ACIL ALLEN

14 July 2023

Report to Australian Energy Market Operator

Natural gas price forecasts for the Final 2023 IASR and for the 2024 GSOO

Final report

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.

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1.1 Introduction

The Australian Energy Market Operator (AEMO) commissioned ACIL Allen to prepare long term natural gas price forecasts for the Final 2023 Inputs, Assumptions and Scenarios Report (IASR) and for the 2024 GSOO.

The main goal of the work was to provide forecasts of annual gas prices from calendar year 2023 to 2054 for each of the scenarios defined by AEMO for each jurisdiction in the east coast gas market (ECGM) and the Northern Territory. These forecasts represent the marginal prices for new wholesale gas supply, and do not represent the 'average' cost of wholesale gas in the ECGM.

ACIL Allen was also instructed to provide commentary and supporting analysis that made it clear how gas price were expected to trend over the forecast period and the key drivers of price changes across all scenarios that AEMO developed. It was also important for these price forecasts to account for key developments in the market, including the implementation of the Commonwealth Government's wholesale gas price cap.

1.2 The east coast gas market

Figure 1.1 provides a diagrammatic representation of the east coast gas market (including Northern Territory) for which these price forecasts apply. The diagram shows the main current supply sources (conventional and CSG natural gas basins), demand centres and the transmission pipelines that transport gas around eastern Australia.

The ECGM is physically connected across an area from Mount Isa in the north to Hobart in the south, and from Gladstone and Brisbane in the east to Adelaide and Whyalla in the west. The Northern Gas Pipeline (Tennant Creek to Mount Isa) further extends the geographic scope of this interconnected market by tying in the Northern Territory that is a small domestic gas market, but potentially a significant supplier of gas to the eastern states.

There are several indicators that the gas supply system illustrated in Figure 1.1 operates more like a single integrated market than has been the case in the past. The market is now characterised by physical interconnection of the transmission pipeline system, increased levels of interstate gas trade, an increased role for aggregators, correlated price trends in regional short-term trading markets, and the emergence of gas swap arrangements allowing substitution of different sources of gas supply to meet contractual delivery commitments in an efficient manner.

There are now six gas trading markets in operation (Victoria Declared Wholesale Gas Market; Sydney, Adelaide, and Brisbane short-term trading markets; and voluntary trading hubs at Wallumbilla and Moomba). Despite the emergence of these short-term (daily and intra-daily) trading platforms, the ECGM continues to operate primarily based on bilateral contracts, with the spot markets used largely to manage operational and contract imbalances.

Figure 1.1 Diagram of the east coast gas market

Source: Department of Industry, (2015). Gas market report 2015

1.3 Changing dynamics in ECGM pricing

Historically, most of the gas in Australia was bought and sold based on long-term bilateral contracts, typically for terms of 10 to 20 years. Transportation contracts were structured to match these long-term sales contracts and had similar durations. However, there has been a trend toward much shorter term supply in recent years, with many recent gas sales contracts written for periods of less than 5 years (with many of only 1 to 2 years duration). This trend is now beginning to have much more fundamental ramifications for gas prices and how the market evolves and responds to the energy market transition.

With the commissioning of the LNG export projects from 2015, they offered a pathway to international markets where contract prices have traditionally been linked to the price of oil. It has now become commonplace for domestic gas supply contracts to follow movements in international LNG prices. Prevailing international prices are now affecting domestic gas prices through LNG netback prices.

As the demand-supply balance has tightened in recent years and LNG netback pricing has become increasingly important for price setting in the domestic market, forecasting gas prices has become difficult, but is extremely important for investment decisions, particularly as the broader energy market transitions. This is important to ensure investment is still made when necessary and for the gas market to remain reliable and secure.

1.3.1 Government announced price cap

A key change in the gas market pricing landscape has been the implementation of price caps by the Commonwealth Government. The Treasurer and Ministers for Climate Change and Energy and Industry and Science announced actions to limit the impacts of forecast gas price increases on 9 December 2022. The action included the introduction of a temporary price cap of $12/GJ on new domestic wholesale gas contract prices. The temporary cap will expire on 22 December 2023.

On 12 June 2023, the Government announced the final design of a mandatory gas code that is aimed to establish a price anchor through a combination of:

— a price cap to be set at $12/GJ with a review commencing on 1 July 2025

— a process for qualifying for exemptions from the price cap based on making satisfactory ACCC and court enforceable supply commitments to the domestic market

— a provision to allow small gas producers to be exempt from the price cap providing they supply only the domestic market.

The Code will also require all participants to abide by standards of conduct to level the playing field in contract negotiations between users and producers and deliver a better functioning, more competitive gas market.

At the time of writing, drafting of the necessary legislation is underway. The proposed Code's pricing arrangements will apply once the current Temporary Price Order expires on 22 December 2023 and will be reviewed in the second half of 2025.

This cap is now likely to be a central driver of gas price outcomes in the medium term. ACIL Allen has taken account of the operation of the Code and the price cap provisions. We have also taken account of how wholesale prices for different sectors might be affected by these policies.

1.4 Report Structure

This report is structured as follows:

— Chapter 2 sets out ACIL Allen's broader methodology for these price forecasts. This chapter includes a description of our overall approach, our market modelling techniques, and our specific methodology for finalising price forecasts for each of the gas consuming sectors.

— Chapter 3 presents a summary of the scenarios that guide the price forecasts.

— Chapter 4 presents our gas price forecasts for each scenario.

— Chapter 5 summarises our findings and insights.

— Appendix A provided information on ACIL Allen's gas market model, *GasMark.*

Methodology 2

2.1 General approach

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

— a data collection and market analysis phase

— a model preparation phase

— a modelling phase to produce the final forecasts.

These phases are described in more detail in the sections that follow.

2.1.1 Our gas market model - GasMark

First created 25 years ago and extensively developed and enhanced over that period, *GasMark* 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 pipelines or LNG shipping elements.

The equilibrium solution of the model is found using 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** with a maximum time horizon of 30 years. It is therefore a useful tool for looking at the implications of supply & demand variability over long time periods and for forecasting wholesale gas prices.

Although the model results in prices that are economically efficient, the model does take into account the change in pricing dynamics that has resulted from the market becoming internationally linked due to the development of the LNG projects in Queensland. This linkage moved domestic price formation towards LNG netback pricing. This fundamental change in pricing is taken into account in the model. However, the model does not take into account specific contracting arrangements or other aspects of market operations such as the possible influence of market power or vertical integration on pricing. Accordingly, we overlay a further layer of analysis to the results from GasMark to produce the final price forecasts. This is discussed later in this chapter.

2.2 Phase 1: Data collection and market analysis

The first step in the process was to complete a data collection exercise and review of developments in the market. The data collection exercise involved collecting the necessary data and assumptions that are fed into our model to produce the initial forecasts.

The data requirements are required to calibrate the GasMark model to ensure the assumptions and detail on market infrastructure are consistent with the assumptions contained in the Input, Assumptions and Scenarios (IASR) report and the 2023 Gas Statement of Opportunities (GSOO) report.

A supporting piece of work during this phase was reviewing recent developments in the ECGM and the Northern Territory gas market. This ensures that key market developments are fully understood and captured in GasMark.

Some of these key developments include:

— the wholesale gas price caps and the Gas Code of Conduct

— trends in gas market consumption across the ECGM

— developments in international energy markets that influence Brent oil prices and Asian LNG prices

— infrastructure investment in the ECGM

— new gas supply developments

— the potential role of hydrogen and biogas in the future.

2.3 Phase 2: Model preparation

The second phase was conducted in close consultation with AEMO, delivering detailed information to inform ACIL Allen's gas market model.

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 users. As mentioned before, it was important to ensure the model remained consistent with the assumptions provided by AEMO for the various scenarios.

In some cases, our assumptions were simplified to broadly correspond with AEMO's assumptions (e.g., gas field production costs were made consistent across each gas producing basin to align with the approach taken by AEMO).

Specifically, our demand forecasts closely align with forecasts from AEMOs latest market modelling to ensure the price forecasts reflect the assumptions and broad demand scenarios that are defined in the 2023 GSOO. Beyond 2042, ACIL Allen extrapolated AEMO's forecasts through to 2054 (as required by AEMO).

We aligned our gas field supply assumptions with those contained in the 2023 GSOO. In some cases, we may have differing assumptions on new projects and supply quantities from these projects.

Our electricity market model, *PowerMark*, was also used to assist in analysing Gas Fired Power Generation (GPG) gas demand. The model was run to estimate forecast GPG gas consumption by generator, and this was compared as a cross check with AEMO's GPG forecasts. ACIL Allen used AEMO's demand forecasts following discussion of the results to ensure overall gas consumption by the domestic market aligned with AEMO's scenarios.

2.3.1 Data items aligned to AEMO assumptions

ACIL Allen sought AEMO's input and verification on the following model inputs and assumptions to ensure alignment. These included:

- detailed gas demand projections for the three defined scenarios:
  - residential/commercial demand
  - industrial demand
  - gas fired power generation demand (GPG).
- AEMO's gas industry parameter assumptions:
  - cost of production per basin
  - reserve and resource quantities per basin
  - prospective gas supply projects per scenario (i.e., Beetaloo, Narrabri, LNG import).
- gas transmission pipeline developments per scenario
- pipeline tariffs
- global long term oil prices
- government policy (i.e., effect of price cap and mandatory code of conduct).

Assumptions on reserves and resources in the ECGM and the NT were provided by AEMO. ACIL Allen ensured that our GasMark database alignment was achieved for the provided basin metrics:

- 2P reserves
- 2C resources (we did not include prospective resources)
- estimated costs of production.

Reserves and resources contained within the model were aligned to AEMO's figures with a one per cent error tolerance.

2.4 Phase 3: Preparing the forecasts

Following phases 1 and 2, ACIL Allen prepared the forecasts for eastern Australia and for the Northern Territory. The forecasts were generated for residential/commercial, industrial and GPG demand.

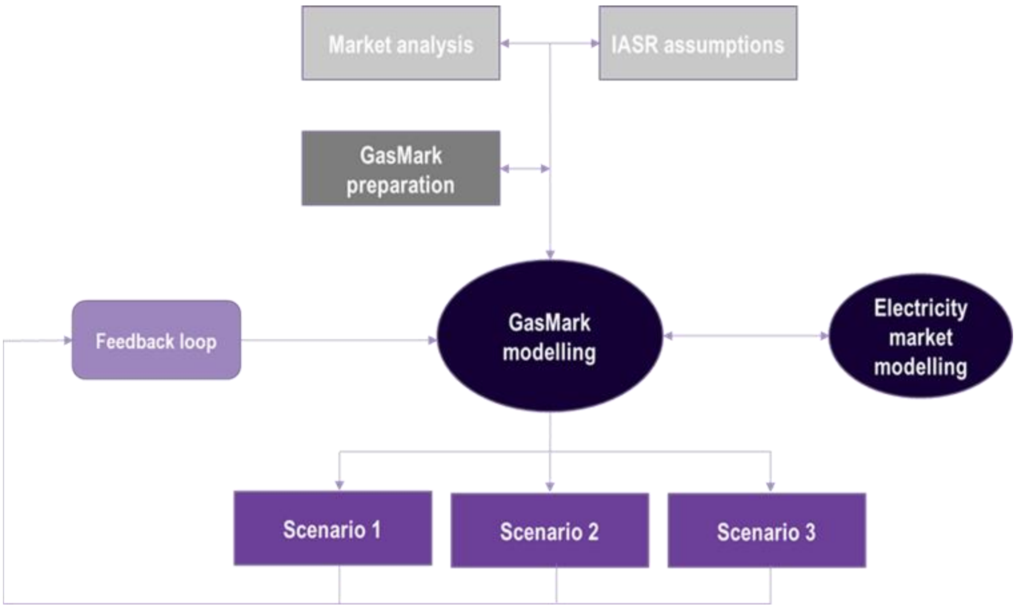
The following forecasts are presented in this report:

- individual gas price forecasts (including transmission and storage) for each existing gas-fired generator within the National Electricity Market (NEM)
- 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 each of the East Coast regions
- annual wholesale contract price gas forecasts (excluding distribution and retail costs) for each region located in the east coast of Australia, and specifically provided for
  - Industrial users consuming above 10 TJ per annum
  - Residential and commercial users.
- annual gas price forecasts for Northern Territory gas-fired generators and for gas consumption in Darwin.

2.5 Modelling framework

Our early phases of analysis which included the data collection exercise and the market analysis task fed into the preparation of our gas market model. We then undertook the forecasts using our GasMark model. Figure 2.1 illustrates this process.

Figure 2.1 Modelling framework for producing our gas price forecasts



Source: ACIL Allen

Our process to produce the final price forecasts was a two-step approach. These steps are illustrated below.

Step 1

The first step in producing the forecasts was to run GasMark and produce underlying forecasts for each major market across the ECGM. Preparation of the assumptions entered into the model was important to confirm and align assumptions with AEMO's modelling processes.

Table 2.1 Modelling components and assumptions

Model component	Key assumptions and data sets
Prices	– Asian contract and spot LNG prices that will affect LNG exports from Gladstone and Darwin – 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 – Broad price tolerances and elasticities for mass market customers, industrial customers, and gas-fired power generators (which we essentially 'turned off' to ensure our modelled consumption aligned with AEMOs forecast demand – Model assumptions to capture the effect of the recently introduced gas price cap on wholesale gas prices
Supply	– Supply field assumptions including 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 – Confirming any specific supply contracts for supply sources with particular demand nodes that is essential for modelling over the long term

Model component	Key assumptions and data sets
	– LNG export project assumptions including capacity profiles, transportation costs, Liquefaction costs, prevailing international market prices – LNG import terminal assumptions including annual delivery capacity, daily injection capacity into the pipeline network and regasification costs
Demand	– Demand assumptions include assumed and projected levels of demand, price tolerances and elasticities and load factor (e.g., relatively flat annual demand for gas or can be variable throughout a year) – Input projected daily demand profiles for individual GPG power stations from AEMO's modelling of the NEM – Confirming 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 – Confirming 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
Timing	– Modelling timeframe – annual average prices from 2023 to 2054 – Monthly pricing in the short term to reflect trends in the spot market

Source: ACIL Allen

GasMark was then run for the three scenarios to produce projected market prices from 2023 to 2054 for the three categories of consumers and for the three scenarios.

Step 2

The underlying forecasts were then subject to a further layer of analysis to include relevant developments and aspects of the market that are not accounted for in the GasMark price. This step is required to ensure the forecasts account appropriately for developments in the market, particularly in relation to the procurement strategies of users. For example, GPG facilities often rely on contract markets for a portion of their supply and then supplement this with spot market purchases. These two different markets are priced differently, and this is especially the case following the introduction of the price cap. This layer of analysis is also important for industrial users who also procure gas in different ways and have different demand characteristics that can influence the price they pay for gas.

The impacts of vertical integration and competition issues are also analysed in this report. Vertical integration has been analysed mainly from the perspective of prices for individual gas generators. The large Gentailers for example, potentially have the capacity to shuffle cheaper portfolio gas to some of their individual generators to minimise the need to source high priced spot market gas. This has been accounted for in our GPG prices.

In relation to competition issues and the potential for market power, we have considered the impact on prices from the perspective of new supply. It is arguably the case that although new supply may potentially help supress prices at some points, it is most likely that new supply entering the market will be priced at levels compared to the 'next best alternative supplier'. For example, in most cases the next best alternative supplier for a gas user in Victoria will be Queensland supply, that would generally be priced off the expected LNG netback price. Therefore, any new supply is likely to be supplied at price points largely influenced by the LNG netback. To account for this, we have 'inflated' new supply costs where appropriate to match the expectation that new supply will be offered closer to LNG netback levels. This is relevant to the period of the late 2020s and early 2030s, and not relevant to any new supply coming on later in the forecast period.

2.6 Residential/commercial and industrial price forecasts

Residential/commercial and industrial gas prices are largely based on outputs from our GasMark model. GasMark contains consumption details for all the key residential and commercial markets in the ECGM. For industrial users, we have details for several large individual industrial users, typically serviced by transmission pipelines in the ECGM, and for smaller industrial users grouped together that are typically serviced through the distribution network.

2.6.1 Residential price forecasts

The key steps for modelling residential and commercial prices were as follows:

- Prepare demand forecasts and align them with AEMO 2023 GSOO forecasts by region
- Finalise all other assumptions and ensure wholesale price cap is operating in the market
- Run GasMark and produce an average annual wholesale price for each region in the ECGM.

A key assumption we make is that all wholesale gas to be delivered to residential and commercial customers is sourced through contracts between retailers and producers. This means that gas being supplied to residential and commercial customers will be subject to the wholesale price cap while the cap is active. While there may be situations where procurement of gas is different for customers, the predominant method is assumed to be through retailers having direct supply contracts with gas producers.

The wholesale price cap is assumed to continue until our model assumes that long run LNG prices influence the LNG netback to fall below the price cap of $12/GJ. At that point, domestic prices are then using the LNG netback as the reference setting price and no longer the wholesale gas price cap. The price cap is operationalised in our model by setting the LNG netback price (measured at Wallumbilla) to not move above $12/GJ.

Currently, the gas price cap is intended to stay operational until 2025 per the most recent announcements by the Commonwealth Government then be subject to a review. This review will determine whether the cap should be extended beyond 2025. Therefore, in our forecasts we have the price cap operational until 2025 and its operation beyond that is subject to trends in the LNG netback price.

No additional load factor adjustment is required given GasMark accounts for the swing in residential/commercial demand throughout a year, for all markets in the ECGM. This is achieved by the model having daily demand profiles for each market based on historical demand. As we assume all residential/commercial demand is from contracted supply, the forecast will not reflect any influence from our spot market series.

2.6.2 Industrial price forecasts

The key steps for modelling industrial prices are as follows:

- Prepare demand forecasts and align with AEMO 2023 GSOO forecasts, per region, in the ECGM
- Ensure wholesale price cap is operating in the market
- **Run 1**: Run GasMark model and produce an average annual wholesale price for each region in the ECGM which is reflective of a contract price (and includes the operation of the price cap)
  - Adjust this price with any adjustment required to account for supply flexibility/load factor that many industrial users require in their gas supply contracts – we will make an assumption on this that will apply for all regions in the ECGM

— **Run 2**: Run GasMark and produce a monthly price series which is more reflective of the spot markets in the ECGM that are not subject to the price cap. This is achieved by removing the price cap and applying the short-term LNG netback as the price influencing mechanism in the market.

— Produce a weighted price that takes into account supply procured through contracts and supply procured through the spot market – based on a 90 per cent/10 per cent split between gas supplied via contracts and spot markets (which we apply to all regions).

We expect that the weighted price will only be applicable in the short to medium term. In the long-term prices will be fundamentally driven by demand and supply, and not by short term factors that spot markets reflect. Therefore, our forecasts long term are more reflective of a long-term contract price and will not reflect a weighted price which accounts for short term factors.

Since the LNG export projects were commissioned, gas pricing and procurement in the ECGM has evolved. Gas prices have increased since these LNG projects were commissioned, and the demand/supply balance has also tightened. The way industrial users procure gas has also changed, and industrial users are now more active in their procurement strategies, with many diversifying their portfolio and tapping into short term markets for supply. However, we have remained conservative and assumed that industrial users source supply from retailers. It is only the very large users that generally have the ability and capacity to manage their supply and trade on the spot market.

We also account for the fact that industrial loads are much flatter than residential loads. Residential customers typically will pay a premium because of the low load factor characteristic of their demand. Industrial users do not require this magnitude of flexibility. The price forecasting for industrial loads takes into account the higher load factor of industrial loads.

2.7 GPG price forecasts

The last consumer segment is GPG. This segment will require ACIL Allen to forecast prices for both existing generators and also new generators that are expected to enter the NEM. ACIL Allen has used AEMO's data on GPG gas demand for this purpose.

Step 1: GPG demand forecasts

The first step for ACIL Allen in forecasting GPG prices was understanding demand for gas from GPG over the forecast period to 2054. ACIL Allen utilised its electricity market model in the first instance to forecast gas-fired generation levels and gas consumption. These outputs (daily gas consumption volumes for each existing and new generator) were then analysed. However, during an initial task of comparing our latest results with AEMO's 2023 GSOO GPG forecasts, we found that there was a difference between our GPG gas consumption figures from the early 2030s compared with all scenarios in the GSOO.

Noting the differences in our forecasts, it made sense from our perspective to use AEMO's forecasts to maintain consistency with AEMO's scenarios on GPG gas consumption in the ECGM. AEMO supplied this data up until the end of 2042.

For the period 2043-2054, we extrapolated AEMO's GSOO forecasts based on GPG modelling done via the 2022 ISP process.

Step 2: Gas market modelling and forecasting

The key steps for modelling GPG gas prices are as follows:

— Prepare demand forecasts (using AEMO's GPG data)

— Ensure wholesale price cap is operating in the market

- **Run 1**: Run GasMark model and produce an average annual wholesale price for each region in the ECGM which is reflective of a contract price and is subject to the price cap.
- **Run 2**: Run GasMark and produce a monthly price series which is more reflective of the spot markets in the ECGM which are not subject to the price cap. As described in the previous section, the short-term LNG netback price becomes the price influencing mechanism in the spot market, and not the price cap.
- Produce a weighted price that takes into account supply procured through contracts and supply procured through the spot market
  - The proportion of supply via contracts and from spot markets is based on the type of generator, the location of the generator, and the expected dispatch profile within a year.

The weighting for each generator is variable, with some generators being highly skewed towards contracted gas supply and other generators (such as stations with Open Cycle Gas Turbines (OCGTs) that act in a ‘peaking’ role) skewed towards the spot market. This analysis is important given current price outcomes in the market and how much we believe generators are paying for gas. Short term prices are also likely to exceed capped prices because of the amount of gas procured from the spot market.

Our assumption is that OCGT’s generally contract 20 per cent of their gas supply and then source 80 per cent of their gas via the spot market, based on their ‘peaking’ role and their low load factor. Some adjustment however is made for OCGTs owned by larger Gentailers, such as AGL or Origin, that are vertically integrated, and have portfolios of supply that could result in less reliance on the spot market. On the other hand, Combined Cycle Gas Turbines (CCGTs) exhibit the opposite assumption with 80 per cent of supply being contracted and 20 per cent purchased from the spot market. This split we expect better reflects their role in the market.

As we mentioned with respect to industrial prices, prices paid for gas by generators will reflect a long-term price arrived at by balancing demand and supply fundamentals, and not short-term factors. Therefore, we believe that future prices paid by generators will reflect prices driven by market fundamentals as produced by GasMark.

Additionally, a premium has been added to the price OCGTs pay in the long term, to account for the additional costs they typically pay to source high volumes of gas at short notice. This is typically related to costs related to reserving pipeline capacity or the costs of storage.

For generators in the Northern Territory, we use AEMO’s GPG forecasts of gas demand to forecast prices.

3 Scenarios

3.1 Modelled Scenarios

Considering the uncertainties in the rate at which energy markets decarbonise and the resulting effects on gas sector transformation, AEMO uses scenarios and sensitivities to explore the needs of gas consumers and the adequacy of gas infrastructure to meet those needs. ACIL Allen aligned our assumptions with AEMO's scenarios to produce price forecasts consistent with the market playing out in line with these scenarios.

Definitions for AEMO's scenarios used in this analysis to forecast prices are summarised below from AEMO's 2023 GSOO report[1].

— **Green Energy Exports** reflects very strong decarbonisation activities domestically and globally, resulting in rapid transformation of Australia's energy sectors, including greater development of alternative energy sources domestically, particularly green hydrogen.

— **Step Change** is most similar to the 2022 ISP's Step Change scenario studied in the 2022 GSOO and continues to be used as the most likely scenario based on the 2022 ISP. It applies the net zero emission commitments of the Climate Change Act (2022), contributing towards energy-sector transformation and assumes global momentum towards decarbonisation. In this scenario, consumers embrace opportunities to reduce emissions through electrification across all sectors where technically practical, as well as investing in energy efficiency at a greater scale than in other scenarios.

— **Progressive Change** includes lower assumed forecast economic growth than historical trends. It follows a slower global recovery from the COVID-19 pandemic and ongoing disruptions affecting the international energy markets and associated supply chains, which affect energy consumers' actions to decarbonise the economy. This scenario is most similar to the 2022 ISP's Slow Change scenario that did not feature in the 2022 GSOO. This scenario anticipates slow economic growth and a challenging economic environment affecting energy consumers' actions to decarbonise the economy, including the greatest industrial closure risks. As such, this scenario is materially different to the 2022 GSOO Progressive Change scenario.

The scenarios apply alternative assumptions regarding the various dimensions and drivers affecting gas demand, particularly regarding traditional drivers of gas consumption (such as economic and population growth), the degree of electrification of existing gas demand, uptake of energy efficiency measures, biomethane demand, hydrogen demand, and the technology used to produce hydrogen[2].

[1] AEMO: 2023 Gas Statement of Opportunities Report, March 2023.

[2] AEMO: 2023 Gas Statement of Opportunities Report, March 2023.

As we use AEMO's overall demand forecasts, the drivers above of changing demand are accounted for in our modelling exercise. In addition to the demand side it is also necessary to consider what is possible from the supply side. New projects will be required to meet future demand. However, development in reserves and resources will also depend on economic conditions and future expectations of gas market demand.

In Table **3.1** we have summarised the key drivers which underpin our modelling of how prices might trend. We align with AEMO as closely as possible.

Table 3.1 Scenario assumptions

Assumption	Green Energy Exports	Step Change	Progressive Change
Demand	Green Energy Exports scenario demand from 2023 GSOO	Step Change scenario demand from 2023 GSOO	Progressive Change scenario demand from 2023 GSOO
Reserves and resources	2P reserves + 2C resources	2P reserves + 2C resources	2P reserves + 2C resources
Production costs	Aligned with 2023 GSOO costs	Aligned with 2023 GSOO costs	Aligned with 2023 GSOO costs
New gas supply projects (NSW)	No Narrabri	Narrabri proceeds	Narrabri proceeds
New gas supply projects (VIC)	**Gippsland** - GBJV expansion (Kipper) **Otway** - Enterprise from 2024 and Thylacine in 2023 **Bass** - No further development	**Gippsland** - GBJV expansion (Kipper, Turrum); Manta and Longtom are developed **Otway** - Enterprise in 2024 and Thylacine from 2023 **Bass** - Trefoil is developed	**Gippsland** - GBJV expansion (Kipper, Turrum); Manta and Longtom are developed **Otway** - Enterprise in 2024 and Thylacine from 2023 **Bass** - Trefoil is developed
New gas supply projects (QLD)	**Surat Basin** – projects related to the LNG proponents are progressed in alignment with reserves and resources development	**Bowen Basin** – Mahalo project (Santos) **Surat Basin** – Senex Atlas expansion; projects related to the LNG proponents are progressed in alignment with reserves and resources development	**Bowen Basin** – Mahalo project and expansion of Moranbah Gas Project **Surat Basin** – Senex Atlas expansion; projects related to the LNG proponents are progressed in alignment with reserves and resources development
New gas supply projects (SA)	No new projects	No new projects	No new projects
New gas supply projects (NT)	Beetaloo – long term supply capacity of 20 PJ for ECGM	Beetaloo – long term supply capacity of 50 PJ for ECGM	Beetaloo – long term supply capacity of 100 PJ for ECGM
New storage	No new storage	Golden Beach storage project developed	Golden Beach storage project developed
Pipeline development (greenfield/brownfield)	According to 2023 GSOO	According to 2023 GSOO	Additional long term expansion of Carpentaria Pipeline, SWQP and MSP
Pipeline tariffs	According to 2023 GSOO	According to 2023 GSOO	According to 2023 GSOO
Global long term oil price	Long term US$45 per barrel	Long term US$65 per barrel	Long term US$85 per barrel
Queensland LNG exports	Green Energy Exports scenario demand	Step Change scenario demand	Progressive Change scenario demand
LNG import terminals	No LNG import terminals	Port Kembla online from 2028	Port Kemba online from 2026

Source: ACIL Allen

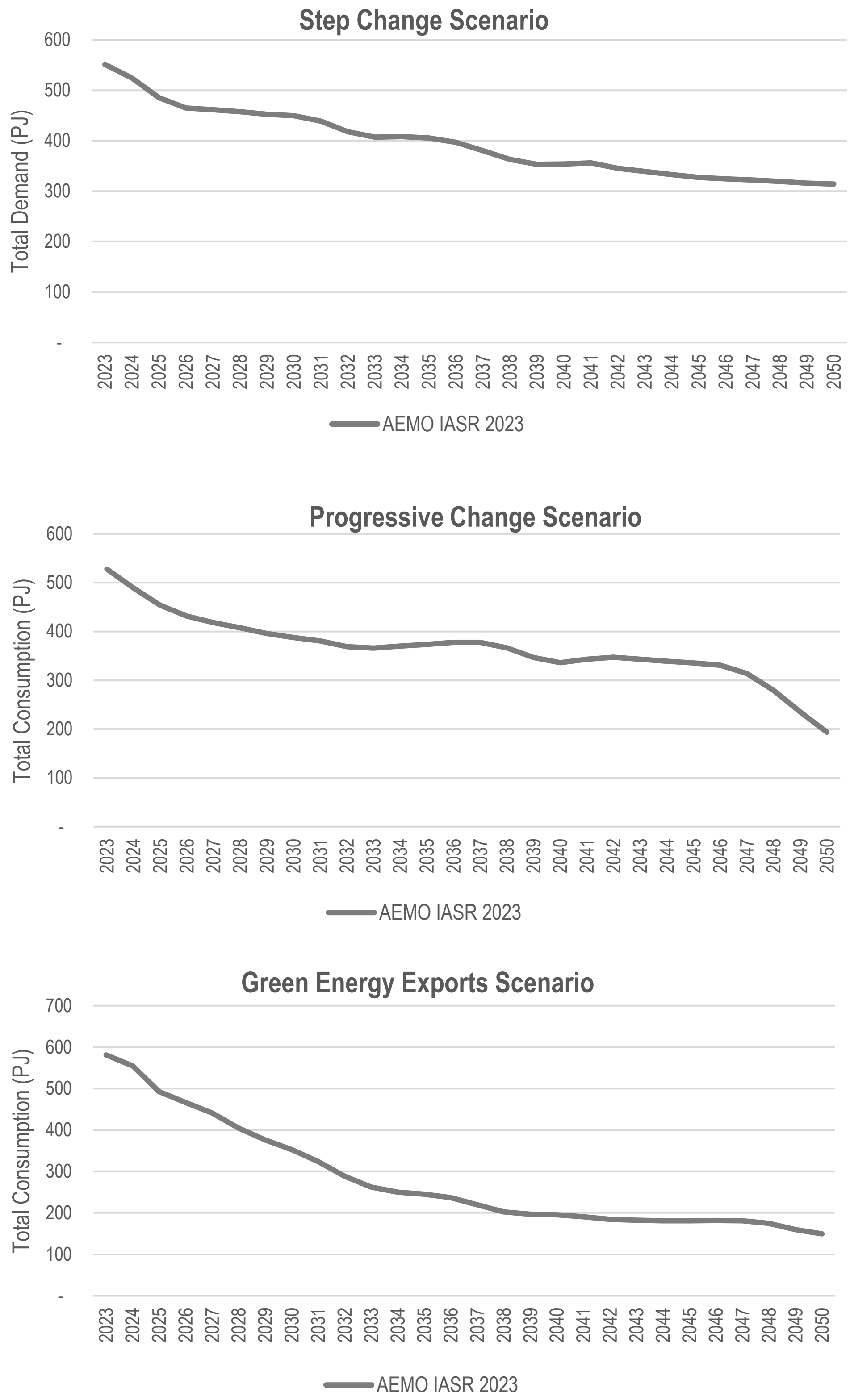
Although we have specific projects coming online in each of the scenarios, the total levels of reserves and resources are aligned with AEMO's assumptions. Therefore, the supply entering the market in our modelling is more about the composition of supply, and not the total level of resources or reserves differing.

3.2 Key assumptions

3.2.1 Assumptions for gas demand by GPG

The gas demand forecasts for GPG for the three scenarios were based on data provided by AEMO as shown in Figure 3.1.

Figure 3.1 GasMark Demand Alignment per Scenario

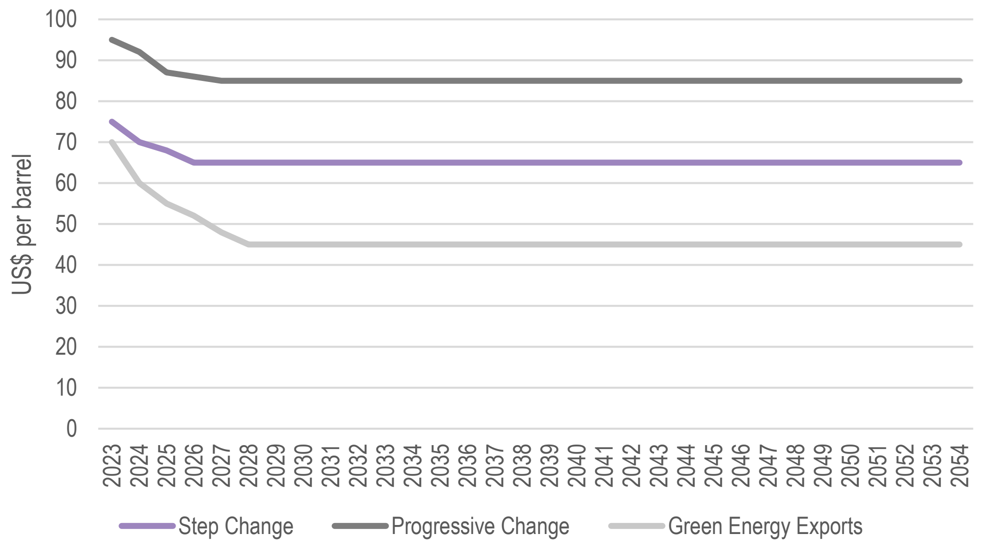


To align demand throughout the forecast period, our model has not assessed the demand impact from changing prices. If this were tested in our model, there would likely be a demand response as prices change. However, this would likely be minimal.

3.2.2 Oil price assumptions

Our oil price assumptions are illustrated in Figure 3.2. These assumptions are important in the modelling as they determine LNG export and import prices. They then also have an impact on the LNG netback price which is fundamentally important in price formation in the domestic east coast gas market. Our oil price assumptions have been based off various forecasts for oil prices. We have essentially attempted to assume an oil price for each scenario which broadly aligns with how various forecasters expect oil to trend. Agencies and organisations which we reviewed include the International Energy Agency, the World Bank, the International Monetary Fund, the United States Energy Information Agency, The OECD and others.

Figure 3.2 Oil price assumptions per scenario



Source: ACIL Allen

Based on the oil price assumptions above, ACIL Allen has calculated the expected long run average LNG price for each scenario:

— Step Change: A long run average LNG price of $11.00/GJ

— Progressive Change: A long run average LNG price of $12.50/GJ

— Green Energy Exports: A long run average LNG price of $9.00/GJ.

These LNG prices are important in our modelling framework as they reflect the price which helps set the LNG netback price in the ECGM, which has been increasingly important in how prices are set for domestic contracts in recent years.

3.2.3 Reserves and resources

ACIL Allen has aligned our reserves and resources by basin with AEMO's data used for the 2023 GSOO report. The underlying data was produced by Rystad Energy for AEMO's 2023 GSOO report and reports reserves and resources as of December 2022. The level of reserves and resources are the same for each scenario.

Table 3.2 Reserves and resources by basin (in PJ)

Basin	2P reserves	2C resources
Amadeus	134	348
Bass	30	147
Bonaparte	4,595	11,088
Bowen/Surat	24,564	39,662
Clarence-Moreton	3,309	5,631
Cooper/Eromanga	1,287	6,019
Galilee-Drummond	-	73
Beetaloo/Georgina	26	32,447
Gippsland	2,085	2,027
Otway	720	876
Total	**36,757**	**98,338**

Source: AEMO, 2023 Reserve Cost Assumptions workbook to support 2023 GSOO report

Gas price forecasts 4

This chapter presents our price forecasts for all customer segments in each of the three modelled scenarios. **All prices are presented in real 2023 dollars**.

4.1 Residential and commercial markets

Residential/commercial gas prices are largely based on the 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 average annual wholesale prices for each region in the ECGM.

In the short term, residential and commercial prices are expected to remain largely influenced by the price cap over the next two to three years, before declining in line with international LNG prices. By 2025, the LNG netback price is forecast to move below the price cap. The Code is expected to be reviewed in 2025 and we have assumed that the price cap will be removed at this point. Price formation from 2026 is then based off the LNG netback pricing mechanism, which was the price setting mechanism until the price cap was introduced.

We also assume that supply for this market is 100% contracted. Therefore, prices for residential and commercial users are based on gas supply agreements between gas retailers and gas producers, that are subject to the price cap up until 2025.

The contract component of these price forecasts represents 'new contract' prices and reflects the cost of purchasing gas from the market from 2023 to 2054. They do not reflect 'average contract' prices which would include the prices of some existing contracts that are likely to have been struck prior to the introduction of the cap.

4.1.1 Step Change results

The forecasts under the Step Change scenario place prices in the 'middle of the pack' compared to other scenarios – Progressive Change and the Green Energy Exports scenarios. This is mainly attributed to forecast demand declining over time in a measured way, plus mid-range international LNG price and supply assumptions.

Wholesale prices in the short term are influenced largely by the price cap and are expected to range between $12/GJ and $15/GJ until 2025. From 2026, our forecasts suggest prices will decline to levels averaging $9 to $10/GJ by the late 2020s.

This is primarily a result of declining international LNG prices. The level to which prices fall in each scenario over the decade, is largely due to the assumption of how far international LNG prices fall, which, in turn, determines the LNG netback price in the ECGM. For the Step Change scenario, we assume that the Brent crude oil price to average US$65/barrel (Brent being the key benchmark used to determine Asian LNG contract prices).

Prices are then expected to begin increasing, by a rate largely determined by the long term demand/supply balance, rising costs of production and our assumptions on long term international LNG prices. In the case of the Step Change scenario, this increase is relatively consistent, with most regions' prices peaking at around $12/GJ towards the end of the projection period.

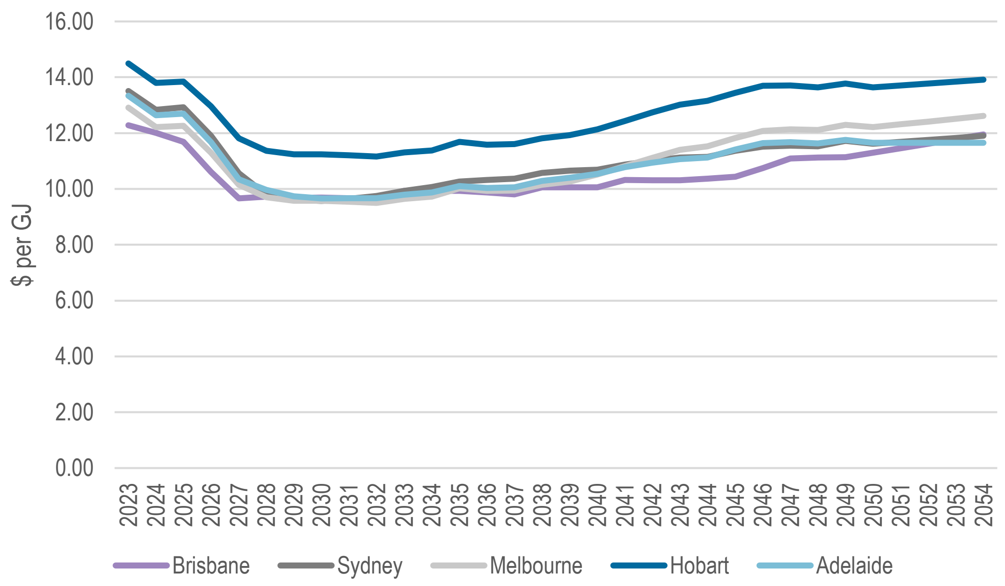
It is important to note that we anticipate several new sources of supply enter the market under this scenario from the late 2020s onwards. These sources of supply include:

— LNG imports at Port Kembla
— the Narrabri Gas Project
— offshore Victorian supply projects
— some supply from the Beetaloo Basin from the 2030s.

Together with declining demand as forecast by AEMO (by the mid-2030s, 150 PJ of domestic demand is projected to be lost from the market), wholesale prices average between $10 and $12/GJ over the long term (excluding Hobart which averages between $12 to 14/GJ). In the long run, prices in Melbourne are the highest after Hobart as a result of weak southern supply development and reliance on more northern gas to meet demand.

Most markets are forecast to face similar prices. The notable exception is Tasmania. Prices in Tasmania are generally more expensive given the additional transport costs to transport gas from the mainland to markets throughout the Tasmanian network.

Figure 4.1 Residential/Commercial Prices: Step Change Scenario



4.1.2 Progressive Change results

Under the Progressive Change scenario prices follow a similar trajectory to the Step Change scenario in the short to medium term. This is largely due to similar supply and demand profiles over this period. In the longer term, the two scenarios begin to diverge with respect to demand and higher LNG price assumptions in the Progressive Change scenario. Demand for gas, particularly from GPG, is forecast to remain higher in the Progressive Change scenario with significant additions of GPG capacity to the National Electricity Market in the long term.

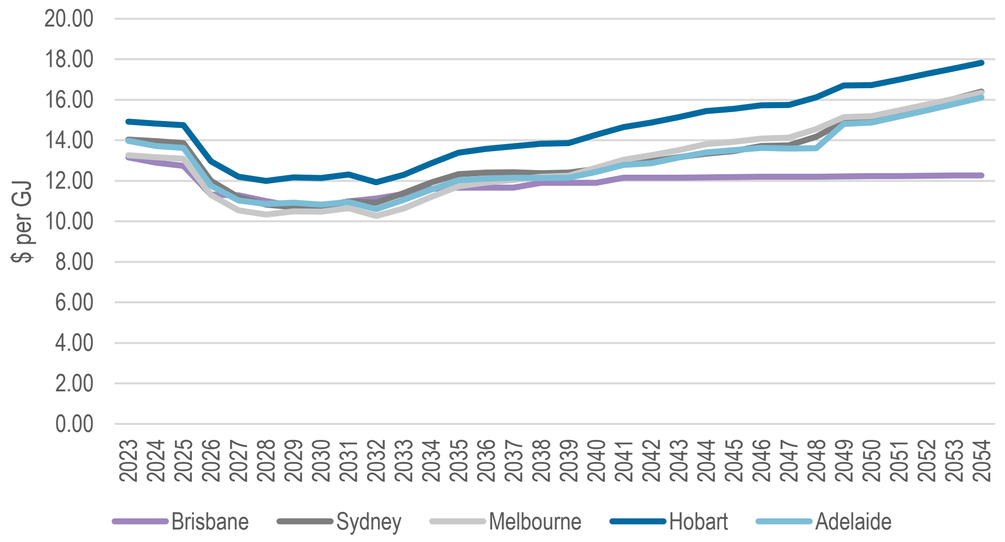
The additional GPG capacity affects the southern markets the most (notably Victoria). This, together with stronger seasonal residential demand, places considerable pressure on the seasonal swing suppliers (southern production swing and storage) to meet demand. The result is higher prices in the long term in response to this increase in demand.

LNG demand under the Progressive Change scenario assumes that the LNG facilities run at high-capacity factors throughout the projection period, instead of starting to roll off in the late 2030s as is the case under the Step Change scenario. This places further pressure on southern production and LNG imports, contributing to this late price rise.

It is noted that the Brisbane market is largely exempt from this price rise. This is because QLD markets are generally self-sufficient for supply, and do not face physical constraints in delivering supply to markets around the state. This contrasts with the capacity constraints that we expect to see on pipelines such as the South-West Queensland Pipeline and Moomba to Sydney Pipeline, that deliver gas from Queensland to southern markets. These pipelines experience considerable southern flows that increase as we move through the forecast period. This results in capacity constraints over time, which affects southern markets significantly in the 2040s.

The LNG price is also assumed to be higher under this scenario, with the assumed long run oil price averaging US$85/barrel. This equates to an LNG netback of around $12.50/GJ in the long term.

Figure 4.2 Residential/Commercial Prices: Progressive Change Scenario



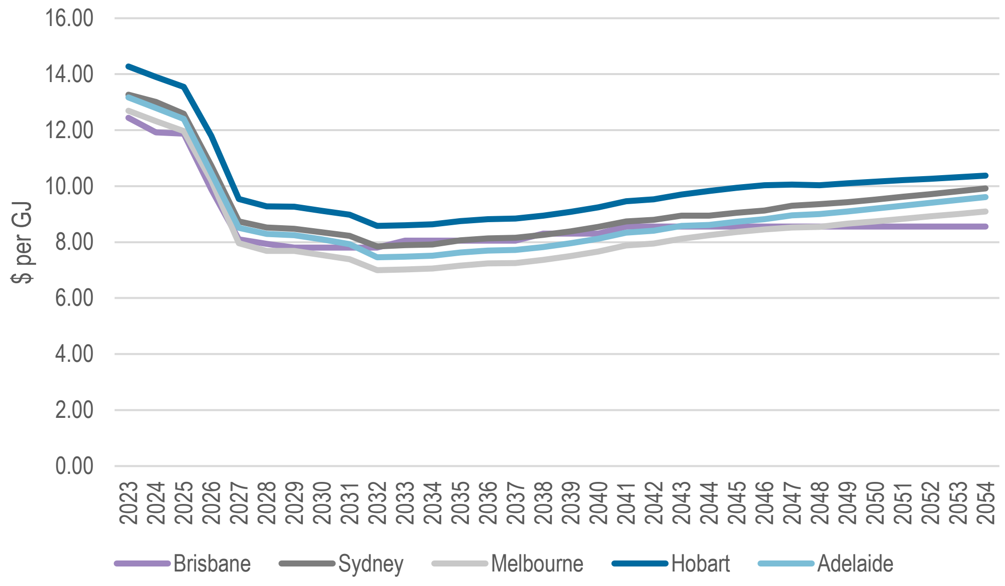
4.1.3 Green Energy Exports scenario results

Under the Green Energy Exports scenario, the prices in the near-term follow a similar trajectory to other scenarios. However, for a number of reasons, prices remain relatively subdued and only marginally increase over the rest of the forecast period.

This medium to long term outlook is characterised by low LNG prices (based on a long term average oil price of US$45 per barrel), low long term LNG Demand, and much lower domestic demand. Domestic demand in particular falls significantly compared to the other scenarios as the energy market moves away from gas at a faster pace. For example, domestic demand in this scenario is approximately one third of current levels by 2040 (representing a reduction in demand of nearly 400 PJ).

These factors (especially the large reduction in domestic demand) lead to surplus supply conditions, supressing price rises in all sectors. The lower demand also removes the need for suppliers to develop higher cost fields, which also helps to subdue prices.

Figure 4.3 Residential/Commercial Prices: Green Energy Exports Scenario



4.2 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.

As in the residential/commercial market, prices are expected to remain relatively steady until global LNG prices begin to fall, and the price cap is removed in 2025. Prices bottom out as LNG prices fall, then gradually climb back in line with pressures from the demand/supply balance and increasing costs of production.

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.

4.2.1 Step Change Results

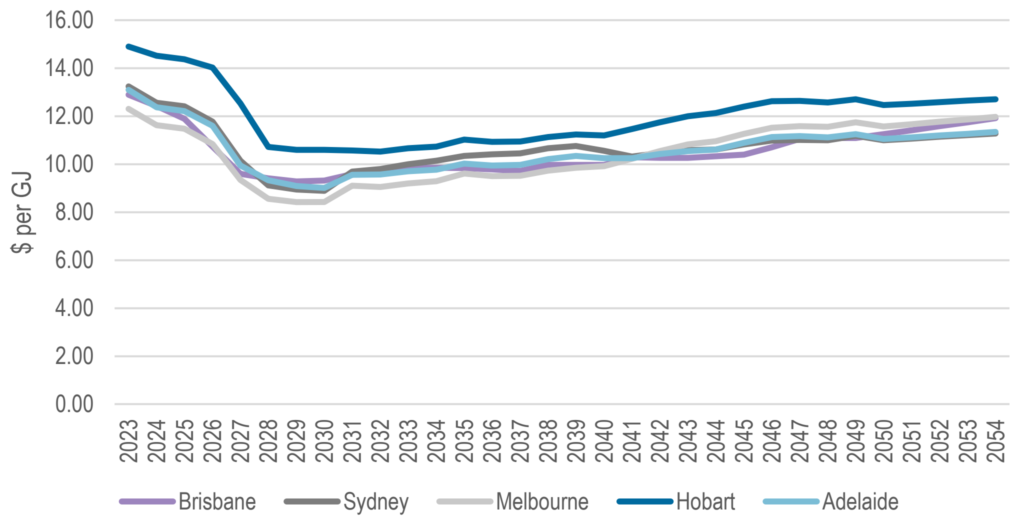
Under the Step Change scenario, industrial prices follow a familiar trajectory to the residential/commercial price forecasts in most jurisdictions. Melbourne prices bottom out lower than other cities as a result of faster rates of declining industrial demand and as a result of our treatment of load factor/seasonality in price formation for industrial users.

Our forecasting methodology for industrial users focuses on removing much of the seasonal impact on prices due to fluctuating residential and GPG demand throughout a year. As industrial demand is generally much flatter than residential or GPG demand, industrial customers typically pay lower prices for supply than retailers who pay a premium so suppliers can 'shape' their supply to meet retailers' needs. Industrial users also rarely need to use storage facilities, unlike retailers, who utilise these facilities at a cost to help meet seasonal demand. Therefore, for more seasonal markets, the impact on industrial prices is more significant given a larger seasonal cost component is removed.

On the other hand, prices for industrial users in Brisbane for example are similar to the prices for residential and commercial users as they have similar demand profiles throughout each year.

Over the long term, the shape in prices for industrial users in all markets is much the same as forecasts for the residential and commercial market. In the long run the projections show that Melbourne experiences the highest prices after Hobart due to weak southern supply and increasing reliance (and cost) on northern supply to meet demand.

Figure 4.4 Industrial Prices: Step Change Scenario

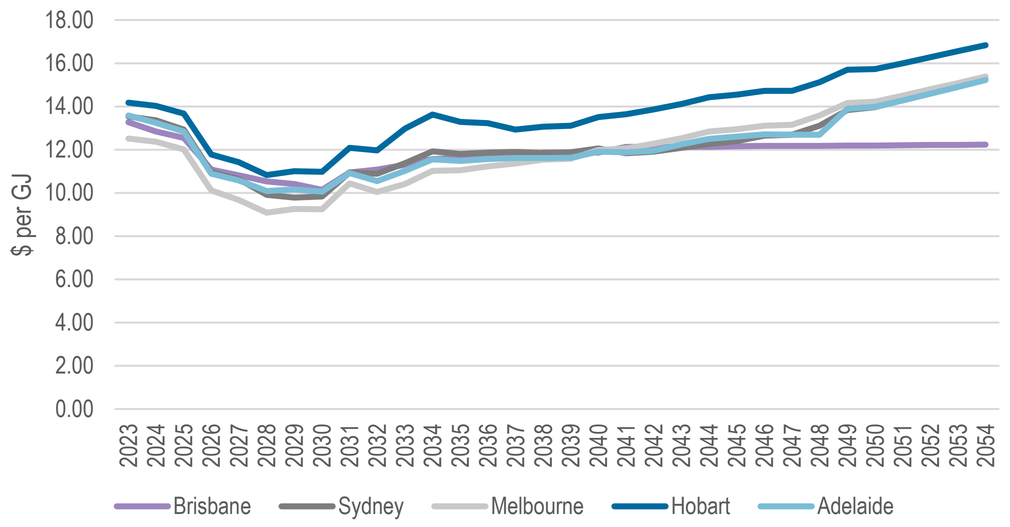


4.2.2 Progressive Change Results

Under the Progressive Change scenario, supply fields find it more difficult to meet demand in the long run, which means prices escalate at a faster rate than in the other scenarios, particularly in relation to southern states. This was seen in residential/commercial segment as the prices for northern and southern markets begin to diverge in the late 2030s.

While industrial users are generally quite well insulated from winter prices, this scenario sees gas markets tightening to a point where industrial users become exposed to pipeline constraints and the additional cost of much longer gas transmission distances associated with sourcing northern gas. A divergence between northern and southern markets is also observed. However, this occurs later than in the residential/commercial markets.

Figure 4.5 Industrial Prices: Progressive Change Scenario

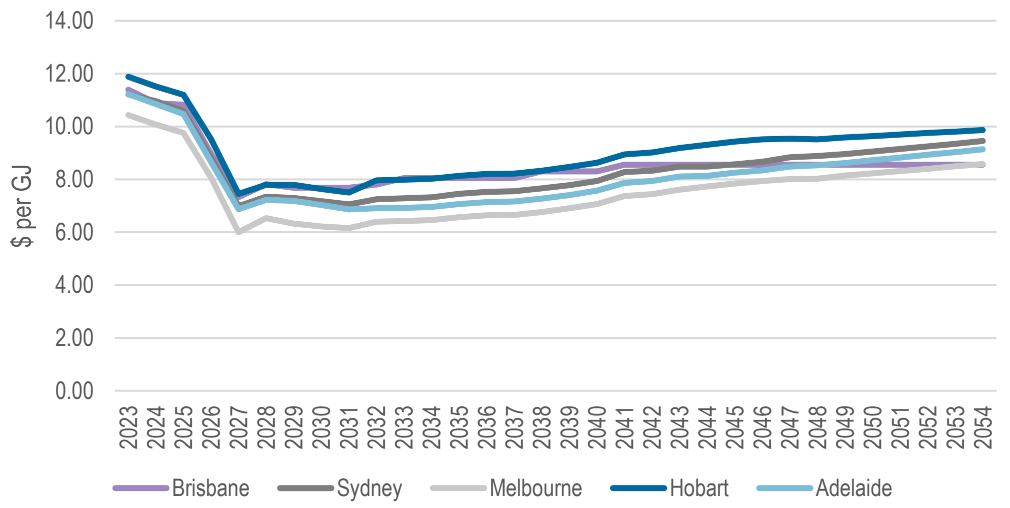


4.2.3 Green Energy Exports scenario results

Industrial prices under the Green Energy Exports scenario follow a similar pattern as in the residential/commercial market, with the impact of the reduced seasonality observed here as well.

Industrial prices fall to noticeably lower levels than in the other scenarios. Prices are sustained at much lower prices due to much higher rates of gas substitution and lower LNG netback prices. Melbourne prices are forecast to fall lower than other markets as industrial demand falls the furthest of all markets.

Figure 4.6 Industrial Prices: Green Energy Exports Scenario



4.3 GPG price projections for the ECGM

GPG demand relies on the interplay between the gas and electricity markets, and the associated assumptions for both. ACIL Allen initially undertook our own GPG demand projections for these price forecasts. However, early data indicated a divergence between ACIL Allen consumption and data provided by AEMO. As such, GPG consumption data provided by AEMO was used in each scenario of these forecasts for consistency.

For the period 2043-2054, AEMO's GSOO forecasts have been extrapolated based on GPG modelling undertaken via the 2022 ISP process. The extrapolation was made in consultation with AEMO with demand forecasts agreed upon before proceeding to modelling.

As in the industrial component, two runs were performed to generate the annual wholesale price reflecting gas purchased under contract and gas purchased from the spot market. A weighting was then 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 verses CCGT), location of the generator, and the expected dispatch profile within a year.

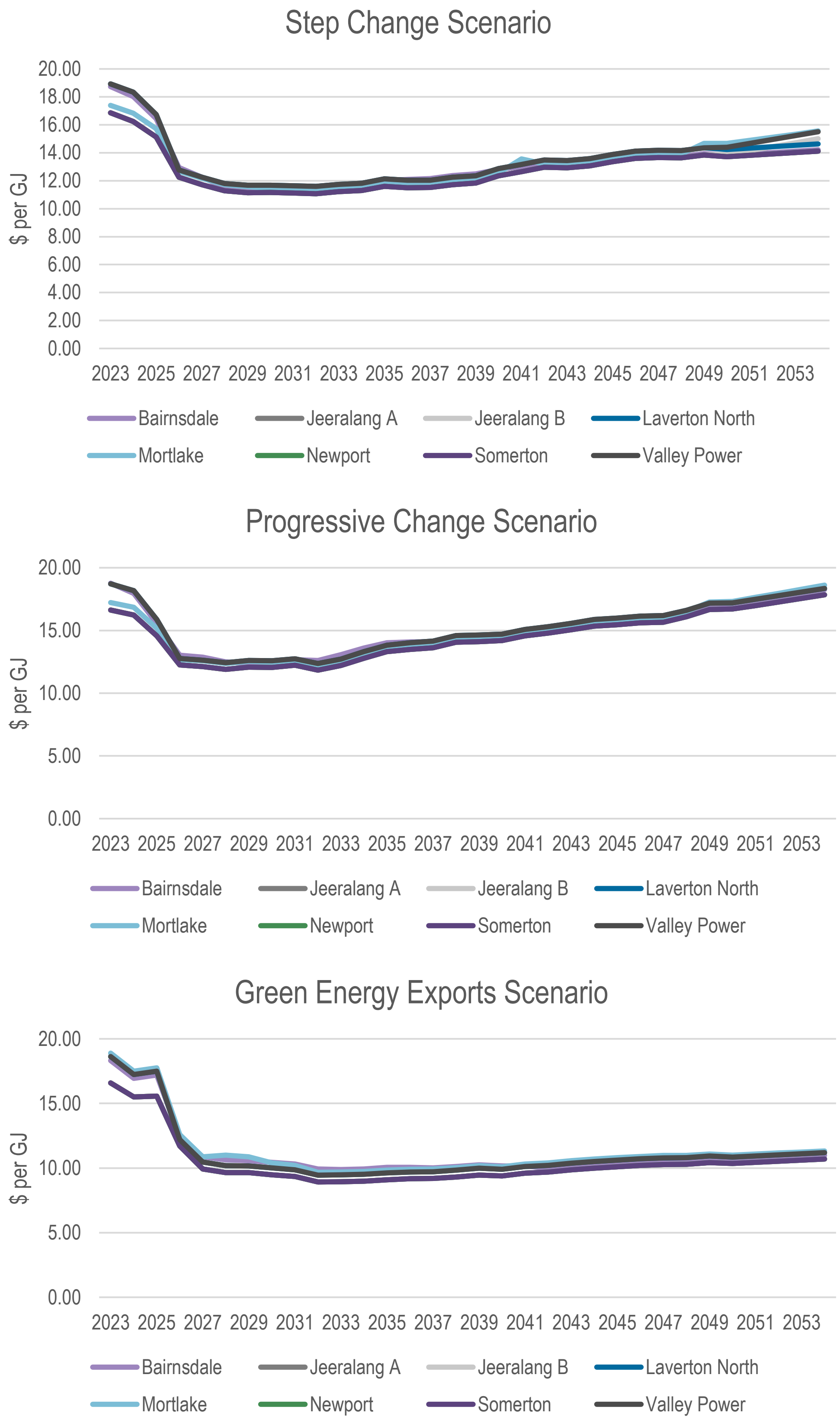
As we mentioned in respect to industrial prices, in the long-term gas prices for generators will reflect long-term demand and supply fundamentals rather than short-term factors. Therefore, forecast prices in the long-term will be more reflective of contract prices.

A premium has been added to the price OCGTs pay for gas in the longer 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.

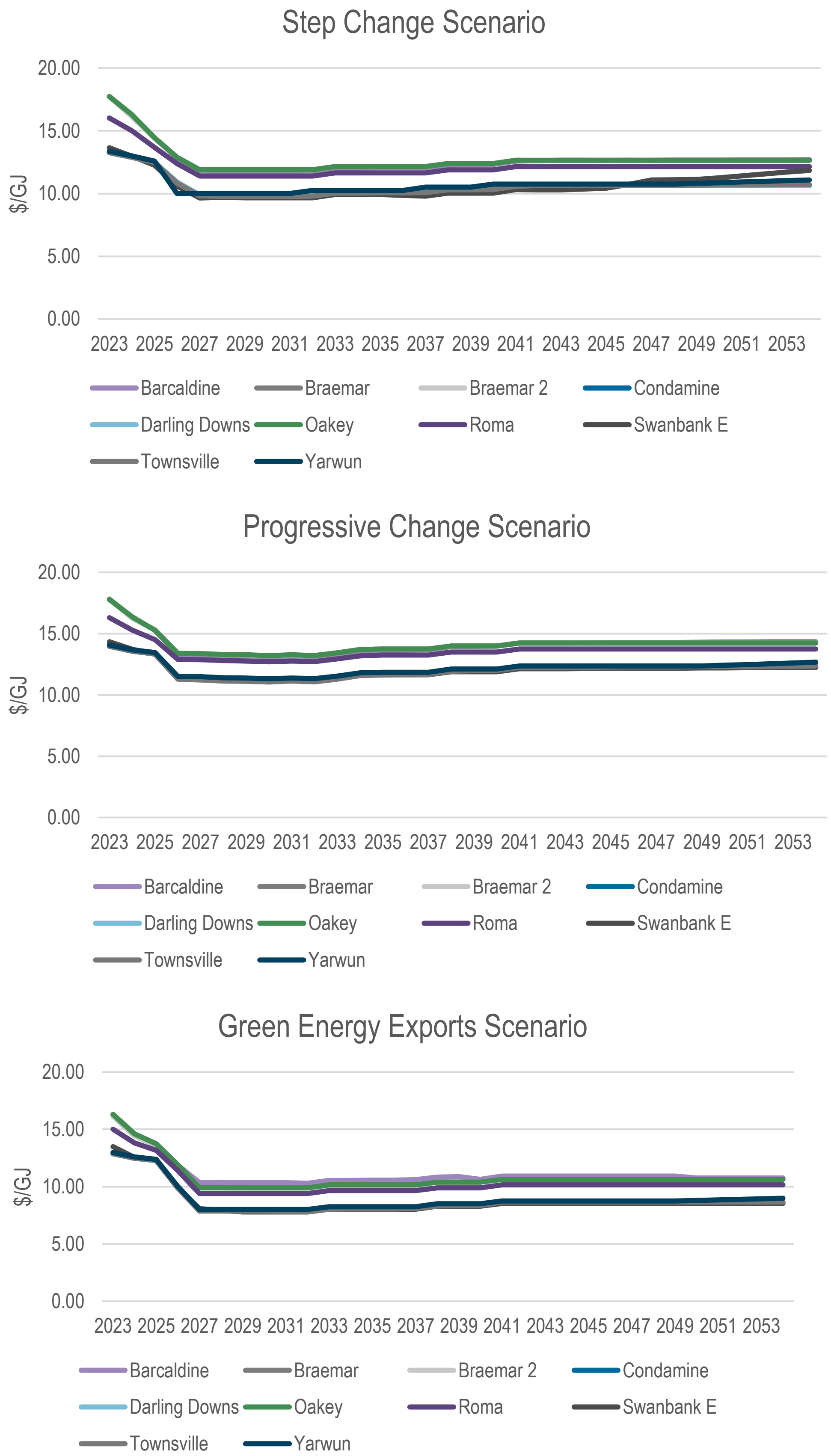
4.3.1 Victorian GPG results

Figure 4.7 Victorian GPG price results



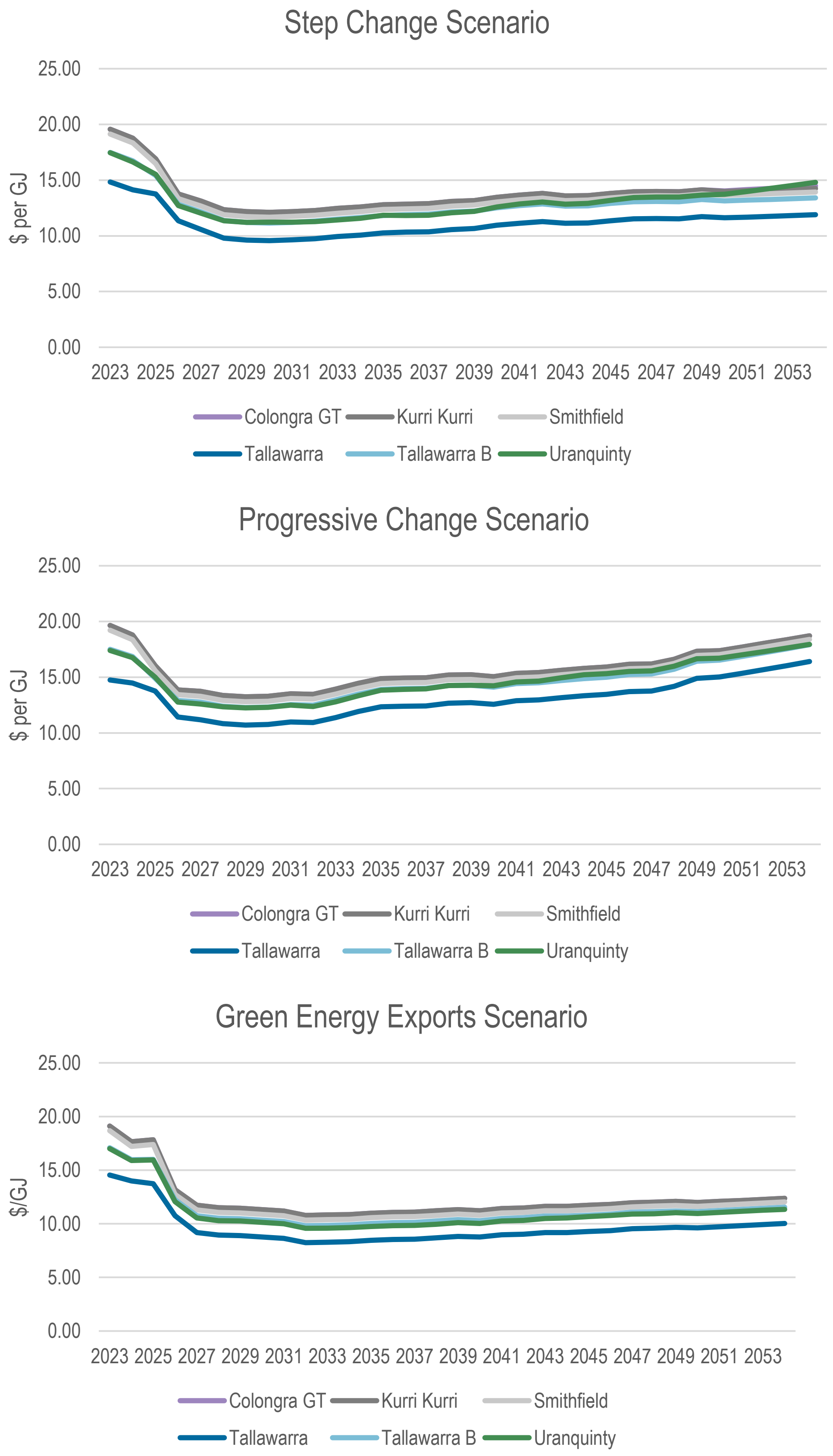
4.3.2 Queensland GPG results

Figure 4.8 Queensland GPG prices



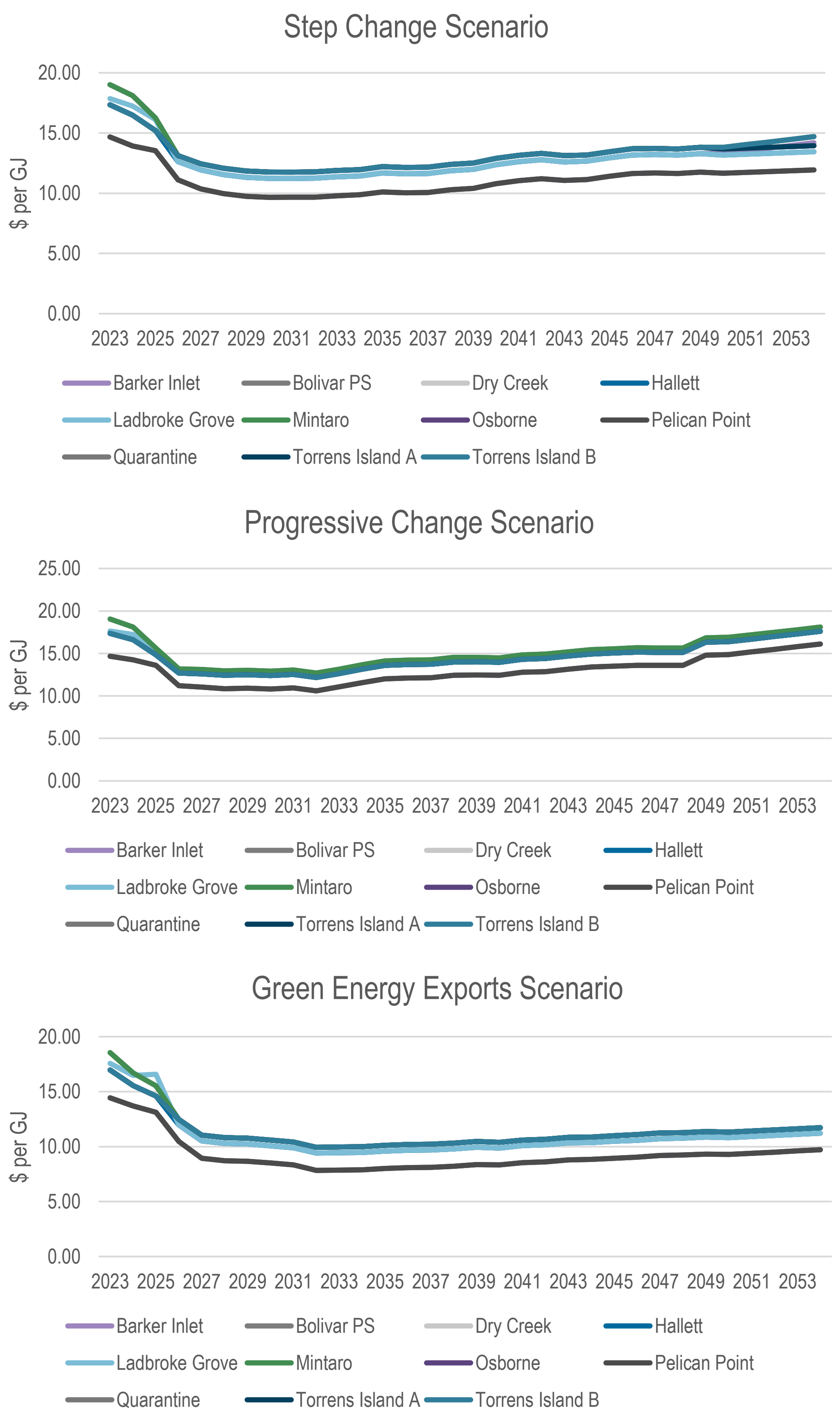
4.3.3 New South Wales GPG results

Figure 4.9 New South Wales GPG prices



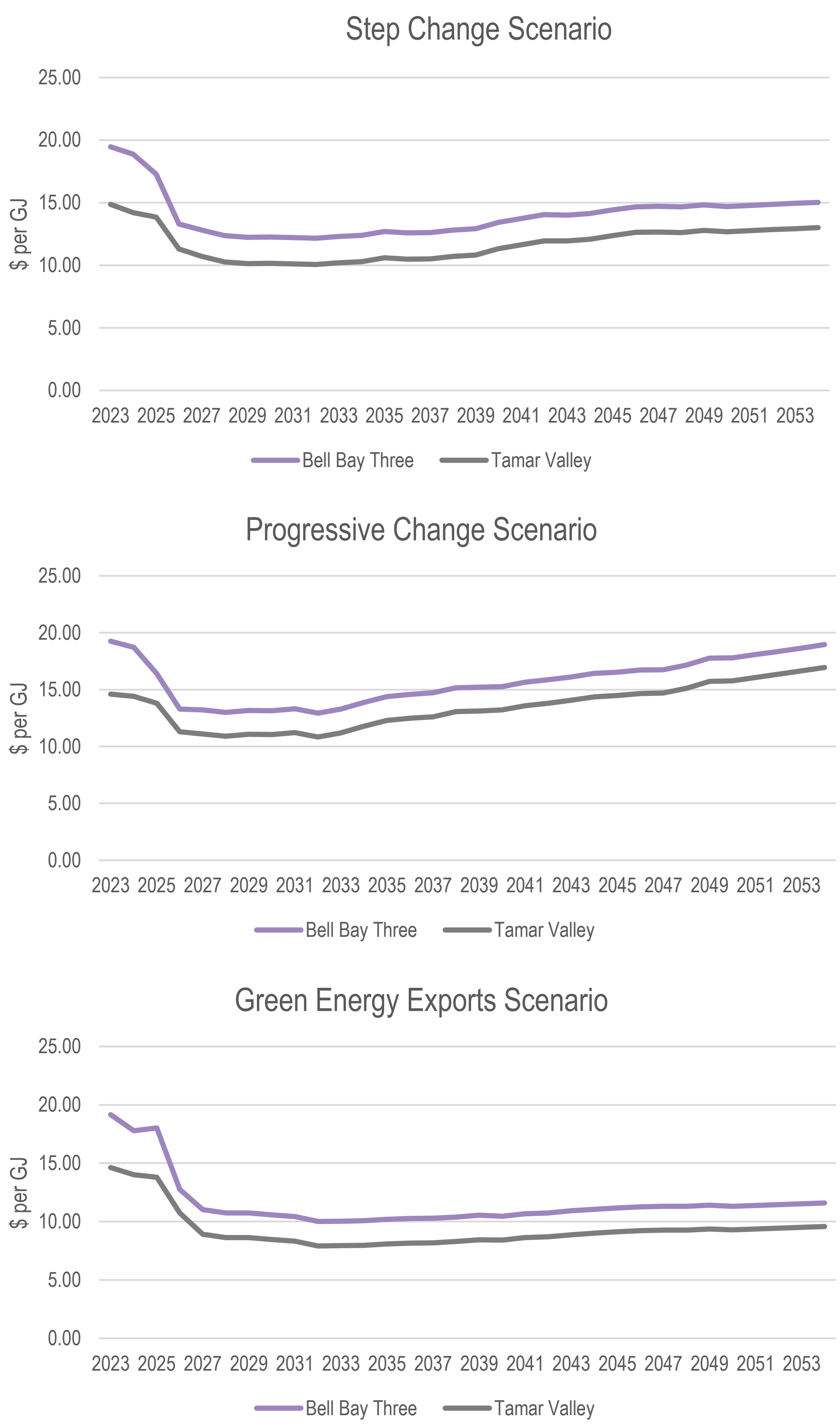
4.3.4 South Australia GPG results

Figure 4.10 South Australian GPG prices



4.3.5 Tasmanian GPG results

Figure 4.11 Tasmanian GPG prices

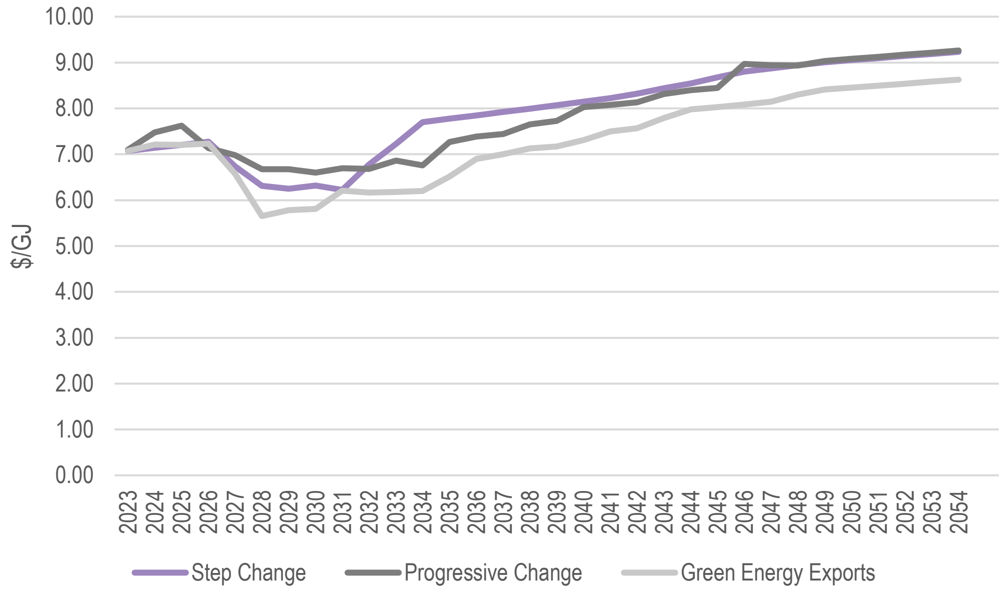


4.4 Northern Territory results

4.4.1 Darwin gas prices

Figure **4.12** below presents our forecasts for gas prices in Darwin. This price applies for any consumption of natural gas outside of GPG. It is our understanding that gas consumption outside of GPG is relatively minor in the Northern Territory. The fall in forecast prices in the late 2020s is largely attributable to our assumptions on the development of the Beetaloo project.

Figure 4.12 Darwin gas prices



4.4.2 Northern Territory GPG prices

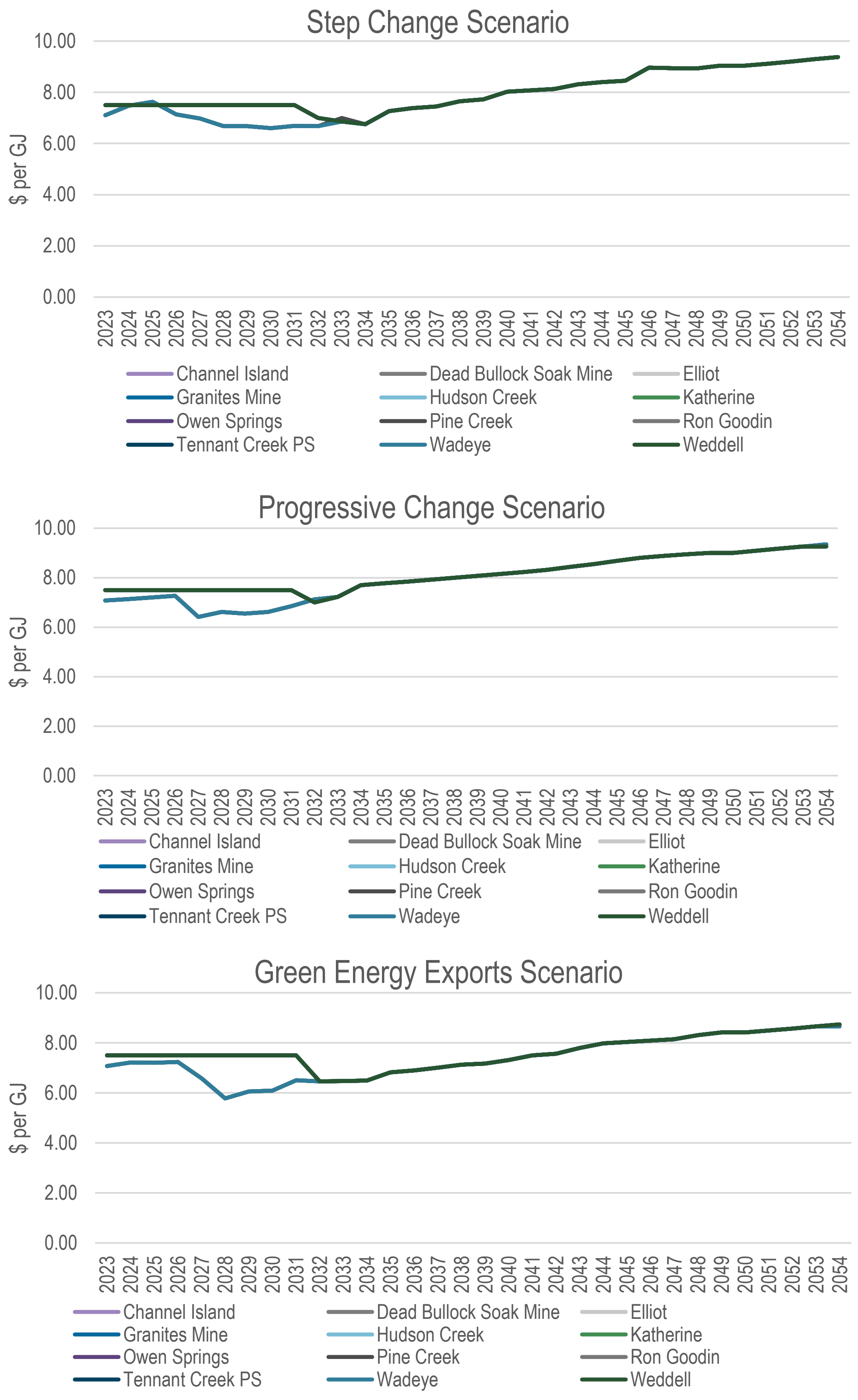
Our forecasts for Northern Territory generators are largely based on the assumption that some generators (those owned by Territory Generation) are currently purchasing gas under long term contracts that are estimated to expire towards the end of this decade. Our methodology has therefore been based on our estimate of the price in these contracts up to 2030, and then estimating prices beyond 2030 using our GasMark model.

For non-Territory Generation generators, we use the price forecast from our model to indicate what they could pay in the future for gas. GasMark estimates that prices in the Step Change and Progressive Change scenarios could average around $7-8/GJ over the period to the early to mid-2030s, before increasing to levels around $10/GJ by the end of the forecast period.

The Green Energy Exports scenario on the other hand, projects prices to remain lower for longer and average between $6 and $8/GJ over much of the forecast period. This is mainly a result of our assumption that the Beetaloo Basin is more significantly developed, resulting in higher levels of supply for both LNG export demand and state-wide demand (which is overwhelmingly demand from GPG). In the other scenarios, we do not assume the Beetaloo Basin is developed to such a scale, which leads to prices rising at a faster rate.

4.4.3 Northern Territory results

Figure 4.13 Northern Territory GPG prices



5 Findings and insights

5.1 Residential and commercial price forecasts

The key findings for forecast residential and commercial prices are:

- Over the period to 2025, wholesale gas prices are contained to a large degree by the wholesale gas price cap in all scenarios. The cap acts as a substitute for the LNG netback in contract negotiations and prices should be $12/GJ plus transport.
  - From 2023 to 2025, wholesale gas prices delivered to the major capital cities are projected to range between $12 and $15/GJ depending on location.
- During the period to 2025, we also expect Asian LNG prices to continue to retreat from the peak prices experienced in 2022. By 2026, we expect that LNG prices will have retreated to levels below the wholesale price cap level. Therefore, the LNG netback will take over as the price reference for domestic contracts from 2026 (assuming the price cap is lifted following the review of the Code).
- Prices in the **Step Change scenario** decline to levels around $10/GJ in the late 2020s and early 2030s before rising steadily to levels around $11-13/GJ by the end of the outlook period.
- Prices in the **Progressive Change scenario** decline to levels around $10-12/GJ in the late 2020s and early 2030s before most cities see prices rising to levels around $16/GJ by the end of the forecast period (except for Brisbane).
- Prices in the **Green Energy Exports scenario** decline to levels around $7-8/GJ in the late 2020s and early 2030s and increase marginally over the outlook period.
- The sharpness in the decline in prices in each scenario in the 2020s is mainly attributable to the level international LNG prices are expected to fall.
- The pace and level at which prices increase over the longer term is mainly influenced by forecast demand levels. Larger declines in demand place more downward pressure on prices.

5.2 Industrial price forecasts

The key findings for forecast industrial prices are:

- As with the residential and commercial market, wholesale gas prices are contained to a large degree by the wholesale gas price cap in all scenarios. The cap limits the price of wholesale gas for industrial users over the period from 2023 to 2025.
  - From 2023 to 2025, wholesale gas prices delivered to large industrial users is projected to range between $11 and $15/GJ depending on location
- Prices in the **Step Change scenario** decline to levels around $9-10/GJ in the late 2020s and early 2030s before rising steadily to levels around $11-12/GJ by the end of the outlook period.

- Prices in the **Progressive Change scenario** decline to levels around $10-11/GJ in the late 2020s and early 2030s before most cities see prices rising to levels around $15/GJ by the end of the forecast period (except for Brisbane).
- Prices in the **Green Energy Exports scenario** decline to levels around $6-9/GJ in the late 2020s and early 2030s and increase marginally over the outlook period.
- The key difference between the prices forecast for industrial users and those for residential and commercial customers, is the assumption that industrial load profiles are much flatter over the year. The ultimate price paid by industrial users is typically lower due to this flat load profile and this is reflected in the price forecasts.
- Prices over the medium and long term are mainly driven by expected levels of demand. In some states, such as Victoria, larger forecast reductions in demand over the next 10-15 years result in forecast prices being marginally lower than other states during this period. Then as declines occur in other states towards the back end of the forecast period, prices then converge for most locations.

5.3 East Coast GPG price forecasts

The key findings for forecast east coast GPG prices are:

- As with the residential and commercial market, wholesale gas prices are contained to a large degree by the wholesale gas price cap in all scenarios. The cap limits the cost of wholesale gas for GPG over the period from 2023 to 2025.
  - Wholesale gas prices delivered to east coast GPG stations is projected to range between $12/GJ and $20/GJ depending on location and generation technology from 2023 to 2025
- Prices in the **Step Change scenario** decline to levels around $10-12/GJ in the late 2020s and early 2030s before rising steadily to levels around $11-15/GJ by the end of the forecast period.
- Prices in the **Progressive Change scenario** decline to levels around $10-13/GJ in the late 2020s and early 2030s before most cities see prices rising to levels around $13-19/GJ by the end of the forecast period.
- Prices in the **Green Energy Exports scenario** decline to levels around $8-11/GJ in the late 2020s and early 2030s and increase to levels around $9-12/GJ towards the end of the forecast period.
- The key difference between OCGTs and CCGTs is the impact in the short term of an expected divergence in contract and spot market prices. OCGTs that rely heavily on the spot market are forecast to pay higher prices for gas in the short term while wholesale price caps limit contract prices.
- In some scenarios, particularly the Progressive Change scenario, significant additional GPG capacity is brought online in the southern states in the later years. This results in higher prices for generators in these states to procure gas compared with generators in Queensland for example, where limited new GPG capacity is needed and gas supply from Queensland suppliers is more readily accessible compared to the southern states.

GasMark model A

A.1 GasMark

GasMark Global (GMG) is a generic gas modelling platform developed by ACIL Allen. GMG has the flexibility to represent the unique characteristics of gas markets across the globe, including both pipeline gas and LNG. Its potential applications cover a broad scope — from global LNG trade, through to intra-country and regional market analysis. *GasMark Global Australia* (GMG Australia) is an Australian version of the model which focuses specifically on the Australian market (including both Eastern Australia and Western Australia), but which has the capacity to interface with international LNG markets.

The model can be specified to run at daily, monthly, quarterly, or annual resolution over periods up to 30 years.

A.1.1 Settlement

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 'arcs' 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 objective function of this solution, which is well established in economic theory, consists of three terms:

— the integral of the demand price function over demand; minus
— the integral of the supply price function over supply; minus
— the sum of the transportation, conversion, and storage costs.

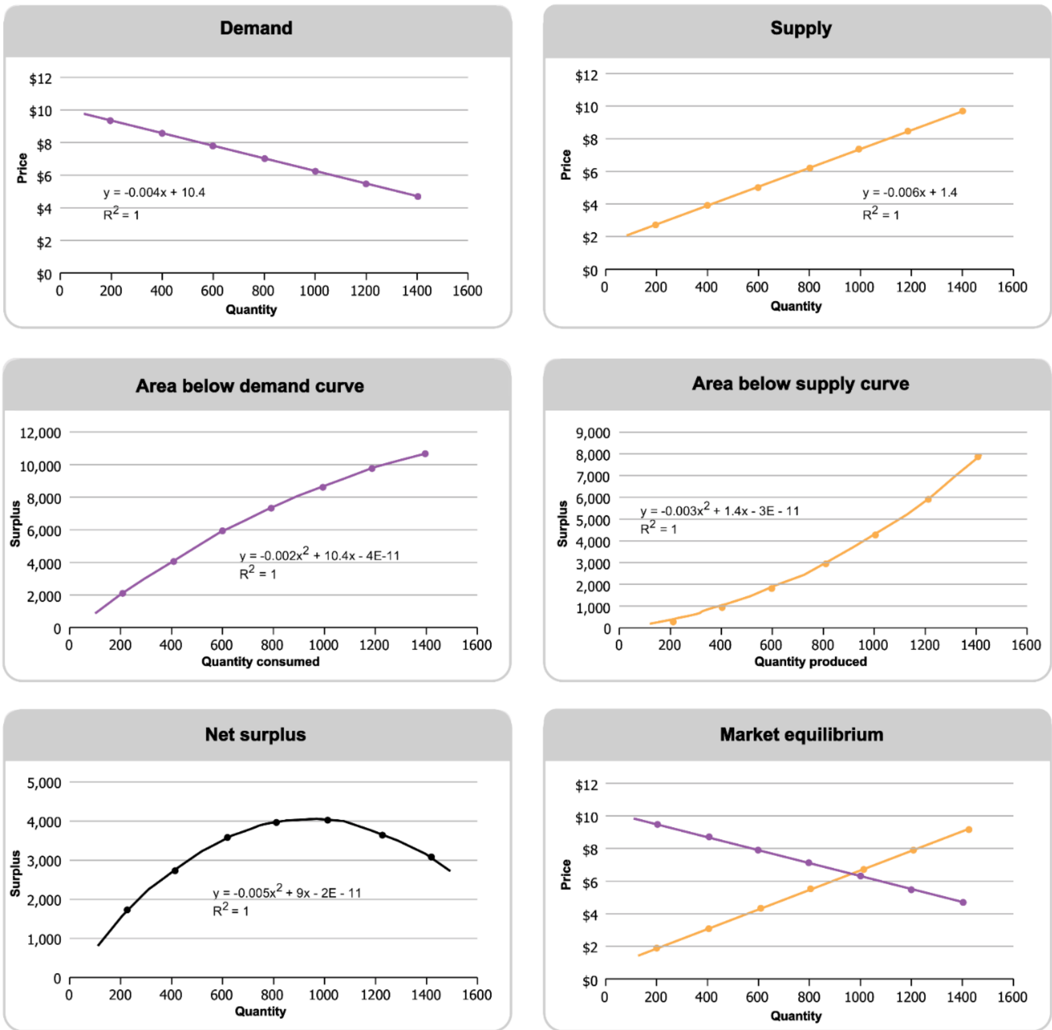
The solution results in an economically efficient system where lower cost sources of supply are utilised before more expensive sources and end-users who have higher willingness to pay are served before those who are less willing to pay. Through the process of maximising producer and consumer surplus,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

Figure A.1 seeks to explain diagrammatically a simplified example of the optimisation process. The two charts at the top of the figure show simple linear demand and supply functions for a particular market. The charts in the middle of the figure show the integrals of these demand and supply functions, which represent the areas under the demand and supply curves. These are equivalent to the consumer and producer surpluses at each price point along the curve. The figure on the bottom left shows the summation of the consumer and producer surplus, with a maximum clear at a quantity of 900 units. This is equivalent to the equilibrium quantity when demand and supply curves are overlayed as shown in the bottom right figure.

The distinguishing characteristic of spatial price equilibrium models lies in their recognition of the importance of space and transportation costs associated with transporting a commodity from a supply source to a demand centre. Since gas markets are interlinked by a complex series of transportation paths (pipelines, shipping paths) with distinct pricing structures (fixed, zonal or distance based), GMG Australia also includes a detailed network model with these features.

Spatial price equilibrium models have been used to study problems in a number of fields including agriculture, energy markets, mineral economics, as well as in finance. These perfectly competitive partial equilibrium models assume that there are many producers and consumers involved in the production and consumption, respectively, of one or more commodities and that as a result the market settles in an economically efficient fashion. Similar approaches are used within gas market models across the world.

Figure A.1 Simplified example of market equilibrium and settlement process



Source: ACIL Allen

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