Australian Government
Department of Industry, Science and Resources

Office of the Chief Economist

Future Gas Strategy

Analytical Report

May 2024

Contents

Further information

For more information on data or government initiatives please see Planning for gas to 2050 from the Department's website at: www.industry.gov.au/mining-oil-and-gas/oil-and-gas/planning-gas-2050

Executive Summary

On 9 May 2023, the Minister for Resources was tasked to develop the government's strategy for the future of natural gas. This analytical report provides an evidence base to support development of the strategy.

Gas underpins a wide range of economic activity in Australia and globally, with secure gas supplies being a core component of energy security for many economies. However, the production and use of gas also accounts for 24% of Australia's greenhouse gas emissions in 2021–22.

Australia has legislated targets to achieve net zero emissions by 2050. Australia's domestic climate action is progressing against a backdrop of growing global momentum to deliver the goals of the Paris Agreement. Emissions from gas must therefore reduce significantly.

The impact global actions will have on the future demand for gas remains uncertain, due to the differing nature of country level decarbonisation pathways and the uncertain timing of alternative energy sources at scale. This uncertainty is observed in the wide range of gas demand projections at a global, regional and domestic level.

In all scenarios, projections indicate continued gas use to 2050 and beyond at a global and regional level. In the medium term (to 2035), sustained domestic gas demand reflects the key role gas will continue to play in firming renewable electricity and for high heat (above 500°C) industrial applications — for many other applications, electrification already provides an alternative commercial energy source. Within the Asia region, demand for liquefied natural gas (LNG) is also likely to be sustained, as gas is one element of trading partners' energy transition plans.

In the longer run, to 2050 and beyond, the role of gas for harder-to-substitute uses is highly uncertain and will be determined by the eventual relative cost and availability of substitutes (in particular, electrification and low-carbon fuels) and other forms of abatement (such as carbon capture, use and storage i.e. CCUS). To be consistent with net zero goals in 2050, all emissions from remaining gas supply and use are abated or offset.

Australian contracts for liquified natural gas (LNG) exports will expire between 2030 and 2035. Within the Asian region to which Australia currently exports LNG, demand for LNG is expected to continue to 2050 and beyond and consultation indicates continued demand for secure exports from Australia. For some trading partners, continued demand for LNG reflects a choice to retain or preference gas use and pursue international trade in CCUS and low-carbon alternatives (such as ammonia) due to relatively limited options for renewable energy. The level of demand is uncertain, with relatively high demand under current policies and much lower demand in scenarios consistent with committed climate action.

In the domestic scenarios examined, there is a significant gap between projections based on current policy and industry action and the demand level consistent with net zero goals. Projections by the Australian Energy Market Operator indicate that demand for gas in the east coast will decline over the medium term – as current policy settings encourage gas substitution – but not at rates consistent with national emissions targets. Demand for gas on the west coast is forecast to *rise* from 2030 due to greater gas use in power generation as coal fired power retires and growth in critical minerals processing.

A key challenge is reducing emissions while balancing energy security through the transition. In the near term, projected domestic supply shortages are a significant concern. On the east coast, supply shortages are predicted from 2028. New supply will increasingly come from Queensland and the Northern Territory to feed the southern states' industries and consumers, increasing costs and raising concerns about capacity of the network. Risks of ongoing market volatility also need to be managed. To build the resilience of the east coast gas market, a range of additional supply measures are likely needed and quickly, including import terminals (which offer the shortest potential time frames to develop), new east coast production and new pipelines. Orderly reduction in gas demand would assist to reduce the supply gap and may be necessary if supply solutions are not available in the required timeframes.

The demand and supply of gas through the energy transition will depend on production and transport costs, and pricing to consumers. Production costs in the east coast market today are well above legacy domestic contract prices. Rising costs and the need for investment to maintain supplies are expected to put further upward pressure on domestic prices, encouraging users to find alternatives. In contrast, LNG prices are expected to ease in coming years as supply from the United States and Qatar rises. These factors will raise the relative value proposition of import terminals.

West coast supply may fall short of demand in the near term, requiring drawdown from storage. From 2030, without greater use of alternatives, efficiencies and investment in new supplies, growing demand will drive increasing shortages and potentially place pressure on prices and contracting.

Introduction

Terms of Reference

The scope of work outlined in the Future Gas Strategy (FGS) Terms of Reference is:

The [Future Gas] Strategy will develop quantitative evidence on the supply-demand balance of gas out to 2050 drawing on existing analysis where possible, including by Australian Energy Market Operator (AEMO) and the Australian Competition and Consumer Commission.

a. *Demand projections / scenarios will:*

   i. *examine both domestic and regional markets.*

   ii. *consider the impact of increased competition from other exporters;*

   iii. *leverage other work including the AEMO Integrated Systems Plan (to ensure consistency and avoid duplication); and*

   iv. *will be consistent with existing State and Commonwealth policy settings across climate, energy and our trading partners' policy settings and ambitions.*

b. *Supply projections / scenarios will include both gas resources potential and reserves, including an assessment of technical and contingent risks that prevent or otherwise influence the ability of new gas supply to reach domestic and international markets.*

c. *The evidence base will also consider greenhouse gas emissions forecasts and projections associated with the production, transport, and use of gas, including heavy industry and manufacturing, drawing on existing greenhouse gas emissions forecasts and projections.*

Approach

Consistent with the Terms of Reference, the Department of Industry, Science and Resources (DISR) has used existing analyses where possible — drawing heavily on the existing work of the Australian Energy Market Operator (AEMO), the International Energy Agency (IEA), the Australian Energy Regulator (AER), the Australian Competition and Consumer Commission (ACCC), the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and other government departments. When modelling future scenarios, DISR has used the existing scenarios described in AEMO's Gas Statement of Opportunities (GSOO) and the IEA's World Energy Outlook — which themselves share a common set of scenarios and assumptions.

The report structure is as follows:

Chapter 1. A primer on the global and Australian gas markets introduces the current context around Australian natural gas and explores the history of its resource development.

Chapter 2. Emissions from the supply and use of gas focuses on the emissions profile associated with Australia's gas sector, supply chain gas emissions, and the trade-offs associated with different end users of gas.

Chapter 3. Domestic demand outlook turns to Australia's gas demand, its segmentation into east and west coast markets, and which areas of Australia's demand have the highest gas abatement opportunities.

Chapter 4. International demand outlook outlines the two-way trading relationships between Australia and gas export destinations as well as investor countries, how these relationships might change under accelerated pathways to net-zero, and the role that gas plays in underpinning regional energy security.

Chapter 5. Supply outlook examines the geographic breakdown of Australia's current gas supply, where future supply is possible, and considers the factors that materially impact production decisions. It also examines the future balance between supply and demand.

Chapter 6. Competition, costs and pricing examines the concentrated nature of the gas supply chain, the major components of the cost of gas and how these are expected to change over time, and the interactions between costs and gas pricing.

Chapter 7 Closing regional supply gaps examines the possibilities for future supply.

The Energy Trilemma

A useful rubric for thinking about the trade-offs present in the energy market — and so clearly exhibited today — is the so-called 'energy trilemma'. This refers to the challenge of simultaneously: having affordable energy; building a reliable energy system; and reducing emissions to achieve net zero targets.

Affordability — The low energy density of natural gas by volume makes it one of the most capital intensive and challenging fuels to transport from wellhead to end user. There are high fixed costs and very low short run marginal costs associated with gas production and transportation. The associated key to gas affordability has been to either consume gas where it is produced or achieve *economies of scale* so that the fixed costs can be spread across a sufficiently large user base and recovered over time.

Security — Gas markets are a physical energy system that rely heavily on key pieces of infrastructure, where the costs of disruption can be significant. Maintaining energy security in gas markets has historically relied on a combination of redundancy, minimum requirements, and spare capacity throughout the system. Infrastructure, such as storage facilities and pipelines, can sit un- or under-utilised for months or years to help meet demand when a crisis emerges. Building in redundancies adds to the cost of gas, raising a trade-off between affordability and security.

Sustainability — The production and use of natural gas contributes to greenhouse gas emissions. Gas is also often used to fuel both the refining process and gas transportation, so liquefied natural gas (LNG) exports contribute to domestic Australian emissions. The emissions can be viewed as a negative supply externality to the extent that the environmental cost of production is not fully reflected in the economic price, causing gas demand to be higher than socially desirable. Reducing sectoral emissions involves a combination of lower gas production and demand, less carbon-intensive gas production processes and offsets for gas-related emissions. What substitutes for gas — or what gas replaces — has important implications for emissions reduction pathways both domestically and globally.

In addition, there can be positive 'spill over' impacts of gas production on specific parts of the economy and on some regional communities. There are both potential positive and negative 'spill over' impacts of gas production on global greenhouse gas emissions. Gas has the potential to be part of the solution in the context of well-planned and executed transitions to fully decarbonised energy systems in other countries.

Use of scenario analysis

With an uncertain future, it is important to consider a range of scenarios

The global and Australian economies must change the way they produce and consume energy if they are to reduce greenhouse gas emissions and meet the Paris Agreement goals. Different countries will take different pathways in the pursuit of their decarbonisation goals and face different opportunities and challenges, reflecting their energy needs, geography, demographics, and composition of their economies.

Scenarios are an essential tool for exploring and understanding the future gas outlook depending on global emissions reductions pathways, based on varying assumptions. Importantly, scenarios are not meant to be predictions but rather represent instruments that facilitate a comparison of potential future versions of the energy landscape.

To inform the Future Gas Strategy, useful illustrative scenarios must be identified that provide insights into gas (including LNG) demand and supply across Australia, in the region, and at a global scale. This report builds upon pre-existing energy transition scenarios produced by the IEA and the AEMO.

There is a strong basis for the choice to rely on scenarios developed by the IEA and AEMO. The scenarios are well known and tested, with methods and workbooks transparently published. They reflect policy decisions and intentions across the world and in Australia. They also provide a sufficient range of outcomes that facilitate the exploration of the many likely ways that the global climate transition journey could play out.

The IEA explores multiple scenarios based on varying assumptions about the evolution and end-state of the global energy system:

- Net Zero Emissions (NZE) is a normative scenario which sets out a pathway for global energy sector to achieve net zero carbon dioxide (CO_2) emissions by 2050 and does not rely on emission reductions outside of energy sector to achieve its goal.
- Announced Pledges Scenario (APS) is an exploratory scenario which assumes climate commitments made by governments around the world will be met in full and on time.
- Stated Policies (STEPS) is another exploratory scenario which reflects the current policy settings based on the assessment of sector and country-specific policies currently in place around the world.

AEMO has also developed a set of scenarios that align with IEA scenarios (see Table 1.1) in order to explore a range of plausible outlooks for east Australian gas market demand and the investments needed to meet future gas demand to 2043. In the most recent GSOO for 2024, three main scenarios for the east coast and Northern Territory gas market are discussed:

- Step Change scenario achieves a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels. Electrification is a key enabler to transition the economy at a pace aligned with beating the 2°C abatement target of the Paris Agreement.
- Green Energy Exports reflects very strong decarbonisation activities domestically and globally aimed at limiting temperature increase to 1.5°C, resulting in rapid transformation of Australia's energy sectors, including a strong use of electrification, green hydrogen and biomethane
- Progressive Change Scenario reflects Australia meeting its current Paris Agreement commitment of 43% emissions reduction by 2030 and net zero emissions by 2050. This scenario has more challenging economic conditions, higher relative technology costs and more supply chain challenges relative to other scenarios.

AEMO has also developed consistent assumptions for the west coast gas market to outline WA's gas supply, demand and investment needs out to 2033. In their latest 2023 Western Australia Gas Statement of Opportunities (WA GSOO), they utilise three main scenarios: low, base, and high.

Table 1.1: Scenario Comparison

Scenario	Climate Pathway	IEA Scenario	AEMO Scenario	How to interpret scenarios?	Energy implications
Current Policies	RCP 4.5 ~2.4 to ~2.6°C	Stated Policies Scenario (STEPS)	Progressive Change (east coast)	A conservative benchmark about where the energy system might go without a major additional steer from policy makers or significant technological development, based on measures and policies that have actually been put in place.	Vast majority of energy mix in 2050 (>85% of ~4600 billion cubic metres i.e. bcm) is sourced from unabated natural gas. Important role for biogases.
Net zero post–2050	RCP 2.6 ~1.6 to ~1.8°C	Announced Pledges Scenario (APS)	Step Change	Assumes all the climate commitments made by governments around the world will be met in full and on time. There remains an 'ambition gap' that needs to be closed to achieve the 1.5°C goals agreed at Paris in 2015.	Majority of global energy mix in 2050 (>50% of ~3500 bcm) is sourced from unabated natural gas. Important role for low-emissions hydrogen production (incl. with CCUS) and biogases.
Net zero by 2050	RCP 1.9 ~1.5°C	Net Zero Emissions Scenario (NZE)	Green Energy Exports	A narrow but achievable pathway for the global energy sector to achieve net zero CO_2 emissions by 2050, consistent with limiting the global temperature rise to 1.5°C without a temperature overshoot (with a 50% probability).	Minority of global energy mix in 2050 is sourced from abated natural gas. Majority of energy produced from low-emissions hydrogen production and biogases.

Source: AEMO (2024a), IEA (2023f)

1. A primer on the global and Australian gas markets

Summary

Chapter 1 highlights the diverse use of gas within the economy. Domestically, Australia's gas underpins a wide range of economic activity across the residential, industrial, mining and power generation sectors. However, gas use also accounts for a large proportion of Australia's emissions.

Australian gas is exported as LNG, largely under long-term contracts which extend to between 2030 and 2035. Australian LNG is primarily used for power generation in our key Asian regional trading partners that have adapted their systems to run on LNG imports. Looking forward, several trading partners face challenges with regards to renewable energy due to the differences in economies, geography, and geology.

1.1 Global and domestic gas markets

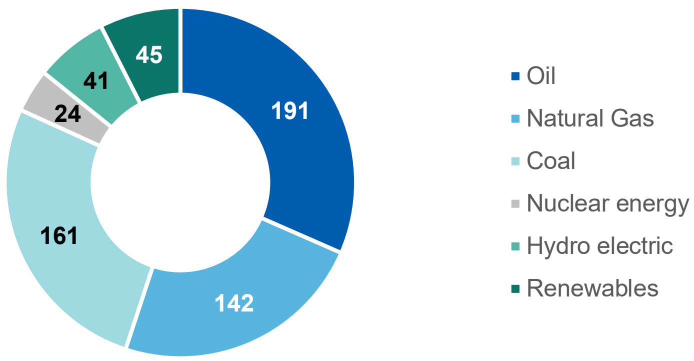
Gas accounts for a quarter of current global energy consumption

Roughly 83% of global energy consumption is sourced from fossil fuels, including 25% from natural gas.[1] Australian domestic use of fossil fuels is higher than global consumption levels: roughly 92% of current Australian energy consumption is derived from fossil fuels. Gas accounts for just over a quarter (27%) of Australia's energy consumption (Figures 1.1 & 1.2).

Gas is a versatile fuel which is utilised differently in different markets

A defining feature of gas is its versatility across a wide range of economic activities. Gas is heavily used in all types of energy and all parts of the economy, with data on gas consumption, production and trade statistics available, in energy content units and volume or mass units. A brief explanation of units used in gas are provided in Appendix C.

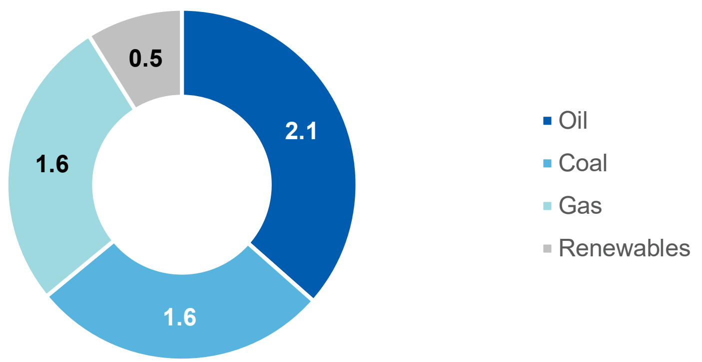
Figure 1.1 Global energy consumption by fuel, 2022



Notes: Figures are in Exajoules. Primary energy comprises commercially traded fuels including renewables used to generate electricity.

Source: Energy Institute (2023)

Figure 1.2: Australian energy consumption by fuel, 2021–22



Notes: Figures are in Exajoules. Renewables include hydroelectric generation.

Source: DCCEEW (2023b)

[1] The 'gas economy' concept of interest for this analysis covers a range of gaseous fuels, including natural gas in gaseous form, liquefied natural gas for export, liquefied petroleum gas, compressed natural gas and hydrogen.

Domestically, gas has become an important component of the Australian energy system. Australia used 5,762 petajoules (PJ) of gross gas in 2021–22 (including gas for LNG production and export). Gas is used in most sectors in the Australian economy due to its responsiveness (it can be turned on and off quickly) and ability to deliver high volumes of heat.

Globally, 40% of gas is used to produce electricity (Figure 1.3). Another 35% of gas is used in the industrial sector — as either a chemical feedstock (mainly to produce hydrogen as a precursor to nitrogen fixation) or as a high-grade source of industrial heat. And 24% of gas is used to fuel (space) heating in buildings. This diversity in consumption use differs to coal, where 60% of the fuel is used for thermal generation (electricity), and oil, where 60% is used for transport fuel.

Gas use varies substantially by geography. In Europe, North America and China, gas plays a large role in space heating for buildings. By contrast, East and Southeast Asian gas usage is more in industry and in electricity generation.

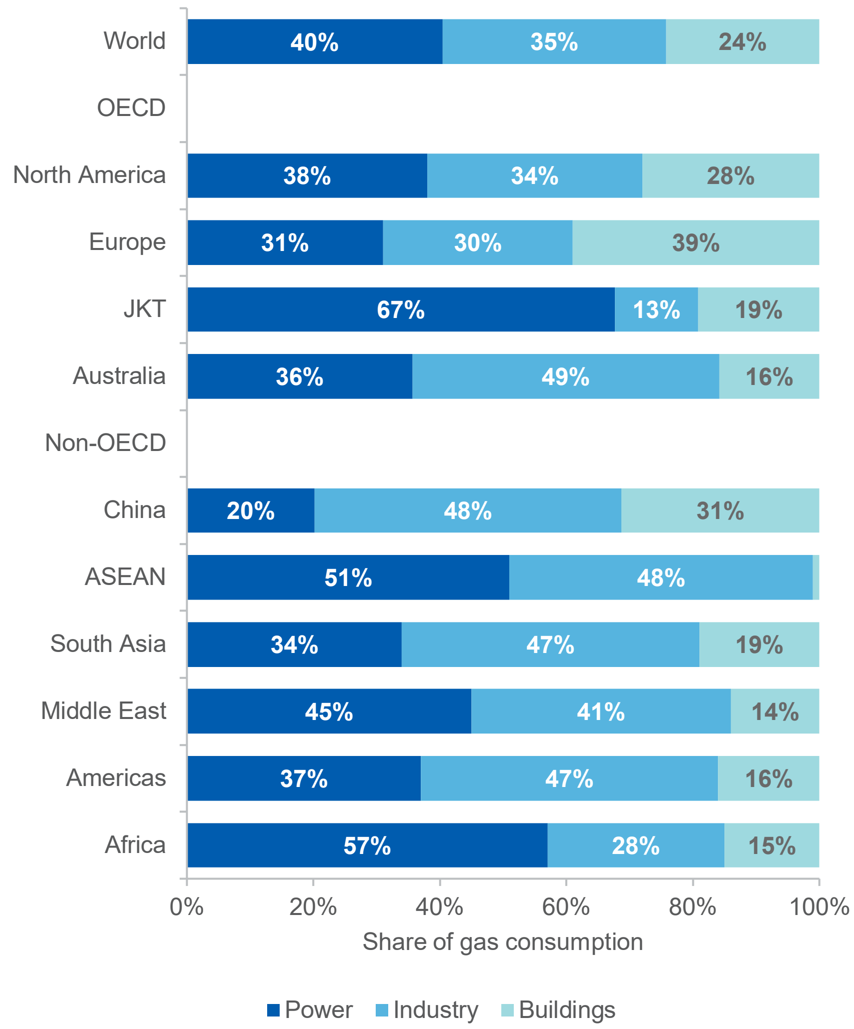
Gas is a complex fuel that is traded less than other fossil fuels

Gas has low energy density by volume when compared with conventional fuels, such as oil and coal. This feature renders gas expensive to transport and has confined natural gas to generally being a 'localised commodity' — globally 75% of all produced gas is consumed domestically compared to 29% of oil (Figure 1.4).

When gas is traded, it either involves pumping gas through large, long-distance pipelines or cooling gas at very low temperatures (below approx. -161°C) to create LNG in highly technical liquefaction facilities for shipping.

Both methods involve significant upfront capital costs and often necessitate the construction of large-scale projects. To secure finance to construct such facilities, gas producers have typically agreed to long-term (15–20 year) offtake contracts, providing a level of price and volume security for both buyers and sellers. This security ensures that each party will be able to pay back the high costs associated with establishing their export and import infrastructure.

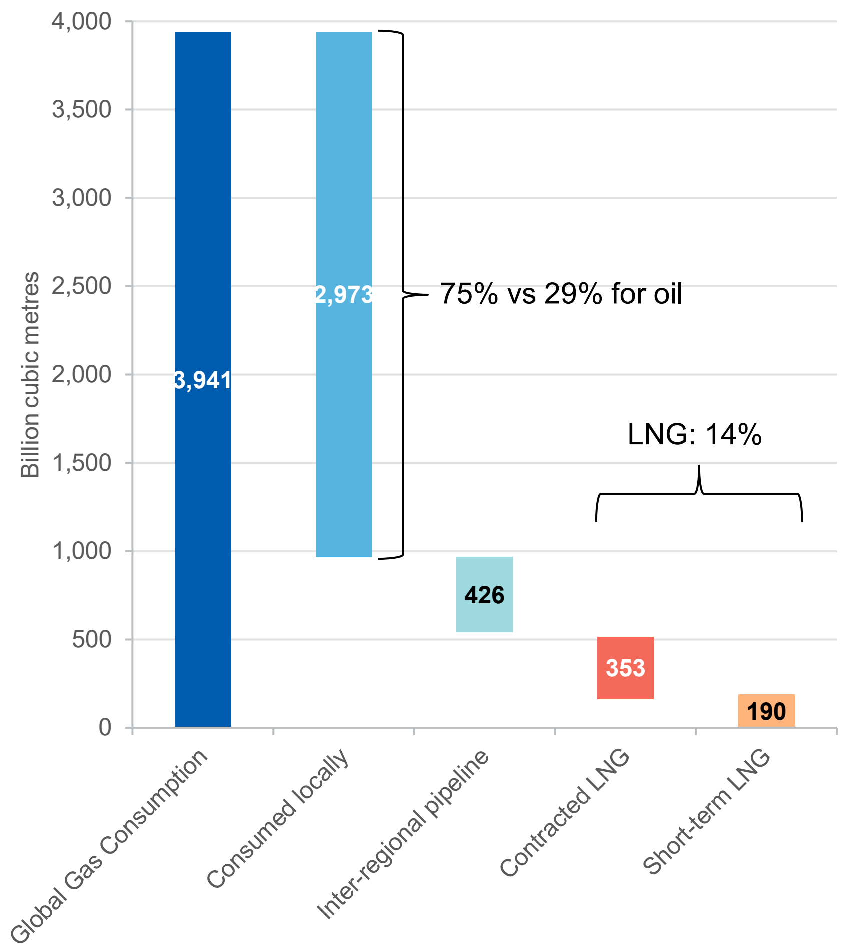
Figure 1.3: Share of natural gas consumption by sector and region, 2022



Notes: Gas consumption excludes gas used in energy transformation to make LNG. Residential and commercial gas demand is captured in buildings category.

Source: NexantECA (2024)

Figure 1.4: Global gas consumption by source, 2022



Notes: Locally consumed gas is inferred as the difference between total gas consumption and total gas trade. Pipeline trade data was sourced from Bloomberg and LNG data was sourced from GIIGNL.

Source: Bloomberg L.P (2024); Energy Institute (2023); GIIGNL (2023)

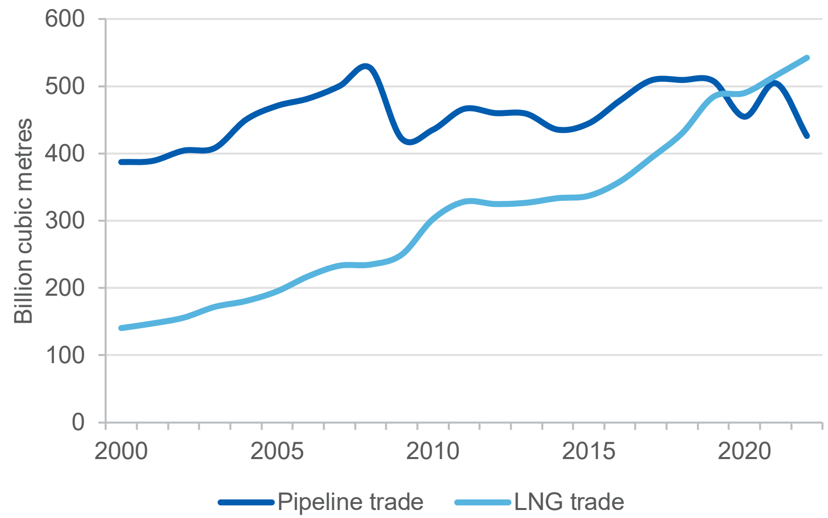
The high upfront costs associated with constructing this infrastructure means that Australia has historically relied on large flows of foreign direct investment to finance the construction of our export facilities.

Global LNG trade has grown rapidly this century

Between 2000 and 2022, global LNG trade roughly tripled from 140 billion cubic metres (bcm) to 542 bcm — an annualised growth rate of 6% (Figure 1.5). Geographically, the demand for LNG has been concentrated in East Asia, where it is used almost exclusively to generate electricity.

There has been rapid global development of LNG export and import capacity. From 2013 to 2022, global LNG import capacity grew by almost 50% across 48 countries and now sits at approximately 4 bcm per day. In the near term, the Asian and European regions are expected to lead growth in import capacity installation. China, India, Germany, Cyprus, and Brazil are all in the process of building terminals, and New Zealand is considering adding capacity. This expansion of LNG import capacity is consistent with a path of strong growth in LNG demand. This aligns with the IEA's STEPS scenario, but not its 'net zero' pathway.

Figure 1.5: Global gas trade, 2000 to 2022



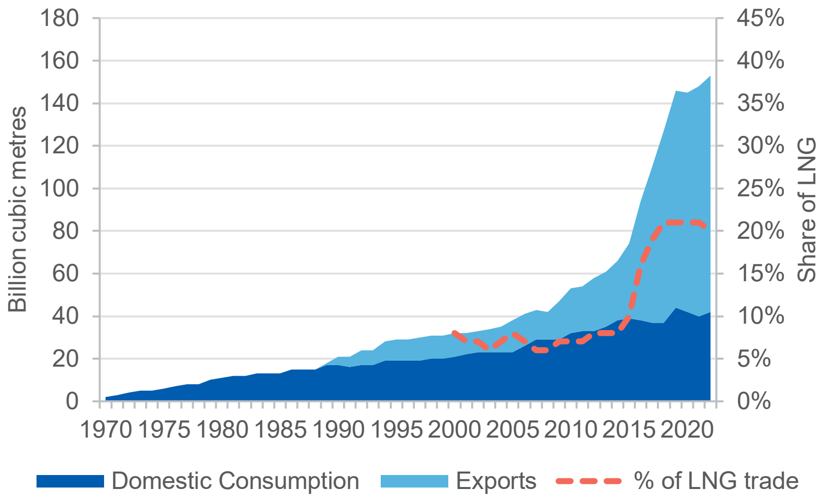
Source: Energy Institute (2023)

Australia's LNG export growth has outpaced global growth

Australia's LNG exports play an important role in the global gas landscape. In 2022, Australia produced 152 bcm of natural gas, of which just under three quarters (111 bcm) was exported as LNG. While Australia accounted for less than 4% of global gas production in 2022, Australia was the largest global LNG exporter — accounting for 20% of the global LNG trade (Figure 1.6).

Australia's role as a significant net exporter of gas has only emerged in the past 20 years, coming on the back of dramatic growth in Australian gas production and exports. In 12 years, our LNG exports quintupled from 21 bcm in 2010 to 111 bcm in 2022 — an annualised growth rate of 14%.

Figure 1.6: Australian gas production, 1970 to 2022



Notes: Exports are implied as the difference between Australian production and consumption. Data on LNG trade is not available prior to 2000.

Source: Energy Institute (2023)

Australian LNG is mainly exported to gas markets in East Asia

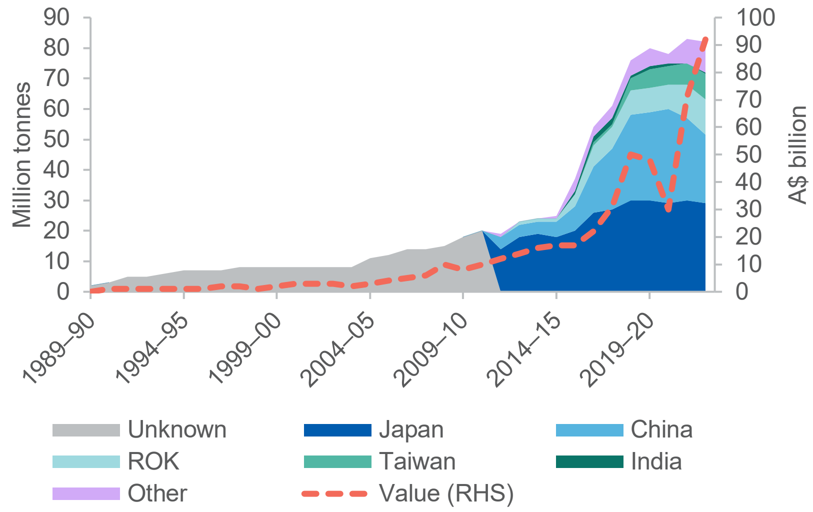
Unlike most gas markets where gas is primarily supplied from local sources, generally gas in East Asia is primarily supplied via LNG imports. These imports tend to be utilised in high value end uses.

Australia's LNG exports are concentrated across four economies in Asia: Japan, China, Republic of Korea (ROK) and Taiwan. In 2022–23, the export earnings derived from these four buyers amounted to almost $85 billion, equivalent to nearly 92% of the total Australian LNG export earnings of $92 billion. (Figure 1.7).

Australia's top export customers predominately use LNG in the power generation sector, where it plays a crucial role in maintaining a reliable and robust electricity supply during periods of peak demand.

In most of these markets, gas-fired power generation has been used to displace the market share of oil, coal and — in Japan's case — nuclear power generation (after the Fukushima Daiichi nuclear reactor accident).

Figure 1.7: Australian LNG export earnings and exports by destination, 1989–90 to 2022–23



Notes: Figures cannot be disaggregated prior to 2011–12.

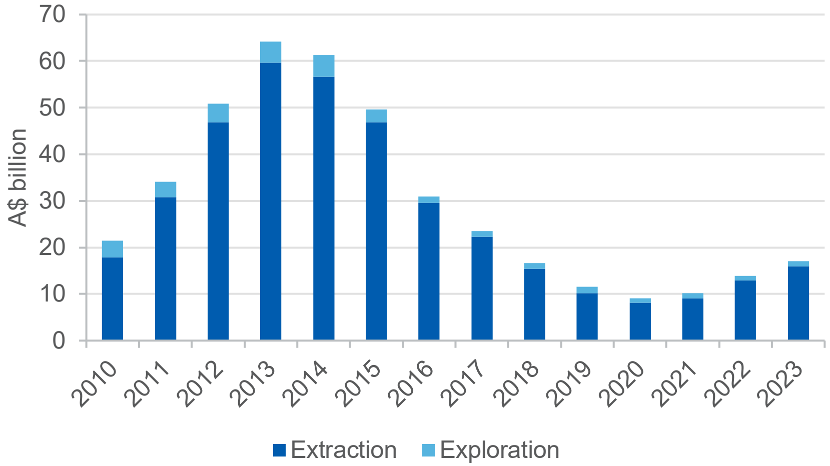
Source: DISR (2024)

The foundation of Australia's LNG infrastructure rests upon a framework of investment and long-term legacy contracts with Asian consumers, which provide price and volume security over a long-term time horizon. Between 2010 and 2023, the cumulative investment in Australia's oil and gas sector exceeded $414 billion, which included the completion of 8 LNG projects across Australia costing an estimated A$290 billion (Figures 1.8 & 1.9).

Insight: Japan, ROK and Taiwan's energy sectors are currently reliant on Australia's LNG exports, secured by long-term contracts.

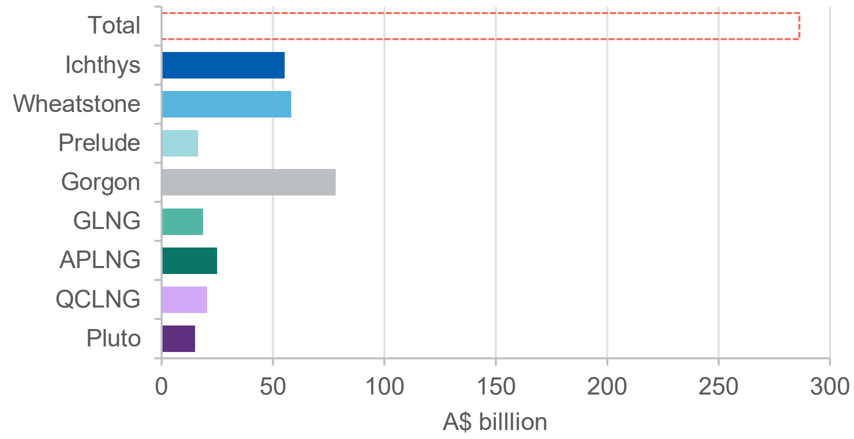
In 2023, ten LNG export facilities operated in Australia and were clustered in three geographic regions on the west, north and east coasts. Currently, Australia must produce 68 million tonnes (Mt) of LNG each year to meet contractual obligations that are due to expire in the first half of the 2030s (Figure 1.10 & Figure 1.11). These contracts are the foundation of Australia's total LNG exports, which reached over 80 Mt in the last financial year (Figure 1.7).

Figure 1.8: Annual Australian petroleum expenditure, 2010 to 2023



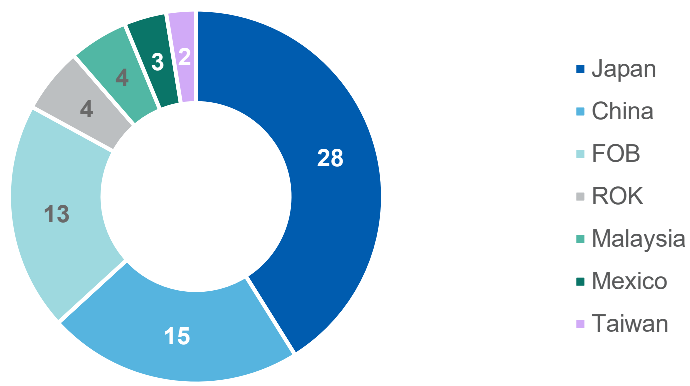
Notes: Extraction expenditure only captures capital expenditure.
Source: ABS (2023a, b)

Figure 1.9: Project costs for Australia's recent LNG facilities



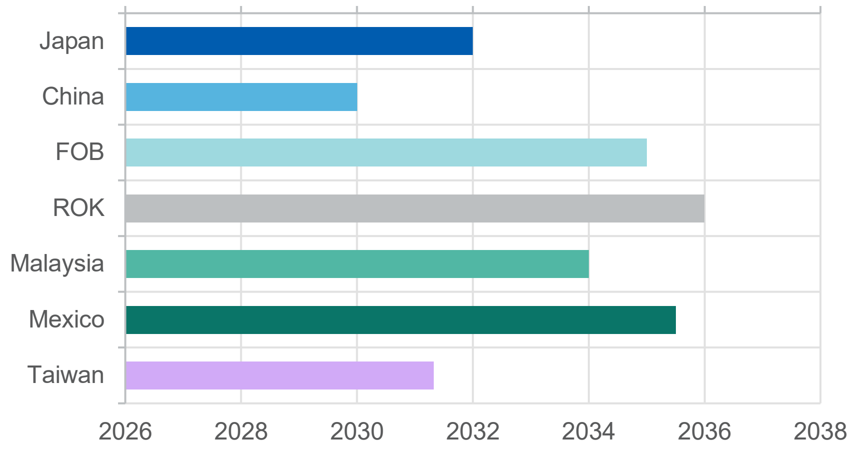
Notes: Figures are departmental estimates derived from publicly available information.
Source: DISR (2019)

Figure 1.10: Australian LNG contracts by trading partner, Mt, 2022



Source: GIIGNL (2023)

Figure 1.11: Average end-date of Australian contracts by trading partner



Notes: Only includes contracts that are publicly known.
Source: GIIGNL (2023)

Contribution of gas sector to the Australian economy

Given the widespread use of gas in Australia and the large contribution to exports, gas contributes significantly to the Australian economy today. Consultants ACIL Allen (2023) estimate that the Australian gas industry directly contributed $84 billion (equivalent to 3.5% of Australian GDP) to the Australian economy in the year 2021–22, encompassing all upstream and downstream sectors including gas production, transportation, chemical manufacturing, electricity generation, and other manufacturing. These sectors rely heavily on the gas industry, as gas serves as a critical input for their operations. The value of gas usage domestically amounts to $6.5 billion, with the percentage of total gas inputs ranging from 7.4% to 12.4% for the top five gas-using sectors in 2021–22. The gas industry directly supported 81,940 full-time equivalent (FTE) jobs in Australia.

The LNG export sector is the largest contributor within the Australian gas industry. Australia has 10 LNG facilities operated by 6 LNG joint ventures. Between 2010 and 2020, direct investments in both up and downstream LNG facilities in Australia was nearly $250 billion. For the 2022–23 financial year, LNG export earnings were $92 billion, representing nearly 20% of total Australian export earnings.

Direct employment within the LNG industry amounts to around 15,000 people, generating $2.5 billion in wages. The LNG industry makes a valuable regional contribution through spending in local economies, including on community development. For example, one large gas producer allocated over $3.2 billion to Australian local businesses in 2022. The Maranoa Regional Council highlighted that the mining sector contributed $401 million to their local economy in 2021–22 financial year.

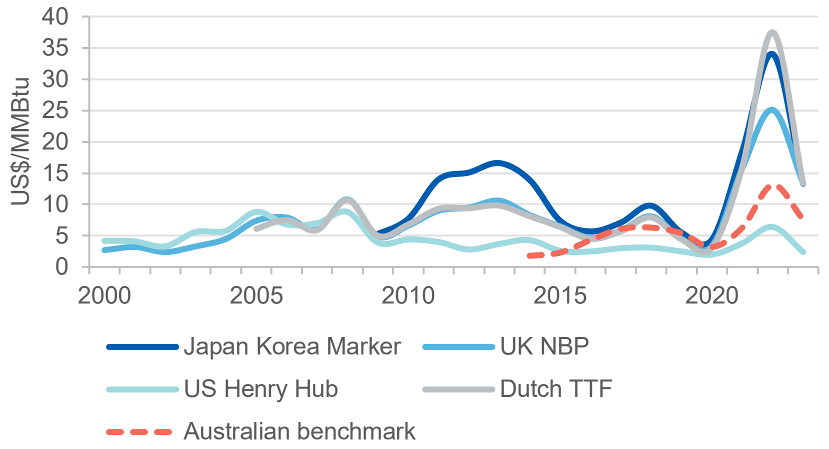
Insight: Gas plays a significant role in today's Australian economy. In 2021–22, the gas sector contributed 3.5% of GDP, accounted for 7.4–12.4% of inputs for the top 5 gas-using sectors, and LNG was 20% of exports by value.

The global gas trade is, and will continue to be, vulnerable to disruption

Global gas and LNG trade is reliant on pipeline and liquefaction infrastructure that makes it vulnerable to disruption. In 2022, Russia disrupted Europe's supply of pipeline natural gas, resulting in an enormous spike in global gas prices — in Europe, prices spiked to almost four times the average price of the previous 5 years.

On the east coast of Australia, higher international gas prices strengthened the incentive for gas producers to export LNG rather than supply into the domestic market. In 2022, this strong incentive to export coincided with higher domestic demand for gas-fired power generation and residential heating, causing domestic spot prices to double (Figure 1.12, also see Box 6.2).

Figure 1.12: Historical gas prices, 2000 to 2023



Notes: Nominal prices. Australian benchmark prices estimated as the annual average day-ahead price at the Wallumbilla Gas Supply Hub.

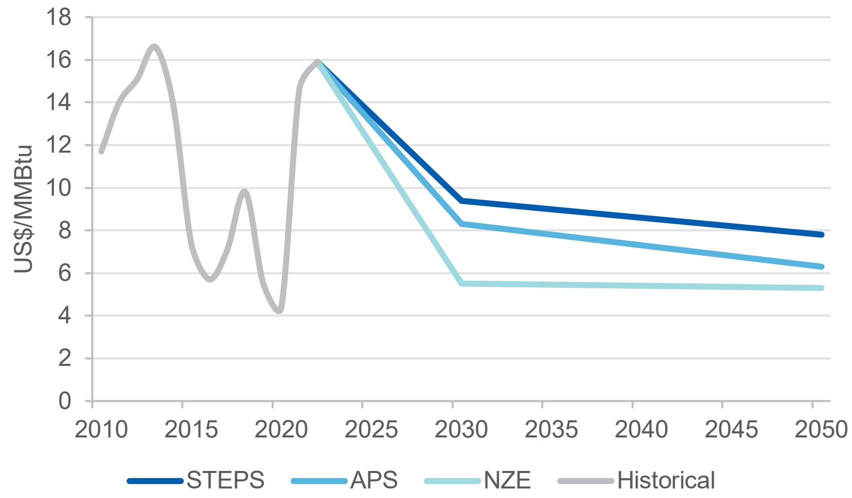
Source: AEMO (2023a); AER (2023a); Energy Institute (2023).

Insight: Like all energy commodities, gas production and LNG trade will remain susceptible to disruption — from geopolitical upheavals, industrial disputes, climate-related events, and other shocks.

The IEA's (2023f) forward projections for Asian LNG prices are for a return to the low prices seen pre-Russia shock (Figure 1.13). That is, Asian LNG prices are expected to range between USD5 and USD10 per million metric British thermal unit out to 2050. The variation in price depends on spare capacity in LNG export facilities (itself, partly a function of demand).

Over 98% of Australia's gas is exported to economies with net zero commitments, suggesting demand may be impacted significantly over time by decarbonisation efforts in partner economies.[2] Gas prices are projected to be lower under the IEA's (2023) NZE scenario than under pathways where decarbonisation goals are less ambitious. The logic for price drops stems from declining LNG demand. Lower LNG demand reduces capacity utilisation of LNG export facilities. The assumed price level is not high enough to incentivise new investments but does allow some facilities to maintain operations (Figure 1.13). Demand scenarios for Australian LNG through the transition are explored in Chapter 4.

Figure 1.13: Asian gas price forecasts by scenario, 2010 to 2050



Source: IEA (2023e)

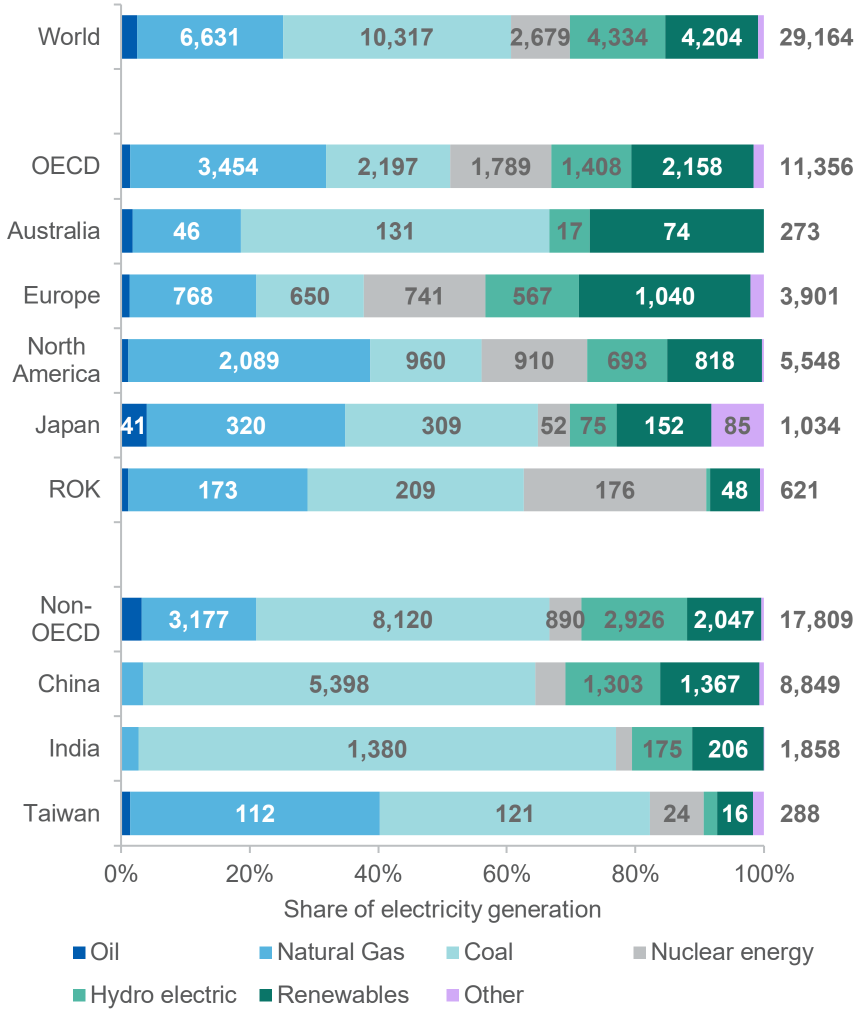
Rising gas generation can help reduce emissions in the electricity sector

The net benefits for different countries and sectors to substitute away from gas depend on the contribution gas makes to economic production (as both a feedstock and a source of energy/heat), the alternatives available (and their emissions profile), and the relative cost (including carbon cost) associated with adopting alternatives. We will explore these considerations further as they apply to Australia in Chapters 3 and 4.

Roughly 20% (or 6,600 Terawatts) of global electricity generation is powered by gas (Figure 1.14).

2 Department of Climate Change, Energy, the Environment and Water analysis of Department of Foreign Affairs and Trade, *Trade statistics* (2024).

Figure 1.14: Electricity Generation by fuel and region, TWh, 2022



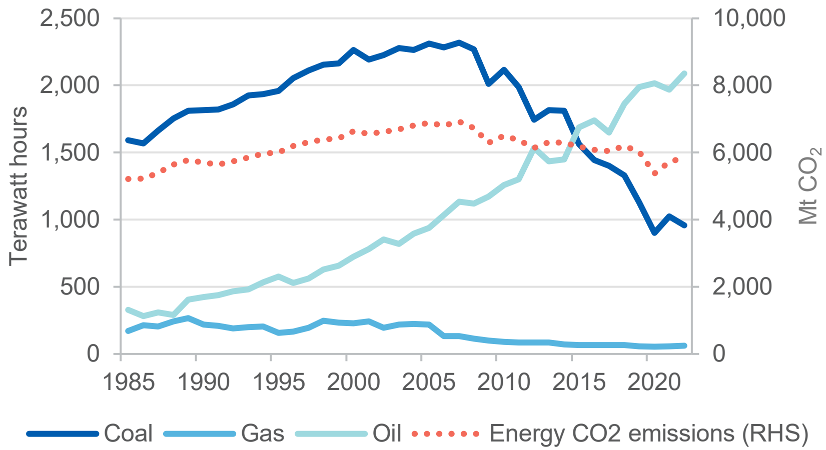
Note: Figures are in terawatt hours.
Source: Energy Institute (2023)

Within foreign electricity sectors, the key to whether a reduction in the use of gas will be associated with lower greenhouse gas emissions depends on what alternatives energy sources are available. In some markets, cheap renewable technologies and expanding electricity grids can both replace the role of fossil fuels and reduce emissions. Gas may be used to support this transition in a firming role. While hydroelectric power generation has increased, nuclear power has remained steady.

Where renewable energy sources or alternatives are limited or constrained (especially in the near term), gas or LNG may be a lower emissions option compared to other fossil fuels such as oil or coal. CSIRO notes that if Australian natural gas was used to displace domestic coal-fired electricity generation, emissions would fall by an estimated 31% (for open cycle gas turbines) and 50% (closed cycle gas turbine).

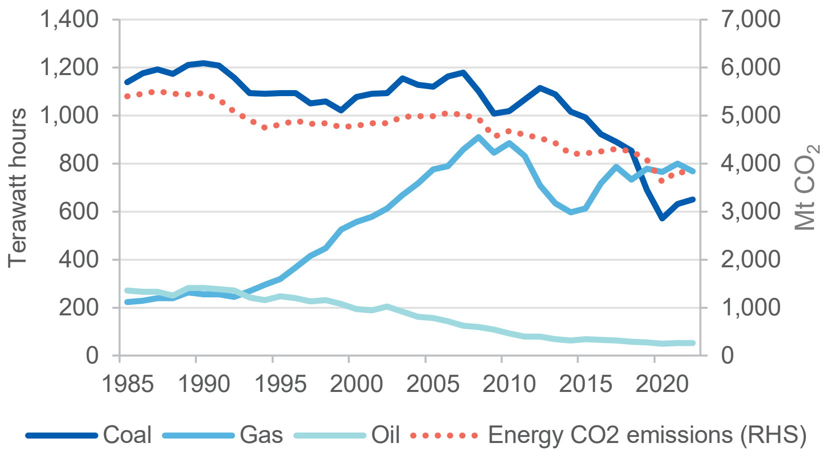
Over recent decades, gas-powered generation has replaced coal in North America and oil in Europe helping to contain emissions (Figures 1.15 and 1.16). In markets where coal remains the dominant source of power generation — as in Asia Pacific — emissions have risen sharply (Figure 1.17). In economies pursuing a slower track to net zero under the Paris agreement and seeking to raise living standards through greater energy access, gas could provide a lower-emissions intensity of energy production than growth through coal or oil as a complement to renewable power generation.

Figure 1.15: North American electricity generation by fuel, 1985 to 2022



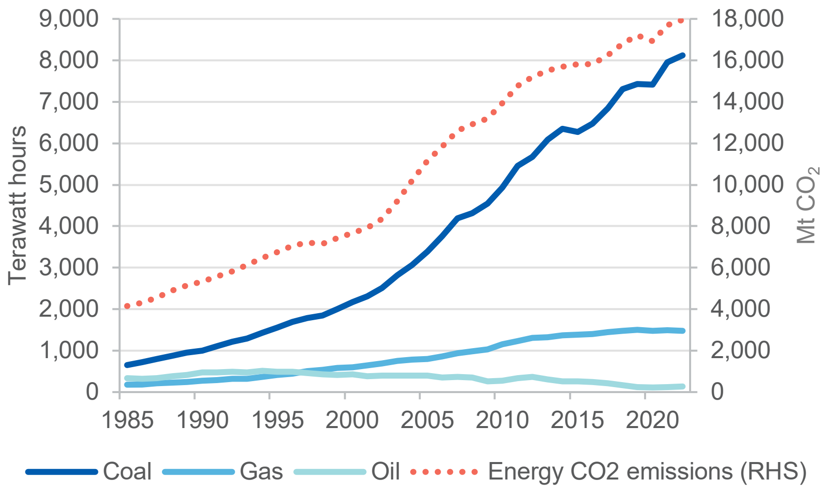
Source: Energy Institute (2023)

Figure 1.16: European electricity generation by fuel, 1985 to 2022



Source: Energy Institute (2023)

Figure 1.17: Asia-Pacific electricity generation by fuel, 1985 to 2022



Source: Energy Institute (2023)

2. Emissions from the supply and use of gas

Summary

Chapter 2 examines the emissions associated with gas supply and use, as well as the opportunities to reduce these emissions — either through efficiency improvements or other abatement technologies or practices. Opportunities for demand reduction are considered in Chapter 3.

In Australia, emissions associated with the production and domestic use of gas accounted for 24% of total emissions in 2021–22, similar to the global average of 23%. Australian emissions associated with gas peaked in 2018–19 and have since fallen. This recent downward trend is projected to continue to 2035, driven by policies including the Safeguard Mechanism.

Projections are not guaranteed — they are highly uncertain. Crucially, lower emissions projections incorporate further action by individuals and firms to reduce emissions in both supply of gas and LNG and domestic use (largely residential, commercial and industrial). The most recent Australian Government emissions projections indicate material progress towards meeting Australia's 2030 emissions reduction target. However, risks associated with inaction or higher demand for gas remain. To hit net zero by 2050, sustained action to lower gas use and abate emissions from the remaining gas use is required.

The supply and use of Australian gas exports account for sizeable emissions across the Asia Pacific. In 2018–19, emissions associated with the use of Australian LNG exports ('consequential emissions') were approximately equivalent to 40% of Australian domestic emissions across all sectors and 195% of emissions from domestic production and use of natural gas (Burke et al. 2022). Under the United Nations Framework Convention on Climate Change (UNFCCC), cutting these emissions is the responsibility of relevant parties who set their own emission reduction targets (see Chapter 4).

Significant improvements in the emissions intensity of production and use, and in finding alternatives to gas, will be essential to reaching Australia's net zero target. The emissions intensity of use is much higher than for supply, so demand reduction and abatement will play a key role in reducing emissions. Six sectoral plans will map out decarbonisation pathways by 2050 for each sector, articulating how Australia will transition to a net zero economy, consistent with our international and domestic commitments. Alternatives exist for many applications, with the primary option being electrification to harness renewable energy (see Chapter 3).

Yet it will also be necessary to focus on reducing the emissions intensity of gas supply. For many sectors, it is costly to shift off gas (see Chapter 3), and gas demand will likely remain after 2050. Gas will play a small but important role in firming renewable energy generation — depending on the relative cost of offsets, abatement technologies and alternative fuels.

Options to reduce (rather than offset) emissions in gas/LNG supply range in cost. There are abatement technologies at the production stages that have low economic cost and may even create economic value if adopted. These include reduced use of flaring, energy optimisation, and methane leak mitigation. Recent studies suggest electric-powered LNG trains are increasingly economic for new facilities if secure firmed renewable electricity is available, though it is more costly to retrofit an existing facility.

Carbon capture, use and storage (CCUS) is a higher cost abatement technology but has potential to noticeably reduce emissions from the supply of gas, particularly fugitive emissions. Globally, there are 41 operational CCUS projects and 351 in development spanning a range of industries. Of these, there are 45 facilities (operating or in development) for natural gas processing. In Australia, historically there hasn't been a commercial driver to deploy CCUS, but that may change with the Safeguard Mechanism reforms.

Gas can also play an important role in contributing to lower-carbon electricity generation in Australia and our trading partners. Gas-powered generation provides firming to enable the renewable transition in Australia. Australia's LNG exports typically serve to provide energy security to electricity networks of regional trading partners and provide a cleaner alternative to greater coal use. Similarly, for heavy industry users of coal (such as steel manufacturing), gas can provide an intermediate step toward future use of hydrogen in production while lowering emissions.

2.1 Australia's gas emissions

This chapter draws on the 2023 baseline emissions projections from the Department of Climate Change, Energy, the Environment and Water (DCCEEW) to show the expected future trajectory of Australian emissions from the supply and use of gas. [3] We use a combination of emissions projections (estimates of future emissions) and emissions inventories (historical greenhouse gas emissions data).[4]

Relationship of emissions estimates to demand and supply estimates

The emissions projections provide annual estimates of Australia's emissions out to 2035. They account for the latest information on economic activity, domestic and international demand for Australian energy products, as well as technology costs and uptake. They are based on federal and state and territory policies which have been implemented or where detailed design is well progressed. The emissions projections are compiled using the UNFCCC accounting approach consistent with Australia's accounting for the 2030 target.

Presenting a single scenario — over the medium term only — contrasts with other chapters of this report in two respects. First, a range of projections of gas demand covering low, medium, and high levels of climate ambition, were provided to reflect the uncertainty of gas demand. Second, projections in the rest of this report are provided where possible for the medium (into 2035) *and* long-term horizons (into 2050). As the long-term emissions trajectory for Australian gas is highly uncertain, we supplement *quantitative* emissions projections with other information sources to draw *qualitative* descriptions that point to a range of likely paths for future Australian emissions.

The emissions projections are intended to reflect current policy settings and do not neatly align with any particular AEMO projection. For example, residential and commercial consumption is based on the orchestrated step change demand scenario, adjusted with various energy efficiency, electrification and hydrogen blending values, based on expert advice.

Box 2.1: Incentives to decarbonise

Targets and policy incentives

Australia has legislated targets to reduce its emissions to 43% below 2005 levels by 2030 and achieve net zero by 2050. The Australian Government is also developing a medium-term emissions reduction target for 2035 and a plan to reach net zero by 2050. The Paris Agreement requires all parties, including Australia, to submit their next Nationally Determined Contributions, including a 2035 emission reduction target, in 2025. This target will be informed by Climate Change Authority advice and current work mapping Australia's sectoral emissions reduction pathways.

In addition, as part of the first Paris Agreement Global Stocktake at the recent COP28 climate conference held in December 2023, the 195 parties to the Paris Agreement recognised the need to transition away from fossil fuels in the energy sector. Under the UNFCCC reporting guidelines for the preparation of greenhouse gas inventories, countries account for greenhouse gas emissions that occur within their borders. More than 97% of Australia's LNG exports are covered by net zero commitments.

The Safeguard Mechanism is a key piece of legislation for achieving Australia's climate objectives. Under the Safeguard Mechanism, Australia's largest existing industrial facilities (those with direct emissions greater than 100,000 tonnes of carbon dioxide equivalent (CO_2-e) per year) are required to keep their net emissions below a specified baseline. Facilities' baselines are reduced predictably and gradually over time in line with a calculated 'decline rate' set to achieve national emissions reduction targets. New entrants are set baselines

[3] This chapter covers emission from the supply and use of gas, contrasting with other chapters where production and consumption are used.

[4] The supply chain focus differs to the emissions projections and quarterly emissions updates from DCCEEW, where emissions from the use of gas are aggregated on a sector basis rather than by emissions source.

based upon lowest emissions intensity production globally. This includes new gas fields that supply existing LNG facilities, which will be given best practice baselines for their reservoir CO_2 emissions of zero. New projects extracting or exploring a shale gas formation are required to have net zero scope 1 emissions from entry.

Environmental approvals processes for new gas projects are also important. For projects in Commonwealth waters[5] activities are regulated by the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA). Under the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (OPGGS Act) and associated regulations, NOPSEMA assesses the potential environmental impacts and risks of activities over the life of an offshore project. For projects that occur onshore or in state and territory waters, relevant state and territory environmental legislation will apply. The Environment Protection and Biodiversity Conservation (EPBC) Act 1999 assessment will be required if the project is likely to have a significant impact on a matter protected by the EPBC Act.

In November 2023, Australia joined the Global Methane Pledge which aims to reduce global methane emissions by at least 30% from 2020 levels by 2030. Under this pledge, Australia and other signatories will work individually and cooperatively to continuously improve the accuracy, transparency, consistency, comparability, and completeness of national greenhouse gas inventory reporting under the UNFCCC and Paris Agreement.

Financial sector and shareholder pressures

There are pressures from the financial sector on producers to improve emissions outcomes. A growing number of financial institutions have been reviewing their engagement with oil and gas companies. Publicly traded oil and gas companies have been most affected by equity and debt coming under greater scrutiny due to shareholder activism and stricter lending policies by the financial sector. To date, this has predominantly affected funds from banks rather than from superannuation funds and foreign investors – which has moderated the impact on financing gas projects. In consultations, major banks and superannuation funds all expressed that they were looking for their customers to develop transition plans which outline their plans for decarbonisation.

According to the IEA, just under 20% of global oil and gas production comes from companies that have announced a target to diversify their activities into clean energy. Clean energy investment represented 2.7% of their total capital spending in 2022. Furthermore, over half of clean energy investment by oil and gas producing companies was from four companies – Equinor, TotalEnergies, Shell and BP – which each spent around 15–25% of their total budgets on clean energy. This report by the IEA was prepared before COP28, where 50 global oil and gas companies committed to net-zero by 2050 and increasing their investment in clean energy technologies.

Emissions abatement will depend on the path that companies choose in research and development (R&D), abatement technology adoption and offset use. A range of factors influence this choice. Pressure from shareholders and the lending market to decarbonise is pushing companies to adopt net zero targets. Investors are looking for companies to develop transition plans that outline their pathway to net zero.

Many companies have incorporated a price of carbon in their projects well above current market prices (such as Australian Carbon Credit Units (ACCUs), which averaged $30.67 per tonne in the second half of 2023). This has the effect of bringing forward investment in abatement. However, many companies may also hedge their adoption of abatement technologies under the Safeguard Mechanism through buying ACCUs and Safeguard Mechanism Credits.

[5] More than 3 nautical miles from shore, extending to the boundary of Australia's exclusive economic zone.

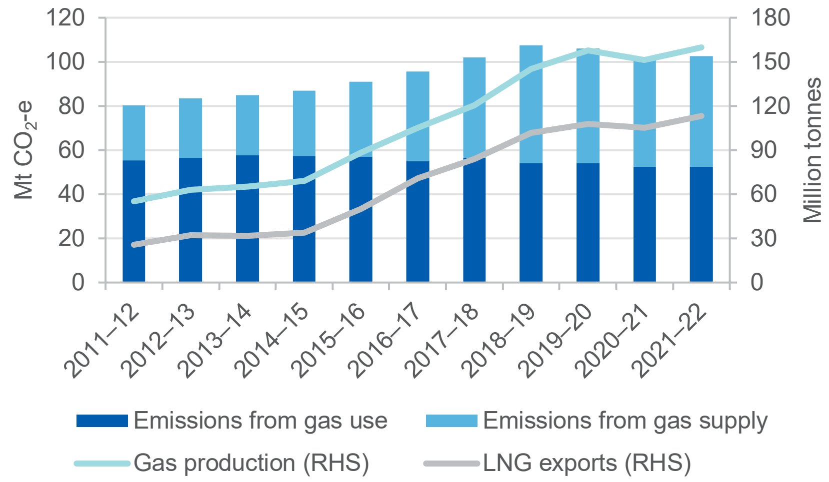
Historical emissions from the supply and use of gas

As discussed in Chapter 1, emissions from the supply and use of natural gas are responsible for a large share of Australian and global emissions. In 2022, emissions from natural gas accounted for 24% total emissions in Australia and 23% of global emissions (DCCEEW 2022a, IEA 2023c).

Emissions from natural gas can be categorised into those associated with its supply and its end use. Supply refers to the extraction, production, processing, distribution and storage of gas for domestic and export use, and end use refers to the combustion of gas for industrial and electric power, to heat residential and commercial space in Australia or as a feedstock in industrial processes.

Emissions associated with natural gas supply and its end use, peaked in 2019 at 108 Mt of carbon dioxide equivalent (CO_2-e), and are projected to continue to steadily decline. In 2022, emissions associated with natural gas supply and use in Australia were estimated to be 103 Mt of CO_2-e (Figure 2.1). Emissions associated with supply of gas accounted for 50 Mt of CO_2-e in 2021–22 (49% of emissions from gas), and emissions associated with the use of gas accounted for 52 Mt of CO_2-e (51% of emissions from gas).

Figure 2.1: Australian gas emissions and production, 2011–12 to 2021–22



Source: DISR (unpublished a) analysis of and AEMO (2023b) and DCCEEW data (National Greenhouse Gas Inventory dataset)

Between 2012 and 2022, emissions from gas supply and use increased by 28%. This was largely driven by the rapid expansion of Australia's LNG industry, with LNG production increasing by 341% over this period. High gas flaring levels during the initial years of some LNG facility operations added to emissions. Gas flaring levels have since declined as those facilities have moved to a steadier state of operations.

Most of the emissions from gas supply in 2021–22 came from two sources: fugitive emissions (43% of supply emissions) released from unintentional leaks or intentional venting and flaring; and stationary emissions (44%) associated with the direct combustion of fuels to run equipment in gas extraction, production and processing. (Table 2.1).

Table 2.1: Sources of emissions in the supply of gas

Term	Description	Share (volume)
Fugitive emissions	Emissions released during the extraction, processing and delivery of fossil fuels	43% (22 Mt CO_2-e)
Stationary emissions	Emissions from the combustion of fuels to generate steam, heat or pressure, other than for electricity generation and transport	44% (22 Mt CO_2-e)
Electricity generation	Emissions from the combustion of fuels to generate electricity (including both grid electricity and on-site electricity)	11% (6 Mt CO_2-e)
Other emissions	Emissions from transport and industrial processes incurred in the supply and extraction of natural gas and LNG.	1.1% (10.5 Mt CO_2-e)

Note: Percentages might not sum to 100% due to rounding.

Source: DCCEEW (2024)

Emissions from the use of gas, saw a modest decrease of 5.1% between 2011–12 and 2021–22 (Figure 2.2). This trend is broadly consistent across sectors (Table 2.2). In gas use, the manufacturing sector accounted for 39% of 2021–22 emissions, the electricity sector accounted for 38%, and residential and commercial buildings accounted for 21%.

Insight: Emissions from gas supply and use accounted for about a quarter (24%) of Australia's total emissions in 2021–22. Emissions from gas supply and use peaked in 2018–19 following a period of strong growth since around 2015 as the LNG industry expanded. Emissions have declined since 2018–19 due to reduced flaring in LNG operations as they reach steadier states of operation. Emissions from use of gas has remained relatively flat.

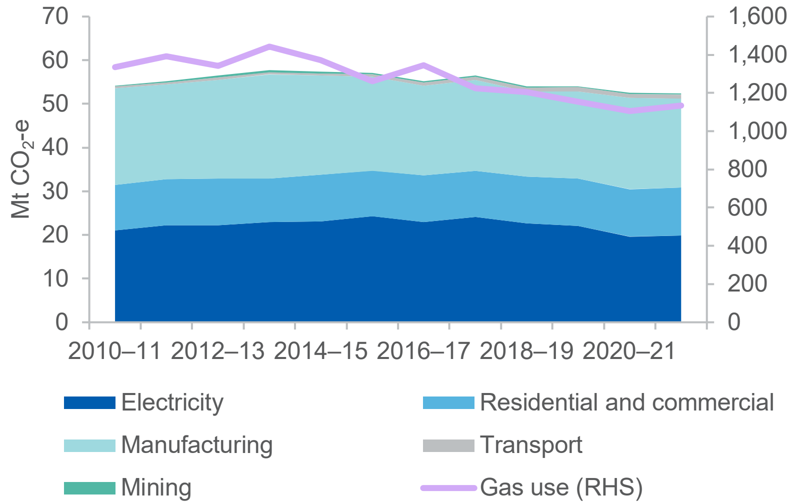
Table 2.2: Sector descriptions for use of gas and shares

Term	Description	Share (volume)
Electricity	Emissions from gas combusted for electricity production in the NEM, WEM, other small grids and off-grid.	38% (20 Mt CO_2-e)
Residential and commercial buildings	Emissions from gas combusted in residential and commercial buildings as well as construction activities associated with infrastructure, and commercial and residential buildings.	21% (11 Mt CO_2-e)
Manufacturing and other emissions	Emissions from gas combusted to provide energy and emissions from gas that is used as a feedstock in the manufacturing sector. Some sub-sectors include steel, non-ferrous metals, chemicals, food processing, non-energy mining, and pulp and paper.	39% (20 Mt CO_2-e)
Transport	Emissions from gas combusted for mobility. This includes road, domestic aviation, rail, domestic shipping, off-road recreational vehicle activity, and gas pipeline transport.	1.8% (1.0 Mt CO_2-e)
Mining	Emissions from gas combusted in coal mining and other mining sectors. Emissions from electricity generated at mining sites is allocated to the electricity sector.	0.5% (0.3 Mt CO_2-e)

Note: Percentages might not sum to 100% due to rounding. Other emissions include emissions from the forestry and fishery industries.

Source: DCCEEW (2024)

Figure 2.2: Emissions from use of gas by sector, 2010–11 to 2021–22



Notes: Gas use is AEMO consumption figures for electricity, industrial and residential and commercial sectors but excludes the LNG sector. Emissions from electricity generated at mining sites is allocated to the electricity sector. For consistency with emissions projections, AEMO 2023 GSOO is used.

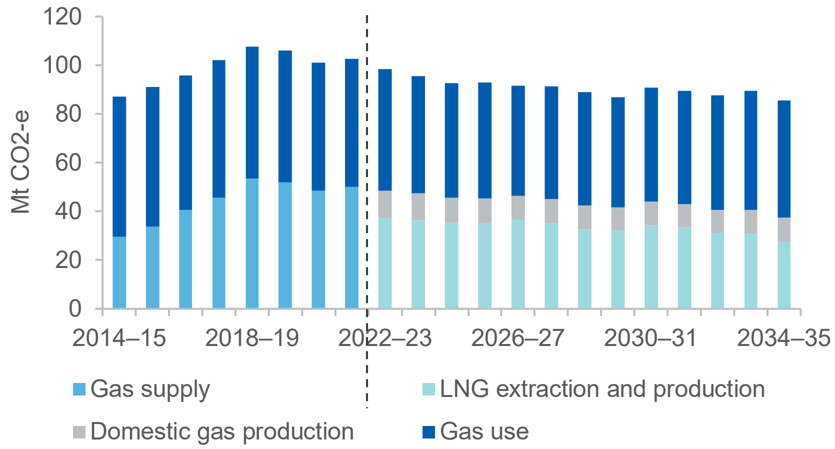
Source: DISR (unpublished b) analysis of AEMO (2023b) and DCCEEW data (Australia's emissions projections dataset)

Emissions projections for the supply and use of gas

Emissions associated with natural gas are expected to continue to fall by 17% between 2021–22 and 2034-35, from 103 Mt of CO_2-e to 85 Mt of CO_2-e (Figure 2.3 and Figure 2.4). Emissions from gas supply are expected to fall by 25% from 50 Mt CO_2-e to 37 Mt of CO_2-e, driven primarily by the Safeguard Mechanism reforms. Emissions from gas use (the larger share) are expected to fall by a more modest 8.2% from 52 Mt of CO_2-e to 48 Mt of CO_2-e.

The projected decline in emissions from gas supply is expected to be achieved by substantially lower fugitive and stationary emissions as facilities respond to the Safeguard Mechanism reforms. Fugitive emissions are projected to decline by 28% between 2022 and 2035, due to assumed efficiency gains, flaring reduction, and CCUS projects at LNG facilities.

Figure 2.3: Gas emissions by sector and use, 2014–15 to 2034-35



Notes: Emissions from LNG extraction and production include emissions from electricity, stationary energy (excluding the electricity sector) and fugitive emissions from gas.

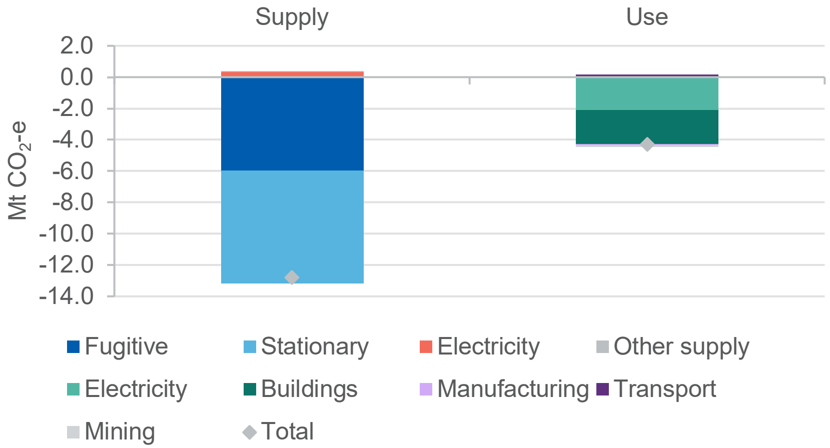
Source: DISR (unpublished b) analysis of DCCEEW data (Australia's emissions projections dataset)

On-site stationary emissions for gas supply (which are covered by the Safeguard Mechanism) are projected to decline by 32% between 2022 and 2035, driven mainly by improvements in energy and process efficiency and the electrification of LNG compressors. The natural gas use that is avoided through electrification is a potential source of additional gas supply for alternative uses.

Emissions associated with the consumption of grid electricity for the purpose of gas supply are projected to decline in line with declining emissions in the east coast National Electricity Market (NEM) and west coast Wholesale Electricity Market (WEM). These emissions will be influenced by policies affecting the electricity sector – such as the 82% renewable electricity target – rather than the Safeguard Mechanism.

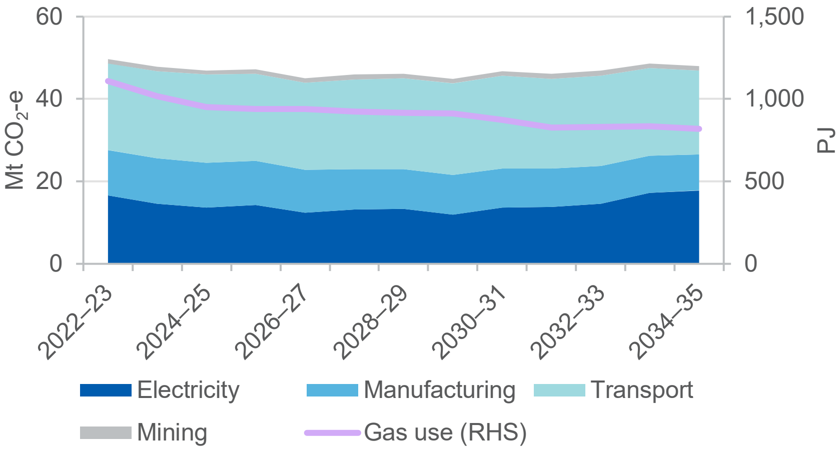
The projected decline in emissions from gas use is largely in the residential and commercial sectors (Figure 2.5), driven by efficiency improvements and electrification. The electricity sector's gas use is projected to increase from 2030 as electricity demand grows and gas provides firming and peaking supply (see Chapter 3).

Figure 2.4: Contribution to emissions reductions, 2021–22 to 2034–35



Source: DISR (unpublished b) analysis of DCCEEW data (Australia's emissions projections dataset)

Figure 2.5: Gas use emissions and gas use, 2022–23 to 2034-35



Notes: Gas use projections from AEMO's orchestrated step change scenario, which is used in DCCEEW's emissions projections.

Source: DISR (unpublished b) analysis of AEMO (2023b) and DCCEEW data (Australia's emissions projections dataset)

Uncertainty in emissions projections and hitting 2030 emissions targets

Australia has committed to reducing emissions by 43% by 2030 on 2005 levels and to achieve net zero emissions by 2050. Australia is making progress towards meeting this target (DCCEEW 2023a). This progress should be seen as part of continued efforts to get, and keep, Australia on a pathway to achieve net zero emissions by 2050. However, emissions projections are inherently uncertain. The projections assume action by gas producers and users in line with current incentives to decarbonise, including actions that facilities have indicated they are considering though are not necessarily committed to at this time. Action must continue to be taken to meet Australia's emission reduction targets.

The uncertainty surrounding emissions projections comes in many forms. Emissions could fall more than expected due to lower gas demand and supply, or from lower emissions intensity of gas consumption and production. They may also fall faster than expected due to technological advances that reduce the cost of existing abatement technologies or create new unanticipated methods of reducing or abating emissions. Alternatively, emissions may be higher than expected due to slower-than-expected adoption of abatement technologies, slower-than-expected development of commercially viable substitute technologies, greater-than-expected Australian gas production or higher than expected domestic demand for gas.

Insight: Australia has committed to reducing emissions by 43% by 2030 on 2005 levels and to achieve net zero emissions by 2050 (DCCEEW 2023; DCCEEW 2024). To meet Australia's emission reduction targets, continued action to reduce emissions by gas suppliers and users is needed. There are upside risks if emissions reduction activities occur more slowly than currently projected.

The assumed actions of gas suppliers and users underpinning the emissions projections broadly align with insights from the Future Gas Strategy consultation process. However, there remain upside risks if emission reductions activity does not continue apace – supply side emission reduction options are considered in more detail below in Section 2.2.

In consultations, gas and LNG operators highlighted the need to decarbonise at least cost with maximum effect, and emphasised the role that renewable gases can play in decarbonisation. Consultation with both the gas industry and very large industrial users of gas also highlighted CCUS as a practical pathway for reducing CO_2 emissions for specific hard-to-abate industrial processes, such the production of fertiliser, explosives or very high heat processes (see Chapter 3).

Insight: To reach net zero by 2050, continued reduction over time in gas demand and action to abate residual use will be required.

Other stakeholders suggested that the Australian oil and gas industry can address around 90% of methane emissions through existing technologies. These mature technologies can replace emitting equipment across the oil and gas value chain, with a significant portion of this abatement suggested to be cost-effective.

One key difference between the emissions projections and stakeholders is the challenge represented by electrification of LNG facilities. Stakeholders indicated electrification faces significant technical, commercial, legal and stakeholder barriers. DCCEEW's (2023a) emissions projections suggest that stationary energy emissions will fall, partly due to electrification of LNG compressors. If electrification of LNG compressors is not viable for LNG facilities, operators may choose to purchase offsets to meet their Safeguard obligations.

Insight: Consultation supports the assumptions underlying the projections. However, risks remain. Opportunities to reduce emissions from gas use vary by sector and use case. Some consultations suggested further action is needed to incentivise emissions reduction via reduced gas demand and adoption of abatement technologies.

In addition to these factors, the emissions profile of future gas projects is somewhat uncertain due to a lack of information about the composition of reserves. The environmental impact statements (EISs) submitted as part of the approval for future gas projects include this data, and some (but not all) companies report this information in their drilling results. As a result, there is greater uncertainty for reservoir CO_2 for prospective projects that have not yet submitted EISs. This uncertainty is likely to affect the venting emissions that are required to remove CO_2 prior to liquefaction or refining.

Under the Safeguard Mechanism, all new gas projects backfilling an existing LNG facility are given best practice benchmark values of zero reservoir CO_2 emissions, and will need to abate or offset these emissions. New shale gas projects — including in the Beetaloo Sub-basin — are required to have net zero scope 1 emissions from entry. Future domestic gas projects will have baselines set at international best practice benchmark values. The Safeguard Mechanism does not cover emissions from the supply of gas in the Greater Sunrise field of the Greater Sunrise Regime Area.

Reducing gas use is a key pathway to reduce emissions from gas use. Consultation suggests a range of industries are pursuing electrification and biofuels. Some gas users noted that electrification faces significant cost and infrastructure barriers, with some industry stakeholders suggesting current regulatory frameworks do not incentivise electrification enough.

Some manufacturers that use gas as a feedstock have decarbonisation plans that include switching from gas to renewable ammonia as their current plants reach end of life and low emission gases become cost competitive (later in the projection period). However, some major industrial users indicated an intent to increase gas consumption to facilitate coal-to-gas switching as part of their decarbonisation plans, as a step to using other renewable gases. Other large industrial users close to existing gas fields propose to use CCUS to reduce their CO_2 process emissions.

Energy efficiency measures were also highlighted as a key way of reducing emissions from gas consumption.

What is the long-term (beyond 2035) outlook for gas emissions?

To reach Australia's commitment to net zero by 2050, emissions from gas must be reduced. The emissions projections extend to 2035, and, as such, there are no official Government projections out to 2050. However, continued in emissions reductions through reduced gas demand and actions to abate emissions from gas use will be required to achieve net zero by 2050.

Australia's emissions reduction targets are currently supported by policies, plans, and legislation, including the Safeguard Mechanism reforms and the 82% renewables electricity target in 2030. Australia will publish net zero sectoral plans that will further guide decarbonisation pathways across sectors, and in 2025, it will set its 2035 national emissions reduction target as part of the UNFCCC-led process.

The Safeguard Mechanism legislates emissions reductions at Australia's largest industrial facilities out to 2050. After 2030, the decline rate under the Safeguard Mechanism will be set in five-year blocks such that net emissions decline on a trajectory to reach net zero by 2050. This will continue to provide a strong incentive for emissions covered under the Safeguard Mechanism to continue to decrease.

2.2 LNG emissions in Australia and overseas

Consequential emissions from Australian LNG exports

Under the UNFCCC reporting guidelines for the preparation of greenhouse gas inventories, countries account for greenhouse gas emissions that occur within their borders. Emissions from the consumption of products that are exported from Australia are reported by the country consuming the products. For example, emissions from the extraction, production, processing, and transmission of natural gas associated with LNG produced in Australia are reported in Australia's emissions inventory. The emissions from the use of Australia's LNG exports are accounted for in the consuming country's greenhouse gas inventory.

It is important to show the total emissions from Australian gas, whether consumed domestically or internationally, given global decarbonisation efforts and the impact that it will have on the Australian gas sector. The emissions from the use of gas exported by Australia are much larger than the emissions from the production of gas for domestic use. This is measured through the level of consequential emissions – emissions at the point of use or processing tied to Australian exports.

Insight: The emissions from the use of gas exported from Australia far exceed the emissions from gas in Australia. There are opportunities for Australia to help countries reduce their emissions from gas consumption, as well as opportunities to provide energy security through other lower emissions energy sources.

In 2018–19, the 'consequential' emissions from Australian LNG exports were estimated to be 210 Mt CO_2-e. This is estimated to be equivalent to 40% of Australian domestic emissions across all sectors and 195% of Australian domestic emissions from gas (Burke et al. 2022).

Despite the significant emissions from gas, emissions are likely to fall if gas displaces a higher emissions intensive fuel on a unit of energy basis. CSIRO (2019) notes that if Australian natural gas was used to displace domestic coal-fired electricity generation, emissions would fall by an estimated 31% (for open cycle gas turbines) and 50% (closed cycle gas turbine). Consequential emissions from LNG exports are much lower than exported coal on an energy content basis (Table 2.3). For countries and sectors that are unable to replace coal entirely with renewable energy generation, emissions would fall if coal was displaced by natural gas. This reduction would be more significant if lifecycle emissions from LNG fall, specifically liquefaction and regasification.

Table 2.3: Emissions from LNG exports and coal

Commodity	Quantity Mt/year	Energy content GJ/t	Emission factor kgCO$_2$/GJ			GHG emissions MtCO$_2$-e/year
			CO_2	CH_4	N_2O	
Gas	75	54.4	51.4	0.1	0.03	210
Thermal Coal	210	27.0	90	0.03	0.2	511

Source: Burke et. al (2022)

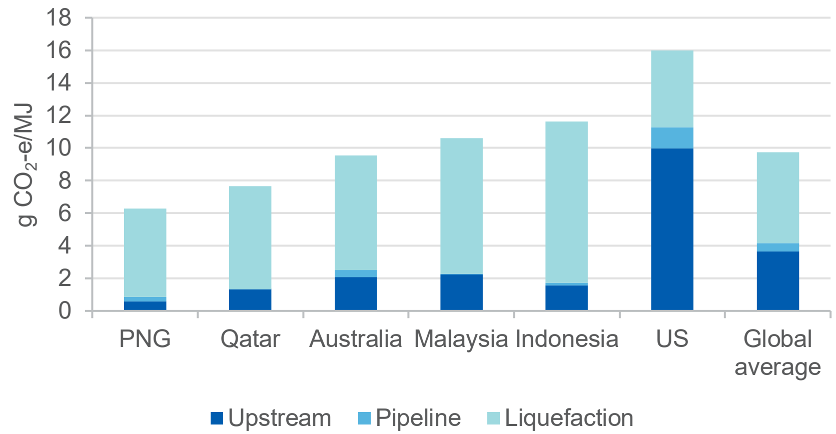
Insight: Gas can reduce emissions in the medium term if it replaces more emissions intensive fuels. However, there are sizable emissions from the supply and use of gas. To reach net zero, this transitional use of gas must be replaced either wholly or in part with a low-carbon alternative and all remaining emissions from gas must be abated or offset.

Comparing Australian upstream and midstream emissions to foreign LNG exporters

The gas supply chain can be grouped into three categories - upstream activities (such as drilling, flaring, methane losses, processing, production and venting), midstream activities (such as pipeline, liquefaction, shipping and regasification) and downstream activities (consumption). Upstream, pipeline and liquefaction emissions are related to the nature of the fields and the emissions from activities involved in the production, processing and transportation of the gas. Australia's upstream, pipeline and liquefaction emissions intensity compared to other gas exporters will become increasingly important in a carbon-constrained world, especially if carbon prices are adopted globally or for trade.

Focusing only on LNG that is loaded onto vessels, average Australian upstream emissions from gas production are estimated to be around 2.1 grams (g) CO_2-e per megajoule (MJ). This is below the global average of 3.6g CO_2-e per MJ (Figure 2.6). However, this global average is heavily skewed by US upstream emissions, which are much higher than other major producers due to the nature of unconventional production as well as the distances that gas travels from the basin to the liquefaction plant. Across major exporters, Australian upstream emissions intensity is higher than Papua New Guinea (0.6 g CO_2-e per MJ), Qatar (1.3g CO_2-e per MJ), and Indonesia (1.55g CO_2-e per MJ). However, it is slightly lower than Malaysia (2.24g CO_2-e per MJ) and substantially lower than the United States (US) (10.0g CO_2-e per MJ).

Figure 2.6: LNG export emissions intensity across the world, normal operating conditions



Notes: Shown as the emissions under normal operating conditions. Measured for LNG loaded onto vessels. Includes operational and under construction projects.

Source: Wood Mackenzie (2024)

Australian liquefaction emissions are estimated to be around 7.0g CO_2-e per MJ. Australian emissions are higher than the global average 6.4g CO_2-e per MJ, due to the large amounts of CO_2 vented at LNG facilities. Combining upstream, pipeline and liquefaction emissions, Australian LNG has an emissions intensity of 9.5g CO_2-e per MJ, slightly lower than the global average of 9.7g CO_2-e per MJ. However, this average is again skewed by US emissions being much higher than other major exporters. Qatar projects have generally low upstream emissions but its liquefaction emissions are similar to Australia's due to the relatively high amounts of CO_2 vented – the planned projects in Qatar (North Field East and North Field South) will have CCS which will reduce CO_2 venting intensity at LNG facilities.

Many of the large-scale greenfield projects under development and some that have reached final investment decision (FID) within the last decade feature designs with compressors driven by electric motors and variable speed drives. These designs significantly reduce the stationary energy emissions in the liquefaction process. This decline is expected to be more notable in other exporting nations, as Australian liquefaction capacity and investment in LNG facilities is not expected to increase at the same rate as

Qatar and the US, and so technology adoption is expected to lag (see Chapter 4).

In Australia, coal seam gas projects typically have much higher upstream emissions due to higher methane losses, gathering and boosting requirements and the significant compression required for long pipelines. Furthermore, some LNG projects in Western Australia and Northern Territory have relatively high CO_2 content in their feedstock gas, driving up liquefaction emissions.

Figure 2.7: Emissions from Australian LNG exports, 2019

Notes: Ranges shown are for Qld CSG to LNG and Jansz-lo field LNG, both shipped to China
Source: CSIRO (2021)

For export-oriented gas sectors, such as Australia, upstream and liquefaction emissions do not capture the full picture for producing and transporting gas to consumers. CSIRO analysis – for a coal seam gas project in Queensland and offshore gas project in WA – suggests that upstream emissions account for between 40 to 42% of upstream and midstream emissions (Figure 2.7). Liquefaction accounts for a similar proportion, with shipping and regasification accounting for a much smaller share. This suggests that lowering emissions in the upstream and liquefaction stages would considerably lower emissions from Australian gas supply (noting use of gas accounts for the largest share of emissions along the gas supply chain).

For the use of gas, abatement generally includes measures that reduce gas consumption, either through electrification or adoption of alternative fuels. For residential and commercial customers, emissions reduction is expected from adoption of electric appliances for space heating, cooking and water heating. These appliances are readily available and already have lower lifecycle costs than gas appliances. For industrial and mining sectors, there are existing technologies that abate gas consumption, although they are less cost effective and are not currently available in certain sectors. Costs are also relatively high for low emission gases – such as biomethane, hydrogen, ammonia, and e-methane – that can substantially decarbonise gas supply chains. Ongoing abatement of the use of gas would benefit from research and development that reduces technology adoption costs for industrial users and the production costs of low emission gases.

2.3 Abatement technologies to reduce gas supply emissions

Costs of different abatement technologies are highly uncertain and will vary across firms and facilities, depending on forecasts of the future price of carbon and electricity, as well as the cost of developing and incorporating new technologies into bespoke engineering designs and builds. Costs will also be different for new builds versus retrofits to existing facilities and include significant testing to ensure safety and efficient operation. Costs also change over time as new discoveries in engineering are made, with costs generally decreasing as issues with technology are resolved, processes become more efficient and expertise is shared.

There are several upstream abatement technologies that are already available and cost effective. For these technologies, reducing upstream emissions may create economic value for project proponents as it may increase production, increases gas availability or reduce energy consumption. In contrast, a range of other technologies are much more expensive and are at low levels of 'technology readiness'.

Low cost, immediate options

There are several upstream abatement technologies that are already cost effective and being implemented in Australia. For these technologies, reducing upstream emissions may create economic value for project proponents as it may increase production, increases gas availability or reduce energy consumption. Carydias and Nielsen (2023) estimates a negative marginal cost of abatement – which indicates that the economic benefits exceed the costs – for a substantial share (around 20%) of gas emissions. Such measures – which could be adopted within two years – include:

- Reducing routine flaring and venting through production optimisation;
- Reducing trip-related flaring through reliability optimisation;
- Energy optimisation with improved emissions intensity & recovered sales gas; and

- Methane leak mitigation.

The IEA (2020) has previously argued that stopping all non-emergency flaring and venting is the single most impactful measure in reducing methane emissions in the resources sector. At COP28, 50 global oil and gas companies (including major Australian producers and LNG operators such as Woodside, Exxon, BP, Shell and INPEX) were signatories to the Oil & Gas Decarbonization Charter where they committed to net zero operations by 2050 and ending routine flaring by 2030.

Electrifying LNG facilities

Electrification of LNG facilities would reduce the volume of natural gas used in processes to produce and export LNG. This would substantially reduce the stationary emissions from the oil and gas sector. It could also have additional benefits. Reducing gas use in LNG production could potentially assist to reduce the domestic shortfall on the east coast forecast from 2028. Electrification could also provide opportunities to dispatch flexible gas-powered electricity to other parts of the economy. If operations electrify their auxiliary energy needs, the significant on-site gas-powered generation capacity of LNG facilities could be held in reserve to provide peaking and firming with already existing assets, negating the need for some additional gas-powered generation capacity elsewhere.

For LNG operators, the economic viability of electrifying LNG facilities is informed by a range of factors, including LNG prices and a facility's operational requirements.

Electrification would require significant capital expenditure and a secure supply of electricity to a facility. Recent modelling for the Australian Government suggest that electrification of LNG facilities is becoming more cost effective (DCCEEW 2022b). For new builds, electrification appears more viable – in Australia, onsite renewable power is being considered for the second train expansion at Pluto LNG. Given the significant energy requirements of LNG facilities, electrification requires additional renewable electricity generation either sourced from the grid or on site.

Given the capital needed to reduce emissions in existing LNG facilities, investors require assurance the assets will have an economic lifespan beyond the 10–15 years remaining on existing contracts. Certainty around Government policy will be important in encouraging this investment, as will companies' assessment of future LNG prices.

The commercial viability of electrification of LNG facilities may also be influenced by how electricity generation is treated under the Safeguard Mechanism. Electrifying LNG facilities would reduce both stationary emissions from natural gas and electricity emissions, if replaced with renewable sources. Typically, LNG facilities have a small land footprint, and any renewable generation build would need to be built offsite. While the Safeguard Mechanism provides a strong incentive for electrification, consultation indicates that changing the treatment of offsite electricity generation under the Safeguard Mechanism would further strengthen the incentive to electrify in specific circumstances.

Insight: Consultation indicates that electrifying Australia's LNG facilities will require firmed power supplies and for investors to be confident they will receive an adequate rate of return on significant capital costs.

CCUS and geological storage

CCUS refers to a suite of technologies and applications — including point-source CO_2 capture, transport and underground geological storage, and emerging carbon dioxide removal technologies such as direct air capture combined with geological storage.

Originally used to pressurise oilfields to boost extraction (enhanced oil recovery), globally there are now 41 operational CCUS projects and 351 in development. These span a range of industries (including ethanol, hydrogen, ammonia and cement output). Of these, there are 45 CCUS facilities (in operation or development) for natural gas processing.

As CCUS refers to a range of technologies, the availability and cost varies considerably by technology and use case. For example, point source capture costs for concentrated CO_2 streams are generally lower. Capture costs for more dilute CO_2 streams, such as those captured through direct air capture (DAC) are significantly higher, with relatively smaller-scale plants in operation (IEA 2023). Many factors will affect the total cost, including costs associated with capture, transport and storage or use.

CCUS is the only group of technologies that both reduces emissions from the continued use of fossil fuels and removes CO_2 to balance emissions that are challenging to avoid. CCUS is therefore critical to achieving net-zero goals (IEA 2020).

CSIRO (2022) estimates suggest that the greatest potential for sequestration in Australia is from geological sequestration, with a theoretical sequestration potential of 227 gigatonnes. While the practical storage capacity, accounting for factors such as injectivity, economics and resource competition may be much lower, the total storage capacity in Australia is still expected be substantial. The Oil and Gas Climate Initiative (2022) estimated that Australia possesses 31.4 gigatonnes of sub-commercial storage resource. CSIRO (2022) notes that while CCUS alone cannot provide a path to net zero, it can play an important role in achieving decarbonisation objectives.

While many large-scale CCUS projects are not yet commercially viable, recent policy changes overseas (such as the introduction of incentives under the US Inflation Reduction Act), may bring them closer to realisation by increasing the rate of investment in research and development. In Australia, the Safeguard Mechanism incentivises onsite abatement, which provides a driver for certain facilities to consider CCUS as an abatement option where it is cost-competitive to do so. In particular, the decision to allocate a zero baseline for reservoir CO_2 emissions for new and backfill gas fields is expected to accelerate plans to deploy CCUS, particularly offshore CCUS. Capture, transport and storage costs vary depending on the concentration of the CO_2 capture stream, the distance to the storage site and characteristics of the geological reservoir.

Public perceptions of CCUS in Australia have been affected by CCUS' historical links with the oil and gas industry and its use for Enhanced Oil Recovery (EOR). More recently, public perception has been affected by some of the technical issues associated with Australia's only operational CCUS project, the Gorgon CCS project. Despite these issues, Gorgon is still one of the most successful CCUS projects globally, having stored more than 9 Mt of CO_2 between August 2019 and December 2023. Remediation work is underway at the Gorgon CCS project to increase its sequestration capacity.

Overseas, CCUS is used in a range of locations, notably in the US where industrial gas is captured and used to pressurise existing oil wells. It is increasing in use as it is incentivised under the US Inflation Reduction Act.

As CCUS can also abate emissions from industrial users, more information is provided in Section 2.4.

2.4 Abatement options to reduce gas use emissions

Residential and commercial electrification

For residential and commercial customers, emissions reduction is largely expected to be from adoption of electric appliances for space heating, cooking and water heating. These appliances are currently available, with upfront costs of electric appliances comparable to gas appliances. Electric appliances are estimated to be more cost effective over the long term, with lifecycle costs of purchasing the appliance and ongoing costs generally found to be lower than gas appliances (Grattan 2023; Victoria State Government 2024). The current rate of change from gas to electric appliances is less than is required to meet Australia's net zero targets (see Chapter 3).

Some state and territory governments have introduced policies for no new gas connections, enforcing adoption of electric appliances rather than gas appliances in new commercial and residential buildings. Without regulations, household decisions are likely to be based on factors such as appliance and installation cost, and expected ongoing fuel and maintenance costs.

Industrial and mining electrification

Decarbonising industrial and mining sectors processes will require a wide range of new technologies given the diverse processes in which gas is used. For industrial consumers, low-temperature process heat is currently able to be electrified at relatively low cost, but solutions for high-temperature process heat and feedstock use are not currently cost-effective and have not been deployed at scale. For industrial consumers who use gas in high-temperature process heat, future alternatives to natural gas include electric arc heating and alternative clean fuels.

Chapter 3 expands on the use of gas in industry and mining, and on options for reducing demand.

Research in the EU suggests that most industrial processes are likely to be electrifiable at some point – Madeddu et. Al. (2020) found that 78% of energy demand is electrifiable with already established technologies, with 99% electrification possible using technologies under development. However, there is significant uncertainty about the timeframe for technology development (and its cost), future capital and operational costs of each technology and which technology will end up the most effective. Such factors will tend to delay investment in electrification despite the decarbonisation potential.

Low-emissions gases – biomethane, hydrogen, ammonia and e-methane

Low-emission gases – such as biomethane, hydrogen, ammonia, and e-methane – have the potential to substantially decarbonise gas supply chains.

The IEA (2023f) forecasts that the global supply of low-emission gases will double by 2026 – mostly in Europe and the US. Subsidies provided as part of the REPowerEU (European Union) and the Inflation Reduction Act (United States) are expected to support growth in low-emissions gases and both regions can support distribution through well-developed gas networks. Emerging market participants such as Brazil, China and India are also expected to notably increase their production of low-emission gases.

In the near term to 2026, over half of global production growth in low-emission gases is from biomethane. Biomethane has a chemical composition very close to natural gas and under Australian National Greenhouse Accounts Factors, biomethane has a zero CO_2 emission factor as its combustion releases carbon that has been recently absorbed from the atmosphere. Biomethane can be injected directly into the gas network as a substitute for natural gas.

According to the Australian Renewable Energy Agency (ARENA) (2021), biomethane production costs are currently more attractive than other renewable gas pathways such as hydrogen. Future Fuels CRC (2022) suggests that the cost of producing biomethane in Australia varies considerably by geography, with the levelised cost of energy (LCOE) ranging between $15/GJ to $25/GJ for the sites with the lowest LCOE. Although this remains higher than the long-run average of natural gas in Australia ($10.74/GJ between 2019 and 2023), it is significantly lower than the current cost of green hydrogen, which was suggested to be around USD5/kg (equivalent to AUD60/GJ at 2020 exchange rates).

Furthermore, injecting of biomethane into the natural gas grid does not require significant upgrades of gas infrastructure or appliances. Jemena's Malabar Biomethane Injection plant is the first demonstration project in Australia to produce biomethane and inject it into a gas network. This pales in comparison to global leaders in biomethane, with Europe having 1,322 biomethane producing facilities, over half of which are connected to distribution grids.

The feedstock to make biomethane, however, is unevenly distributed in Australia and can only partially replace demand for natural gas. For instance, the Grattan Institute estimates that the 48 PJ that could be produced annually from local feedstock in Victoria would not meet the 124 PJ required to meet the annual gas demand in homes and small businesses. In this way, biomethane is likely to be more valuable to gas users where electrification is not feasible, and hydrogen is not an option or not economically viable. In Australia, several large industrial users of natural gas are building biomethane demonstration plants onsite to reduce reliance on natural gas for high heat processes.

Hydrogen is another potential low-emissions gas that could replace the use of natural gas for high heat processes or firming power generation. The emissions intensity of hydrogen varies considerably depending on energy source and production method. Hydrogen can be produced through three primary methods:

- Grey Hydrogen – the most common form of hydrogen production, produced from natural gas using a process called steam methane reformation, but without capturing or storing the greenhouse gases made in the process. Highest emissions
- Blue Hydrogen – produced from natural gas using steam methane reformation, using CCUS to trap and store the resulting emissions.

- Green Hydrogen – produced using electrolysis powered by renewable electricity. Lowest emissions

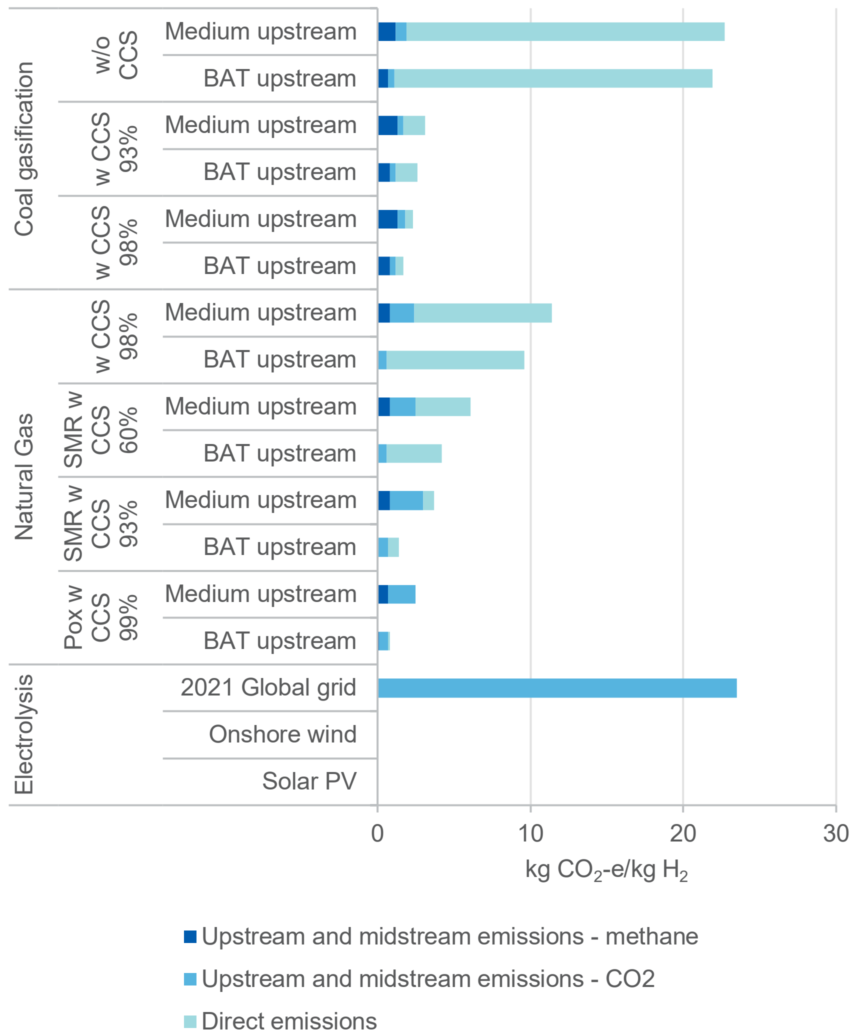
Natural (or white) hydrogen is also found in the Earth. Although this is an emerging industry, estimates suggest that the cost of natural hydrogen may be less than blue or green hydrogen. Furthermore, natural hydrogen has relatively low emissions intensity.

The relative emissions intensity is key to whether hydrogen can provide a useful fuel in a net-zero-emissions economy. Green hydrogen can potentially be manufactured with zero emissions if powered by renewable electricity. However, blue hydrogen is being produced in the US at relatively high CCUS capture rates so that the emissions intensity of final energy use is considerably lower than other forms of hydrogen produced using natural gas (represented in Figure 2.8 as the hydrogen produced from natural gas with lower emissions intensity). Further reductions in the cost of green hydrogen will be required to make it competitive in the near term with blue hydrogen (see Box 3.8).

Australia has significant potential to use renewable electricity to manufacture green hydrogen and there are many hydrogen projects at various stages of approval around Australia (DISR 2023). As noted in Chapter 3, under the AEMO (2024a) scenarios, hydrogen and biomethane uptake could reduce east coast gas use by up to 30 PJ per year by 2031. This change is driven by gas-to-hydrogen switching by industrial/mining and power generation sectors. The potential of hydrogen to replace gas within industrial processes is further examined in Box 3.8.

Key LNG trading partners (notably Japan) also see potential in Australia's future hydrogen industry and have invested in pilot programs in Australia's hydrogen sector.

Figure 2.8: Comparison of the emissions intensity of different hydrogen production routes, 2021



Notes: BAT = best available technology; CCS = carbon capture and storage; SMR = steam methane reforming; Pox = partial oxidation; Median upstream emissions = global median value of upstream and midstream emissions in 2021; BAT upstream emissions = best available technology today to address upstream and midstream emissions.

Source: IEA (2023b)

E-methane is produced by combining low-emission hydrogen and a carbon source. Although it could play a significant role in decarbonising existing gas networks without the need for retrofitting, the IEA (2023f) expects that e-methane supply will increase less quickly than biomethane and hydrogen. Due to its production costs and complex value chains, ongoing technology development and policy support were highlighted as key enablers to drive the cost of e-methane down. The IEA estimates costs in 2022 were between $76.48/GJ and $78.01/GJ.

CCUS to abate emissions from gas use

Domestically, several industries will require gas in the medium term, until low-emission gases become available at scale or until battery technology progresses well beyond today's capabilities. International climate models project a broad role for CCUS in abating emissions in hard-to-abate industries and hydrogen production. Several large industrial users are pursuing CCUS to capture emissions from industrial uses.

Overseas, there are a growing number of CCUS projects that intend to store industrial CO_2 emissions. For example, Longship in Norway is expected to become operational in 2025. Longship is a cross-border carbon capture and storage project, storing industrial emissions for consumers across Europe.

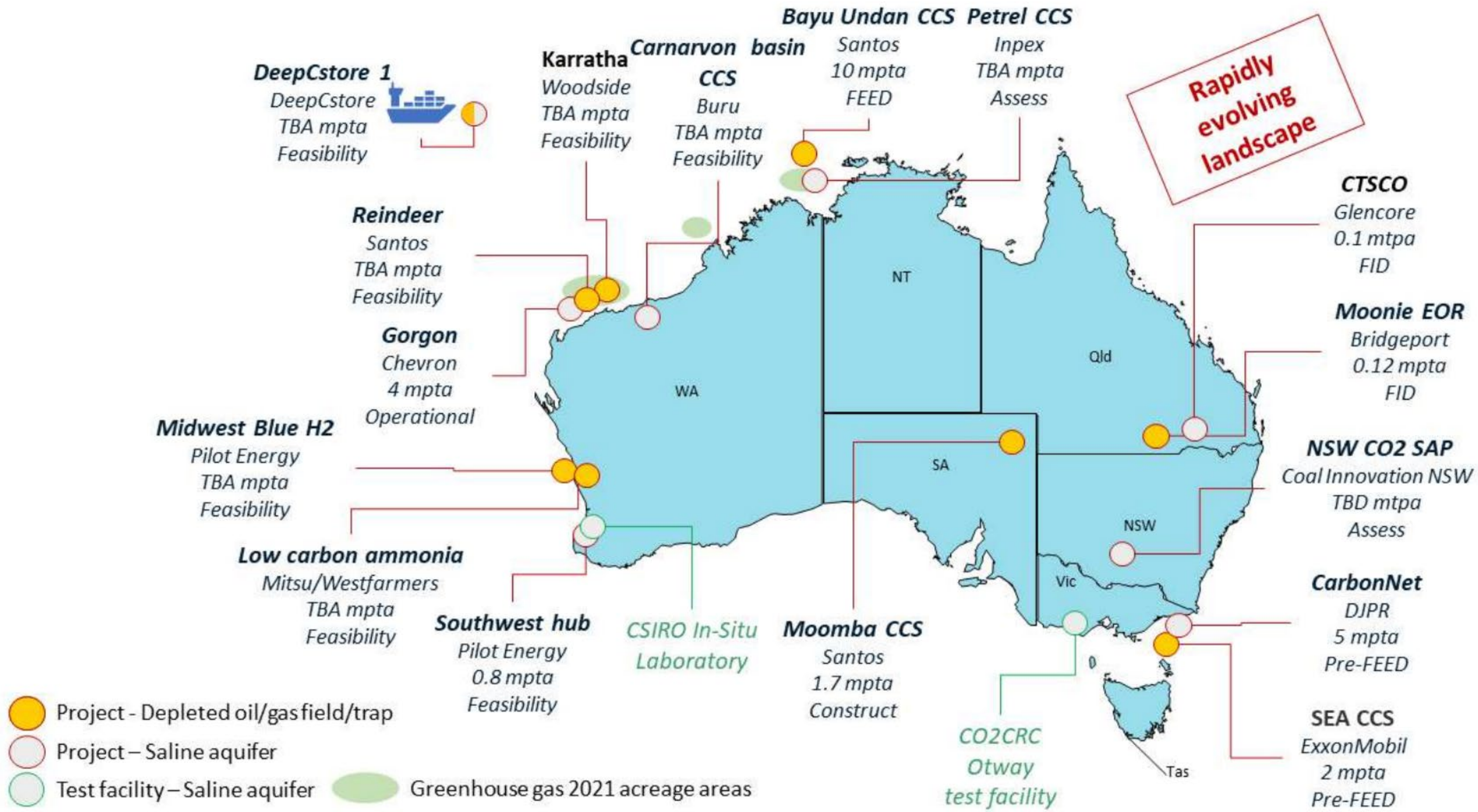
Key regional and trading partners are looking to work with Australia to utilise suitable geological storage capacity to help them meet their energy security and decarbonisation targets, including through the movement of CO_2 across international borders into offshore geological storage.

Australia passed the *Environment Protection (Sea Dumping) Amendment (Using New Technologies to Fight Climate Change) Act 2023* in November 2023. This enables Australia to ratify the 2009 amendment to the 1996 Protocol to *the Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter 1972* (the London Protocol). Ratifying this amendment is required before any CO_2 can be lawfully imported or exported for offshore geological storage.

Australia is working with trading partners on the necessary policy and regulatory frameworks to meet our obligations under the London Protocol. This collaboration will support industry to decarbonise their supply chains and provide energy security and carbon management solutions.

Insight: Climate models have projected a broad role for CCUS in abating emissions in hard-to-abate industries, hydrogen production and negative emissions technologies like direct air capture over the long term.

Figure 2.9: Location of potential CCUS projects, October 2022



Source: CSIRO (2022)

3. Domestic demand outlook

Summary

In Australia, gas underpins a wide range of economic activity and is a core component of energy security. In buildings, it is used to heat homes, heat water and to cook. It is also used to generate electricity, with gas accounting for around 5% of electricity generation and 16% of generation capacity in the NEM (east coast), and 38% of electricity generation in the WEM (west coast). In industry, it is used to produce heat (up to very high temperatures) and power, and as a feedstock for numerous chemical processes.

This chapter evaluates domestic demand for gas in the medium term (to 2035) and for the east coast out to 2043 using the scenario-based projections of gas demand produced by AEMO. The supply of gas, and whether it can meet demand, is considered in Chapter 5.

Australia has two distinct gas markets: on the east and west coasts. Projections by AEMO indicate that demand for gas in the east coast is likely to fall in the medium term as gas substitutes are adopted under current policy settings. In contrast, demand on the west coast is likely to rise in the medium term due to increased use of gas in power generation and the minerals processing sector. This is despite energy efficiency improvements in the sector. These trajectories reflect the different mix of gas use across the two sides of the country.

While domestic data beyond the medium term (beyond 2033 in the west coast and 2043 in the east coast) is scarcer and leaves important gaps for understanding the long-term trajectory of domestic gas demand, the sectoral story provides a reasoned basis to expect there to be domestic demand for gas into 2050, particularly among hard-to-abate gas use cases. Taken together with the international demand projections in Chapter 4, there is a clear role for Australian gas into 2050 across all levels of climate ambition.

The AEMO demand outlook for residential and commercial consumers indicates different pressures for the power generation and industry sectors.

Based on current technology, **gas-powered electricity generation** is expected to provide essential firming services as the renewable power generation capacity expands and coal-fired power exits Australia's grids. Within the NEM and Northern Territory, demand is projected to be volatile, with declines expected in the medium term, and increases from out to 2043 and to 2050. In particular, peak daily demand for gas in the NEM may increase by a factor of two to three by 2043. Uncertainty is high. The scenarios show a wide range of non-linear scenarios depending on the closure of coal-fired power generators and rate of build of renewables. The role of gas in firming by 2050 is uncertain but likely.; The rollout of alternatives to firming, such as long-duration batteries, hydrogen and thermal storage gives rise to this uncertainty. Within the WEM, gas demand for power generation is expected to rise to 2033.

For **residential and commercial** buildings, it is already possible to electrify household appliances (which involve low heat) and projected falls in east coast gas demand are sizeable by 2043. The key question is whether replacement of existing appliances will meet expectations.

On the east coast, **industrial** demand is also expected to decline out to 2043, but to a lesser extent. Across the diverse set of industries that use gas, multiple new technologies are needed to enable the transition off gas, involving re-engineering of processes to use different feedstock or electrification. For very high heat and feedstock applications, alternatives are still in development and expected to take longer to become viable. This is particularly a factor for west coast demand. For some processes it may not be possible to remove the use of natural gas entirely.

There are upside demand risks. Large industrial users reliant on coal for onsite power generation or as a feedstock have indicated that switching to gas could lower emissions in the interim before transitioning to hydrogen gas in the future. Stronger than expected growth in minerals processing and industrial production also creates uncertainty for gas demand.

3.1 Overview of gas demand in Australia

What are the markets for gas in Australia, and what shapes them?

Two key characteristics are critical to analysing Australian gas demand.

First, a wide range of economic factors drive and shape the demand for Australian gas (Figure 3.1 outlines share of gas use by industry and state). A brief history of the gas sector's development (Box 3.1) reveals that demand for gas (at least on the east coast) has grown in part due to its relative abundance at key points in time. Today, households, businesses and electricity markets determine the level of residential, industrial and power sector gas demand while foreign consumers determine the level of demand for Australian LNG. This chapter focuses on demand from domestic users.

Second, the profile of gas demand over the year varies across user groups and geography. Thus, both total annual demand and peak daily demand need to be considered. Seasonal changes affect the levels of gas demand, with peak daily demand in the colder months (when temperatures fall) in the southern regions and demand for heating and electricity double the levels of warmer months (Figure 3.2).

In the warmer regions of Queensland, the Northern Territory and Western Australia, consumption profiles are relatively flat throughout the year due to the dominance of demand from industrial and mining sectors, and the limited need for space heating. Demand driven by power generation can also fluctuate in response to the conditions of the electricity market across Australia, ranging from outages at a coal-fired power stations to major weather events being significant drivers of peak daily demand.

While there are common drivers, trends in demand differ across the east and west coast markets due to the different sectoral composition in each market. Information about demand is therefore presented separately for the for the east and west coast gas markets.

Box 3.1: History of Australian gas demand

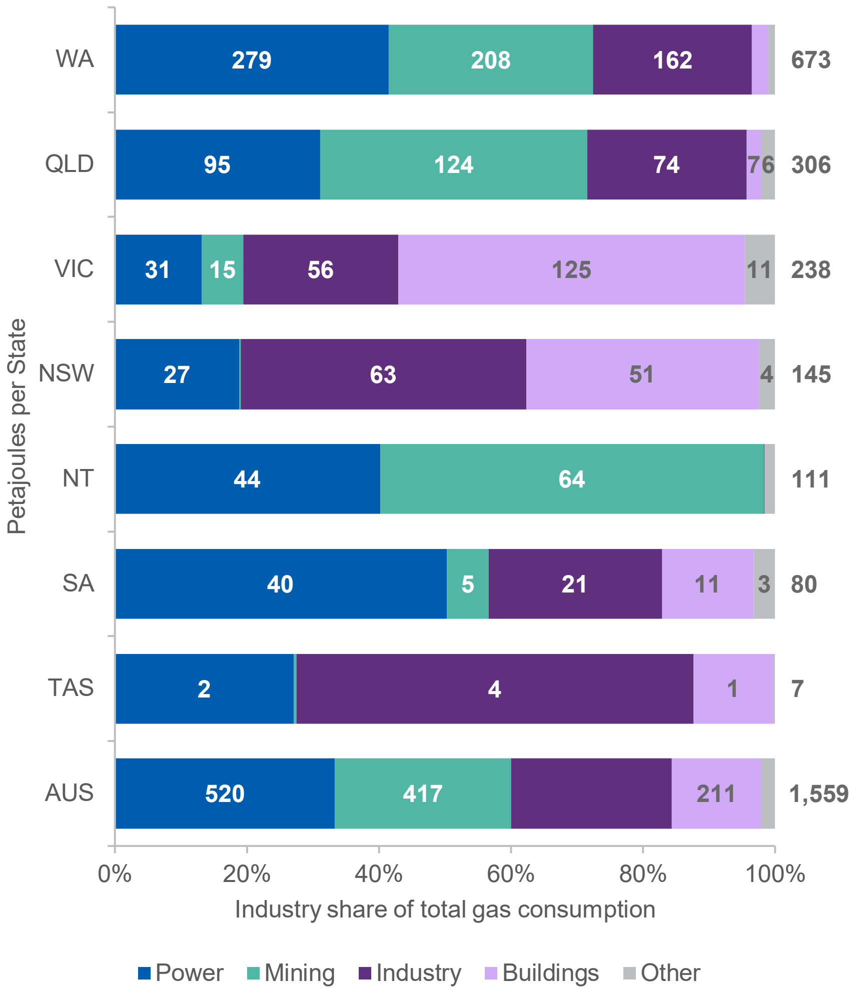
Gas has been part of the Australian economic landscape since 1841. Gas was initially used for street lighting, sourced from town gas (gas that is made from coal and distributed using pipelines). Throughout the 19th and early 20th centuries, gas street lighting became common in major Australian cities, along with gas cookers, water heaters and fires.

Major developments in the exploration and production of Australia's natural gas (that is, gas extracted from petroleum wells) industry began in the 1960s on the east coast and 1970s on the west coast. Melbourne was the first major Australian city to switch from town gas to natural gas due to its proximity to an abundant supply. Gas basins in Victoria also produced valuable crude oil and condensate which helped subsidise the production of natural gas. Because natural gas was cheap and abundant, it was used to provide space heating to a fast-growing population of residential users. The larger loads facilitated the development of the gas network, including into regional areas.

Western Australia's gas industry was initially based on town gas with the City of Perth Gas Company being formed in 1882.

The late 1960s saw a number of natural gas discoveries in WA, with the first natural gas piped to Perth in 1971. In the same year, a number of discoveries were made on the North West Shelf. Early work focused on an LNG facility, but it was deemed not feasible at this time. With the financial underpinning of the WA Government and support from Alcoa (the state's largest consumer of gas), the North West Shelf and gas industry in WA continued to grow, and the first LNG from the North West Shelf was delivered in 1989.

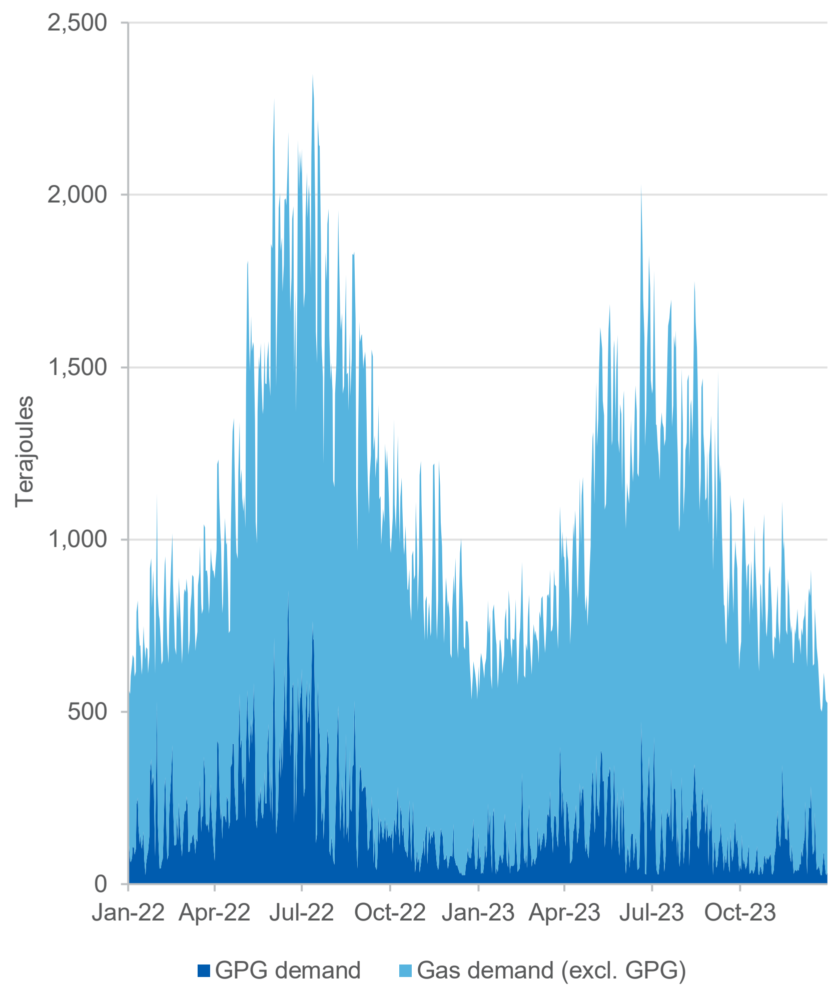
Figure 3.1: Gas demand by state and sector, and total, 2021–22



Notes: ACT included in NSW. On-site electricity generation is included in the power sector. Buildings demand includes gas use in both commercial and residential buildings. Mining demand includes gas used to power LNG liquefaction. Power demand includes gas consumed by the manufacturing sector to generate off-grid electricity. Other demand consists of gas use for transportation, agriculture, construction, water and waste treatment and gas supply. Data in this graph may not align with that produced by AEMO.

Source: DCCEEW (2023c)

Figure 3.2: Daily gas demand in Victoria, NSW, ACT, SA, and Tasmania, 2022 to 2023



Notes: GPG refers to gas-powered generation.

Source: AEMO (2024b)

Current gas use by sector

The four main end uses for natural gas that dominate Australian domestic gas markets are (Figure 3.1):

- electricity generation via gas-fired power plants and on-site electricity generation (520 PJ or 33% of 2021–22 Australian demand),
- mining and minerals processing (417 PJ or 26%),
- other industrial uses, including chemical processing, and high-grade industrial heat (380 PJ or 24%), and
- residential and commercial uses, such as cooking and heating by households and businesses (211 PJ or 14%).

Insight: About 33% of current Australian domestic gas demand is used for power generation, 26% for mining and minerals processing, 24% for (other) industrial users and 14% for residential and commercial buildings. Gas demand by sector varies across the states and territories.

The power sector is the largest source of domestic gas demand. The majority of this gas is used in gas-powered generators to produce electricity for the east and west coast, while the remainder is used in industrial and mining facilities for on-site (called 'behind-the-meter') electricity generation. Gas-powered generators are versatile: they can scale up and down rapidly, and so can provide supply during peak electricity demand (called 'peaking') to complement coal, wind and solar generation (called 'firming'). Gas-powered generators are a component of electricity markets covering every state and territory in Australia, ranging from 2% to 86% of electricity markets.

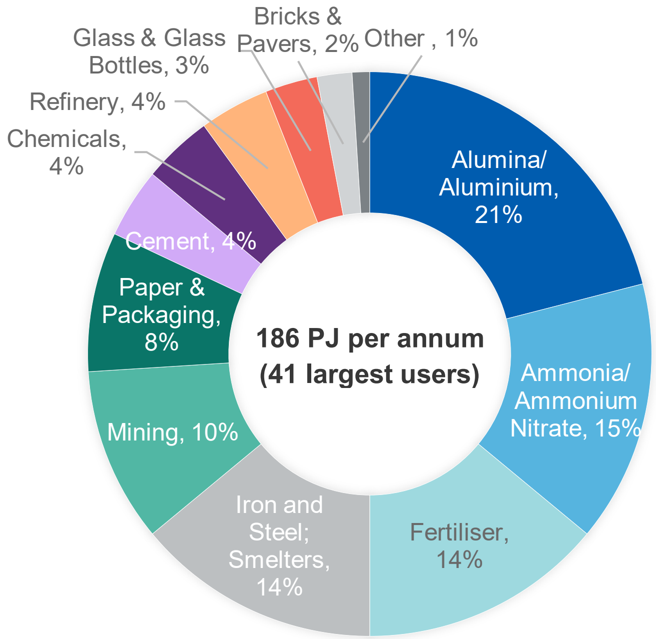
Industrial gas demand is diverse and considerably so when compared with demand from the residential, commercial and electricity sectors (Figure 3.3). In general, gas is the preferred fuel where processes require a lot of energy, high heat or as a feedstock.

The majority of gas consumed in the mining and resources is in LNG export facilities to liquify natural gas for export, and a smaller proportion is used to generate heat for mineral processing in the mining sector.

Gas is also used by industry as an input to manufacture pulp, paper, chemicals, stone, bricks, glass and processed foods. It is a chemical feedstock to produce ammonia for fertilisers and explosives, which play a major role in Australia's agricultural and mining sectors.

EnergyQuest (2023a) estimates that 74% (294 PJ) of industrial gas use in 2021–22 is for heat and other manufacturing processes, 17% (65 PJ) as a feedstock and 9% (37 PJ) for on-site electricity generation (Figure 3.3).

Figure 3.3: Indicative large industrial gas demand segments and shares - east coast and Northern Territory



Source: EnergyQuest (2023a)

Gas used by residential and commercial consumers for cooking and heating. Figure 3.1 shows that residential demand comprises 25% (195 PJ) gas demand in the east coast and 2% (17 PJ) on the west coast. The east coast market average masks significant variability between states, with 52% of residential and commercial gas demand in Victoria, 35% in NSW and 2% in Queensland.

3.2 Projections of east and west coast gas demand

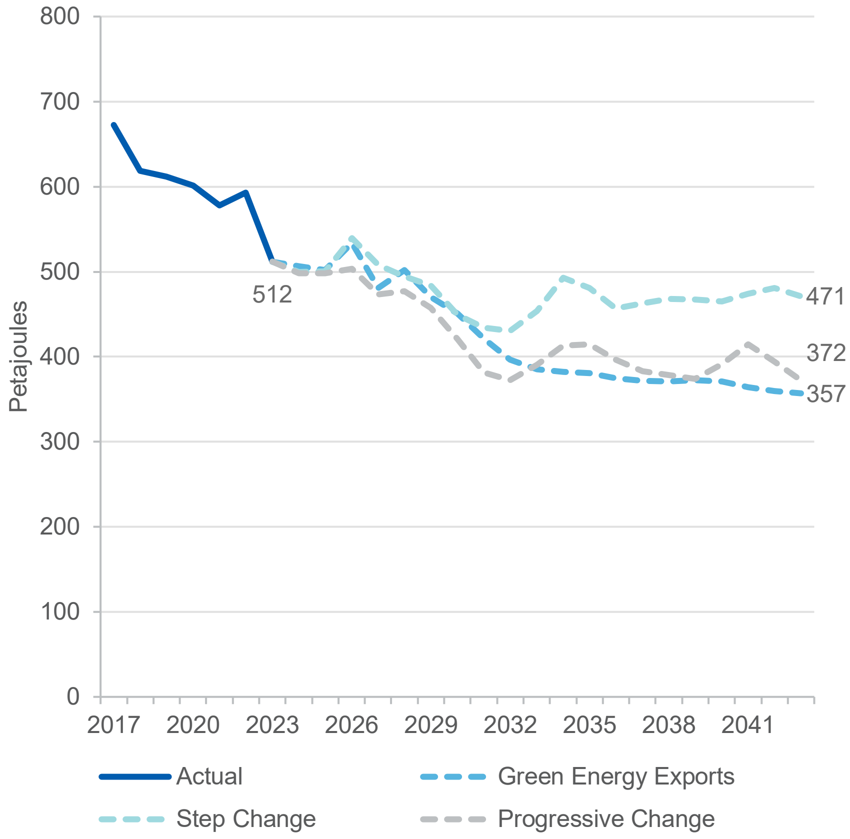
The best current source of information on domestic Australian gas demand are the detailed projections of the east coast and west coast demand scenarios in AEMO yearly publications — the Gas Statement of Opportunities (GSOO on the east coast and the WA GSOO for the west coast). AEMO projections of gas demand (drawn heavily from the 2024 GSOO and 2023 WA GSOO reports) are based around similar temperature and emissions outcomes as the three global climate-constrained scenarios published by the IEA (used in Chapters 1 and 4)[6] although they only extend to 2043. For the west coast, the outlook extends to 2033 only.

There is a wide band of potential domestic gas demand outcomes projected for both the east and west coast markets. Each trajectory depends on assumptions about the adoption of alternatives to gas and economic and social conditions. AEMO updates their projections yearly to reflect changes in knowledge, and while projections can appear to be volatile, these projections reflect the best knowledge available at the time.[7]

Insight: Annual domestic gas demand is forecast to fall on the east coast across all scenarios between 2023 and 2043, but there is a wide range of potential outcomes. In all scenarios, gas demand persists for hard-to-abate activities in 2043 and is expected to continue to 2050. Overall, there are upside risks to these scenarios in the medium term.

The rate of decline in east coast demand — across the range of scenarios — follows a broadly similar path to IEA projections of global demand (Figure 3.4).

Figure 3.4: East coast gas demand projections, 2017 to 2043



Notes: Forecasts assume demand is met by natural gas, and renewable gases if they are developed. NT domestic gas consumption (excludes LNG forecasts) is included in AEMO's east coast projections from 2020 onwards.

Source: AEMO (2024b)

[6] Consistent with the Future Gas Strategy Terms of Reference, we have chosen these pathways as off-the-shelf projections for east and west coast markets. Three major scenarios are for the east coast (Progressive change, Step Change and Green Energy Exports), and three for west coast (High, Base and Low).

[7] For AEMO's 2024 GSOO, adoption of alternative gases is explored in their Step Change scenario.

East coast demand is forecast to fall in all published scenarios. Under the most ambitious emissions scenario (called 'Green Energy Exports'), demand is projected to decline by 30% by 2043 when compared with 2023, with a spike in near-term demand reflecting accelerated coal-to-gas fuel switching. Under the least ambitious climate trajectory (Step Change), demand is projected to fall by around 8% by 2043.

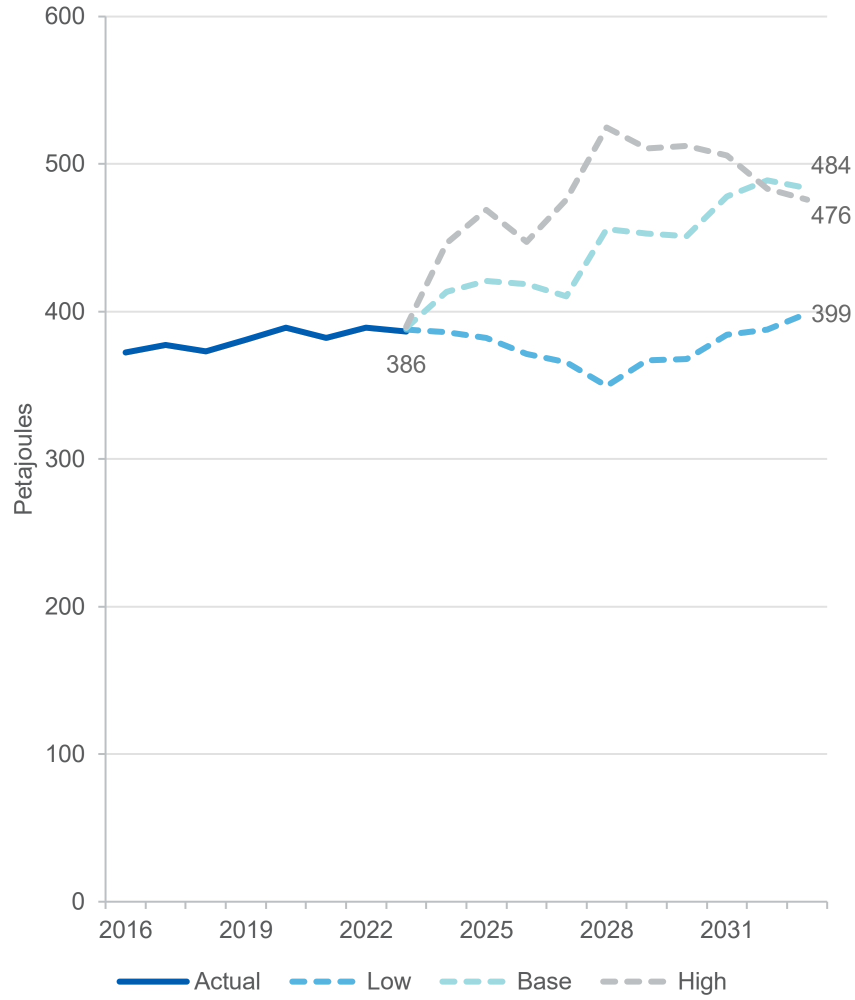
There are also upside risks associated with: facilities switching from coal to gas at a faster rate than assumed, residential demand reduction rates proceeding slower than assumed, or if the roll out of sufficient renewables and enabling technologies is slower than assumed. These issues are explored further in Section 3.3, which examines demand by sector.

The range of west coast demand scenarios varies from stable long-term gas demand under the most ambitious climate scenario (called 'Low'), to a 25% rise in gas demand over the next decade under the least ambitious climate scenario (called 'High') (Figure 3.5).

With residential demand accounting for a small component of west coast demand, differences between scenarios are explained by expected rates of growth in gas demand for new minerals processing (such as lithium hydroxide, see Box 3.2), mining and manufacturing consumers, assumed rates of increase in energy efficiency from these sources of demand, and expected rates of gas-to-electricity switching associated with renewables. There is a high degree of uncertainty for the growth rates of industrial consumers, due to the wide range of potential pathways for the adoption of emissions abatement technologies.

Insight: Annual domestic gas demand on the west coast is projected to remain steady or rise out to 2033, due to coal-to-gas switching and growing demand for gas for mining and industrial uses. AEMO does not project demand for the west coast beyond 2033 but it is likely gas demand will remain strong given the large share of gas demand from hard-to-abate industrial users on the west coast.

Figure 3.5: West coast domestic gas demand, 2016 to 2033



Notes: Low demand growth scenario assumes lower population growth and weaker investment growth in mining. High demand scenario assumes stronger decarbonisation objectives and moderate economic and population growth relative to the base scenario. Data from 2016 and 2017 was sourced from the 2022 WA GSOO.

Source: AEMO (2022;2023d)

3.3 East coast demand projections by sector

Buildings

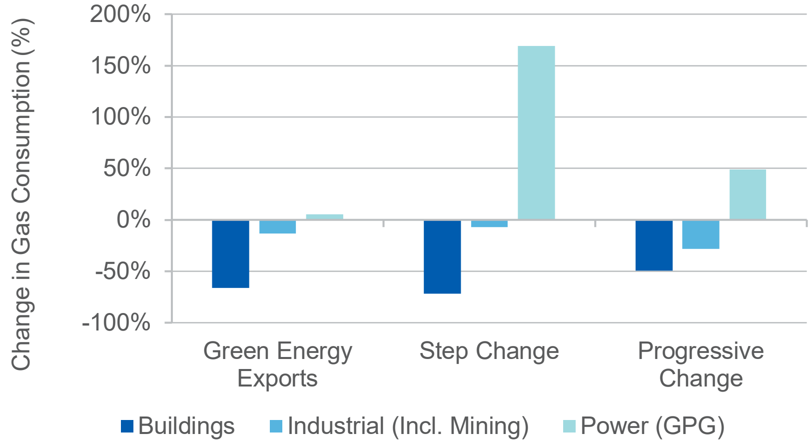
The largest declines in gas demand on the east coast (between 47% and 71% declines compared with 2023 levels) out to 2043 are forecast for buildings (Figure 3.6). Such projections assume that declines in gas use are driven by two factors: increases in the rate of electrification (the replacement of existing gas heating, hot water, and cooking appliances with an electric alternative) and reducing the growth rate of new household and commercial gas connections, largely as fewer new buildings connect to gas networks. The combined impact of these two factors on building demand outlined for AEMO's scenarios is shown in Figure 3.7.

East coast domestic projections shows that electrification could reduce gas consumption by somewhere between 136 to 203 PJ by 2043, accounting from more than a third to more than half of the reduction in gas demand depending on the scenario (Figure 3.8). Although these electrification projections also account for other sectors, most of the natural gas reduction is expected to come from electrification in buildings.

The choice to embrace electric alternatives to gas appliances depends on a range of considerations including cost, lifespan, quality of products, urgency of need for replacement, and the financial constraints the household faces. The Grattan Institute (2023) argues that households typically choose to replace like for like, especially if financially constrained or in urgent need of a replacement.

Insight: The largest projected reductions in gas demand are in the residential and commercial sector due to electrification. Falls in industrial gas demand are likely to remain more muted. Gas demand in power generation is expected to rise, due to growing total electricity demand and to firm variable renewable energy generation

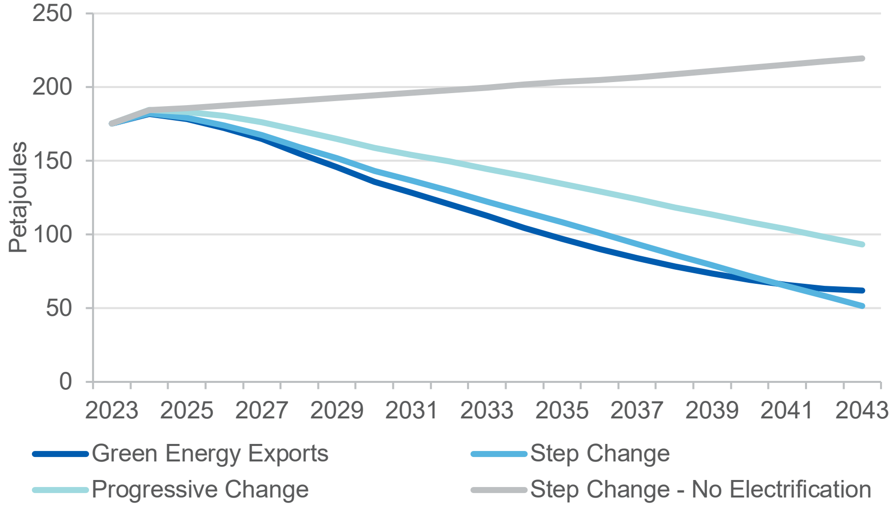
Figure 3.6: Changes in east coast demand by sector and scenario, 2023 to 2043



Notes: Step Change is comparable to the Orchestrated Step Change in the 2023 GSOO.

Source: DISR calculations of AEMO (2024b) data

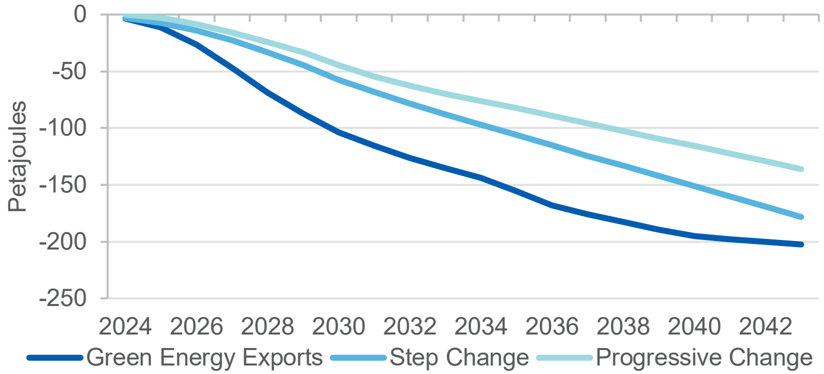
Figure 3.7: Building demand for gas by scenario, 2023 to 2043



Notes: Building demand covers gas used for residential and commercial heating, water heating and cooking on the east coast.

Source: AEMO (2024b)

Figure 3.8: Projected reduction in east coast gas consumption from electrification by scenario, 2024 to 2043



Notes: Electrification refers to the transition from gas appliances to electric appliances
Source: AEMO (2024b)

To provide an indication of the magnitude of this transition, the east coast would need to disconnect the equivalent of 143,000 net average households from gas a year for the next 20 years (just under 400 per day) to meet the reductions in household gas demand assumed within AEMO's high-ambition scenario ('Green Energy Exports'). This compares with estimates from the Grattan Institute (2023) that between 2010 and 2020, the number of residential gas customers grew by 37% in the Victoria and NSW, 22% in the ACT and 18% in South Australia. Approximately 68,000 households joined the gas network across NSW, Victoria, South Australia, and the ACT in 2021 alone.

Notwithstanding that both the Victorian and ACT governments have announced policies to stem growth in gas demand by banning new gas connections, the rate of disconnection over the coming 5 years in order to meet the most ambitious climate scenario — with close to 400,000 net reductions in connections in 2028 highlighting the difficulty of the task and there are large upside risks to the range of climate-constrained scenarios.

Improvements in energy efficiency have the potential to reduce demand by an estimated 7 PJ per annum on the east coast. Energy efficiency measures are concentrated in the residential and commercial sectors and are driven by building improvements which reduce gas demand for space heating. These improvements are supported by several state (such as the NSW Energy Savings Scheme and Victorian Energy Upgrades) and federal government initiatives surrounding construction codes and monitoring and measurement programs.

Gas-powered generation: outlook to 2035

The role of gas-powered generation is expected to evolve over time. There are important differences in the medium term (to 2035) and longer term (to 2050) outlooks for gas-powered generation. We deal with each in turn below.

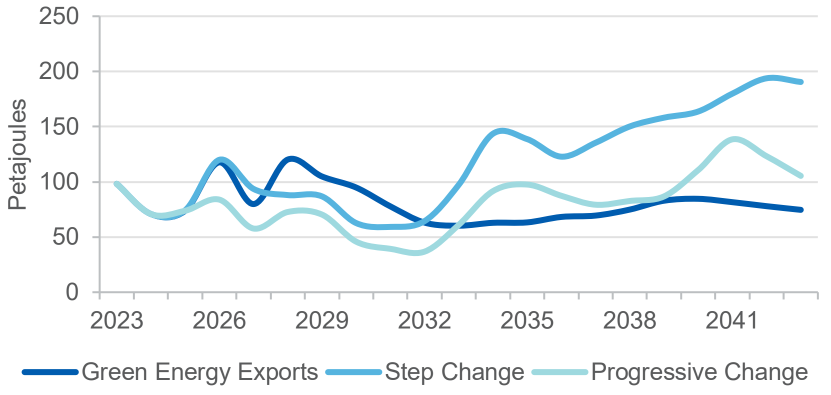
Projections suggest electricity demand will be volatile in the medium-term. Between 2024 and 2032, annual gas demand is expected to range between 37 PJ (Progressive Change) and 120 PJ (Step Change), increasing slightly from 2026 due to the retirement of coal-fired generation and growing electricity demand. Overall, AEMO projects declines in gas-powered generation that range between 34% and 63% of 2023 levels by 2032, depending on the level of climate ambition, economic growth, and industrial activity (Figure 3.9).

From 2032, annual gas demand is forecast to more than double in the Steps (from 64 PJ to 139 PJ) and Progressive Change (from 37 PJ to 98 PJ) scenarios by 2035. In contrast, the level of annual gas demand is forecast to remain stable (between 60 PJ to 63 PJ) from 2032 to 2035 in the Green Energy Exports scenario as more renewable generation, transmission and electricity storage projects are commissioned in this scenario.

AEMO's Draft 2024 Integrated System Plan suggests that gas will continue to play key role in peaking and firming generation, although it is expected to play a relatively small role in the power generation mix (Figure 3.10).

The wide range of possible outcomes – and volatile trajectory over time – reflects how gas demand depends on other aspects of the electricity market, in particular the rate of closure of coal-fired power generators and rate of build of renewables. Figure 3.9 shows that under the 'Step Change scenario' gas will underpin a greater volume of electricity generation, but a decreasing share over time (Figure 3.10), and continue to play a role in power generation to 2050 and beyond. 'Gas use' in Figure 3.10, however, is not limited to natural gas use — alternative fuels such as hydrogen and biomethane may take over the role of natural gas over time.

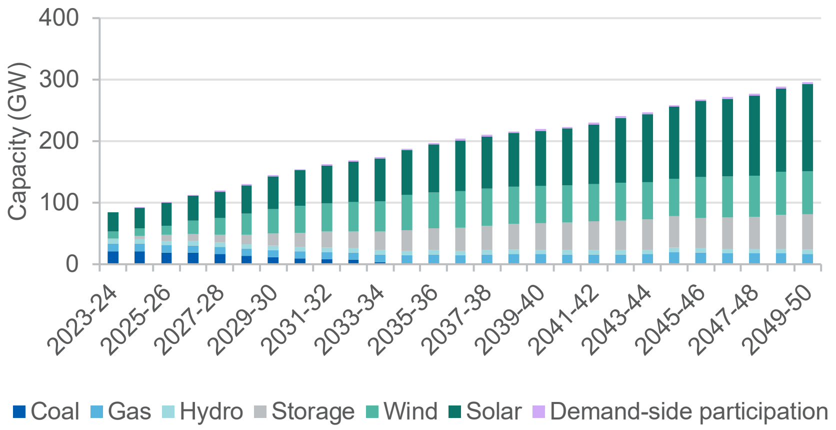
Figure 3.9: Annual gas-powered generation demand by scenario, 2023 to 2043



Notes: Includes the NEM and, from 2020, includes the Northern Territory. Assumes generators close according to schedule and not when economically unprofitable.

Source: AEMO (2024b)

Figure 3.10: Projected energy source in the NEM, Step Change



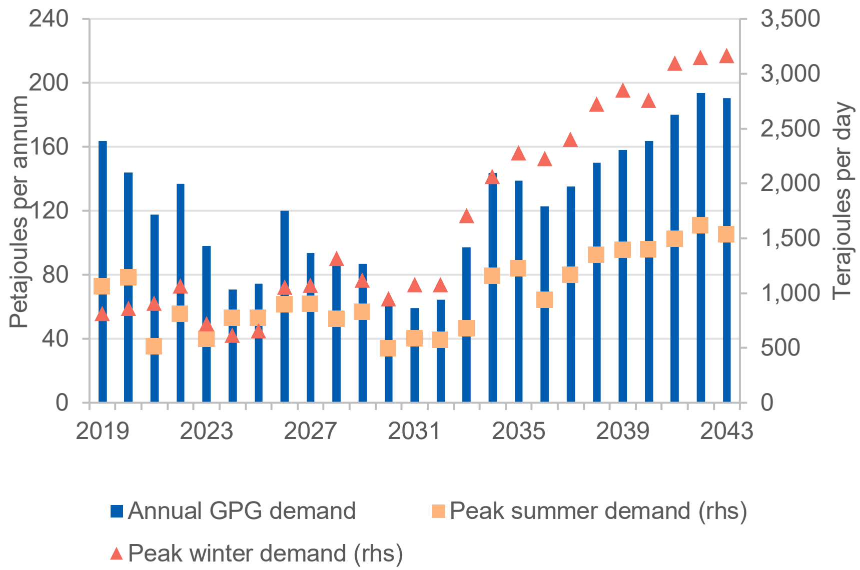
Notes: Data derived from the 2024 Draft Integrated System Plan (ISP) report for the Step Change scenario.

Source: AEMO (2024e)

The forecast increase in annual and peak daily gas demand from 2032 signals a need for investment in additional gas-powered generation capacity (or storage), to satisfy peak electricity demand and firm up variable renewable energy generation. The east coast and Northern Territory market experienced peak daily gas demand for gas-powered generation of 724 terajoules (TJ) in 2023. Under the Step change scenario, AEMO projects peak east coast daily gas demand for gas–powered generation to almost triple 2023 levels by 2035, to around 2281 TJ per day (Figure 3.11). There are also demand (and pricing) risks associated with a disorderly exit of coal fired power stations.

A significant increase in system daily capacity — and a concurrent increase in idle capacity during non-peak days — over a declining regular user base will place additional strain on the gas transmission system to deliver affordable gas. Gas costs are discussed further in Chapter 6.

Figure 3.11: Annual and peak day gas-powered generation demand, Step Change scenario, 2019 to 2043



Notes: 1,000 Terajoules is equal to 1 Petajoule.

Source: AEMO (2024b)

Gas-powered generation outlook to 2050 (and beyond)

Predicting demand for natural gas for power generation to 2050 and beyond is difficult. AEMO's Integrated System Plan (ISP) highlights the role that gas-powered generation is forecast play to 2050, but it also highlights that alternative gases or fuels will play an increasing role by 2050.

Between 2032 and 2043, AEMO forecasts per annum gas demand to rise to between 120 PJ and 200 PJ. This growth is to meet growing electricity demand and provide support in periods of low renewable generation. This trend reflects an increase in peak demand, especially in winter, where renewable power generation output is low and coal-fired power generators have since been retired. AEMO forecasts indicate large volumes of gas demand by the end of their outlook period, highlighting a significant role for gas-powered generation to maintain system security and reliability. While AEMO's current projections indicate an increase in annual gas demand, uncertainties in future energy trends and technological demand could affect the future role of gas.

There is significant potential for natural gas demand by the electricity sector to then fall beyond 2043. AEMO assumes that alternatives will be available well before 2050 – with projected demand for natural gas for electricity generation in 2043 ranging from 75 PJ to 190 PJ (AEMO 2024).

The role of gas in electricity generation will decline over time as the number of the potential commercially viable substitutes to unabated methane gas for power generation is expected to expand over the longer term. Prospective alternatives include hydrogen gas, energy storage, pumped hydro, batteries, biomethane and other biofuels. Which option(s) will ultimately prove to be most reliable and cost effective will depend on its whole-of-life price, performance, reliability, safety and other factors in the system. The technical challenges of hydrogen, in particular, as a substitute for natural gas are discussed in Box 3.7. When such alternatives will be available will become clearer over time and will be shaped by policies in Australia and overseas.

A range of energy storage technologies will compete with gas to support the electricity grid as it decarbonises. Lithium-ion batteries increasingly provide ancillary services, reducing the importance of gas to these roles. Pumped hydro provided around 8% of generation in the NEM in 2022 and will continue to play an important role in the future, including through the Snowy 2.0 and Borumba Dam projects. Other more nascent storage technologies, including flow batteries and thermal batteries, may also play a role in reducing the need for gas across the grid. However, for longer pauses in renewable generation (days to weeks) gas remains the only currently economic option.

Insight: Gas-powered peaking power generation is a core component of the NEM and Northern Territory market to 2050 and beyond. A cycle of demand is expected – with declining demand in the next decade, rising demand thereafter as coal-fired power is retired, and declining demand during the 2040s as it is assumed a greater number of alternatives to gas for peaking and firming become available. Outcomes will depend on the availability of low-carbon alternatives such as hydrogen, energy storage and the ability to safely and effectively abate natural gas.

Industrial and mining consumers

Demand by east coast industrial and mining consumers is expected to fall by less than demand from buildings (Figure 3.6 above). Across the scenarios, industrial gas demand is expected to fall by a maximum of 29% by 2043 after an initial rise due to the rapid decrease in use of coal — similar to 2023 levels (Figure 3.12).

Modest projected declines in gas consumption reflect how industrial and mining uses offer the most challenging prospects for abatement. Reducing demand may require advancement in a range of different technologies, and changes to a single facility can have a large step-change impact on demand.

There are upside risks to these projections, given proposed coal-to-gas switching by high emitters in heavy industries (particularly aluminium and steel manufacturing) not captured in the projections. Consultation indicates that some large emitters may use natural gas as the first step to reduce emissions before alternative energy sources (hydrogen) and alternative technologies are fully established.

Box 3.2: Lithium processing

Lithium processing requires high amounts of gas. Lithium can be extracted from spodumene concentrates after roasting and acid roasting operations. A concentrate with at least 6% lithium oxide or Li_2O (approximately 75% spodumene) is suitable for roasting at very high temperatures of about 1050°C during which spodumene will go through a phase transformation from α- to β-spodumene.

After roasting, the material is cooled and then mixed with sulphuric acid (95-97%). The mixture is roasted again at about 200°C. An exothermic reaction starts at 170°C and lithium is extracted from β-spodumene to form lithium sulphate (soluble in water), which is then transformed into lithium hydroxide.

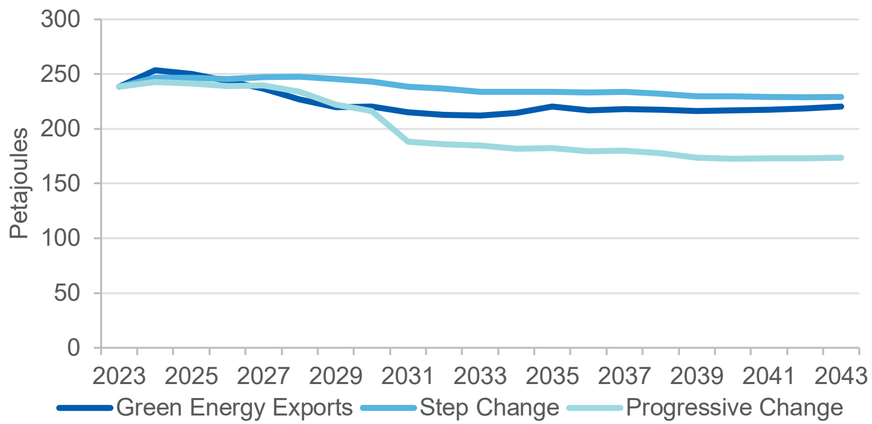
Western Australia has large deposits of lithium, and its increase in use for battery technology is continuing to climb. Australia is increasing its processing capabilities, and this will continue to impact gas demand until lower temperature processes or alternative high heat technologies become more feasible.

Source: SGS Minerals Service (2010)

The availability of gas (for coal-to-gas switching) and the accessibility of electricity for direct electrification will influence firms as they consider their gas consumption needs going forward. Given the large energy requirements of industrial and mining users, adequate gas supply is a key source of uncertainty for future gas demand (domestic supply and future gas shortfalls are examined in Chapter 5 and 7).

For example, BlueScope are considering swapping from metallurgical coal to gas for their carbon-based feedstock and high-heat processes in one east coast-based steel manufacturing facility covered by the Safeguard Mechanism. It claims this could lead to a 60% reduction in carbon emissions of their operations. This change would raise aggregate annual east coast demand by up to 32 PJ from 2032 onwards. This equates to 6% of the 2022 east coast market demand, equivalent to the entire NSW residential and commercial demand.

Figure 3.12: Industrial (incl. mining) gas demand scenarios, 2023 to 2043



Notes: Industrial users comprise fertiliser producers, mineral processing, primary metal, paper and chemical producers, oil refineries and mining. Category also captures onsite electricity generation that consumes gas. Does not capture gas used for LNG feedstock.

Source: AEMO (2024b)

Insight: In the medium term, industrial gas demand is expected to be relatively buoyant due to the versatile role that gas plays in producing very high heat, as a feedstock, and for coal-to-gas fuel switching as an emissions reduction strategy. In the long-term, reduction in industrial gas demand will depend on adoption of alternatives, and their relative costs. This includes biofuels, hydrogen and direct electrification.

Energy efficient measures will also be important and potentially low cost for industrial gas users (Box 3.3).

Box 3.3: Energy efficiency in the industrial and large commercial sectors

Northmore Gordon (in its report to the Victorian Government) identified the largest gas consuming sub-sectors in Victoria as Food and Beverage Manufacturing (16 PJ), Pulp and Paper (9 PJ), Petroleum and Coal Product Manufacturing (7 PJ), Non-Metallic Mineral Product Manufacturing (7PJ) and Basic Chemical and Chemical Product Manufacturing (6 PJ).

Using a cost-benefit analysis approach, the top ranked energy efficiency activities for Industrial sectors were Heat Recovery (11 PJ gas reduction potential, benefit-to-cost ratio (BCR) of 4.7), Burner and boiler upgrades (7 PJ gas reduction potential, BCR of 8.8), and low temperature heat pumps (8 PJ gas reduction potential, BCR of 3.9).

The top ranked energy efficiency activities for Large Commercial were: Reverse cycle chillers and packaged units (4 PJ gas reduction potential), and low temperature heat pumps (3 PJ gas reduction potential). If fully implemented, Northmore Gordon's modelling suggested potential annual reductions of 22.5 PJ across all industrial and large commercial sub-sectors by 2040.

Source: Hawkins (2022)

Industrial and mining users: high heat processes

A range of high heat processes exist in manufacturing and minerals processing. Examples include the production of alumina (Box 3.4), steel (Box 3.5), glass, bricks, ceramics and lithium hydroxide (Box 3.6).

Box 3.4: Alumina production

Alumina refining requires two high heat stages. The first — digestion — requires heat and steam at approximately 200 degrees Celsius. The second — calcination — requires heat at around 1000 degrees Celsius. According to Climateworks, there are near-term electrification options to replace fossil fuels in the digestion stage. Although gas is currently the cleanest of the economic options to produce the high heat required for calcination, hydrogen and direct electrification are prospective pathways for the calcination process in alumina production.

Source: Climateworks Centre and CSIRO (2023)

Processes require temperatures that range from above 200ºC[8] to above 1600ºC, which are difficult to achieve at manageable cost without gas or coal given current technology. This is in contrast to low-heat applications, where electrification is a viable alternative, and processes needing combustion under 500°C, which can be accommodated by thermal energy storage. There are instances globally where electrification has been indicated as a potential solution already for high heat processes. Biofuels are another promising option; for example, Rio Tinto, Brickworks and Adbri are currently incorporating greater use of biofuels into their operations.

Box 3.5: Steel Manufacturing – the road to hydrogen

The steel industry illustrates that the pathway to decarbonisation is likely to involve increased demand for gas for some industries. According to Climateworks' Pathways to Industrial Decarbonisation report, the pathway to zero emissions for steel involves adopting new processes that use gas in place of coal, before switching to hydrogen:

- Today's processes involve passing inputs of iron ore, coking (metallurgical) coal and limestone through a blast furnace and basic oxygen furnace (BF-BOF) to produce steel. Emissions per tonne of steel are 2.2t CO_2.
- Direct reduced iron and electric arc furnaces (DRI-EAF) offer significant emissions savings and is a technology that is currently in early-stage deployment. Emissions per tonne of steel using natural gas feedstock are 1.4t CO_2. However, this process will need to be adjusted for Australian ore types.
- DRI-EAF can also be operated with hydrogen in place of natural gas with zero emissions of CO_2.

Source: Climateworks Centre and CSIRO (2023)

[8] It's important to note that there is no established consensus on the boundary between low- and high- temperature heat. The range presented here is consistent with meta-analysis by IEA Bioenergy (2021).

Feedstock

Natural gas is also used as a feedstock (i.e. to provide molecules) to make other products, such as plastics, fertilisers, packaging, clothing, tyres, detergents, insulators, rubber, propellants, pharmaceuticals refrigeration, adhesives, cosmetics and many others.

A range of manufacturing or refining processes are looking to hydrogen as a potential substitute. Hydrogen gas is an alternative for processes that convert methane gas to hydrogen, such as for fertiliser and explosives production (see Box 3.6). However, it should be noted that for some reactions, substituting hydrogen for natural gas may also require sourcing alternative sources of carbon (see Box 3.7).

Box 3.6: Natural gas as a chemical feedstock

Fertiliser and explosives

The Natural Gas/Methane molecule is comprised of one carbon atom and four hydrogen atoms (CH_4). Combining Natural Gas (CH_4) with water vapor (H_2O) via steam-methane reforming yields one molecule of carbon monoxide (CO) and three molecules of Hydrogen atoms ($3H_2$).

Steam methane reforming reaction:

$$CH_4 + H_20 + (heat) \rightarrow CO + 3H_2$$

The residual carbon monoxide (CO) is then combined with more water vapor (H_2O) to create carbon dioxide (CO_2) and an additional molecule of hydrogen (H_2) via a water-gas shift reaction.

Water-gas shift reaction:

$$CO + H_2O \rightarrow CO_2 + H_2$$

After Hydrogen $3H_2$ has been separated from water and natural gas, it's then combined with atmospheric nitrogen (N_2) via the Haber-Bosch process to create two ammonia molecules ($2NH_3$) which is the primary building block for fertilisers and explosives.

Haber-Bosch Process:

$$N_2 + 3H_2 \rightarrow 2NH_3$$

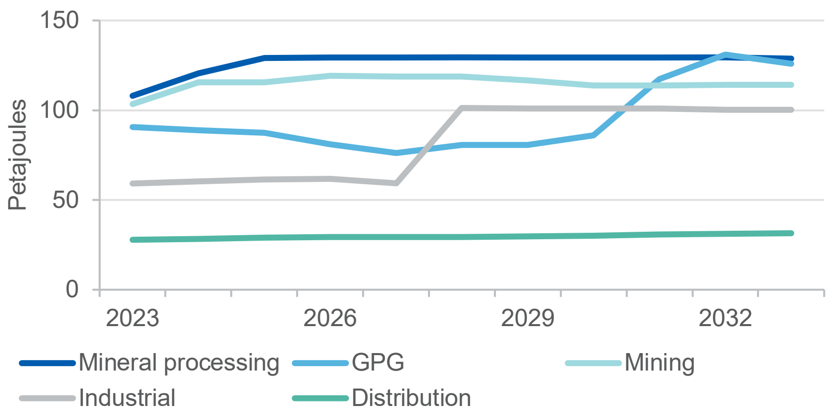
An emerging alternative to natural gas is green ammonia that is produced using renewable energy. Green ammonia can be used as a feedstock for both current applications (such as chemicals, fertilisers and explosives) and new applications (such as power generation, maritime transport and as a transport medium for hydrogen). Green ammonia production is expected to increase over the coming decade, both in Australia and globally. Existing grey ammonia (fossil-fuel based) firms in Australia — including Orica, Yara and Incitec Pivot — are actively engaged in developing pathways from grey to green ammonia in their operations. Globally, as of 2023, there were over 185 planned projects that intend to make ammonia from hydrogen). Similar to green hydrogen, ammonia is expected to become more cost competitive against gas in future decades.

There are barriers to altering feedstock. Chemical processes are typically fully integrated into a wider facility structure, and significant upfront capital investment may be required to modify existing equipment or add a new stage to the process entirely. It is therefore likely to require a change to the whole operation rather than a gradual change. It may also require facility-specific development of new processes, technologies and testing prior to commercial deployment.

3.4 West coast demand projections by sector

The factors driving demand from east coast gas consumers are also relevant to the west coast, despite differences in sectoral composition in each market (Figure 3.13). Western Australia has a high concentration of industries which use high heat and a large mining and minerals processing sector, and gas-powered generation demand is increasing by 2033 as part of a coal-to-gas switch. The Western Australia government in its Energy Transformation Strategy sees gas-fired generation remaining important beyond this outlook period, despite a move to increase the proportion of clean energy sources into the energy mix. There is a lack of modelling available for the west coast beyond the next decade. Given the more concentrated structure of the west coast market, detailed sector analyses are considered commercial in confidence and unavailable for publication.

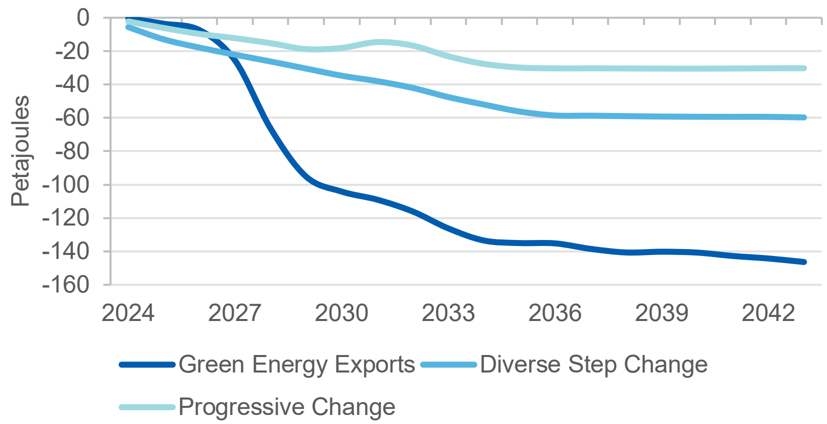
Figure 3.13: West coast gas demand by sector, 2023 to 2033



Notes: Projections are derived from WA's base case scenario.

Source: AEMO (2023c)

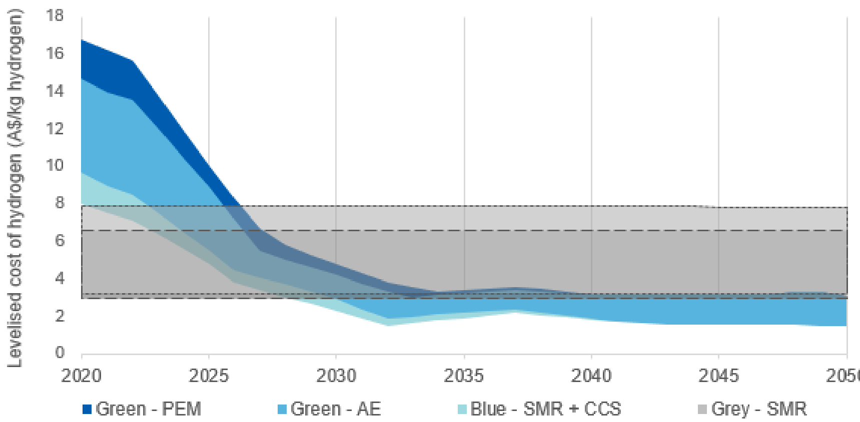
Figure 3.14: Forecast reduction in gas consumption due to biomethane and hydrogen uptake by scenario, 2023 to 2042



Notes: The hydrogen and biomethane forecast was not updated in the 2024 GSOO as there were no material additional commitments since the 2023 GSOO. Forecast is from the 2023 GSOO.

Source: AEMO (2023b)

Figure 3.15: Levelised cost of hydrogen in NEM regions, 2020 to 2050



Notes: PEM = Proton Exchange Membrane, AE = Alkaline Electrolysers, SMR = Steam Methane Reforming. Analysis by CSIRO and Australian Industry Energy Transitions Initiative.

Source: Climateworks Centre and CSIRO (2023)

Box 3.7: The potential of hydrogen to reduce gas demand

Hydrogen is a high potential fuel for producing high temperature heat and is a useful source of molecules for industrial processes such as ammonia. According to the scenarios modelled by AEMO[9], hydrogen and biomethane uptake could reduce east coast domestic gas consumption somewhere between 30 to 150 PJ by 2042 (Figure 3.14). This accounts for more than half of the total reduction in gas demand in the high ambition scenario ('Green Energy Exports', 66%), medium-ambition scenario ('Step Change', 68%) and low-ambition scenario ('Progressive Change', 60%), respectively.

This change primarily comes about due to gas-to-hydrogen switching by industrial/mining and power generation sectors (in this box, gas refers to natural gas rather than hydrogen gas). Opportunities for household and commercial use are limited. The IEA estimates that burning green hydrogen in boilers would require three-to-five times more renewable energy than highly efficient heat pumps to deliver the same amount of heat in a home. Further, most gas appliances currently tolerate a maximum of 13% of hydrogen blended with natural gas.

Increasing the blend further would require households to invest in hydrogen-compatible appliances — which appears unlikely to be cost competitive relative to electrification that works with current appliances. For households and low-heat commercial activities, electrification and renewable energy are the strongest alternatives to natural gas.

Hydrogen is not currently viable for industry. There are significant challenges in delivering hydrogen economically at the scale needed by industry and power generation. The challenges include:

- The cost of gas to industrial users
- The cost of producing hydrogen, whether powered by gas or renewables, and
- The viability and cost of transporting hydrogen from point of manufacture to the user.

As the cost of gas increases, there is greater incentive for industries to substitute to green hydrogen production. Both grey (using gas) and blue (using gas and CCS) hydrogen are currently cheaper than green hydrogen in Australia and overseas. High gas prices in the wholesale market can increase the cost of blue and grey hydrogen by increasing prices paid by industrial users under long-term contracts.

While the relatively high cost of green hydrogen currently hinders widespread adoption, costs are expected to decline substantially over the coming decades. This will be driven by falling costs in hydrogen production, with solar and electrolyser costs forecast to fall between 2023 and 2050 by around 60% and 90%, respectively. Water is expected to account for around 10% of hydrogen production costs in 2050, but costs will vary by location and access to water pipelines.

Industry stakeholders have reported that their current production costs sit between AUD4/kg and AUD8/kg, well above levels considered 'economically viable'. Nonetheless, modelling by the CSIRO suggests green hydrogen could be cost competitive with grey hydrogen (using unabated gas) and blue hydrogen (using gas and CCUS) in the 2030s (Figure 3.15). By 2050, the levelised cost of hydrogen production in Australia is expected to fall to between AUD2.24/kg and AUD3.63/kg (or USD1.46 to USD2.36) depending on location (the national average is expected to be AUD2.89/kg or USD1.88/kg). Australian project production costs for 2050 fall within the range of USD1–2/kg expected to be globally competitive.

In line with price declines and other incentives, Australian hydrogen production is expected to increase significantly between 2025 and 2050.

The degree of uncertainty around when and at what price hydrogen will

[9] These scenarios are from the 2023 GSOO. No updates were made to the hydrogen and biomethane forecast in the 2024 GSOO, as no material renewable gas facilities (biomethane or hydrogen) have been committed since the 2023 GSOO.

be available at scale should not be underplayed. Future widespread production of green hydrogen will be dependent on sufficient renewable energy availability, particularly solar and wind generation. Insufficient renewable energy production or high renewable energy costs would likely limit green hydrogen production or increase costs.

In addition to low-cost hydrogen becoming widespread, industrial processes will also need to be significantly altered to allow for hydrogen-based energy production. This will require significant R&D over a sustained period to enable this transition. The manufacturing process itself may need to be altered to accommodate the change from a carbon-based feedstock to hydrogen (for example see Box 3.6). Even if a direct replacement, different engineering optimisation will be required due to the different chemical properties of hydrogen and gas. Extensive testing and new safety protocols will also be needed.

Furthermore, hydrogen can damage (embrittle) most ferrous metals. The extent of this damage is influenced by factors such as hydrogen concentration, pressure, temperature, and material composition. Therefore, a switch to hydrogen from natural gas would necessitate upgrades to various components of current infrastructure and industrial facilities, as well as potential changes to processes. Upgrades and changes may include using materials that are more resistant to hydrogen embrittlement and blending hydrogen with natural gas for transport via existing gas pipelines. Some pipelines in Australia are already hydrogen-ready, particularly distribution pipelines.

4. International demand outlook

Summary

The role of Australian gas in the regional energy transition is within scope for this inquiry. Australia is currently one of the world's largest LNG exporters, providing an essential energy contribution to Asia in particular. This supports regional economic prosperity and regional energy security, while Australia receives economic and strategic benefits from strong bilateral relationships. Foreign direct investment from key energy trading partners may also assist Australia to innovate in the supply of lower-emissions fuels, such as hydrogen.

Nonetheless, emissions from Australian LNG contribute significantly to Australia's emissions reduction challenge and to global greenhouse gas emissions (see Chapter 2). Reducing emissions from the production and use of LNG is critical to achieving Paris-aligned targets. There are concerns raised by climate-vulnerable countries in the Asia-Pacific, particularly Pacific Island countries, and other partners regarding the climate impacts of Australia's continued gas production and export.

This chapter provides analytical evidence of demand for Australian LNG over the transition period, drawing on IEA projections of demand under different scenarios, consultation and modelling by DISR using the NexantECA World Gas Model.

Under IEA (2023) scenarios, global gas use continues until 2050 and beyond, although the ability to abate gas use through CCS is also assumed. Significant reductions in demand are implied under the IEA's APS (announced pledges) and NZE (net zero emissions by 2050) scenarios. However, consultation suggests gas may play a more significant role in the world during the transition (and beyond) than what is currently built into the IEA's forecasts. Indeed, there are risks in the short term that gas use will exceed even the IEA's (2023) World Energy Outlook STEPS (current policies) scenario forecasts.

Today, Australia exports to the Asia region, building on its long trading and investment relationship. Regional demand for Australian gas is expected to sustain throughout the transition, albeit with declines from current levels under the APS and NZE scenarios. While Australia's direct cost base for gas production is high relative to our exporting peers, our institutional settings make us an attractive partner for those seeking energy security at affordable prices.

A balancing consideration is that alternative sources of supply are emerging in the Asia region. While Australia might be a preferred trading partner, our Asian neighbours could instead (or also) source gas from alternative partners including the US and Qatar, but potentially also Papua New Guinea, Canada, or Russia.

Relative emissions intensity will likely prove an important consideration for export demand in the future. Currently Australian LNG has an average emissions intensity relative to peers. Reductions in venting and flaring and action to reduce LNG train emissions could see Australian LNG become more attractive to trading partners as they undertake their respective transitions to clean energy. With Asian trading partners looking for abatement through CCUS, demand may become increasingly shift to gas exporters who offer lifecycle emissions management.

The availability of Australian gas to service Asian demand is unlikely to prove a binding limit on the level of ambition that Australia might wish to achieve (domestic supply considerations will be discussed further in Chapter 5). However, significant investment in exploration and development would be needed to prove up new gas resources on an export scale (see Chapter 7).

4.1 Developments in global gas supply and LNG trade volumes

Australian LNG is likely to play an important role in supporting the energy needs of partners. However, there are concerns raised by climate-vulnerable countries in the Asia-Pacific, particularly Pacific Island countries, and other partners regarding the climate impacts of Australia's continued gas production.

This chapter first presents the bilateral trading relationship between Australia and gas export destination (and investor) economies. We then examine how Australia's trading relationships might change under different pathways of climate ambition, and then turn to the role that Australian gas plays in underpinning regional energy security.

Underpinning the narrative of global gas demand are the three different levels of climate ambition based on the scenarios from IEA's World Energy Outlook (WEO) 2023. Here, we complement WEO projections with the Nexant World Gas Model and examine LNG (and Australian LNG) demand by key trading partners in the region.

We note that these models are based on price signals alone, and that there are additional factors (such as energy and supply diversification needs) that could encourage the purchase of Australian LNG.

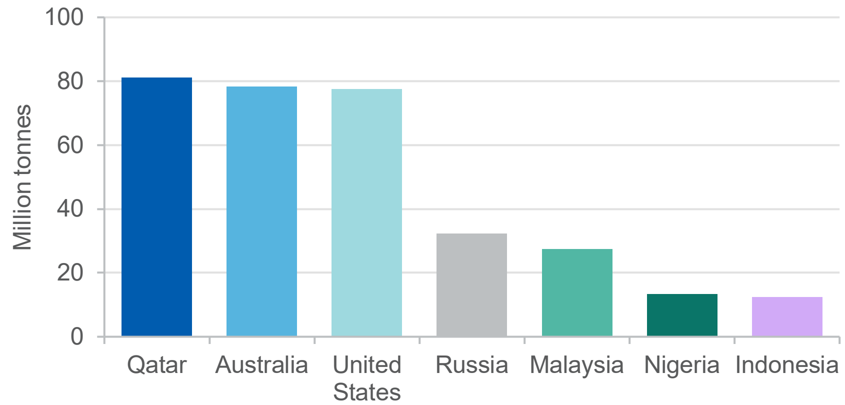
Australia's LNG exports underpinned by investment relationships

Australia currently accounts for a fifth of global LNG trade and 4% of the global gas trade. In 2022–23, Australia exported 81 million tonnes (Mt, or megatonnes) of LNG, which is comparable to the LNG volumes exported by the US and Qatar and among the largest exporters in the world (Figure 4.1). Australian natural gas is solely exported as seaborne LNG, whereas other countries include varying degrees of pipeline exports in their trade mix.

Australia's LNG investment and stable supply have been fundamental to our regional bilateral relationships, with Australia receiving economic and strategic benefits beyond LNG sales. Significant foreign direct investment in Australian gas production from these regional energy partners has also made an important contribution to Australia's own domestic energy security and affordability. Foreign direct investment by these partners is also assisting Australia to innovate solutions needed as part of the energy transition, with countries such as Japan investing in early-stage development of new technologies such as hydrogen manufacture and transport.

In 2022–23, over a third of Australian LNG was exported to Japan (accounting for 36% or 29 Mt), followed by China (28% or 23 Mt) and ROK (15% or 11 Mt) (Figure 4.2). All three of these countries are long-term export destinations — with Japan receiving its first Australian LNG shipment in 1989, ROK in 2003, and China in 2006. Members of the Association of Southeast Asian Nations (ASEAN) accounts for another 10% (or 8 Mt), with the main importers in the bloc being Singapore, Thailand and Malaysia.

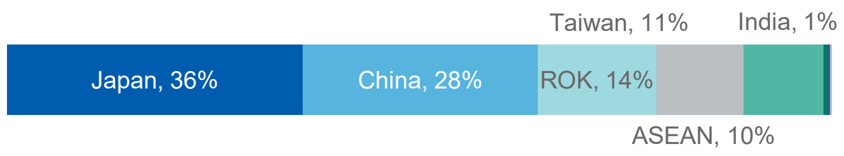
Figure 4.1: Major LNG exporter volumes in 2022–23



Notes: Inclusive of top seven export volumes based on shipping data.
Source: Kpler (2023b)

Insight: About 90% of Australia's 2022–23 LNG exports went to Japan, China, ROK and Taiwan. The Australian LNG sector has long been a beneficiary of investment funds from these trading partners; Japan since the late 1980s and others since the 2010s. Japan, ROK and Taiwan heavily rely on Australia's LNG, meeting 36% of their combined gas demand. These economies have hard-to-abate emissions profiles and have indicated a need for Australian LNG as they strive to meet net zero goals and targets.

Figure 4.2: Export destinations for Australian LNG in 2022–23

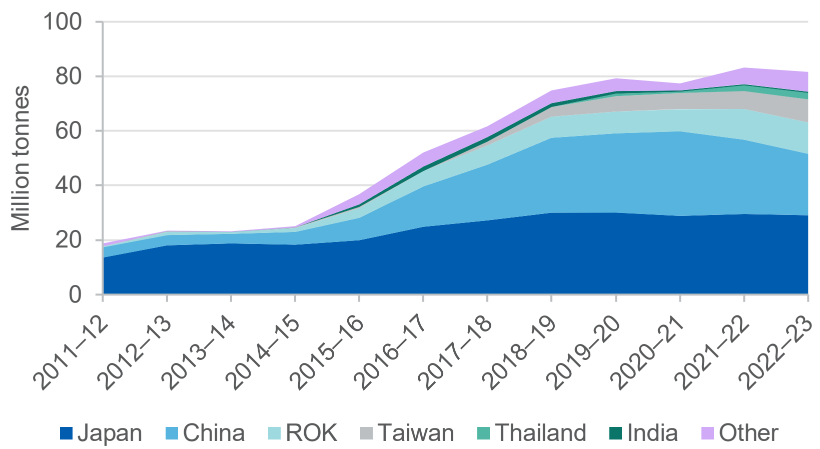


Notes: ASEAN includes Indonesia, Malaysia, Philippines, Singapore and Thailand. Other is less than 1%.

Source: Kpler (2023a)

Japan was a key early investor in the Australian LNG sector, as a sponsor of Australia's first export project (the North West Shelf Joint Venture Project) in the late 1980s. Contracts with other Asian trading partners were signed in the 1990's (China) and early 2010s (ROK and Taiwan) (Figure 4.3). Figure 4.3 shows how Australian LNG export volumes have grown rapidly in the past decade.

Figure 4.3: Australian LNG exports, by destination, 2012 to 2023

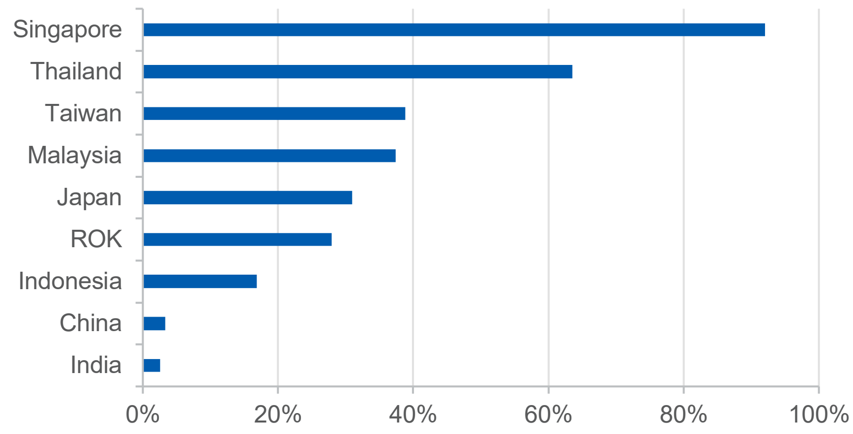


Notes: Export figures cannot be disaggregated prior to 2011–12 and were omitted.

Source: EnergyQuest (2023c)

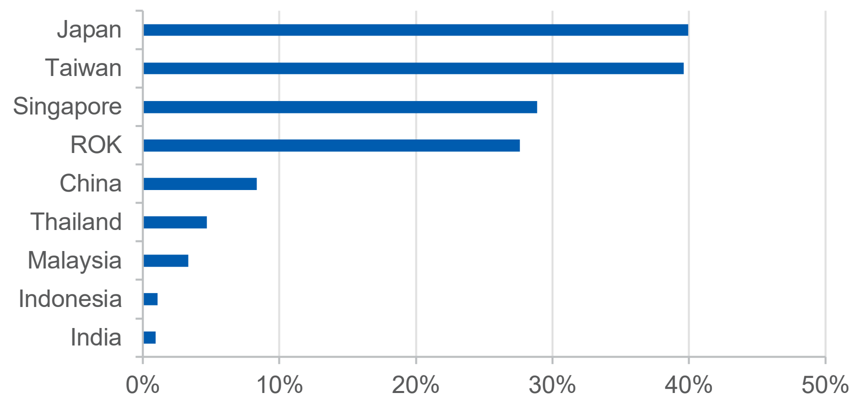
In terms of uses, Japan, ROK, Taiwan and Singapore use natural gas to fuel substantial shares of their power sectors and have significant shares of Australian LNG in their total gas supply (Figures 4.4 & 4.5).

Figure 4.4: Share of natural gas used as a fuel for electricity generation in 2022, selected economies



Source: Energy Institute (2023)

Figure 4.5: Australian LNG as a share of total gas supply, selected economies, 2022



Source: Energy Institute (2023); EnergyQuest (2023c)

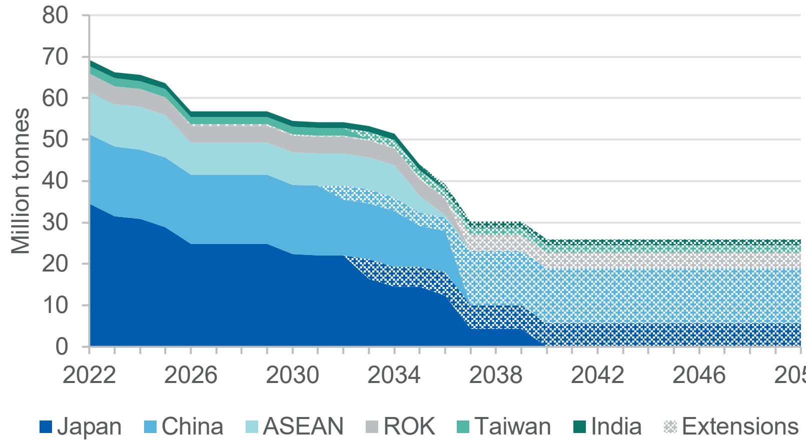
There are 51 medium- to long-term contracts (five years or longer) in force which underpin Australian LNG exports. The volumes of gas exported under these contracts will decline out to 2040 as contracts expire. The extent of decline projected will be less if contracts are extended to take advantage of existing infrastructure. This is likely to be desirable to investors who have made significant recent investments on new, large-scale projects with high capital costs, and that seek gas supply beyond the foundation contract period. Figure 4.6 shows the volumes of gas exported under contracts today, and an illustrative situation in which 19 contracts are extended to 2050, resulting in close to 30 Mt of Australian LNG exported to the Asian region in 2050.

Other major gas producing nations are investing in significant additional capacity

Australia's relative market share in global LNG is projected to fall during the energy transition under all climate ambition scenarios (Tables 4.1 and 4.2). This reflects a significant near-term expansion in global LNG. The IEA WEO 2023 notes that 'starting in 2025, an unprecedented surge in new LNG liquefaction projects that have started construction or taken FID are set to add 250 bcm per year of liquefaction capacity by 2030, equal to almost half of today's global LNG supply'. New LNG export capacity is also being installed along the Pacific Rim, with committed projects in Canada and Mexico.

Additional supply is being driven by significant investment in both Qatar and the US. Qatar is projected to increase its output from 81 Mt in 2023, to 147 Mt of LNG in 2030. This would result in a 21% market share in 2030, and an 81% increase in volumes on 2023 levels. Qatar has indicated that it views gas as a commodity likely to be needed in significant quantities for at least the next 50 years. The US is expected to export 191 Mt of LNG in 2030, representing a 28% market share in 2030, and an 145% increase in export volumes on 2023 levels. The US has recently announced a pause on new export licences for LNG while the government assesses its posture with regard to gas going forward. This pause may delay or reduce any future supply coming into the market in the next few years, depending on its duration. However, the expected growth trajectory out to 2030 will not be affected, since the projects that make it up are already approved,

Figure 4.6: Australian LNG medium and long-term contract volumes in force, with assumed contract extensions, by buyer, 2022 to 2050



Notes: Contract extensions are modelled on the following basis: that Australia maintains a gas trading relationship with Japan, China, ROK, Taiwan, and India, subject to remaining reserves in key fields, with field and contract choice informed by future gas consultation processes.

Source: GIIGNL (2023)

Insight: Supply options for the Asia Pacific are increasing. Global LNG supply is expected to increase over the next 5 years, with new supply coming in particular from the US and from Qatar. New export terminals are also being built in Northern America that will more easily service Asia Pacific. Nonetheless, demand for Australian gas will remain.

Table 4.1: Historical LNG market share, percent, 2012 to 2022

Country	2012	2015	2018	2022
Australia	10.1	11.5	21.4	19.6
Qatar	32.3	33.1	24	20.2
USA	0.1	0.1	9.1	19.5
Other	57.5	55.4	45.4	40.6

Source: NexantECA (2023)

Additional supply is being directed both into the long-term contract market and into the spot market. In 2022, a large number of contracts (with an average duration of 20 years) were signed by large exporters, including the US (39 contracts with annual contract quantities of 64 Mt), Qatar (three contracts) and Russia (two contracts) (Figure 4.7). US supply has to date been directly largely to spot markets for cargo optimisation, made possible because LNG exports have developed as a by-product of developing additional gas fields to feed the large domestic market. This has had the effect of increasing the depth of global spot markets, one reason the global market was able to pivot quickly to address European gas shortfalls in 2022.

Other suppliers are joining the market as well. The Kitimat project, described by Canadian Prime Minister Justin Trudeau as ‘the single largest private-sector investment project in Canadian history’, will commence in 2025 and is expected to provide Canada with an annual LNG export capacity of 26 Mt once its second stage is completed. Mexico is also expected to complete the Saguaro Energía (Mexico Pacific) LNG project by 2025. Both projects will take advantage of being on the west coast of North America, providing ease of access to Asian markets and avoiding bottlenecks through the Panama Canal.

There is a stark contrast between recent contract behaviour in Australia and these other LNG exporters. Only one Australian contract was signed in 2022, continuing a trend in the past five years in which few new contracts have been entered into. While this reflects exporters operating at close to nameplate capacity, it is also consistent with general low levels of domestic exploration and investment in recent years (which are explored further in *Chapter 5*).

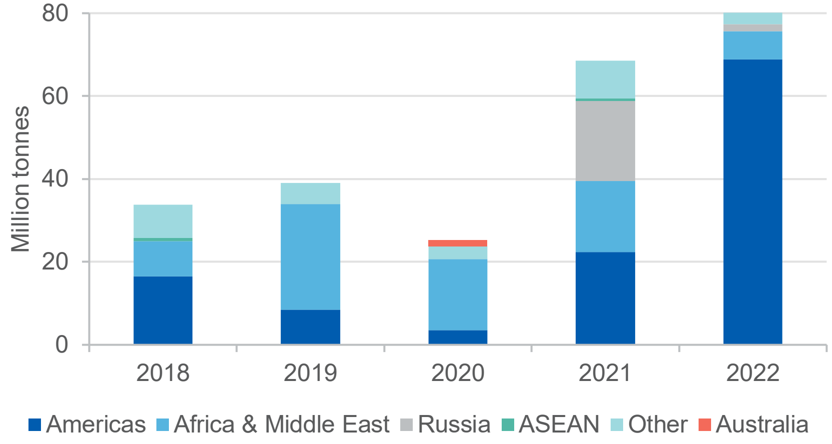
Table 4.2: Projected LNG market share, percent, 2022 to 2050

				STEPS
Country	**2022**	**2030**	**2040**	**2050**
Australia	19.6	14.6	13.1	11.4
Qatar	20.2	21.5	21.1	21.6
USA	19.5	28	31	31.7
Other	40.6	36	34.8	35.3
				APS
Australia	19.6	13.8	7.7	6.1
Qatar	20.2	24.6	30.4	38.2
USA	19.5	28.6	29.8	35.3
Other	40.6	33	32.1	20.4
				NZE
Australia	19.6	15.5	5.4	9.4
Qatar	20.2	19	17.1	44.4
USA	19.5	35.2	44.5	20.7
Other	40.6	30.3	33	25.4

Notes: NZE scenario assumes a significant expansion in near-term gas demand as part of accelerated transition towards renewables. As a result, relative share of Qatari (and Australian) LNG declines; notwithstanding substantial Qatari investment in supply. There is also an assumed rapid decline in USA gas production after 2040 in the NZE scenario.

Source: NexantECA (2023)

Figure 4.7: Medium and long-term contract quantities signed by seller's country of origin, 2018 to 2022



Notes: Portfolio contracts which are not country-specific are included in the other category.
Source: GIIGNL (2019; 2020; 2021; 2022;2023)

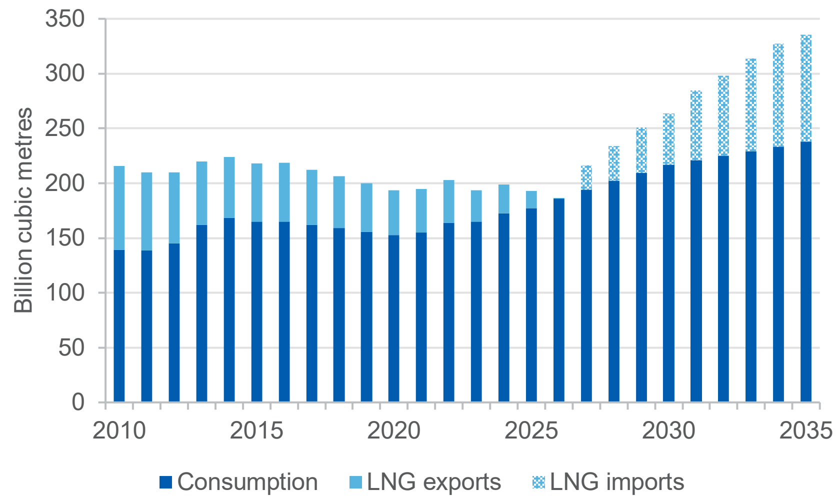
Increased supply in the Asia Pacific has potential to reduce demand for Australian exports over time, but consultation suggests overall demand will sustain. Australian LNG is valued by partners due to its long-term and stable supply and the investment relationships built up over time. More generally within the Asia region, imports of Australian LNG allow economies to achieve import diversity and energy security, helping to secure economic growth. Australia also offers much shorter transport distances through relatively secure waters.

Demand for LNG is increasing, particularly from Asia

Supporting the potential for higher global LNG trade, global LNG import capacity is also in a phase of significant upswing. This has been accelerated by European countries switching away from Russian pipeline gas after Russia's illegal invasion of Ukraine. Import terminals are also being built across the ASEAN region, which will drive demand for Australia's LNG, including from new import partners.

Many Asian economies view gas as a crucial component of their pathway towards net zero. Even in the IEA's most ambitious decarbonisation scenario gas is expected to play a role in economic activity and energy security through to 2050 (see Introduction). Demand for LNG is also growing in several Asian countries that have historically produced enough domestic gas to meet their own demand. China, Malaysia and Indonesia are the region's largest producers, with other countries such as Thailand, India and Vietnam also producing gas for domestic purposes. Declining domestic production and reserves have led these countries to import LNG to maintain their gas supply balance. Beyond providing energy security, access to gas can also promote a smoother energy transition within the region —— by offering a flexible power source to complement renewable power, and by replacing heavier-emitting coal.

Figure 4.8: Medium-term ASEAN gas demand supply balance, with net trade, 2010 to 2035



Notes: Based on the STEPS projection.
Source: NexantECA (2023)

Projections suggest ASEAN will become a net importer of LNG by 2027 (Figure 4.8). Within ASEAN, Singapore has been a trading partner for Australian LNG since 2015, with Thailand emerging as a trading partner in 2023. 2023 also saw Vietnam and the Philippines report their first imports of LNG, with additional LNG import terminals currently under construction throughout the region. Cambodia announced a new gas-fired power plant with accompanying LNG import terminal in November 2023. While the European Union is not a direct buyer of Australian LNG, Australia's contribution to the global market frees up other LNG producers to supply European consumers.

4.2 Global gas demand

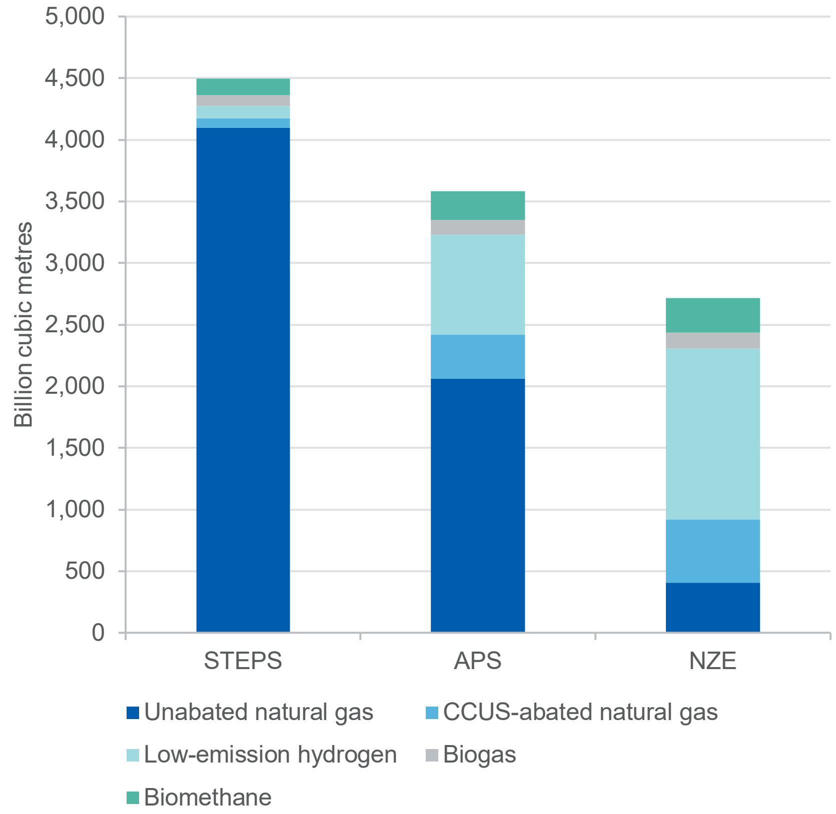
There are many possible paths to a achieving the Paris Agreement temperature goal of well below 2ºC, while pursuing efforts to keep 1.5°C within reach. For example, technological breakthroughs that lower the cost of low-emissions hydrogen can result in a larger substitution of hydrogen for LNG by 2050. Alternatively, advances in CCUS could reduce the impact of gas production on national emissions or can facilitate higher gas production for a given contribution to the carbon budget. At this point, the pathway forward in inherently uncertain.

In the IEA's (2023f) Net Zero scenario, the majority of global demand for gas-equivalent fuels is met by low-emissions hydrogen production and 34% of demand derives from natural gas (abated and unabated; Figure 4.9). This is a significant reduction compared to the STEPS current policy setting scenario, in which natural gas represents more than 90% of global gas production (similar to 2021 levels), and largely unabated. However, it still represents demand for almost 900bcm of natural gas, almost one quarter of the STEPS scenario (Figure 4.10).

This pathway also assumes that all countries move directly to renewable energy from coal, and gas use in electricity grids is minimised. Consultation suggests that gas substitution may form part of individual country decarbonisation plans, so the potential for gas demand as a transition fuel is likely higher than represented in the IEA net zero scenario. Nonetheless, it indicates that gas demand will need to fall significantly from today's levels to achieve net zero.

Insight: Under the IEA's Net Zero scenario there is significant growth in use of hydrogen gas, but even so natural gas use does not disappear.

Figure 4.9: IEA's 2050 outlook for gas-equivalent fuels by scenario



Source: IEA (2023e)

Global gas demand for the three IEA scenarios is shown in Figures 4.10 to 4.12. Three important observations emerge when examining projected levels of global gas demand, global LNG demand, and Asian regional gas demand.

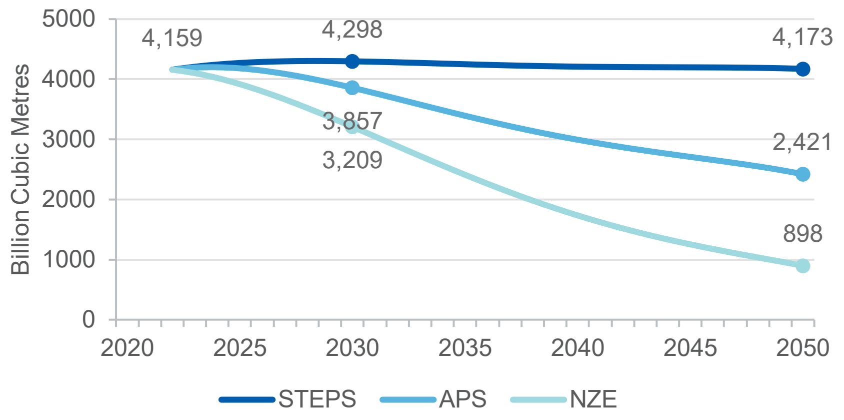
First, significant policy action is required at a global level to reduce gas demand toward levels consistent with announced pledges and net zero targets. The IEA's scenarios range from effectively no change in gas production in 2050 relative to today — based on current policy settings — to approximately 35% reductions in 2050 gas demand — based on current stated levels of climate ambition, and approximately 70% reduction in gas demand in 2050 under a pathway to net zero CO_2 emissions by 2050.

Second, there is a high degree of uncertainty around the pathways that governments around the world will take and therefore around demand over time.

Third, Asia Pacific demand for gas is likely to hold up relative to other regions. Regional gas demand is projected to decline by less than global gas demand in the available scenarios (Figures 4.11). Global LNG demand (Figure 4.12), however, falls faster than global gas demand in the APS scenario. Given the low share of gas production in the Asia region and legislated hard end date to LNG imports in Europe, this likely reflects continued demand for LNG within Asia.

Insight: There are a wide range of gas demand estimates in 2050 that correspond with different levels of global ambition to reduce emissions. With national pathways to net zero in development around the world, global gas demand through the transition and in 2050 remains highly uncertain.

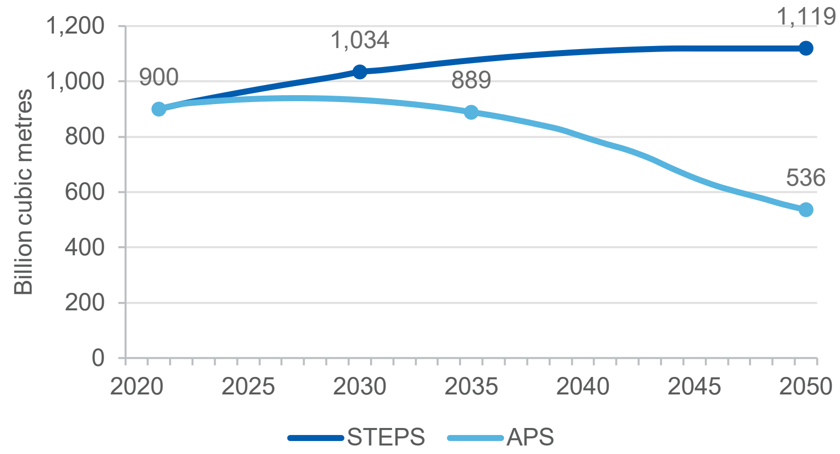
Figure 4.10: Global gas demand, by scenario, 2022 to 2050



Notes: Trendline uses a quadratic polynomial order. Based on total final consumption.

Source: IEA (2023f)

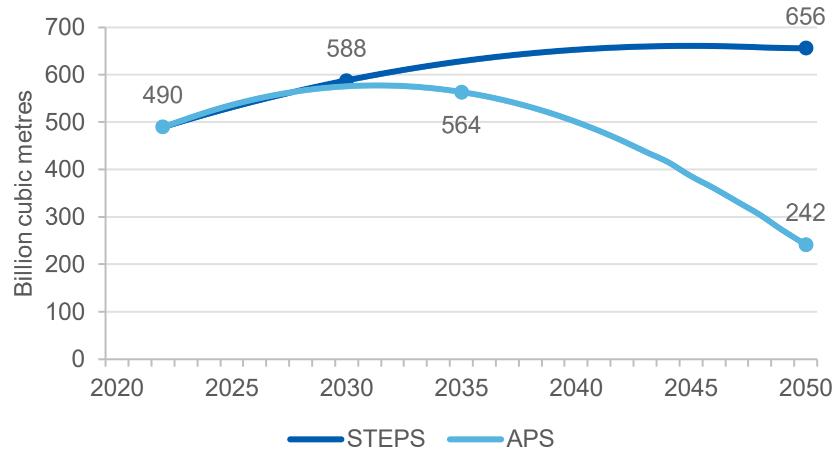
Figure 4.11: Asia Pacific gas demand by scenario, 2020 to 2050



Notes: IEA does not publish disaggregated forecasts of NZE gas demand.

Source: IEA (2023f)

Figure 4.12: Global LNG demand by scenario, 2020 to 2050



Source: IEA (2023f)

4.3 Modelled gas exports by scenario

This section models demand for Australian exports under the range of IEA WEO's scenarios and provides a brief introduction to the Nexant World Gas Model (WGM).

Box 4.1: Introducing the World Gas Model

The WGM frames gas trade in terms of global, regional, and national gas supply and demand balances on an annual basis from 2022 to 2052.

The model finds the optimal level of gas production (supply) for a given (exogenic) level of demand to produce forecasts for gas production, exports, and consumption over a 30-year forecast horizon. To determine optimal supply, the model uses detailed data (and assumptions) on global trade networks, production capacities and contractual obligations. The model also factors in the price of energy substitutes in the power sector (like oil and coal), and the price elasticity of demand.

The WGM receives quarterly updates to reflect the rapid pace of developments worldwide. This report uses the September 2023 version as its projections align closest with the IEA WEO 2023. Events such as the conflict in Gaza, the pause on LNG exports in the US, and updated demand projections are not captured in this version.

More information about the Nexant WGM and its underlying assumptions can be found in Appendix B and Section 4.6.

Australian LNG volumes vary significantly by scenario

There is a high degree of uncertainty around future demand for gas in our region. With varying domestic energy transition pathways among our trading partners, existing barriers need to be addressed to deliver announced emissions targets. Stranded asset risks also increasingly weigh on gas investment decisions while customers nevertheless demand certainty around future supply.

Projections for Australia's LNG exports differ by exogenous input by IEA scenario; under low climate ambition (STEPS), exports are stable out to 2050, in contrast to a gradual decline (APS) and a greater decline (NZE) from 2030. In all cases, Australia maintains a relatively large share of LNG trade with existing partners over the medium term (to 2035), albeit with Australia's relative share of the global LNG market diminishing over time.

Figures 4.13 and 4.14 present the projected level of Australian LNG exports and the relative global share by scenario, respectively.

In the STEPS projection, Australian LNG capacity increases slightly and is sustained as new projects are brought online, taking advantage of a gradual increase in regional demand, particularly in ASEAN by 2050. As mature economies steadily reduce their Australian gas use (particularly Japan and China), emerging ASEAN demand is expected to take its place.

In the APS projection, Australian LNG volumes throughout the region are relatively stable towards 2035 but start to fall gradually. The transition away from gas will gradually reduce its price, impacting revenue and limiting new gas developments due to lack of profitability and climate pressures. Ambitious investment into renewables capacity is likely to drive gas prices down, offset to a degree by increased demand for critical minerals. With a muted gas demand growth trajectory for ASEAN and constrained Australian gas production, exports to ASEAN cease by 2035 as Qatar and Papua New Guinea meet ASEAN demand alongside limited endogenous production in the region. Australia continues to supply its existing trading partners at a lower level.

The NZE scenario explores implications for demand if renewable technologies are adopted at a much faster rate than currently indicated by Asian countries. In this scenario, gas takes on a greater role in this decade, as part of a rapid early shift out from coal, and then the decline in Australian gas demand accelerates from 2030. Export volumes to trading partners decrease proportionally as gas demand decreases over time, but contractual obligations remain to be met until expiry. East coast exports cease by 2050 in the NZE scenario.

In both APS and NZE scenarios, Australian LNG is assumed to remain committed to maintaining relationships with existing key trading partners

(Japan, ROK, Taiwan, and China) via contractual obligations, but uncontracted spot LNG sales of Australian gas will be scarce in line with declining demand.

4.4 Projections by Asian region

Consultations have indicated a general expectation of strong gas demand from our region, although the role of Australian supply is more ambiguous for new importers than for established trading partners.

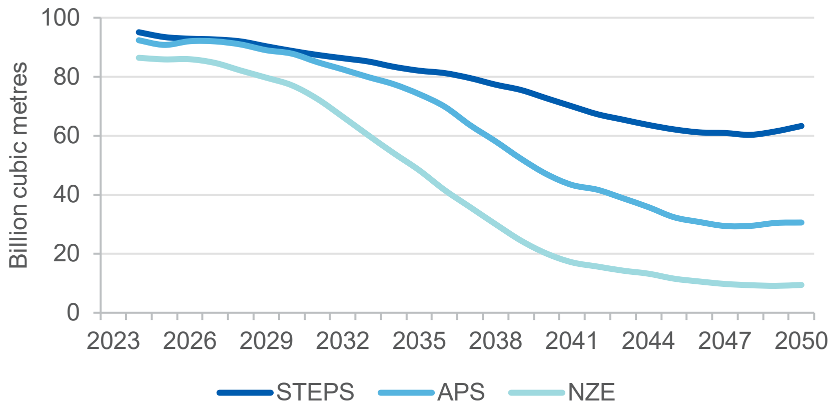
East Asia

The Nexant WGM projects East Asia's overall demand for Australia LNG to steadily decline to between a third (STEPS) to less than a tenth of 2023 levels (NZE) by 2050, depending on the level of modelled climate ambition (Figure 4.13). However, under all scenarios there remains demand in the region for Australian LNG exports out to 2050 and beyond.

Two factors drive the decline in export demand in the APS and NZE scenarios. First, there is expected to be a shift toward alternative suppliers of LNG on a cost basis. The region's lack of domestic gas production and unsuitable geography (except China) subjects its economies to a reliance on imports for their energy needs. However, Australian gas is relatively expensive compared to US exports. Transport costs and broader geopolitical influences maintain demand for Australian LNG in the medium term. Beyond this, East Asia will have new opportunities to source natural gas from the west coast of North America, where several suppliers are looking to build new LNG export facilities into the Pacific region.

Second, gas demand is expected to fall as economies in East Asia integrate alternative energy sources into their energy plans. The restart of Japan's nuclear fleet and the ROK's recent reversal on nuclear policy were cited as necessary to transition away from coal completely and meet their climate targets. Economies in the region are also looking to establish supply chains for carbon-neutral fuels. Japan has indicated that its transition to net zero will involve switching from the use of natural gas to an alternative such as ammonia or hydrogen once this becomes economic, and is investing in development of these technologies and early stage demonstrations of transport and import capability.

Figure 4.13: Australian LNG exports to East Asia, by scenario, 2023 to 2050

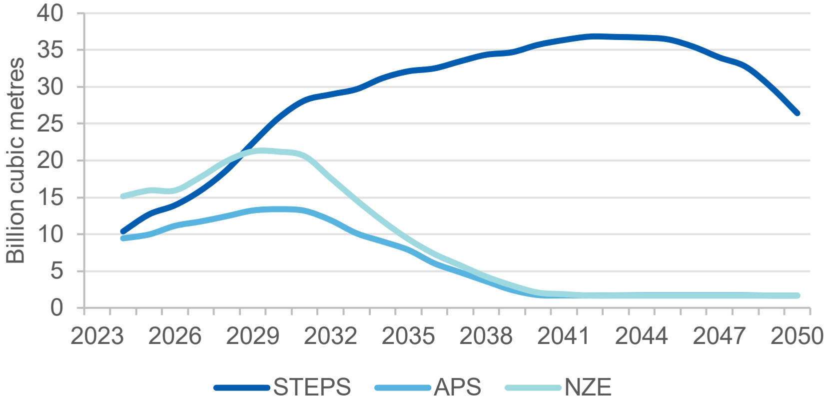


Source: NexantECA (2023)

Southeast Asia and other partners

The Nexant WGM projects significantly different outcomes for Southeast Asian demand depending on the level of global climate ambition (Figure 4.14). While regional gas production has been substantial, a combination of declining reserves and rapid energy demand associated with strong economic growth means demand for LNG is growing, with the Nexant WGM forecasting Southeast Asia to become a net importer of LNG by 2027. In a STEPS scenario, export levels to Southeast Asia grow to levels comparable with current exports to China by mid–2030s as policy is driven by a focus on economic growth. In contrast, under the APS and NZE scenarios, demand for Australian LNG begins to decline in the 2030s.

Figure 4.14: Australian LNG exports to Southeast Asia, by scenario, 2023 to 2050



Source: NexantECA (2023)

ASEAN member states share some common principles with regard to the energy transition: the need to respect country-specific circumstances through the transition; that growing economies need to prioritise energy security, including through use of LNG; and that ASEAN members require financial and technical support to decarbonise. However, there is no 'one size' approach, with variations based on country-specific circumstance. Several ASEAN member states have signaled their intention to engage in greater use of gas to reduce their dependency on coal. Importers have identified Australia among others as a major possible supply partner as a source of LNG. This is evident through investments in Australian major LNG projects, including Malaysian state-owned company Petronas.

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Outside of East and South-east Asia, the Nexant WGM sees little reach of Australian LNG. India remains a minor destination for Australian LNG as its gas import needs are largely met by Qatar, partly due to its proximity. While countries such as China, Japan and ROK may re-export excess LNG, it is usually retained in the region. Nonetheless, the US and EU have emphasised the important indirect role Australia plays in the global export market, and how significant disruptions to Australian operations contribute to the volatility of gas prices globally.

4.5 Data modelling and assumptions

The assumptions used to construct the scenarios are presented in Appendix A. Major considerations around the modelling concern the cost of production (this can indicate which gas fields are more likely to drop out of global supply) and the emissions intensity of production (as carbon constraints bind more tightly, there will be more pressure on high-emissions gas producers to drop out of global supply).

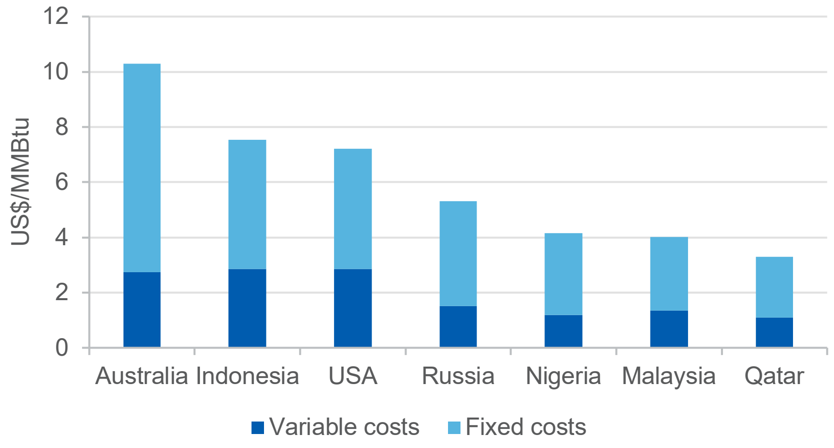
Cost of production and non-price factors

The key factor driving demand for LNG under the WGM model is the relative cost to the user. Over 90% of global LNG production in 2022 was sourced from seven major producing countries: Qatar, Australia, USA, Russia, Malaysia, Nigeria and Indonesia. Australia's average production cost (at USD10.28/MMBtu in real 2020 USD) is higher than other major producers (Figure 4.15), largely reflecting higher capital costs.

There are also a number of reasons why high average per-unit costs of Australian production can coexist with large volumes of exports. It follows that the results modelled below do not present a full picture of demand for Australian LNG and should not be taken as predictions.

First, there are geopolitical and national relationship motivations to trade. It is assumed that Australia meets contractual obligations of its gas supply agreements to uphold its reputation as a reliable supplier of gas.

Figure 4.15: Production cost curve of select LNG exporters



Notes: Full lifecycle costs including upstream production and liquefaction cost. Variable costs represent the priced-in short run marginal cost of production.

Source: NexantECA (2023)

Second, the fragmented nature of gas markets means that there is relatively low competition between regions. The WGM breaks the world into a number of regions. Australia has a competitive advantage in shipping and transportation to the Asia region. Shipping times (and costs) are competitive (Table 4.4), and there is no reliance on the Middle East, Malacca Strait, South China Sea or Panama Canal (all of which raise the prospect of instability and generally longer shipping durations).

Third, the fragmented nature of gas markets means that there is relatively low competition between regions. The WGM breaks the world into a number of regions. Australia has a competitive advantage in shipping and transportation to the Asia region. Shipping times (and costs) are competitive (Table 4.3), and there is no reliance on the Middle East, Malacca Strait, South China Sea or Panama Canal (all of which raise the prospect of instability and generally longer shipping durations).

Fourth, long-established facilities can price in terms of the short run marginal cost (SRMC) of production (the cost of producing and transporting a unit of gas, labelled 'variable costs' in Figure 4.14), rather than the total average cost of production (SRMC plus capital costs, labelled 'fixed costs').

Importantly, the high costs for Australian production stem predominantly from fixed (establishment) costs. Australian variable costs (which are more relevant for established projects that are beyond their capital-recovery phase) are closer to the international community. This suggests that established Australian production is able to be more competitive than prospective new sites.

Table 4.3: Average LNG shipping duration, by LNG region

Days	China (Shanghai)	Japan (Tokyo)	ROK (Incheon)	India (Gujarat)
Western Australia	8	7	8	9
Queensland	8	9	9	14
US Gulf Coast (via Panama Canal)	20	22	21	21
US Gulf Coast (via Cape of Good Hope)	36	34	35	24
American West Coast	10	9	9	19
Qatar (Ras Laffan)	14	12	13	2

Notes: Days shipping is based on a vessel at maximum speeds of 19.5 knots. WA Department of Jobs, Tourism, Science and Innovation analysis based on information from ShipScene and GIIGNL. US Gulf Coast (via Cape of Good Hope) and North American West Coast estimated from S&P and Shell reports.

Source: Government of Western Australia (2024)

Emissions intensity of production

As a rule of thumb, the tighter the carbon constraints, the more pressure there is on high-emissions gas producers to drop out of global supply. With policy change, there may be costs for importers buying LNG with higher scope 1 and 2 emissions (from the production, transport, and processing of gas).

Over time, Australian gas exports will be heavily dependent on emissions reduction targets in the Asia Pacific, with net zero commitments either enshrined in law or in policy documents (see Table 4.5). Such commitments are particularly vital in shaping Australian gas use and the possibility that CCUS will play an important role in decarbonisation plans

Insight: Australian LNG is characterised by high direct capital costs and an emissions intensity close to the global average. Australian LNG remains attractive for Asian buyers, due to lower transport costs and non-price factors including geopolitical relationships, secure trading routes, transparent institutions, and openness to foreign investors taking majority ownership stakes in gas. Australia also has the potential to be a low-emissions LNG exporter if emissions from venting and liquefaction can be reduced.

Table 4.4: Emissions reduction targets, by trading partner

	Net Zero Target	Status	Share of natural gas in APS scenario
Japan	2050	In law	16.2% in 2030, down from 21.7% in 2022
ROK	2050	In law	22.9% in 2030, up from 18.5% in 2022
Taiwan	2050	In law	50% in 2025, up from 20.2% in 2020
ASEAN	Between 2050 and 2070	In policy document and oral pledges	17.7% in 2030, down from 18.2% in 2022
China	2060	In policy document	8.2% in 2030, up from 7.8% in 2022

Source: IEA (2023a, f); IEA (2023g); Policy documents

It is important to note that our trading partners can offer advancements in meeting global emissions reduction targets beyond their own national targets — for example Japan partnering on emissions reductions with ASEAN members (through capability and investment), and Japan and ROK investing in potentially transformative technology such as hydrogen. Accordingly, Australia works closely with these economies and in international clean energy partnerships to reduce global emissions and address climate change.

Alternative projections to the IEA

It is important to acknowledge that there are a wide range of scenarios that are different from the IEA's projections of gas demand. While the IEA's WEO underpins the strategy, other publications such as the IEA's *Medium-Term Gas Report* and external publications such as the Institute of Energy Economics Japan (IEEJ) have modelled alternative projections. There are suggestions that the actual level of gas demand in 2030 could be materially higher assuming that the short-term forecasts are accurate, and that planned consumption by trading partners is inconsistent with emissions reduction commitments.

IEA and AEMO scenarios are built around assumptions that net-zero by 2050 is achieved (NZE) or that various decarbonisation policies are successfully enacted (STEPS and APS). There is no single story about the future of global energy.

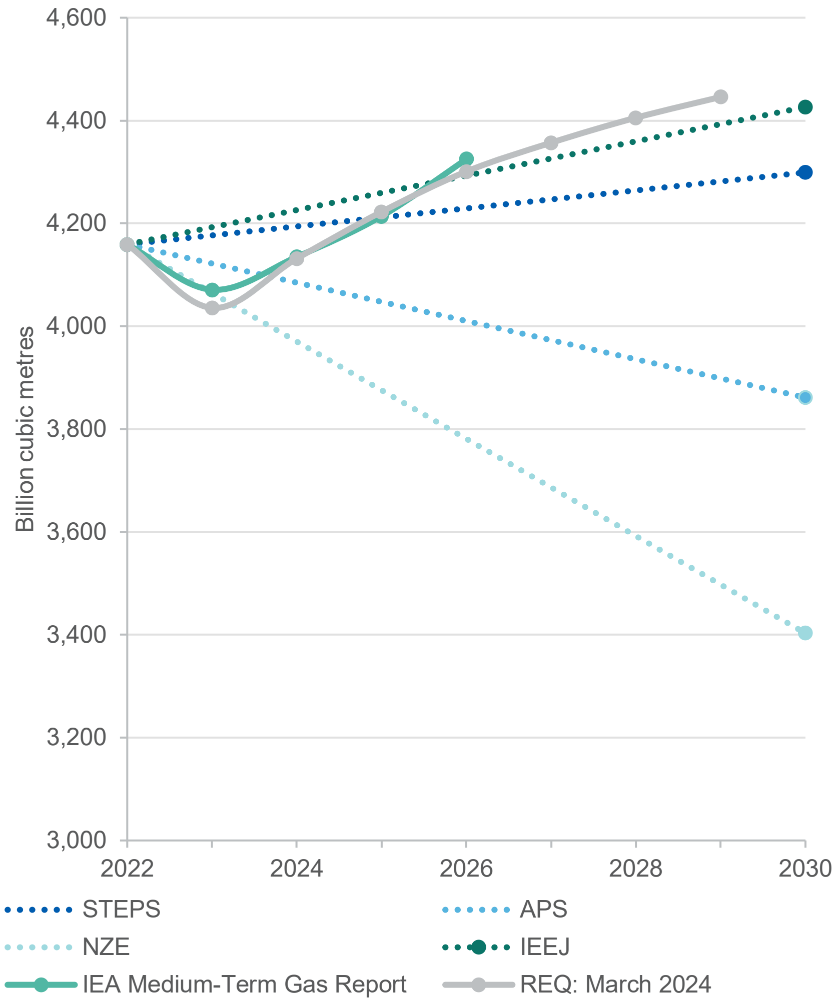
Table 4.5: Alternative global gas demand projections, bcm, by source

	2030	2040	2050
IEA WEO 2023 – STEPS	4,298	4,209	4,172
IEEJ	4,364	4,798	5,387
GECF			5,360
ExxonMobil	4,547	4,862	5,059
Shell	4,265	4,495	4,494

Notes: Based on STEPS or a STEPS-equivalent. Shell is based on the Islands scenario.

Source: IEA (2023f); IEEJ (2023); Gas Exporting Countries Forum (2024); ExxonMobil (2023); Shell (2021)

Figure 4.16: IEA gas demand projections vs alternative gas demand forecasts, 2020 to 2030



Source: IEA (2023e, d); IEEJ (2023); DISR (2024)

Industry projections

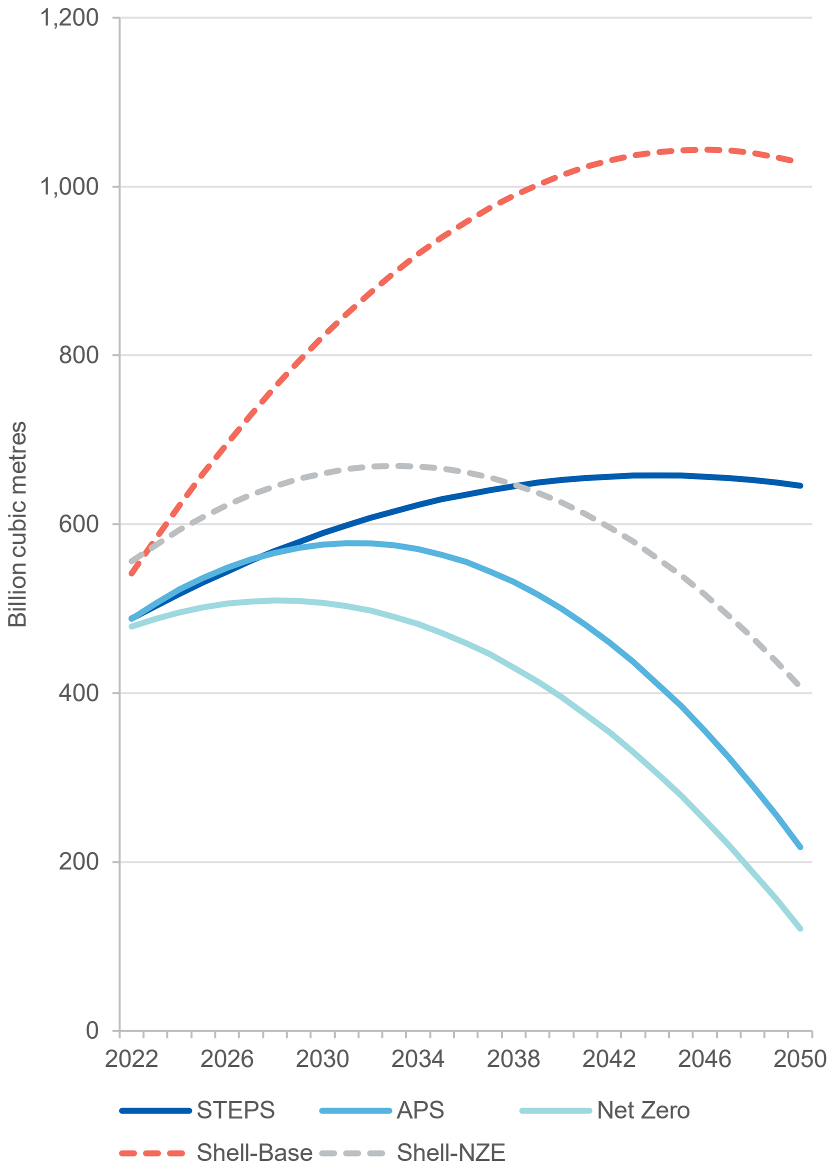
The industry holds a different view around the trajectory of gas demand, with scenarios based on how quickly decarbonisation can be achieved. Projections and industry analysis suggest upside potential in gas demand relative to projections from the IEA.

Energy producers have previously argued that while various net zero scenarios provide a best-case pathway towards global decarbonisation, limiting the range of scenarios to a 'baseline' based on current policy settings (AEMO's Progressive Change scenario and the IEA's STEPS scenario) — or more ambitious outcomes — does not capture a full range of likely pathways, including those that fall closer to a worst-case pathway towards global decarbonisation.

Projections published by gas producers tend to include a path for gas where demand is materially higher in 2050 than current levels, rather than equal to or materially lower (Table 4.6). Compared to IEA scenarios, these projections are a result of more bullish assumptions around the level of economic development and demand for energy to sustain rising living standards, particularly relating to the developing world, alongside assumptions that gas displaces coal-powered electricity generation as part of the transition. Under these assumptions, global gas demand projections are significantly higher in 2050 than in 2020.

In addition, certain scenarios examined by Shell imply higher LNG trade within a net zero scenario. In their APS-aligned scenario, natural gas displaces coal in developing countries. Gas demand expands beyond established regions and existing pipeline networks, with LNG becoming the dominant form of global trade to meet new gas demand. Developing countries are reluctant to invest in pipelines due to the decade-spanning construction times and need to lock in supply to be sourced and consumed in particular locations. Demand for LNG doubles from 2020 levels by 2050 (Figure 4.17). Demand for Australian LNG would likely be maintained in such a scenario.

Figure 4.17: IEA LNG demand forecasts compared with Shell, 2022 to 2050



Source: IEA (2023e); Shell Energy (2021)

5. Supply outlook

Summary

In the near term, there is significant concern and uncertainty around the potential for a shortage of supply over coming years.

On the **east coast**, major annual shortages are expected to emerge from 2028 – that is, the forecast supply levels fall short of expected demand. The supply commitments made by producers under the Gas Market Code are expected to reduce the shortfall volumes going forward, but to close the gap requires further supply or a reduction in demand.

There is a particular risk of shortfalls in south-eastern states. South-eastern states are becoming increasingly reliant on gas from northern states as gas production from southern gas fields declines. Constrained pipeline capacity from Queensland to southern states implies that southern shortfalls will emerge in coming years regardless of additional northern production. There are also risks of seasonal supply shortfalls in south-eastern states from 2026 due to higher winter demand levels exceeding pipeline capacity from the north in the winter months.

East coast supply shortfall forecasts have been consistent over the last decade, as forecasts are based on 2P reserves (i.e. proven and probable). As resources are proved to be commercially viable and translated to 2P reserves, forecast supply shortfalls have typically been pushed further out. However, the circumstances today are different to the past in that they offer fewer options to increase supply in the timeframes required. Chapter 7 explores the most likely supply option, time frames to delivery, and their potential to address regional supply shortages. There remain risks that supply comes on slower than expected, and that demand proves stronger than expected (as outlined in Chapter 3).

On the **west coast**, demand in the near term is likely to exceed new supply so that storages will continue to be run down, with larger shortages emerging from 2030. The Western Australian Parliament's Economics and Industry Standing Committee interim report into the WA Domestic Gas Policy found a shortfall in the amount of gas being delivered into the local market. The report concluded large offshore producers have delivered about 8% of production to the local market, well short of the 15% domestic reservation requirement (the impact of a closer adherence to a 15% requirement is explored in Chapter 7).

These regional shortages are expected despite Australia having substantial reserves and resources of natural gas. The volume of gas that can be produced depends largely on how much exploration and development activity occurs to prove up gas fields, and the price at which they become commercial to develop and connect to the grid. Exploration and investment in the gas industry at a national level has been low over recent years, so that the pipeline of supply coming forward has fallen.

5.1 Near term shortages in gas supply

Chapter 5 focuses on gas remaining crucial to Australian energy security. We first present the near-term shortages in gas supply at a national and regional level. We examine available resources and trends in investment.

In this chapter we use forecasts from the ACCC's *Gas Inquiry December 2023 interim report*. We recognise that several other Australian gas production forecasts have been produced based on various assumptions by parties including AEMO and EnergyQuest. While these forecasts may vary slightly, they do not alter the conclusions contained here.

There is significant potential for a shortage of supply, both on the east and west coast, over coming years. Near term shortages in supply may particularly affect southern gas users in the eastern market, especially if the increasing gas supplies from the north are limited by capacity constraints within the network over the coming years.

Total Australian gas production (for east coast, west coast, and export purposes) reached a historical high level in 2012–22 at 6,076 PJ (DCCEEW 2023d). At current levels of investment, the expected decline in east coast Australian gas production from proven and probable (i.e. 2P) reserves (44% between 2022 and 2032) falls faster than the demand under the most ambitious climate scenario in both the east coast (a 13% fall by 2032 under 'Green energy exports' scenario) and west coast (a less than 1% fall by 2032 under 'Low' scenario) markets that were canvassed in Chapter 3 (AEMO 2023d, 2024b).

As a result, a major annual gas supply gap[10] is expected to emerge by 2028 on the east coast and the annual imbalance is expected to grow over time (Figure 5.1). Note that the gas supply forecast in Figure 5.1 includes gas from both developed and undeveloped 2P reserves but does not include all additional gas committed through the Code of Conduct processes.

The production capacity of the Gippsland, Otway and Bass facilities is expected to continue to decline as fields mature. Replacing this capacity which would require the equivalent of a second Iona storage facility or new offshore greenfield developments (tied back to existing infrastructure), to take into consideration relatively high CO_2 in some fields, as well as the associated capital expenditure.

There are also risks that the supply gap may emerge faster or prove larger than forecast. The forecast may overstate the near-term gas supply potential due to uncertainties in the ability of new gas supply to clear significant regulatory, infrastructure and commercial hurdles (outlined in Chapter 7). At the same time, there is upside potential for demand (see Chapter 3). While demand for gas in the east coast is forecast to fall in the medium term as gas substitutes are adopted, peak daily gas demand is expected to increase significantly to support electricity generation for peak and firming, especially during winter. Risks such as unexpected coal power station closures or delays in renewable energy deployment could drive up gas demand further.

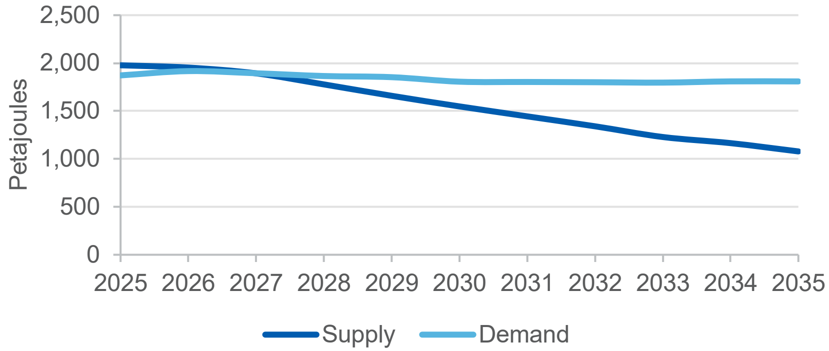
Insight: Annual supply shortfalls are expected in the east coast market by 2028, and the annual supply shortfall is expected to continue in the west coast market, increasing from 2030. The balance of risks is such that shortages may emerge earlier, particularly at peak times of year.

5.2 East coast supply imbalance

A feature of the east coast shortage is the imbalance between southern state demand and production. Between the north and south there is a firm capacity constraint in the network in the maximum daily quantity (MDQ) of the South West Queensland Pipeline (SWQP) — the only pipeline connecting Queensland to the southern states — of 512 TJ/day.

Based on current projections of supply in the south, annual demand from the south is expected to exceed the annual pipeline capacity of the SWQP by around 40–140 PJ especially from 2028 onwards. However, southern peak day shortfalls during winter are expected to exceed the pipeline capacity increasingly from 2026. On these days high demand for gas-powered generation (GPG) coincides with substantial residential, commercial, and industrial demand, as cold weather drives up both GPG and residential consumption. Peak day shortfalls occur when southern demand on a given day (coloured blue on Figure 5.4) is greater than the collective ability of southern production, transportation, and storage facilities to meet that demand on that day (solid lilac line). As such, excess Queensland gas will not be able to address south-eastern shortfalls without additional transport capacity. This also highlights the critical role of southern storage in addressing the peak day shortfalls.

Figure 5.1: East coast gas supply and demand outlook, 2025 to 2035

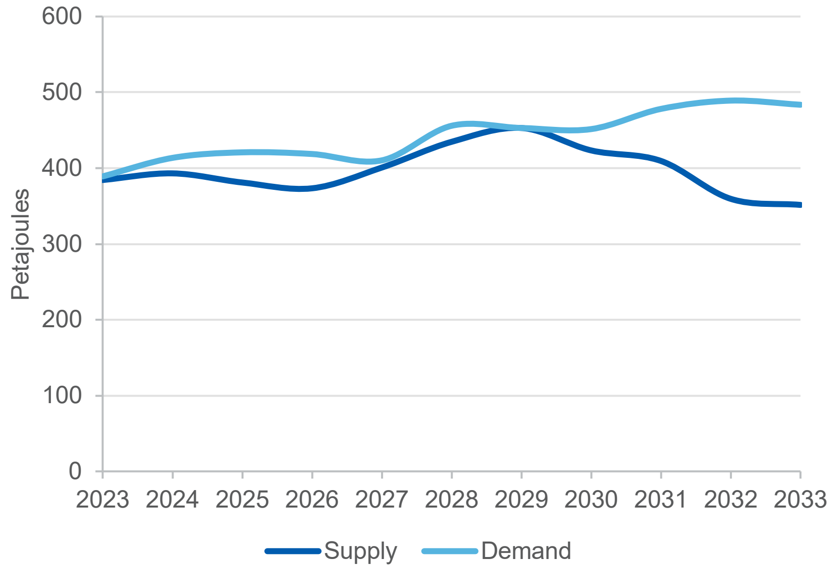


Notes: Forecast supply and export demand are based on aggregate information provided by gas producers to the ACCC as of September 2023. Demand is based on the medium ambition Step Change scenario. The forecast supply includes a portion of additional gas commitments made by gas producers under the code.

Source: ACCC (2023); AEMO (2024b)

[10] There are typically two types of supply-demand imbalances: 1) A seasonal or annual supply gap is generally driven by broad lack of available gas production or transport capacity and 2) A peak shortfall is generally driven by insufficient capacity to meet demand on an extreme peak day; A region may experience peak day shortfalls under extreme peak days during a certain period without facing annual supply gap.

Figure 5.2: West coast gas supply and demand outlook, 2023 to 2033



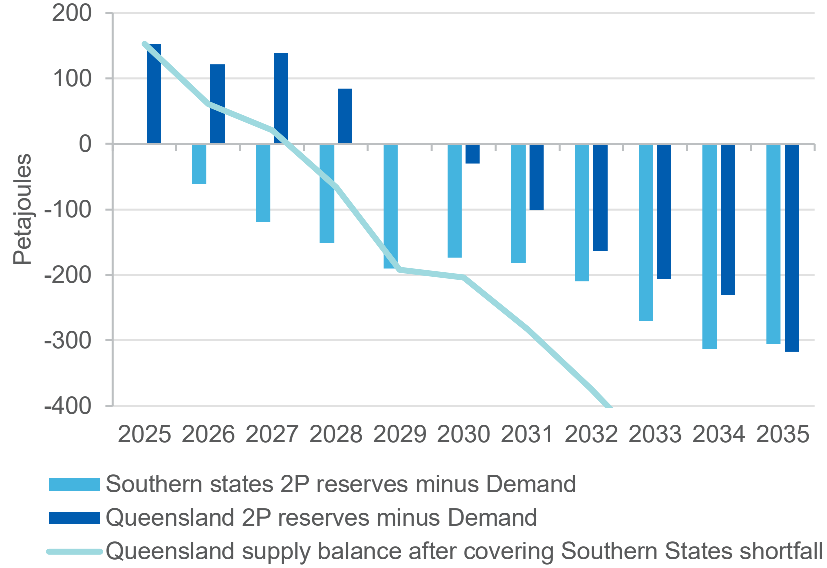
Notes: Does not account for gas sold as LNG from offshore basins due to data limitation. Both gas supply and demand are based on AEMO's Expected scenario from WA GSOO (2023).

Source: AEMO (2023d).

Figure 5.4 shows that southern states are expected to have: a maximum peak day shortfall of around 2,000 TJ/day assuming gas is only drawn from southern states' production (at maximum production) (AEMO 2024b). This supply gap falls to around 800 TJ/day if SWQP and storage options (mainly from Iona, Dandenong, Golden Beach and Newcastle storages),[11] are also used. Peak day shortfall will result in increased risk as these actions will likely coincide with very high spot prices, impacting consumers.

However, retail gas bills do not necessarily have a direct proportional relationship with wholesale spot price fluctuations. In Australia, wholesale gas costs generally only make up around 27% of the retail gas price (DISR 2018). Also, retailers typically hedge against spot gas price changes by entering into contracts, which means the effect on retail prices depends on factors such as the retailers' exposure to spot prices, their portfolio structures, and the timing of their contracts (see Chapter 6 for more discussion on gas prices).

Figure 5.3: Regional supply outlook, 2025 to 2035



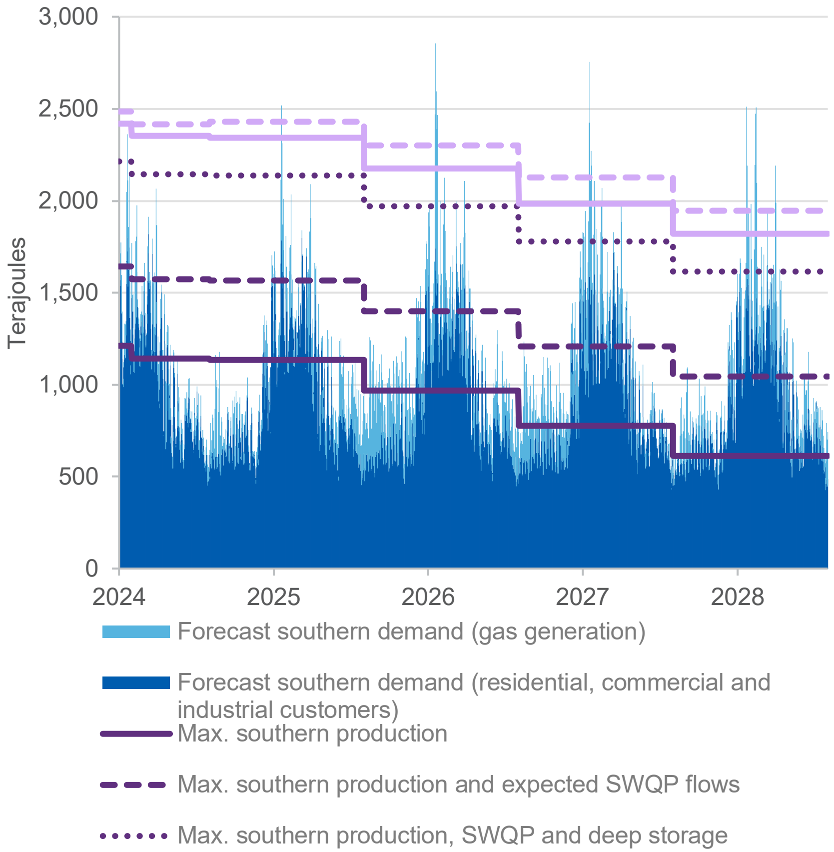
Notes: Forecast supply and Queensland's demand are based on information provided by gas producers to the ACCC as of September 2023. Southern states demand is from AEMO's GSOO 2024 (The medium ambition Step Change scenario).

Source: ACCC (2023); AEMO (2024b)

Insight: Capacity constraints in the east coast distribution network mean that a shortage will emerge for southern states from 2028 regardless of additional supply from northern gas fields.

[11] Golden Beach storage is expected to be commissioned by around 2027.

Figure 5.4: Forecast daily southern supply shortfalls, 2024 to 2028



Source: AEMO (2024b)

Impact of the Code of Conduct on east coast supplies

The Australian Government introduced the Gas Market Code (the code) as part of the Energy Price Relief Plan announced in December 2022. This measure was introduced to ensure east coast gas users can contract for gas at reasonable prices and on reasonable terms. Key elements of the code relevant to the supply and price of gas for the domestic market include:

- a price cap, set at $12/GJ to anchor wholesale contract negotiations between gas producers and buyers.
- an exemptions framework to incentivise producers to commit additional supply in the short term and facilitate new investment in the medium term to support access to gas at reasonable prices and on reasonable terms.

Exemptions under the code include an exemption from the pricing requirements of the code, subject to conditions that support the supply of reasonably priced gas to the domestic market.

As of 30 April 2024, four Ministerial exemptions have been granted under the code. Australian Government analysis suggests that this totals 564 PJ in supply and investment commitments have been made by producers between 2024 and 2033. Further exemptions under the code would reduce the projected shortfall in the east coast.

Insight: The code is expected to reduce the shortfall volumes going forward.

5.3 West coast supply imbalance

In the west coast, the current gas supply gap is expected to remain until 2030 (which relies on gas storage to continue filling short term gaps). Potential supply from committed and expected projects is expected to be up to 11% below forecast demand. From 2030, the annual imbalance is expected to grow substantially due to the increase in GPG demand (Figure 5.2).

Western Australia relies on a small number of large projects some of which are in decline. The demand and supply balance in Western Australia is tightening due to delays in project development and changing demand patterns. Pricing may be put under pressure as the market tightens.

Demand proving lower than expected may also reduce the shortage. The decision by Alcoa to close the Kwinana Alumina Refinery (a large industrial user) will also help delay the expected shortfall beyond current forecasts.

Demand remains uncertain. Demand picks up in 2028 as the Perdaman Karratha Urea Project begins production and grows again with coal-fired generation retirements. The timing of the Woodside's H2Perth hydrogen project also creates uncertainty in terms of future demand.

The timing of lithium downstream processing will also impact demand. There are four developments aimed at processing hard rock spodumene into lithium hydroxide. But the current lithium market is under significant pricing pressure discouraging downstream investment (and even spodumene supply cuts) and technical difficulties associated with processing lithium hydroxide further adds to uncertainty.

While peak day shortfalls — due to network capacity constraints — are a near term consideration for the east coast market, this is not a concern on the west coast. The Dampier to Bunbury Natural Gas Pipeline (DBNGP) is WA's most important gas pipeline, delivering gas from WA's main gas fields (Northern Carnarvon/Roebuck Basin) to its largest demand centre (Perth). The pipeline has a capacity of 845 TJ/day and can deliver over 1 PJ a day. The capacity of the pipeline exceeds WA's forecast daily gas supply gap out to 2033 (ranging from 0 to 360 TJ/day out to 2033). In addition, DBNGP has been connected to another important transmission pipeline — the Goldfield Gas Pipeline in July 2023, which provides an alternative gas supply route for consumers in the Southern Goldfields region.

5.4 Australia's gas resources

The Australian gas production and supply system comprises four key components, all of which play a crucial role in delivering gas from source to end-users:

- **basins**: geological provinces represented by a series of sediment formations (on- or offshore) that commonly contain natural gas resources and serve as the primary source of gas extraction.
- **fields**: accumulations of natural gas in defined structures within basins. Commercial quantities of natural gas are being developed by the drilling of production wells.[12]
- **processing facilities**: remove impurities from gas like water, hydrogen sulphide and carbon dioxide and prepare for transportation.
- **transportation and storage facilities:** gas pipelines transport gas along a network, and gas storage facilities manage variable demand.

The level of gas resources that are held in basins and fields is generally reported as the *best estimates* of reserves (referred to as '2P' – proven and probable- these are commercially recoverable and have been justified for development) and *best estimates* of contingent resources (referred to as '2C', these resources are potentially recoverable but not considered mature enough for commercial development due to technological or business hurdles).[13]

The level of supply to end users will depend not only on the level of reserves and extraction rate, but also on the ability to process and move gas from the field to the end user. This chapter outlines what is known about Australia's gas reserves and the capacity of the gas network, as well as issues likely to arise in the future.

Australia has substantial gas resources concentrated in a few locations

Table 5.1 and Figures 5.5 and 5.6 present the levels of 2P reserves and 2C resources by market, sub-region and basin, and the level of production in 2022.

[12] Supply forecasts are typically produced by aggregating well or a group of wells performance data, which will then be complied to the filed level or project level using a bottom-up approach.

[13] SPE-Petroleum Resources Management System. An elaborate system of categorisation has been established based on different level of probability that the quantities can be recovered. 1P (Proved): at least 90% probability that gas reserves recovered will equal or exceed the low estimate of reserve; 2P (Proved + probable): at least 50% probability that gas reserves recovered will equal or exceed the best estimates of reserves; 3P (Proved + probable + possible): at least 10% probability that gas reserves recovered will equal or exceed the high estimates of reserves; 1C: at least 90% probability that gas resources recovered will equal or exceed the low estimate of contingent resources; 2C: at least 50% probability that gas resources recovered will equal or exceed the best estimates of contingent resources; and 3C:at least 10% probability that gas resources recovered will equal or exceed the high estimates of contingent resources.

Table 5.1: Gas reserves and resources, by region and market

Market	Reserves (2P) (PJ)	Contingent Resources (2C) (PJ)	2022 Production (PJ)
West coast	*69,054*	*101,190*	*3,554*
Western Australia	*53,149*	*47,164*	*3,093*
Bonaparte/Browse[a]	*15,905*	*54,026*	*461*
East coast	32,814	41,100	1,939
Southern states	*2,318*	*5,929*	*367*
Queensland	*30,276*	*29,383*	*1,557*
Northern Territory	*220*	*5,788*	*15*
Total	**101,868**	**142,290**	**5,493**

Notes: The 2P reserves and 2C resources data are reported at the end of March 2023 and during the year 2021, respectively. A: Bonaparte/Browse Basins include Browse- Ichthys project, and Bonaparte's Blacktip and Darwin LNG projects. Northern Territory consists of Amadeus and McArthur and Beetaloo sub-basin (note that gas from Browse-Ichthys is processed in NT and can be supplied as emergency gas to Darwin). Southern states include NSW (including the ACT), South Australia, Victoria and Tasmania. Reserves are based on 2P reserves and production as of 2022.

Sources: EnergyQuest (2023c); Geoscience Australia (2023)

Figure 5.5: 2P reserves and 2C resources by region and type

Notes: The 2P reserves and 2C resources data are reported at the end of March 2023 and during the year 2021, respectively. 2P reserves, 2C resources and accumulative production figures cannot be presented for the same period due to data limitation. Bonaparte/Browse Basins are included in NT's calculated resources. Australian gas resources can be classified into conventional and unconventional categories based on their geology and reservoir type. Unconventional gas resources: such as Coal Seam Gas (CSG) which is trapped within coal seams or coal beds and requires specialised or advanced techniques to extract such as hydraulic simulation techniques, and also includes shale or tight gas.

Source: GA (2023); EnergyQuest (2023c)

Australia has substantial levels of gas resources: a total of 101,868 PJ in 2P gas reserves as of March 2023 (Table 5.1).[14] 72% of 2P reserves are conventional gas (72,905 PJ) and 28% are unconventional gas (28,962 PJ, Figure 5.5). Out of 142,290 PJ of 2C resources in 2021, 73% are located in conventional gas fields (104,532 PJ) and 27% are in unconventional gas fields (37,758 PJ).

Insight: Australia has substantial reserves. Reserves in the southeast are 86% depleted, but significant reserves remain in WA (33% depleted), Queensland (33% depleted) and NT (only 4% depleted). However, the majority of gas resources are located geographically far from key demand centres and have limited infrastructure connecting them to the network. There is also substantial unexplored territory both onshore and offshore that has geological potential for gas basins, some of which is located close to demand centres.

While Australia has substantial levels of gas resources, they are concentrated in certain locations. The vast majority (97%) of Australia's 2P reserves are concentrated in Western Australia, Queensland, and the Northern Territory, which places the majority of the Australian 2P (and 2C) gas reserves (resources) geographically far from key domestic demand centres in southern states (GA 2023, EnergyQuest 2023c).

More than two-thirds of southern states' total gas resources (and 86% of the region's 2P reserves) have been depleted. At the current production level, existing southern 2P reserves will be largely depleted within 10 years.[15] After the depletion, the southern states face the prospect of developing new reserves or becoming wholly dependent on gas transported from northern gas fields or LNG import terminals to meet domestic demand. To be viable, all such options involve considerable investment and costs.

In contrast, around one-third of total gas resources in Western Australia and Queensland have been exploited. Whereas the Northern Territory has only used 4% of its gas reserves (Figure 5.5 & 5.6).

For 2P reserves and 2C resources, judging the potential of gas fields is inherently risky and overestimating the potential reserves can lead to shortages where long-term contracts are involved. In some cases, expected reserves from initial estimates of dedicated LNG supply have not proven accurate. The east coast has 'lost' more than one train of LNG worth of gas (over 10,000 PJ) in the transition from initial contingent gas resources estimates to current stated proved reserves.

Prospective resources

In addition to 2P reserves and 2C resources, Australia hosts an unquantified level of prospective gas resources currently undiscovered.[16] South Australia, Queensland, and the Northern Territory are east coast onshore locations that could all be the site of potential future basins (areas of purple shading in Figure 5.7). Little is known about the size, commerciality, and emissions profile of these prospective resources.[17]

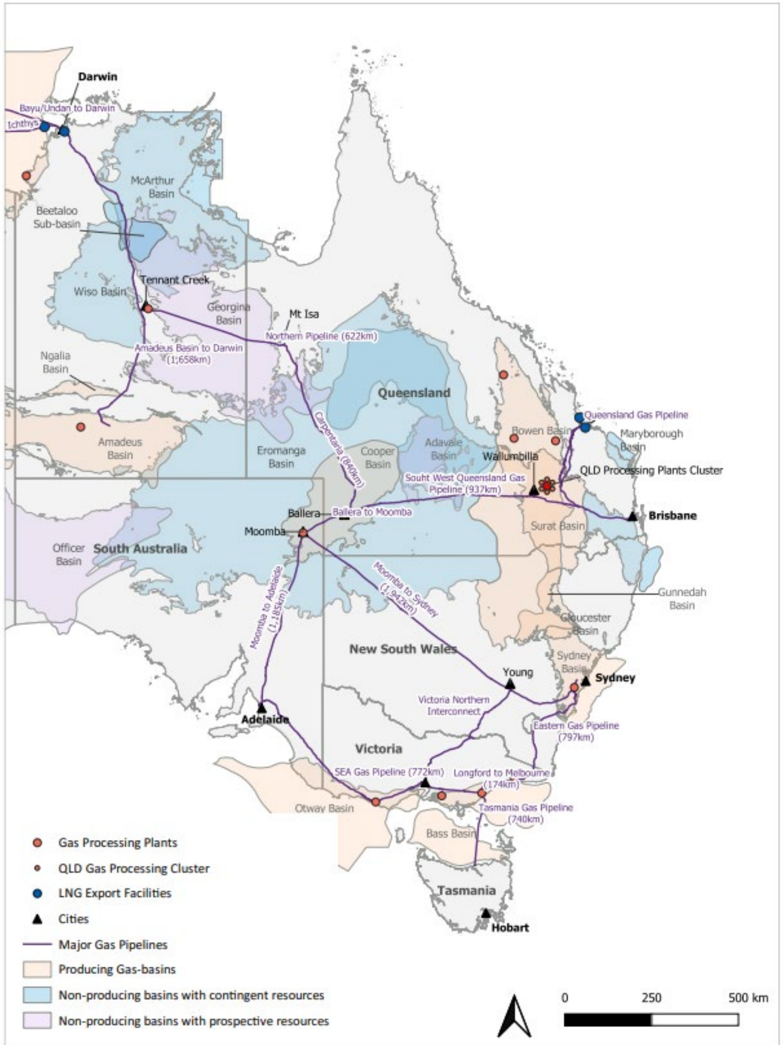
[14] 1 PJ is 10^{15} joules or 278 gigawatt hours, 1 PJ generally allows energy used by 19,000 homes in a year (https://www.energy.gov.au/sites/default/files/2016-australian-energy-statistics-info3.pdf)

[15] In ACCC's latest December Gas Inquiry report, they forecast that southern 2P reserves will be largely depleted within the next 10 years,

[16] Prospective resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations.

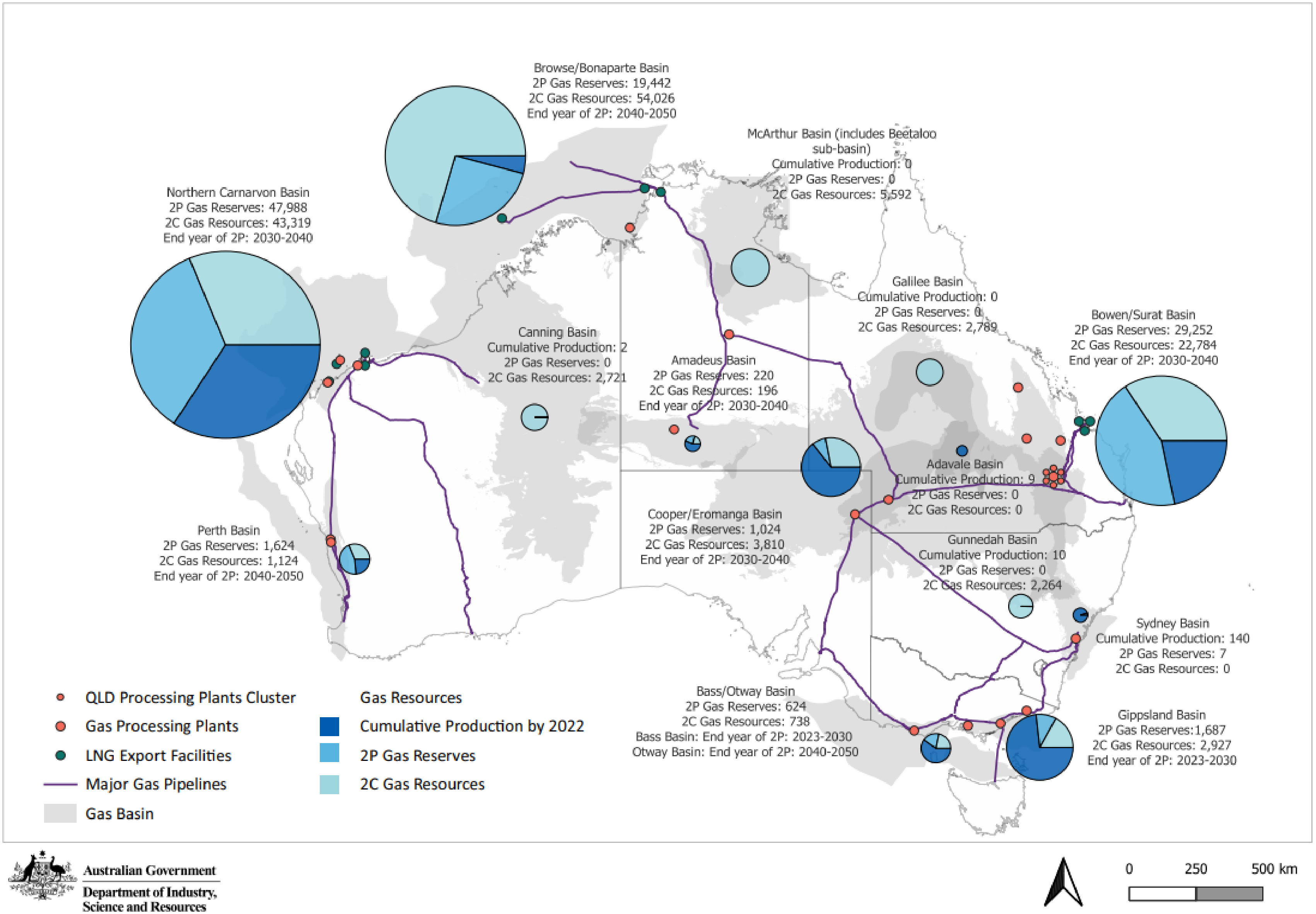
[17] As companies rarely report their prospective resources, having companies submit their prospective resource estimates or implementing precompetitive work programs that target new data acquisition in underexplored basins would help to increase our understanding of prospective resources.

Figure 5.6: East coast prospective onshore gas resources, 2023



Notes: This map is intended to be a high-level representation only.
Source: DISR created the map based on data from GA

Figure 5.7: Australian gas basins, pipelines and LNG facilities[18]



[18] Cumulative production figures are estimated by adding the cumulative production estimates for 2021 from GA with 2022 production from EnergyQuest. End-year of 2P reserves for each basin is estimated by GA (not all basins can be estimated). This map is prepared by the DISR, Office of the Chief Economist, Location Service team.

5.5 Investment trends and outlook

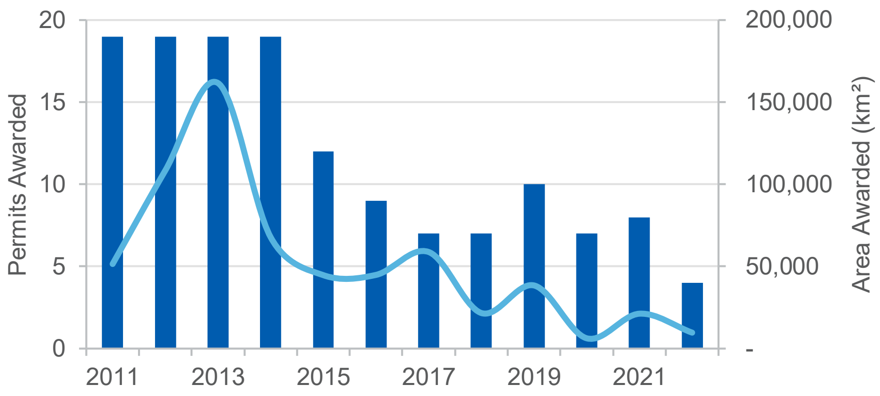
Both maintaining production and accessing prospective resources is dependent on the exploration spending on released acreage (among other things). However, exploration expenditure has declined significantly in recent times, with WA reporting the lowest spend in the last 25 years (ABS 2023a).

This decline can be observed in three inter-related areas, including:

- less offshore acreage being released, fewer bids made and awarded (in terms of both numbers and area, Figure 5.8);
- low rates of exploration spending, particular for offshore projects (measured by petroleum expenditure, Figure 5.9); and
- increasing time taken to award acreage once it has been released for exploration (as measured by time taken to issue a permit, Figure 5.10).

The causes of Australia's low gas investment in exploration are multifaceted. The exploration and production industry experienced a downturn due to the pandemic and impending oil market crash, and the inflationary environment that followed. Also, investment has been limited as Australian LNG projects are currently in their production phase. International companies may also be focused on lower cost and lower risk fields in other countries.

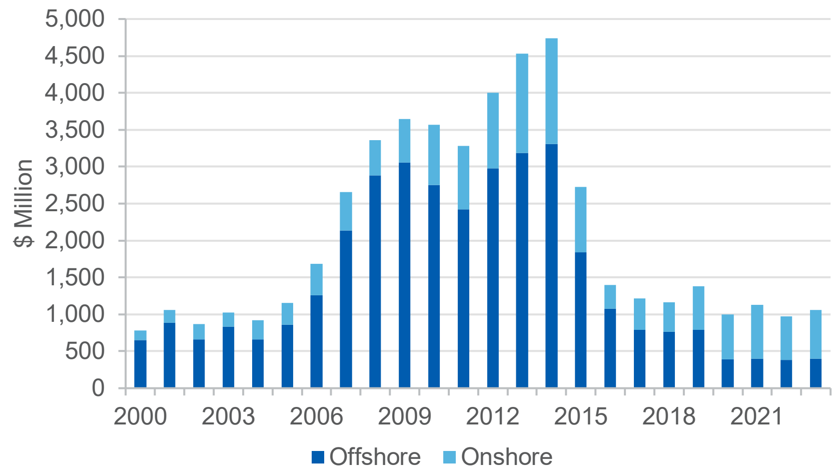
Figure 5.8: Awarded offshore acreages by count, 2011 to 2022



Notes: Based on offshore petroleum exploration acreage release reports.

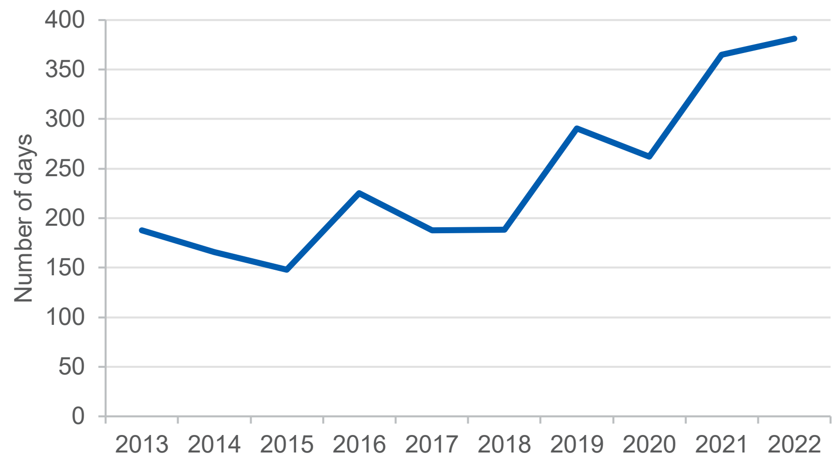
Source: DISR (unpublished c) analysis of petroleum exploration acreage database

Figure 5.9: Oil and Gas exploration expenditure, by type, 2000 to 2023



Source: ABS (2023a)

Figure 5.10: Average days taken to issue permit for offshore acreages, 2013 to 2022



Notes: The duration is calculated based on permit award dates and the bidding close dates.

Source: DISR (unpublished d) analysis of National Offshore Petroleum Titles Administrator data

Stakeholder consultation has indicated that the range of factors that might contribute to low investment levels may include:

- Global developments, such as cyclical (and structural) movements in oil and gas markets and prices, a generalised poor environment for access to project finance, the attractiveness and availability of new gas investment opportunities in other parts of the world, and advances in substitutes to gas such as renewable energy technologies;
- Commonwealth and state government project approval processes;
- Prominent legal challenges to large projects, such as to drilling and fracking in the Beetaloo sub-basin by resources companies;
- The concentrated Australian market for gas production and transmission, which along with large levels of undeveloped reserves in discovered resources may contribute to 'gas hoarding' behaviour;
- State government interventions that affect gas supply and demand, such as Victorian bans on exploration and production of onshore unconventional gas and Victorian/ACT bans on new gas connections;
- The cumulative effect of Australian government interventions such as the Australian Domestic Gas Security Mechanism (ADGSM), the code, Safeguard Mechanism and changes to tax regimes;
- A perceived decline in the social license required for the gas industry to operate in Australia (and associated access to project finance from banks and other institutions).

The gas industry has also raised concerns over how changes in the regulatory environment at a State and Federal level reduce incentives to invest. They argue a stable regulatory environment is required to enable long term investments, and in particular, that interventions that limit the upside returns to investment limit incentives.

Compared to history, Australia would need to maintain a higher level of exploration to maintain current production levels than in the past. Unconventional gas fields need continual investment to maintain output levels. The CSIRO report that the average drilled well will supply conventional gas for 20-30 years, and unconventional gas investments are typically of shorter duration (10–20 years). It follows those lower levels of investment lead to lower production levels after a short delay.

Insight: Australia will need to see much higher levels of investment in exploration and development before production levels can increase.

6. Competition, costs and pricing

East coast summary

The east coast market faces challenges in terms of high levels of concentration (implying low competition) and cost increases that will put upward pressure on pricing over coming years. While the gas shortfall forecast for south-eastern Australia this decade has eased following a range of policy interventions, upward pressure on prices will remain. As well as impacting the price consumers pay directly for gas, price pressures will likely also put pressure on electricity pricing.

Recent initiatives to allocate more onshore exploration permits to junior explorers and non-LNG aligned producers support greater diversity. However, concentration at the production stage remains high, with 88% of production controlled by the top 5 producers.

Costs of production are increasing as existing field productivity declines. Costs of gas delivered to the wholesale market have averaged above $10 from 2021. The cost curve for the east coast gas market, particularly for non-LNG dedicated production, is relatively steep. The largest reserves of low-cost supply are contracted to LNG production. High potential fields for commercial production have estimated average production and transport costs of between $9 and $13 delivered to Melbourne.

Other factors also put pressure on prices. As southern gas fields deplete, the southern shortage will need to be met via northern gas fields or via interstate or international imports. Transport costs will unavoidably increase, both due to increased distance and the need for further investment in network capacity. Demand spikes through winter may increasingly be met via LNG transport from interstate or internationally at a higher cost than today.

International prices are the key driver of 'contract' prices in the east coast market. Over the next five years, international prices are expected to soften as new LNG supply comes online. However, despite the code and easing international prices, upward pressure on domestic costs is likely to persist. Future prices will be determined by a range of factors including international prices, the costs associated with flexible capacity and storage, new transport infrastructure and LNG regassification facilities if import terminals are constructed.

Price uncertainty and volatility is also expected to remain high over the energy transition period. In 2023, gas prices were less volatile and more subdued as international prices fell, southeast Australia experienced a mild winter, coupled with stronger use of swaps with LNG producers and retailers. A sharp winter or outage at a coal fired power station would see volatility pick up again in the market.

Beyond 2024, while international LNG prices are expected to ease, cost increases will continue to place pressure on domestic prices. Overall, risks to prices are on the upside.

West coast summary

Compared to eastern States, Western Australian domestic prices have been relatively low. Lower prices reflect a lower cost of production and gas prices have not historically been set by LNG netback pricing.

However, the demand and supply balance in Western Australia is tightening due to delays in project development and changing demand patterns. Pricing may be put under pressure as the market tightens further in coming years. The Western Australia domestic gas market is projected to remain in deficit between 2024 and 2029, with potential supply from committed and expected projects up to 11% below forecast demand.

6.1 Upstream competition and market concentration

Previous chapters discussed demand and supply absent from pricing. However, demand and supply are crucially dependent on prices today and future price expectations. The level of competition within the market also impacts pricing and how quickly supply can respond to price incentives. This chapter discusses the level of competition in upstream production, the costs of production, and discuss recent trends and the outlook for pricing.

Investment in new gas supply has been well below historical levels (Figure 1.8). There are a range of factors that can contribute to this, including permitting, expectations of future demand and pricing, and a lack of competition. Competition to produce gas is important to bring on additional supply in a timely and efficient manner.

The economics of production tend to imply high concentration and potentially lower levels of competition. The gas industry globally is characterised by high cost, high risk exploration (akin to R&D expenditure), long uncertain development and approval lead times, and production decisions that involve long lead times (which is linked to the high fixed cost, low variable cost nature of offshore production). In Australia, it is common for gas fields and upstream infrastructure to be built by joint ventures to manage risk.

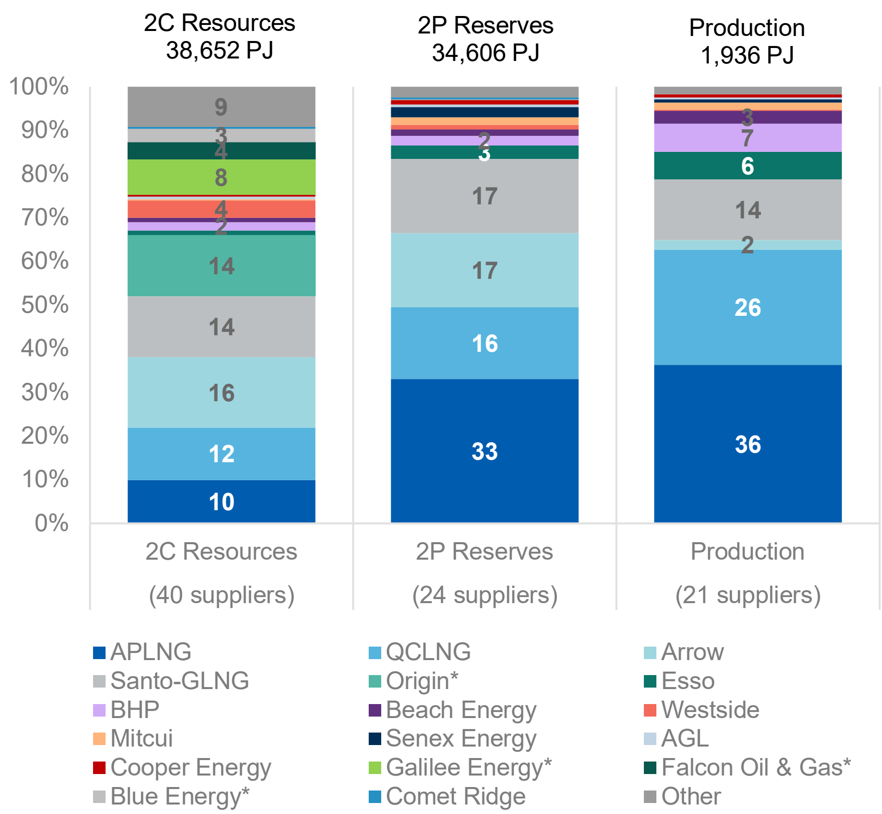
Governments can influence the level of concentration via the licencing regime. Gas reserves are owned by the Crown and allocation to producers is managed by the government — with the Commonwealth allocating offshore tenements and states and territories allocating onshore tenements. Various time-limited and tradeable licences exist: exploration licences, retention leases and production licences. Companies and joint ventures bid for exploration licences. At or prior to expiry, the company may apply for a production lease (if it is commercial to begin production immediately) or a retention lease (to retain control of the tenement even though it is not yet commercial to begin production).

Gas market participants have suggested changes to licencing regimes to raise competition and incentivise new supply which may be warranted. In particular, limiting the duration of licences or the ability to renew has been suggested — this would prevent potential supply sources from being warehoused.

Concentration in east coast markets

In its 2021 *Review of Upstream competition and the timeliness of supply on the east coast*, the ACCC found that market concentration was not a concern at the exploration stage. However, market concentration increases significantly once gas production commences. Figure 6.1 demonstrates the top 5 suppliers on the east coast market own 89% of production, 83% of 2P reserves but only 68% of 2C resources.

Figure 6.1: Producers share of 2C resources, 2P reserves and production, as of 30 June 2020



Notes: These suppliers at the time only have interests in 2C resources.
Source: ACCC (2021)

The LNG producers are particularly dominant, jointly controlling 83% of 2P reserves and 79% of production, either through direct ownership or purchases from associated entities.

The ACCC found diversity in ownership of 2C resources has benefited from actions taken by the Queensland and South Australian Governments to raise diversity by awarding more tenements to junior explorers over recent years. However, junior producers have been less likely to develop fields themselves once resources were proven. Economies of scale for larger producers — due to access to capital and existing infrastructure — enable larger producers to outbid juniors in the development phase.

The ACCC did not recommend changes to licencing but did recommend that governments consider regulation to reduce access barriers faced by smaller producers to upstream infrastructure owned by other producers as a potential way to increase competition within basins.

Governments' reservation policies (and other policies) also influence the market structure. Onshore fields in Queensland are licenced on the basis of domestic or export production. In Western Australia, 15% of production from exports is required to be delivered to the domestic market.

ACCC's (2021) review of the *Australian Market Supply Condition* (Supply Condition) that applies to acreage release in Queensland found for small to medium-sized explorers and producers, the Supply Condition improved their competitiveness for land release tender.

The review also found the Supply Condition would struggle to deliver gas to the east coast gas market during peak winter periods given the relatively higher percentage of Queensland demand to LNG users and infrastructure constraints. Gas swaps, recommended in the Supply Condition review, are assisting to match supply and demand peaks and troughs. Term swap agreements also increase the certainty of supply and will help market participants to sign up for increased pipeline capacity.

The review also found the Supply Condition would struggle to deliver gas to the east coast gas market during peak winter periods given the relatively higher percentage of Queensland demand to LNG users and infrastructure constraints. Gas swaps, recommended in the Supply Condition review, are assisting to match supply and demand peaks and troughs. Term swap agreements also increase the certainty of supply and will help market participants to sign up for increased pipeline capacity.

Insight: Strict enforcement of retention leases and domestic gas reservation policies will increase supply.

6.2 Wholesale gas costs

Costs of upstream production and delivery to the wholesale market are relevant for determining pricing and supply. In most markets, the marginal cost of producers will be a key determinant of the market clearing price and level of supply.

The major components of the cost of wholesale gas include wellhead and field costs, processing costs, and the delivery of gas to the nearest network hub. The costs of retailing gas to consumers reflect the need to hedge against price and volume variability, access to pipeline infrastructure, compliance costs and the costs associated with running a retail business (Box 6.1).

Box 6.1: Factors that influence cost of production

Wholesale gas costs

Costs include permitting, exploration, appraisal and pilot programs, development of extraction and pipeline infrastructure, processing, operational costs, corporate overheads, cost of capital, abandonment and restoration costs, tax and royalties. Factors that affect the cost variability of gas extraction depend on the nature of the field reserves (costs will still vary with the permeability and porosity of the rock, plus saturation and reservoir structure). Offshore production is also affected by water and reservoir depth. Costs associated coal seam gas include permeability, gas saturation, seam thickness and depth. These factors influence the extraction technique and well spacing. Lastly, distance to the network will affect gathering costs and upstream infrastructure.

Retailers' gas costs

Retailers' costs are higher than for producers, reflecting the significant additional services they supply to their clients. Retailers typically manage a range of risks for clients, including gas supply and demand risks, pricing risks and delivery risks. The costs associated include costs procuring wholesale gas (including any market participation fees), market and regulatory compliance costs, transport and storage costs, and the costs of operating a retail business.

Looking forward, costs on the east coast are expected to increase for three underlying reasons: cost inflation associated with production coupled with declining field productivity, the increasing infrastructure costs associated with the need to transport more gas between northern and southeast Australia to meet the anticipated gas shortfall in southern states, and the cost of abating emissions as required under the *Commonwealth Safeguard Mechanism* (as outlined in Chapter 5). Retail costs will also increase in line with wholesale cost increases.

In Western Australia, costs of domestic gas production will be under less pressure than the east coast. WA gas fields are more productive, contain more liquids and require less sustaining capital expenditure as they are primarily larger offshore gas fields. The costs of capital expenditure are also spread across both LNG and domestic gas production, as gas is typically supplied to the market from LNG producers, and thus benefit from economies of scale. Average costs in Western Australia are expected to continue increasing when factoring in whole-of-project costs used for under-development projects and efforts to address field depletion.

AEMO (2023) projects the real costs of production in the Western Australian domestic gas market ($2.90/GJ in 2023 compared with $10/GJ in Queensland) to increase by just over 4% in the coming decade. Risks due to supply shortages are likely tilted to the upside.

Production costs on the east coast

As above, wholesale costs include costs of exploration, production and distribution to the hub. The marginal costs are typically taken to be the primary hub for Queensland, Wallumbilla, because the marginal cost of production is determined by Queensland supplies.

A range of costs are experienced on the east coast. In 2023, volume-weighted average production costs for Queensland producers (wellhead production costs plus delivery costs to Wallumbilla) were measured at $7.61/GJ (Table 6.1).

In 2023, volume-weighted average production costs for Queensland producers (wellhead production costs plus delivery costs to Wallumbilla) were measured at $7.61/GJ (Table 6.1).

Once the Queensland tenements controlled by LNG exporters are excluded to derive a cost of production for domestic gas, the volume-weighted average cost is $9.44/GJ. Tenements held by exporters have an average cost of production and delivery to Wallumbilla of under $4.00/GJ.

The lower costs of production for exporters reflect a combination of economies of scale and, most importantly, having permits in the most productive gas fields in the Surat and Bowen Basins.

Victorian weighted average production costs were under $3.00 /GJ, reflecting low costs of conventional (but depleting) gas production in the Bass Strait. More recently developed fields had higher costs ranging from $3.50 to $3.80/GJ. However, Bass Strait is expecting a near 50% fall in producing wells by 2025. Supply from newer offshore Victorian gas fields or tie backs to existing hubs tend to be significantly higher than existing average costs. This is due to a combination of factors, including smaller field sizes, higher levels of impurities requiring more expensive processing, and higher development costs compared to historical average costs. Tying new offshore Victorian fields into existing infrastructure and building new processing plants does not increase supply capacity – it simply maintains it and increasingly adds to costs.

Table 6.1: Weighted average costs of production from Queensland, 2023, $/GJ (ex-plant and including delivery costs)

	Ex-plant	Wal. GSH	Syd.	Melb.	Adel.	Reserves and selected resources (PJ)
Including LNG projects	6.80	7.61	9.20	9.57	9.30	33,735
Excluding LNG projects	6.51	9.44	8.60	8.60	8.74	7,126
Change since 2020	- 4%	24%	- 6%	- 10%	- 6%	

Notes: Ex-plant costs refer to production costs at wellhead.

Source: EnergyQuest (2023a)

Table 6.2: Estimated delivery costs by destination, $/GJ

Basin	Wallum-billa	Adelaide	Melb. (Max)	Melb. (Min)	Sydney
Amadeus	4.25	5.78	5.87	4.61	4.48
Bass (OP)	4.04	1.37	1.87	0.13	1.77
Bass (AP)					1.55
Bonaparte	5.02	6.55	6.64	5.38	5.25
Bowen-Surat	0.00	2.36	3.72	2.46	2.33
Cooper	1.46	0.90	2.72	1.47	1.34
Gippsland (OP)	4.59	1.37	1.87	0.13	1.55
Gippsland (AP)	4.04				
Gunnedah (OP)	3.04	2.71	2.72	1.47	1.34
Gunnedah (AP)		2.24			
Macarthur	4.25	5.78	5.87	4.61	4.48
Otway	3.68	1.07	1.87	0.13	1.49

Notes: OP = Original Path; AP = Alternate Path. Alternate path indicates a lower cost path. Min Delivery Tariff and Max Delivery Tariff represent the upper and lower range of different throughput charges experienced by market participants delivering gas to Melbourne-based customers through the Victorian Transmission System. While delivery prices for transporting natural gas via interstate pipelines are provided for reference, in practical scenarios, consumers are unlikely to receive gas transported over very long distances.

Source: DISR (unpublished e) analysis based on publicly available pipeline data

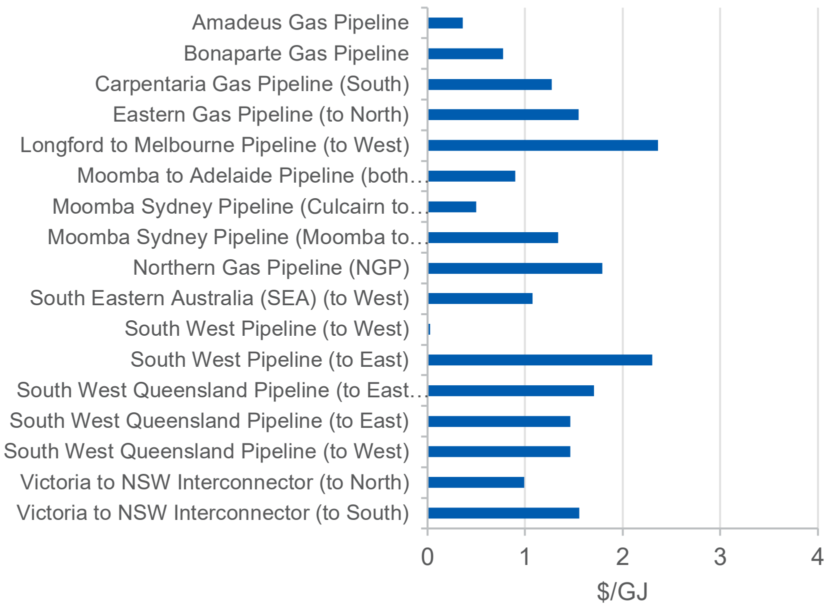
Transport costs on the east coast

The cost of transport is a significant component of the wholesale cost, which involves the cost of connecting the well to the national (east coast) transmission network and then delivery through the network to the hub. Pipeline tariffs are shown in Figure 6.2, with network charges in Figure 6.3.

Total transmission costs are largely driven by the distance between demand centres and gas producing fields, plus the pressure under which the gas is transported. Typically, the 'longer and fatter the pipe' the higher the capital cost. Higher pressure allows greater volumes of gas to be transported (and stored as 'line pack' i.e. the amount of gas stored in the pipeline). The large distances between southern and northern states explains the larger delivery costs for meeting demand in southern states from northern-sourced gas (Table 6.2). In many cases longer pipelines have lower tariffs than shorter pipelines, reflecting lower levels of utilisation.

As more gas is produced in northern fields and transported to southern users, the overall cost of gas will increase in proportion to increased transport costs. The cost premium to receive gas in Victoria from Wallumbilla is typically around $3/GJ. However, transport costs would be higher if new gas (to replace existing Victorian supply) is sourced from the Northern Territory, with delivery to Melbourne costing around $8/GJ.

Figure 6.2: Pipeline tariffs, 2024



Source: DISR (unpublished e) analysis of publicly available pipeline data

Table 6.3: Network charges, $/GJ

Service	Price
VicHub	0.14
VTS Delivery Charge (Max from North)	1.39
VTS Delivery Charge (Max from East or West)	1.87
VTS Delivery Charge (Min non-cross system)	0.13
Cross VTS Charge (Tariff D)	0.28
MAS Wallumbilla-Culcairn/Wilton	2.33
MAS NGP Receipt to Culcairn/Wilton	2.33
MAS NGP Receipt to Wallumbilla	2.10

Note: VTS = Victorian Transmission System, where injections are subject to Transmission Use of System charges; MAS = Multi Asset Service, where terms apply to firm services contracted across more than one APA pipeline.

Source: DISR (unpublished e) analysis based on publicly available pipeline data.

Pipeline expansion can also help to facilitate a more efficient market. Last year, APA increased capacity between Wallumbilla and Wilton by 12% (with a similar expansion planned to be ready for the winter peak in 2024). The expansion included an expansion of the Moomba Sydney Pipeline, which helped facilitate increased gas swaps with LNG producers and retailers. Current expansion plans can assist with pressure on the existing network and price stabilisation through swaps but will not lower the cost of transportation overall.

Increasingly, the additional transportation costs may influence decisions around where businesses with high gas needs will locate. A valid consideration for southern firms is whether to relocate closer to gas fields where supply is lower cost.

Insight: There is upward cost pressure in domestic production. Factors driving future costs include cost inflation, declining field productivity, the increasing infrastructure costs associated with the need to transport more gas between northern and southeast Australia to meet the anticipated southern states gas shortfall, and the cost of abating emissions as required under the *Commonwealth Safeguard Mechanism*.

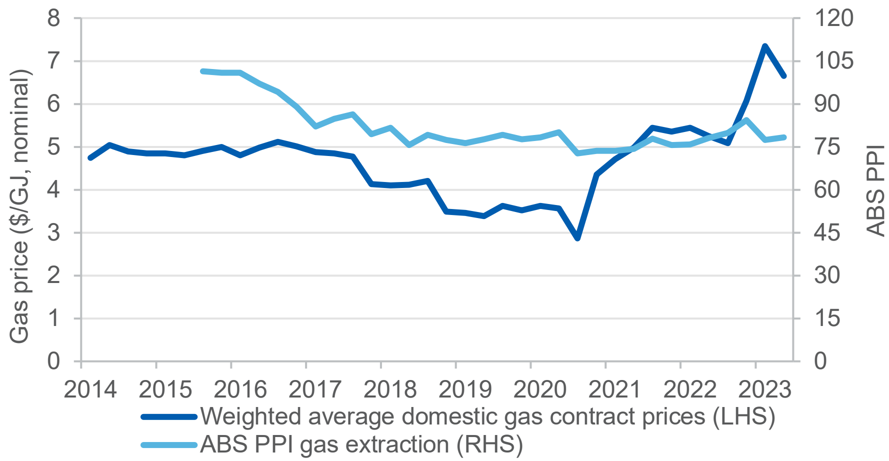
Wholesale gas costs on the west coast

Wholesale gas prices are considerably lower in Western Australia compared to the east coast market (Figure 6.3). However, they have been rising in recent years, as on the east coast. AEMO (2023c) estimates the average cost of domestic gas production in Western Australia to be $2.90/GJ in 2023. In real terms, AEMO expects costs to increase by only 4% over the next 10 years. The lower costs of production reflect the very low short run marginal costs of producing extra molecules from the large LNG projects, and the application of the Western Australian domestic gas reservation scheme on a bigger LNG production base. However, contract prices in 2022 and 2023 rose as both the west coast market and international energy markets tightened, reaching an average contract price of above $7/GJ in 2023.

New Western Australian gas supply (and relative costs) will fluctuate with the development of new fields. Between 2027 and 2029, supply is forecast to grow as Scarborough, South Erregulla, Lockyer Deep, and Waitsia are expected to enter the domestic market.

In the medium term, exploration remains relatively subdued.

Figure 6.3: Western Australia domestic gas prices, 2014 to 2023



Note: ABS PPI is Producer Price Index produced by the Australian Bureau of Statistics

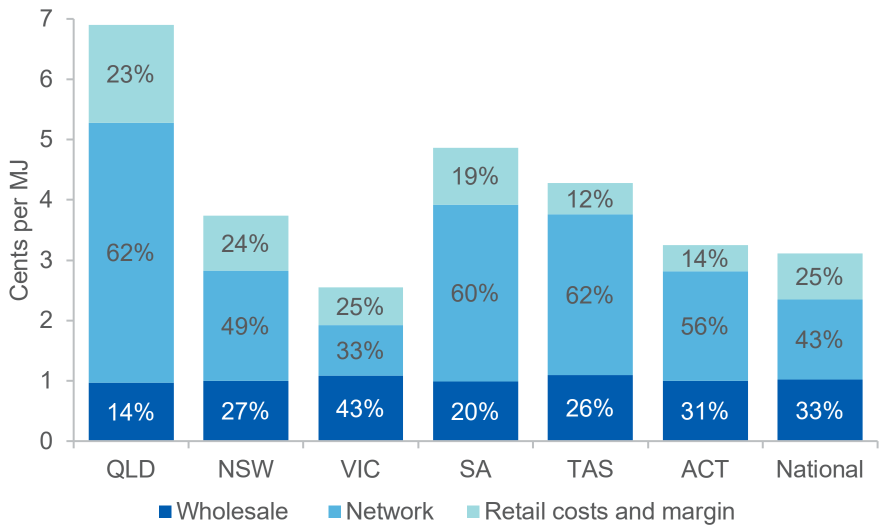
Source: AEMO (2023d)

Retail energy costs

Higher wholesale gas prices flow through to consumers via higher retail gas prices and higher electricity prices given the role gas plays in the NEM. See Box 6.2 for more information on the impact gas has on electricity prices.

Forward pricing for short term supply retail transactions for 2024 to 2027 average around $17.60/GJ which is higher than the wholesale cost. This reflects retailers offering additional services to clients beyond what is offered in the wholesale market (see Box 6.1). The ACCC is currently conducting an inquiry into retailer pricing behaviour. The first stage of the review found the tight and volatile market conditions in 2022 and early 2023 posed significant challenges for retailers and commercial and industrial gas users, and contributed to a deterioration in retail competition and some retailers' selling practices. The review also found conditions in the latter half of 2023 had started to improve, with retail competition increasing and some retailers reverting to their standard selling practices.

Figure 6.4: Breakdown of gas retail prices, 2017



Notes: Data is estimates at 2017. Average residential customer prices exclude GST (real A 2018–19). Percentages may not add to 100% due to rounding. This is the most up-to-date data available, and costs may have changed since 2017.

Source: DISR (2018)

Only a relatively small share of the retail cost of gas is related to the wholesale cost. A breakdown of residential pricing into wholesale costs, network costs and retailer costs and margins are available for 2017 by state (Figure 6.4). The breakdown illustrates the high costs associated with distributing gas around the network.

Box 6.2: Gas plays a pivotal firming role in electricity markets

Gas is and will continue to be a key generation source in Australian energy markets, particularly as a peaking fuel when there is low renewables generation and storage options have been exhausted.

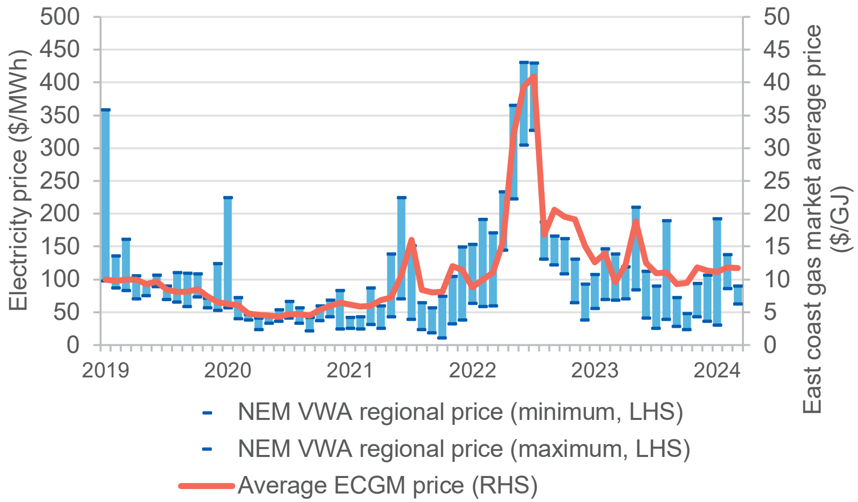
As highlighted by the AER in its *Wholesale Electricity Market Performance Report 2022*, electricity costs reflect the mix of power generation in the grid. Historically, this has reflected the cost of coal and gas fired power stations. The increasing penetration of low-cost variable renewables in recent years has displaced coal generation, increased competition and reduced prices at the times renewables are producing electricity. Gas generation is highly flexible as it can increase and decrease production quickly, but it is also one of the most expensive fuels. Gas tends to be used as a peaking fuel for this reason. When gas units are providing peaking and firming capacity for the grid, the cost and price of electricity increases.

Gas can also influence the behaviour of other peaking generators such as hydroelectric power stations and batteries. Hydro generation tends to offer electricity to the market at prices between those of coal and gas, depending on the desired level of dispatch. As a result, even though gas infrequently sets prices, the price it offers its capacity at influences how hydro generation is offered. When the offers of gas (or coal) generators increase, hydro generators generally follow suit. To date, batteries have had limited deployment in electricity markets, but as their market share grows, their offers are likely to be greatly influenced by offers of other generation.

Therefore, the price of gas and electricity can track closely, particularly at times where there are tight supply-demand conditions, as shown in Figure 6.5.

As the system increasingly relies on gas for peaking and firming, gas supply and pricing will continue to be a key determinant of the cost of firmed electricity to industry and households, particularly as renewable generation increases and coal-fired generation retires. In addition, there will continue to be price impacts during winter when gas supply is stretched between gas demand for heating and gas-powered generation. In the long run, alternatives such as hydrogen, ammonia, thermal storage or other long-term storage options may be able to displace the use of gas.

Figure 6.5: Comparison of east coast gas and electricity prices 2019 to 2024



Note: Monthly electricity prices are the volume-weighted average (VWA) minimum and maximum for NEM regions. ECGM is east coast gas market.

Source: AER (unpublished) analysis of AEMO's NEM, Short Term Trading Market and Victorian Declared Wholesale Gas Market data for DISR

6.3 Pricing in the east coast market

Gas pricing is largely undertaken through bilateral contracts within the gas wholesale markets — there is no single market clearing price. The wholesale spot market is a smaller but growing component of the market. Spot wholesale prices have become more volatile as the overall gas market tightens. Spot market trading can also be a useful mechanism for participants to manage imbalances in their contract positions.

While contract and spot prices vary across the east coast, the LNG netback (based on contracted LNG) works as an important determinant in setting prices.

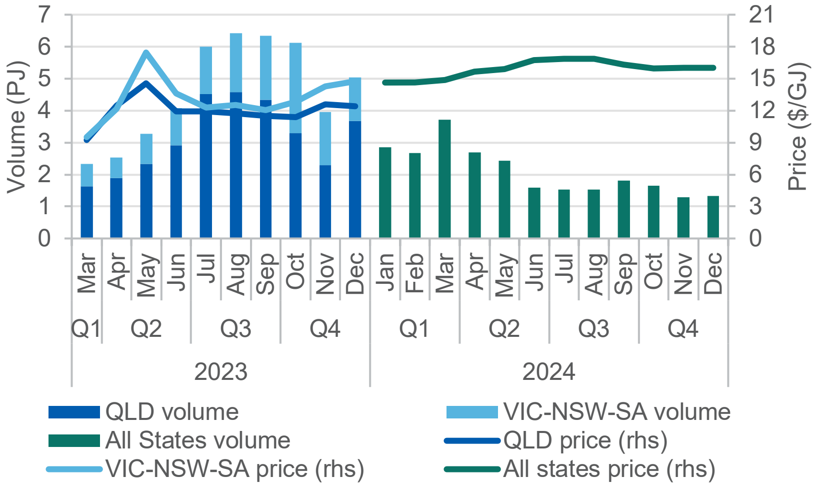
Current pricing

Current pricing has stabilised at close to 2021 levels after spiking during the 2022 energy crisis (Box 6.2). The AER (2023c) found the volume-weighted price for gas traded for delivery in 2024 was $15.88/GJ (similar to analysis from the ACCC *December 2023 Gas Inquiry Interim Report*). Smaller customers (more likely commercial and industrial) appear to have contracted at higher prices (Figure 6.6).

The final factor is greater uncertainty (for example, about the future of gas and greater volatility of demand associated with aging power infrastructure) raises the risks to producers of contracting for firm supply. The cost of managing those risks will likely to be passed on to users.

The ACCC (2023) has observed fewer offers for supply in 2024 compared to previous years. This may be due to a combination of factors, including reduced Longford production capacity (particularly the uncertainty on timing when capacity will reduce below critical capacity of 700 TJ/day during or after winter 2024), seasonal slowdown and the industry's response to regulatory uncertainty. LNG producers appear to be adding to domestic supply offers.

Figure 6.6: Volume-weighted average prices and supply volumes, 2023 and 2024



Note: The above volume-weighted prices and quantities are based on the supply dates of the reported transactions and include all pricing structures. For 2023 the analysis is split between Queensland as an indicative northern price while Victoria, NSW and South Australia (VIC-NSW-SA) are grouped together for an indicative southern price. For 2024 all 4 states are grouped together. Reported transactions are for bilateral contracts up to a year in length (not multi-year contracts).

Source: AER (2023b)

The ACCC (2023) reported east coast LNG producers offered over 26 PJ of gas to the domestic market for supply in 2023, in addition to previous offers of over 274 PJ for 2023 supply made between 19 August 2022 and 15 February 2023.

The code is a key element of the government's Energy Price Relief Plan. It is designed to deliver additional gas to the market at reasonable prices, on reasonable terms, and to facilitate the efficient functioning of the wholesale east coast gas market. The code does this through an exemptions framework which incentivises suppliers to commit more gas to the east coast gas market in the short-term and facilitate new investment to meet ongoing demand in the medium term.

In January 2024, it was announced that four exemptions under the code had resulted in the gas industry committing to resume works to progress towards making a FID of 564 PJ for delivery to the east coast market from 2024 to 2033, providing more affordable gas to the Australian market in the short to medium term.

The code, as well as easing international and domestic conditions, all put downward pressure on prices in the first quarter of 2024 compared with the previous 12 months.

Despite ongoing geopolitical tensions, Asian and European LNG markets have been stable with prices trending down. In the first quarter of 2024, Asian spot LNG prices remained stable as most of the northern hemisphere went through a mild winter. European LNG storage reached record high levels throughout the period and even the increase in spot activity from Asia at the back end of the quarter did not have a material impact on global LNG prices.

East gas coast demand was 10% higher for the first quarter of 2024, but increased demand was entirely attributable to higher LNG exports. GPG, consumer and industrial demand declined from the previous quarter.

Prices remain subdued despite decade low production at Longford and a pipeline rupture near Gladstone. AEMO (2024c) reported lower production at Longford was partially offset by healthy Iona storage levels post winter 2023.

Insight: Wholesale prices since June 2023 have averaged below $12/GJ. The code and a combination of lower and less volatile international prices, plus lower east coast gas demand, all put downward pressure on recent east coast prices.

LNG netback pricing and multi-year outlook for domestic prices

Looking beyond 2024, pricing pressures are mixed. LNG pricing is likely to ease, placing less pressure on domestic prices. However, cost pressures on the east coast will continue. In such an environment, balancing supply and demand implies lower supply or higher prices to incentivise domestic production.

First, LNG outlook is for increasing supply, but there are risks for pricing. Growth in global LNG supply is expected to outpace growth in demand. In December 2023, global LNG exports hit a monthly record of 37 Mt.

On the flip side, an increase in global LNG supply by the end of 2025 will put downward pressure on prices. Future demand for LNG may be stronger than expected, however, with many countries building new floating regasification facilities and import terminals for energy transition and security reasons. Similarly, seasonal demand from China can swing pricing.

LNG is an attractive fuel source for Asian buyers as gas has a lower emissions footprint than coal. In addition, the low ramp rate of gas-powered generators provides grid stability through renewables firming and peaking.

The geopolitical outlook also poses supply risks. Additional sanctions may be placed on Russian LNG exports. Increasing tensions in the Middle East are impacting shipping flows in the Red Sea and Persian Gulf. A combination of a higher geopolitical risk premium and potential supply disruption may push prices higher.

Insight: Beyond 2024, while international LNG prices are expected to ease, cost increases will continue to place pressure on domestic prices. Overall, risks to prices are on the upside.

Increasing costs of production and distribution may also imply domestic price increases may be required to maintain current levels of output (which requires ongoing investment). Without price increases, supply may be constrained. In such an environment, less productive users of natural gas would typically be priced out of the market in order to balance supply and demand.

Box 6.3: The 2022 energy crisis and 2023 experience

2022 was characterised as a ‘perfect storm’ of shocks that culminated in substantial price increases in the wholesale gas market (Figure 6.7).

First, in February 2022, the Russian invasion of Ukraine limited the international supply of gas and raised LNG netback prices and expectations, leading to a strong flow of non-contracted gas into the export market.

Then in the domestic winter, coal-fired power generation outages and lower electricity production from renewables led to unexpected increases in gas demand from gas-fired power generators. Further, wet weather affected supply from a range of gas fields in Queensland, the Northern Territory and the Cooper Basin.

Finally, the forced closure of Weston Energy led to a spike in demand from other retailers for new gas to meet their obligations to new clients under the Retailer of Last Resort requirements.

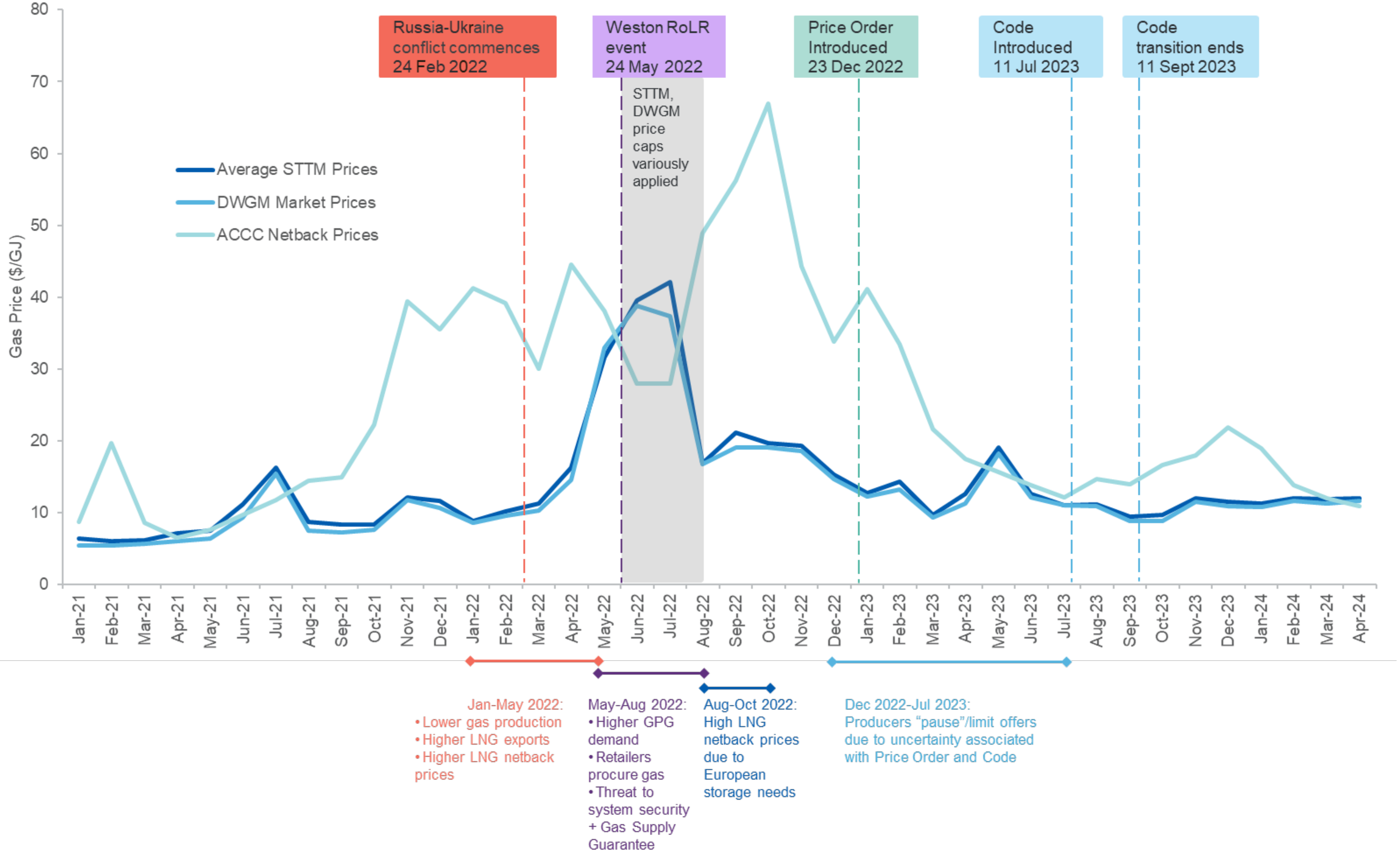
These shocks also occurred in a market that had been tightening for several years. The tightening in the market exacerbated both international and domestic demand and supply shocks.

What was called the ‘energy crisis’ led to government action. Under the Gas Market Emergency Price Order in December 2022, producers were required to offer short-term contracts for 2023 supply at or below $12/GJ. Market conduct provisions were also enacted to support contracting, which was constrained due to high price volatility and limited bargaining between parties. The finalisation of the code and price-cap exemption framework in mid-2023 also assisted to ease market conditions. Since the implementation of the code, gas prices have trended down, averaging below $12/GJ since June 2023.

Within the contract market, over 85% of gas delivered in Q3 2023 was traded at less than $12/GJ, which was the cap applied to exporter and producer participants. Prices above this reflected sales by market participants not subject to the cap (retailers, power generators and short notice LNG exports).

Pricing tended to be lower in Queensland (volume-weighted price of $11.98/GJ) than in southern states (Victoria, NSW, and South Australia; volume-weighted price of $13.15/GJ) – reflecting that a larger share of gas is produced in northern states and transported (with associated costs) to southern states, coupled with the cost of storage and variability of demand.

Figure 6.7: East coast gas prices, 2021 to 2024



Notes: Price data for Short Term Trading Market (STTM) and Declared Wholesale Gas Market (DWGM) are from AEMO. Netback prices are from ACCC. STTM consists of Adelaide, Brisbane and Sydney.

Source: AEMO (2024); ACCC (2023)

7. Closing supply gaps

Summary

This chapter looks at options to *increase supply* to close regional gaps in east, north and west coast markets of Australia. Significant risks associated with adequate supply in the Eastern Market remain.

East and north coast markets

Forecasts for supply suggest a shortfall in the eastern markets from 2028. However, the risks of a short run supply shortfall are to the upside. For example, a company's 120 PJ of new production (coupled with necessary pipeline expansions) are conditional on further approvals. If approvals are not granted, the shortfall will occur by 2027. Over the medium term, there are also risks forecasting supply, particularly from the Narrabri and Surat Basins.

Recently announced additional production from existing offshore Victorian fields is insufficient to prevent a shortfall occurring in the southern states. Resolving southern shortages requires both additional northern state and territory production, as well as overcoming constraints in the existing network to deliver gas from the northern to southern states.

Based on stated reserves and contingent resources, the most likely to be developed but yet-to-be sanctioned fields are in the Surat Basin (Queensland), Narrabri (NSW) and Beetaloo Sub-basin (Northern Territory). The estimated costs of production and delivery to Melbourne from Surat, Narrabri and Beetaloo are estimated at around $9 to $13/GJ.

However, these 3 fields are unlikely to provide additional (above forecast) supply ahead of forecast shortfalls. All fields require further exploration and development to prove commerciality, and well and completion costs will depend on the efficiency of new extraction methods as well as the emissions potential of these fields (currently unknown). These fields will be subject to regulatory approvals and strong competing land use claims.

Until recently, the Northern Territory was a net exporter of gas to eastern states. An unanticipated fall in offshore production means the Northern Territory must now rely on supply from LNG facilities to meet local demand. The commerciality of the Beetaloo Basin will determine the ability of the Northern Territory to shift back to being a net exporter of gas.

Options to increase transportation to the south-eastern states from potential future fields include additional pipelines and processing facilities, as well as LNG import terminals. Import terminals provide the fastest date to completion but face regulatory and commercial hurdles. Pricing of gas from import terminals is likely to be higher than current domestic prices.

The price of gas from proposed import terminals is uncertain. Developers are also finding it difficult to secure offtake agreements with domestic users. Import terminals also offer crucial storage near demand centres and can improve the resilience of the system as peaking demand from GPG grows and becomes more volatile over time. But, like new gas supply, import terminals face regulatory, infrastructure and commercial hurdles.

West coast market

On the west coast, the demand and supply balance hinges on the level of domestic gas requirements placed on LNG exporters and potential new and offshore discoveries.

AEMO (2023) forecasts the Western Australia domestic gas market will be in deficit between 2024 and 2029. The demand and supply balance in Western Australia is tightening due to changing demand patterns, delays in project development and the reduced ability of existing fields to supply gas as they deplete and enter end-of-life phase. Pricing may be put under pressure as the market tightens.

The Western Australian Parliament's Economics and Industry Standing Committee interim report into the Western Australian Domestic Gas Policy found the domestic gas reservation scheme was 'no longer fit for purpose' and may require government intervention.

7.1 Potential to increase east coast production

This chapter explores developments and options to *increase supply* and help alleviate shortages both at a national and regional level. Potential supply shortages are due to falling southern and northern production in existing fields, delays to anticipated supply in NSW and Queensland, plus limited pipeline capacity to transport gas from northern to southern states.

To the extent possible, this chapter also explores pricing implications of those developments and options.

Options to reduce demand are covered in Chapter 3.

Chapter 5 shows the east coast gas market could have sufficient gas supply to meet domestic (and LNG export) demand for many years if additional (above forecast) gas supply can be developed from existing 2P reserves, possible reserves, contingent and prospective resources. However, this will require both forecast and new projects to be developed in the required timeframe.

Risks around existing forecast production

Supply from fields expected to come online must also do so at the speed expected. Current forecasts include a range of supply from new investments in fields close to current users, including from the Surat, Bowen and Galilee Basins in Queensland, the Gunnedah Basin in NSW, the Bonaparte, Amadeus and Macarthur Basins in the Northern Territory, offshore Victoria and the Cooper Basin in South Australia.

Each of these potential sources of supply included in current forecasts face uncertainty for a range of technical, licence to operate, regulatory approval and funding reasons:

- The Surat, Bowen and Galilee Basins face competing land use claims and surface risk. The Galilee Basin must also overcome technical reservoir challenges associated with dewatering and hydraulic stimulation.
- The Gunnedah Basin faces competing land use claims and still requires regulatory approval.
- The Amadeus, Bonaparte and Macarthur Basins must prove reserves then overcome infrastructure funding and regulatory approvals.
- Offshore Victoria faces declining supply and issues associated with reservoir performance during end-of-life production.
- Declining well performance in the Cooper Basin makes it more difficult to ensure consistency in plant and processing infrastructure.

If these gas supply developments are delayed in financing or regulatory approvals processes, supply shortages will emerge that could affect both domestic demand and exports.

For example, if the Atlas project in the Surat Basin is delayed, then forecast production on the east coast would be 60 PJ lower by the end of 2025 and 120 PJ by the end of 2027. The delay would bring forward the east coast supply shortfall to 2026.

Avoiding a shortfall in the southern states is most dependent on the development of Narrabri gas fields because it is relatively close to southern demand. Northern fields (i.e. Surat and Beetaloo) are more likely to backfill LNG shortages first.

The forecast shortfalls for the east coast's gas market could have major implications for domestic demand and LNG exports. To meet both contracted LNG export obligations and forecast domestic demand, new gas supply and connecting infrastructure is needed from undeveloped fields.

Most likely commercial fields

Outside of current forecasts, new fields in the Surat and Narrabri Basins and the Beetaloo Sub Basin are the 3 most likely to be developed for large-scale gas supply. However, lead times for exploration, development and connection to the network via pipeline suggest new supply will not come online to alleviate shortages that will emerge from 2028, though it could improve the supply outlook beyond this.

Expenses include wellhead costs, costs of new pipeline infrastructure and cost of abatement. Currently, on a field size and average volume-weighted cost of production basis, the following fields would deliver the largest scale and lowest cost gas production (EnergyQuest 2024). However, with few reserves proved up, these costs are uncertain, and the fields will also require significantly more investment in exploration and development:

- Undeveloped Surat Basin fields – 5,761 PJ (2022) at $6.70/GJ ($9.16 and $10.42/GJ delivered to Melbourne).
- Undeveloped Narrabri fields – 1,316 PJ (2022) at $9.90/GJ ($11.37 and $12.62/GJ delivered to Melbourne).
- Undeveloped Northern Territory fields – 5,365 PJ (2022) at approximately $6.84/GJ ($11.45 and $12.71/GJ delivered to Melbourne).

They will also require pipelines to connect to the existing grid, which likely involves long lead times and high costs. Using an average pipeline construction cost associated with previous builds of $1.53M/km suggests a ballpark figure for the cost of new pipelines before cost inflation.

- Beetaloo Sub Basin: APA Group has an agreement with Tamboran to build a pipeline connecting Beetaloo to the Amadeus Gas Pipeline (AGP). FID is expected in 2024. The distance between the Beetaloo Sub Basin and AGP is around 150 km. Ballpark cost of construction is $230 million.
- Narrabri Basin: Santos plans to build the Hunter Gas Pipeline (HGP) and the Narrabri Lateral Pipeline which connects Narrabri to Newcastle. FID is expected in 2025. The total length of the two pipelines is estimated at around 900 km. Ballpark cost of construction is $1,377 million.
- Surat Basin: the distance between the North Surat Basin and the South West Queensland Pipeline (SWQP) is around 100 km. Ballpark cost of construction is $153 million.

Going forward, all new gas fields must abate reservoir emissions through carbon capture and storage or another alternative. The 3 supply options have different carbon content, and are likely to experience different costs of abatement that would add to the cost of the gas delivered to the wholesale market. The Surat Basin has the lowest CO_2 content at 1.1% on average, compared to the Beetaloo Sub Basin (3% on average) and Santos Narrabri Project (5% to 10%).

7.2 Basin by basin development potential

Key factors that will determine whether new supply is developed include price expectations, and the ability of producers and users to reach agreement on upfront funding to underwrite the risks of exploration and development.

Future development of the Surat Basin and Beetaloo Sub Basin will be underpinned by ongoing LNG contracts, plus the need to backfill contracted supply. For other fields, the upward trajectory of costs suggests domestic prices may need to be higher than current levels to underpin future development.

Onshore developments on, or encroaching, agricultural land will continue to face competing land claims. The largest near-term potential source of new onshore gas is the Surat Basin, a region of agricultural land where access by the gas industry is highly controversial.

A further complication is that companies may also face internal or external limits on risk exposure or borrowing which may impact on their ability to undertake new investment. Financing investment in exploration and development of gas is difficult in the current environment. Many creditors are limiting their exposure to the oil and gas sector, although international company profits in the sector remain high and are supportive of internally funded investment.

Surat Basin

Additional supply is also required to maintain export levels as required by foundational LNG contracts. Without additional supply, LNG producers will have to rely on third party gas to meet contracted demand, with implications for domestic market supply. If anticipated supply from the Surat Basin is delayed, or does not occur, this issue could emerge earlier.

AEMO (2023c) forecasts show LNG exporters have sufficient production:

- from existing and committed facilities to meet forecast exports until 2025.
- if anticipated investments proceed, to meet forecast exports until 2027.

New investment is required to bring supply online to meet contracted cargoes from 2027, in particular for QCLNG. This supply is most likely to come from the Surat Basin, which is close to LNG facilities and already includes significant LNG operations. However, there are barriers to increasing production in the region, including securing enough drill rigs to substantially increase production, securing necessary landowner consent and applications to secure necessary pipeline land access.

Narrabri Basin

EnergyQuest forecasts suggest the Narrabri Basin will supply 55 PJ of gas to the domestic market by 2030, accounting for about 10% of the domestic usage anticipated in 2030.

As outlined earlier, Narrabri faces significant competing land use claims and additional steps associated with regulatory compliance. In addition, the Narrabri Basin must also be connected to pipeline infrastructure.

Narrabri owner Santos has set out some of the conditions to complete FID by 2025:

- Resolution of the Notice of the Appeal for Native Title Tribunal hearing in August 2023. In March 2024, the full Federal Court allowed an appeal against the determination by the National Native Title Tribunal that proposed future acts, being the grants of Petroleum Production Lease Application Numbers 13, 14, 15 and 16 for the Narrabri Gas Project, to proceed. The Court determined the National Native Title Tribunal erred at law by declining to have regard to evidence on climate impacts that were tendered on behalf of the Gomeroi applicant. The Court’s orders regarding next steps are yet to be undertaken.
- The company is also progressing land access and survey activity to support Project Approvals and Pipelines License Applications.

In the company’s February 2024 results presentation, Santos stated the earliest gas expected from Narrabri is 2028.

Beetaloo Sub Basin

There are large volumes of gas in the Beetaloo Sub Basin. The number of contingent reserves are increasing as improvements in fracture stimulation techniques and efficiencies are trialled (for example, there has been recent success in applying ‘US Style’ completion techniques to improve well performance).

Until recently, the Northern Territory was a net exporter of gas to eastern states (Box 7.1). But an unanticipated fall in offshore production means the Northern Territory must now rely on supply diverted from LNG facilities to meet local demand.

Beetaloo is much closer to Darwin than the Gladstone LNG facilities. Beetaloo can help supply gas in the domestic Northern Territory market, backfill LNG out of Darwin, and supply the east coast. East coast supply can be delivered via connection to pipeline infrastructure or as LNG shipped around the coast to import terminals. Beetaloo faces regulatory approval uncertainty and competing land use claims. The liquids content in the Beetaloo may also necessitate LPG removal to meet gas specifications, lifting capital and processing costs.

Beetaloo faces regulatory approval uncertainty and competing land use claims. The liquids content in the Beetaloo may also necessitate LPG removal to meet gas specifications, lifting capital/processing costs.

Insight: The lowest-cost supply options are the Surat Basin, Narrabri and undeveloped Northern Territory fields. All need substantial investment in exploration, development and pipelines. New supply is highly unlikely to fill shortfalls emerging in 2028, but would assist to fill supply gaps in coming years.

Box 7.1: The Northern Territory gas market

The Northern Territory supplies gas for three LNG trains and a 26 PJ local market. Of the 26 PJ of local demand, just under 20 PJ is used for GPG. The remainder is used for mining and nitrogen removal (necessary to strip from gas stream to meet gas specifications) when gas is transported to Queensland via the NGP.

The Darwin single train LNG project is operated by Santos. The source of feedstock gas is currently the offshore Bayu-Undan gas field. LNG production has ceased and residual Bayu-Undan gas is being supplied into the Darwin domestic gas system. Plans are underway to backfill Darwin LNG with the Barossa Field. The two train Ichthys LNG project is operated by INPEX. The source of feedstock gas is the Ichthys field. Both LNG projects are connected to the Darwin pipeline system and are contracted to provide emergency gas supply to the Northern Territory.

Until recently, the Northern Territory was a small net exporter of gas, with the majority of offshore gas coming from the Blacktip field. However, production from Blacktip has recently been lower than expected.

The Northern Territory market is connected via a pipeline to Mt Isa. Previously, the Northern Territory had exported up to 20 PJ of gas to eastern states. However, with field decline – especially from Blacktip – Northern Territory domestic gas supply is no longer able to meet local demand. In 2023, just over 4 PJ of the 26 PJ of domestic demand were supplied by the Ichthys LNG project. Northern Territory LNG projects typically do not supply domestic demand. LNG has recently been supplying domestic demand under emergency supply procedures.

Domestic gas pricing in the Northern Territory is relatively opaque. Gas is supplied to the sole GPG provider and mining companies through individual contracts. Gas costs have been increasing and EnergyQuest estimate the cost of Blacktip production is now over $14/GJ.

The Beetaloo Sub Basin has large quantities of gas. Gas developers are continuing to drill, prove reserves and optimise completion techniques. If technical hurdles continue to be overcome and competing landowner land use claims are resolved, the Beetaloo Sub Basin can provide LNG backfill, as well as gas to the Northern Territory and eastern domestic markets (via connection to pipeline infrastructure or as LNG shipped around the coast to import terminals).

If commercial development is viable, Beetaloo gas is expected to be relatively low cost and low carbon.

7.3 Increasing transport capacity on the east coast

New transport capacity is required to overcome shortfalls in the south-eastern fields coupled with the additional supply of gas. In particular, the South West Queensland Pipeline (SWQP) and Moomba to Sydney Pipeline (MSP) are key constraints within the system and would prevent northern gas from filling the full demand from southern states. This section looks at the potential for more pipelines and the impact of LNG import terminals.

Potential new pipelines and pipeline expansion on the east coast

Developing pipeline infrastructure and expanding pipeline capacity is crucial to bringing more sources of supply to the east coast market. This reflects the need to connect gas fields to the existing network, expand existing regional pipelines to move gas from north to south in particular, and additional distribution network expansions within southern states.

- Table 7.1 lists the potential new gas pipeline projects for commissioning by 2028. These potential new gas pipeline projects essentially aim to connect the potential new gas supply from Beetaloo sub-basin and Narrabri gas projects in Gunnedah Basin to the east coast market (discussed in section 5.4).
- Table 7.2 summarises major pipeline expansions that have the potential for commissioning by 2028. One of the major pipeline expansion projects is currently being carried out by APA, which aims to raise the nameplate capacity of SWQP and MSP by 25%. Stage 1 was commissioned prior to winter 2023 while stage 2 will be commissioned shortly ahead of winter 2024.

These pipeline projects are yet to achieve FID, with competing land use claims and commercial and financial concerns yet to be fully addressed.

Table 7.1: Potential new pipelines for commissioning by 2028

Developer	Name/Description	Nameplate capacity	Key dates (FID, Commission)
APA	Shenandoah South to Amadeus Gas Pipeline (AGP): connects Beetaloo to Amadeus Gas Pipeline (AGP) in NT	~40–100 TJ/day	2024, 2025
APA	NT - Beetaloo - East Coast Pipeline: connects Beetaloo to east coast gas network	~500 TJ/day	N/A, 2028
Santos	Hunter Gas Pipeline (HGP): connects Narrabri to Newcastle	250 TJ/day	2025, 2027
Santos	Narrabri Lateral Pipeline: connects Narrabri to HGP	250 TJ/day	2025, 2027

Source: ACCC (2023)

Table 7.2: Potential pipeline expansions for commissioning by 2028

Developer	Name/Description	Nameplate capacity	Key dates (FID, Start)
APA	Western Outer Ring Main (WORM): provides new connection between Melbourne and Wollert in the north	Add 23 TJ/day to 517 TJ/day	Complete; Jan 2024
APA	East Coast Gas Grid Expansion: increases winter peak capacity of the east coast grid by 25%	Add to 565 TJ/day, then to 599 TJ/day	Stage 1 completed and commissioning commenced for stage 2, with operation expected in 2024; undertaking engineering and design work for Stage 3a
Jemena EGP	Project Marlin: connects PKET with EGP in NSW	522 TJ/day, Bi-directional 200 TJ/day	Lateral complete
Tasmanian Gas Pipeline (TGP)	Expansion of VicHub: increases gas receipt options for TGP	Increase capacity from 129 TJ/day to between 150-350 TJ/day	2024, 2024–25
SEA Gas	Port Campbell to Adelaide (PCA) East: creates Bi-directional reconfiguration of the PCA to send gas west-east (SA to VIC).	In development	Unknown, unknown

Source: ACCC (2023)

New gas storage developments on the east coast

Gas storage plays a crucial role in balancing supply and demand. It helps to build reserves during low gas demand periods and allows withdrawals as required. Adequate storage near high-demand areas ensures timely delivery during peak times and helps to address peak-day gas supply shortfalls.

Table 7.3 summarises the gas storage developments with potential for commissioning prior to 2028 (both projects are yet to reach FID).

Table 7.3: Gas storage development with potential for commissioning by 2028

Developer	Name/Description	Nameplate capacity	Key dates (FID, Commission)
GB Energy	Golden Beach Energy Storage: adds new gas storage field in Victoria	Up to 35 PJ of gas storage capacity (but much of which is cushioning to maintain sufficient pressure so usable capacity is lower) - 250 TJ/day withdrawal - 125 TJ/day injection. - 375 TJ/d capacity is being considered, with the possibility of 500 TJ/d.	2024, 2027
Lochard Energy	Heytesbury Underground Gas Storage expansion project (HUGS Project): expands Iona Gas Storage Facility in Victoria	Increase Iona's capacity from 570 TJ/day and 24.4 PJ nameplate capacity to 615 TJ/day and 26 to 28 PJ nameplate capacity	2024, 2026

Source: ACCC (2023)

Potential LNG import terminals on the east coast

LNG terminals offer some advantages compared to pipelines in expanding the supply of gas to the south-east region.

The key advantage is they offer a source of significant new gas supply from 2026, which could help reduce or close shortfalls due to emerge in the south-east region from 2028. Table 7.4 outlines known import terminal proposals, their capacity and potential completion dates. Together, two import terminals would almost bridge the gap between expected supply and expected demand in the south-east region from 2028.

A range of additional infrastructure would also been needed before supply can flow effectively from proposed terminals to where it is likely to be needed. An Adelaide terminal would require additional pipeline capacity to Victoria. A Port Kembla terminal would need additional compression to increased supply into Victoria. An import terminal at Geelong would require additional pipeline looping and compression. In addition, floating import terminals offer flexibility that can add to the resilience of supply and potentially reduce price volatility. First, the source of supply is not fixed, meaning supply can be sourced from Queensland, the Northern Territory, Western Australia or foreign fields. Second, the floating storage and regasification units (FSRUs) can provide storage services to the network at much higher volumes than gas pipelines and can be delivered at times of peak demand closer to where gas is needed. Third, FSRUs can be relocated if utilisation rates fall in the future, reducing the risk the asset becomes stranded.

LNG import terminal developers are having difficulties securing offtake agreements with domestic users. Larger users and smaller retailers remain reluctant to contract their full annual volume requirements as uncertainties around future needs and supply options are high. A second problem lies in the seasonal need for gas in southern states. Terminals can provide large capacity, but the annual capacity is not well matched to seasonal winter demand. Larger annual capacity will not be needed until 2028 when Longford capacity is forecast to step down.

There is also no current legislative requirement for gas supply reliability. Large users and small retailers are increasingly not contracting gas to cover all their requirements.

Table 7.4: Proposed LNG Import Terminals

Company	Name	Current Status	Capacity	Earliest assumed year
NSW				
Squadron Energy	Port Kembla Energy Terminal (PKET)	Construction underway	130 PJ/y	2026
SA				
Venice Energy	Port Adelaide	Pre-FID	110 PJ/y	2026
VIC				
Viva Energy	Geelong	FEED completed	140 PJ/y	2027
Vopak	Port Phillip Bay	Pre-FEED	270 PJ/y	2028

Notes: Figures are based on estimates and/or upper range.
Source: ACCC (2023)

A combination of solutions is most likely needed. More pipeline capacity from the north will help with baseload supply as southern supply falls away post–2030, but storage and import terminals may be more economical solutions for winter seasonal supply and to support gas generation.

The key cost will be the price of LNG in international markets (which may be sourced from Australia). While international prices have been very high relative to domestic prices in recent years, the next few years are likely to see international prices ease (DISR 2024). New international LNG developments are being priced relatively cheaply compared to recent years. For example, recent Qatari contracts have been priced at around 12.5% of the oil price they are linked to, down from 14.5% in 2022. At the same time, the cost of production on the east coast is likely to rise.

LNG terminals may prove to be a similar cost to pipelines for delivery of northern gas to the south-east. A recent study suggests costs of transport by pipeline versus LNG liquefaction and shipping equalises between 3,000km and 7,000km, within the distance from the Northern Territory offshore fields to Victoria.

There will also be additional costs to cover capital and operating expenses of terminals and regassification. This will largely depend on the expected throughput of the terminal. The sum of these costs can be thought of as 'LNG plus (regas)'.

With additional supply from other exporters coming online, there is also the potential for Australian import terminal operators to buy offshore volume and swap with Australian LNG producers (both east and west) to deliver gas at prices below LNG plus to Australian consumers (Box 7.2).

LNG terminals setting east coast gas prices

As the south-east supply gap continues to grow — as a likely result of natural field decline from the Bass Strait and Moomba — LNG terminals could play an increasingly significant role in providing gas to southern states. In such a scenario, LNG terminals would effectively set southern states gas prices.

Today, wholesale prices on the east coast are linked to the JKM netback price, which is the price of LNG in the Asian region less liquefaction and transport costs. The JKM price is an average price reflecting a range of different pricing slopes, indexes and contracts. The price of imports, however, would likely reflect JKM including liquefaction, some shipping costs (although lower than the cost to East Asia) and regassification, above the current netback price. Delivered prices would also include a component to cover capital costs of import terminals, as well as pipeline transport from ship to final destination.

Current forecasts suggest a relatively low price for JKM as international supply expands. However, high historic volatility in international prices and reliance on import terminals will increase exposure of south-east customers to this volatility. Table 7.6 sets out the volatility of JKM prices, taking into account the costs of regas and transport from LNG terminals to Melbourne or Sydney.

Box 7.2: Using international swaps to reduce costs of gas

Table 7.5 sets out the potential for price arbitrage. At an oil price of USD 80 a barrel, a new LNG contract that prices at a 12% slope plus a regassification cost of $1.85 would give a final price of $15.6/GJ to the consumer. At a slope of 14% the price would be $17.90/GJ. The $2.30 saving offsets the regassification cost. Import terminals could buy cargoes with similar shipping times to large Australian customers (like Canadian LNG) and simply swap with existing east, north or west coast for gas delivered into Adelaide, Melbourne or Wollongong.

When accounting for the infrastructure investment needed to connect northern basins to existing pipelines, plus the associated portion of transport costs, imported LNG (applying a 12% pricing slope) at oil prices under USD80/barrel is likely to be cost competitive. However, whether the market will move to take advantage of potential swaps and realise commercial opportunities is uncertain. At this point, commercial uncertainty remains for all 3 LNG import options securing foundational contracts and funding.

Table 7.5: Arbitraging new versus established LNG contracts (delivered Victorian price)

Oil Price (USD)	12% index	12% LNG plus regas	14% index	14% LNG plus regas	Delta
40	6.9	8.7	8.0	9.9	1.1
60	10.3	12.1	12.0	13.9	1.7
80	13.7	15.6	16.0	17.9	2.3
100	17.1	19.0	20.0	21.9	2.9

Notes: Conversion assumes 70 c AUD/US and $1.85/GJ regasification cost. EnergyQuest estimates the cost of transporting gas from Port Kembla to Sydney to be $0.73/GJ and Geelong to Melbourne to be $0.44/GJ.

Source: DISR estimates

Table 7.6 illustrates that if a JKM plus pricing methodology had been in place (assuming no price caps, ability to arbitrate or hedge) between 2012 and 2024, end users would have seen costs as low as $5.15/GJ in Melbourne during the COVID pandemic, however on average paid over $19/GJ and over $30/GJ since the start of the Ukraine War.

Table 7.6: Examples of JKM-plus prices to Melbourne and Sydney (prices 2012 to 2024)

JKM-plus price	USD	AUD	Regas price	Melbourne (landed Geelong)	Sydney (landed Port Kembla)
Low (1 Apr 2020)	2.00	2.86	4.71	5.15	5.44
2015–2020	7.09	10.13	11.98	12.42	12.71
Average	11.76	16.80	18.65	19.09	19.38
Post Ukraine Invasion (Feb 2022 to 2024)	21.37	30.53	32.38	32.82	33.11

Notes: Conversions assumes 70 c AUD/US and $1.85/GJ regasification cost. EnergyQuest estimates the cost of transporting gas from Port Kembla to Sydney to be $0.73/GJ and Geelong to Melbourne to be $0.44/GJ.

Source: DISR estimates

Insight: South-eastern LNG import terminals may provide supply to reduce the south-east supply gap in the timeframes needed but face barriers and will expose south-eastern markets to a ‘JKM-plus (regas)’ price.

Risks to LNG terminal completion

Table 7.1 outlines the nameplate capacity of the 4 import terminals currently under consideration. If the terminals are developed, additional pipeline and injection capacity spend will be required to match import delivery with the ability to deliver gas to market. For example, the SWP pipeline between Geelong (site of 2 proposed terminals) to Melbourne.

To bridge the forecast ACCC east coast shortfall of 300 PJ by 2030, two import terminals would be needed. To bridge a larger gap of 360 PJ if the expected Narrabri, Surat and Beetaloo developments are late or no longer proceed, at least 2 import terminals would be needed.

However, the commercial viability of import terminals and contracts underpinning offtake are complex. Potential gen-tailer and large industrial partners are unwilling to bear all the delivery and offtake risks. There are also competition issues. While import terminals would help close the looming supply gap, development is far from certain.

7.4 Increasing production on the west coast

AEMO (2023c) forecasts gas prices in Western Australia's domestic market to remain relatively low despite a forecast market shortfall. Western Australian gas supply is forecast to be 105 PJ short to 2026. The low-cost base and domestic gas reservation scheme, coupled with declining residential demand, is forecast to keep Western Australia wholesale prices low relative to the east coast.

There are options in the near term to keep prices from rising too quickly. Western Australia will have to rely on long-term storage at Tubridgi to meet near-term shortfalls. However, the Tubridgi long-term storage will be depleted by the end of 2026. Uncontracted LNG — a much larger share of production on the west coast compared to east coast LNG producers — may also offer an option to fill demand shortfalls.

Nonetheless, gas prices may be put under pressure as the market tightens. The demand and supply balance in Western Australia is tightening due to delays in project development, the expiration of legacy domestic supply contracts and changing demand patterns.

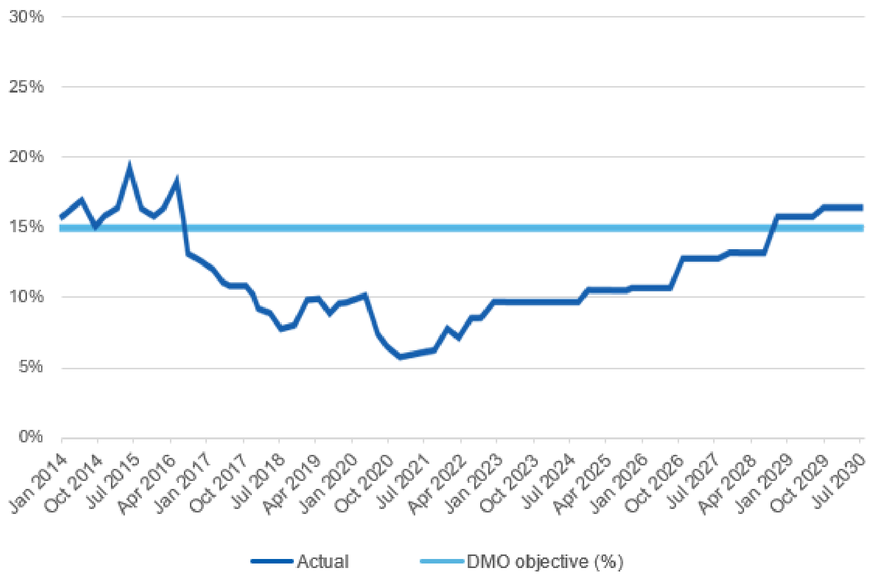
Between 2027 and 2029, supply is forecast to grow. The Scarborough (timing uncertain), South Erregulla, Lockyer Deep, and Waitsia developments are expected to enter the domestic market. Progressing the West Erregulla or further expansion of Beharra Springs will also help alleviate shortages. However, by 2030, unless undeveloped resources commence production, supply will begin to decline due to natural field depletion.

Demand conditions have and will continue to change. With higher prices some users may reduce demand. AEMO (2023c) has found that industrial demand is priced out of the market from around $10/GJ. On the other hand, new large industrial projects are incentivised at prices around $5/GJ, suggesting a floor on prices.

A further issue on the west coast is the operation of the domestic gas policy of the Western Australian Government — resolution of issues may lead to additional supply. On 21 February 2024, the Western Australian Parliament's Economics and Industry Standing Committee released their interim report into the WA Domestic Gas Policy. The interim report notes that the domestic gas reservation scheme has spared the state from the price and supply volatility that has affected the east coast in recent years. However, the reservation policy was found to be 'no longer fit for purpose' and may require government intervention.

According to the interim report of the inquiry, LNG exporters have, on average, delivered domestic gas equating to about 8% of total production since their commitments started, considerably lower than the 15% required under the scheme. Figure 7.1 shows data from a submission from the DomGas Alliance that sets out a year-on-year 15% domestic gas obligation versus delivery.

Figure 7.1: 15% Western Australian domestic gas reservation versus actual, 2014 to 2030

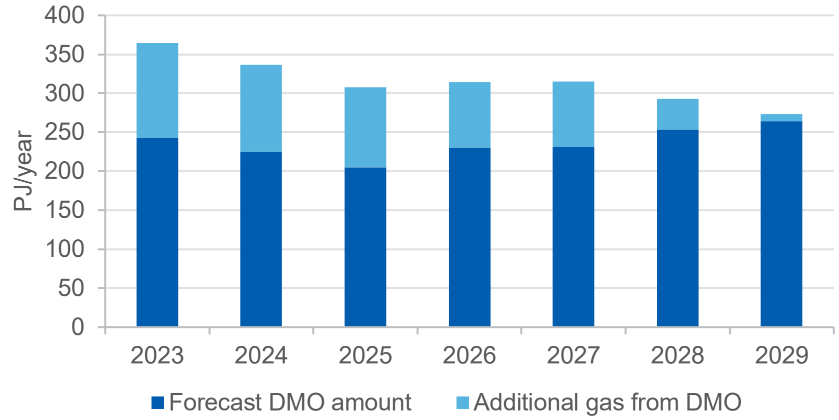


Source: DomGas Alliance (2023)

Any future changes to the reservation policy would affect domestic gas supply and thus expected gas shortages in the coming decade. The final inquiry is expected to be released on 30 May 2024.

Figure 7.2 sets out the additional domestic supply which could potentially come from a year-on-year 15% domestic market obligation on all LNG projects. The stricter application would result in an additional 100 PJ of gas in 2025, 80 PJ in 2026 and 2027 and 40 PJ in 2028. The additional gas supply would address the predicted gas deficit from 2024 to 2029.

Figure 7.2: Additional domestic supply from domestic market obligation, 2023 to 2029



Notes: Additional gas is derived from a flat 15% applied every year.

Source: Forecast DMO percentages are estimated based on the submission by DomGas Alliance (2023) to the Department of Industry, Science and Resources. Forecast LNG production is from EnergyQuest (2023b)

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Table A.1: Scenario Comparisons

Parameter	Green Energy Exports	Step Change	Progressive Change
Equivalent IEA Scenario	NZE	APS	STEPS
Equivalent 2023 WA GSOO	High	Base/Expected	Low
2023 GSOO	Green Energy Exports	Orchestrated Step Change	Progressive change
National decarbonisation target	At least 43% emissions reduction by 2030. Net zero by 2050	At least 43% emissions reduction by 2030. Net zero by 2050	At least 43% emissions reduction by 2030. Net zero by 2050
Global economic growth and policy coordination	High economic growth, stronger coordination	Moderate economic growth, stronger coordination	Slower economic growth, lesser coordination
Australian economic and demographic drivers	Higher (partly driven by green energy)	Moderate	Lower
Consumer energy resources uptake (batteries, PV and EVs)	Higher	High	Lower
Consumer engagement such as virtual power plant (VPP) and demand side participation (DSP) uptake	Higher	High (VPP) and moderate (DSP)	Lower
Energy efficiency	Higher	Moderate	Lower
Hydrogen Use	Faster cost reduction. High production for domestic and export use	Medium-Low production for domestic use, with minimal export hydrogen.	Low production for domestic use, with no export hydrogen.
Hydrogen blending in gas distribution network	Up to 10%	Up to 10%	Up to 10%
Biomethane/synthetic methane	Allowed but no specific targets to introduce it	Allowed but no specific targets to introduce it	Allowed but no specific targets to introduce it
Supply chain barriers	Less challenging	Moderate	More challenging
Global/domestic temperature settings and outcomes	Applies Representative Concentration Pathway (RCP) 1.9 where relevant (~1.5°C)	Applies RCP 2.6 where relevant (~1.8°C)	Applies RCP 4.5 where relevant (~2.6°C)

Notes: AEMO 2023 GSOO also includes a diverse step change scenario. Diverse Step Change (1.8°C) scenario, like the Orchestrated Step Change (1.8°C) scenario, includes a global response to climate change with commensurate action domestically to meet Australia's climate change commitments. This scenario puts the greatest action to decarbonise on the industrial gas sector and features a lower contribution from end-use consumers to the energy transformation, with early development of biomethane resources. While in many sectors the electrification of existing loads has already commenced, some uncertainty remains over how quickly consumers are able to invest to shift their energy use away from gas. To identify the potential influence of slower electrification on gas adequacy risks, AEMO has also studied the impact if the current and future forecast electrification trends were halted, in the Orchestrated Step Change (1.8°C), No Electrification sensitivity.
Source: AEMO (2023f)

Appendix B: Nexant World Gas Model

The WGM models gas trade in terms of global, regional and national gas supply and demand balances on an annual basis from 2022 to 2052.

The model finds the optimal level of gas production (supply) for a given (exogenous) level of demand to produce forecasts for gas production, exports and consumption over a 30-year forecast horizon. To determine optimal supply, the model uses detailed data (and assumptions) on global trade networks, production capacities and contractual obligations. The model also factors in the price of energy substitutes in the power sector (like oil and coal), and the price elasticity of demand.

Given the limitations outlined below, this modelling should be taken as incomplete and should not be relied upon in isolation of other data points, for example modelling provided by trading partners.

The WGM:

- Optimises supply through a detailed and intricate network of global trade and production, which covers every major basin and every country in the world, subdivided into nodes (regions). The WGM includes Beetaloo, Browse and Scarborough basins.
- Optimises one year at a time with quarterly profiles to capture seasonal variation in demand (includes flexibility, production, infrastructure and storage requirements).
- Models specific demand price forecasts (Table 2.7).
- Accommodates a variety of assumptions about demand for different countries, so information provided from trading partners can inform modelling of future demand pathways for gas.

The WGM is limited in its ability to model behaviour relating to:

- Energy Security – trade flows are determined on a minimum-total-(market) cost basis. However, countries operate under a broader suite of considerations including energy security (and a preference for diversification of source of gas supply), broader trading relationships, and other geopolitical or broader macroeconomic considerations.
- Emissions intensity: while future gas production should converge in areas with the lowest upstream emissions intensity, there is limited accounting for that in supply costs. Carbon price assumptions are instead modelled as demand-side carbon taxes.

Further, across all scenarios modelled in this chapter, we assume:

- WGM inputs are derived from IEA historical data with developments up to September 2023, and forecast demand projections from the IEA's 2023 World Energy Outlook (Table 2.6).
- Production costs separately identify operating costs and capital expenditure, allowing short-run marginal cost pricing where appropriate. The production cost assumptions in the WGM broadly align with Wood Mackenzie and EnergyQuest data, and factors in historical performance of producing facilities and fields.
- Planned and prospective LNG terminals and producing fields reported by project sponsors (announced) are included in the model. The model takes into account whether price or demand assumptions render any announced project infeasible.
- Coal, oil and natural gas price projections by scenario as shown in Table 2.6, which also factors in carbon adjustments according to CO_2 price assumptions.

These assumptions are expressed in Table B.1. Demand and pricing projections by scenarios are also added as inputs into the model as follows in Tables B.2 – B.3.

Table B.1: Model assumptions by scenario

Input (source)	STEPS	APS	NZE
Australian domestic demand (AEMO)	Progressive Change (2.6°C), High	Orchestrated Step Change (1.8°C), Expected	Green Energy Exports (1.5°C), Low
Asian gas demand (see Table 2.3)	STEPS projection	APS projection	NZE projection
Australian gas production capacity*	WGM original and maximised	Constrained (WoodMac)	Constrained (WoodMac)
Short-run marginal cost (Australia & USA)	Enabled	Enabled	Enabled
LNG contract renewal (with Australia)	Selected contracts renewed	Selected contracts renewed	Less contracts renewed, all Russia expired
Fossil fuel and carbon prices	STEPS projection	APS projection	NZE projection
Carbon cost sensitivity*	Medium	Medium	High
Power of Siberia 2 Pipeline Extension*	Built	Built	Cancelled

Notes: WGM provides the maximum daily production capacity of all producing gas fields and assumes maximum utilisation of nameplate capacity by existing liquefaction facilities. Wood Mackenzie provides an expected, realistic projection based on historical utilisation rates, performance and outages, creating a constrained production estimate. LNG contract renewal has been selected by both Nexant (default input) and analyst discretion. In the NZE scenario, we assume the phase out of Russian LNG via sanctions and the Power of Siberia 2 pipeline discontinued due to being uneconomical.

Source: AEMO (2023c; 2024a); IEA (2023f), NexantECA (2023), EnergyQuest (2024); Wood Mackenzie (2023)

Table B.2: Natural gas demand, by scenario, selected economies

Gas demand (bcm)	STEPS		APS		NZE	
	2030	2050	2030	2050	2030	2050
World	4,299	4,173	3,861	2,422	3,200	900
China	458	452	410	185	-	-
Japan	66	44	60	19	-	-
Southeast Asia	191	254	171	122	-	-

Notes: Trendline uses a quadratic polynomial order. Based on total final consumption. IEA does not provide a NZE projection for gas consumption for particular economies.

Source: IEA (2023e) Tables 2.2 & B.2

Table B.3: Fossil fuel prices by scenario

Fossil fuel	STEPS		APS		NZE	
	2030	2050	2030	2050	2030	2050
IEA crude oil ($/barrel)	85	83	74	68	42	25
Natural gas ($/MMBtu)	8.9	7.8	8.1	6.3	5.7	5.3
Steam coal ($/tonne)	97	78	80	64	64	49
CO_2 assumption ($/tonne)	35	71	88	180	115	225

Notes: Average 2022 real price in US dollars. CO_2 prices are used to adjust competing fuels.

Appendix C: Units and conversions

Table C.7.4: Units of measurement and abbreviations

Units		Metric prefixes			Other abbreviations	
J	joule	k	kilo	10^3 (thousand)	bcm	billion cubic metres
L	litre	M	mega	10^6 (million)	m^3	cubic metre
t	tonne	G	giga	10^9 (billion)	ft3	cubic feet
G	gram	T	tera	10^{12} (trillion)	bbl	barrel
W	watt	P	peta	10^{15}	Mtoe	million tonnes oil equivalent
Wh	watt hour	E	exa	10^{18}	MMbtu	million British thermal units
		b	billion	10^9	Tonnes	metric equivalent of tons

Units of energy

The basic international unit of energy across all energy types is the joule (J). Concepts, definitions and presentation align as closely as possible with the framework used by the International Energy Agency.

The basic unit of power, or energy per unit time, is the watt (W), which is equal to one joule per second. In Australia, electricity usage (power consumption) is typically reported in gigawatt hours (GWh), and gas usage and production as petajoules (PJ).

Many other units of energy are in use in Australia and internationally, including British thermal units (Btu), cubic metres (cm or m^3) and tonnes of oil equivalent (toe). Conversions between other common units of energy are provided in Table C.3.

Table C.2: Conversion between units of volume

To:	bbl	ft^3	L	m^3
From:	Multiply by:			
bbl	1	5.615	159	0.159
ft^3	0.1781	1	28.3	0.0283
L	0.0063	0.353	1	0.001
m^3	6.289	35.3147	1,000	1

Table C.3: Conversion between units of energy

To:	PJ	Mt	Bcm	TBtu	Mtoe
From:	Multiply by:				
PJ	1.000	0.021	0.028	0.952	0.024
Mt	48.747	1.000	1.360	46.405	1.169
Bcm	36.000	0.735	1.000	34.121	0.860
TBtu	1.050	0.022	0.029	1.000	0.025
Mtoe	41.868	0.855	1.163	39.683	1.000

Notes: Derived from BP (2022).

Appendix D: Glossary and definitions

Term	Description
2C	The best estimate of contingent resources
2P	Proved and Probable; or Proved plus Probable
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACCU	Australian Carbon Credit Units
ACT	Australian Capital Territory
ADGSM	Australian Domestic Gas Security Mechanism
AE	Alkaline Electrolyser
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGP	Amadeus Gas Pipeline
AIE	Australian Industrial Energy
APLNG	Australia Pacific LNG
APS	Announced Pledges Scenario
ARENA	Australian Renewable Energy Agency
ASEAN	Association of Southeast Asian Nations
AUD	Australian Dollar
AWE	Alkaline Water Electrolysis
BAT	Best Available Technology
BCM	Billion cubic metres
BCR	Benefit-cost ratio
BF-BOF	Blast Furnace-Basic Oxygen Furnace
BP	British Petroleum
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Use and Storage
CH_4	Methane
CIE	Computability in Europe
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2-e	Carbon dioxide equivalent
CSG	Coal Seam Gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAC	Direct Air Capture
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DISR	Department of Industry, Science and Resources
DRI-EAF	Direct Reduced Iron and Electric Arc Furnaces
DWGM	Victorian Declared Wholesale Gas Market
ECGM	East Coast Gas Market
EGP	Eastern Gas Pipeline
EIS	Environmental Impact Statement
EPBC	Environment Protection and Biodiversity Conservation
EU	European Union
EV	Electric Vehicles
FEED	Front-End Engineering and Design
FID	Final Investment Decision
FOB	Free-on Board – LNG exports with no defined import ports as part of their contracts
FSRU	Floating Storage and Regasification Unit
FY	Financial Year
GB	Golden Beach
GDP	Gross Domestic Product

GECF	Gas Exporting Countries Forum
GHG	Greenhouse Gases
GIIGNL	International Group of Liquefied Natural Gas (LNG) Importers
GJ	Gigajoule
GLNG	Gladstone LNG
GPG	Gas-powered Generation
GSH	Gas Supply Hub
GSOO	Gas Statement of Opportunities
GST	Goods and Services Tax
GTG	Gas Turbine Generator
H_2	Hydrogen
H_2O	Water
HGP	Hunter Gas Pipeline
HUGS	Heytesbury Underground Gas Storage
IEA	International Energy Agency
IEEFA	Institute for Energy Economics and Financial Analysis
IEEJ	The Institute of Energy Economics, Japan
INPEX	International Petroleum Exploration-Teikoku Oil stock company
ISP	Integrated System Plan
JKT	Japan, Korea and Taiwan
j	Joule – the amount of work done by a force of one newton exerted over a distance of one metre
Li_2O	Lithium Oxide
LCOE	Levelised Cost of Energy
LDAR	Leak Detection and Repair
Li_2O	Lithium Oxide
LNG	Liquefied Natural Gas
MACC	Marginal Abatement Cost Curve
MDQ	Maximum Daily Quantity
MJ	Megajoule
MMBtu	Million British Thermal units
MOU	Memorandum of Understanding
MSP	Moomba Sydney Pipeline
Mt	Million tonnes or Megatonnes
Mt CO_2-e	Million tonnes Carbon dioxide equivalent
MTPA	Million tonnes per annum
MW	Megawatt
N2	Nitrogen
N2O	Nitrous Oxide
NOPTA	National Offshore Petroleum Titles Administrator
NEM	National Electricity Market
NG	Natural Gas
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
NSW	New South Wales
NT	Northern Territory
NZE	Net Zero Emissions Scenario
OPGGS	Offshore Petroleum and Greenhouse Gas Storage
PAWE	Pressurised Alkaline Water Electrolysis
PCA	Port Campbell to Adelaide
PEM	Proton Exchange Membrane
PEMWE	Proton Exchange Membrane Water Electrolysis
PJ	Petajoules
PKET	Port Kembla Energy Terminal
PPI	Producer Price Index
QCLNG	Queensland Curtis LNG

R&D	Research and development
RCP	Representative Concentration Pathway
REQ	Resources and Energy Quarterly
SA	South Australia
SMR	Steam Methane Reforming
SOEC	Solid Oxide Electrolysis Cells
SRMC	Short Run Marginal Cost
STEPS	Stated Policies Scenario
STTM	Short-Term Trading Market
SWQP	South West Queensland Pipeline
TGP	Tasmanian Gas Pipeline
TJ	Terajoules
TWh	Terawatt hours
UNFCCC	United Nations Framework Convention on Climate Change
US	United States
USA	United States of America
USD	United States Dollar
VIC	Victoria
VTS	Victorian Transmission System
WA	Western Australia
WEM	Wholesale Electricity Market
WEO	World Energy Outlook
WGM	World Gas Model
WORM	Western Outer Ring Main