries that will help Australia to transition to net zero emissions while strengthening economic resilience, including hydrogen, and critical minerals.

As well as support for renewable electricity and derived products, the FMA also provides incentives for critical minerals, green metals and low-carbon liquid fuels and clean energy manufacturing. This includes funding for the domestic manufacture of batteries, which could provide additional opportunities for proposed lithium and vanadium industries to add value to their products.

There are explicit exclusions in incentives currently available, for example hydrogen production pathways involving steam reformation of natural gas or coal gasification are not eligible under the

Hydrogen Production Tax Incentive. Further, the FMA Act (s.10A) specifically states that support must not be provided by the Commonwealth, a Commonwealth entity or a Commonwealth company for any of the following activities:

- the extraction of coal, crude oil or natural gas
- the construction of infrastructure for the primary purpose of extracting coal, crude oil or natural gas
- directly financing investments for the sole purpose of the use of coal, crude oil or natural gas.

So, while there are restrictions on industrial processes that can be chosen and which activities are excluded, there appears to be no specific exclusions associated with CCUS use by industries as long as the primary purpose is not for steam methane reforming¹² or the extraction of coal, crude oil or natural gas.

It is noted that several government programs are, or have previously been, focussed on grants for the demonstration and scale-up of technologies associated with both hydrogen and CO₂ capture (see Figure 44 for examples). For both categories, possible proponents for these types of grants would benefit from access to a shared low-emissions hub, be this renewable electricity or CCUS infrastructure.

¹² Steam Methane Reforming (SMR) is not explicitly mentioned in the FMA Act. The assumption for saying it would be excluded from the FMA relates to the wording in the act stating “Future Made in Australia support must not be provided for any of the following activities: c) directly financing investments for the sole purpose of the use of coal, crude oil or natural gas” (Australian Parliament, 2024, pg. 5). SMR, as well as Autothermal Reforming or Thermocatalytic Decomposition of methane require natural gas a feedstock to produce hydrogen. Coupled with CCS the hydrogen produced could have a relatively low emissions intensity, as well as be used to offset fossil fuel use elsewhere in the economy. It is not clear whether the financing in this case would be at odds with the goals of the FMA, therefore the conservative assumption made in this report is that direct financing is not available for what would be SMR (Or its variants) coupled with CCS.

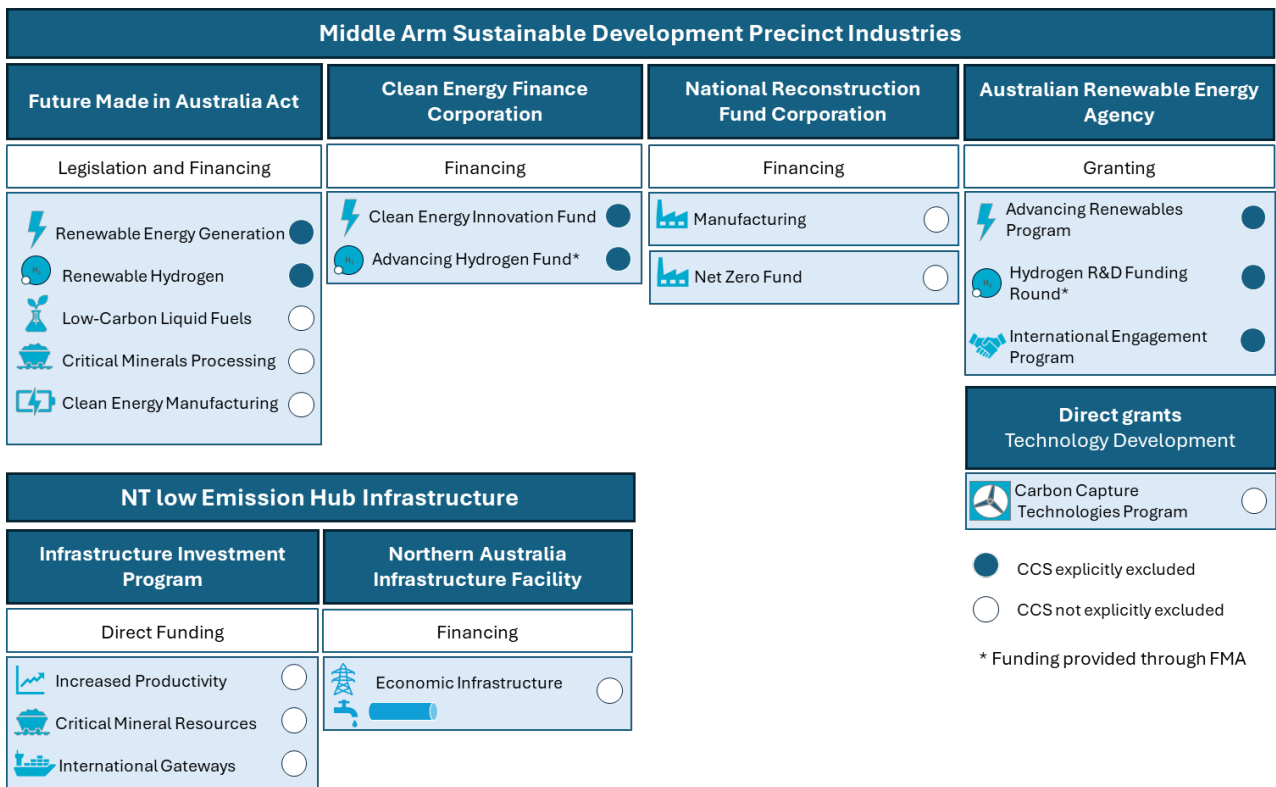


Figure 42: Australian government policy mechanisms that could be used to support both proposed MASDP industries and NT Low Emissions Hub infrastructure

The Net Zero Fund

The Net Zero Fund was recently announced as part of Australia’s updated 2035 NDC. This \$5 billion fund will focus on supporting large-scale industrial facilities as they decarbonise their assets. This will include investing in the technologies and capital infrastructure required to transition to lower emissions or more productive processes and also support scale up of manufacturing renewable and low emissions technologies. The purpose of this fund is to ensure that Australia retains industrial capabilities vital to our national interest while working towards Australia’s 2035 target.

Consultation on the design of the Fund is now closed and further information on its design is pending (DISR, 2025). Of note is that this fund will be administered through the National Reconstruction Fund Corporation (DISR, 2025) (and associated Act) which provides debt and equity funding and guarantees for projects. Whilst there are specific prohibitions on coal and natural gas extraction, (and pipeline infrastructure for extracting natural gas), there appears to be no specific prohibition on the funding of CCS projects.

As examples, this could include the provision of funding through the FMA Innovation Fund or the Net Zero Fund (see box above), as long as the purpose is not for coal, crude oil or natural gas production. The Infrastructure Investment Program objective to enhance links between producers and markets, including through international gateways and intermodal terminals, could also enable the development of CCUS infrastructure. An example of this type of infrastructure funding is the proposed \$1.5 billion equity investment in the MASDP. In addition, concessional loans through the Northern Australia Infrastructure Fund could be considered as a mechanism for

financing. Although these mechanisms appear to be available to support CCUS, further detailed investigation and clarification are warranted on the eligibility of CCUS for these funds and financing. If these mechanisms were to be used to address policy gaps, there would be a need for close cooperation across governments to ensure alignment.

Future gas strategy

The Future Gas Strategy sets out Australia's long-term vision for the role of natural gas in its transition to NZE by 2050. Rather than phasing out gas entirely, this strategy positions it as a critical enabler of decarbonisation, energy security and economic stability. It acknowledges that while gas use will decline over time, it will remain essential for certain high-value applications—particularly in industries where alternatives are not yet viable.

As discussed above, Australia has committed to reaching net zero, and the strategy makes clear that any ongoing use of gas must be accompanied by efforts to reduce or offset emissions. This includes investing in CCS and supporting the development of low-emissions gases such as hydrogen and biomethane, while simultaneously modernising infrastructure to improve efficiency.

The strategy also emphasises the importance of maintaining affordable and reliable energy for households and businesses, especially during the transition. It recognises that electrification is progressing, but in some cases gas remains a practical solution.

Internationally, the strategy acknowledges Australia's role as a trusted supplier of LNG, particularly to key trading partners in Asia. The strategy outlines how Australia will continue to support global decarbonisation efforts by exporting cleaner energy and offering geological storage for carbon emissions.

Importantly, the strategy includes a strong focus on respectful engagement with First Nations communities and regional stakeholders. It aims to ensure that these groups benefit from the energy transition through job creation, infrastructure investment, and economic opportunities.

In essence, the future gas strategy is a balancing act—preserving energy reliability and economic competitiveness while steering Australia towards a lower greenhouse gas emissions, more sustainable future.

NT low emissions hub infrastructure policies and mechanisms

When considering the infrastructure needs for the CCUS and wider NT low emissions hub there are two primary investment mechanisms available from the Australian Government.

Infrastructure Investment Program

Through the Department of Infrastructure, Transport, Regional Development, Science, Communication and the Arts (DITRDCA), the Australian Government makes nationally significant investments in land transport infrastructure across the country through its \$120 billion Infrastructure Investment Program (IIP) (DITRDCA, n.d.).

These investments are based on long-term planning, including robust project identification and selection processes. This longer-term commitment provides certainty for stakeholders, enabling industry to efficiently manage skills and resources, and allowing state and territory governments to consider the most effective sequencing of major projects to maintain capacity in the construction sector. The IIP is designed to ensure that Australia's national land transport system is well-placed to meet future challenges (DITRDCA, 2022).

The government considers nationally significant transport infrastructure projects to comprise projects that require a clear role for the Commonwealth, and include at least two of the following characteristics:

- an Australian Government contribution of at least \$250 million
- alignment with government priorities
- situated on or connected to the National Land Transport Network and/or other key freight routes, such as those identified in the National Freight and Supply Chain Strategy
- supporting other emerging or broader national priorities such as housing, defence, the development of critical mineral resources and Closing the Gap (DITRDCA, 2023).

The government priorities that will guide project eligibility include the project's ability to: increase productivity and enhance supply chain and land transport infrastructure resilience; advance equity and connectivity of communities and improve safety; and reduce transport emissions. Within the 2023 Infrastructure Policy Statement (DITRDCA, 2023), ensuring reliable links between producers and markets, including through international gateways and intermodal terminals, is noted as being critical to improving the efficiency and competitiveness of national supply chains.

IIP funding is split equally between Australian Government and state and territory delivery partners. In addition to this direct funding mechanism, to obtain greater value for money the program also allows the consideration of a range of other funding mechanisms, such as concessional loans, guarantees, phased grants and availability payments, equity injections, value capture and wider application of user charging (DITRDCA, 2022b).

MASDP infrastructure funding

The Australian Government is also supporting other large-scale projects in northern Australia, such as the MASDP in the Northern Territory. The government's \$1.5 billion in planned equity, which is separate to the aforementioned IIP above, will be used to support the development of the Middle Arm will pave the way for the precinct to be a globally competitive, sustainable precinct with a focus on renewable hydrogen and minerals processing, providing significant economic benefit and sustainable jobs and driving Australia's future net zero economy (DITRDCA, n.d).

Northern Australia Infrastructure Facility

The Northern Australia Infrastructure Facility (NAIF) is an Australian Government financier, providing concessional loans for infrastructure projects within Northern Australia and the Australian Indian Ocean Territories (NAIF, n.d).

Any project seeking funding from the NAIF must submit an investment proposal that meets all the following criteria:

1. the project involves development or enhancement of Northern Australia economic infrastructure
2. the project will be of public benefit
3. the project is located in, or will have a significant benefit for, Northern Australia
4. for financial assistance in the form of a loan, the loan will be able to be repaid or refinanced
5. the project includes an Indigenous engagement strategy
6. if an alternative financing mechanism is provided in the form of equity or equity-like investment, this will generate a return to government.

In addition, the project must align with one or more of the government's policy priorities, which are:

1. sustainable and resilient economic development and the alleviation of economic or social disadvantage in Northern Australia
2. working with jurisdictions to deliver key infrastructure projects in Northern Australia
3. sustainability, climate change and circular economy principles and solutions in Northern Australia
4. realising the critical minerals strategy 2023–30
5. materially improving the lives of Indigenous peoples and communities.

For both the NAIF and the IIP, CCUS is not explicitly excluded. As such there could be the opportunity for investment in the infrastructure required to activate new industries within the MASDP using these two mechanisms. However, there would need to be a compelling case that this expenditure would generate returns to the wider economy and that infrastructure would be able to generate a return sufficient to cover the service debt. Although we note the NAIF as an example of a specialist direct investment vehicles, others may be relevant for the MASDP, for example those provided by Export Finance Australia and similar entities.

Reflections on fiscal policies that could be used to enable an NT CCUS low emission hub

Whilst there are a number of fiscal policies that could help enable the development of the MASDP industrial development and its associated infrastructure, there are potential gaps within this fiscal policy that may delay investment until there is greater technical and financial certainty.

For example, there are a number of funding mechanisms for the technology development and pilot projects, however these funding opportunities will not be suitable for the deployment of large-scale infrastructure or industrial facilities decarbonisation (Figure 43).

Where technical and financial risks have been sufficiently reduced (but may be higher than those for conventional financial instruments) there are a number of fiscal policy instruments in place

that can assist project large scale project development and delivery (Figure 43). These instruments include concessional loan equity and guarantees.

Between these fiscal policy categories there is potentially a funding gap where government policy could be used to bring forward investment in supporting infrastructure or decarbonisation technologies which otherwise could not attract finance due to cross chain risks (i.e. the inability to sanction projects until all other parts of the value chain are sanctioned). This has been the focus of recent policy in other jurisdictions globally where a range of approaches have been used to address this gap.

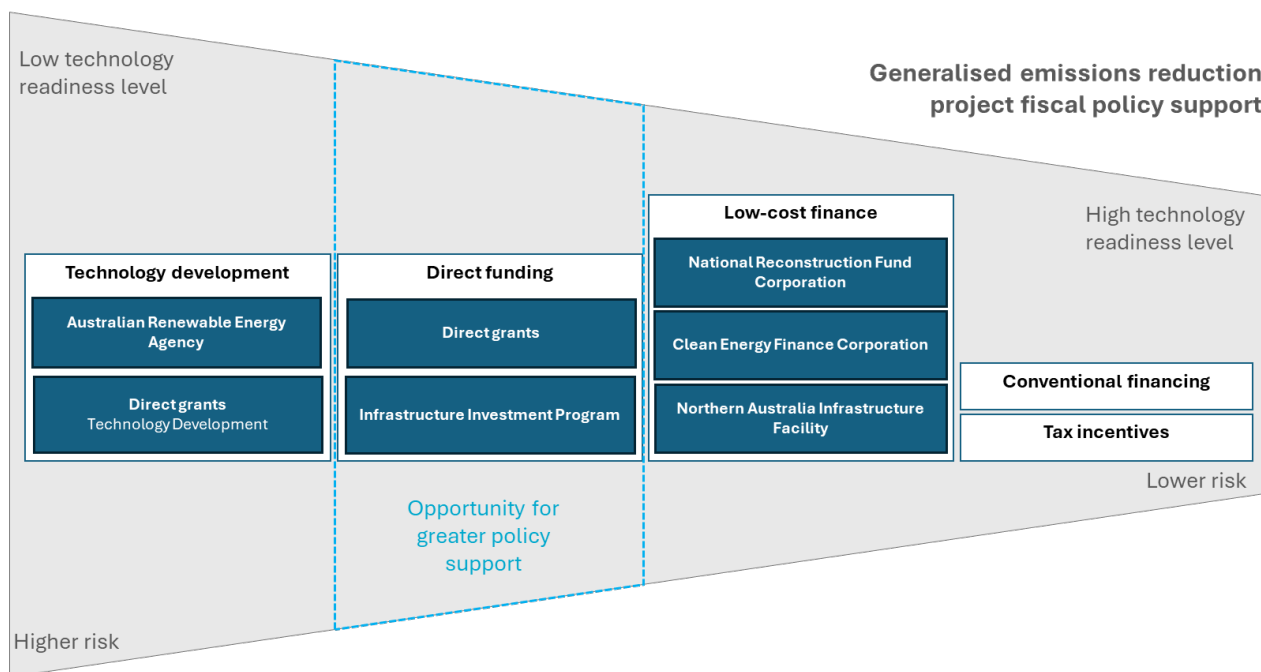
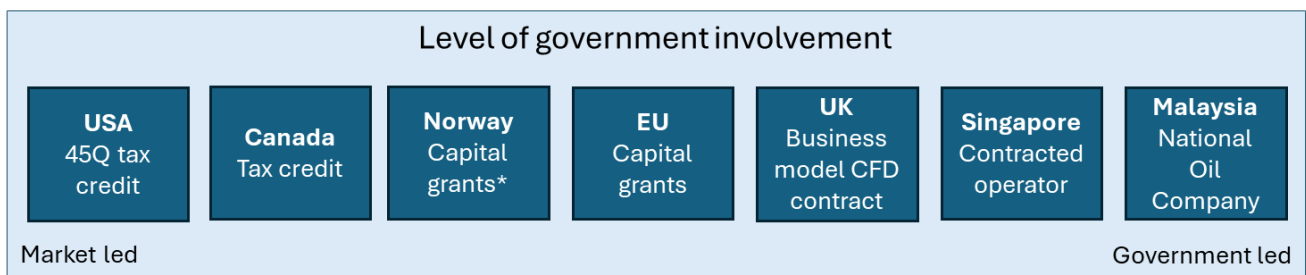


Figure 43: Generalised emission reduction project fiscal policy support, illustrating potential gaps in fiscal policy support depending on technical fiscal risk

International policy examples

Across the business case reports there has been extensive reference to international emissions reduction policies, including those that support low-emissions product manufacture, the development of low-emissions hubs and CCUS (Joodi et al., 2024a; Stalker et al., 2024; Tock et al., 2025). The purpose of this section therefore is not to repeat the content of these reports, but to identify common policy approaches that could be relevant to advance the development of a Northern Territory CCUS hub and the associated industries. These policies could also be relevant when considering other low-emissions hubs around Australia.

In the development of emissions reduction and specifically CCUS fiscal policies across the globe there has been a wide diversity in approaches (Figure 44), ranging from tax incentives to direct investment in projects through national oil companies (NOCs). This has typically reflected the level of desire of governments to directly participate in the development of the CCUS value chain. Many of these policy mechanisms exist in Australia (although they may not be applicable for CCUS) and there are advantages and disadvantages to each.



* Recipients include Equinor (NOC)

Figure 44: Policy mechanisms that are being used to incentivise the uptake of CCS

Tax credit model

For example, the 45Q tax credit, used in the US, provides generous and fungible tax credit for reductions in CO₂ emissions through the use of CCS. These incentives, tapered with time, incentivise accelerated deployment and therefore early action to reduce CO₂ emissions. Another advantage of this policy is that while the incentive is generous, costs to the government will only be realised on completion and operation of the projects. The industry financial risks are minimised, and government upfront investment risk is also minimised, as the market is responsible for development of the CCS infrastructure. This may lead to inefficiencies and duplication, but any cost efficiencies that can be obtained through scale and shared infrastructure represent enhanced returns. This regime allows the market to find the optimum economic outcomes for proponents, but this may lead to uneven distribution of market power.

Proponents of CCUS hub development in North America, particularly on the Gulf Coast, are looking at very large-scale hub developments, partly due to the very large aggregate size of emissions available (some of which are already captured) for capture and storage, but also as an enabler for new, greenfield industrial development around port and CCUS hub infrastructure (e.g. Corpus Christi Carbon Storage Hub; Businesswire, 2023). For the NT CCUS hub the vision includes a similar scale of operations, combining already existing sources of CO₂ that are being captured from LNG processing together with greenfield development of new low-emissions industries.

NOC model

In contrast, the development of CCS projects directly by NOCs allows a government to direct development in the best interests of the country, whereby the government takes all financial risk through its NOC. Note applicable to NTLEH because Australia does not have a NOC.

Granting model

Other mechanisms, such as grants, allow industry to lead the development of CCS projects, but grant provisions provide government control of outcomes. These grants require large upfront capital expenditure by government, and returns (both economic and emissions reductions) are not guaranteed. Typically, grants are undertaken within a strategic framework to be able to strategically target investments (see Tocock et al., 2025).

In Norway, a jurisdiction with significant experience with CCS and strong financial support from the Norwegian Government in the form of grants has significantly reduced the burden of risk and uncertainty, while the partners learn-by-doing the business of developing and operating a CCS hub. The Norwegian Government's investment in the nascent CCS industry is seen as a national

competitive advantage that can be leveraged to generate revenue for Norwegian industries and the taxpayer over the medium to long term whilst also achieving decarbonisation targets. The delivery of CCS projects in Norway is through the use of the equivalent to a government business enterprise (GBE), Gassnova (see box below) which has allowed day-day CCS activities to be removed from central government functions.

Gassnova

Gassnova's purpose is to act as a strategic and technical advisor to the Ministry of Energy on CO₂ management and represent the Norwegian state's interests in the capture, transport and geological storage of CO₂. The company has an important responsibility to contribute to the knowledge base for the further development of CO₂ management and is tasked with actively facilitating the exchange of knowledge and experience in Norway and abroad. The company is responsible for the implementation of the government's overall CO₂ management policy, to which it also contributes.

Gassnova actively brings together specialist areas within research, industry and public sector organisations and, through its various tasks, its own initiatives and in cooperation with others, acts to facilitate achievement of the government's goals for CO₂ management.

It is tasked with:

- mapping opportunities and measures for CO₂ management at combustion and process plants in Norway, based on existing instruments – this work is to be seen in the context of the management of the CLIMIT Demo.
- identifying opportunities for reducing CO₂ emissions in industry, with particular emphasis on industrial clusters.

Gassnova manages the Longship project, the Mongstad Technology Centre and the CLIMIT program (Norway's national program for research, development and demonstration of CO₂ CCS) on behalf of the government.

In Australia depending on the structure, a government business enterprise can be responsible for the delivery of government policies (and the provision of advice to policymakers) and due to its separation from the day-to-day operation of government it allows that enterprise to be focused on its core objective (e.g. ARENA, NZEA). Australia has a long history of using these vehicles for delivery, particularly for infrastructure projects.

Contracted operator model

The Singapore model of contracted operators for CCUS hub infrastructure is of note, in that a company (a joint venture of emitters) builds and operates an asset that is both funded and owned by the state (IEA, 2023f)

Cost for difference model

Mechanisms such as contracts-for-difference (CfD) enable financial certainty for investments but also seek to balance up front government investment with a potential future recouping of this

investment (see the box on CfD below) once market conditions improve. This mechanism is being used in a number of countries including the EU and the UK to incentivise CCUS investments.

The UK has an objectives-based strategy for CCUS, which differs from those in Europe, with a sectoral approach being taken for each of the CCUS business models that has been developed by the government. For each business model there are support mechanisms for the development of the respective CCUS hubs, which include CfD models and contractual mechanisms to defray cross-chain risk (i.e. participants of hubs not maintaining alignment on project delivery and timing). Reflections from the UK's experience of the development and implementation of these approaches is that the careful design of the policies is critical to ensure intended outcomes (Stalker et al., 2024).

Policy development and direct contracting with government can be useful in retaining government control of decarbonisation strategy implementation, but it can lead to exposure to risk associated with a change of government and policy approaches (Stalker et al., 2024). Subsequently the administration of CCUS CfD contracts has been transferred to the Low Carbon Contracts Company (Low Carbon Contracts Limited, n.d.) which is a government owned enterprise. It is a private, not-for-profit company wholly owned by the Secretary of State for Energy Security and Net Zero.

Contracts for difference

CfD mechanisms are a financial tool used by governments to support investment in energy projects—especially those involving low-emissions technologies—by stabilising revenue for producers while protecting consumers from price volatility. The mechanisms can be used to support low-emissions product and electricity production as well as CCS.

Carbon Contracts for Differences (CCfDs) reviewed by the Global CCS Institute (2025) are emerging as a powerful policy tool across Europe to accelerate industrial decarbonisation. These contracts offer financial certainty to companies investing in low-carbon technologies by guaranteeing a fixed price for each tonne of CO₂ they abate. If the market price for carbon falls below this agreed strike price, the government pays the difference. Conversely, if the market price exceeds the strike price, the company may return the surplus (Figure 45).

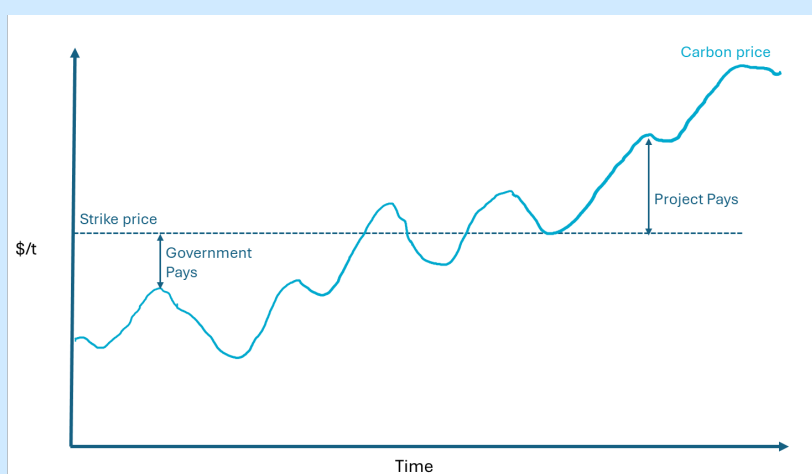


Figure 45: CCfD mechanism operational principles

The UK has the most comprehensive approach, having developed distinct CCfD models for industrial carbon capture, hydrogen production, and dispatchable power. Germany, France, the Netherlands, Denmark, and others are also rolling out CCfD schemes, each with unique design features.

Across these schemes, common themes emerge: a focus on cost-effectiveness, deliverability, and environmental impact. Some countries, such as the UK and France, also reward innovation and economic co-benefits. Risk management is a critical component, with mechanisms to address delays in transport and storage infrastructure and penalties for failing to meet capture targets. Most countries require disclosure of other public subsidies and may deduct overlapping support. In some cases, revenue from carbon credit sales must be returned to the state to ensure taxpayer value.

The benefit of CCfDs and CFDs more generally is that price certainty allows producers to commence development earlier than would otherwise be possible. The mechanism can be tailored to specific sectors or technologies and can stimulate innovation. However, strike price determination requires careful market forecasting, and if strike prices are set too high, taxpayers may bear excessive costs, but if they are set too low there will be no take-up of the incentive.

Key points

- There is a clear price gap between the cost of producing low-emissions products in the Northern Territory and the prices of unabated products currently achievable in the market.
- There are carbon pricing mechanisms in place (including ACCUS and SMCs in Australia) in many regional jurisdictions that over time will reduce the differential between unabated and abated products.
- The degree to which industry and governments pre-invest to secure early access to these emerging markets-while delivering economic benefits and reducing emissions is at the core of industrial decarbonisation policy.
- These policy choices directly shape infrastructure needs, including renewable energy, water access, and CO₂ removal capabilities.
- A wide range of policy levers can be used by governments to enact policy objectives
- To enable investment in the necessary infrastructure for a CCUS hub there needs to be a clear economic incentive; regulatory and legislative mechanisms need to make CCUS, hydrogen and low-emissions product manufacture a feasible alternative; there needs to be a clear demonstration of how technical challenges can be overcome; and social licence needs to be secured and retained from the community.
- The Australian Government has implemented a wide range of policies to drive emissions reductions across all sectors of the Australian economy.
- Comparative analysis of CCUS and hydrogen policy has identified policy gaps in each of these areas.
- A CCUS strategy could help to provide clarity on government priorities, including the role of CCUS hubs in the decarbonisation of Australian industry. There are examples of this occurring in other jurisdictions.
- There is an absence of CCUS financing and incentives to provide 'market pull' and address the pricing gap between the cost of ACCUs and CCUS technology implementation.
- Existing financial and incentive mechanisms that could be used to support MASDP industry and CCUS hub development fall into the following categories: (1) policies and legislation applicable to most industries in the MASDP; (2) specific MASDP industry-related policies and mechanisms; and (3) NT Low Emissions Hub infrastructure policies and mechanisms. Specific MASDP industry related policies and mechanisms
- Understanding the role of risk and technology levels is important to identification of areas where fiscal policy can most effectively accelerate investment
- Other jurisdictions globally have implemented a range of policies to incentivise CCUS and CCS, which vary with their level of government involvement.
- CfD mechanisms have the potential to accelerate low-emissions product, CCS and renewable energy investments due to price stability and financial risk reduction.
- This mechanism also allows return of initial investments made by governments to support prices.
- Whilst fiscal policies are important the delivery mechanisms used for their deployment are also important. Learnings that can be obtained from Norway's Gassnova and the UK's Low Carbon Contracts Company government owned enterprises.

8 Business model and options

This section of the report first explores the options for CCUS hub development in the Northern Territory to illustrate the potential advantages and disadvantages of low emission hub development. This is followed by a proposed business model for the realisation of the NT CCUS hub, as well as the potential next steps required to progress the NT CCUS hub development.

CCUS and low emission hub development options

Based on the findings of this business case, the Northern Territory and Commonwealth Governments and industry have several potential development options to consider. This section outlines three key options:

1. **Non-intervention:** Neither government takes no action to support the infrastructure underpinning the MASDP, allowing market-led development without direct government involvement.
2. **All-at-once implementation:** The government plays a central role in coordinating the development of the MASDP. This approach would require substantial financial investment and close collaboration among all stakeholders and would be challenging due to inadequate infrastructure and workforce.
3. **Strategic facilitation:** A middle-ground approach where the government guides and sequences investments and activities in a structured and planned manner to achieve the MASDP's objectives.

Depending on the chosen path, there are likely to be impacts to the following themes:

- Decarbonisation aspirations within the Northern Territory as well Australia's emission reduction ambitions
- Existing trade relationships and the future flow of investment
- Future development of energy infrastructure and scale-up opportunities
- The role of government policy to reduce uncertainty and encourage cost reduction and technology development, and
- Economic diversification and broader social benefits for the Northern Territory

Each of these themes is discussed below, starting with the non-intervention option.

It is important to note that these options are to stimulate discussion only, reality of any of the options will be far more complex in their implementation.

Whilst the focus is on the CCUS hub options, as discussed elsewhere in this business case report, the CCUS hub cannot be seen in isolation and there would need to be considerations of the other infrastructure requirements associated with the MASDP development (e.g. renewable power provision).

Non-intervention

If the NT and Commonwealth governments choose the non-intervention option, it may impact the Northern Territory's ability to achieve NZE by 2050. Project emissions in the territory are predominantly related to gas extraction and processing, mining and power generation (Rogers et al., 2024b). Both INPEX and Santos' operations are covered by the Safeguard Mechanism and they are therefore required to reduce their emissions to net zero by 2050. Reservoir emissions make up a significant component of each company's scope 1 emissions, with sequestration the only feasible means for abatement. Currently each company is exploring options to develop the necessary infrastructure to sequester CO₂ within the Bonaparte Basin. As of yet, no company has made final investment decision (FID), but if the projects go ahead significant investments will be required to develop the gas conditioning, compression and pipeline, and necessary injection well infrastructure.

If the Northern Territory and Commonwealth Governments choose not to invest in the broader MASDP CCUS infrastructure, it is likely that this CCS infrastructure will be developed only to meet the individual decarbonisation objectives of the NT LNG industry and those with whom they successfully negotiate CO₂ off-take arrangements. This would occur despite anticipated demand for CO₂ sequestration, both domestic and international, exceeding the combined reservoir emissions of all participating companies. This is because investments in additional capacity provision would be significant and the companies will be seeking to minimise their CO₂ abatement costs.

The target CO₂ capture volumes for both LNG facilities have been established and potential international CO₂ supplying partners have likely been already identified. This has allowed front end engineering design (FEED) planning for the necessary interconnections, pipeline and injection well options to achieve the desired annual sequestration volume. The capital-intensive final investment decisions (FID) will be based on the options that best represent secured and contingent volumes of CO₂ at least cost to the companies.

Following FID, the CCS capacity of the associated infrastructure becomes fixed, limited by the maximum flow rate between the onshore facilities and the offshore sequestration site. While future demand for CO₂ sequestration may arise, and additional injection wells could be constructed, these systems are typically designed around annual capacity and are difficult to scale once constructed due to their integrated nature. The key constraint remains the capital investment and regulatory approvals required to connect new CO₂ sources to existing or expanded sink infrastructure. Installing additional pipelines to scale to future demand would require substantial additional capital, may be constrained by existing easements through the Darwin harbour, and could be more expensive than earlier installations, particularly as the original pipeline routes and options would have been selected through a cost-minimisation process.

Based on the aforementioned factors it is reasonable to assume that, in the absence of government intervention, from a capital investment perspective the required infrastructure will only be developed to achieve Santos' and INPEX's decarbonisation and commercial objectives. This is despite the possibility that the demand for sequestration, and the associated infrastructure required, could exceed each company's requirements.

The constraint on CO₂ transport and storage capacity could affect low-emissions hydrogen production in the NT, particularly where hydrocarbon feedstocks are used. This industry would not be developed if the sequestration services required as part of these operations were not available. Consequently, decarbonisation of power generation could be affected, as gas turbines that could utilise hydrogen would lack a low emissions supply. It is unclear with an industry-only led development whether sufficient sequestration capacity would be included in final investment decisions to enable the establishment of a hydrogen industry.

Since hydrogen is a key chemical feedstock for producing other low-carbon fuels and petrochemicals, there is a sequencing risk: if sequestration capacity is not available, hydrogen production, and therefore the production of low emissions intensity derivative fuels and petrochemicals, may also be delayed. This would limit the availability to use these products to decarbonise other sectors in the Northern Territory.

Australia and the NT have the potential to import and permanently store millions, or even tens of millions, of tonnes of CO₂ annually from international sources. Achieving this scale would allow the capital costs of CCS infrastructure to be spread across a larger volume of CO₂, improving economic efficiency and reducing financial risk across the CCS value chain. However, without government intervention, there is a combined sequencing and financial risk. NT CO₂ sequestration site operators would need to invest in their CCS infrastructure ahead of confirmed international demand. This would require significant upfront capital, while facing uncertainty around both the timing and volume of CO₂ imports. Such uncertainty could delay investment decisions and limit Australia's ability to establish itself as a regional hub for carbon sequestration.

In the absence of government intervention, operators may pursue alternative decarbonisation pathways that avoid investment in additional decarbonisation measures beyond the capture and storage of reservoir CO₂ emissions. To minimise costs, ensure regulatory compliance and fulfil their fiduciary duties to maximise shareholder returns, operators will assess all available decarbonisation options, including the use of offsets rather than the investment in capture facilities from power generation or the use of low emission hydrogen fuels if the costs of doing so are lower.

While this may offer short-term cost advantages to the individual operators, it could limit the Territories' ability to develop an integrated CCS system and diminish its strategic position as a regional carbon management hub. Beyond the impacts on decarbonisation there are other economic impacts that are associated with the non-intervention approach.

Future investments with the Territory's existing trading partners may be affected, particularly as most emissions associated with the Territory's exports occur within the borders of these partners countries such as South Korea and Japan. These countries have domestic obligations to reduce emissions and are actively exploring pathways to decarbonise while safeguarding energy security and economic growth. Historically, both nations have played a key role in developing Australia's gas resources, providing substantial capital for projects and acting as major offtakers.

As their domestic emissions obligations intensify, future investment faces a dual challenge: ensuring continued energy security while sourcing resources with progressively lower associated emissions intensity. Technologies such as CCS and low-carbon fuels present viable options to address this challenge. However, without sufficient government support, there is a risk that capital may be redirected to other countries or even other Australian states offering more favourable

conditions. If projects outside the Territory are perceived as more attractive, investment may gradually shift away, especially once existing resources are depleted. This could lead to a progressive winding down of gas extraction activities, with significant implications for employment and the businesses that support this sector.

Combined with broader non-intervention risks, this option could reduce economic diversification in the Northern Territory, leaving it more vulnerable to price fluctuations from a limited range of commodities and undermining long-term growth. Missed opportunities in low-emissions technology development and deployment may result in reduced competitiveness, declining industrial activity, and fewer employment prospects, ultimately weakening the Territory's long-term economic resilience.

The potential implications discussed above stem from the assumption that the market will play only a limited role in developing the MASDP. The counterfactual would assume that sufficient private incentives exist to develop the hub without government coordination or fiscal support. However, given that investment in emissions abatement is largely driven by government policies that compel the market to internalise the cost of emissions, it is unlikely that the development of a hub would emerge as a purely market-led initiative. Furthermore, our review of international low-emissions hubs revealed a consistent pattern: governments have played an active and key role in their development.

All-at-once implementation

A second option could involve the governments undertaking full development of the MASDP supporting infrastructure. This approach would require substantial fiscal investment, with the government assuming the bulk of financial and operational risks. These risks stem from the government's leading role in planning, funding, and delivering the precinct infrastructure. While other stakeholders, including industry, would be involved, their participation would largely be reactive in that they are responding to government-led initiatives rather than driving them.

From a decarbonisation perspective, the development of CCS infrastructure would be more favourable under a government-led approach, as it would help de-risk related projects in several key areas allowing more certainty and lower risk investment decisions. In particular, public capital could be used to develop and underwrite CO₂ transport and storage infrastructure at a scale beyond what would be expected without government support (i.e. medium to long term future prospective CO₂ capacities could be secured), facilitating higher storage volumes and potentially accelerating deployment timelines. This approach would also reduce the exposure of private capital to key risks, such as the underutilisation of infrastructure due to uncertain or insufficient demand. Such an approach does not mean that all the risks are borne by government, private capital would still be needed for the capture of CO₂ and construction of injection wells, however these elements can scale relatively easily when compared to the infrastructure that connects sources to sinks.

Developing the necessary infrastructure to scale carbon capture and storage (CCS) could help international partner countries and their industries meet their decarbonisation goals, particularly in cases where alternative decarbonisation options are limited. This would require construction of a liquid CO₂ import terminal and establishing a fleet of ships to transport CO₂ to the MASDP. This

investment could be made in partnership with those countries. Access to such import infrastructure could contribute to lowering Australia's domestic emissions, by providing lower unit costs of storage for Safeguard facilities, due to economies of scale. However, this depends on supporting CCS infrastructure in the MASDP being both available and cost-effective compared to other decarbonisation options.

Developing the capability to import CO₂ and the capacity across the CCS system for these volumes of CO₂ could help mitigate risks associated with existing trade flows from the region. Capturing emissions associated with LNG exported from the territory and reinjecting them into the original reservoir may enable continued gas extraction while also supporting emissions reductions in importing countries. This approach offers a transitional option for trade partners seeking to decarbonise their economies, whilst other low emission technologies become more financially viable.

In addition to importation of CO₂ the development of low-emissions products, namely hydrogen and its derivatives, could provide firms further opportunities for decarbonisation. As noted in the MASDP "Balance Scenario" there are several million tonnes of low-emissions product that could be utilised for shipping, power generation, chemical manufacturing, minerals processing, advanced manufacturing, and export.

The risks of an all-at-once implementation include the lack of utilisation of the built infrastructure leading to a long-term liability for the NT government. In addition, if the CCS infrastructure was underutilised the sunk capital costs associated with the all-at-once implementation may have been deployed more effectively elsewhere to realise emissions reductions.

Strategic facilitation

The third option would be for the NT and Commonwealth governments to act in a strategic facilitation role (see hub key learnings box below), maximising future emissions reduction potential and economic development opportunities while minimising up-front costs. In this model strategic investments could be made by government that would enable foundational CCS infrastructure to be built (Phase 1 MASDP CCUS hub and LCO₂ import facilities), combined with fiscal and regulatory policies that support the development of new low emissions industries in the NT. This would help de-risk investment by transport and storage companies in pipeline and injection well infrastructure with capacity beyond their reservoir CO₂ and existing offtake agreement volumes.

Depending on the approach taken the strategic facilitation approach could bring forward decarbonisation investment decisions that otherwise would be deferred or not taken (e.g. the establishment of a hydrogen industry - in the first instance using hydrocarbon feedstocks and then over time transitioning to renewable energy-based production).

This strategic facilitation role has the potential to reduce the cost of regret and long-term liabilities for the Northern Territory and Commonwealth governments. At the same time, it would demonstrate to partner countries and international investors a clear commitment to supporting the transition of high-emitting industries and assisting partners in meeting energy transition and emissions reduction targets. This approach would allow Australia to provide those countries with a

series of options for emissions reductions, from their importation of LNG and export of resultant CO₂, through to the provision of low emission products originating from the MASDP.

This option would also allow the development of the CCUS infrastructure, and industries would use it at a pace that was more sustainable for the NT economy, which has historically been characterised by waves of capital investment. A gradual approach allows the NT to grow its skilled workforce and not rely as heavily on transient workforces sourced from other states in Australia, providing greater social benefits to the NT community. Enabling the establishment of low emission industries through the provision of CCUS infrastructure would allow diversification of the NT economy through the ability to transform or add value to existing commodities, reducing exposure to international commodity markets.

Hub key learnings

The synthesis of the case study examples and stakeholder interviews identified (discussed in Stalker et al., 2024) identified the key learnings that could be applied to CCUS hubs in Australia and the Northern Territory.

The emergence of CCUS hubs

The evolution of the CCUS hub model has been a response to the risks associated with single-source-to-sink models, which carry significant risk of failure if one part of the value chain fails. Hubs still require anchor emitters; however, hubs can diversify risks through the inclusion of multiple emitters and in some cases multiple sinks. The collation of additional emissions sources also, in principle, leads to greater volumes of CO₂ being stored over the phased development and improve economic outlooks.

A long-term vision

Many countries as well as the EU have developed strong long-term policy visions and have a holistic view of emissions reduction, including a requirement for CCUS as part of their emissions reduction strategies. The EU provides a clear market signal on future CCUS capacity requirements and statements of the desire to achieve targets, including the role of CCUS hubs in attaining negative emissions over the long term. There is significant benefit for countries seeking to reduce their emissions through a shared, supported and coherent articulation of a long-term vision that includes CCUS.

Building on prior work

While it can be hard to piece together the evolution of hubs in many jurisdictions, they often represent the continued development of prior studies, building on that past work. Ultimately, neither the fundamentals of many of the CCUS hub projects nor the industrial regions from which emissions are generated and their proximity to potential sinks have changed. What has changed is the scale and diversity of CCUS hubs, and the development of a range of new business models to enable their implementation and operation.

Reducing business model uncertainty

In all CCUS hub developments, governments are involved, either through direct funding, cost for difference mechanisms or tax incentives. Each government has a clear understanding of the benefit and return on investment (e.g., continued manufacturing capability in hard-to-

abate industries and the economic and employment opportunities those sectors provide). In the case of Norway, the government has recognised CCUS as a national opportunity that can generate revenue and further Norwegian company technology and skills exports, while mitigating exposure to declining activities in other areas such as the oil and gas industry

Government involvement is also important in setting boundary conditions. Aside from providing incentives, there is also the implementation of other measures such as a carbon tax or requirements on hub operators to allow fair and equitable access to infrastructure. Irrespective of financial incentives, governments have also provided certainty and enabled risk reduction to allow private sector investment. To unlock private investment, understanding and having certainty on return on investment is critical. In this regard, the UK is working on an objectives-based framework, which includes an independent economic regulator, the need to understand costs and performance, improved certainty of return over the long term (including adequate return on investment) and protection against demand-side risk to revenue (cross-chain risk).

The role of a coordinating body

In the development of CCUS hubs a single representative organisation is typically identified. This can be a joint venture or government company (e.g. Gassnova in Norway). In the case of Gassnova, this entity is at arm's length to government, enabling it to execute its role without being part of the day-to-day machinery of government. A feature of many CCUS hubs globally is that they incorporate academia and R&D organisations with strong expertise in CCS to facilitate collaboration. This helps minimise risk and allay public concerns, as well as develop future workforce capacities.

Collaboration is critical

Collaboration allows for coordination across the complex activities of the design, development and deployment of low-emissions hubs and clusters no matter their geographical location. The single CCUS hub coordinator role allows common definitions around metrics and project goal success/failure (as undertaken in *Task 0* of this study; Ross et al., 2023), without which there could be a lack of alignment between the proponents. The central CCUS hub coordinating organisation can act as a contract clearing house and undertake many of the administrative activities and, as such, reduce the costs of entry for hub participants. In addition, this organisation can be responsible for knowledge capture and sharing.

Recording progress

Enduring corporate and institutional memory and a clear understanding of roles and responsibilities are instrumental in advancing the development and deployment of low-emissions hubs. It was observed in the deep dive of the different project case studies for north-west Europe (e.g. ROAD and related projects in the Netherlands), that several of the currently active projects are revaluations of older projects that had failed, mainly due to lack of a strong business case. Institutional knowledge (and detailed documentation of prior projects) can help navigate the history of some of these project failings and reduce the risk of repeating earlier mistakes.

Building emissions reduction capacities

While the development of many of the CCUS hubs is being driven by oil and gas companies and their need to reduce their own emissions, opportunities exist to provide much greater

capacities that will bring about wider industrial decarbonisation. However, without market demand signals, these hubs may not be developed with sufficient capacities to maximise economy-wide emissions reduction opportunities and secure economic activity in hard-to-abate sectors. The breadth of organisations (23) involved in Project Greensand demonstrates the interest and drivers for industry and the wide range of skills and expertise that is required to execute not only CCUS hubs but also progress towards broader low-emissions hub developments.

Realisation of the NT CCUS hub

Assuming the strategic facilitation option is adopted for the NT CCUS hub, then a logical approach to the sequencing of the CCUS infrastructure investment can be implemented. This approach could minimize government capital investment whilst providing significant risk reduction for industry. The approach described below is based on the findings from this study. However, this is only one of a number of different approaches that could be taken (see section 7 international policies). In this, possible NT CCUS hub development could be phased over time to scale with future CCS demand (Figure 46). This development model is predicated investment in other supporting infrastructure, including dredging of the MASDP port channel and the provision of sufficient renewable power and water.

Contract for Difference (CfD) mechanism implementation for CO₂ capture and low emissions products

The costs of CO₂ capture, conditioning and compression, if not embedded as part of their industrial processes, represent a significant cost to industries that could be established in the MASDP. The costs of construction and operation of capture facilities are significantly higher than current ACCU prices, thus providing little incentive for new industries to implement CO₂ capture. This lack of incentive will delay CO₂ supply into the NT CCUS hub, increasing supply risks and providing a disincentive for CO₂ transport and storage companies to invest in additional capacity. This risk can be partially mitigated through the use of a Contract for Difference (CfD) mechanism, which could provide price certainty to industries investing in CO₂ capture, conditioning and compression facilities from their initiation. One co-benefit of this approach would be that ACCUs, which these industries would otherwise purchase, will be available to support decarbonisation in other parts of the economy.

The CfD mechanism could also be extended to low emission products generated in the MASDP, mitigating price differentials between incumbent unabated products and low emissions products (as has been implemented for low-emissions ammonia in Japan). For the successful implementation of CfD mechanisms, in effect avoiding a simple subsidy to industry, there needs to be a clear trajectory for an increasing carbon price over time which would exceed the agreed strike price.

This mechanism if successfully implemented would enable a return to the government over the medium to long term to defray the upfront costs of the scheme.

Phase 1: NT CCUS hub infrastructure development

For the initial development of the NT CCUS hub infrastructure, targeting a potential capacity of 6 Mtpa of CO₂, a government funded equity infrastructure model is suggested.

In this model the government would invest in the 3 Mtpa foundational CCUS hub infrastructure for future industries within the MASDP. This would comprise the capital investment required for the installation of header pipelines and the development of the central compression facility to boost medium pressure CO₂ to high pressure dense phase CO₂ for export to the INPEX-Santos export pipelines. In addition to investment into the MASDP CCUS hub, it is suggested that phase 1 of the LCO₂ import terminal, with a capacity of 3 Mtpa, also be funded with equity capital. This will enable international CO₂ imports and diversify CO₂ supply risks to the down-stream transport and storage companies. It is unlikely that the NT CCUS hub and NT CCUS LCO₂ terminal will be fully utilised on completion. As such, the operating costs of the facilities will initially need to be underwritten by government whilst demand increases over time.

The advantages with the use of an equity model over granting is that the government could obtain a long-term return from the CCS assets. The ownership of the assets also enables participation of government withing the CCUS value chain to coordinate government and industry collaboration. The government investment in the facilities can also enable open access and transparent pricing for participants wishing to use the infrastructure (requirements enshrined in EU CCUS legislation).

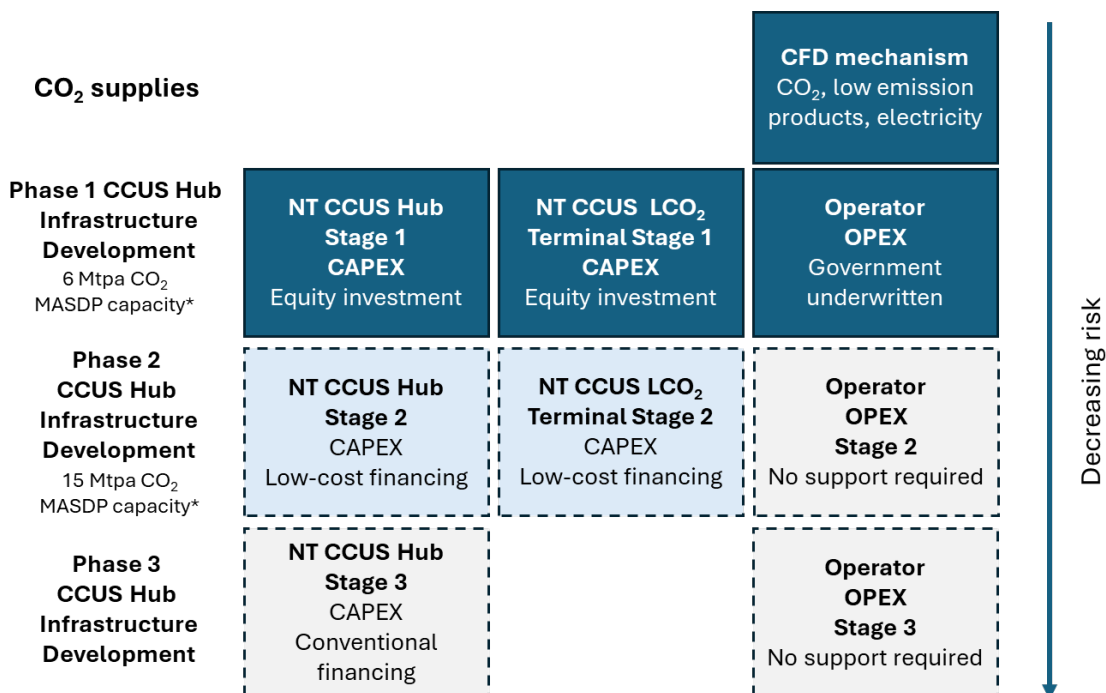


Figure 46: Phased development concept for the NT CCUS hub facilities

Phase 2: NT CCUS hub infrastructure development

Phase 2 delivery of the NT CCUS hub infrastructure would commence once there was sufficient demand for the Phase 1 infrastructure, either through the growth of MASDP industries and/or LCO₂ importation. In this phase low-cost government financing could be sought, as the successful

delivery of phase 1 of the NT CCUS hub and market activation would reduce investment risk. In this phase, as cashflow from the phase 1 of the NT CCUS hub infrastructure development is established, there may not be need for further underwriting of the operating costs of stage 2. If fully implemented this stage would increase the NT CCUS hub to a 15 Mtpa CO₂ capacity.

Phase 3: NT CCUS hub infrastructure development

A future phase 3 development of the NT CCUS hub infrastructure could be envisaged. However, by this stage the business model would be well established, and favourable market conditions allowing conventional financing for further hub development.

Mechanisms for NT CCUS hub delivery

Through this study a number of mechanisms have been identified that could be used in the establishment of the NT CCUS hub, whilst others would need to be developed to further support the hub delivery and expansion (Figure 47).

CfD mechanism implementation for CO₂ capture and low emissions products

It is expected that the deployment of CfD mechanisms would occur at the Commonwealth Government level, enabling their use by other industries within Australia as needed. At present, to CSIRO's knowledge, the necessary policy frameworks and structures to support implementation are not in place, requiring the development of new policy proposals. As outlined above, the administrative delivery of these schemes in other jurisdictions has typically been managed through government business enterprises to reduce risks and simplify engagement for proponents. Lessons from these jurisdictions are valuable in avoiding delays in implementing these mechanisms.

Phase 1: NT CCUS hub infrastructure development

In principle there are already fiscal policy mechanisms in place that could be used to provide equity to support the development of infrastructure, specifically through the Commonwealth Governments Infrastructure Investment Program or NAIF. The degree to which the NT CCUS hub infrastructure would fulfil funding conditions of these two funds would need to be explored further, particularly in context of uncertain short-term returns and the project risks. Such commonwealth funding typically requires co-investment from the state or territory where the funding will be spend (co-financing) and as such the Territory Government as well as the Commonwealth Government would hold equity in the NT CCUS hub. This arrangement may be preferable as any future returns (or losses) associated with the assets would be shared between the NT and Commonwealth. If the Infrastructure Investment Program or NAIF are not suitable, this would likely require a new policy proposal (NPP), which could include the development of a GBE (or inclusion of activities under an existing GBE) to be able to provide equity funding for the phase 1 development. Based on the concept level costing developed by the NT Government, phase 1 equity funding would be \$307 million for the CCUS hub infrastructure for future industries within the MASDP and \$479 million for the NT CCUS LCO₂ Terminal. The level of government investment

associated with underwriting these facilities' operating costs would need to be determined and detailed in final funding requests.

Phase 2: NT CCUS hub infrastructure development

For phase 2 of the development of the NT CCUS hub infrastructure development, assuming that the infrastructure is eligible under the NAIF, the concessional debt funding could be sought for this phase of development. Based on the concept level costing developed by the NT government the funding required for this phase of the would be \$260 million for the CCUS hub infrastructure for future industries within the MASDP and \$367 million for the NT CCUS LCO₂ Terminal.

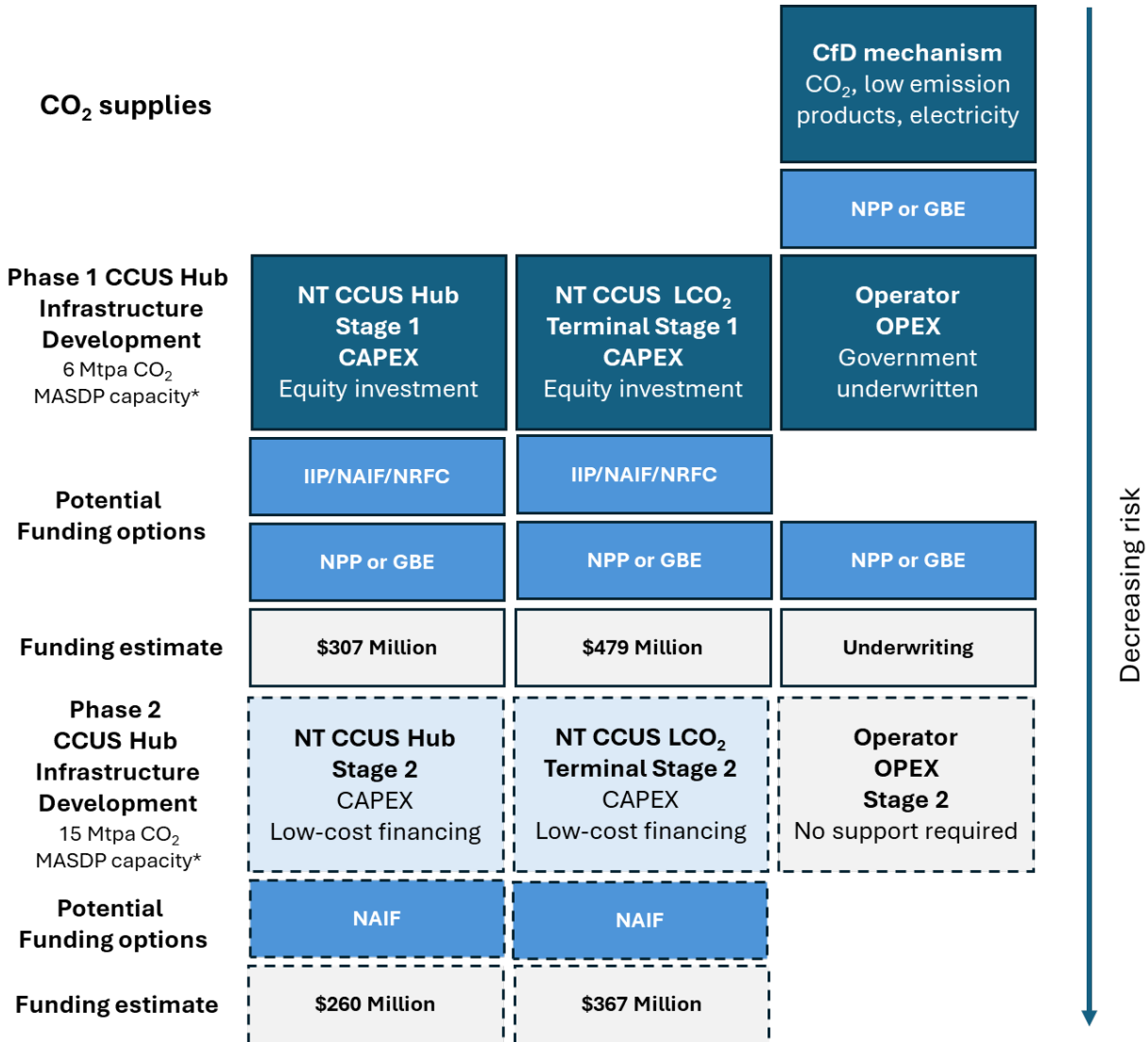


Figure 47: Phased NT CCUS hub delivery mechanisms and concept level costs

The model outlined above is designed to enable investment in industrial CO₂ capture, the CO₂ gathering and compression systems within the MASDP, and the MASDP liquid CO₂ importation terminal. CO₂ from this system will then be transferred into the CO₂ transport and offshore storage network.

Innovation in the NT CCUS hub

The presence of the CCUS and associated infrastructure in the Middle Arm could also provide opportunities for the research and technology development sector. This could be through demonstration of new utilisation, industrial and direct air capture technologies. The demonstration of these technologies may provide further opportunities for the demonstration of downstream technologies, such as the use of hydrogen generated from methane reforming for operational testing of gas turbines.

The ability to evaluate and deploy new technologies could reduce the cost of CO₂ capture and enhance demand for the MASDP hub. This, in turn, could strengthen the hub's role in supporting large-scale decarbonisation efforts and attract further investment. Investment in technology demonstration in the Middle Arm could reduce technical uncertainties associated with scaling up low-emissions industries (e.g. Methanol, SAF, see section 5). Critically the ability to undertake pilot and demonstration activities within the MASDP will help the local R&D community and build the local skills and expertise required for industries that will operate in the MASDP. This approach will enhance Australia's reputation as a 'destination jurisdiction' for research and development (see The role of innovation in CCUS box).

The role of innovation in CCUS

While not explicitly discussed in detail herein, Australia's investment in CCS, and decarbonisation technologies more broadly, over the last decades has allowed the country to maintain its global competitive edge and retain the skills required for the transition to a low-emissions economy.

This position is not guaranteed. Several jurisdictions globally have sought to attract skills, expertise and technology developers through generous incentives. For technology developers needing to scale up their investment and commercialise technologies, the lack of access to deep pools of capital (including venture capital) is a disincentive to them remaining in Australia. This has had the effect of not only having Australian technology developers move their operations to other jurisdictions but also the further development of skills and expertise occurs in these countries. Furthermore, multinational companies with operations in Australia are making investments in the deployment of CCUS technologies in other jurisdictions – as such, invaluable practical experience will be gained elsewhere and investments in Australia are being deferred.

It is for these reasons that CCS policies need to consider the role innovation serves in ensuring the development and retention of CCUS skills and expertise within Australia. Innovation does not just occur at low technology readiness levels; it is required across all technology levels and the value chain. This includes pilot and demonstration projects, through integration of new technologies into existing systems or at scale, or developing new ways of doing business. A vibrant CCUS R&D ecosystem is required to identify efficiencies and address problems as they arise. Current investment in capture and utilisation technologies is prudent as these technologies represent high-cost elements of the CCUS value chain. However, as CCUS becomes operationalised, new R&D opportunities will be identified throughout the CCUS value chain.

NT CCUS hub governance structures

Interviews held between CCUS hub proponents and CSIRO identified that collaboration enables coordination across the complex activities of design, development and deployment of low-emissions hubs and clusters irrespective of their geographical location (Stalker et al., 2024). If the mechanisms by which they are supported/derisked by government intervention preclude the ability to share knowledge and key learnings, then there are significant risks to their successful and timely deployment.

Any governance model/structure needs to ensure high levels of strategic coordination by increasing overall coordination, knowledge sharing, detailed planning and development, using existing infrastructure, identifying common user shared infrastructure, and developing longer term strategic benefits that future-proof investments in hub infrastructure.

CCUS hub business models are complex, and understanding the interplay of financial, regulatory, strategic, public and private roles and responsibilities is highly challenging. Mapping of cross-chain risk is a challenge in itself, as well as the array of government and industry perspectives and actions. Simplification should be sought where possible. There is the need for understanding each organisation's roles in managing risks, incentives and obligations when engaging with stakeholder, shareholder and community perspectives.

A clear understanding of roles and responsibilities is instrumental in advancing the progress of low-emissions hub development and deployment. Institutional knowledge (and detailed documentation of prior projects) can help map the history of past CCUS hub development and reduce the risk of reinventing the wheel looking forward.

Based on these insights there are a number of structures that could be used to deliver the NT CCUS hub and terminal infrastructure. Three are presented in Figure 48 and discussed below.

The structure shown in Figure 48A shows a model where direct government and lender funding in the form of concessional loans and equity is provided to a GBE entity whose role is to build and operate the NT CCUS hub and terminal infrastructure. This would be similar to other infrastructure GBEs that have been used elsewhere in Australia, for example such as Snowy Hydro Limited. The GBE could also have wider responsibilities for the development of the whole of the MASDP supporting infrastructure as well as the CCUS infrastructure. In this model, government funding would be required for the first phase of the NT CCUS hub and terminal infrastructure (see Figure 46 and Figure 47) and carries all of the risks associated with its development. Future phases of development could obtain concessional finance as risks are reduced (see Figure 46 and Figure 47). The incentivisation through CfD mechanisms of capture and low emission product development would need to either be through direct government funding or through an administrative body (discussed in models below). In addition to the GBE, there would also be a need to coordinate across the CCUS value chain, from capture industries, the operator of the NT CCUS hub and terminal, as well as the downstream transport and storage companies. One mechanism could be through the use of an unincorporated joint venture (see The coordinating UJV box below).

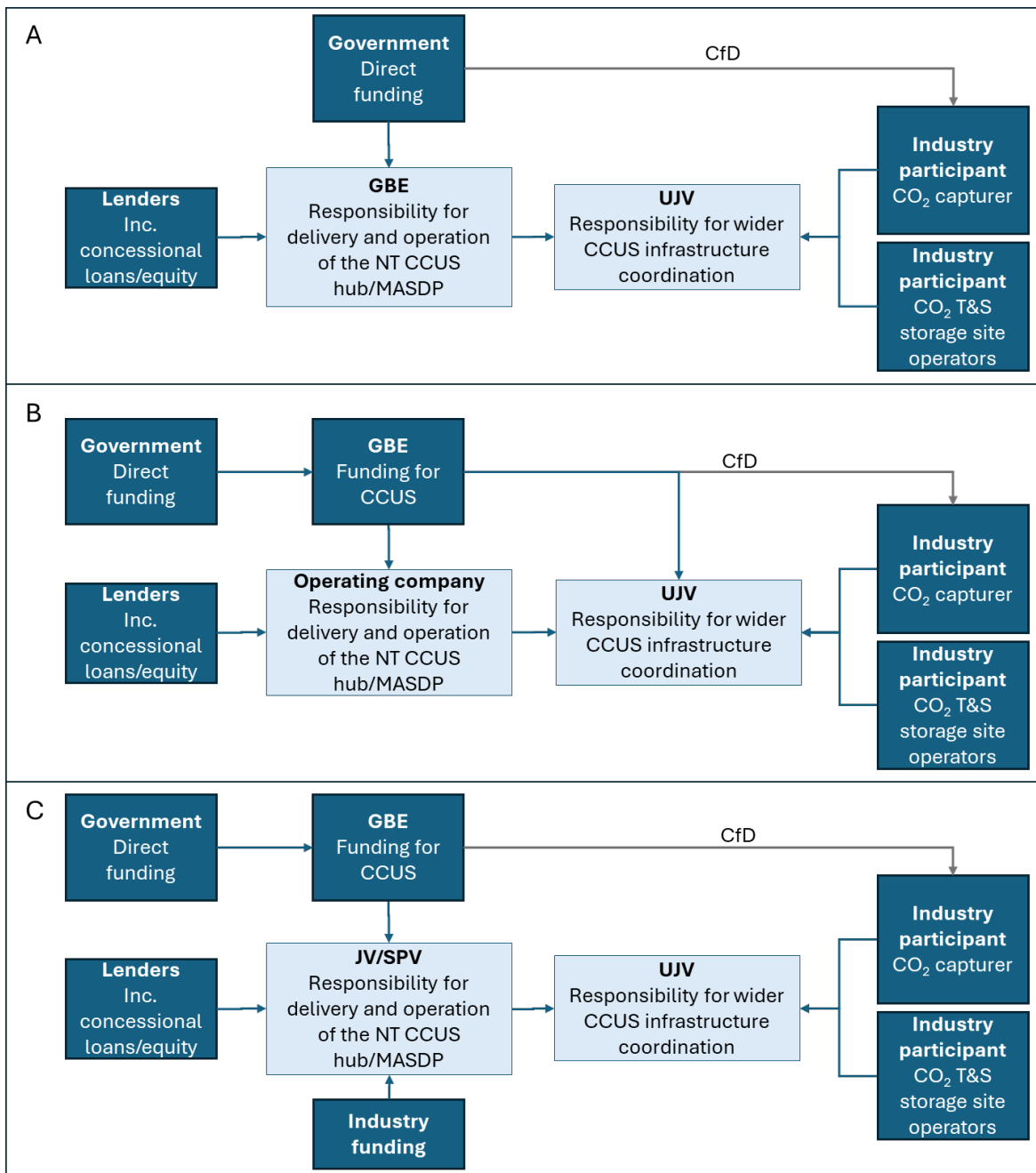


Figure 48: Illustrative management structures for NT CCUS hub and wider CCUS NT value chain

The coordinating UJV

UJV's are widely used in construction and infrastructure projects and large-scale ventures where parties want cooperation without long-term corporate commitments. The UJV (or similar) contractual arrangement will allow collaboration with a formalised structure where contributions are clearly identified.

The NT CCUS hub UJV could have responsibility for:

- CO₂ specification across the CCUS value chain
- Coordination of CO₂ supplies and strategic coordination and planning

- Supplier front door
- Knowledge sharing
- Assisting with CCUS hub contract development or acting as a contracting clearing house
- Coordination on stakeholder outreach

In the development of the UJV there would need to be clear roles and responsibilities and the contributions for the parties into its operation. It is anticipated that over time the UJV would evolve and the membership would change as industries in the MASDP develop.

A second potential structure is illustrated in Figure 48B. Under this model, a government business enterprise (GBE) could provide equity funding for the development and management of the NT CCUS hub and terminal infrastructure, as well as CfD funding for emitting industries and the production of low-emissions-intensity products. This GBE structure would be broadly similar to the Norwegian Gassnova model. In this model, a tender could be issued for the development and operation of the NT CCUS hub and import terminal. Construction and operation of the infrastructure would be undertaken by a company or a consortium with specialist expertise in developing and managing these types of assets. This operated asset model would be similar to that being undertaken in Singapore. Under this arrangement, government would retain ownership of the equity and risk associated with the first phase of the NT CCUS hub and import terminal development (see Figure 46 and Figure 47), while avoiding the need to build specialist delivery capability within the GBE. Operating companies would, however, expect a financial return to justify their involvement. Following completion of the initial phase the operating companies, in coordination with the GBE, could seek additional funding for subsequent phases of development.

As with the prior model there would still be the need for a coordinating body to coordinate activities across the whole of the NT CCS value chain (see The coordinating UJV box above).

A third potential structure is shown in Figure 48C. This structure would be the same as the prior structure with the exception that instead of an operating company the government GBE would invest in the Joint Venture (JV) or Special Purpose Vehicle (SPV) with industry. This approach is consistent with models adopted in several other jurisdictions. Its key advantage is that government risk can be mitigated through the provision of equity and the involvement of industry participants who bring specialist skills. At the same time, industry risk is reduced because participants have direct influence through their equity holdings in the development and future strategy of the NT CCUS hub and import terminal. As with the other models the JV/SPV could be extended to the whole of the MASDP development, however this could increase the complexity of the management of the SPV due to the disparate nature of the possible industry participants. It is assumed that a coordinating UJV would still be required for the CCUS value chain since not all CCUS values chain participants would be participants in the JV/SPV.

Not shown in Figure 48 is that the downstream transport and storage development activities are already being undertaken under JV structures and as such potential industrial participants are very familiar with operating within these structures.

There are other structures that could be employed in the delivery of the NT CCUS infrastructure and CSIRO has not undertaken a deep dive on the structures proposed above. However, these

models would require detailed investigation during FEED to determine the most efficient and effective structure that could be employed for the NT CCUS hub delivery.

Critical next steps

To progress the NT CCUS hub opportunity there are several actions that could be pursued in the near term. These activities could provide greater definition and certainty regarding the costs and feasibility of different components of the hub, strengthen collaboration, and support the development of policy. It is emphasised that these next steps should not be considered policy advice. They instead represent potential next steps that could assist in the further development of the NT CCUS hub opportunity.

Ongoing provision of advice by relevant stakeholders and the broader NT CCUS hub collaboration group

The expertise and knowledge developed through this project will allow those stakeholders with relevant expertise and the NT CCUS hub collaboration group to provide technical advice to the NT and Commonwealth governments in the development of fiscal and regulatory policy for CCUS.

Front End Engineering Design (FEED) for NT CCUS hub infrastructure

The design work for the CCUS hub infrastructure has only been undertaken at a concept and pre-FEED level by the Northern Territory Government. The logical next steps to reduce design and cost uncertainties would be to undertake detailed FEED. Without detailed FEED future final investment decisions cannot be taken. Whilst this could be deferred, this deferral compounds cross-chain risk and decisions (such as offshore storage project FID) may be taken without inclusion of the NT CCUS hub infrastructure due to the uncertainty associated with the design.

FEED on the LCO₂ importation terminal

As with the NT CCUS hub infrastructure the LCO₂ importation terminal design has only been considered at the concept and pre-FEED level by the Northern Territory Government. To reduce the design and cost uncertainty there is also a requirement for a detailed FEED to enable future funding decisions. As with the NT CCUS hub infrastructure, deferral of this activity could impact cross chain risk. Undertaking detailed FEED for the LCO₂ terminal would also send a strong signal to international jurisdictions on the desire for Australia to undertake transnational shipment of LCO₂. It is anticipated several proponents involved in the Middle Arm may already have some of this planning underway, as such collaboration on this activity could enable accelerated delivery of this activity.

Detailed investigation of sector coupling opportunities within the MASDP

The sector coupling research has identified potential pathways for an integrated development of low-emissions industries initially using methane as a feedstock but allowing the transition to electrolysis-derived hydrogen and CO₂ captured by DAC. A detailed study to investigate this concept may be warranted as it could provide a pathway to long term sustainability of the MASDP.

Lowering the cost of renewable power provision to the MASDP

The detailed investigation of the Northern Territory wind resources and alternative energy storage technologies are important requirements for reducing uncertainties and potential costs of firmed

renewable power in the Northern Territory. This understanding is crucial in the decarbonisation pathways of existing and new low-emissions industries in the Northern Territory.

Concept design for embedding pilot and R&D facilities within the MASDP

As discussed, there is the need to consider how R&D could integrate into the development of the MASDP, to both enable testing and derisking of technologies but also to develop the skills and expertise within the NT required for the energy transition and emissions reduction industries. To progress planning on this requirement would require the development of a high-level concept design for these facilities including the identification of the differentiated opportunities that these facilities would offer (versus those already available in Australia and globally). The design of these facilities would not only need to identify the infrastructure needs but also the skills required to support these facilities and therefore the tertiary education and training that could be provided locally.

UJV formation to ensure clear and effective communication between parties

The formation of the UJV could help ensure continued coordination across the various stakeholders involved in CCUS in the NT. While collaboration has occurred informally to date, partly through this project, there may be a clear need to formalise these arrangements through the establishment of the UJV. This would enable the definition of roles and responsibilities and provide a flexible framework that can adapt and expand as activities within the NT CCUS hub progress.

9 Conclusion

Addressing the dual challenges of global decarbonisation and energy transition requires development of the low emissions industrial hubs, of which a CCUS hub is one example, that not only help with the decarbonisation of today's industries but also provide the infrastructure required for the development of future low emissions industries. Understanding the long-term requirements of these hubs is critical in the understanding of the phasing of their development but also the levels of private and public investment required.

This business case project has explored the opportunities for the development of a Northern Territory Low emissions hub. Throughout the project, the MASDP balanced scenario developed by the Northern Territory Government has been used. This scenario anticipates the establishment of a diverse range of industries within the MASDP. While the actual composition of industries will vary, this scenario was adopted to maintain alignment with NTG precinct planning.

While the primary focus has been on CCUS infrastructure requirements, the project has also examined opportunities arising from sector coupling and renewable electrification. These measures will be essential to eliminate emissions from existing industries in the Darwin region and those that may be established in the future.

The project has demonstrated clear demand for CCUS from existing industries in the Darwin region, such as LNG. However, this demand could increase substantially over time, depending on the implementation of domestic and regional emissions reduction policies. The potential demand for low emissions products manufactured in the NT has also been shown to be substantial. However, due to their current production costs and policy uncertainty private industry may be unwilling to make the significant investments to establish these industries. The development of industries producing low-emissions products using CCUS infrastructure is constrained by the absence of a carbon price or a green premium that consumers are willing to pay to bridge the gap between the cost of unabated products and the higher production costs of low-emissions alternatives.

Throughout this project, it has been assumed that the cost of CO₂ emissions (an effective carbon price) will rise, both within Australia and across the region, driving future emissions reduction and the development of low-emissions industries in the NT. The underlying question is how pre-investment can secure low-cost CCS capacity and, when combined with other policy levers such as CfD mechanisms, accelerate the development of new low-emissions industries and achieve earlier emissions reductions—rather than deferring action until emissions costs alone incentivise private investment.

Within this business case, concept designs for the MASDP CCUS Infrastructure were obtained from the NT government. These have been used to identify the key components and costs of the CCUS infrastructure that would be additional to that associated with the existing LNG industries on the Middle Arm. This has allowed the identification of a phased development approach that could be used in the development of CCUS infrastructure that would reduce risks for industries seeking to utilise it and for the transport and storage companies wishing to invest in greater CO₂ storage capacities. A phased development of the wider MASDP industries would also help manage workforce availability and costs.

The initial phase of investment allows government the option to take equity in the developed infrastructure. Whilst government would take on the risks associated with this infrastructure development this comes with benefits such as potential future direct returns to the public, and the ability to be directly involved in the CCS value chain and help shape its direction. Once the CCUS hub infrastructure is developed and utilised it is assumed that future phases of development would be able to attract concessional loans or conventional financing as the business model will have been sufficiently derisked.

Critical to the success of any CCUS infrastructure is the availability of sufficient volumes of CO₂ to justify its development. A proportion of capture costs can be embedded as part of the process costs of an industry (e.g. hydrogen generation from methane) or are new costs to be borne by the industry (e.g. capture of emissions from cement manufacture), where these costs can be significant. Provision of price certainty for capture costs (or low-emissions product production) through a carefully designed CfD mechanism can incentivise early investment into capture facilities (or low-emissions industries) providing the volumes required for effective utilisation of the transport and storage infrastructure.

The mechanisms for the development of the NT CCUS hub infrastructure are important as there needs to be efficient construction and operation of the infrastructure, here the suggestion is made that a GBE could be used to administer government funding and that a JV or SPV could be used to construct and operate the CCUS hub and LCO₂ import infrastructure. The use of a JV or SPV could further reduce the levels of early phase government equity investment through the attraction of private sector finance/contributions. The governance structure also envisages the development of a UJV to provide a forum for coordination between all parties involved in the CCUS value chain, an important part of the reduction of cross-chain risks and uncertainties. Critical next steps have been identified, which are required to be able to progress the development of the Northern Territory CCUS hub, some of which may already have been partially addressed.

Overall, the business case concludes that the Northern Territory has the geological resources, industrial foundations and strategic location to support a major CCUS hub. Realising this potential could depend in part on the coordinated industrial development at MASDP, strong policy support, investment certainty, and the maturation of regional CO₂ shipping markets. With the right settings, the NT could become a significant regional centre for low-emissions industry and carbon management.

Delaying or deferring action is a decision

For the last 20 years there has been consensus that the cost of delaying action on climate change, and by inference, emissions reduction, outweighs the benefits. There are many publications that indicate that the cost of deep cuts in greenhouse gas emissions are a small percentage of future economic growth, and these impacts are frequently not incorporated in conventional economic modelling approaches.

With the diversification of emissions reduction technologies, their continuous improvement in energy efficiency and falling manufacturing costs (e.g. solar panel costs), there is a tendency to employ a wait-and-see approach to their deployment until such time as they become competitive with incumbent unabated technologies.

However, as has been noted in many publications and reviews (e.g. The Cost of Delaying Action to Stem Climate Change (United States Council of Economic Advisers, 2014) “if a policy delay leads to higher ultimate CO₂ [atmospheric] concentrations, that delay produces persistent economic damages that arise from higher temperatures and higher CO₂ concentrations. Alternatively, if a delayed policy still aims to hit a given climate target, such as limiting CO₂ concentration to a given level, then that delay means that the policy, when implemented, must be more stringent and thus more costly in subsequent years. In either case, delay is costly.”

The wait-and-see approach also results in a by-stander risk, where it is anticipated that new technology will arrive that is currently unavailable. This ignores the reality that new technologies typically take decades to move from the laboratory to commercial widespread deployment at scale. As such it is assumed today’s emissions reduction technologies will be used to meet 2050 emissions reductions goals.

Further without demonstration and deployment of these new technologies cost reductions will not be made (learning-by-doing). Limiting or delaying their long term commercial deployment.

Locking in emissions intensive industries and infrastructure during delay or deferral can result in a far more disruptive changes in industries that are high emitters in the future. The risk of sector obsolescence could leave both industry and government with unplanned decommissioning costs, and loss of jobs, skills and opportunities to pivot otherwise funded by these sectors closing down, causing economic and social disruption – and further costs to support some regions who had a monoculture of jobs in say, coal mining. In other words, there can be a significant cost of regret if the energy transition is not planned and orderly, again resulting in further costs incurred if there is a delay or deferral that is unplanned.

A study by Rogelj et al. (2013; Figure 49) draws together research and modelling in the technology and socio-economic uncertainties of low-carbon modelling scenarios and costs with those from the climate modelling community to further the understanding of the interplay of these factors on costs of climate mitigation through generation of many sensitivity models. Political choices – delaying mitigation - was found to have the greatest impact on the distribution of cost/risk. This was followed by geophysical uncertainties – where tipping points are ignored due to lack of understanding of how the physical climate system will respond with increasing emissions. Social factors such as future energy demand forecasts or population growth were the next main contributor, with technological uncertainties, in particular limited availability of mitigation options for deployment (such as CCS) had the least effect. Summarising the results, Hatfield-Dodds (2013) stated that the scenario comparisons of Rogelj et al. (2013) revealed that timing of global action was the uncertainty with the greatest effect on managing temperature rise above pre-industrial levels (see panels c & d below). The models showed that bringing forward global action from 2020 to 2015 would improve chance of limiting temperatures to below 2°C by 56-60%.

Calculations showed that by assuming a US\$60 per tonne CO₂ price for 2015 to reach that 60% target, a US\$150 per tonne CO₂ price target would be required if delaying till 2020 (Hatfield-Dodds, 2013; Rogelj et al., 2013). Delaying to 2025 would reduce the chance of remaining under 2°C to 34% - almost halving the chance of success.

The view of earlier work by Stern (2006) is now accepted that action to limit temperature rise to below 2°C would provide net benefits, and is a reversal of some early pushback of the Stern Review. In addition, Hatfield-Dodds (2013) stated that ‘ambitious global action to limit

emissions is fully consistent with strong economic growth and improvements in living standards Garnaut (2011). While these studies are now nearly 20 years old, their conclusions remain even more relevant now than when they were written.

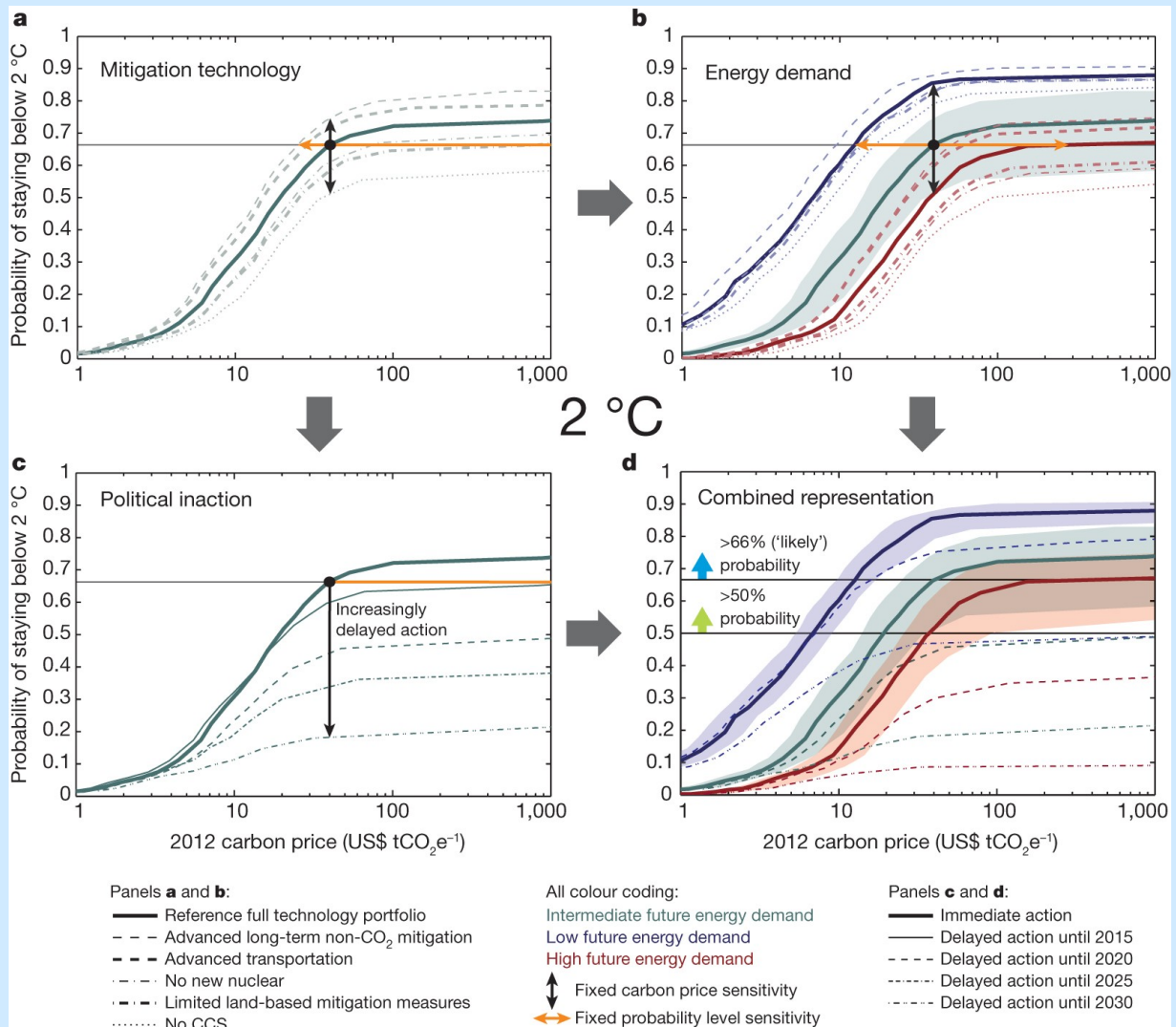


Figure 49. Cost distributions for six cases with varying future availability of specific mitigation technologies (a) and three sensitivity cases for future energy demand (b, thick solid lines). Shaded areas and dashed lines in b represent technology-sensitivity cases comparable to those shown in a. Shaded areas and dashed lines in d represent technology- and politics-sensitivity cases comparable to those in b and c, respectively. c, Impact of delayed global mitigation action. d, Overview figure combining all sensitivity cases. The horizontal line in a-c is the 66% line. From Rogelj et al. (2013).

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