ACIL ALLEN

Wholesale natural gas prices for AEMO

Final Report

14th November 2025

About ACIL Allen

ACIL Allen is a leading independent economics, policy and strategy advisory firm, dedicated to helping clients solve complex issues.

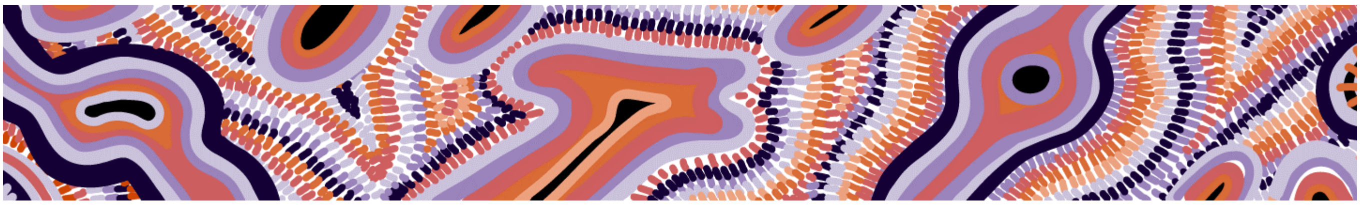
Our purpose is to help clients make informed decisions about complex economic and public policy issues.

Our vision is to be Australia's most trusted economics, policy and strategy advisory firm. We are committed and passionate about providing rigorous independent advice that contributes to a better world.

Report to:

The Australian Energy Market Operator

ACIL Allen acknowledges Aboriginal and Torres Strait Islander peoples as the Traditional Custodians of the land and its waters. We pay our respects to Elders, past and present, and to the youth, for the future. We extend this to all Aboriginal and Torres Strait Islander peoples reading this report.



Goomup, by Jarni McGuire

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Glossary

Abbreviations	Definitions
AEMO	Australian Energy Market Operator
APS	Announced Pledges Scenario (IEA WEO)
bbl	Barrel (of oil)
CCGT	Combined-cycle gas turbine
ECGM	East coast gas market
FOB	Free on board
GJ	Gigajoule
GPG	Gas-powered generation
GSOO	Gas Statement of Opportunities
IASR	Inputs, Assumptions and Scenarios Report
IEA	International Energy Agency
ISP	Integrated System Plan
JKM	Japan/Korea Marker
NEM	National Electricity Market
NZE	Net Zero Emissions (IEA WEO scenario)
OCGT	Open-cycle gas turbine
PKET	Port Kembla Energy Terminal
PJ	Petajoule
STEPS	Stated Policies Scenario (IEA WEO)
TJ	Terajoule
WEO	World Energy Outlook

1 Overview

1.1 Purpose of the study

The Australian Energy Market Operator (AEMO) engaged ACIL Allen to provide projections of future wholesale prices of natural gas for the East Coast Gas Market (ECGM). These projections will be used in various AEMO publications, including (but not limited to) future iterations of the Gas Statement of Opportunities (GSOO) and Inputs, Assumptions and Scenarios Report (IASR), which supports AEMO's Integrated Systems Plan (ISP).

1.2 Scope

ACIL Allen's scope for this exercise, including key outputs, is summarised in Table 1.1.

Table 1.1 Summary of report contents

Item	Geographic scope
Price forecasts for each existing gas-fired generator (including transmission and storage)	NEM, NT
Price forecasts for generic new entry gas-fired generators, both open-cycle gas turbines and combined-cycle gas turbines.	NEM, NT
Wholesale price forecasts including transmission and storage (but excluding distribution and retail costs) for industrial customers consuming more than 10 TJ/day	ECGM
Wholesale price forecasts including transmission and storage (but excluding distribution and retail costs) for residential and commercial forecasts at each major load centre (Melbourne, Sydney, Adelaide, Brisbane, Canberra, Hobart)	ECGM
Estimated cost of imported LNG	ECGM

Note: NEM = National Electricity Market; ECGM = east coast gas market; NEM, ECGM and national results are disaggregated by region/state unless otherwise noted.

Source: ACIL Allen

1.3 Overarching approach and key assumptions

ACIL Allen adopted a three-phase process for developing these gas price forecasts.

1. **Data collection and market analysis.** This phase involved collecting the necessary data for the forecasting exercise, preparing our models to produce the long-term price outlook, and a market analysis piece. The market analysis piece was important to ensure we captured all the relevant drivers of recent price movements across Australia for the various gases and fuels, and how this might evolve over time.
2. **Model preparation.** ACIL Allen employed its model of the ECGM (GasMark) to develop generate the price forecasts. The model was updated for the latest data on gas production fields, LNG receiving terminals and LNG price projections for the three scenarios.
3. **Modelling phase.** The third phase was modelling the price outlooks themselves and iterating as required based on feedback we received from AEMO and from a discussion with the Forecasting Reference Group held on 8 October 2025.

This report provides prices and costs that are presented in calendar years in real terms as of June 2025.

2 Data collection and market analysis

2.1 Data collection

The first step of the process was to complete a data collection exercise and review developments in the market. The data collection task involved collecting the necessary data and assumptions that feed our model of the East Coast Gas Market (EAGM) that produces the final forecasts.

The data requirements were required to calibrate our GasMark model and to ensure the assumptions and detail on market infrastructure are consistent with assumptions contained in the IASR report and the 2026 GSOO.

A supporting piece of work during this phase was reviewing the ECGM, and the Northern Territory gas market. This ensured our understanding of key market developments were taken into account in any post model adjustments considered necessary.

Key developments include:

— Gas Market Regulation and Policies
— Trends in gas market consumption across all markets
— Developments in international energy markets which influence brent oil prices and Asian LNG prices
— Infrastructure investment in all gas markets
— New gas supply developments

2.2 AEMO outlook scenarios

AEMO requested that ACIL Allen provide results for three scenarios. These scenarios are broadly defined as:

— **Step Change** – this scenario achieves the objectives of Australia's government policies in transitioning the energy system and reflects a scale of global and domestic action that limits global temperature rise to below 2°C compared to pre-industrial levels. Consumers continue to embrace opportunities to support the transition through continued investment in consumer energy resources, energy efficiency and electrification, or other investments that can contribute to reducing emissions. In this scenario, Australia's economy grows similar to historical trends, while emerging trends in artificial intelligence and other data-heavy applications encourage growth in data centres in Australia.
— **Slower Growth** – this scenario achieves the objectives of Australia's government policies in transitioning the energy system and reflects domestic action to contribute to lesser global ambition to extend specific commitments to limit temperature rise. While Australia's economy continues to grow in the long term, it has slower growth and lesser continued action beyond current commitments.
— **Accelerated Transition** – this scenario achieves the objectives of Australia's government policies in transitioning the energy system and provides an 'upside alternative' that explores the possible drivers for rapid emissions reduction domestically and globally. It continues to feature a rapid transformation of Australia's energy sectors greater than that required by current domestic and global decarbonisation commitments, to limit temperature rise to 1.5°C above pre-industrial levels. [1]

[1] AEMO (2025), 2025 Inputs, Assumptions and Scenarios Report August 2025, Australian Energy Market Operator

2.3 Impact of provisions of gas market regulations and policies

2.3.1 The Gas Market Code

The Commonwealth Government has implemented a price cap of $12/GJ for natural gas in the ECGM. This is implemented through the Gas Market Code. The purpose of the price cap is to anchor wholesale contract negotiations between gas producers and buyers. The cap does not apply to imported LNG. [2]

The Code includes 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 gas at reasonable prices and on reasonable terms.

Other provisions include transparency obligations, including additional reporting to the ACCC, to increase visibility of the amount of uncontracted gas to be produced, and timing when it will be available to the domestic market and conduct obligations aimed at reducing bargaining power imbalances between gas producers and buyers and establishing minimum conduct and process standards for commercial negotiations.

Our analysis of the code's operation suggests the price cap has not necessarily acted as a price cap, but more like a price floor. Wholesale gas offers and bids have generally been made above $12/GJ, with a minimal number of contracts being struck at $12/GJ or below. The cap has not acted as a cap. It has acted arguably more like a price floor. Some data suggests it is potentially anchoring prices somewhat, but in our view, it is likely that amendments will be required if it is 'binding' more than it currently does.

2.3.2 Heads of Agreement with east coast LNG exporters

Supply from LNG exporters continues to be an important source of supply for the ECGM. Queensland gas from LNG exporters underpins various contracts throughout the east coast and is also a strong source of supply in short term markets during high demand periods.

The LNG exporters and Government entered into a Heads of Agreement (HOA) to ensure domestic gas supply. Under the agreement, the LNG exporters agree to supply the ECGM with competitively priced gas to ensure the market is sufficiently supplied and prevent shortfalls. As Queensland LNG exporters have large reserves of gas, it will remain a key supplier over the long term for the ECGM.

Queensland supply in our modelling builds over the long term as southern sources decline. However, the supply is limited by what the LNG exporters can realistically supply each year and in the years to come, as their reserves inevitably begin to decline. While the supply under foundation customers is untouched in our modelling, LNG exporters then supply the domestic market and export further gas via spot cargoes. Our model suggests that LNG exporters' commitments are crucial in keeping long term prices relatively stable and meeting seasonal demand in the southern states.

The Government is currently conducting a review of the Code and the Australian Domestic Gas Security Mechanism (AGSM) and Head of Agreement (HOA) with east coast liquefied natural gas producers.

[2] DCCEEW (2024), Fact Sheet, Design of the Gas Market Code

2.4 Gas Supply Developments

2.4.1 Current gas production developments

The constant development of future sources of supply is required for the ECGM to prevent annual and seasonal shortfalls. We introduce new supply developments across the east coast with some expansions of existing supply fields and others which are greenfield developments. What we introduce more specifically is summarised in Table 3.1 on page 13 of this document.

A trend that has been developing over time is the increasing need for northern supplied gas to supply the southern market as the Gippsland fields decline. This includes further supply of Queensland CSG and also longer-term supply from the Northern Territory. These developments have been evolving over recent years and are expected to continue with declining supply from mature southern basins such as the Gippsland Basin.

These developments also mean supply chain infrastructure will need to be upgraded. Our assumptions regarding pipeline, storage and LNG import developments are also summarised in Table 3.1 in Chapter 3. LNG import terminals in particular are increasing being regarded as inevitable for the longer-term supply for the ECGM.

3. LNG import terminals in particular are increasing being regarded as inevitable for the longer-term supply for the ECGM.

2.4.2 Potential infrastructure developments

As southern supply sources mature and capacity in the southern portion of the ECGM diminishes, there exists a clear need for new infrastructure to support the evolution of supply sources within the ECGM. As mentioned above, much of the new supply for the ECGM is anticipated to arise from Queensland CSG producers and unconventional production in the Northern Territory. This gas will need to be transported south and stored to provide for the winter demand profile of the south (something that CSG and shale gas is unable to do by virtue of their production characteristics). ACIL Allen's modelling sees that the supply/demand characteristics in the south create a strong opportunity for storage facilities to expand and/or be developed over the medium term. This is exemplified by Golden Beach's inclusion in the Step Change and Slower Growth models by 2029.

Pipeline developments are also important to the supply mix. However, ACIL Allen modelling favours the capacity developments that new and expanded storage offerings can provide to the market. Pipeline developments to expand access to QLD gas tend to enter the modelled scenarios later in the mid 2030s or early 2040s. The south is progressively losing its traditional 'swing' providers, a role that our modelling suggests is not well suited to Queensland CSG producers and expanded pipelines, but rather well suited to storage and LNG imports.

2.4.3 Potential LNG Import Terminals

A number of LNG import projects are now proposed which offer a solution for projected southern market supply. In our view, The Port Kembla Energy Terminal (PKET) is still the most advanced, with landside construction complete, and the project essentially only awaiting the delivery of the Floating Storage and Regasification Unit (FSRU) and confirming the required commercial agreements with users.

Our modelling indicates that an LNG import terminal is initially likely to operate as a seasonal provider of energy and capacity, mainly supplying the market on a short-term basis during high demand periods.

However, an import terminal could transition to a year-round energy supplier depending on the relative prices in international LNG markets and the domestic market.

The debate around LNG import terminals remains troubled, with advantages such as the insurance they provide, balanced against a preferred option of resorting to domestic solutions. At this stage the necessary domestic solutions are not available at the scale required for the ECGM. Therefore, an LNG import terminal is included in our modelling in order for the market to remain balanced in the medium and long term.

2.5 LNG Price Outlook

This section addresses the cost of imported LNG adopted for modelling the impact on gas prices in the ECGM. The LNG price indicator is assumed to be the delivered price of LNG to Asian markets.

2.5.1 Factors affecting long-term LNG price outlook

The outlook for LNG prices over the projection period is now more uncertain than in 2024. The factors that are expected to influence future LNG prices include supply growth from new LNG developments, the outlook for demand from established markets, the outlook for demand from emerging markets, the impact of geopolitical factors, and approaches to gas purchases through contracting or the spot market.

Supply

Analysts have drawn attention to the potential for additional supply from projects under construction or planned, to suppress LNG prices in the medium term. Projects currently under construction are expected to deliver close to 180 million tonnes per annum (mtpa) of new capacity between 2025 and 2028. Most of this will come from new projects in the United States (71 mtpa), Qatar (32 mtpa) and Canada (19 mtpa).[3] Two projects in the US (Woodside's Louisiana LNG and Cheniere's Corpus Christi LNG) and one in Argentina (Southern Energy FLNG) recently achieved final investment decision (FID) and could add a future 28 mtpa capacity, and further projects in the US are expected to reach FID before 2030.

More US projects are expected to add further capacity by 2030. These include Commonwealth LNG Louisiana project, Golden Pass LNG, Port Arthur LNG phase 2, Rio Grande LNG and Plaquemines Phase 2.

Other projects expected to reach FID in the near future include Amigo LNG in Mexico (7.8 mtpa)[4], Ksi Lisims LNG in Canada (12mtpa)[5] and Lake Charles LNG in the US (16 mtpa)[6]. Mexico is emerging as an LNG exporter. It has several projects operational now and under development. A major project yet to reach FID but with potentially 15 mtpa, is the Saguaro Energia LNG project being developed by Mexico Pacific in Sonora with potential to market LNG into the Pacific region.[7]

LNG projects are also in the pipeline in PNG. In addition to the existing PNG LNG project (8mtpa) [8], the Papua LNG project is expected to reach FID in 2025 or 2026.[9]

According to some reports, not all this gas is contracted, suggesting that the share of LNG sold in the spot market could increase in the medium term.[10]

[3] GIIGNL (2025) The LNG industry – GIIGNL Annual Report, International Group of Liquefied Natural Gas Importers.
[4] https://www.lngalliance.com/projects-7
[5] https://www.ksilisimslng.com/
[6] https://energytransferlng.com/
[7] Gaffney Cline (205%), Market Advice and Estimates of Contemporary LNG Contract Prices, ACCC
[8] https://www.pnglng.com/About
[9] https://pnginsight.com/papua-lng-project-totalenergies-update-for-2024-2025-beyond/
[10] GFB Insight (2025) Quarterly LNG Strategic Report Q2 2025

Timing of completion of many of these projects will influence the impact on price in the medium term. For example, Qatar has a goal to reach 142 mtpa of LNG production capacity per year by 2030. If startup for its expansion projects takes longer than planned, this could shift as much as 10 mtpa to beyond 2030.[11]

Demand from established markets

Demand from established markets remains uncertain. European imports of LNG fell by 23 mt in 2024.[12] European demand for LNG is expected to peak around 2027 as renewables slow gas consumption. A return to the days of Europe importing large volumes of gas by pipeline from the Russian Federation appears unlikely. The European Commission is considering an embargo on imports of Russian LNG by 2027.[13]

Demand from established markets in Asia is being maintained with China being the leading importer. However, demand growth may be tempered over the longer term, because of lower than forecast economic activity, increased domestic production and pipeline imports into China.

Demand from emerging markets

A key question for future LNG prices is how emerging markets will respond to lower prices and whether this will ultimately lead to a period of sustained long-term demand growth. Countries in this category include Thailand, Malaysia, the Philippines, Hong Kong, Vietnam and Singapore where imports are increasing. In 2025 for example, Gulf announced an investment decision to construct an 8 mtpa receiving terminal in Thailand [14] and Petronas announced plans for development of a third regasification terminal in Peninsula Malaysia.[15] Imports are also increasing in India, Bangladesh and Pakistan despite affordability challenges. [16]

Egypt has become the largest LNG importer in the Middle East. Imports have also increased in Jordan and the United Arab Emirates.[17]

These developments could support long term growth in LNG demand from emerging markets, particularly those in Malaysia and Thailand. Other markets such as India, Pakistan and Bangladesh face affordability challenges. However, a decline in LNG prices in the coming years could spur growth in demand for gas in these emerging markets, firming up prices in the longer term.

Geopolitical factors

Emerging geopolitical factors are creating increased uncertainty for the direction of LNG prices. Concerns over policy and regulatory change may see buyers favouring contracts over spot purchases, with potential impacts on market liquidity,

Central to the current political scene is potential conflict between Russia and Europe, the impact of Middle Eastern conflicts on LNG flows in the Strait of Hormuz and possible escalation of trade tensions between the US and China.

Potential changes to gas contracting

Traditionally, pricing in LNG contracts has been linked to oil prices. Around 35% to 40% of global trade in LNG is now transacted through the spot market or short-term trades.[18] With a potential surge in supply of uncontracted gas in the short to medium term, it is possible that the ratio of spot market gas to contracted

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[11] Bloomberg (2025), Global LNG Market Outlook 2030

[12] Op Cit GIIGNL

[13] OP Cit Bloomberg

[14] https://www.gulf.co.th/en/newsroom/news-and-activities/473/gulf-and-ptt-tank-signed-epcc-contract-with-posco-e-and-c-and-caz-for-map-ta-phut-phase-3-superstructure-development-to-enhance-thailand-s-energy-security

[15] https://www.argusmedia.com/en/news-and-insights/latest-market-news/2700241-malaysia-s-petronas-to-build-third-lng-import-terminal

[16] Op Cit GIIGNL

[17] https://egyptoil-gas.com/news/egypt-expands-lng-capacity-with-second-long-term-fsru-deal/

[18] Op Cit GIIGNL

gas could increase over the period to 2035. However, increased uncertainty in the global LNG markets could drive some buyers to secure their supplies through contracting.

2.5.2 Approach to the LNG price projections

For the LNG price projections, we have considered the outlook for oil prices, the proportion of LNG traded by oil linked contracts and the outlook for the spot market. The level of uncertainty on the path of future prices has increased over the past year. The longer-term outlook for LNG price outcomes is now wider than in 2024.

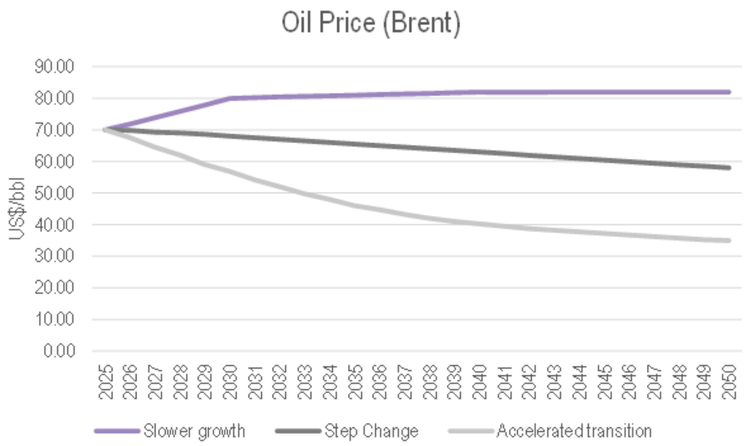
For each of the AEMO Scenarios, LNG prices are expected to fall over the medium term with a higher share of spot market trades over that period. The longer-term outlook for LNG prices will depend on the response from emerging markets, particularly in Asia and the Middle East. The level of uncertainty on the path of future prices has increased over the past year and the possible price scenarios are now wider than before. For the LNG price projections, we have considered the outlook for oil prices, the proportion of LNG traded by oil linked contracts and the outlook for the spot market. The key assumptions by scenario are as follows:

- **Slower Growth Scenario**
  - Policies and programs to achieve net zero by 2050 are significantly curtailed resulting in continued high dependence on petroleum products and LNG across the globe. The share of spot sales of LNG is lower than in the Step Change and Accelerated Transition scenarios over the medium term driven by buyer concern over energy security.
- **Step Change Scenario**
  - Policies and programs to transition energy systems are implemented consistently with limiting global temperature rise to below 2 degrees C compared to pre-industrial levels. Demand for LNG in Europe declines from 2030 and growth in demand for LNG in emerging markets is less robust over the longer term.
- **Accelerated Transition**
  - This scenario assumes countries across the globe achieve rapid emissions reductions achieving global decarbonisation commitments to limit temperature rise to 1.5 degrees C above pre-industrial levels. Demand for conventional petroleum fuels declines significantly and the transition to renewable and nuclear generation of electricity reduces demand for gas and accordingly LNG globally.

2.5.3 Oil price projections

Our oil price projections for each scenario are shown in Figure 2.1.

Figure 2.1 Oil price projections



Source: ACIL Allen

Our projections for the Slow Growth Scenario are 9% higher than the those in the IEA STEPS scenario, the same as the IEA APS scenario and 40% higher than the IEA NZE Scenario in its World Energy Outlook 2024. [19]The latter assumption is based on our assessment that the cost of discovery of new crude oil will underpin oil prices, given limitations on low carbon liquid fuel substitutes for diesel and aviation fuels. The projections are lower than those assumed by the US Energy Information Administration in its 2025 Annual Energy Outlook. For more details see Appendix B.

2.5.4 Spot market share

Spot market LNG prices to 2030 have been based on the JKM forward curve as of October 2025. Beyond 2030, the prices for spot market LNG for the Step Change and Accelerated Transition scenarios have been guided by the IEA longer term forecasts. The longer-term projections for LNG prices in the spot market under the Slower Growth scenario is 21% higher in 2050 than the IEA projections, on the assumption that progress is stalled in the energy transition globally.

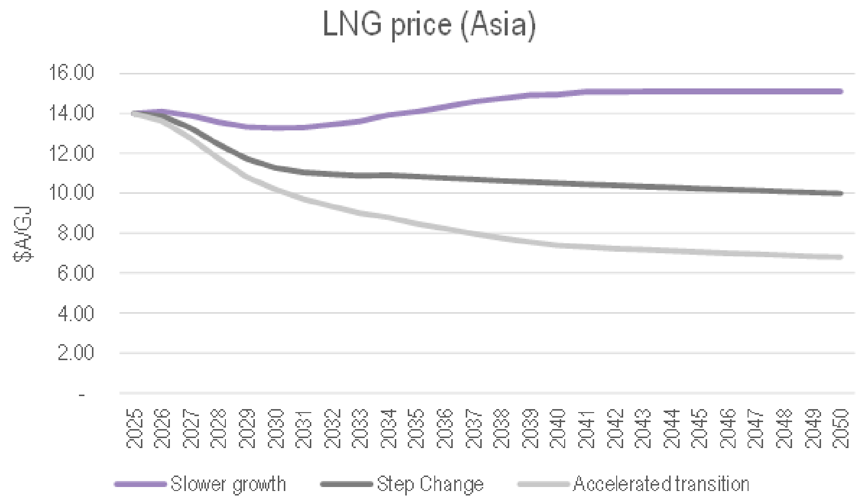
2.5.5 LNG price projections

The LNG price projections have been based on projections of contract prices based on the oil price projections shown in Figure 2.1 and the formula and assumptions shown in Appendix B-1.

The price projections are summarised in Figure 2.2.

[19] The IEA issued its 2025 version of its World Energy Outlook on 12 November 2025 after this report was finalised. The Oil price assumptions for the IEA STEPS and NZE scenarios are not significantly different. However, the IEA has dropped its Announced Pledges Scenario (APS) and introduced a new Current Policies Scenario. The latter has significantly higher oil price assumptions for 2033 and 2050. There is no direct comparison between the CPS and the AEMO scenarios, but it sits above the Slower Growth Scenario in terms of price outlook.

Figure 2.2 LNG price projections



Source: ACIL Allen

The prices in the AEMO Slower Growth and Step Change Scenarios higher than the IEA STEPS and APS Scenarios in all years. In 2030 they are $A2.6/GJ and $AU1.1/GJ higher respectively than in the IEA STEPS and APS Scenarios.

The Accelerated Transition Scenario is about $A3.0/GJ higher than the IEA NZE scenario in 2030 and $A0.1/GJ the NZE scenario by 2050. [20]

The EIA projections are based on a reference case and a high and low oil price case. These scenarios do not match the AEMO scenarios. The Step Change Scenario is $A1.06/GJ lower than the EIA reference case in 2030, and $A4.80/GJ lower by 2050.

2.5.6 Delivered price

Shipping costs

Shipping costs include port, charter, boil-off, insurance and fuel costs. Voyage time including days on hire and waiting are also a driver of costs. Shipping costs can vary depending on movements in LNG demand, ship availability, and seasonal factors.[21] The ACCC reports estimates freight rates for shipments from Gladsome to Tokyo for 5 forward years. The current rates for that voyage vary from US$0.37/mmbtu to US$1.07 /mmbtu.

Shipping costs could vary significantly depending on the source of the LNG. The LNG price assumptions quoted are assumed to be for deliveries to Asian markets and would include an allowance for shipping from distant ports to Asia. Accordingly, the ACCC estimates would be proxy for shipping costs for origins such as Qatar or Canada. On the other hand, shipping costs from Dampier, PNG or Gladstone would be at the lower end of costs. It has not been feasible to project a shipping cost for each individual origin. For the purpose of these calculations, ACIL Allen adopted an average shipping cost of US$0.56/mmbtu ($AU0.80/GJ).

[20] This report has drawn on the IEA World Energy Outlook 2024. The IEA World Energy Outlook 2025 was released on 12 November after this report was prepared. The IEA modified its scenarios dropping the Announced Pledges Scenario (APS) and adding a Current Policies Scenario (CPS), The Stated Policy Scenario (STEPS) and the NZE scenarios and Net Zero by 2050 (NZE) scenarios are broadly similar in both reports. The CPS scenario has higher oil and LNG price assumptions. The CPS scenario does not have a match in the AEMO scenarios.

[21] https://www.economyinsights.com/p/the-true-cost-of-moving-lng-across-the-globe

Regassification costs

ACIL Allen has developed an estimate of regassification costs from estimates of capital and operating costs based on the Australian operating environment. Regassification costs could vary depending on whether the LNG is purchased under a contract or under a spot purchase. In the case of deliveries under contract the regassification cost would include a recovery of capital costs as well as variable costs. In the case of spot purchases, it is possible that the regassification costs would be somewhere between the short run marginal cost (that is variable costs) and full recovery of capital costs.

The assumption for the purpose of this modelling is an allowance of $1.50/GJ for regassification costs in all cases. We are aware this is on the lower end of estimated regasification costs. However, this is supported by key assumptions we have made around Port Kembla's capital cost being sunk, and how the terminal is likely to operate and supply the market in regard to contracted supplies and spot market supply.

Injection price for LNG imports

The injection price for imported LNG into Port Kembla is summarised in Table 2.1. The Shipping cost for alternative import sites such as Geelong have not been calculated given a second terminal is not introduced into the model. The regasification cost may vary for other sites based on the build cost associated with land side terminal works, as well as the final cost or lease arrangement for a prospective FSRU.

Table 2.1. The Shipping cost for alternative import sites such as Geelong have not been calculated given a second terminal is not introduced into the model. The regasification cost may vary for other sites based on the build cost associated with land side terminal works, as well as the final cost or lease arrangement for a prospective FSRU.

Table 2.1 Price of LNG injected into ECGM

	2025	2030	2040	2050
	$AU/GJ	$AU/GJ	$AU/GJ	$AU/GJ
Slower Growth				
Asian LNG price	13.99	13.26	14.94	15.09
Shipping costs	0.80	0.80	0.80	0.80
Regassification	1.50	1.50	1.50	1.50
Injection cost	16.29	15.56	17.24	17.39
Step Change				
Asian LNG price	13.99	11.27	10.50	9.99
Shipping costs	0.80	0.80	0.80	0.80
Regassification	1.50	1.50	1.50	1.50
Injection cost	16.29	13.57	12.80	12.29
Accelerated Transition				
Asian LNG price	13.99	10.20	7.39	6.81
Shipping costs	0.80	0.80	0.80	0.80
Regassification	1.50	1.50	1.50	1.50
Injection cost	16.29	12.50	9.69	9.11

Source: ACIL Allen

Note: All costs are in Australian dollars

In summary

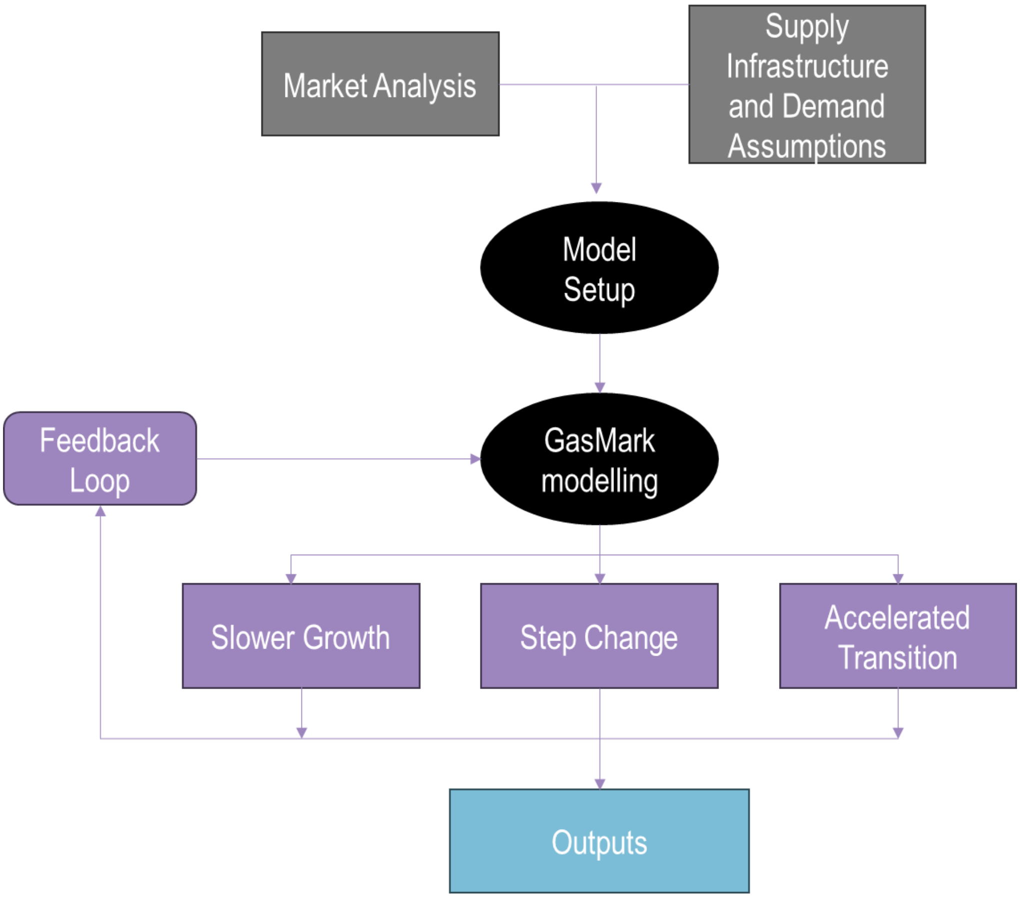
The longer-term outlook for LNG prices is now subject to considerable uncertainty, and the range of potential outcomes has widened since the IEA and EIA projections were published. The projections developed for this report provide a range of potential outcomes for the purpose of modelling gas prices in the East Coast Gas Market.

3 Modelling process

3.1 Summary of modelling framework

In summary, our methodology of the modelling process followed the approach presented in Figure 3.1.

Figure 3.1 Our modelling framework



Source: ACIL Allen

Our GasMark model models hypothetical spot prices and does not model gas contracts specifically. However, with the shortening of gas contracting in recent years, to as low as one year in many cases, and the increasing role of the spot markets, the output is a reasonable indicator of the direction of the wholesale gas price over time.

The output of this process is a series of gas prices by region that broadly reflect the path of wholesale prices, including transmission charges, in each region. Contract prices could be expected to be slightly higher than this price to take account of contract terms such as take or pay, interruptible and other services that are provided.

Other factors we take into account to help produce prices that are reflective of where wholesale contract prices might trend are provided in Appendix A.

3.2 GasMark Model preparation

GasMark has the flexibility to represent the unique characteristics of gas markets across Australia. The model now includes assumptions for over 200 gas fields and more than 250 individual demand nodes. As mentioned before, it was important to ensure the model remained consistent with the assumptions provided by AEMO for the various scenarios.

Specifically, our demand forecasts closely align with forecasts from the GSOO to ensure the price forecasts reflect the assumptions and broad demand scenarios that are defined in the GSOO. For the east coast beyond 2045, ACIL Allen extrapolates AEMO's forecasts all the way through to 2057 (as required by AEMO).

For supply, we aligned our assumptions with AEMO's GSOO reports. In some cases, we may have differing assumptions on new projects and supply quantities from these projects. Some of these key assumptions are summarised in Appendix A.

3.3 Model assumptions

The assumptions adopted for modelling each of the scenarios are shown in Table 3.1.

Table 3.1 Summary of scenario assumptions

Assumption	Slower Growth	Step Change	Accelerated Transition
Demand	Progressive Change scenario demand from 2025 GSOO	Step Change scenario demand from 2025 GSOO	Green Energy Exports scenario demand from 2025 GSOO
Gas supply projects	**Gippsland** – Longford linked developments (including Kipper) provide declining swing quantities until 2034 before complete closure. Orbost provides nameplate until the late 2030s **Otway** – developments provide for nameplate processing capacity until mid 2030s, gradual decline in line with resource depletion thereafter **Bass** – declines significantly from 2029, no backfill. **Bowen/Surat** – In line with public announcements and developments to meet LNG exports **Narrabri** – Proceeds from 2030 full production in 2034 **Beetaloo** – Pilot from 2027, ramping to 50PJ/year from 2032 with further expansions following this to meet LNG export requirements from Curtis Island LNG plants.	**As in Slower Growth Except** **Beetaloo** – Pilot from 2027, ramping to 50PJ/year from 2032.	**As in Step Change Except** **Beetaloo** – Pilot from 2027 **Narrabri** – Does not proceed
New storage	**Golden Beach** Developed by 2029 (19PJ, 127TJ/d in, 375 TJ/d out) **Iona** expanded in 2037 (30PJ, 167.5TJ/d in, 715 TJ/d out)	**Golden Beach** Developed by 2029 (19PJ, 127TJ/d in, 375 TJ/d out) **Iona** expanded in 2040 (30PJ, 167.5TJ/d in, 715 TJ/d out)	**No Storage Expansions**
Pipeline development	**Bulloo Link** – Active from 2042, 800TJ/d **MSP** – 700TJ/d from 2042 **SWQP** – 615TJ/d from 2042 **VNI** – 300TJ/d into Melbourne from 2036 plus 0.2PJ pipeline storage near Wagga Wagga **SWP** – Not expanded **EGP** – Bidirectional from 2029, 300TJ/d backhaul from 2034 **AGP,NGP,CGP** – AGP,NGP to supply 120TJ/d to Mt Isa, CGP backhaul increased to 80TJ/d **Beetaloo export** –1400TJ/d NT to QLD from 2040	**Bulloo Link** – Not required **MSP** – Not expanded **SWQP** – Not expanded **VNI** – 300TJ/d into Melbourne from 2034 plus 0.2PJ pipeline storage near Wagga Wagga **SWP** – Not expanded unless LNG exports located in the south **EGP** – Bidirectional from 2029, 358TJ/d backhaul from 2036 **AGP,NGP,CGP** – AGP,NGP to supply 120TJ/d to Mt Isa, CGP backhaul increased to 80TJ/d	**Bulloo Link** – Not required **MSP** – Not expanded **SWQP** – Not expanded **VNI** – Not expanded **SWP** – Not expanded **EGP** – Bidirectional from 2029 **AGP,NGP,CGP** – Not expanded
Long-term Asian LNG Price	$AU15.09/GJ	$AU9.99/GJ	$AU6.81/GJ
Queensland LNG exports	Progressive Change scenario demand from 2025 GSOO	Step Change scenario demand from 2025 GSOO	Green Energy Exports scenario demand from 2025 GSOO
LNG import terminals	Potential for LNG imports from the mid 2040s depending on resource depletion in QLD and Storage performance in the south. High imports cost are a large factor.	Port Kembla online from 2034, LNG import prices take a while to fall, making it competitive form 2034 rather than 2029.	Port Kembla online from 2029

3.4 Outputs for AEMO

AEMO required various forecasts for eastern Australia and the NT. The forecasts required relate to residential/commercial demand, industrial demand and GPG demand.

The following forecasts have been prepared:

- Individual gas price forecasts (including transmission and storage) for each existing gas-fired generator within the National Electricity Market (NEM) and the NT
- Gas price forecasts (including transmission and storage) for generic new entry gas-fired generators, both open cycle gas turbines and combined cycle gas turbines, for all regions
- Annual wholesale contract gas price forecasts (excluding distribution and retail costs) for each region located in eastern Australia, and specifically provided for:
  - Industrial users consuming above 10 TJ per annum
  - Residential and commercial users.

4 Price projections

4.1 East coast gas market

4.1.1 Residential and commercial prices

Residential and commercial gas prices are direct outputs from the GasMark model. The model contains consumption details for all key residential and commercial markets in the ECGM. Following assumption alignments with AEMO as discussed earlier in this report, the model was run to produce annual wholesale prices for each region in the ECGM.

We also assume that supply for this market is 100 per cent contracted. Therefore, all supply for residential and commercial users is based off gas supply agreements between gas retailers and gas producers. The contract component of these price projections represents 'new contract' prices and reflects the cost of purchasing gas from the market from 2025 to 2057.

Prices in 2025 have been estimated and are a combination of actual prices observed in short term markets and our estimates for the remaining months of 2025 (November and December). Prices from 2026 onwards are then direct outputs from our gas market model. They do not reflect 'average contract' prices which would include the prices of some existing contracts that are likely to have been struck at much higher prices evident in 2022 and 2024.

Step Change scenario

In the short term, residential and commercial prices are expected to decline largely due to lower forecast international LNG prices. This means gas prices in most markets are expected to decline to levels around $12-13/GJ by 2027 (with Brisbane prices slightly lower, dipping below $12/GJ). We do not foresee prices dropping much lower than this due to LNG prices stabilising and the continued uncertainty regarding the domestic demand-supply balance.

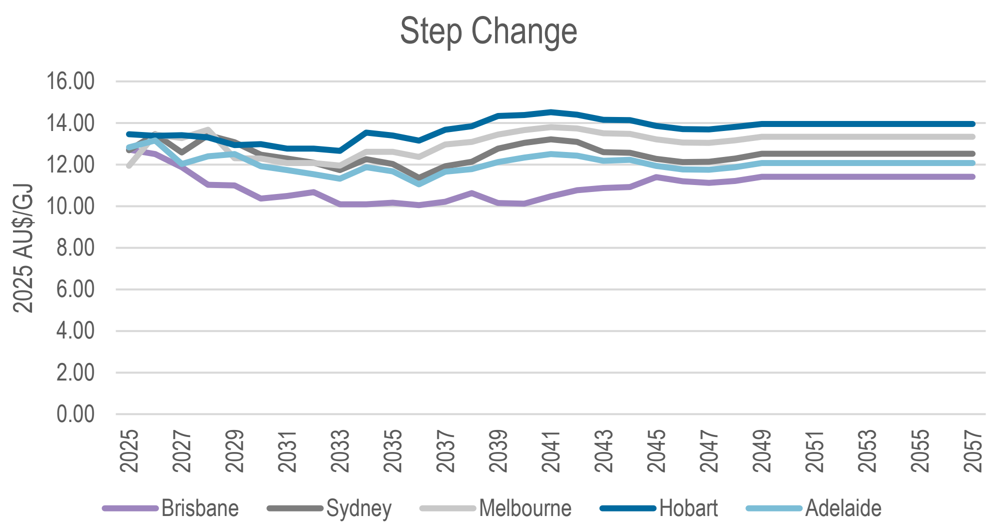
By the early 2030s, the LNG netback price is forecast to move prices to levels below $12/GJ. However, prices in southern markets in particular generally do not follow the LNG netback lower. Upward pressure from falling southern supply and increasing reliance on northern gas means a separation in prices between northern markets and southern markets begins to become more obvious.

Similar to our report for the previous year's forecasts, the Brisbane price in the long term is kept suppressed compared with other markets because of the evolution in supply. From the mid to late 2030s the Brisbane price diverges away from the other markets as the majority of supply by then is coming from northern sources (e.g. Queensland and Northern Territory gas and supply from Moomba). Brisbane hovers at a price around the LNG netback price. On the other hand, the southern cities are increasingly reliant by this period on northern gas (LNG netback plus transport) and higher cost LNG imports to meet demand. This is the key explanation for the divergence in prices that is expected under this scenario. If more southern supply could be found this divergence would likely reduce.

Other supply developments that help stabilise prices over the long term are Narrabri (which we assume is developed by 2030) and further supply from the north. New northern supply is predominantly from the Beetaloo Basin which we assume is developed to a scale of around 50 PJ per annum in this scenario.

Infrastructure developments are also important in allowing more northern gas to flow to southern markets and also to store gas for use over the winter high demand period. The Golden Beach gas storage project is developed in 2029, the Iona facility is upgraded to 30 PJ of storage capacity by 2030, and a number of pipelines taking gas from the NT and Queensland need to be upgraded.

Figure 4.1 Residential/commercial gas prices, by market: Step Change scenario



Source: ACIL Allen

Slower Growth

Prices under the Slower Growth scenario are similar to the Step Change scenario in the short term but the main difference is that prices only marginally fall in the medium term before increasing. In the southern markets, gas prices generally stay above $12/GJ and then end up between $14 to $17/GJ for all markets except for Brisbane.

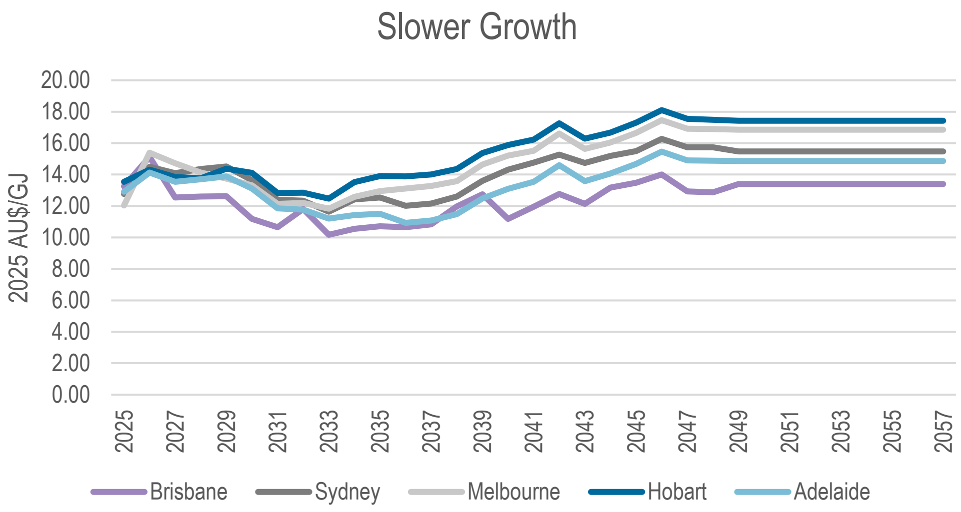
The key driver of this is the international price environment which keeps upward pressure on LNG prices, and therefore the LNG netback price. In this scenario, demand for LNG exports remains strong over the entire projection period (with LNG exports facing a flat demand curve to 2057 and not declining post-2035 as long-term contracts expire). This means the incentive to supply the domestic market is always challenged. As a result, this scenario reflects a situation where there is no ‘cooling down’ of the international LNG market which could have otherwise led to lower prices for domestic users.

Again, similar to our report in 2024, Brisbane in this scenario faces the same dynamic in the long term as was present in the Step Change scenario. Prices do diverge between Brisbane and the southern cities long term due to the evolving nature of northern supply becoming more relied upon by southern cities. This is most evident in the back end of the projection period.

In this scenario, we assume the Beetaloo Basin is developed to a much larger scale than in the other scenarios. To keep LNG export plants in Gladstone full post-2035, the Beetaloo Basin would need to be developed to a large scale. We also assume some development of other emerging production regions like the North Bowen. These sources help supply LNG plants and also contribute to stabilising domestic prices in the long term.

Also important to this scenario is the late entry of LNG imports. Eventually by the 2040s we expect an LNG import terminal to be developed out of necessity to meet long term demand. However, until then the high LNG price makes LNG imports unattractive. It is difficult to see LNG imports competing at prices where the delivered price after regasification would be somewhere in the vicinity of $16-17/GJ.

Figure 4.2 Residential/commercial gas prices, by market: Slower Growth scenario



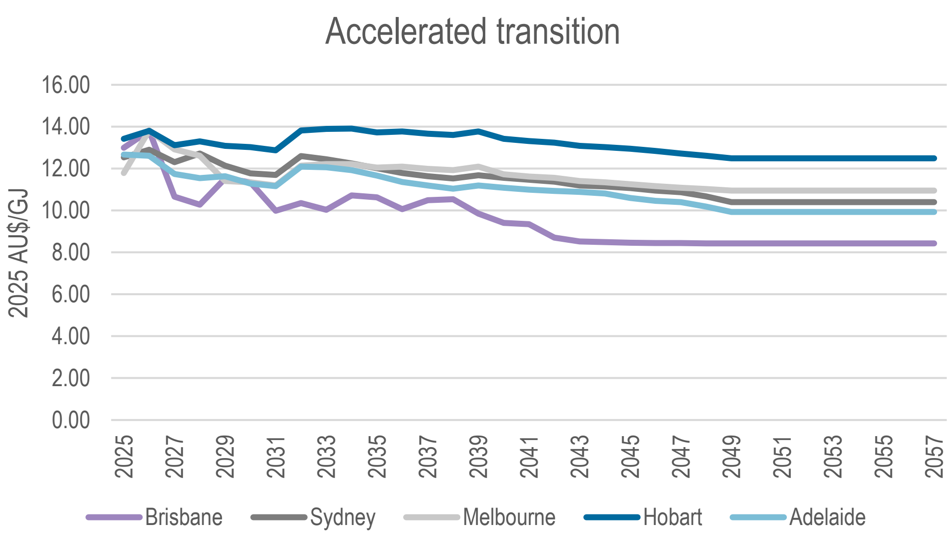
Source: ACIL Allen

Accelerated Transition

The Accelerated Transition scenario demonstrates a scenario where demand for gas trends lower at a faster pace than in the other scenarios. This is relevant for both domestic demand and LNG export demand. As a result, we would expect that gas prices would move lower in this scenario.

Our price outlook demonstrates this is likely to happen, particularly the period to 2030. Prices remain higher for longer compared to our previous forecasts for this type of scenario mainly because of a higher LNG price forecast. The ranking of cities is largely down to location and follows the same pattern as in the other scenarios – Brisbane the cheapest and the southern most cities the highest.

Figure 4.3 Residential/commercial gas prices, by market: Accelerated Transition Scenario



Source: ACIL Allen

In this scenario, prices remain below $12/GJ in the long run. There is more noticeable separation between markets in this scenario, most evident in the late 2030s and early 2040s. This separation remains through the entire projection. This is principally due to less supply being committed in this scenario thanks to the demand outlook and this leads to weak development of additional gas supply. Therefore, existing sources of large supply (Queensland most specifically) become a focal point of long-term supply. This leads to the separation of price with the southern states over time.

Melbourne and Tasmania face the highest prices in this scenario as they are furthest from northern supply sources. Lower cost imported LNG from PKET in this scenario does assist the market to some degree but is less helpful in the short to medium term compared with our previous forecasts given the higher front end to the LNG price forecast.

4.1.2 Industrial prices

Our industrial gas price forecasts are also largely based on the outputs of our GasMark model. For this customer group, the model contains details of several large individual users (typically serviced by transmission pipelines) in the ECGM, and then groups all other users together based on their relative geographic location. The latter group is typically serviced via the distribution network.

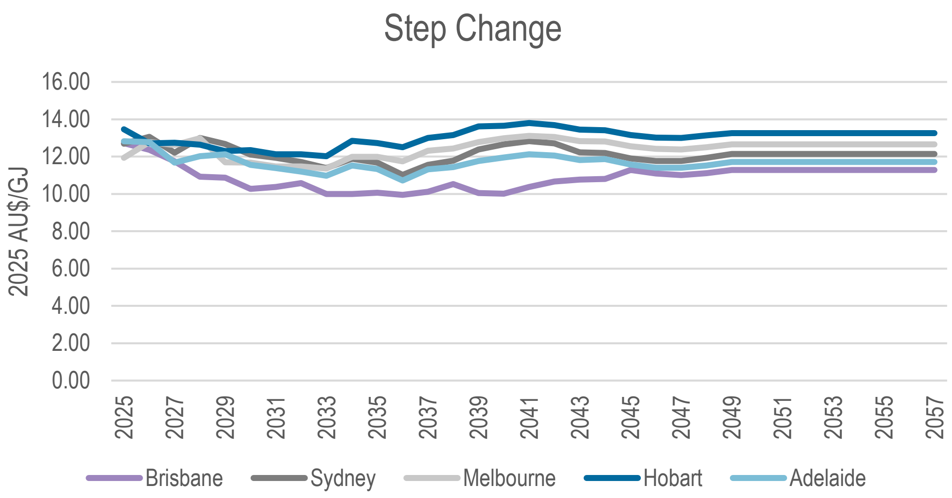
Industrial prices broadly follow the trajectory and 'price ranking' per city of the residential commercial forecasts. Industrial prices exhibit a tighter spread of prices across the different markets than the residential/commercial projection. This is due to the reduced exposure to winter price swing that is a feature of prices in the residential and GPG markets.

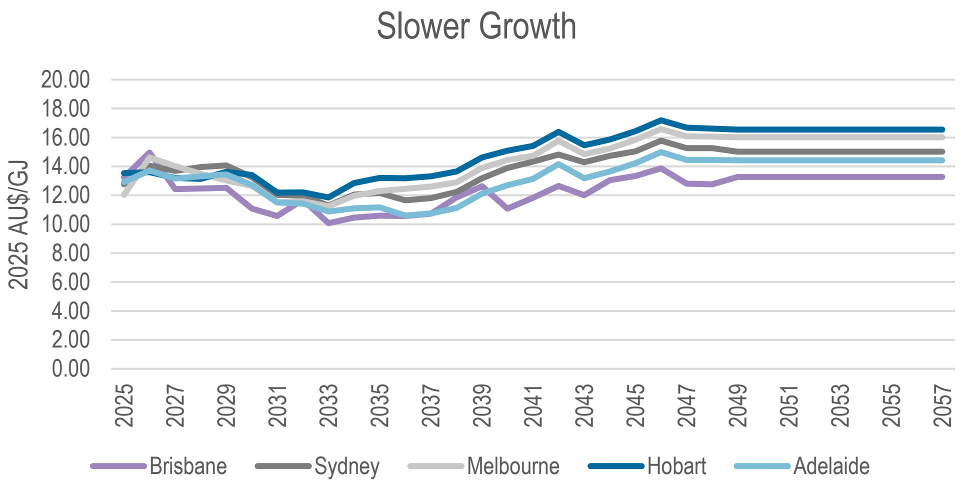
In the Step change scenario, prices are expected to remain relatively steady and marginally fall with lower LNG netback prices. We expect that larger industrial producers are likely to negotiate prices around the $12/GJ mark in the short term. Domestic prices bottom out as LNG prices fall by the late 2020s/early 2030s, then gradually climb back in line with pressures from the demand/supply balance and increasing costs of production.

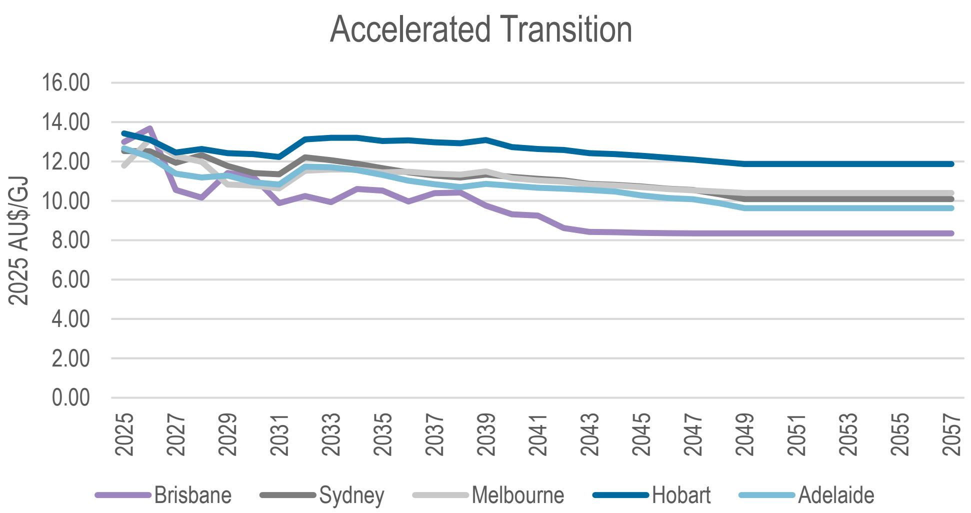
The Slow Growth scenario follows generally the same trajectory as prices in the residential/commercial sector. As we mention previously, prices in this scenario are higher than in the Step Change scenario. This is due to stronger international LNG demand which impacts the domestic market via the LNG netback.

In the Accelerated Transition scenario, we expect that prices will trend to lower levels. As we mention with respect to residential/commercial prices, Melbourne and Hobart face the highest prices in the long term given they are the furthest from supply sources.

Figure 4.4 Industrial gas prices per scenario, by market







Source: ACIL Allen

4.1.3 GPG prices

GPG demand relies on the interplay between the gas and electricity markets, and the associated assumptions for both. As with the other sectors in the gas market, GPG demand data provided by AEMO was used in each scenario of these forecasts for consistency.

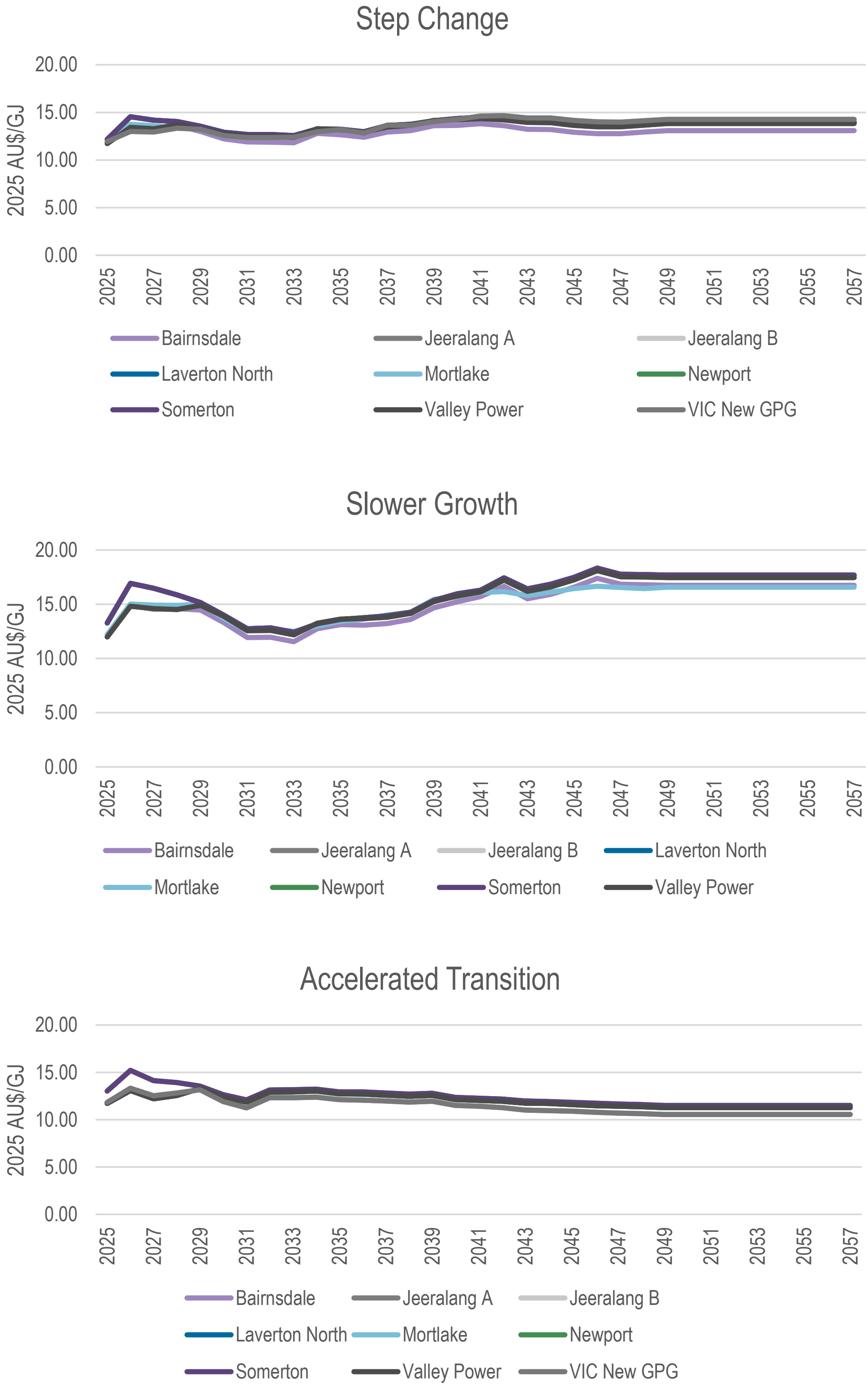
Two runs of our GasMark model were performed to generate the annual wholesale price reflecting contracts, and a monthly output to reflect the spot market. From here a weighting was produced for each generator to account for approximate proportions of contract and spot gas used to supply the generator. This supply balance varies largely based on the generator technology used (e.g., OCGT vs CCGT), location of the generator, and the expected daily dispatch profile within a year.

As we mentioned in respect to industrial prices, in the long-term prices for generators will reflect a long-term price underpinned by demand and supply fundamentals, and not short-term factors. Therefore, projected prices in the long-term will be more reflective of contract prices.

A premium has been added to the price OCGTs pay in the long term, to account for the additional costs they incur to source gas at short notice and at potentially high volumes. This additional cost is typically associated with reserving pipeline capacity and utilising storage. The price of any new CCGT or OCGT entering the market will be the same as that reported for existing generators.

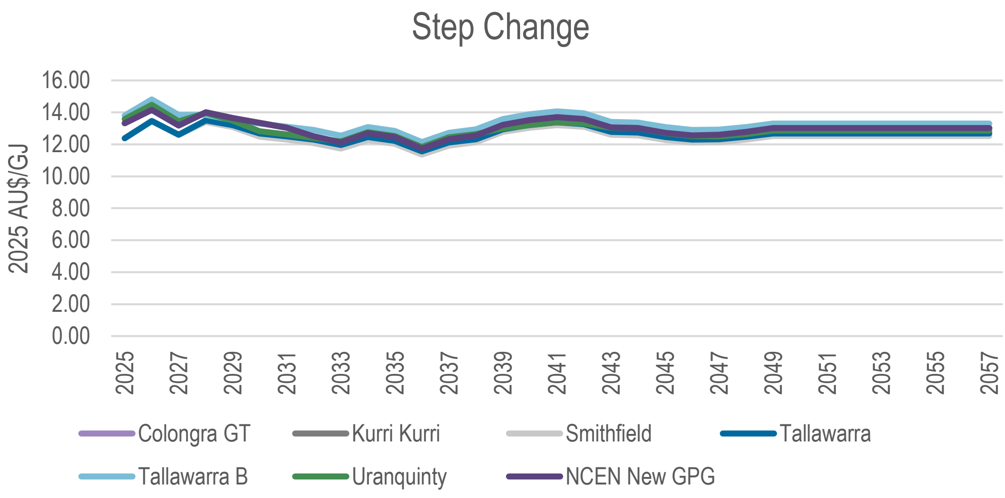
The prices for GPG track much the same as the other sectors for the same reasons across each scenario.

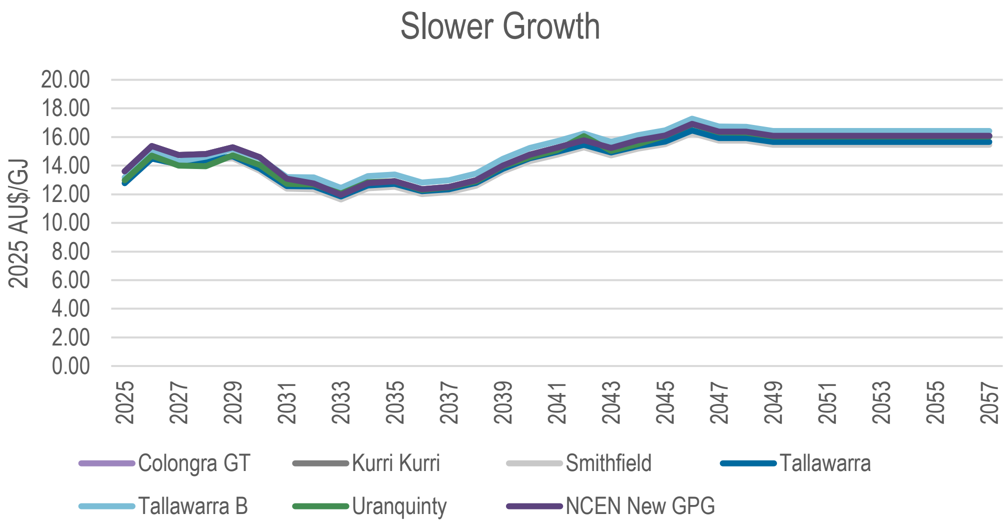
Figure 4.5 GPG gas prices: Victoria

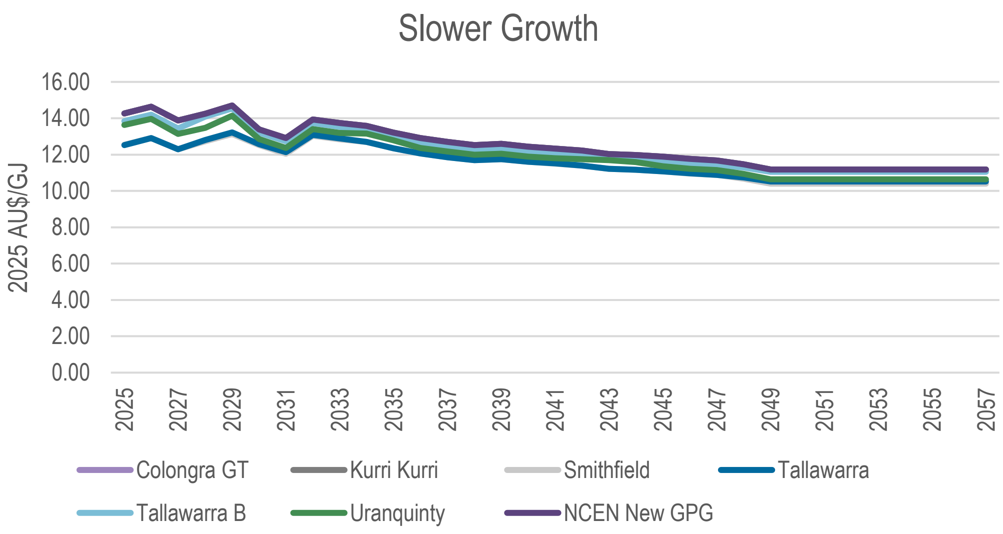


Source: ACIL Allen

Figure 4.6 GPG gas prices: New South Wales

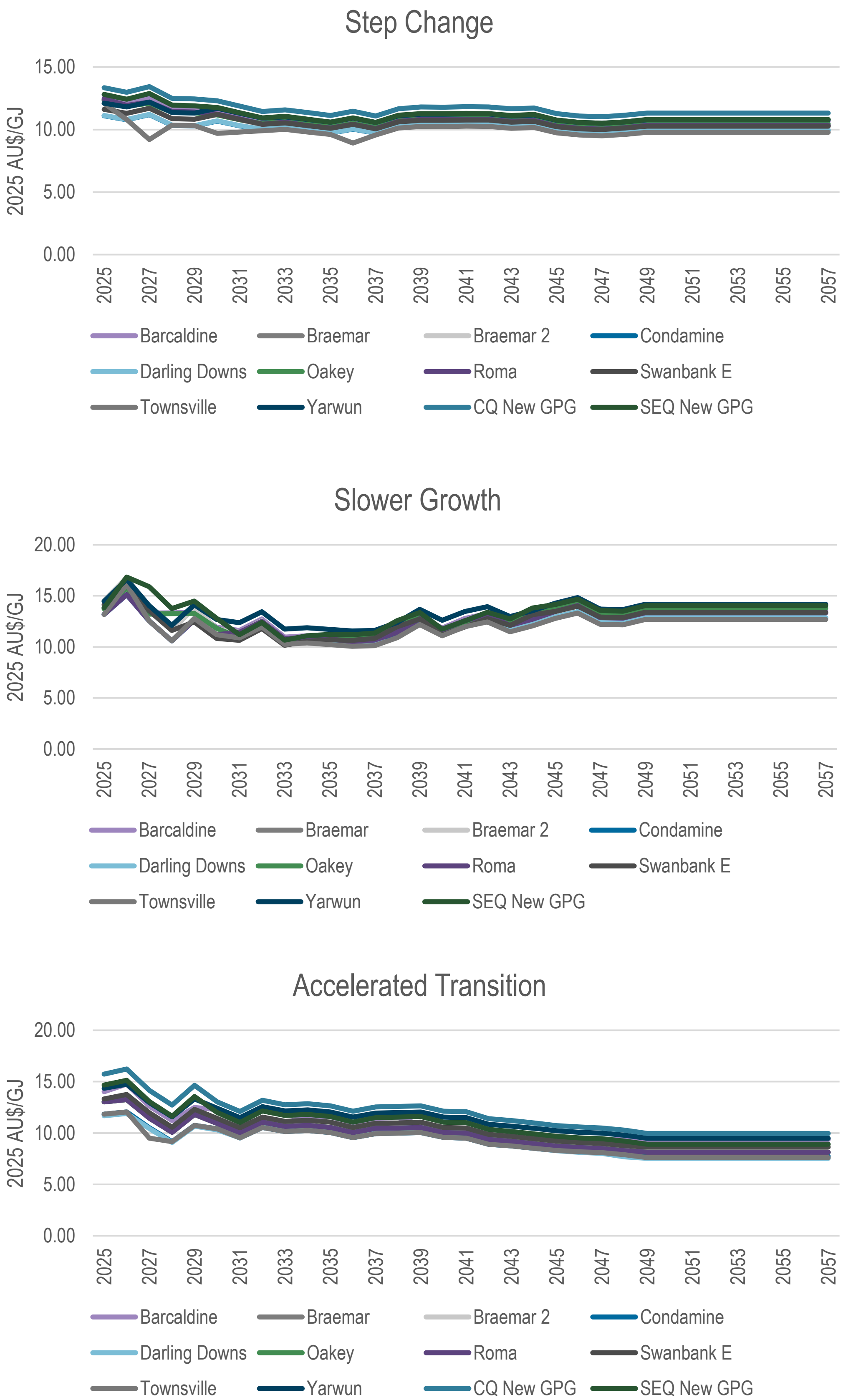






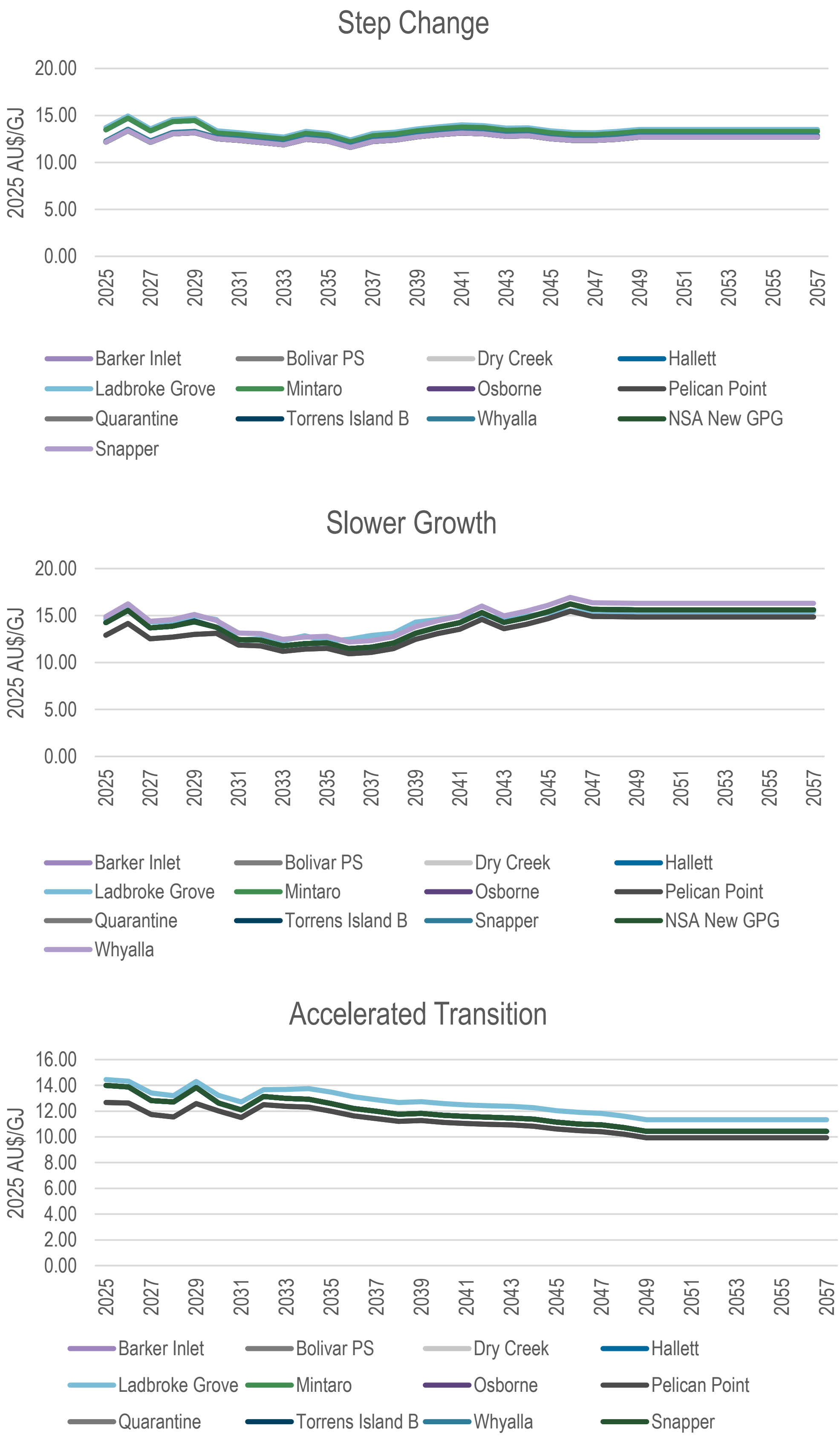
Source: ACIL Allen

Figure 4.7 GPG gas prices: Queensland



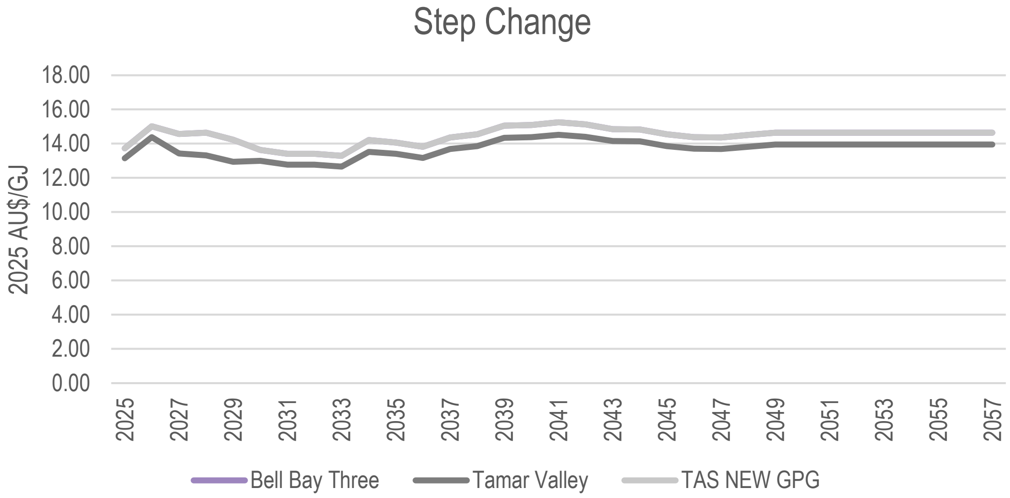
Source: ACIL Allen

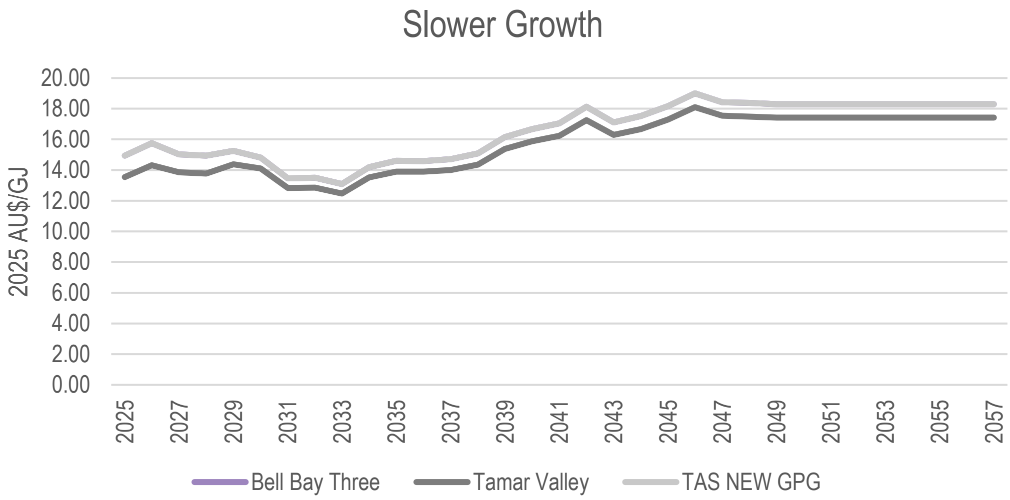
Figure 4.8 GPG gas prices: South Australia

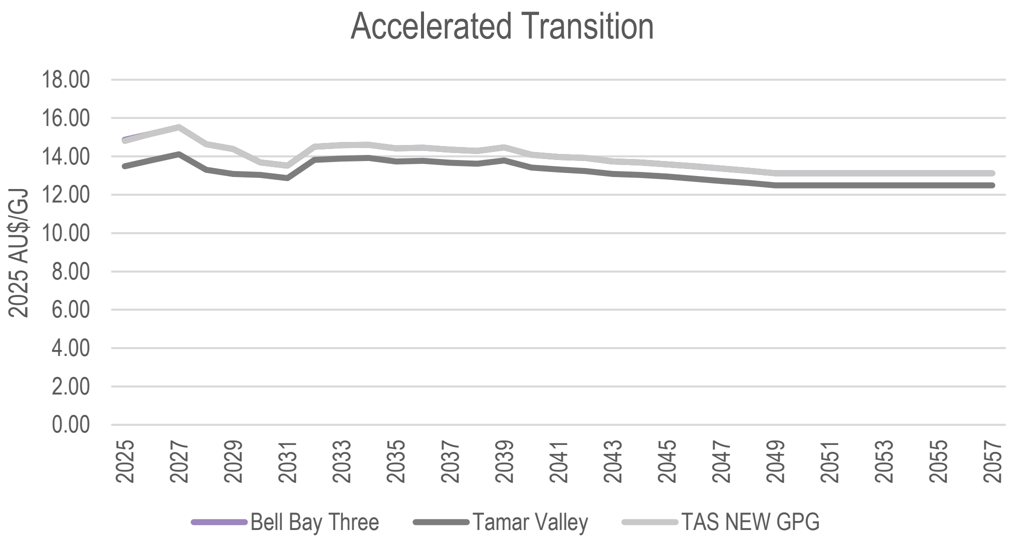


Source: ACIL Allen

Figure 4.9 GPG gas prices: Tasmania







Source: ACIL Allen

4.2 NT gas market results

Gas consumption in the NT market is dominated by power generation and mining (which is essentially to generate power for the most part at these mine sites). Gas used in other sectors of the NT economy is very small in comparison. However, there are distribution networks in Alice Springs and the Darwin metropolitan area that service customers in the residential, commercial and industrial sectors.

We have broken the NT projection up into 3 sections:

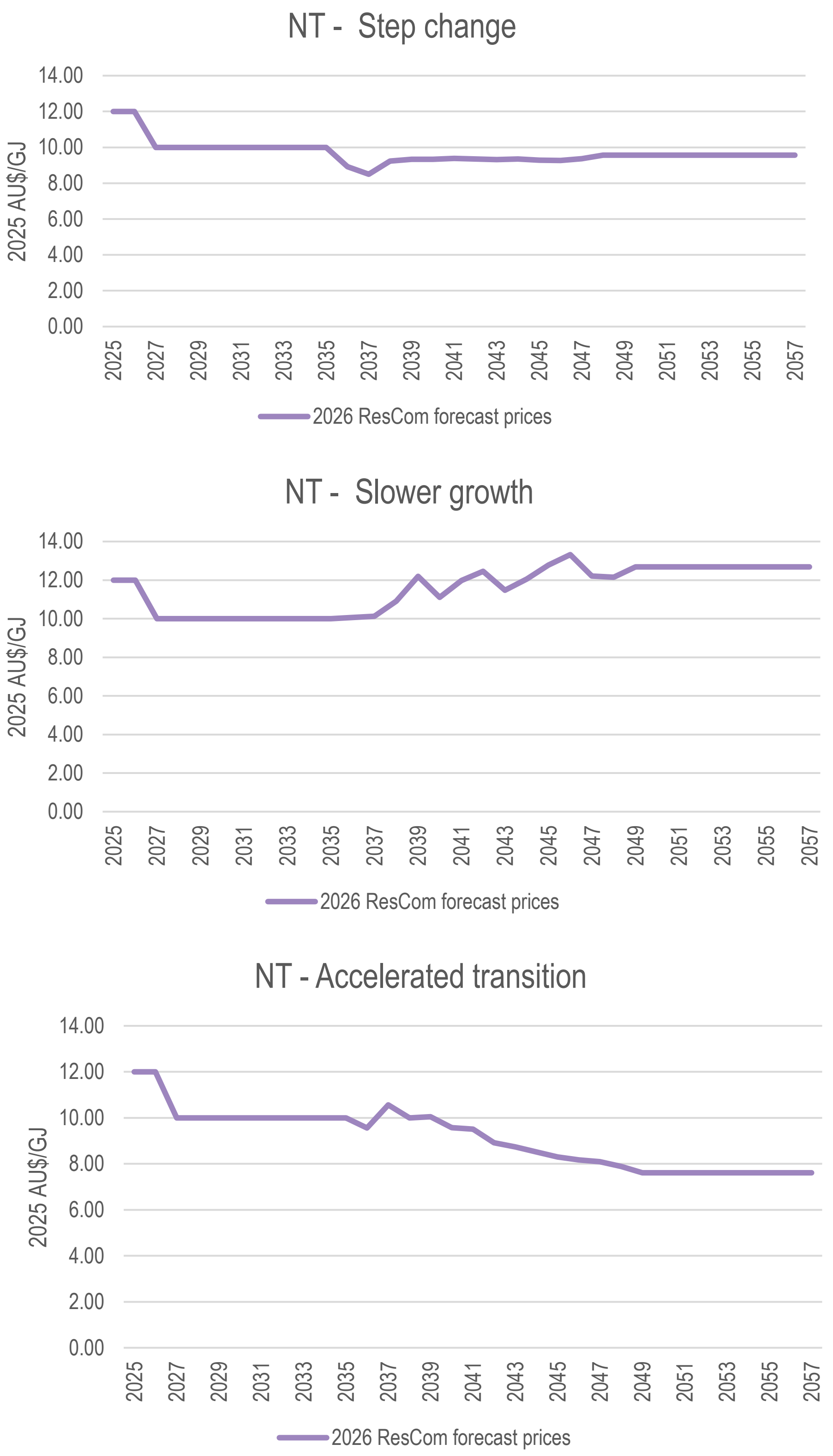
— The first section from **2025-2027** is set to AU$12/GJ to reflect the reality that the NT will continue to face high prices until the pilot gas from the Beetaloo basin begins to flow reliably into the NT market. The high prices are a result of the persistent performance issues at the Blacktip field.

— For the second section from **2027-2035**, the price is set at AU$10/GJ to represent what ACIL Allen sees as a likely contract level for pilot gas from the Beetaloo project. Contracts with PWC extend until 2035.

— For the third section, **2035-beyond**, the price shows a linkage to the QLD market, somewhat mirroring them and reflecting the stronger ECGM interlinkage that the NT may face as the Beetaloo matures.

The NT residential market prices are provided in Figure 4.10.

Figure 4.10 Residential prices: Northern Territory

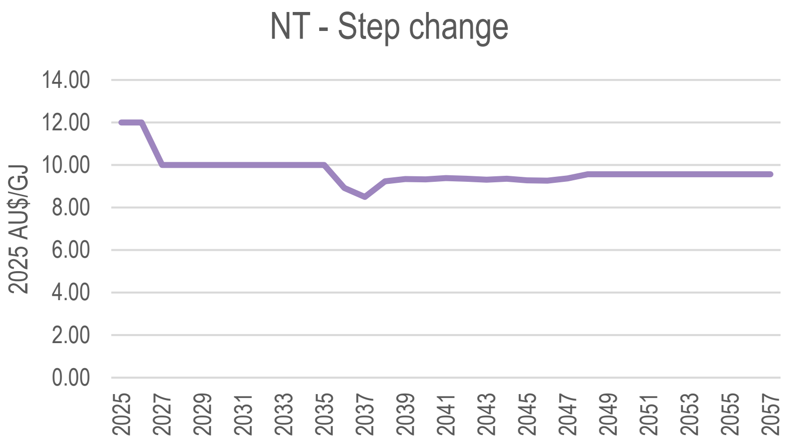


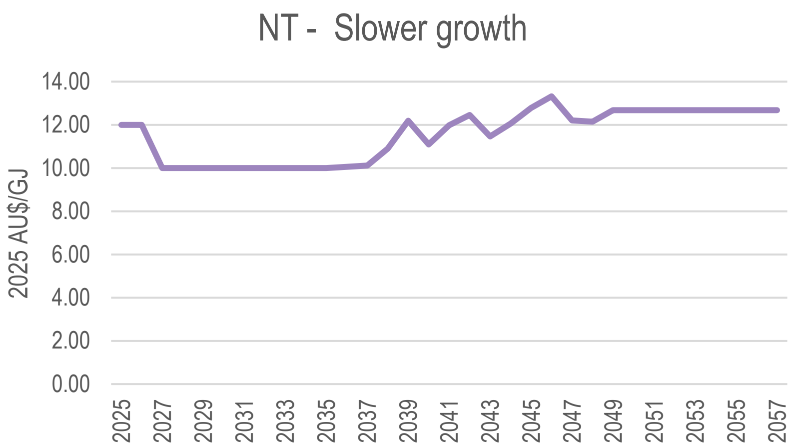
Source: ACIL Allen

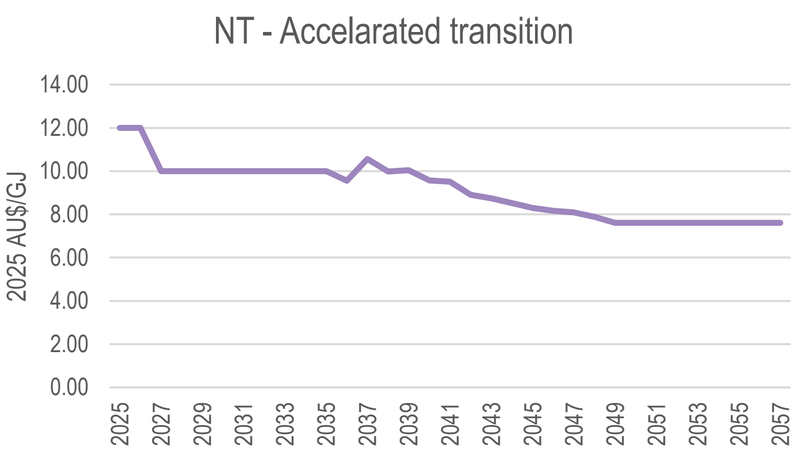
4.2.1 NT industrial market

The NT gas price for the industrial market is provided in Figure 4.11.

Figure 4.11 Industrial prices: Northern Territory







Source: ACIL Allen

4.2.2 GPG prices in the NT

Prices in the short and medium term are highly uncertain for the NT due to events evolving in the Territory around supply and supply disruptions. Our prices are shown below.

Figure 4.12 NT GPG prices

Source: ACIL Allen

Appendices

A Natural gas modelling methodology

A.1 GasMark

A.1.1 Our GasMark model

First created 20 years ago and extensively developed and enhanced over that period, it has been widely applied in analysing the dynamics of the gas markets in both eastern Australia (including the Northern Territory) and Western Australia.

At its core, GasMark is a partial spatial equilibrium model. The market is represented by a collection of spatially related nodal objects (supply sources, demand points, LNG liquefaction and receiving facilities), connected via a network of pipeline or LNG shipping elements (in a similar fashion to 'arks' within a network model).

The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously.

The solution results in an economically efficient system where lower cost sources of supply are utilised before more expensive sources, and end-users who have higher willingness to pay are served before those who are less willing to pay. Through the process of maximising producer and consumer surplus, transportation costs are minimised, and spatial arbitrage opportunities are eliminated. Each market is cleared with a single competitive price.

The model allows projection of future gas supply, demand and price outcomes at **annual, quarterly, monthly or daily resolutions**. It is therefore a useful tool for looking at the implications of short-term supply & demand variability over long time periods.

A.1.2 GasMark preparation

GasMark has the flexibility to represent the unique characteristics of gas markets across Australia. The model now includes assumptions for over 200 gas fields and more than 250 individual demand nodes. We have ensured the model is consistent with the assumptions provided by AEMO for the various scenarios that will be utilised for their GSOO reporting. In some cases, our assumptions have been simplified to broadly correspond with AEMO's assumptions (e.g. gas field production costs might be made consistent across a gas producing basin to align with the approach AEMO takes).

Table A.1 below presents the various components that were confirmed with AEMO before commenced the modelling.

Table A.1 GasMark components and key assumptions

Model component	Key assumptions and data sets
Prices	– Asian contract and spot LNG prices that will affect LNG exports from Gladstone – Asian LNG spot prices that will affect the price of LNG imports from new LNG import terminals proposed – e.g. Port Kembla LNG import terminal – Model assumptions to capture the effect of the recently introduced gas price code on the wholesale gas market

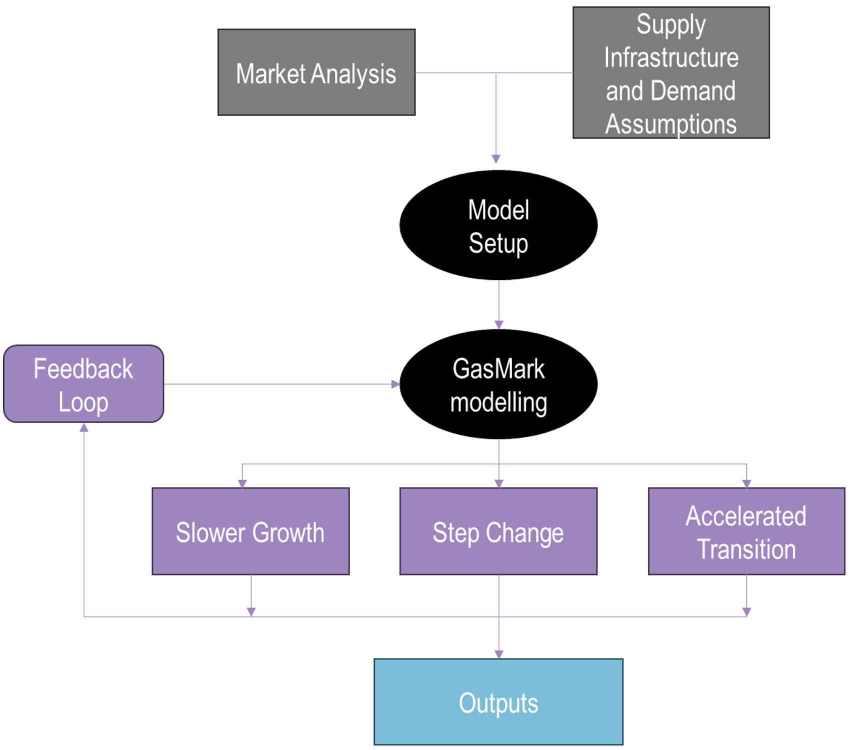
Model component	Key assumptions and data sets
Supply	– Supply assumptions include volume of reserves and resources, production profiles, cost of production, anticipated reserve and resource developments over life span of project and conversion rates for reserves and resources – any specific supply contracts for supply sources with particular demand nodes that is essential for modelling over the long term – LNG export project assumptions including capacity profiles, transportation costs, liquefaction costs – LNG import terminal assumptions including annual delivery capacity, daily injection capacity into the pipeline network and regasification costs
Demand	– Assumptions for demand markets in the ECGM and the Northern Territory – Input projected daily demand profiles for individual GPG power stations from AEMO – Confirmation of any expected users to exit or enter the market
Storage and pipeline infrastructure	– Major transmission pipeline assumptions including flow direction, capacity, flow profile, tariff profile, pipeline connections – Confirmation of any expected new pipelines that may enter the market – Storage facility assumptions including capacity, minimum storage buffers, storage efficiency, opening balances, injection rates, withdrawal rates, injection and withdrawal prices

Source: ACIL Allen

A.2 Summary of modelling framework

In summary, our methodology of the modelling process followed the approach presented in Figure A.1.

Figure A.1 Modelling framework



Source: ACIL Allen

As discussed above, GasMark models hypothetical spot prices and does not model gas contracts. However, with the shortening of gas contracting in recent years, to as low as one year in many cases, and the increasing role of the spot markets, the output is a reasonable indicator of the direction of the wholesale gas price over time.

The output of this process is a series of gas prices by region that broadly reflect the wholesale price, including transmission charges, in each region. Contract prices could be expected to be slightly higher than this price to take account of contract terms such as take or pay, interruptible and other services that are provided.

B LNG price projections

This appendix provides background to the projections of LNG Prices.

B.1 Introduction

This attachment addresses the cost of imported LNG adopted for modelling the impact on gas prices in the ECGM. The LNG price indicator is assumed to be the delivered price of LNG to Asian markets.

The outlook for LNG prices has entered a period of higher uncertainty than in the past driving by:

— supply growth for new LNG developments leading to a potential supply overhang for up to the next decade.
— the outlook for demand from established markets
— the outlook for demand from emerging market growth
— impacts of geopolitical factors on LNG trade
— approaches to gas contracting verses the spot market.

These factors have been considered when constructing the LNG price projections for the three scenarios adopted by for the price projections for the AEMO scenarios.

B.2 Potential supply growth

Many analysts, including the International Energy Agency (IEA) have drawn attention to the potential for an oversupply in the LNG market in the medium term. Projects currently under construction are expected to deliver close to 180 mtpa of new capacity between 2025 and 2028. Most of this will come from projects in the United States (71 mtpa), Qatar (32 mtpa) and Canada (19 mtpa).[22]

The US leads in achieving project FIDs including Woodside's Louisiana LNG (16 mtpa) and Cheniere's Corpus Christi trains 8 and 9 (6 mtpa). Southern Energy FLNG in Argentina (6mtpa) also reached FID in 2025. More US projects are expected to add further capacity by 2030. These include Commonwealth LNG Louisiana project, Golden Pass LNG, Port Arthur LNG phase 2, Rio Grande LNG and Plaquemines Phase 2. [23]

Other projects expected to reach FID in the near future include Amigo LNG in Mexico (7.8 mtpa)[24], Ksi Lisims LNG in Canada (12mtpa)[25] and Lake Charles LNG in the US (16 mtpa)[26]. Mexico is emerging as an LNG exporter. It has several projects operational now and under development. A major project in Mexico yet to reach FID but with potentially 15 mtpa is the Saguaro Energia LNG project being developed by Mexico Pacific in Sonora with potential to market LNG into the Pacific region.[27]

LNG projects are also in the pipeline in PNG. In addition to the existing PNG LNG project (8mtpa) [28], the Papua LNG project is expected to reach FID in 2025 or 2026.[29]

[22] GIIGNL (2025) The LNG industry – GIIGNL Annual Report, International Group of Liquefied Natural Gas Importers.
[23] ibid
[24] https://www.lngalliance.com/projects-7
[25] https://www.ksilisimslng.com/
[26] https://energytransferlng.com/
[27] Gaffney Cline (205%), Market Advice and Estimates of Contemporary LNG Contract Prices, ACCC
[28] https://www.pnglng.com/About
[29] https://pnginsight.com/papua-lng-project-totalenergies-update-for-2024-2025-beyond/

The potential for an oversupply situation introducing a downward pressure on prices is subject to progress on these projects entering the market well as geopolitical.[30]

Timing progress in completion of many of these projects will influence the impact on price in the medium term. For example, expansion timelines for Qatar will have an impact on the availability of supply. Qatar has a goal to reach 142 mtpa of LNG production capacity per year by 2030. If startup for its expansion projects takes longer than planned, this could shift as much as 10 mtpa to beyond 2030.[31]

The outcome of European consideration of sanctions against LNG from the Russian Federation could also shift the LNG supply situation with implications for prices.

According to some reports, not all this gas is contracted, suggesting that the share of LNG sold in the spot market could increase in the medium term, until demand catches up with this additional supply.[32]

On balance downward pressure on prices from oversupply in the medium term is the most likely outcome subject to demand response in established and emerging markets.

B.3 Demand from established markets

A key issue for future gas demand in established markets is whether decarbonisation policies will lead to a long-term structural decline in the demand for natural gas, both for LNG and pipeline gas. Key factors include:

European LNG imports fell by 23 mt in 2024, down 19% on the previous year. This has been attributed to switching away from natural gas by some industries including fertilisers, chemicals steel and ceramics. Increased availability of renewable and nuclear energy for the power sector also contributed to a decline in natural gas consumption in the power sector.[33] Gas demand is expected to recover somewhat but peak by 2017 before continuing to decline as solar and wind energy expands.

In 2024, the European Commission introduced large scale restrictions on imports of Russian natural gas by pipeline. This mainly focused on terminals not connected into the EU's internal gas transmission network and was aimed at restricting the transfer of Russian natural gas to other markets. The EU aims to fully ban Russin gas by 2027.

China maintained its position as a leading LNG importer in 2024 with imports increasing to 78 mtpa in 2024. Reduced economic activity in China combined with higher gas supplies from domestic production and pipeline imports has tempered Chinese demand for LNG in the short term.

— South Korea appears to have shifted its energy policy nuclear power to renewables. This could result in higher LNG demand for gas fired power generation over the longer term.
— Taiwan LNG imports grew by 5% to 21 million tonnes in 2024, driven by an ongoing shift in power generation towards natural gas as the country continues to phase out coal and nuclear energy.
— India imported 27 mt in 2023, an increase of 23% over 2023. Hong Kong, the Philippines and Vietnam increased LNG imports in 2024,
— Japan's increased long-term procurement of LNG, indicating confidence in long term demand. Japanese buyers are reported to be showing a renewed interest in longer term contracts. LNG is a component of Japan's energy procurement strategy.

The established markets are likely to continue to rely on LNG for longer term supply security. A return to the days of Europe importing large volumes of gas by pipeline from the Russian Federation appears unlikely.

[30] Ibid
[31] Bloomberg (2025), Global LNG Market Outlook 2030
[32] GFB Insight (2025) Quarterly LNG Strategic Report Q2 2025
[33] GIIGNL (2025) The LNG industry – GIIGNL Annual Report, International Group of Liquefied Natural Gas Importers.

The potential for Europe to ban LNG imports from Russia will also have implications for LNG markets of interest to Australia.[34]

The possibility of lower economic growth in China remains a concern for LNG demand moving forward. However, the ongoing interest in contracted by Japanese buyers and ongoing commitment to gas in South Korea underpins strength in demand for LNG from established markets in the Asia-Pacific Region.

B.4 Emerging markets

A key question for future prices of LNG is how emerging markets will respond to lower prices in the medium term and whether this will ultimately lead to a period of sustained long-term demand growth.

Recent developments have seen plans announced for new regassification terminals in South and Southeast Asia:

— Imports of LNG into Thailand remained flat in 2024. However, in 2025 Gulf announced an investment decision to construct the 8 mtpa Map Ta Phut receiving terminal. [35]

— Recent entries into the LNG importing countries in Asia, the Philippines, Hong Kong, Vietnam and Singapore continued their LNG import activities and posted the Asian region's highest growth rate in 2024. Emerging markets, like Philippines and Vietnam, have several proposed LNG import projects.[36]

— Petronas announced plans for the development of a third regasification termina in peninsula Malaysia. The Malaysian Government has foreshadowed a need for 50% more gas fired power capacity to meet growing data centre demand in Malaysia.[37]

— India recorded an increase in LNG imports in 2024 to 27 mtpa. Growth in photovoltaic generation in Inda could support further electrification which, in turn, is likely to support demand for gas fired generation for firming in the electricity market. Bangladesh and Pakistan have expanded their LNG imports despite price sensitivity.[38]

— Egypt has become the largest LNG importer in the Middle East. It announced two additional regasification terminals to be added in 2025.[39] Imports of LNG have also increased in Jordan and the United Arab Emirates. [40]

These developments could support long term growth in LNG demand from emerging markets, particularly those in Malaysia and Thailand. Other markets such as India, Pakistan and Bangladesh face affordability challenges. However, a decline in LNG prices in the coming years could spur growth in demand for gas in these emerging markets, firming up LNG prices in the longer term.

B.5 Geopolitical factors

Factors that create uncertainty for future market developments for LNG include the impact of US protectionist policies and the growing influence of geopolitical developments on the LNG market. The move away from a rules-based order in global trade will have implications for global LNG trade. It could also result

[34] Bloomberg (2025), Global LNG Market Outlook 2030

[35] https://www.gulf.co.th/en/newsroom/news-and-activities/473/gulf-and-ptt-tank-signed-epcc-contract-with-posco-e-and-c-and-caz-for-map-ta-phut-phase-3-superstructure-development-to-enhance-thailand-s-energy-security

[36] GIIGNL (2025) The LNG industry – GIIGNL Annual Report, International Group of Liquefied Natural Gas Importers.

[37] https://www.argusmedia.com/en/news-and-insights/latest-market-news/2700241-malaysia-s-petronas-to-build-third-lng-import-terminal

[38] Op Cit GIIGNL

[39] https://egyptoil-gas.com/news/egypt-expands-lng-capacity-with-second-long-term-fsru-deal/

[40] Op Cit GIIGNL

in new LNG projects being tied to bilateral trade agreements and increasing the influence of geopolitical factors on LNG contracting.

The increased involvement of geopolitical factors increases uncertainties for LNG price projections over the longer term.:

— Higher political uncertainty may see suppliers seeking higher returns over shorter periods or contracts that secure their medium-term supply arrangements.
— Concerns over policy and regulatory change may see buyers favouring contracts over spot purchases with more attention paid to policy changes in negotiation of contract terms, potentially affecting market liquidity.
— Longer term price projections may need to factor geopolitical influence over market factors.

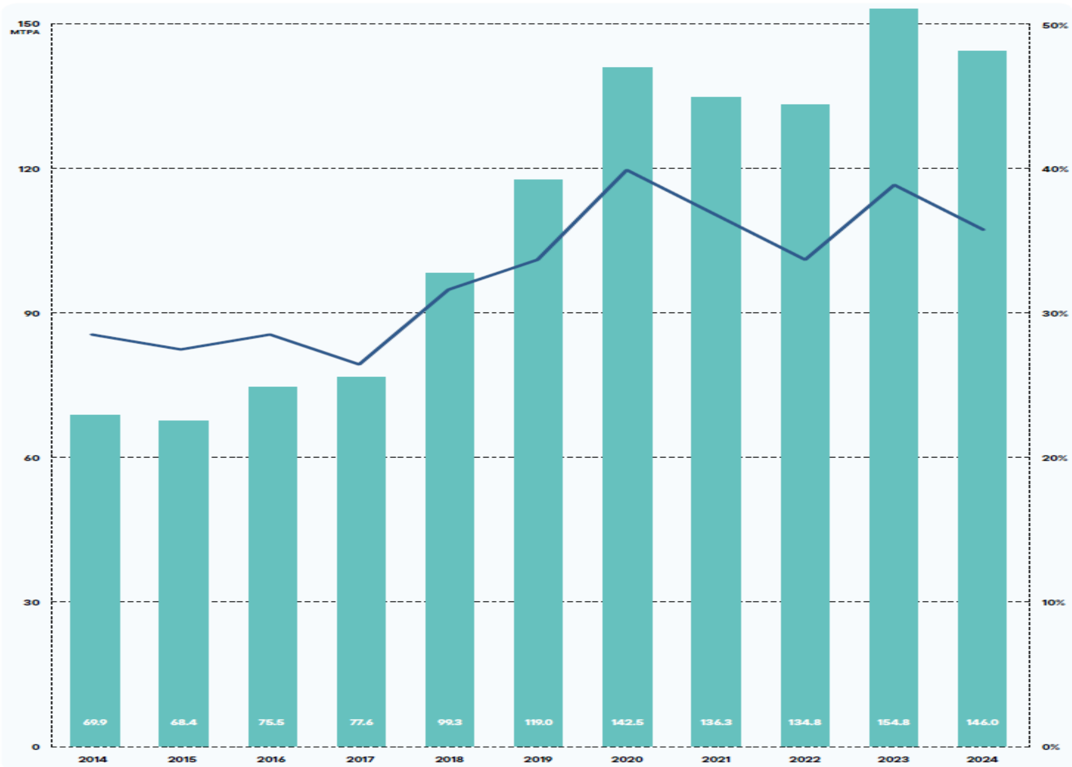
Central to the current political scene is potential conflict between Russia and Europe, the impact of Middle Eastern conflicts on LNG flows in the Strait of Hormuz and possible escalation of trade tensions between the US and China.

The possibility of an EU ban on Russian gas in 2027 would have consequences for LNG prices in markets of relevant to Australia. Over the longer term it is important to look beyond these immediate challenges towards underlying market drivers over the 25 years of the projection period. A potential move away from the rules-based order in global trade would have negative implications for LNG supplies of interest to Australia.

B.6 Market factors

Traditionally pricing in LNG contracts were linked to the oil price. However, around 35% to 40% of global trade in LNG is now transacted through the spot market or short-term trades as shown in Figure B.1.

Figure B.1 Share of spot and short term verses total LNG trade (MTPA/%)



Source: GIIGNL (2025) The LNG industry – GIIGNL Annual Report, International Group of Liquefied Natural Gas Importers.

The proportion of LNG traded through the spot market is likely to increase over the short to medium term because of uncontracted additional capacity reported in Section B.2. This is likely to place downward pressure on spot market prices in the short to medium term.

B.2. This is likely to place downward pressure on spot market prices in the short to medium term.

In the longer term, the proportion of spot traded gas is expected to revert to past levels as buyers seek to shore up contracted supplies in highly volatile markets. For example, Japanese buyers have shown a preference for contracted gas over spot market gas for supply security reasons.

B.7 Approach to the LNG price projections

Overall global LNG is expected to reach 594 mtpa by 2030 which would be 42% higher than 2024 levels. By comparison Global LNG demand is projected to reach 578 mtpa by 2030 which is 39% higher than in 2024. Taking these considerations into account the LNG market appears to be heading into oversupply by 2030.

For each of the AEMO Scenarios LNG prices are projected to fall over the medium term with higher shares of spot market trades over that period. The longer-term outlook for LNG prices will depend on the response from emerging markets, particularly in Asia and the Middle East.

The level of uncertainty on the path of future prices has increased over the past year and the possible outcomes are now wider than before. For the LNG price projections, we have considered the outlook for oil prices, the proportion of LNG traded by oil linked contracts and the outlook for the spot market. The key assumptions by scenario are as follows:

— **Slower Growth Scenario**: Policies and programs to achieve net zero by 2050 are significantly curtailed resulting in continued high dependence on petroleum products and LNG across the globe. The share of spot sales of LNG is lower than in the Step Change and Accelerated Transition scenarios over the medium term driven by buyer concern over energy security.

— **Step Change Scenario**: Policies and programs to transition energy systems are implemented consistently with limiting global temperature rise to below 2 degrees Celsius compared to pre-industrial levels. Consumers continue to invest in energy efficiency, electrification and renewable energy. However, they are less willing to participate in operation of their energy devices through a third party. Demand for LNG in Europe continues to decline and growth in demand for LNG in emerging markets is less robust over the longer term.

— **Accelerated Transition scenario**: This scenario assumes countries across the globe achieve rapid emissions reductions achieving global decarbonisation commitments to limit temperature rise to 1.5 degrees C above pre-industrial levels. Demand for conventional petroleum fuels declines significantly and the transition to renewable and nuclear generation of electricity reduces demand for gas and accordingly LNG globally.

B.8 Oil price outlook

A summary of oil price projections from the International Energy Agency and the Energy Information Administration of the US Department of Energy are provided in Table B.1. [41]

Table B.1 Oil price projections from the IEA and the EIA

	2023	2030	2040	2050
	US$/bbl	US$/bbl	US$/bbl	US$/bbl
IEA STEPS	82.0	79.0	77.0	75.0
IEA APS	82.0	72.0	63.0	58.0
IEA NZE	82.0	42.0	30.0	25.0
US IAE reference case (Brent)		72.	85	91
US EIA high oil prices (Brent)		124	145	157
US EIA low oil prices (Brent)		41	44	48

Source: IEA 2024 World Energy Outlook, Energy Information Agency 2025 Annual Energy Outlook

Note: I EA scenarios: STEPS =Stated Policy Scenario, APS = Announced Pledges Scenario; NZE = net zero emissions by 2050

The IEA assumption of US$25 /bbl by 2050 in the NZE case is likely to be unsustainable if history is any indication. When oil prices fell to that level in the past, there has been a demand response that resulted in prices recovering to a price above US$30/bbl.

Similarly, when prices rose to above US$100/bbl, supply responses have resulted in the price falling back to below US$80/bbl. While the operating environment for conventional fossil fuels may be different in the longer term, ACIL Allen has concluded that prices above US$100/bbl would not be sustainable.

For the purpose of the forecasts, we have adopted the AEMO Scenario as a framework for the projections. Our projections are summarised in Table B.2 and Figure B.2. The key assumptions are:

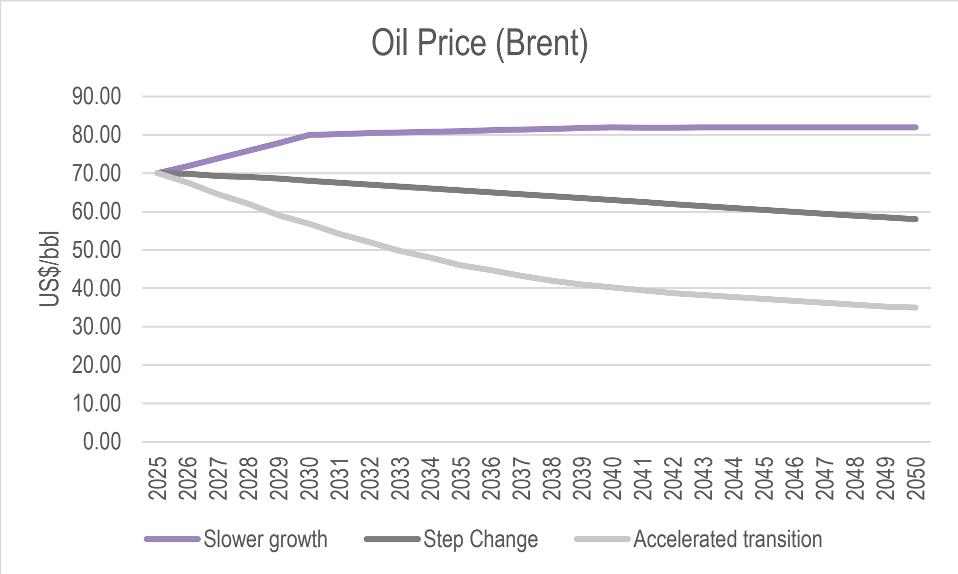
Table B.2 Oil price projection assumptions

	2025	2030	2040	2050
	US$/bbl	US$/bbl	US$/bbl	US$/bbl
Slower growth	70.0	80.0	81.9	82.0
Step Change	70.0	68.0	63.0	58.0
Accelerated transition	70.0	58.0	40.2	35.0

Source: ACIL Allen

[41] The IEA issued its 2025 version of its World Energy Outlook on 12 November 2025 after this report was finalised. The Oil price assumptions for the IEA STEPS and NZE scenarios are not significantly different. However, the IEA has dropped its Announced Pledges Scenario (APS) and introduced a new Current Policies Scenario. The latter has significantly higher oil price assumptions for 2033 and 2050. There is no direct comparison between the CPS and the AEMO scenarios, but it sits above the Slower Growth Scenario in terms of price outlook.

Figure B.2 Oil price projections



Source: ACIL Allen

Note: Oil price projections are for dated Brent in US$/bbl (2025)

B.9 LNG price assumptions

Contracted gas

The relationship between the LNG price and the oil price for contracted gas has been calculated using the following formula:

$$P_{LNG} = \frac{FC + S * Pb}{FX * C}$$

Where:

P_{LNG} = price for LNG in Asia in $AU/GJ

FC = fixed component in US$/mmbtu = 0.40

S = slope = 0.12

Pb= price of Brent Crude Oil in US$/bbl

FX= US$/$AU exchange rate=0.66

C = GJ/mmbtu = 1.055

B.9.1 Spot market gas

ACIL Allen's assumptions for gas through the spot market are summarised in Table B.3.

Table B.3 Percentage of total sales of LNG sold through the spot market

2025	2025	2030	2040	2050
	%	%	%	%
Slower growth	35	39	36	35

2025	2025	2030	2040	2050
Step Change	35	45	35	35
Accelerated transition	35	45	35	35

Source: ACIL Allen

Spot market LNG prices to 2030 have been based on the JKM forward curve as of October 2025. Beyond 2030, the prices for spot market LNG for the Step Change and Accelerated Transition scenarios have been guided by the IEA longer term forecasts.

The longer-term projections for LNG prices in the spot market under the Slower Growth scenario is 21% higher in 2050 than the IEA projections, on the assumption that progress is stalled in the energy transition globally.

B.10 LNG price for the three scenarios.

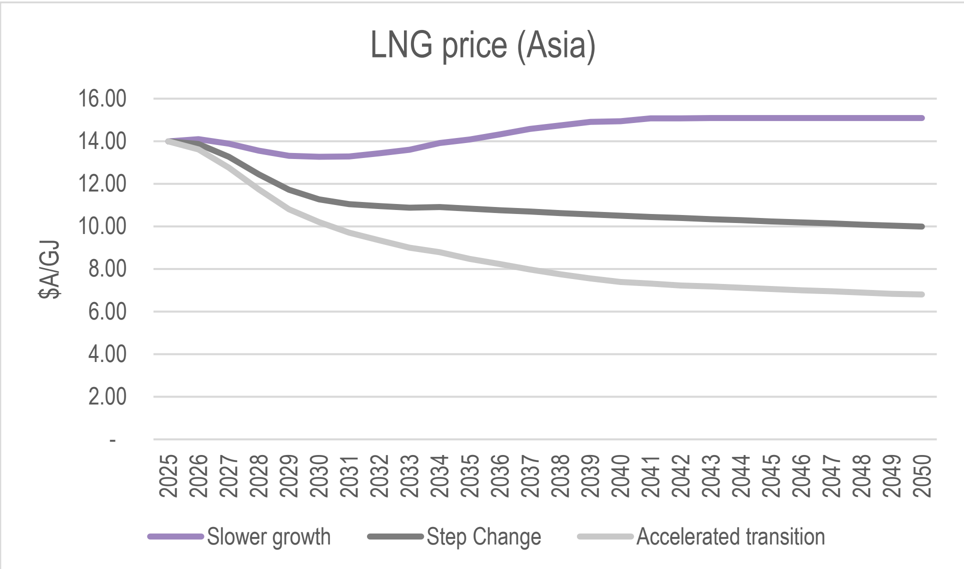
The LNG price assumptions for the three scenarios adopted by AEMO are summarised in Table B.4 and Figure B.3.

Table B.4 LNG price projections

	2025	2030	2040	2050
	$AU/GJ	$AU/GJ	$AU/GJ	$AU/GJ
Slower growth	13.99	13.26	14.94	15.09
Step Change	13.99	11.27	10.50	9.99
Accelerated transition	13.99	10.20	7.39	6.81

Source: ACIL Allen

Figure B.3 LNG price projections



B.10.1 Comparison with other projections

These results are compared with projections developed by the International Energy Agency (IEA) and the US Energy Information Administration (EIA).

IEA

The most recent projections of LNG prices produced by the IEA are in its World Energy Outlook 2024. They are summarised in Table B.5

Table B.5 IEA LNG price projections

	2030	2040	2050
	$AU/GJ	$AU/GJ	$AU/GJ
STEPS	11.92	12.64	12.49
APS	9.77	8.76	8.90
NZE	7.18	6.89	6.89

Source: IEA (2024) World Energy Outlook 2024, International Energy Agency

The IEA scenarios are defined as:

— Stated Policies Scenario (STEPS)
— Announced Pledges Scenario (APS)
— Net Zero by 2050 (NZE)

The prices in the AEMO Slower Growth and Step Change Scenarios higher than the IEA STEPS and APS Scenarios in all years. In 2030 they are $AU2.6/GJ and $AU1.1/GJ higher respectively than in the IEA STEPS and APS Scenarios.

The Accelerated Transition Scenario is about $AU3.0/GJ higher than the IEA NZE scenario in 2030 and $AU0.1/GJ the NZE scenario by 2050.

US EIA

The most recent projections of LNG prices produced by the US EIA are drawn from the organisation's Annual Energy Outlook 2025. They are price assumptions used by the EIA for the purpose of modelling global energy supply and demand. They are summarised in Table Table B.6.

Table B.6.

Table B.6 EIA LNG price projections

	2030	2040	2050
	$AU/GJ	$AU/GJ	$AU/GJ
High oil price	11.98	14.58	15.68
Reference case	12.32	14.03	14.79
Low oil price	13.23	14.99	14.40

Source: EIA (2025), Annual Energy Outlook, US Energy Information Agency

Note: Prices are for LNG delivered from Henry Hub to Asia assuming US$2.5/mmbtu liquefaction cost and US$3/mmbtu shipping cost

The EIA projections are based on a reference case and a high and low oil price case. These scenarios do not match the AEMO scenarios. The Step Change Scenario is $AU 1.1 /GJ lower than the EIA reference case in 2030, and $AU4.8/GJ lower by 2050.

B.11 Delivered price

The quoted prices in Section B.10 represent prices delivered to Asian markets. To translate these into a delivered price it is necessary to deduct shipping and regassification costs.

The quoted prices in Section B.10 represent prices delivered to Asian markets. To translate these into a delivered price it is necessary to deduct shipping and regassification costs.

B.11.1 Shipping costs

Shipping costs include port, charter, boil-off, insurance and fuel costs. Voyage time including days on hire and waiting are also a driver of costs. Shipping costs can vary depending on movements in LNG demand, ship availability, and seasonal factors.[42] The ACCC reports estimates freight rates for shipments from Gladsome to Tokyo for 5 forward years. The current rates for that voyage vary from US$0.37/mmbtu to US$1.07 /mmbtu.

Shipping cost to an eastern Australian port will also be influenced by the distance travelled. The shipping distance from Qatar to Port Kembla is around 7,000 nautical miles requiring about 40 days for the round trip. The distance from Gladstone to Tokyo is around 4,000 nautical miles and 27 days for the round trip. By comparison, the sailing distance from Dampier to Port Kembla is about 2,900 nautical miles and 20 days round trip and the sailing distance from Gladstone to Port Kembla is about 770 nautical miles and around 3 days round trip. [43]

Shipping costs could vary significantly depending on the source of the LNG. The LNG price assumptions quoted are assumed to be for deliveries to Asian markets and would include an allowance for shipping from distant ports to Asia. Accordingly, the ACCC estimates would be proxy for shipping costs for origins such as Qatar or Canada. On the other hand, shipping costs from Dampier, PNG or Gladstone would be at the lower end of costs. It has not been feasible to project a shipping cost for each individual origin. For the purpose of this these calculations, ACIL Allen adopted an average shipping cost of US$0.56/mmbtu ($AU 0.80/GJ).

B.11.2 Regassification costs

ACIL Allen has developed an estimate of regassification costs from estimates of capital and operating costs based on the Australian operating environment. Regassification costs could vary depending on whether the LNG is purchased under a contract or under a spot purchase. In the case of deliveries under contract the regassification cost would include a recovery of capital costs as well as variable costs. In the case of spot purchases, it is possible that the regassification costs would be somewhere between the short run marginal cost (that is variable costs) and full recovery of capital costs a well. It was not possible to predict what approach the regassification operators would take for this exercise. However, the possibility of regassification costs including some recovery of short run marginal costs has been taken into account.

The assumptions for the purpose of this modelling are an allowance of $1.50/GJ for regassification costs in all cases.

B.11.3 Injection price for LNG imports

The injection price for imported LNG into Port Kembla or Geelong is summarised in Table B.7. The Shipping cost for alternative import sites such as Geelong is expected to similar to the quoted value, however the regasification cost may vary depending on the build cost associated with land side terminal works, as well as the final cost or lease arrangement for a prospective FSRU.

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[42] https://www.economyinsights.com/p/the-true-cost-of-moving-lng-across-the-globe

[43] https://sea-distances.org/

Table B.7 Price of LNG injected into ECGM

	2025	2030	2040	2050
	$AU/GJ	$AU/GJ	$AU/GJ	$AU/GJ
Slower Growth				
Asian LNG price	13.99	13.26	14.94	15.09
Shipping costs	0.80	0.80	0.80	0.80
Regassification	1.50	1.50	1.50	1.50
Injection cost	16.29	15.56	17.24	17.39
Step Change				
Asian LNG price	13.99	11.27	10.50	9.99
Shipping costs	0.80	0.80	0.80	0.80
Regassification	1.50	1.50	1.50	1.50
Injection cost	16.29	13.57	12.80	12.29
Accelerated Transition				
Asian LNG price	13.99	10.20	7.39	6.81
Shipping costs	0.80	0.80	0.80	0.80
Regassification	1.50	1.50	1.50	1.50
Injection cost	16.29	12.50	9.69	9.11

Source: ACIL Allen

Note: All costs are in Australian dollars

B.12 Conclusion

The longer-term outlook for LNG prices is now subject to considerable uncertainty, and the range of potential outcomes has widened since the IEA and EIA projections were published. The projections developed for this report provide a range of potential outcomes for the purpose of modelling gas prices in the East Coast Gas Market.