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Investor Group on Climate Change

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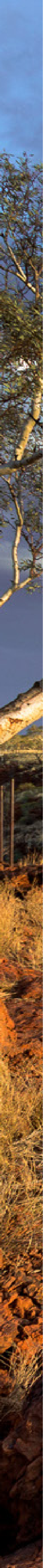
A changing climate for Australian gas

A 1.5°C scenario analysis of new Australian gas projects



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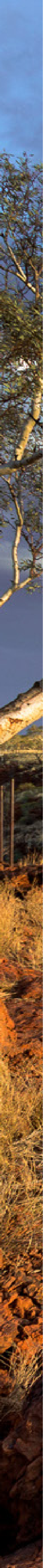

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About IGCC

The Investor Group on Climate Change (IGCC) is a collaboration of Australian and New Zealand institutional investors and advisors, managing over $3.7 trillion in assets under management and focusing on the impact that climate change has on the financial value of investments. IGCC aims to encourage government policies and investment practices that address the risks and opportunities of climate change.

About CA100+

Climate Action 100+ (CA100+) is an investor initiative to ensure the world's largest corporate greenhouse gas emitters take necessary action on climate change. More than 575 investors with more than $54 trillion USD in assets collectively under management are engaging companies on improving governance, curbing emissions and strengthening climate-related financial disclosures. The companies include 100 systemically important emitters, accounting for two-thirds of annual global industrial emissions, alongside more than 60 others with significant opportunity to drive the clean energy transition.

About Wood Mackenzie

Wood Mackenzie, a Verisk business, is a trusted source of commercial intelligence for the world's natural resources sector. For nearly 50 years, we have been providing quality data, analytics, and insights, establishing us as the global research and consultancy business powering the natural resources industry. We empower clients to make better strategic decisions, by arming them with objective analysis and advice on assets, companies, and markets. Our dedicated oil, gas abd LNG, power and renewables, chemicals, metals and mining sector teams are located around the world and deliver research and consulting projects based on our assessment and valuation of thousands of individual assets, companies, and economic indicators such as market supply, demand, and price trends. We partner with our customers to provide the analytics solutions they rely on to inspire their decision making and, ultimately, accelerate the world's transition to a more sustainable tomorrow.

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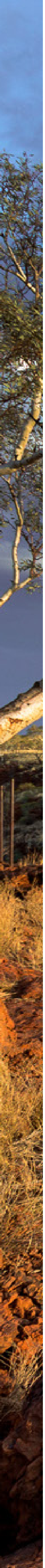
Disclaimer

The information presented in this report is not intended to imply any recommendation or opinion about a financial product, but to provide a general analysis of movements and trends within the Australian LNG industry.



1 EXECUTIVE SUMMARY

The role of gas in the transition to net-zero emissions by 2050 is highly uncertain and controversial. Accordingly, investors seek to better understand the impact of the changing energy landscape on Australian gas and liquified natural gas (LNG). This is particularly so for proposed new projects, which generally assume gas demand will remain steady or increase in the coming decades.

To test this assumption, the Investor Group on Climate Change (IGCC) commissioned Wood Mackenzie to assess the viability of a shortlist of proposed new or recently sanctioned Australian gas projects. The viability of the projects was tested against two energy transition scenarios aligned with limiting global warming to 1.5°C above pre-industrial global average temperatures. These scenarios were selected because of the current policy momentum towards this goal, the usefulness of the scenarios to 'stress test' company decision making and the relative rarity of lower temperature scenarios in company analysis.

The scenarios adopt the same 1.5°C-aligned carbon budget and apply different assumptions for factors such as the speed of uptake of renewables with long-duration storage, the commercialisation of carbon capture, use and storage (CCUS) and other emerging technologies, and policy and regulatory settings. The scenarios have been used to provide demand outlooks for Australian domestic gas and LNG exports to 2050 and to test whether proposed gas projects remain cash-flow positive under the assumed future conditions.

Key findings include:

All assessed projects record lower cash flow under both 1.5°C scenarios, particularly from the 2030s onwards and in the scenario that assumes accelerated uptake of renewables with storage.

Australia's net export of LNG declines slightly to 2030, then decreases sharply to less than 20% of current levels by 2050 under both scenarios as the cost of backfill projects makes Australian LNG uneconomical (see Figure 1.a).

Projected demand for domestic gas takes vastly different pathways under the two scenarios. Between 2020 and 2030, domestic gas demand increases slightly under the progressive uptake of renewables scenario and declines substantially under the accelerated uptake of renewables scenario: this outlook is dependent on how quickly long-duration energy storage for renewables is adopted (see Figure 1.b). By 2050, domestic gas demand declines to 87% of current levels in the progressive uptake scenario and 50% of current levels in the accelerated uptake scenario.

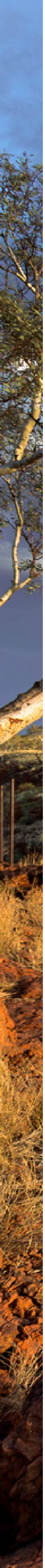


Figure 1.a.
Rate of decline for LNG supply (2020 - 2050)

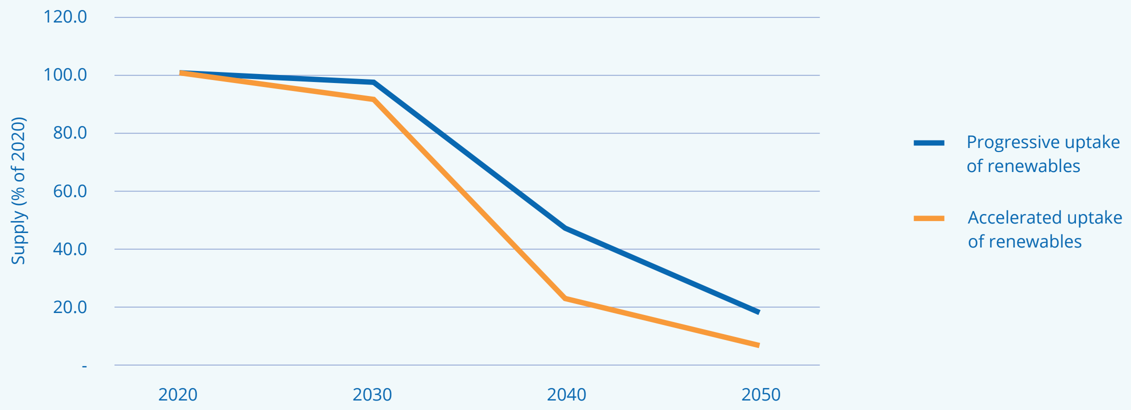


Figure 1.b.
Rate of decline for domestic gas demand (2020 - 2050)

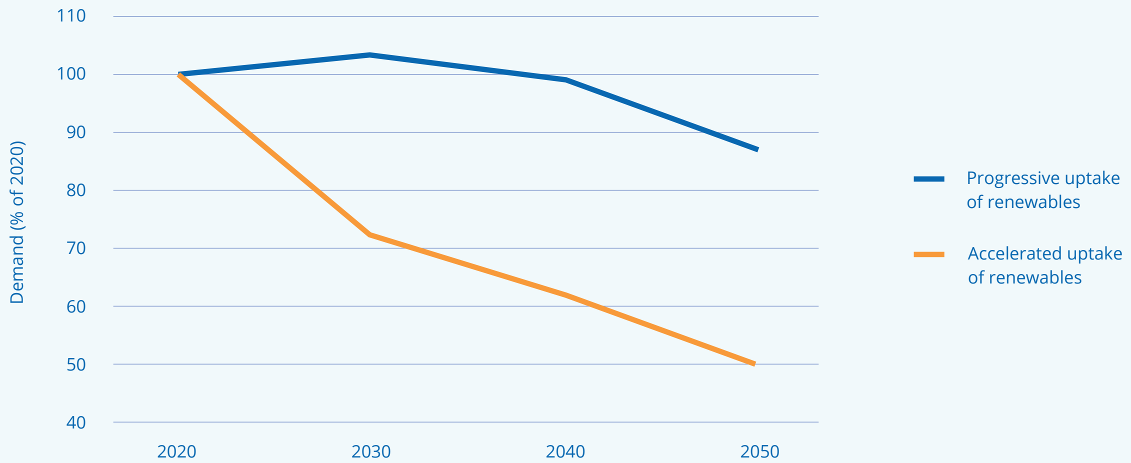


Figure 1. Projected future demand as a percentage of demand in 2020 (petajoules) for a) liquified natural gas (LNG) and b) domestic gas under accelerated and progressive uptake of renewables with storage under 1.5°C scenarios from 2020 to 2050. Modelling was undertaken at 10-year intervals by Wood Mackenzie.

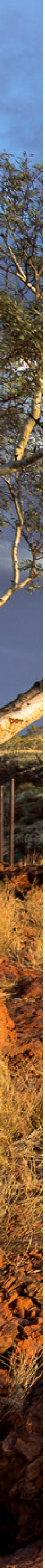
Other findings

Other results that are relevant to investors engaging with Australian oil and gas companies, either via individual engagements with companies or via collaborative initiatives like the Climate Action 100+ (CA100+), include:

- Rapid policy support for the renewable energy transition in Australia and key export markets will decrease the competitiveness of gas against other energy sources.
- Projects slated for export, or have higher production-related emissions, or are located in remote geographies and/or carry higher development costs have higher risk exposure.
- Projects that serve domestic markets, or have lower production-related emissions, or are geographically more connected and/or have lower development costs have lower risk exposure.
- The 2030s is a key decade for change in gas economics in both scenarios, meaning that projects with longer payback periods for up-front capital expenditure (CapEx) carry a higher stranded asset risk.
- The commercialisation of CCUS, yet to occur at scale, is key to the future of Australia's gas industry: with CCUS, there is an opportunity for oil and gas companies to participate in the production of blue hydrogen. However, the economics and favourability of green hydrogen are important considerations for investors.
- As the momentum to achieve global net-zero emissions increases, the focus on fossil fuels at a community level is likely to increase, exacerbating issues with social license to operate and the difficulty of securing approvals and support for new projects.

While this report focuses on the risks to Australian gas projects, there are also opportunities for Australian energy companies in the transition to net-zero emissions. The ability of oil and gas producers to successfully transform their business and tap into these opportunities is another important theme for investors. The dual importance of managing transition risk and opportunities highlights the need for gas companies to develop and implement business strategies today that will enable them to thrive in a carbon-constrained world.

This analysis was completed in late 2021, and since then, there have been significant geopolitical shifts linked to global oil and gas supply and demand. At present, it is unclear what the impact of the conflict between Russia and Ukraine will mean for gas supply and demand globally, including the impact on pricing, global sentiments about oil and gas use and domestic energy security concerns. The conflict may have a number of flow-on effects on pricing, supply and demand.



2 INTRODUCTION

This report assesses the risks associated with new Australian domestic gas and liquified natural gas (LNG) projects in the context of a global energy transition aligned with 1.5°C of warming. Such a transition must be characterised by rapid policy and technology developments that enable at least a 45% reduction of emissions by 2030 and economy-wide decarbonisation by 2050.[1] Limiting warming to 1.5°C above pre-industrial global average temperatures is the more ambitious of the two temperature targets included in the Paris Agreement. This report focuses on 1.5°C-aligned scenarios, given the increase in global policy signals indicating that 1.5°C is becoming the preferred emissions pathway.

As of November 2021, over **140 countries representing about 90% of global emissions** have committed to net-zero or carbon neutrality.[2] Similarly, the Glasgow Financial Alliance for Net Zero, which requires a net-zero by 2050 target for financed and portfolio emissions, **grew from 160 to over 450 global members** representing over US$130 trillion between April and November 2021.[3] Over **730 institutional investors**, coordinated by the Investor Agenda, signed a statement calling on governments to adopt 2030 and 2050 emission reduction targets consistent with 1.5°C of warming ahead of the 26th Conference of the Parties to the United Nations Framework Convention on Climate Change.[4] The Glasgow Climate Pact, adopted by all 192 nations that are signatory to the Paris Agreement, reaffirmed support for these goals.[5]

A rapid energy transition represents a risk to emissions-intensive companies, their investors, workers and affected communities if they fail to develop and implement robust climate transition plans as a matter of priority. To better understand these risks, the Investor Group on Climate Change (IGCC) commissioned Wood Mackenzie to develop two 1.5°C scenarios to test the impact that different technology developments might have on demand for Australian domestic gas and LNG between 2020 and 2050.

The scenarios assume the same national carbon budget of 3,521 metric tonnes of carbon dioxide equivalent (MtCO2e) but differ in assumptions about the pace of uptake for carbon capture, use and storage (CCUS) and renewables with long-duration storage. The scenarios that underpin this report are intended to provide a local supplement to more high-level scenarios, such as the International Energy Agency's Net Zero by 2050 Roadmap (IEA NZE),[6] which has provided fossil fuel demand data regionally.

While the scenarios that underpin this report have been developed to be as plausible as possible, the trajectory to net zero is dependent on many complex and interrelated factors. As such, these scenarios are intended to assess the effect of policy and market levers that may influence the pace of gas demand decline over the next 30 years, as opposed to providing deterministic forecasts.

The results of this analysis are intended to equip investors with the questions needed to better understand and manage transition risks faced by Australian gas companies.

3 BACKGROUND ON THE ROLE OF GAS IN THE ENERGY TRANSITION

Global risks to gas supply

The role of gas in the global energy transition is uncertain and contentious. Gas is a fossil fuel and emits significant amounts of greenhouse gases; however, as it is less emissions intensive than coal and oil, it has historically been promoted as a transition fuel. This narrative has been prominent in Australia, where the Federal Government is promoting new gas development as a driving mechanism for economic recovery from the COVID-19 pandemic.

However, the relative emissions advantage of gas is under question. For example, the full life cycle emissions profile of gas projects includes fugitive methane emissions, which are estimated to be 80 times more potent at warming than CO2 over a 20-year period[10]. Different gas projects have different life cycle emission portfolios: for example, LNG has a more energy-intensive production process than domestically piped gas.

The emissions liability faced by gas producers is further impacted by growing pressure on fossil fuel producers to mitigate the emissions of their customers (Scope 3) alongside their direct emissions (Scopes 1 and 2). According to the IEA, only 25% of emissions from gas are associated with production, processing and transportation, so a substantial risk is posed by changing customer appetite for the gas industry's downstream emissions.[11]

Australia, Qatar and the United States are currently the largest LNG exporters worldwide. The IEA NZE scenario suggests that LNG exports are likely to become more concentrated among the lowest cost producers by 2050, with the largest share produced in the Middle East, and that Australian LNG exports could peak and begin to decline before 2030 (see Figure 2).[12] A recent analysis by the Institute for Energy Economics and Financial Analysis highlights the specific competitive risk that expanded gas production in Qatar poses to Australian LNG exports.[13]

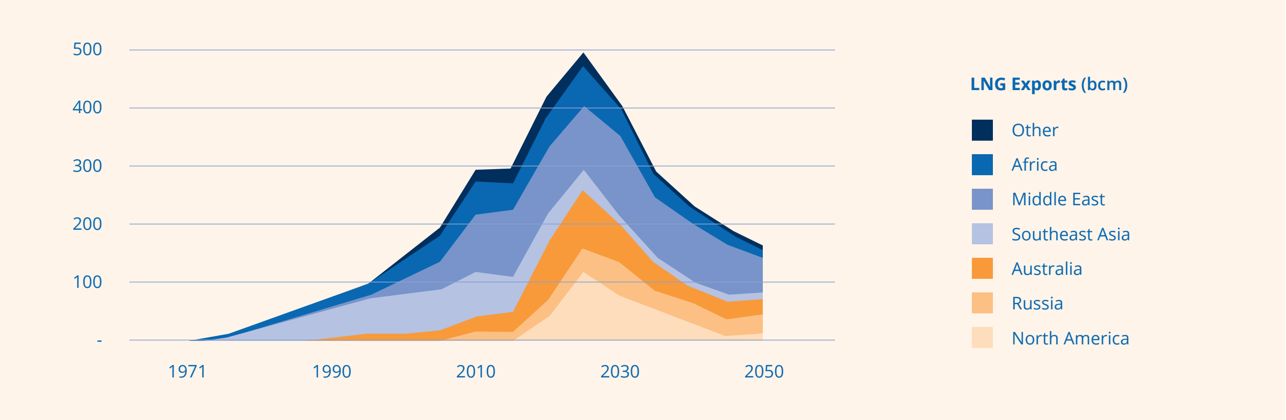
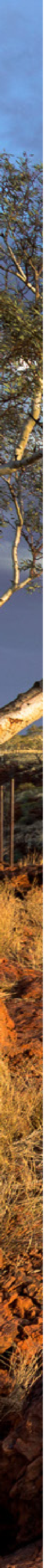


Figure 2. Global liquified natural gas (LNG) exports by region between 1971 and 2050 indicated in billion cubic metres (bcm). Source: IEA (2021) 'Net Zero by 2050: A roadmap for the global energy sector', p. 75. All rights reserved.

Cost competitiveness is not the only driver of energy demand: climate policy, including carbon prices and sanctions, also impacts the use of a particular fuel. For example, Australia's three largest importers of LNG—China, Japan and South Korea—have set net-zero emission reduction targets underpinned by domestic energy transition policies. On the supply side, social and environmental concerns, such as opposition from Traditional Owners or gas extraction that threatens biodiversity, may also significantly impact project approvals. For some investors, including superannuation funds, there is also growing pressure from members to divest from high-emitting companies.



Australian gas today

In Australia, gas meets 21% of total energy demand and is predominantly used for power (31%), industry (39%), residential, commercial, and agricultural sectors (19%), and gas operations (11%). Domestic gas demand declined between 2014 and 2020, driven primarily by the increase in variable renewable energy (VRE) and distributed solar power.[7]

The Australian Energy Market Operator (AEMO) has predicted that the growth of VRE will continue to displace gas from the national energy market, though gas will maintain a critical role in the peaking market over the next decade. Even so, AEMO has emphasised that future demand for gas in Australia is highly susceptible to policy and technology developments, and gas may be displaced faster than currently expected.[8]

Significantly, 74% of Australian gas is exported as LNG, primarily to Asian markets.[9]

Engaging with complexity

The combination of these factors demonstrates the complexity of modelling domestic gas and LNG supply and demand into the future. It is dependent on the decarbonisation of multiple sectors across different countries, which, in turn, depends on technological and policy developments.

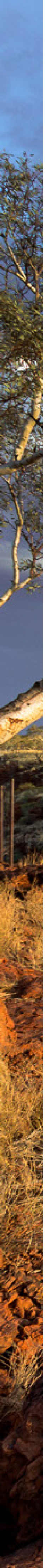
For example, while gas may continue to play a firming role in the electricity grid to complement VRE, pumped hydropower and big batteries are already competing for this role and could displace gas faster than currently expected. Similarly, the pace of uptake of renewables continues to increase, including recently announced projects in offshore wind in Victoria and several new ‘big battery’ projects recently approved or under consideration. The uncertainty surrounding the change in demand makes new gas projects a complex engagement topic for investors. For companies, there will be a balancing act to ensure enough gas supply to firm renewables where needed, especially as coal-fired power stations are retired, and not too much that it risks stranded assets, locking in unnecessary emissions and/or crowding out investment in renewables with storage.

Australian investors have been engaging with gas companies on these issues, both directly and through collaborative initiatives like CA100+. While all Australian CA100+ gas companies have set net-zero targets for Scope 1 and 2 emissions by 2050 or earlier, insufficient attention has been given to Scope 3 emissions. Given the materiality of Scope 3 emissions in the gas sector, investors are calling for increasingly sophisticated decarbonisation strategies and capital allocation plans that align with decreasing demand for gas under a 1.5°C trajectory.

Together, these factors indicate a need for gas companies to explore new low-carbon business opportunities as a matter of priority. Diversifying away from fossil fuel products will strengthen their portfolios and deliver long-term shareholder value while supporting the transition to a net-zero emissions economy.

Investor expectations of oil and gas companies

More information on investor expectations of gas companies is included in the CA100+ Net-Zero Company Benchmark[14] and the Institutional Investors Group on Climate Change Oil and Gas Standard.[15] The Science-based Targets Initiative (SBTi) is developing a methodology for Oil and Gas, which will also provide details on transition pathways for oil and gas companies. At the time of publishing, SBTi has suspended acceptance of commitments from fossil fuel producers.[16]



4 METHODOLOGY

Scenarios

Wood Mackenzie developed two bespoke 1.5°C scenarios to test the impact that various policy and technological levers would have on demand for Australian gas.

The selection of two 1.5°C scenarios rather than scenarios with higher temperature outcomes reflects the:

- clear preference for the 1.5°C outcome in global policy discussions
- usefulness of these scenarios to 'stress test' company decision making
- relative rarity of 1.5°C scenarios in company level scenario analysis.

One scenario is based on the Wood Mackenzie Accelerated Energy Transition 1.5°C Scenario (WM1.5) ('Progressive uptake of renewables') and the other on the IEA NZE ('Accelerated uptake of renewables'). Although these high-level scenarios provided context and key policy and technology developments that might drive gas demand, Wood Mackenzie developed additional country-level supply and demand projections for the IGCC.

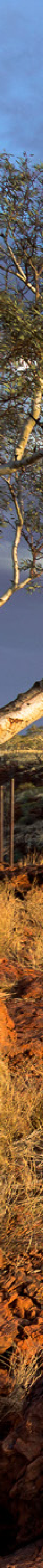
Table 1 summarises the assumptions within the scenarios that underpin this report. To demonstrate the impact of these policy and technology levers, orange shading in the table indicates that the lever generally accelerates the pace of gas demand decline, whereas blue shading indicates a slower impact.

Table 1. Overview of 1.5°C scenarios, including policy and technology developments.

	Progressive uptake of renewables	Accelerated uptake of renewables
Characteristics		
High-level scenario	WM1.5	IEA NZE
National emissions budget	3,521 MtCO2-e: aligned with limiting warming to 1.5°C	
Carbon sequestration	Land-use change and forestry: 162MtCO2e in 2050 Direct air capture (DAC): 174 MtCO2e in 2050	
Levers and impact on gas demand		
Policy commitment	Incremental policy approach.	Ambitious policy agenda to achieve rapid decarbonisation across all sectors.
Electrification	Electrification grows incrementally, and gas maintains its firming role in the electricity grid.	Electrification rapidly scales, with high renewable energy plus storage penetration across all sectors.
Hydrogen	Blue and green hydrogen become commercial post-2030, following substantial investment this decade, and Australia is a key global exporter by 2050.	Hydrogen becomes commercial post-2030, following substantial investment this decade, with a higher proportion and quantity of blue hydrogen driven by earlier commercialisation of CCUS.
CCUS	CCUS scales rapidly post-2030 and must absorb a greater quantity of emissions to meet the 1.5°C carbon budget in this scenario.	CCUS is commercialised slightly earlier than in the progressive scenario, enabling higher production of blue hydrogen in the medium term. Demand for CCUS is lower in this scenario by 2050.
Renewables and storage	Renewables make up more than 90% of the power mix by 2040, enabled by the uptake of long-duration grid storage. Gas is used where renewables with storage face cost and physical constraints.	Renewables have a higher take-up rate due to faster commercialisation in long-duration storage.
High-level outcomes and limitations		
Modelled outcomes regarding the role of domestic gas	Domestic gas maintains a firming role in the national electricity market to 2050.	Policy settings enable faster uptake of renewables with long duration storage, which immediately begins to displace gas in power and industrial sectors.
Modelled outcomes regarding the role of domestic LNG	Australian LNG exports remains cost competitive globally until reserves deplete in the 2040s.	Australian LNG production enters decline as existing commercial contracts expire this decade. Backfill projects are not developed due to low commerciality
Potential limitations to assumptions	Increased demand for domestic gas in the medium term depends on CCUS and blue hydrogen overcoming substantial technical and economic challenges.	Faster pace of decarbonisation across all sectors, especially industry and power, is dependent on the immediate introduction of a sufficiently high carbon price.

Slower impact on the pace of gas demand decline (light blue)

Accelerates the pace of gas demand decline (orange)



Projects

To investigate key attributes that determine the competitiveness of Australian LNG and domestic gas, eight pre–final investment decisions (FIDs) or recently sanctioned gas projects were selected for analysis (see Table 2 for an overview). These projects were selected for analysis because of their size, proposed timing and the opportunity for investors to engage with the FID or early development process based on the findings of this report.

Cash-flow analysis was undertaken at different points in time to determine whether the projects' ongoing operations would be able to compete in the future market conditions of the two scenarios. The cash-flow analysis stress tests assets under lower price outcomes to see if they still generate positive cash flow over an extended period. This approach was taken, rather than a full life cycle assessment that would determine whether the project would make an acceptable return on investment, given that some of the assessed projects are onstream and CapEx is essentially a sunk cost.

This report does not publish project-specific projections; however, aggregated analysis is included in the report findings.

Table 2. Overview of the eight pre-FID and recent-FID Australian gas projects selected for cashflow analysis under the two 1.5°C scenarios. Source: Wood Mackenzie.

Company	Project (type)	Remaining reserves (bcfe)	Production timeline	CapEx (US$/ mcfe)	OpEx (US$/ mcfe)	Intended market
Origin	**Beetaloo** (greenfield)	10,370	Start: 2029 End: 2057	0.7	0.3	Domestic gas
	Ironbark (APLNG backfill)	121	Start: 2029 End: 2043	1.0	0.3	LNG (APAC) & domestic gas
OilSearch	**Muruk** (PNG LNG backfill)	6,636	Start: 2032 End: 2054	0.4	0.2	LNG (APAC)
	Elk/Antelope (greenfield)	7,074	Start: 2027 End: 2054	1.0	0.2	LNG (APAC)
Santos	**Barossa** (Darwin LNG backfill)	4,452	Start: 2027 End: 2054	0.8	1.0	LNG (APAC)
	Narrabri (greenfield)	480	Start: 2014 End: 2051	1.6	0.2	Domestic gas
Woodside	**Scarborough** (LNG backfill)	11,057	Start: 2026 End: 2053	0.5	0.9	LNG (APAC) & domestic gas
	Browse (NWS LNG backfill)	16,723	Start: 2029 End: 2056	0.7	0.6	LNG (APAC) & domestic gas

5 REPORT FINDINGS

LNG supply

The key findings for LNG supply are outlined below and in Figures 3 and 4. The scenarios focus on projected demand from Asia, including China, Japan, South Korea, Taiwan, Indonesia, Malaysia, the Philippines, Singapore, Thailand, Vietnam and India, and the implications for LNG supply from Australia.

Comparison of the scenarios in Table 3 shows that reserve depletion and low gas backfill commerciality will affect LNG supply in both scenarios in the medium to long term, while a change in government policy across the Asia–Pacific region (APAC) also has the potential to reduce LNG exports in the near term. Analysis of backfill projects finds that many of the proposed projects are high-cost and often located in remote areas.

Table 3. Overview of impacts on LNG demand under the two 1.5°C scenarios.

Both scenarios	Overall	Australian LNG production is expected to retain its current market share in the near term due to existing contracts. However, post-2030, these contracts will expire, and Australia's LNG market share will decrease.
	Green hydrogen	Australia is expected to develop a green hydrogen export economy, which will divert industry investment and development focus to new green hydrogen export capabilities over LNG.
Progressive uptake of renewables scenario	APAC LNG demand	Demand increases by 27% to 2040 and then decreases to 12% above 2020 levels, comprising 14% of the region's energy mix by 2050.
	Share of AU LNG in regional imports	Australia's LNG market share falls from 29% in 2020 to 5% by 2050 due to the combined effects of reserve depletion and low gas backfill commerciality and increased competition from other low-cost producers. This analysis is based on firm and announced reserves.
Accelerated uptake of renewables scenario	APAC LNG demand	Demand is forecast to grow by 19% this decade but faces strong competition from renewables post-2030. This competition leads to a much-reduced role for gas by 2050, comprising a market share of only 6% of the energy mix. The demand reduction is led by investment in renewables and long-duration storage, coupled with additional government enforcement and taxation to minimise carbon emissions.
	Share of AU LNG in regional imports	Demand for Australian LNG is expected to fall due to the low commerciality of backfill projects and a quicker industry shift towards alternative low carbon in the long term. By 2050, Australia is forecast to have minimal, if any, LNG exports. There is no demand for new projects under this scenario, aligning with IEA NZE.

Explaining the commerciality of gas backfill projects

New LNG projects have a high, up-front cost of development and are less economically competitive than existing projects that have relatively lower operating expenditure (OpEx). However, a key consideration for the forward-looking analysis of gas project viability is the commerciality of backfill projects.

Generally, the initial investment in an LNG project will support approximately 20 years of production. As these reserves deplete, new gas fields must be developed to backfill production and enable the plant to continue supplying LNG. Therefore, a decision to extend production from an existing LNG plant depends on the cost and commerciality of developing the backfill reserve and the cost of refurbishing key project infrastructure (e.g., turbines).

Analysis conducted by Wood Mackenzie under two 1.5°C scenarios shows that the additional costs associated with backfill projects will likely undermine the economic competitiveness of Australian LNG exports from the mid-2030s.

Figure 3.a.
Supply of Australian LNG with progressive uptake of renewables plus storage

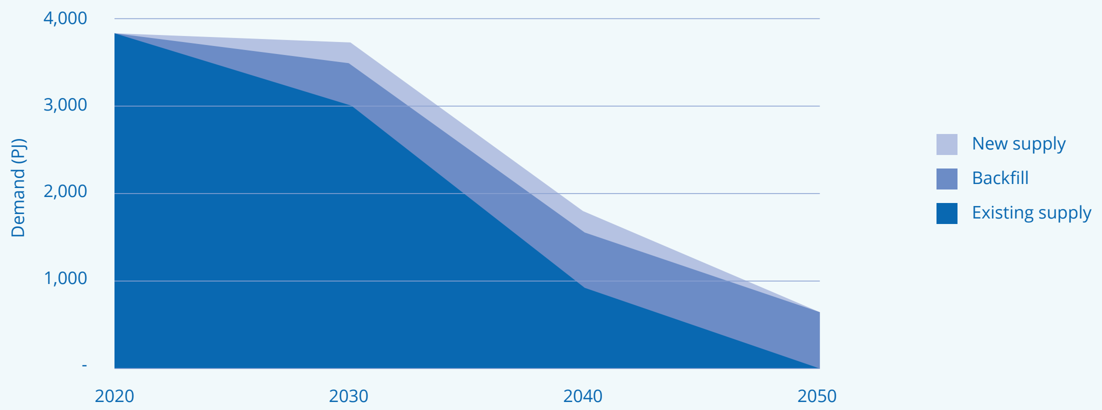


Figure 3.b.
Supply of Australian LNG with accelerated uptake of renewables plus storage

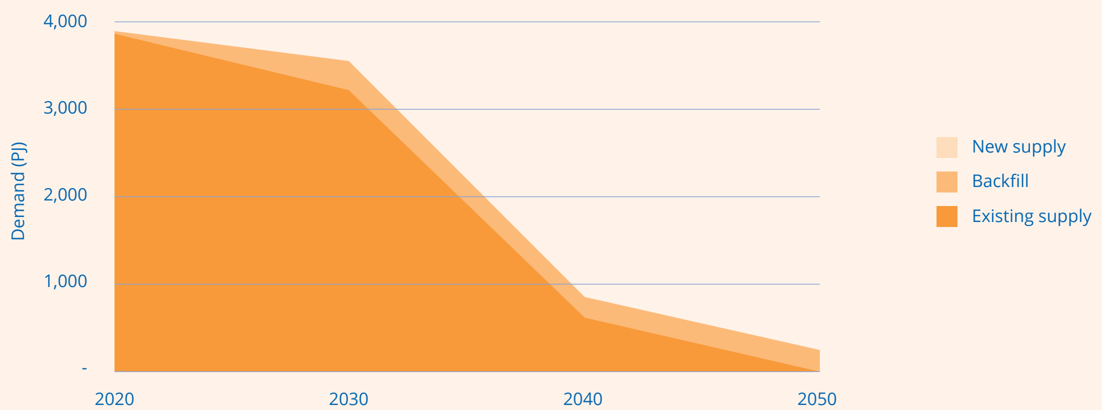


Figure 3. Australian liquified natural gas (LNG) supply scenarios under a) progressive uptake and b) accelerated uptake of renewables scenarios for existing, backfill and new projects from 2020 to 2050. Supply is indicated in petajoules (PJ). Modelling was undertaken at 10-year intervals by Wood Mackenzie.

Figure 4.
Comparison of Australian LNG exports under three 1.5°C scenarios

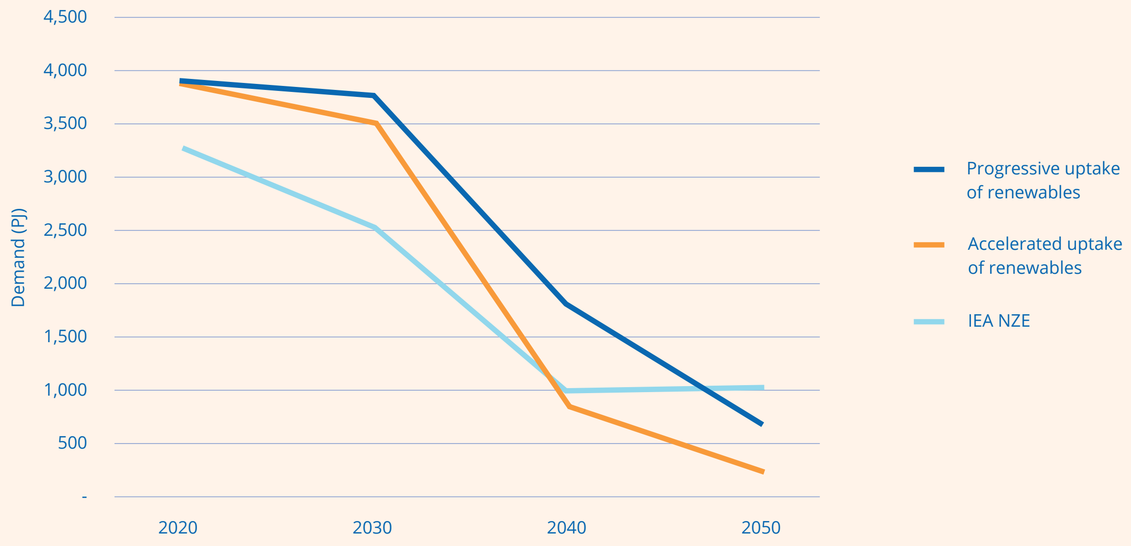
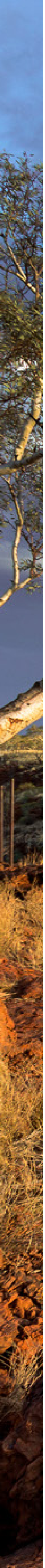


Figure 4. Australian liquified natural gas (LNG) exports under progressive uptake of renewables, accelerated uptake of renewables and IEA NZE scenarios between 2020 and 2050. Exports are indicated in petajoules (PJ). Accelerated uptake and progressive uptake scenario modelling were undertaken at 10-year intervals by Wood Mackenzie. IEA NZE scenario data are from IEA (2021) 'Net zero by 2050: A roadmap for the global energy sector'.



Domestic gas demand

The key findings for domestic gas demand are outlined in Table 4 and Figures 5 and 6. Comparison of the scenarios shows that technological developments, particularly the speed of commercialisation of CCUS and batteries, are important in determining when, and how significantly, gas will be displaced in each sector.

Table 4. Overview of impacts on domestic gas demand under the two 1.5°C scenarios.

Both scenarios	Overall	Gas demand reduces from current levels across all sectors to 2050, except for blue hydrogen. However, blue hydrogen's competitiveness is highly dependent on the commercialisation of CCUS in the near to medium term and may be threatened by green hydrogen if it commercialises faster over the time frame.
	Power	Demand reduces from 2020 under both scenarios as gas is displaced by renewables with long-duration storage.
Progressive uptake of renewables scenario	Overall	Domestic gas demand increases by 3% to 2030 and then decreases steadily. By 2050, gas comprises 12% of the energy mix, compared to 21% today.
	Power	Gas demand for firming capacity in the grid decreases by 15% between 2020 and 2030 as it is displaced by lower-cost renewables and storage.
	Industry and residential, commercial and agriculture	Gas demand marginally increases by 0.5% to 2030; however, post-2040, gas may be displaced due to new commercial technologies and old process retirements. By 2050, demand decreases by 36%.
	Blue hydrogen	Gas demand increases by 15% from today to 2050. Demand is lower than in the accelerated uptake scenario due to the relative delay in the commercialisation of CCUS.
	Carbon capture (Figure 7)	CCUS takes slightly longer to be commercialised in the progressive uptake scenario; however, by 2050, more emissions are being captured than in the accelerated uptake scenario (40 compared to 28 $MtCO_2e$).
Accelerated uptake of renewables scenario	Overall	Gas comprises 21% of Australia's energy mix today: in the accelerated uptake scenario, gas immediately decreases to 17% of the mix in 2030 and 7% by 2050. Renewables are expected to scale much more quickly as grid infrastructure constraints are met, battery commercialises earlier, and greater government incentives are implemented.
	Power	Demand decreases by 44% between 2020 and 2030, as it is replaced by lower-cost renewables. Gas has a diminishing role in grid stability and firming in the medium term.
	Industry and residential, commercial and agriculture	Demand decreases by 20% between 2020 and 2030 and decreases by a further 53% to 2050 due to new commercial technologies and old process retirements.
	Blue hydrogen	Demand increases by 29% between 2020 and 2050. Demand is higher than in the progressive uptake scenario because earlier commercialisation of CCUS enables earlier and ongoing production of blue hydrogen.
	Carbon capture (Figure 7)	CCUS is commercialised sooner in this scenario, but by 2050 fewer emissions are being captured than in the progressive uptake scenario (28 $MtCO_2e$).

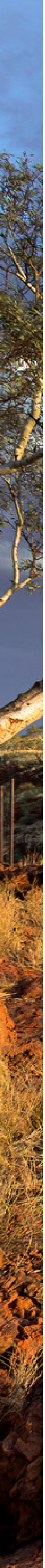
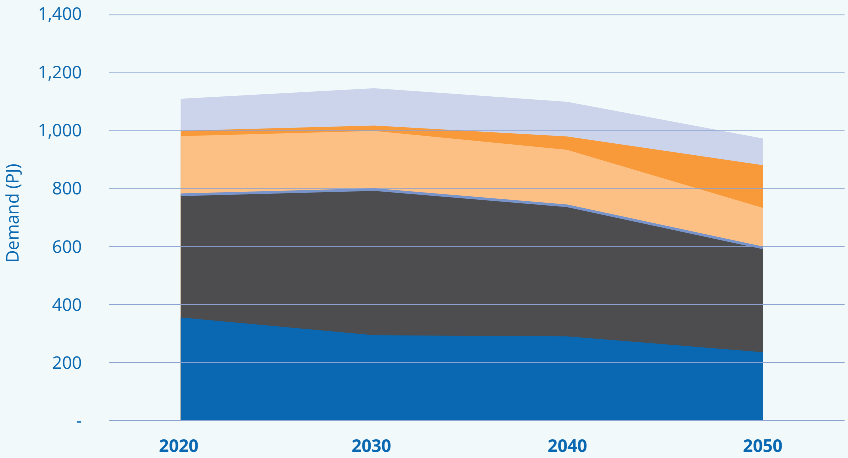
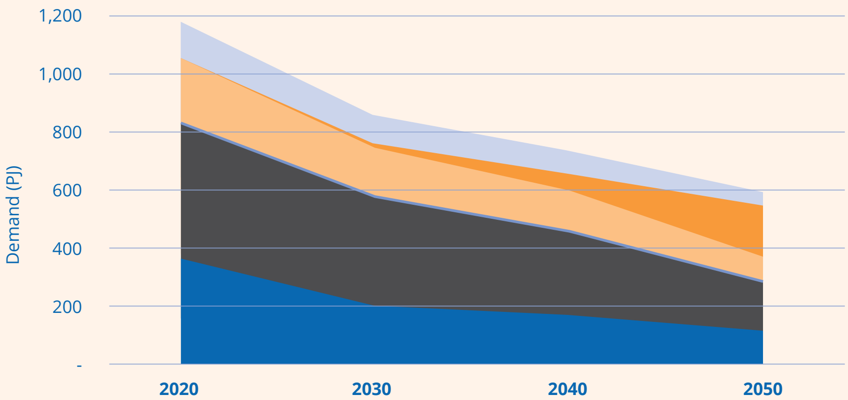


Figure 5.a.
Demand for Australian domestic gas with progressive uptake of renewables with storage



	2020	2030	2040	2050
Losses	117	129	116	89
Blue hydrogen	-	11	53	144
Residential, commerical & agriculture	209	210	185	133
Transport	4	3	3	3
Industry	435	501	458	359
Power	346	293	287	242

Figure 5.b.
Demand for Australian domestic gas with accelerated uptake of renewables with storage



	2020	2030	2040	2050
Losses	117	91	71	44
Blue hydrogen	-	12	60	161
Residential, commerical & agriculture	209	167	133	84
Transport	4	3	3	3
Industry	435	335	255	157
Power	346	194	166	104

Figure 5. Australian domestic gas demand under a) progressive and b) accelerated uptake of renewables scenarios from 2020 to 2050. Demand is indicated in petajoules (PJ). Modelling was undertaken at 10-year intervals by Wood Mackenzie.

Figure 6.a. Comparative demand for domestic gas in the power sector

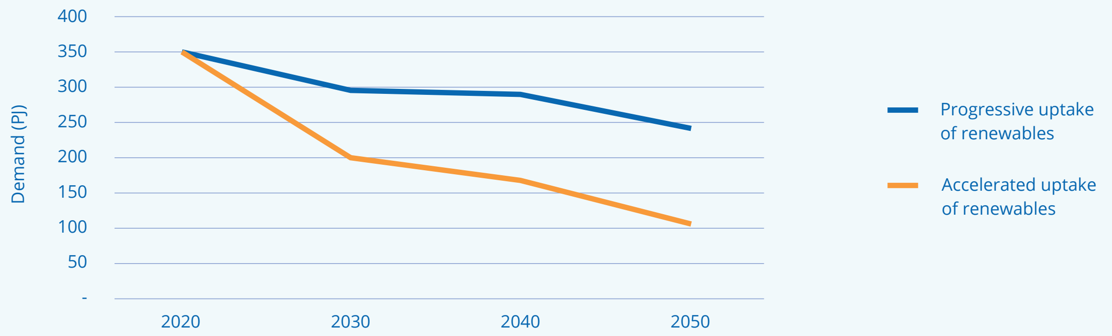


Figure 6.b. Comparative demand for domestic gas in the industrial sector

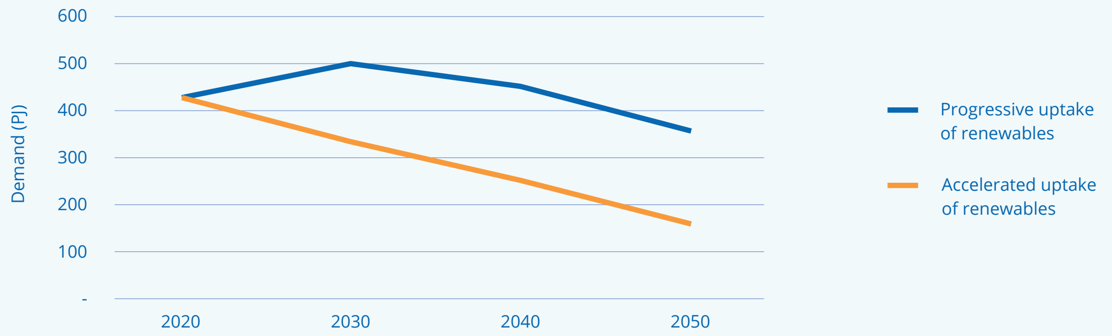


Figure 6.c.
Comparative demand for domestic gas in the residential, commercial and agricultural sectors

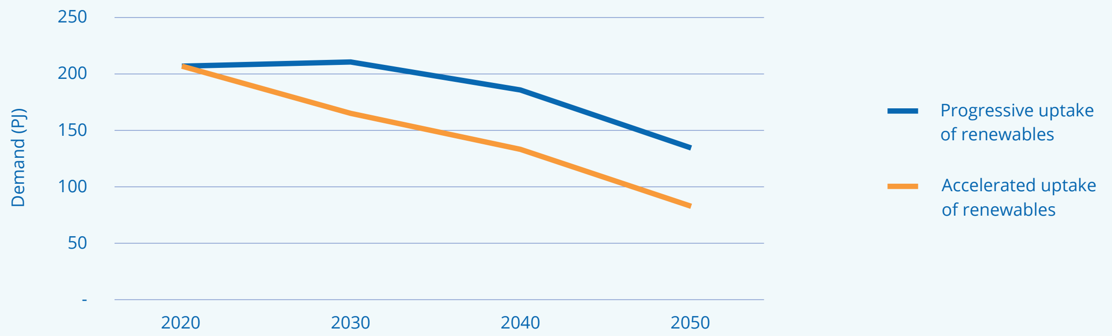


Figure 6.d. Comparative demand for domestic gas for blue hydrogen

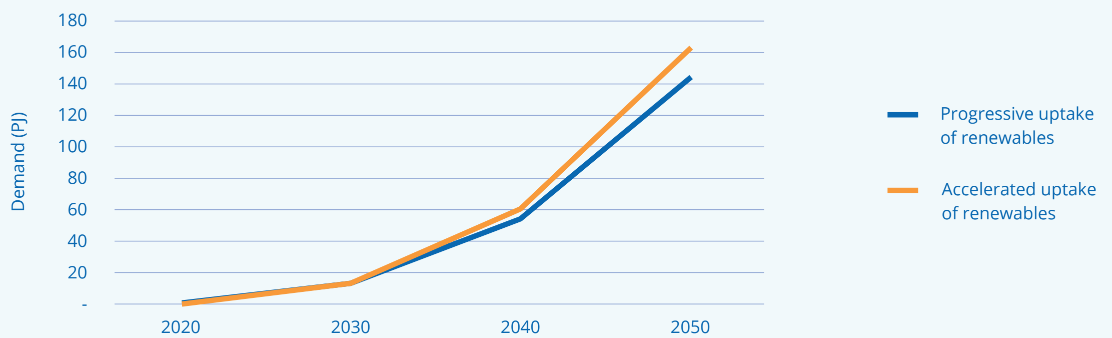


Figure 6. Domestic gas demand under progressive and accelerated uptake of renewables scenarios between 2020 and 2050 for a) power sector, b) industry, c) residential, commercial and agricultural sectors and d) blue hydrogen. Demand is indicated in petajoules (PJ). Modelling was undertaken at 10-year intervals by Wood Mackenzie.

Figure 7.
Comparative emissions absorbed by CCUS under two 1.5°C scenarios

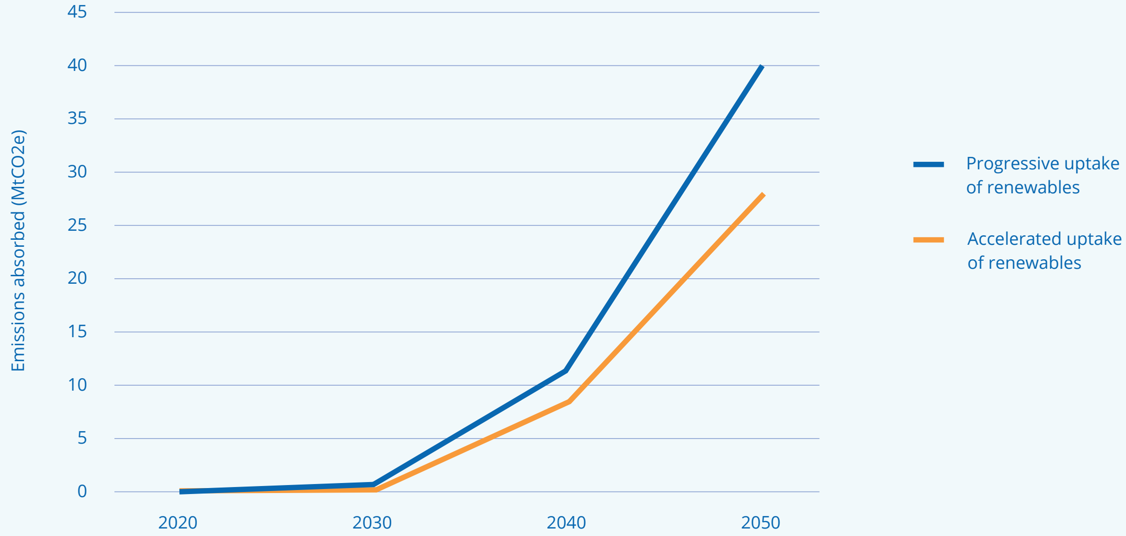
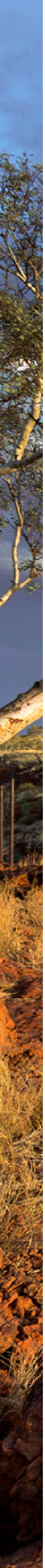
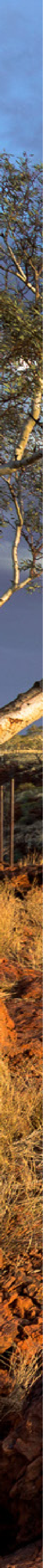


Figure 7. Emissions absorbed by carbon capture, use and storage (CCUS) under progressive and accelerated uptake of renewables scenarios between 2020 and 2050. Emissions absorbed are indicated in metric tonnes of carbon dioxide equivalent (MtCO2e). Modelling was undertaken at 10-year intervals by Wood Mackenzie.





Project-level risks

While both scenarios imply continued demand for gas in the near to medium term, not all the assessed projects are equally likely to fill this demand. The results of the cash-flow analysis showed varied competitiveness between the selected projects. Importantly, while some projects remained cash-flow positive under both scenarios, investment returns were lower across all projects under both scenarios.

LNG projects were generally at higher risk than domestic projects, partly due to international competition, especially under the scenario that assumed accelerated uptake of renewables plus storage. That said, some high-cost domestic projects also showed significant cash-flow risk. Higher-risk projects generally had higher development costs, higher carbon intensities and/or were located in remote geographies.

This modelling highlights that it is not sufficient for gas companies to demonstrate that there will be demand for gas in the near to medium term. It is necessary to show how their projects will compare with their competitors.

Key risks for investors and gas companies

Analysis of the planned Australian gas projects under the 1.5°C scenarios identified a broad and dynamic set of key risks that investors and gas companies should consider before taking a FID on new projects. These risks are outlined in Table 5.

Table 5. Key risks for investors to consider for planned Australian gas projects.

General risks to new gas projects

Increasingly cost-competitive energy alternatives, including green hydrogen and long-duration storage for renewables, will displace gas demand in the near to long term.

Delayed commercialisation of CCUS will threaten the competitiveness of blue hydrogen relative to green hydrogen.

Decreasing social licence to operate may create legal challenges, impede capital raising and/or impact regulatory approvals for new gas projects, especially where projects impact biodiversity or culturally significant sites.

Growing policy support for the energy transition in Australia and key export markets, including carbon taxes, sanctions or other financial incentives, will narrow the range of projects that are competitive against other energy sources.

Gas price volatility may compromise the break-even price, especially for higher-cost projects.

Risks to individual projects

High emissions or operational costs will decrease the competitiveness of individual projects to fill declining regional demand in the medium to long term.

High up-front capital costs and shorter operating lives of projects due to changing energy policies and demand in the medium to long term threaten investor returns.

The long life expectancy of new gas projects underscores the challenge for companies and investors. While a project may be able to compete with energy alternatives on price in the near term, the rapid maturation of new energy technologies and evolution of social attitudes and energy policies presents serious medium- to long-term risks to returns.

The contribution of a project's Scope 3 emissions to global temperature rise is another serious consideration for investors and companies that have made Paris-aligned emission reduction commitments, especially where investment can be made in zero-carbon alternatives.

To continue attracting investment throughout the energy transition, gas companies need to present detailed decarbonisation and business transformation strategies that position the company to succeed in a net-zero economy. Business transformation is essential in the long term, as strategies reliant on CCUS and offsets may reduce the carbon liability of gas producers in the near to medium term but are unlikely to be cost competitive with renewable energy alternatives in the long term.

Uncertainties related to carbon capture, use and storage (CCUS) and blue hydrogen

The scenarios used for this report include different underlying assumptions for CCUS and hydrogen. The roles of these two technologies are closely related, and differences in these assumptions have a material effect on the outlook for gas.

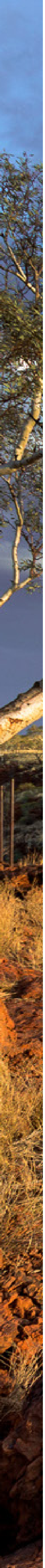
Hydrogen

As the world increasingly seeks to decarbonise, a role for hydrogen has gained widespread interest. Hydrogen, produced from renewables (green hydrogen), nuclear (pink) or fossil fuels with CCUS (blue), could enable decarbonisation across hard-to-abate sections of key sectors, including transport, chemicals and steel production and winter peak demand. It also may play a role in the integration of renewables in electricity. The modelling conducted for this report showed that in the accelerated uptake of renewables scenario, there is a lesser role for blue hydrogen, which in turn reduces projected gas demand. In the progressive uptake of renewables scenario, however, CCUS is commercialised to the extent that a blue hydrogen industry can prolong the role of gas. It is anticipated that blue hydrogen will only play a role for a period, specifically until green hydrogen is fully commercial and has a lower cost. IGCC will be releasing a report on Australia's investment opportunities for hydrogen in quarter two, 2022.

CCUS

The modelling done for this report revealed a close relationship between the commercialisation of CCUS and Australian gas. For example, the use of CCUS with gas-fired power is considered a possible way that countries such as Japan and China can prolong gas use, and CCUS is also used to produce blue hydrogen alongside gas. However, the economic and technological challenges posed by CCUS are significant. Simply put, if CCUS cannot be commercialised and used at scale, gas demand may drop further as alternatives like green hydrogen and/or renewables with storage mature.

For more information on CCUS opportunities in Asia, see 'Carbon capture and storage in the decisive decade for decarbonisation', a report published in 2021 by the Asia Investor Group on Climate Change (AIGCC).



6 RECOMMENDATIONS FOR ENGAGEMENT

The results of this report highlight three key concerns:

1. Demand for gas from Australian companies will decrease under a 1.5°C-aligned decarbonisation pathway. While regional LNG demand is forecast to increase up to 2040, backfill LNG investments from Australia are unlikely to be competitive in a future market.
2. The rate of decline is dependent on technological advances, cost reduction of existing technologies, social attitudes, and policy developments.
3. Not all projects are equally likely to fill declining demand. Projects with relatively higher emissions or development and operational costs and those in remote geographies will face higher risks and are more likely to become stranded.

Gas companies who intend to fill the declining demand for gas should be prepared to articulate how they will manage these concerns. Some suggested engagement questions for investors include:

1. Managing project-level risks

a. What methodology does the company use to assess whether new projects, including backfilling, are aligned with a credible 1.5°C scenario? Companies should be prepared to present the results of a scenario analysis using 1.5°C to meet investor expectations.

b. What is the operational emissions intensity of the project, and how does this compare to peers/other projects in Australia and competitor markets overseas?

c. What is the break-even price for this project, and how does this compare to peers/other projects in Australia and competitor markets overseas?

d. What other key attributes may impact the project's competitiveness and/or social licence (e.g., remote geography, high biodiversity, cultural significance)?

e. What is the company doing to measure (rather than estimate) and reduce methane emissions from their projects?

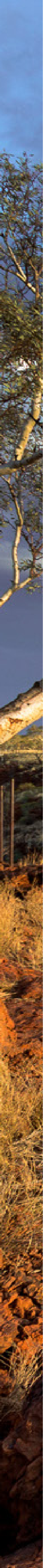
f. What existing contracts does the company have in place for the project, and when will these contracts end? Where does the company predict new contracts will come from to the end of the project? How are the net-zero commitments of companies and countries factored into this planning?

g. What proportion of supply is contracted versus left to sell on the spot market for new projects? How does this compare to previous projects in terms of proportion and tenure?

h. What internal risk management framework does the company use to determine whether projects should go ahead? How does this framework differentiate near-, medium- and long-term risks, given the long-term nature of LNG contracts? How has the company evaluated the risk and costs of decommissioning stranded assets (including sold assets for which the company still has liability)? Are these costs represented on the company's balance sheet?

i. Has the company had problems securing investment or insurance?

j. How is the company accounting for decommissioning costs and early closure if required?



2. Managing demand decline

a. How will the company manage the risk to returns if a faster rate of decline eventuates?

b. What are the key developments that the project depends on to retain commercial value in the medium and long term (e.g., commercialisation of CCUS)? What is the company doing to support these developments (i.e., specific research and development and partnerships)? How will the company manage the risk if these developments do not eventuate?

c. Does the company have a plan for early wind up of projects, should demand decline faster than expected?

3. Managing decarbonisation strategies

a. What is the company's decarbonisation strategy to meet its emission reduction targets? Refer to the CA100+ Net-Zero Benchmark and the IIGCC Oil and Gas Standard.

- **i.** If the company's decarbonisation strategy depends on CCUS or offsets, what price is used to determine future competitiveness?
- **ii.** Does the company have, or are they developing, Scope 3 targets?

b. What portion of the company's revenue comes from gas versus alternative, low-carbon products in 2030, 2040 and 2050?

- **i.** What strategies are in place to develop alternative revenue streams?
- **ii.** What investment is being made today in alternative revenue streams?
- **iii.** What technological or policy developments do these alternative revenue streams depend upon? How is the company supporting these developments?

c. What expertise does the company board have to support a business transformation away from carbon-intensive products? What expertise and experience gaps remain, and what plan does the company have to fill them?

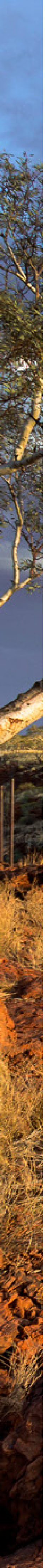
d. What are the company's climate lobbying membership/s and practices? Are these aligned with achieving a 1.5°C-aligned transition pathway?

4. Undertaking scenario analysis

a. Has the company undertaken quantitative scenario analysis that explicitly includes a 1.5°C scenario, covers the entire company, discloses key assumptions and variables used, and reports on the key risks and opportunities identified, per the CA100+ Net-Zero Benchmark?

b. Which scenarios has the company used, why, and have they disclosed key levers that would impact demand for their gas (e.g. faster commercialisation of long-duration storage)?

Alongside direct engagement with gas companies, investors are increasingly able to make their view of decarbonisation strategies, proposed or sanctioned new gas projects and CapEx alignment clear to the company and the market through 'Say on Climate' votes, alongside their existing shareholder rights such as voting on shareholder resolutions and for or against the election of directors.



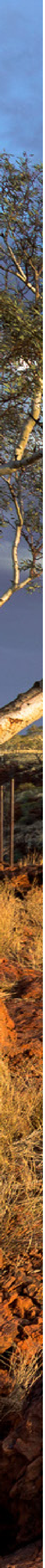
7 CONCLUSIONS

Under the 1.5°C scenarios explored in this report, Australian gas will have a diminishing role in the transition to net-zero emissions, particularly from the 2030s onwards. By 2050, Australia is forecast to have minimal LNG exports or domestic gas demand, suggesting new projects carry a substantial risk of stranding should key policy and market changes materialise.

Key risks to domestic gas demand are faster low-carbon technological developments, including batteries or alternative industrial processes, slower commercialisation of CCUS and strong national and regional climate policies, including carbon taxes, sanctions and other financial incentives. These factors also impact demand for Australian LNG. However, as gas demand in APAC is forecast to rise to 2040, the bigger risk for this sector is reserve depletion and low commerciality of gas backfill projects in Australia compared to other, lower-cost gas producers.

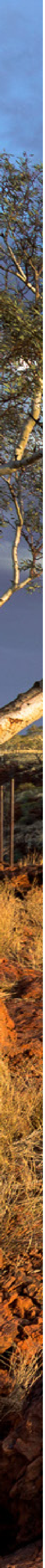
Many investors in Australian oil and gas companies have been engaging with company boards and management on these risks for many years and take the responsibility to balance risks and rewards seriously. However, it is essential that investors have access to the information and external analysis needed to understand and critically engage with the basis for major board-level company decisions, like sanctioning new projects. Misjudging the pace of transition and the uptake of a range of technologies discussed in this report is a clear risk to companies and investors and, by extension, their beneficiaries and the broader community.

The costs of mismanagement of the energy transition could be significant: stranded assets and decommissioning costs alone would be a heavy burden for the Australian taxpayer. Investors have a key role in ensuring that oil and gas producers responsibly manage these risks and increase their focus on the opportunities of the transition, which will help them build a sustainable long-term business strategy beyond gas.



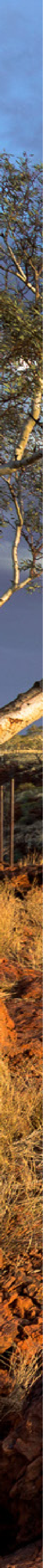
8 GLOSSARY

Backfill	A supply of natural gas from a new source that will support the continued operation of an existing facility or operation.
Blue hydrogen	Blue hydrogen is created when natural gas is split into hydrogen and CO2, either by Steam Methane Reforming or Auto Thermal Reforming, and the CO2 is captured and stored.
Direct emissions (Scope 1 and 2)	Emissions from sources that are owned or controlled by an entity. Scope 1 emissions are the result of the entity's actions, including manufacturing processes or burning of diesel fuel in trucks. Scope 2 emissions are from the consumption of purchased electricity, heat or steam.
Fugitive emissions	Emissions of gases or vapours from pressurised equipment due to leaks and other unintended or irregular releases of gases.
Green hydrogen	Green hydrogen is produced by splitting water via a renewable-energy powered electrolysis process, which produces hydrogen and oxygen.
Indirect emissions (Scope 3)	Emissions that are a consequence of the activities of the reporting entity but occur at sources owned or controlled by another entity. Scope 3 emissions include, for example, those from waste disposal and the extraction and production of purchased materials and fuels.
Net zero emissions	The state where greenhouse gas emissions have been reduced to as close to zero as possible, and any residual emissions have been effectively offset through lasting carbon sequestration methods.
Near-, medium- and long-term	Near-term refers to the period between the present and 2025. Medium-term refers to the period between 2026 and 2035. Long-term refers to the period between 2036 and 2050.
Stranded assets	Assets that will cease earning an economic return before the end of their scheduled economic life as a result of chances associated with the transition to a low-carbon economy.



9 ACRONYMS

AIGCC	Asia Investor Group on Climate Change
APAC	Asia-Pacific region
bcfe	Billions of cubic feet equivalent
bcm	Billion cubic meters
CA100+	Climate Action 100+ investor initiative
CapEx	Capital expenditure
CCUS	Carbon capture, use and storage
CO2	Carbon dioxide
FID	Final Investment Decision
IEA NZE	International Energy Agency's Net Zero by 2050 Roadmap
IGCC	Investor Group on Climate Change
LNG	Liquified natural gas
mcfe	One thousand cubic feet of natural gas equivalent
MtCO2e	Metric tonnes of carbon dioxide equivalent
PJ	Petajoule
WM1.5	Wood Mackenzie's Accelerated Energy Transition 1.5°C Scenario



10 ENDNOTES

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