ACIL ALLEN

Gas, liquid fuel, coal and renewable gas projections

Final report

25 February 2025

About ACIL Allen

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

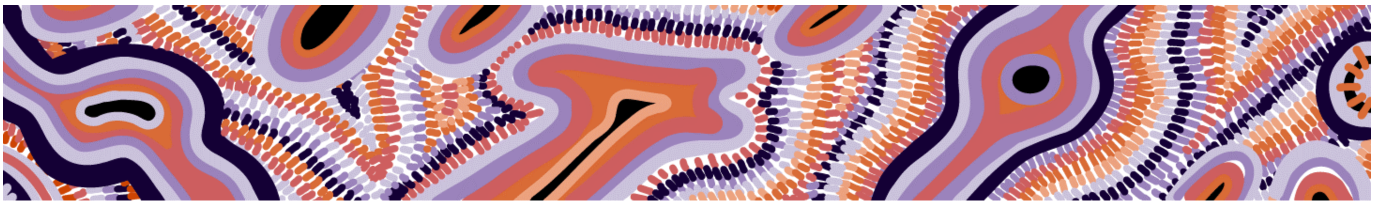
Our purpose is to help clients make informed decisions about complex economic and public policy issues.

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:

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
AD	Anaerobic digestion
AE	Alkaline electrolysis
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
EV	Electric vehicle
FOB	Free on board
GJ	Gigajoule
GL	Gigalitre
GPG	Gas-powered generation
GSOO	Gas Statement of Opportunities
HV	Hybrid vehicle
IASR	Inputs, Assumptions and Scenarios Report
IEA	International Energy Agency
ISP	Integrated System Plan
JKM	Japan/Korea Marker
kL	kilolitre
NEM	National Electricity Market
NZE	Net Zero Emissions (IEA WEO scenario)
OCGT	Open-cycle gas turbine
PEM	Proton exchange membrane (electrolysis)
PHEV	Plug-in hybrid vehicle
PKET	Port Kembla Energy Terminal
PJ	Petajoule
REZ	Renewable Energy Zone
SMR	Steam methane reforming
STEPS	Stated Policies Scenario (IEA WEO)
SWIS	South-West Interconnected System
TJ	Terajoule
VRE	Variable renewable energy
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, coal and liquid fuels, and projections of the cost, demand and available volume of various renewable gases (renewable hydrogen and biomethane). 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 scope

Fuel	Item	Geographic scope	Report section(s)
Natural gas	Price forecasts for each existing gas-fired generator (including transmission and storage)	NEM, SWIS, NT	2.2, 2.3, 2.4
	Price forecasts for generic new entry gas-fired generators, both open-cycle gas turbines and combined-cycle gas turbines.	NEM, SWIS, NT	2.2, 2.3, 2.4
	Wholesale price forecasts including transmission and storage (but excluding distribution and retail costs) for industrial customers consuming more than 10 TJ/day	ECGM, SWIS	2.2
	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	2.2
	Wholesale transmission costs for each major gas pipeline	ECGM	2.2
	Estimated cost of imported LNG	ECGM	2.2
Renewable gas	Delivery cost for hydrogen blended into distribution pipelines	National	3.1
	Delivery cost for hydrogen delivered direct to industrial user	National	3.1
	Export hydrogen production volume	National	3.3
	Green commodity production volume and hydrogen input volume	National	3.3
	Feedstock hydrogen supply	National	3.3
	Biomethane cost curves (cost vs volume)	National	3.2
Coal	Price forecasts for each existing coal-fired generator	NEM	4
Liquid fuels	Diesel price forecasts for each existing power station	NEM	5

Note: NEM = National Electricity Market; SWIS = South-West Interconnected System (WA); ECGM = east coast gas market; NEM, ECGM and national results are disaggregated by region/state unless otherwise noted.
Source: ACIL Allen

1.3 Scenario definitions

AEMO requested that ACIL Allen provide results for three scenarios:

— Progressive Change
— Step Change
— Green Energy Exports.

These scenarios are broadly defined as:

— **Progressive Change** scenario – remains characterised by a slow rate of transformation, featuring more challenging conditions that necessitate decarbonisation efforts being deferred to their latest practical point to achieve the intent of relevant policies
— **Step Change** scenario – remains characterised by a level of energy transition that is consistent with policy including Australia's commitments to international climate obligation
— **Green Energy Exports** scenario – continues to reflect a high growth case, where economic and technological opportunities support a rapid and significant scale of energy system transformation.

1.4 Overarching approach and key assumptions

ACIL Allen adopted a three-phase process for developing these gas price forecasts; a data collection and market analysis phase; a model preparation phase; and a modelling phase to produce the final forecasts. These phases are described in more detail in the sections that follow.

The **first phase** was a key preparation phase of this project. It involved ACIL Allen collecting the necessary data for the forecasting exercise, preparing our models to produce the long-term price outlooks, and a market analysis piece. The market analysis piece was important for us to ensure we have captured all the relevant drivers of recent price movements across Australia for the various gases and fuels, and how this might evolve over time.

The **second phase** was preparing our various models. ACIL Allen has developed models in the natural gas, renewable gas and coal sectors. For liquids (diesel), we developed a model to estimate delivered prices for each generator that can or could potentially be run on diesel.

The **third and final phase** was modelling the price outlooks themselves and iterating as required based on feedback we received.

This report provides prices and costs that are:

— are presented in real (inflation-adjusted) January 2024 dollars unless otherwise noted.
— natural gas results are presented in calendar years for consistency with GSOO inputs.
— renewable gas results are presented in financial years for consistency with ISP inputs.
— coal prices are also presented in financial years to remain consistent with previous year prices.
— liquid prices are presented in calendar years.

1.5 Report structure

Given the range of projections presented in the report, the body of the report details the key results and the detailed methodology and assumptions are provided in the appendices.

The report is structured as follows:

— Natural gas price outputs are presented in section 2, with methodology in appendix A
— Renewable gas outputs are presented in section 3, with methodology in appendix B
— Coal price outputs are presented in section 4, with methodology in appendix C
— Liquid fuel price outputs are presented in section 5, with methodology in appendix D.

2 Natural gas prices

2.1 General approach

ACIL Allen developed a three-phase process for the natural gas prices. These phases are described in more detail below. In the beginning we embarked on a data collection and high-level market analysis phase to ensure we were across all of the developments in the east coast gas market (ECGM) and the WA gas market. A model preparation phase then followed where we ensured the models were correctly specified and the assumptions have been confirmed. The final phase was undertaking the forecasts themselves.

Specific material and background on our GasMark model and assumptions for each scenario are provided in Appendix A.

Phase 1: Data collection and market analysis

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 which produce the final forecasts.

The data requirements were required to calibrate our GasMark model and to ensure the assumptions and detail on market infrastructure were consistent with the assumptions contained in the IASR report and the 2024 GSOO.

A supporting piece of work during this phase was reviewing the ECGM, Northern Territory and WA gas markets. This analysis is always an important task for these modelling exercises. It ensured our understanding of key market developments are fully understood, and can treat these effectively in our model or via post model adjustments.

Some of these key developments included:

— Wholesale gas price caps recently introduced by the Commonwealth Government relevant to the ECGM
— 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
— The role of hydrogen and how it might trend in the future.

Phase 2: 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 WA, 2024 to 2033 we broadly aligned our demand with AEMO. However, we deviate based on some market developments and project announcements since the release of AEMO's 2023 GSOO (e.g. Alcoa Kwinana has since committed to closing). Beyond 2033, we have produced demand curves for the three scenarios which have differing levels of consumption for various industries over time.

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.

Phase 3: Undertaking forecasts

Following phases 1 and 2, ACIL Allen undertook the final forecasts. AEMO required various forecasts for eastern Australia, NT and WA. The forecasts required relate to residential/commercial demand, industrial demand and GPG demand.

The following forecasts are presented:

- Individual gas price forecasts (including transmission and storage) for each existing gas-fired generator within the National Electricity Market (NEM), NT and WA (in the SWIS)
- 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 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 wholesale contract price gas forecasts (excluding distribution and retail costs) are also provided for industrial users in WA.

2.2 East coast gas market results

2.2.1 Residential and commercial prices

Residential and 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 annual wholesale prices for each region in the ECGM.

We also assume that supply for this market is 100% contracted. Therefore, all supply for residential and commercial users is based off gas supply agreements between gas retailers and gas producers, that are currently subject to the price anchor. The contract component of these price projections represents 'new contract' prices and reflects the cost of purchasing gas from the market from 2024 to 2057.

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 2023.

Step Change scenario

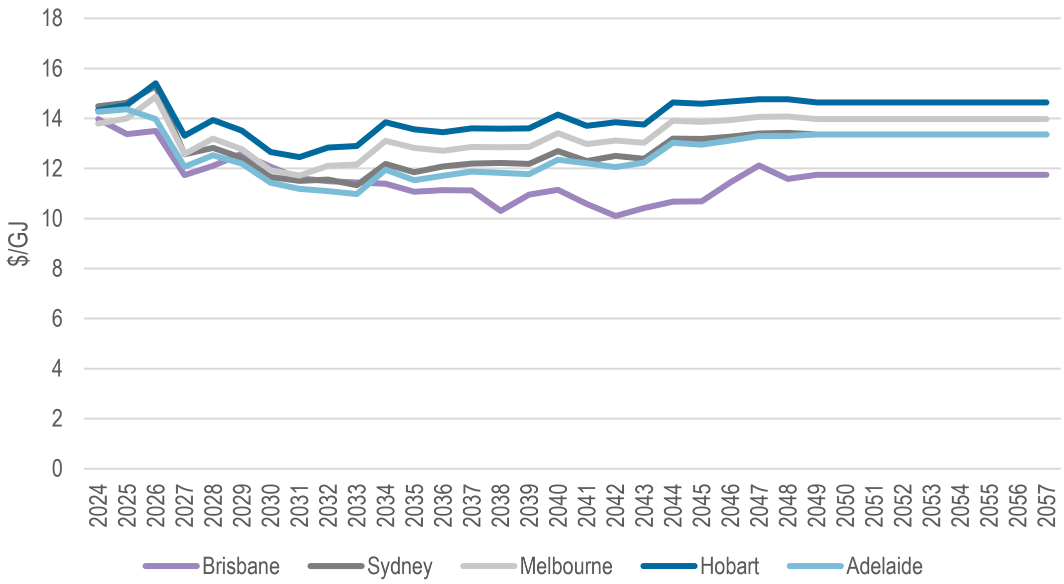
In the short term, residential and commercial prices are expected to remain largely influenced by the gas code's $12/GJ price anchor over the next two to three years, before declining in line with international LNG prices in all three scenarios. This means gas prices in all markets is reflecting $12-13/GJ gas plus transport to different markets across the east coast. In 2026, prices do experience a small spike due to the market being tight for gas. We have the Port Kembla LNG terminal (PKET) importing gas into the market in 2027 and not in 2026. It is possible that this spike in 2026 could be better kept in check if the terminal was in the market. As there are some doubts still on when it could enter the market, we have conservatively assumed PKET is online from 2027.

By the early 2030s, the LNG netback price is forecast to move prices to levels below $12/GJ with delivered prices in most markets averaging between $11 and $13/GJ. Prices from then on increase over the projection period and finish around $14-15/GJ.

The exception is Brisbane. 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 including 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.

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 100 PJ per annum in this scenario.

Figure 2.1 Residential/commercial gas prices, by market: Step Change scenario



Source: ACIL Allen

Progressive Change scenario

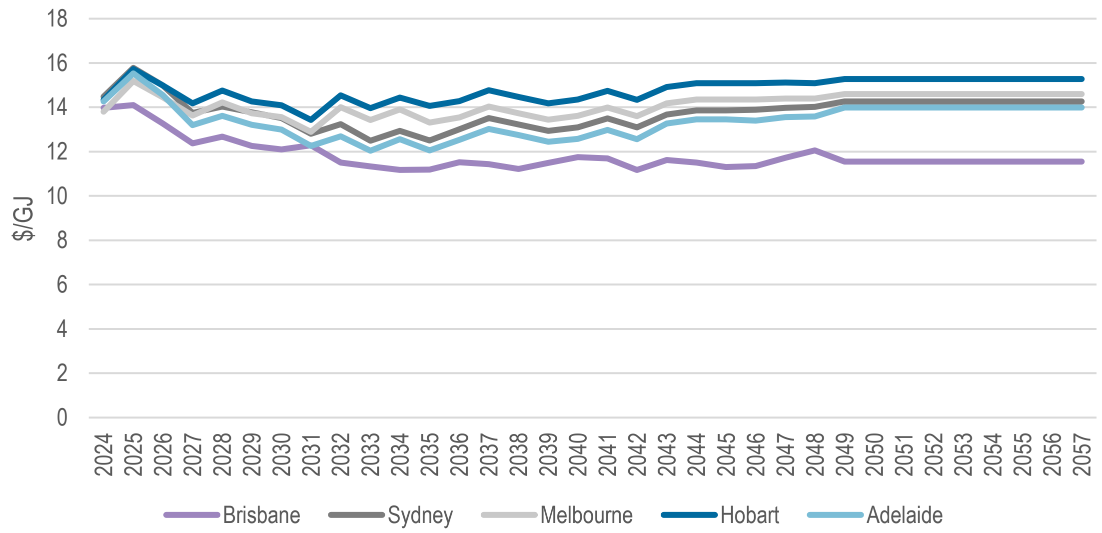
The prices under the Progressive scenario are similar to the Step Change scenario in the short term but the main difference is that prices only marginally fall in the medium term before increasing. In the southern markets, gas prices are kept above $12/GJ for the entire projection and end up between $14 to $16/GJ.

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 market which could lead to lower prices for domestic users.

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 fill LNG plants and also contribute to stabilising domestic prices in the long term.

Figure 2.2 Residential/commercial gas prices, by market: Progressive Change scenario



Source: ACIL Allen

Green Energy Exports scenario

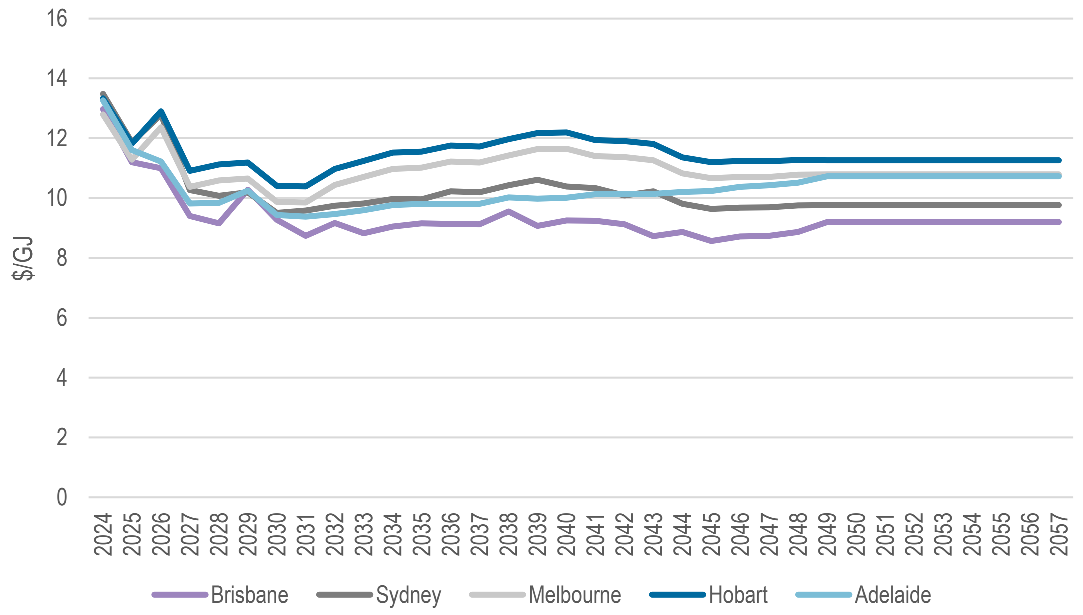
The Green Energy Exports scenario demonstrates a scenario where demand for gas does trend lower at a faster pace than in the other scenarios. This is relevant for both domestic demand and LNG export demand. As a result we would expect that gas prices would move lower in this scenario.

Our price outlook demonstrates this is likely to happen. In the short-term prices down trend down expect for a small spike in 2026. This is largely due to a spike in GPG demand and a tight demand/supply environment as mentioned previously. Gas prices by the early 2030s are hovering between $9 and $11/GJ. 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.

In this scenario, prices in the long run remain below $12/GJ. There is some separation between markets most evident in the late 2030s and early 2040s. This separation is then narrowed over the long term. This is principally due to market demand becoming less peaky and supply better handling demand (even though demand is falling more rapidly than in the other scenarios). Less supply is committed in this scenario due to the demand outlook and this does lead to prices increasing for periods of the outlook.

Melbourne and Tasmania face the highest prices in this scenario as they are furthest from northern supply sources. Sydney benefits from lower cost imported LNG from PKET in this scenario.

Figure 2.3 Residential/commercial gas prices, by market: Green Energy Exports scenario



Source: ACIL Allen

2.2.2 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.

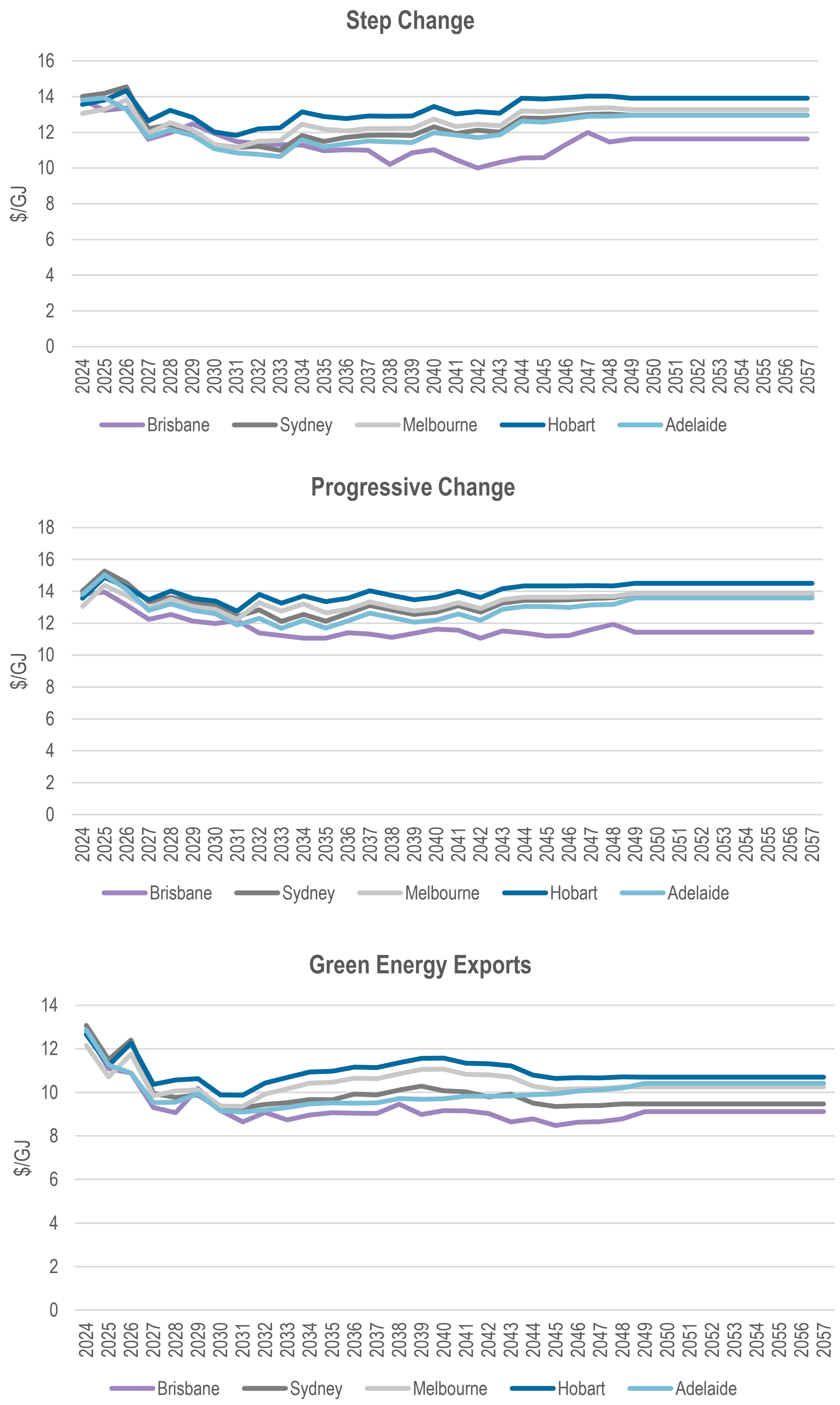
Industrial prices broadly follow the trajectory and 'price ranking' per city of the residential commercial forecasts. Industrial prices exhibit a tighter spread of prices across the different markets than the residential/commercial projection. This is due to the reduced exposure to winter price swing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

In the Step change scenario, prices are expected to remain relatively steady until global LNG prices begin to fall. 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 Progressive change 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 Green Energy Export scenario we expect that prices will trend to lower levels. Like 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 in the long term.

Figure 2.4 Industrial gas prices per scenario, by market



2.2.3 GPG prices

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

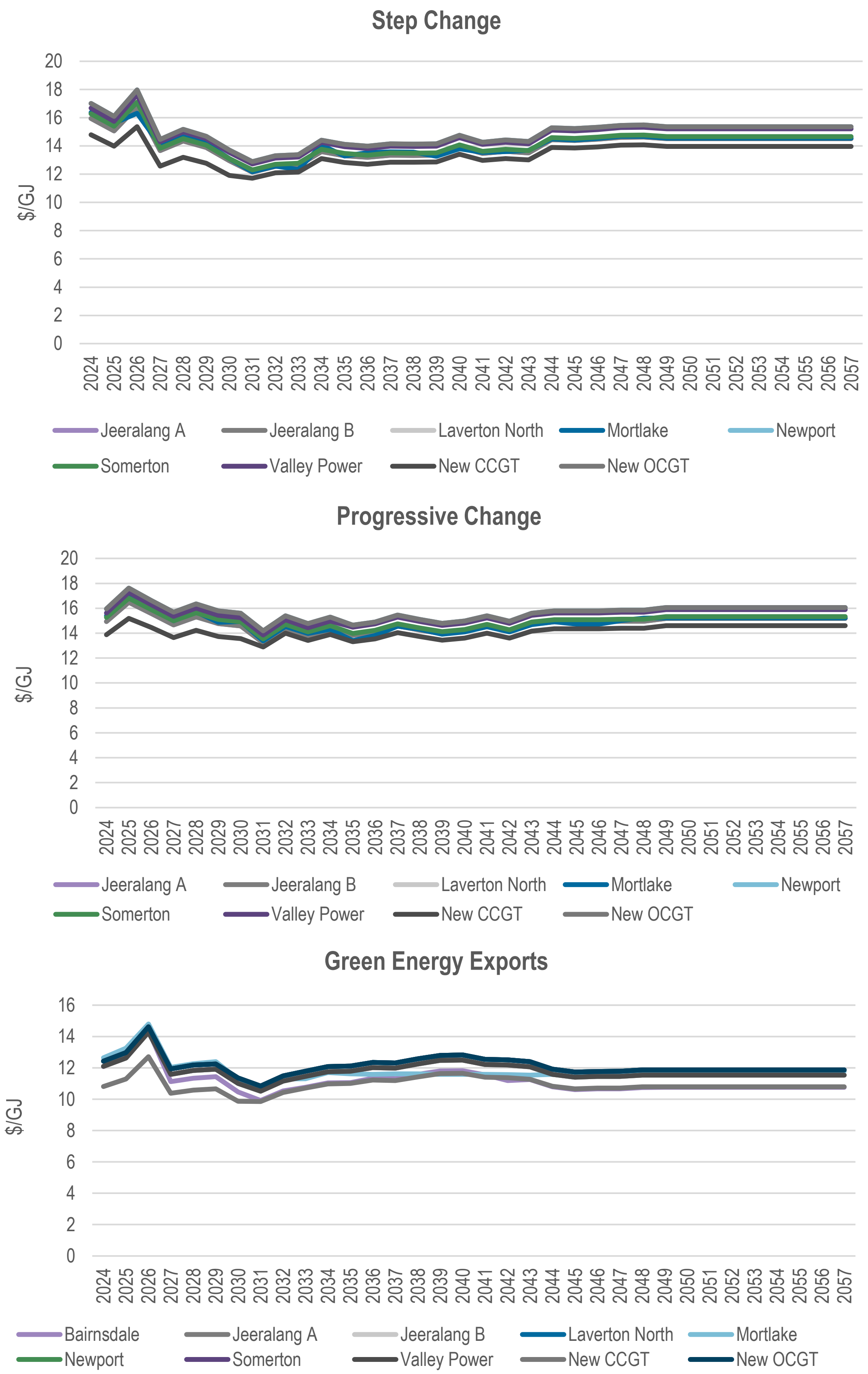
Two runs of our GasMark model were performed to generate the annual wholesale price reflecting contracts, and a monthly run to reflect the spot market. From here a weighting was produced for each generator to account for approximate proportions of contract and spot gas used to supply the generator. This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

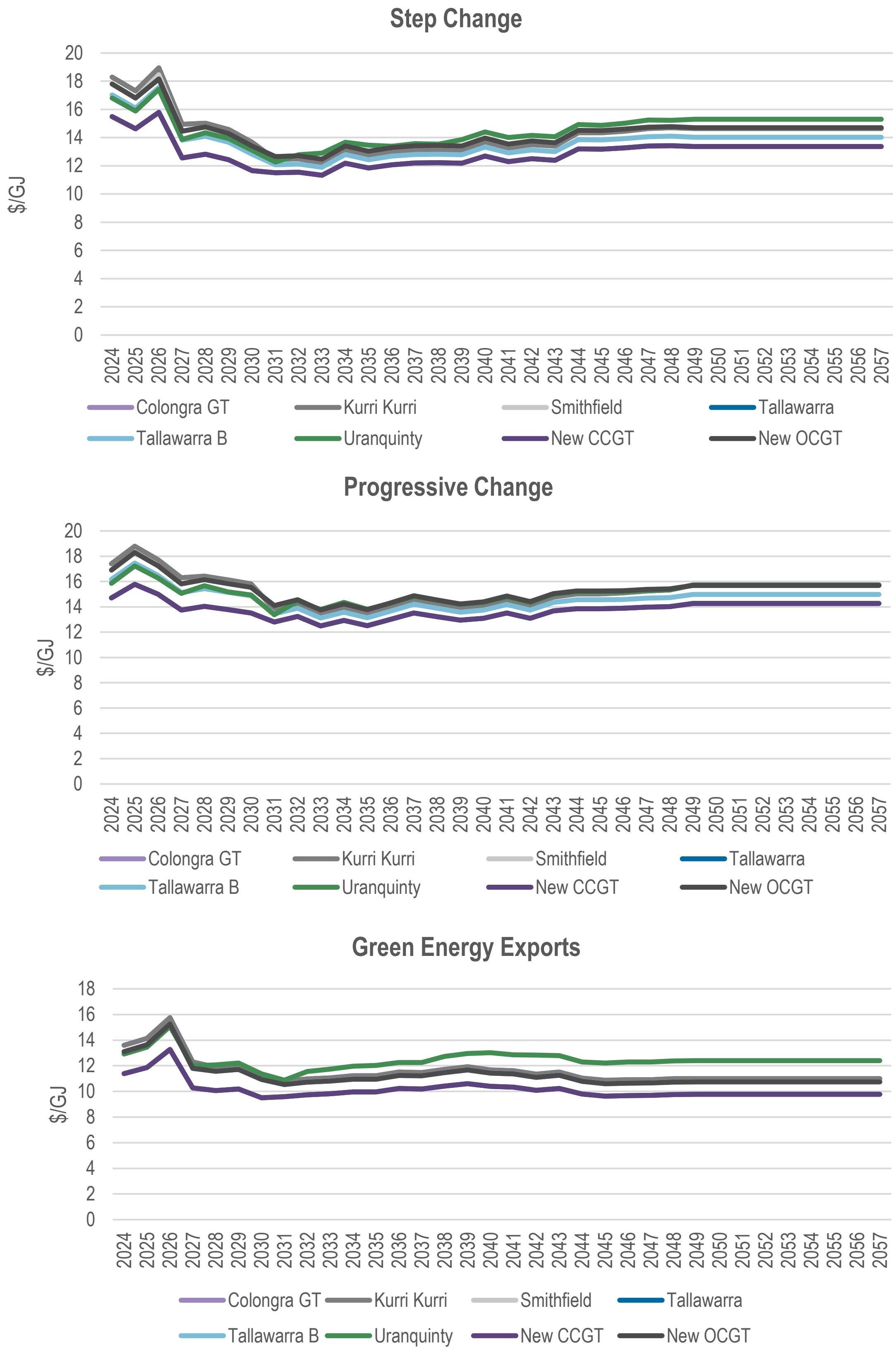
The prices for GPG track much the same as the other sectors for the same reasons across each scenario.

Figure 2.5 GPG gas prices: Victoria



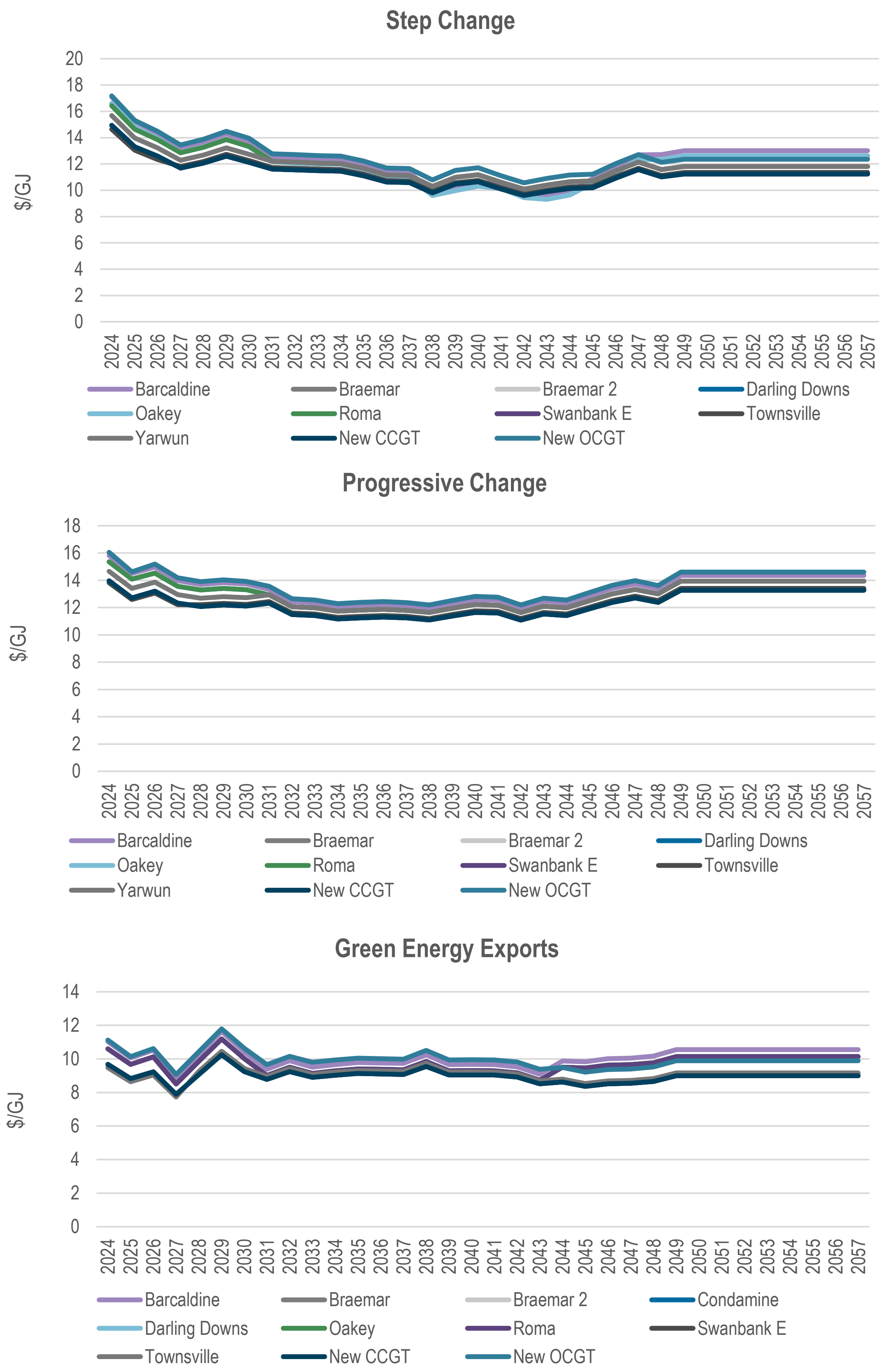
Source: ACIL Allen

Figure 2.6 GPG gas prices: New South Wales



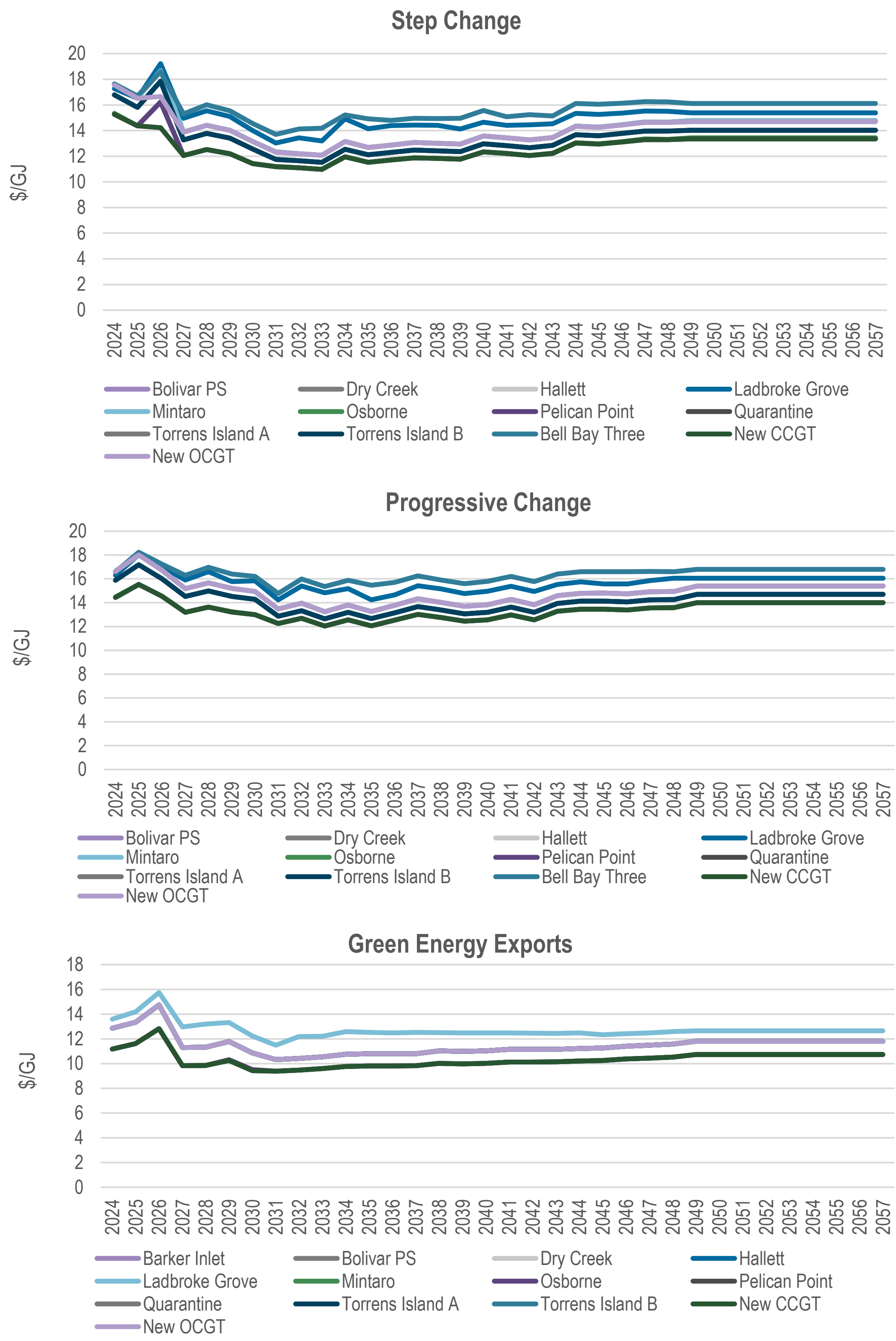
Source: ACIL Allen

Figure 2.7 GPG gas prices: Queensland



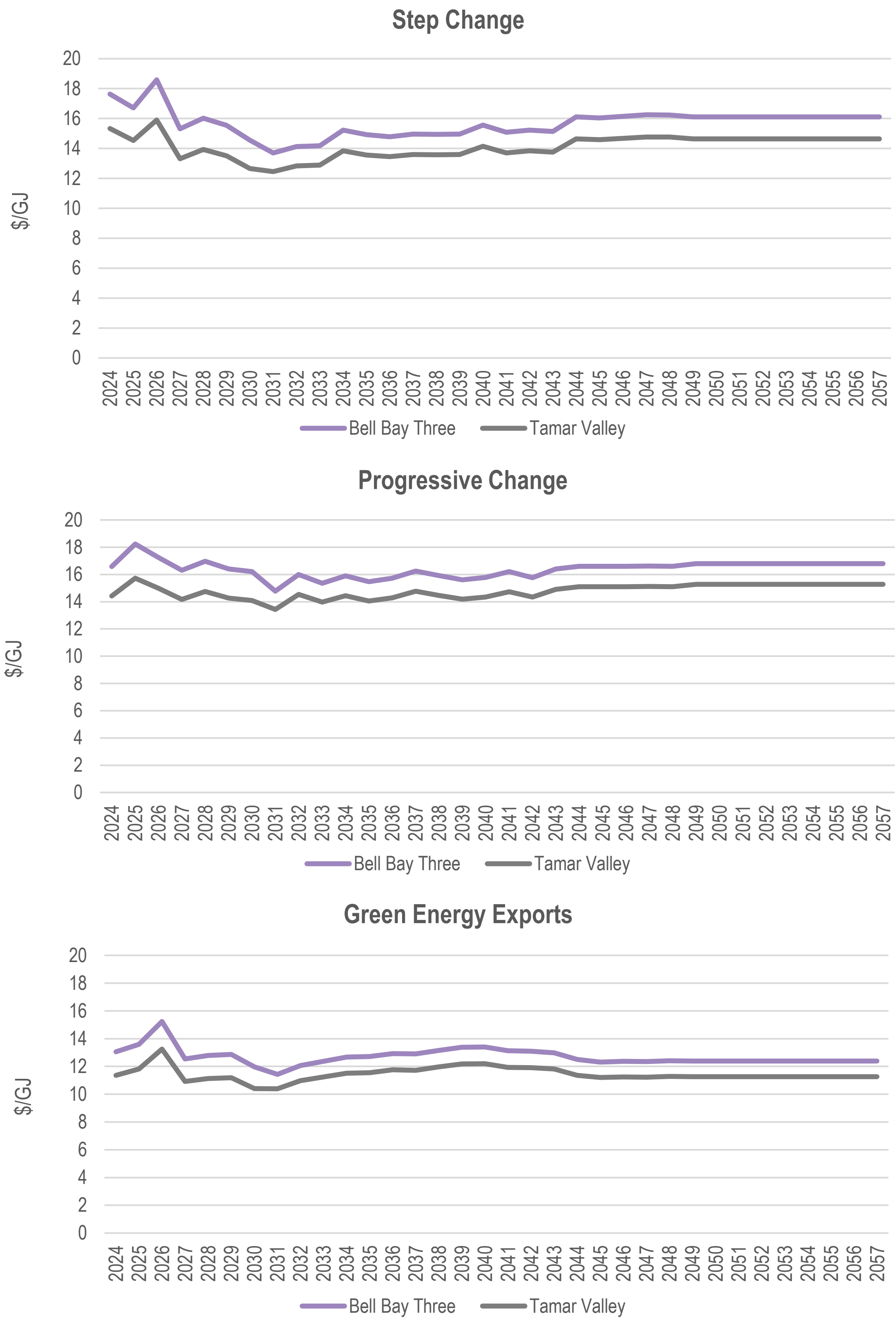
Source: ACIL Allen

Figure 2.8 GPG gas prices: South Australia



Source: ACIL Allen

Figure 2.9 GPG gas prices: Tasmania

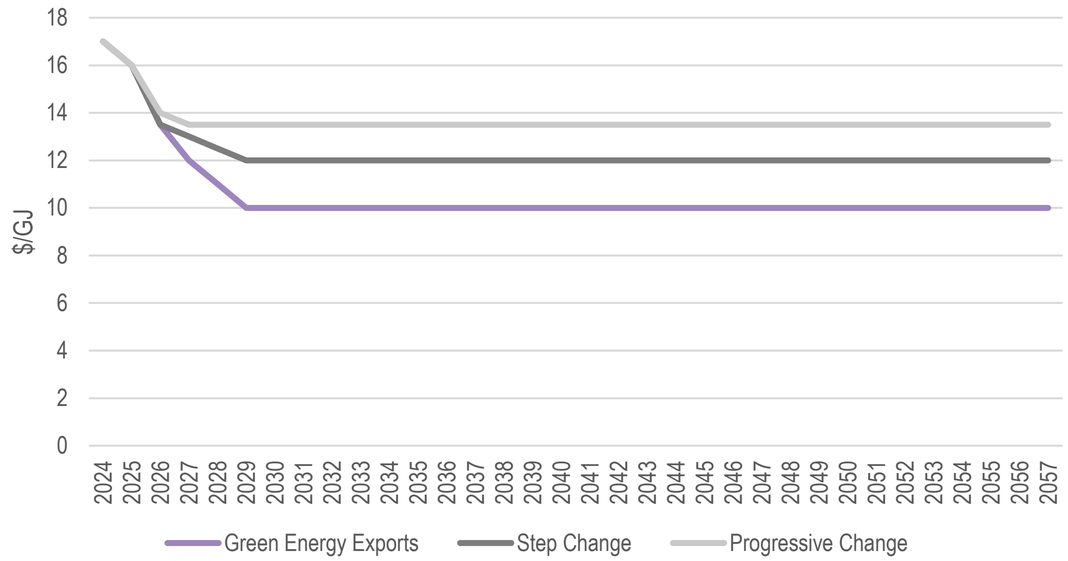


Source: ACIL Allen

2.2.4 Cost of imported LNG

The cost of imported LNG for each scenario is presented in Figure 2.10 below.

Figure 2.10 Assumed cost of imported LNG, by scenario



Source: ACIL Allen

ACIL Allen followed the same approach as last year for LNG import price assumptions. We reviewed how Asian LNG prices are expected to trend and how LNG is traded over time with respect to contracted LNG and spot LNG. We also reviewed how the Brent crude oil price is expected to trend as this is still important in LNG price formulation in Asia.

LNG demand is expected to continue to grow, particularly in Asian countries such as China, India and other emerging Asian markets. On the supply side, additional supply is coming on stream from the US, Qatar and Australia. If all LNG export projects under construction are completed on time, available liquefaction capacity is expected to rise globally by 300 billion cubic metres per year by 2030 (IEA, 2024).

This expanded production capacity has the potential to exceed growth in demand, putting downward pressure on LNG prices.

In the short term (to 2030) we have some visibility of how LNG forward curves are trending. Most forward curves for Asian LNG (especially the JKM benchmark series) are forecast to trend lower over the period to 2030 as the international supply of LNG increases. Our expectation is that additional LNG capacity will be brought online from various LNG exporters in the coming years – particularly from the Middle East (e.g. Qatar) and the United States.

Post-2030, the ability to understand how Asian LNG prices might track is becomes more difficult. From that point onwards we looked at the following series:

— IEA LNG price forecasts from the 2024 WEO
— Brent crude oil price forecasts.

We do not foresee LNG import prices falling as much as the IEA predict in their WEO. Our expectation is that LNG projects are still difficult to sanction, Asian LNG demand will remain strong and that a premium on long term LNG contracts could return to the market.

The oil price is still an important influence on the price of LNG. While the demand for crude oil is expected to decline around 2030 in the three scenarios, the expectation in some forecasts, including the IEA, that prices could fall as low as $25/bbl in some scenarios is unlikely over the longer term in our view. As discussed in Chapter 5, below, crude oil production in the Middle East contributes to sustaining national budgets while the countries in question transition to more broadly based economic models. Middle Eastern producers still can exert some market power and are unlikely to allow the price to fall to those levels for long.

Table 2.1 LNG price assumptions based on the Brent crude oil price

Scenario	Brent crude price (US$/bbl)	LNG price (AU$/GJ)
Progressive Change	80	12.50
Step Change	65	11.00
Green Energy Exports	50	9.00

Source: ACIL Allen

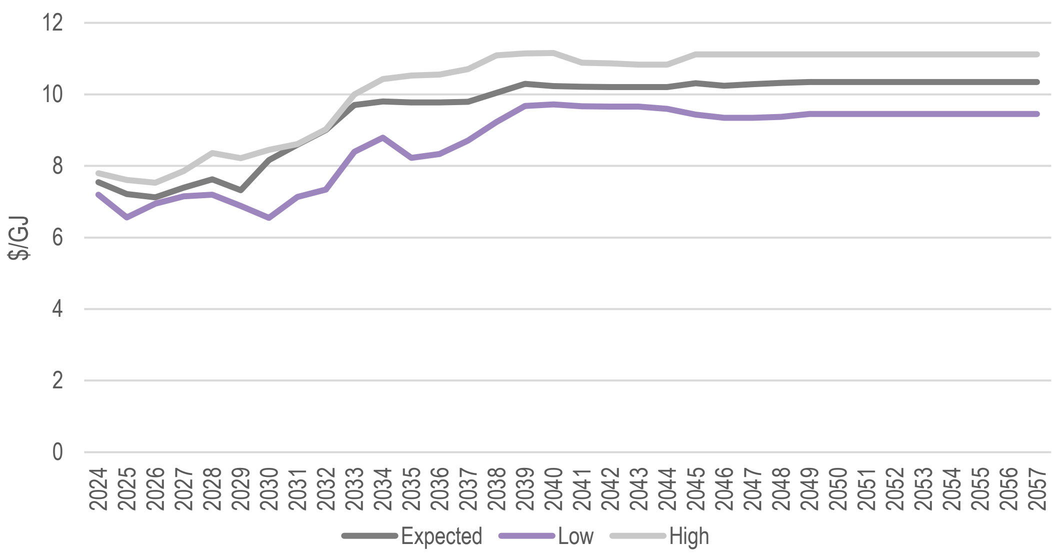
2.3 WA gas market

Modelled annual long term wholesale gas prices are presented for WA below that represent contact prices for industrial users. The prices reflect the cost of wholesale gas in the Metro/Parmelia region of the Western Australian network. Gas demand in WA is mainly from mineral processing, power generation and a number of very large industrial users.

The process for WA is the same that was taken for formulating prices for the east coast.

2.3.1 Industrial prices

Figure 2.11 Industrial gas prices: Western Australia



Source: ACIL Allen

Contracts in the short term are likely to be offered at prices around the $7-8 mark in the WA market. For some smaller industrial users and other more variable loads, prices are likely to be higher than what we have presented.

The late 2020s represents a period of time where some new large gas users come online (e.g. Perdaman), and potentially some coal to gas switching begins to occur in the industrial sector (for instance, the Worsley alumina refinery). During this period, the timing of supply and demand projects is crucial with respect to market balance. By the early-to-mid 2030s, this market tightness is expected to drive domestic prices to around $10/GJ delivered to the Perth area. This represents approximately a doubling of the gas price that the WA market has experienced in the past few years.

During this time domestic only fields are well and truly depleting, and the market becomes incrementally more dependent on DMO gas from LNG producers. Furthermore, many legacy LNG fields are expected to begin to decline (especially within Wheatstone and NWS tenements). These factors align to result in sustainably higher prices over the projection period. Prices essentially tend towards a netback relationship as evident in the east coast gas market as healthy domestic supply conditions are well in the past.

Our expectation is that government policy which reserves gas for domestic use will become less effective in the long term at keeping prices at levels which have been experienced in recent years. This is due to the limited number of new supply projects currently in the pipeline. Without new supply, less will be reserved for the domestic market and prices will tend to trend towards a netback price over time.

This netback pricing is expected to become more prominent from the mid-2030s and continue out to the end of the projection period. The Browse development offers further stability to the market from the late 2040s in the face of Gorgon's expected fulfillment of its DMO in the early 2040s.

Sustained higher gas prices are expected to stretch the price tolerance of some industrial loads, however as demonstrated in the east coast, this is expected to have a limited impact on overall consumption as companies adjust to the increase in cost.

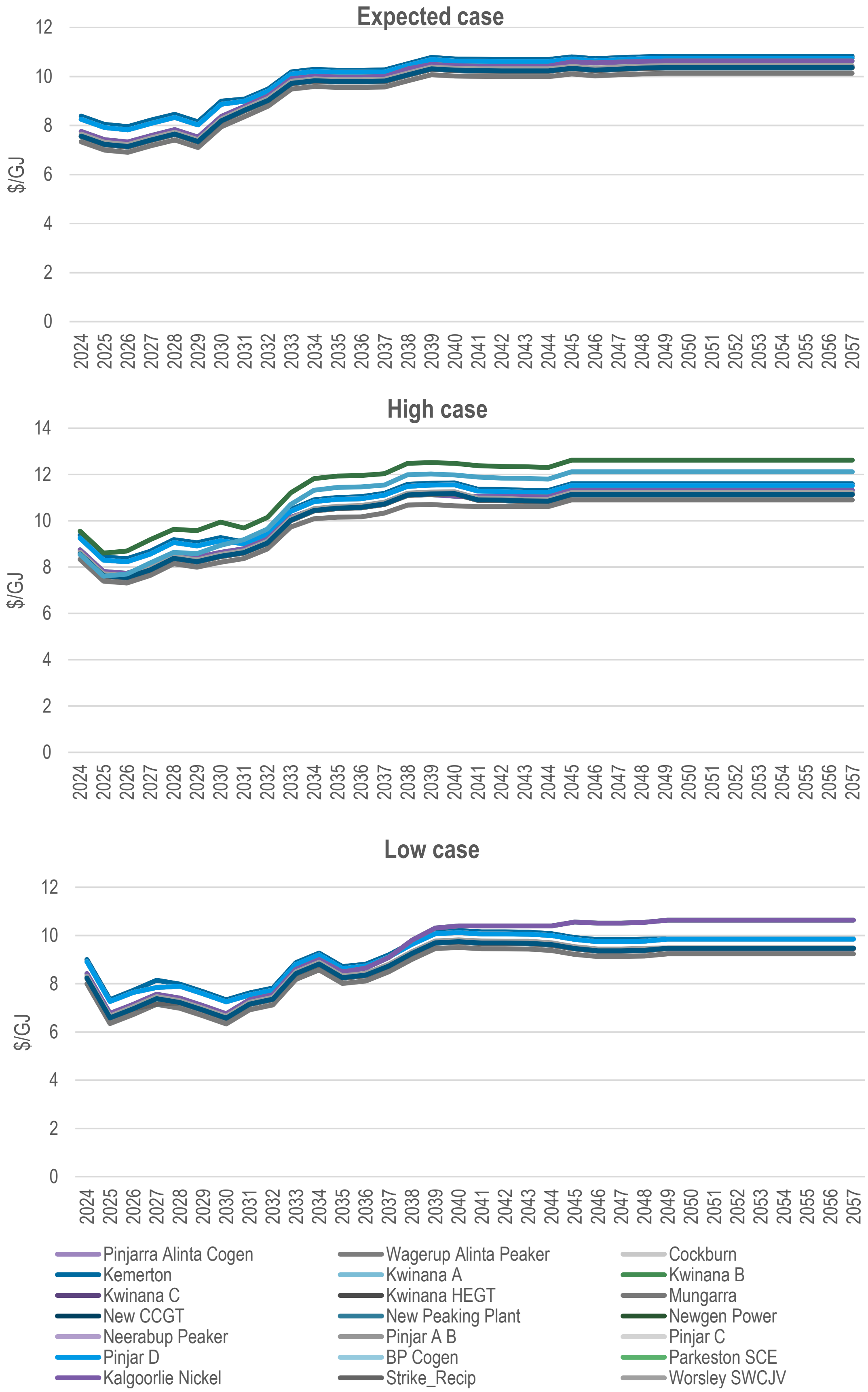
2.3.2 GPG prices

Our GPG prices are presented in Figure 2.12 below.

GPG prices in WA are expected to follow the general trend in other markets across the forecast period. Our assumption, like that in the east coast, is that OCGTs generally contract some portion of their supply and some from the spot market. However, we do not assume it's to the same degree as the east coast.

The WA market gas been well supplied for some time and most gas generators would have had their supply under contract. However, our assumption is that may change over time as GPG gets increasingly peaky, and less frequent. Some generators, therefore, may position themselves to purchase more of their supply on the spot market. The premium to purchase gas on the spot market is less in WA than what we assume for the east coast.

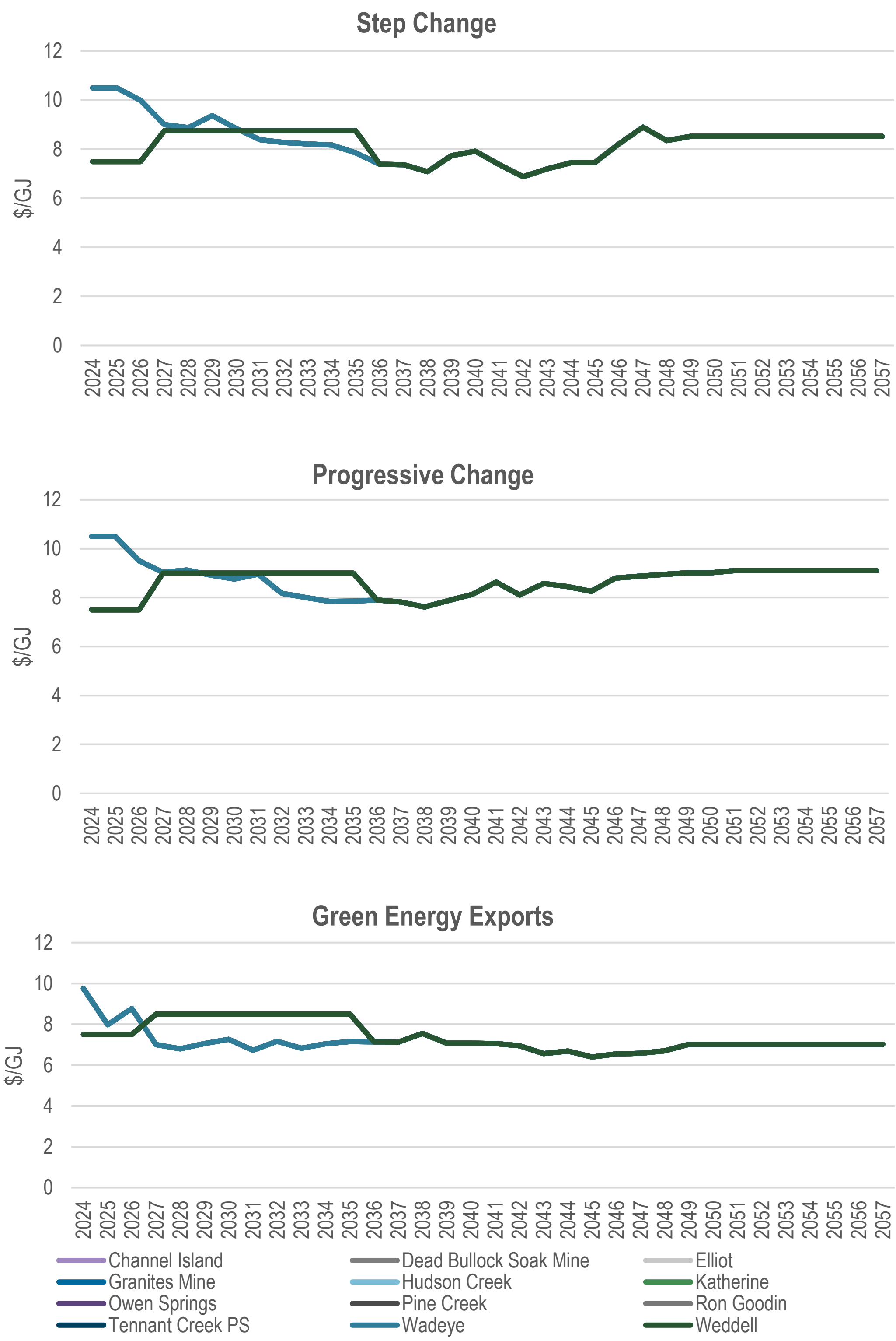
Figure 2.12 GPG gas prices: Western Australia



2.4 NT gas market

Prices for the NT market are presented in Figure 2.13.

Figure 2.13 GPG gas prices: Northern Territory



Source: ACIL Allen

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.

Based on that, we have projected prices for the power generation, and these also reflect prices paid by the other sectors (e.g. residential/commercial and industrial users). In reality, this is not likely to be the case. However, we have limited visibility on prices in these networks.

Our assumption last year was that many of the Territory Generators held long term contracts that were anticipated to expire around 2030. Price estimates put these contracts between $7 and $8/GJ. To reflect the recent situation in the NT around supply shortages and disruptions, we anticipate that these prices and contracts may not be sustainable for that period. From 2027 onwards, we assume new contracts are written potentially with a new supplier (such as a producer like Tamboran Resources) at a price between $8 and $10/GJ for gas supply out to 2035. This price represents a fair margin given AEMO's cost of production assumptions for Beetaloo and is competitive relative to the cost of delivering the same gas into Wallumbilla. There are some examples where the price might be higher than $10/GJ. However, our modelling needs to balance what we hear on the ground with assumptions on production costs from AEMO's scenarios.

We have minimal visibility on what generators outside of Territory Generation's portfolio are paying, as such we assume that these generators are paying a price linked to Wallumbilla hub less delivery tariffs into Wallumbilla hub (given the current supply situation). This creates a price series that represents the new interlinkage to the east coast that the NT is likely to have given the assumed role of Beetaloo gas in these scenarios and the disrupted supply environment in the NT.

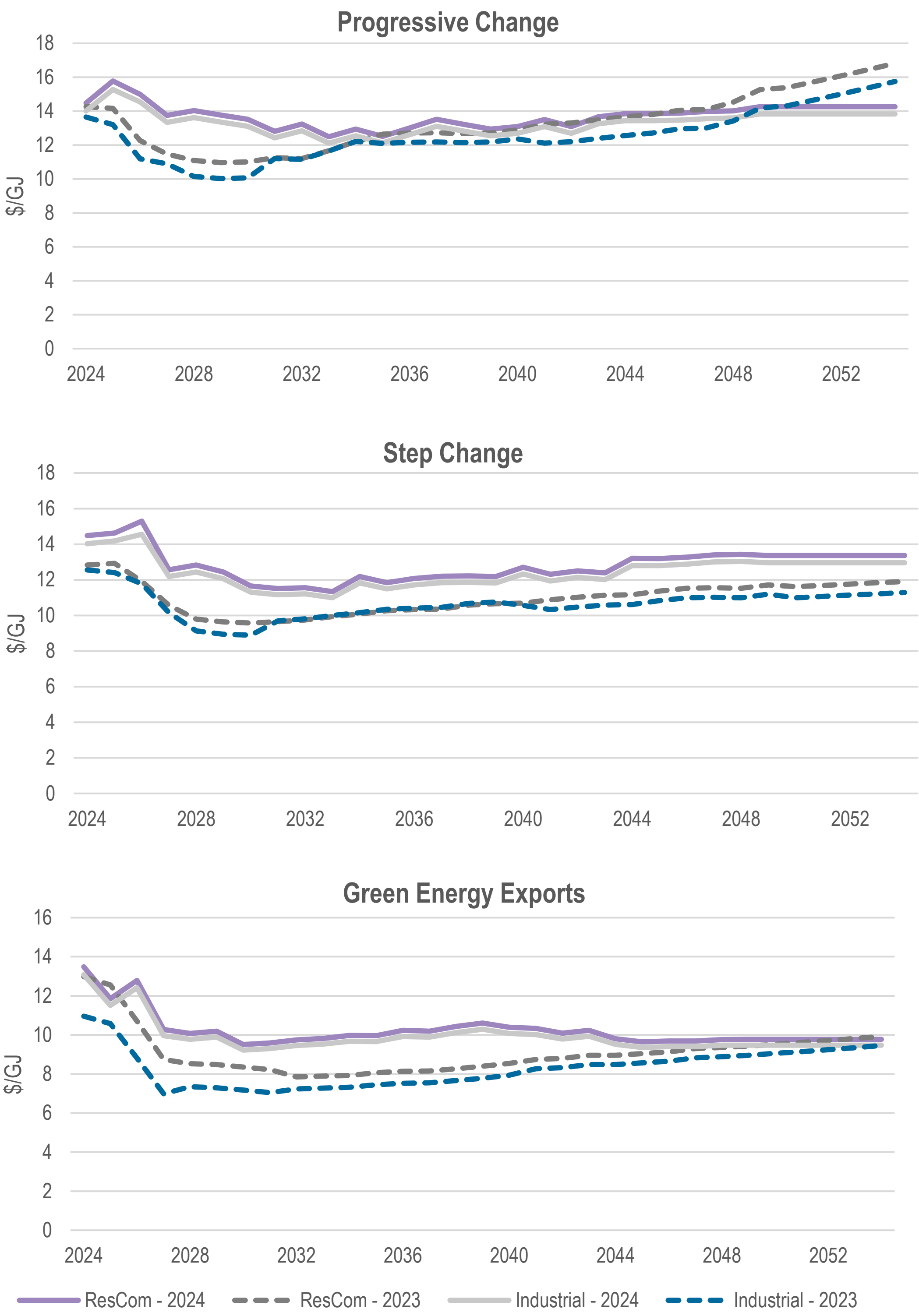
2.5 Changes in natural gas prices since 2023

Our prices compared with last year are summarised below (comparing residential/commercial and industrial prices). What is clearly evident is the difference between our current prices and last year's prices over the short term in particular.

There are four key differences between this year's and last year's prices.

1. **Methodology change** – we have modelled this year's prices at a daily resolution to pick up the impact on prices more accurately from increasingly peaky GPG. Our 2024 prices are generally higher (particularly in the short to medium term) because our model is accounting for higher daily winter prices.
2. **Stickiness in prices due to the influence of policy** – our 2024 prices are higher in the period to 2030 because we anticipate contract prices will be anchored more around $12/GJ than what we had last year – which were well below the $12/GJ mark.
3. **International LNG prices** – last year's prices were influenced by a forecast of faster declines in LNG prices. We have altered the assumption on LNG prices this year based on recent market data.
4. **More rapid decline in southern production** – Prices this year reflect a sharper decline in southern production compared with last year (we had a long tail-off in southern production last year which was arguably too long compared with AEMO assumptions).

Figure 2.14 Comparison between 2024 and 2023 price projections



Source: ACIL Allen

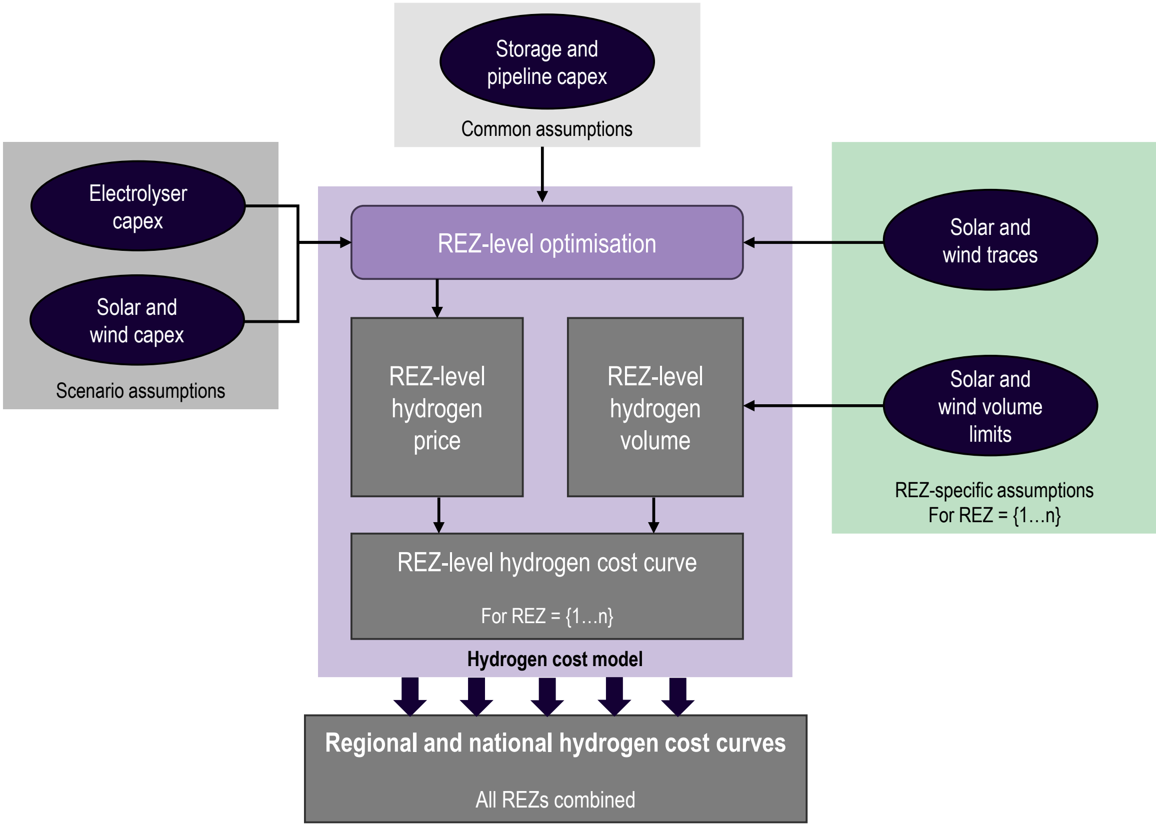
3 Renewable gas

3.1 Hydrogen storage and transport costs

ACIL Allen used its detailed hydrogen cost model to develop estimates for the all-inclusive cost of hydrogen supply based on off-grid supply, with dedicated or 'behind-the-metre' solar and wind generation supplying electrolysers (assumed to be located in each Renewable Energy Zone or REZ), supported by ancillary infrastructure such as battery storage (to support constant base plant electricity requirements), hydrogen storage, compressors, pipelines (to transport hydrogen from the REZ to the point of consumption) and water supply.

We optimise costs for each REZ based on cost parameters and solar and wind traces drawn from AEMO's IASR for the 2024 ISP.[1] These sources, along with detailed sources on storage and pipeline costs, and other ancillary costs, are brought together using the methodology summarised in Figure 3.1.

Figure 3.1 Hydrogen supply modelling methodology



Source: ACIL Allen

ACIL Allen's hydrogen cost modelling was used to derive storage and transport costs to add to CSIRO's estimates of hydrogen production costs based on its multi-sector modelling.

[1] Solar and wind traces are available from AEMO's 2024 ISP webpage (AEMO, 2024). Solar, wind and electrolyser costs, and other assumptions, are available from AEMO's IASR webpage and assumptions workbook (AEMO, 2023).

3.1.1 Cost of storage

We assumed that all hydrogen production would be supported by hydrogen pipeline storage. This is because the geographic availability and potential scale of lower-cost underground storage solutions such as lined rock caverns or salt caverns are very uncertain. Further details on the costs of these storage options are provided in Appendix B.1.2.

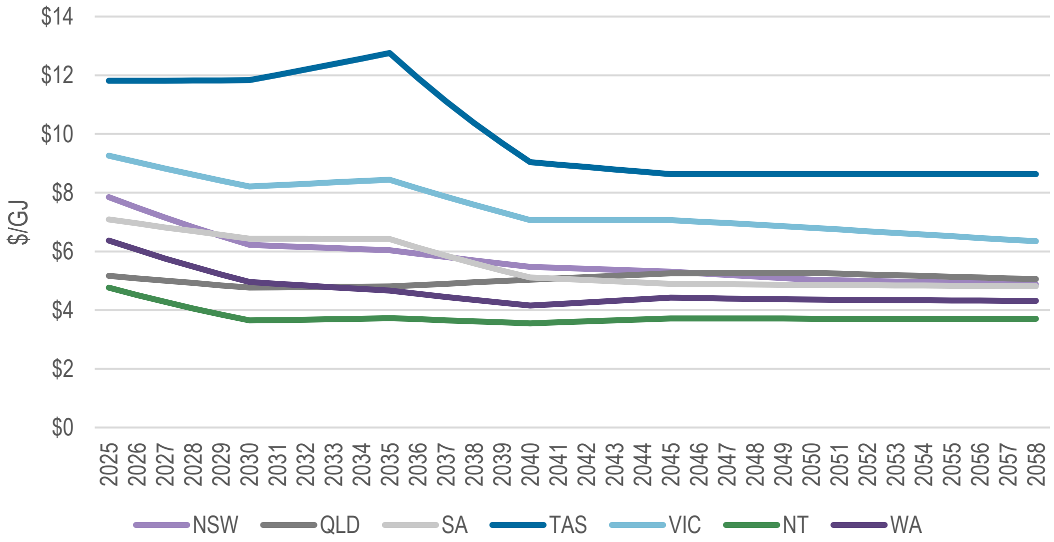
The high cost of pipeline hydrogen storage relative to underground storage makes our storage cost estimates somewhat conservative, but this is offset by our assumption that hydrogen-using plant will have a degree of demand flexibility, consistent with the expected performance of major hydrogen-using plant such as green ammonia plants. A range of technology providers expecting that electrically-driven ammonia plant operating on green hydrogen will have the capability to reduce output to as low as 10% of nameplate capacity depending on the availability of green hydrogen (see for example Topsoe (2024)). To be conservative we assumed that hydrogen-consuming plant would be able to reduce demand to 50% of nameplate capacity in response to low solar or wind availability.

Storage costs are specific to each REZ and year, and are a function of a range of factors including:

- the relative use of wind and solar generation
- the extent of 'over-sizing' of wind and solar generation relative to electrolyser capacity, and electrolyser capacity relative to hydrogen demand
- REZ-specific variations in wind and solar output, especially the extent to which they exhibit large seasonal or year-to-year variations.

For consistency with CSIRO outputs, ACIL Allen averaged REZ-level storage costs (weighted by REZ-level hydrogen production volume) to estimate regional storage costs for each scenario. Figure 3.2 presents costs for the Step Change scenario (costs are comparable for the other two scenarios). More detail on storage-specific assumptions used in ACIL Allen's hydrogen cost modelling are provided in Appendix B.1.

Figure 3.2 State-average hydrogen storage costs, Step Change scenario



Source: ACIL Allen

3.1.2 Cost of transport and delivery

As noted above, ACIL Allen reported hydrogen transport costs as a standalone item to be added to CSIRO's hydrogen costs to provide an all-inclusive hydrogen cost estimate. The primary cost represents bulk hydrogen transmission (by pipeline) from the REZ-based production location to a corresponding demand or export hub. Details on the spatial and pipeline cost assumptions used in ACIL Allen's hydrogen cost modelling are provided in Appendix B.1.

Based on these assumptions, Figure 3.3 presents the state-level average hydrogen transport costs. These costs do not vary over time or between scenarios. State-level differences in these costs primarily reflect the distance between REZs in each state and a suitable consumption or export location. REZ-level costs are weighted by potential hydrogen production volume to derive the state-level average.

Figure 3.3 State-level bulk hydrogen transmission costs, all years and scenarios ($/GJ)

Source: ACIL Allen

In addition, AEMO requested ACIL Allen to estimate hydrogen delivery costs for two classes of users:

— distribution-connected customers, using hydrogen blended into existing natural gas networks
— industrial customers receiving hydrogen directly from a bulk supply pipeline or hub via a dedicated lateral pipeline.

Based on the sources detailed in Appendix B.1 we estimated the cost of hydrogen blending to be $0.42/GJ and the cost of direct delivery to industrial customers to be $1.26/GJ. These costs were held constant across all years and scenarios.

3.2 Biomethane supply

Biomethane is a renewable gas composed primarily of methane that is sourced from biogenic material. As both biomethane and natural gas consist mainly of methane, biomethane is generally a 'like-for-like' replacement for natural gas, and compatible with most natural gas appliances, pipelines and storages.

Biomethane is typically produced by purifying or 'upgrading' biogas. Biogas is produced when biogenic material is broken down by bacteria working in the absence of oxygen ('anaerobic digestion' or AD). Biogas consists of a mix of methane, carbon dioxide and impurities, and so carbon dioxide and other impurities must be reduced to a level compatible with pipelines to become biomethane.

Biomethane can also be produced through gasification of biomass (Box 3.1), but the economics of this approach is generally challenging due to the additional processing steps required. As a result, for this study we have only considered the potential for biomethane production from AD-suitable feedstocks.

Box 3.1 Producing biomethane by gasifying biomass

A very wide range of biomass, including biomass that is not suitable for anaerobic digestion, can be gasified to a 'syngas' mixture of carbon monoxide and hydrogen. Once broken down, the syngas mixture can be further transformed to a mixture of carbon dioxide and hydrogen through the 'water-gas shift reaction), and then be converted into biomethane through the Sabatier (methanation) reaction.

Source: ACIL Allen

The main sources of AD-suitable biomethane feedstock considered in this report are:

— landfill gas, where organic material breaks down anaerobically in landfill and the resulting biogas collected through a series of pipes
— AD of waste streams, such as organic material separated from municipal or commercial waste streams, food processing waste or sludge produced in wastewater treatment plants
— AD of agricultural crop residues, where these residues are separated from the marketable crops and collected.

Although it is technically feasible to produce biogas and biomethane from specifically grown 'energy crops', we do not include this production pathway in our estimates here as this would necessarily displace crops and farmland from their existing purposes.

Biomethane supply is limited in volume by the inherent limitation on feedstocks suitable for anaerobic digestion. There are also significant regional variations in feedstock availability, with some feedstocks being primarily driven by population (for example landfill gas and municipal organic waste) and others being driven by the location and extend of agriculture.

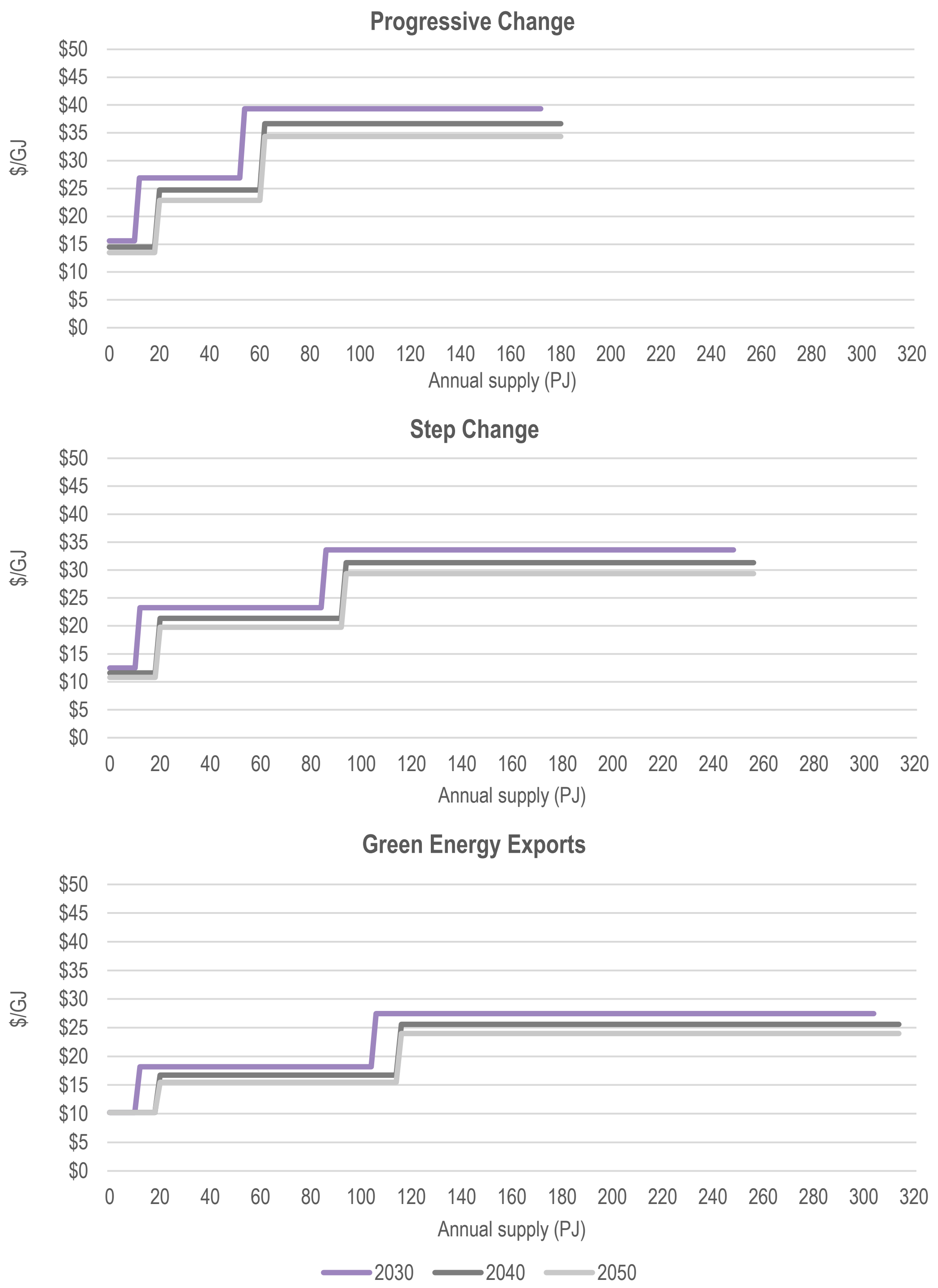
We have used a range of sources to estimate the potential scale of biomethane production, including adjusting the theoretical potential level of production (which is determined by gross feedstock volumes) downwards to reflect commercial constraints, such as logistical and cost barriers to biomass collection and possible competing uses of these feedstocks. Our sources and assumptions are detailed in Appendix B.2.

We have estimated the cost of biomethane in three cost 'steps' as set out further in Appendix B.2:

— Landfill gas is the cheapest as biogas must typically be collected from landfills due to regulatory obligations and so the cost of biomethane primarily represents the cost of upgrading this biogas. However, upgrading landfill gas can be more expensive than other sources of biogas due to the high volume of impurities.
— AD of waste streams is the next most expensive, as a range of wastes are either already collected as part of existing processes (e.g. food processing) or can offset the cost of collection through avoided levies (such as municipal, commercial or industrial waste, where AD avoids landfill fees) or sale of byproducts (particularly 'digestate', which is a nutrient-liquid byproduct of the AD process). The primary cost of biomethane from these sources is the digester and upgrading plant.
— AD of crop residues is the most expensive: in addition to the costs of the digester and upgrading plant, sourcing biomethane from crop residues will typically incur collection costs, both for transport and to incentivise farmers to forgo the use of residues on their land. Some of these costs may be offset through sale of digestate.

Together our volume and price assumptions create supply curves with small volumes of relatively low-cost landfill gas-based biomethane, a higher cost and larger step of production based on AD of wastes, and the largest and highest cost price step of production based on AD of crop residues. The cost of each biomethane resources is highest in the Progressive Change scenario and lowest in the Green Energy Exports scenario, while the volume of resource is lowest in the Progressive Change scenario and highest in the Green Energy Exports scenario. Cost curves across the three scenarios are presented for selected years in Figure 3.4.

Figure 3.4 Biomethane supply curves, 2030, 2040 and 2050



Source: ACIL Allen

3.3 Hydrogen demand

We have estimated demand for a range of green commodities and use cases that require the production of hydrogen, and estimates for the associated green hydrogen demand:

- green hydrogen for export
- green ammonia (whether the ammonia is used directly as a chemical or fuel, but not as a hydrogen carrier, which is included in green hydrogen for export)
- green methanol
- green iron and steel
- alumina
- aluminium
- green hydrogen used to substitute for natural gas in existing or proposed gas-based ammonia plants.

We modelled demand for these commodities, and the associated hydrogen production required to produce them based on a range of sources, which are set out in Appendix B.3. In broad terms, our methodology involved:

- sizing overall international demand for each commodity based on IEA analysis in the 2023 World Energy Outlook, with
  - the IEA's Stated Policies scenario aligning to AEMO's Progressive Change scenario
  - The IEA's Announced Pledges scenario aligning to AEMO's Step Change scenario
  - The IEA's Net Zero Emissions scenario aligning to AEMO's Green Energy Exports scenario
- estimating Australia's share of this international demand based on the fundamental availability of key inputs, including variable renewable resources, biomass (relevant for methanol production) and iron ore (relevant for green iron production)
- further adjusting volumes to reflect the extent of international trade and Australia's established position in each market.

Table 3.1summarises our national-level estimates of production of each of the commodities analysed

Table 3.1 Summary of commodity volumes by scenario, selected years (Mt)

	Commodity/use case	2030	2040	2050
Progressive Change	Hydrogen exports	0.0	0.0	0.0
	Ammonia (green)	0.0	0.0	0.0
	Methanol	0.0	0.0	0.0
	Green iron	0.0	0.0	0.1
	Green steel	0.0	0.0	0.0
	Alumina	18.2	18.2	18.2
	Aluminium	1.6	1.6	1.6
	Ammonia (existing and proposed gas-based plants)	3.5	3.5	3.5
Step Change	Hydrogen exports	0.0	0.0	0.0
	Ammonia (green)	0.1	0.8	2.5
	Methanol	0.0	0.0	0.0
	Green iron	0.0	0.0	0.7
	Green steel	0.0	0.0	0.1
	Alumina	18.2	18.2	18.2
	Aluminium	1.6	1.7	1.8
	Ammonia (existing and proposed gas-based plants)	3.5	3.5	3.5

	Commodity/use case	2030	2040	2050
Green Energy Exports	Hydrogen exports	0.0	0.6	1.8
	Ammonia (green)	1.2	21.9	53.2
	Methanol	0.0	0.4	1.0
	Green iron	1.2	35.0	124.7
	Green steel	0.3	7.5	26.6
	Alumina	18.2	18.2	18.2
	Aluminium	1.6	1.9	2.0
	Ammonia (existing and proposed gas-based plants)	4.2	4.7	4.7

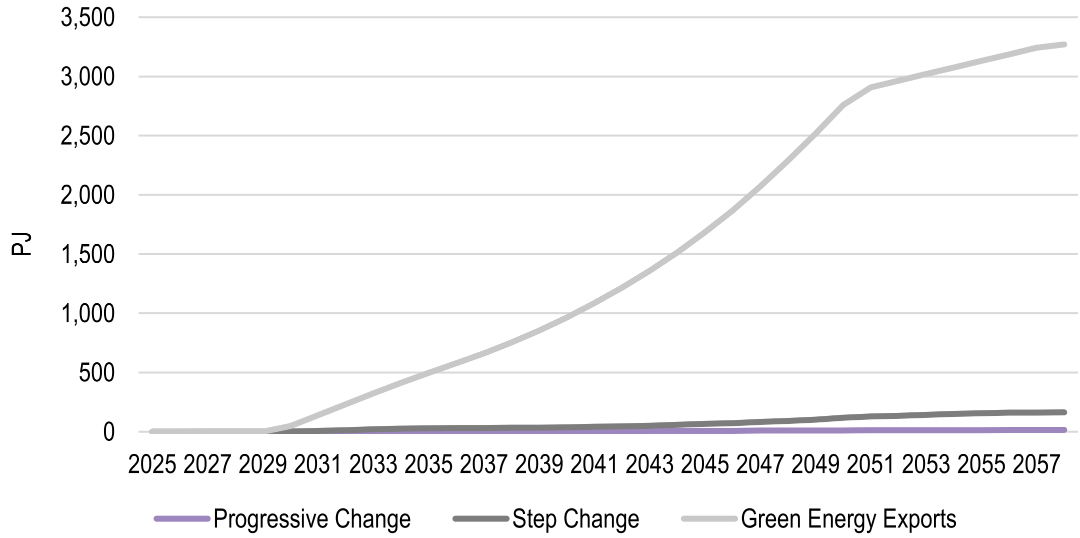
Note: volume of hydrogen exports is the volume of hydrogen itself. For all other commodities the volume shown is the volume of the commodity produced. Iron and steel volumes exclude existing production at integrated (coal-based) steelworks.

Source: ACIL Allen

Different commodities use hydrogen differently and therefore have a different level of hydrogen intensity. In general terms direct export of hydrogen is the most intensive use of hydrogen (highest volume of hydrogen input per unit of output), and ammonia is the next most hydrogen-intensive. Alumina and gas-based ammonia production adopts hydrogen gradually and so have very low hydrogen-intensity in early years of the projections, and especially in the Progressive Change scenario.

Figure 3.5 presents our estimates of national-level hydrogen production by scenario, for the uses in-scope for our analysis (green hydrogen exports and green commodities). Our hydrogen production volumes exclude hydrogen produced for general domestic use, for example in the residential or commercial sectors, for industrial heat (outside of the green commodities listed above) or for transport.

Figure 3.5 Hydrogen production by scenario (PJ)



Note: hydrogen production covers green hydrogen exports and green commodities only.

Source: ACIL Allen

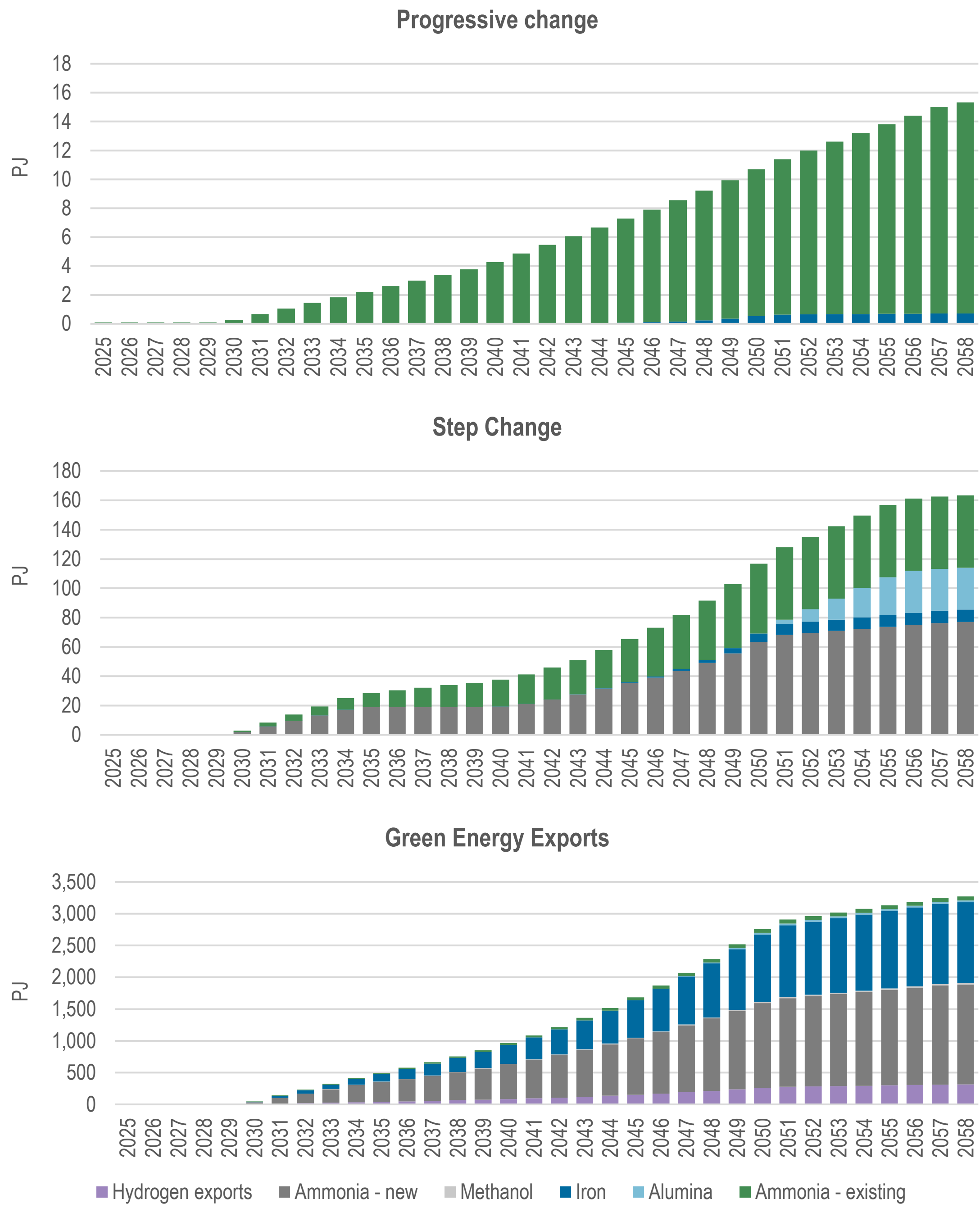
Figure 3.6 presents our estimates of national-level hydrogen production by end use and scenario. Green ammonia is generally the largest green hydrogen end use but:

— in the Progressive Change scenario green hydrogen in only adopted in existing gas-based ammonia plants, rather than through new dedicated green ammonia production

— in the Step Change scenario green iron is also a major use of hydrogen, comparable in scale to, but slightly lower than, green ammonia.

Hydrogen exports are a modest source of hydrogen demand in the Green Energy Exports scenario, but remains significantly smaller than green ammonia or green iron.

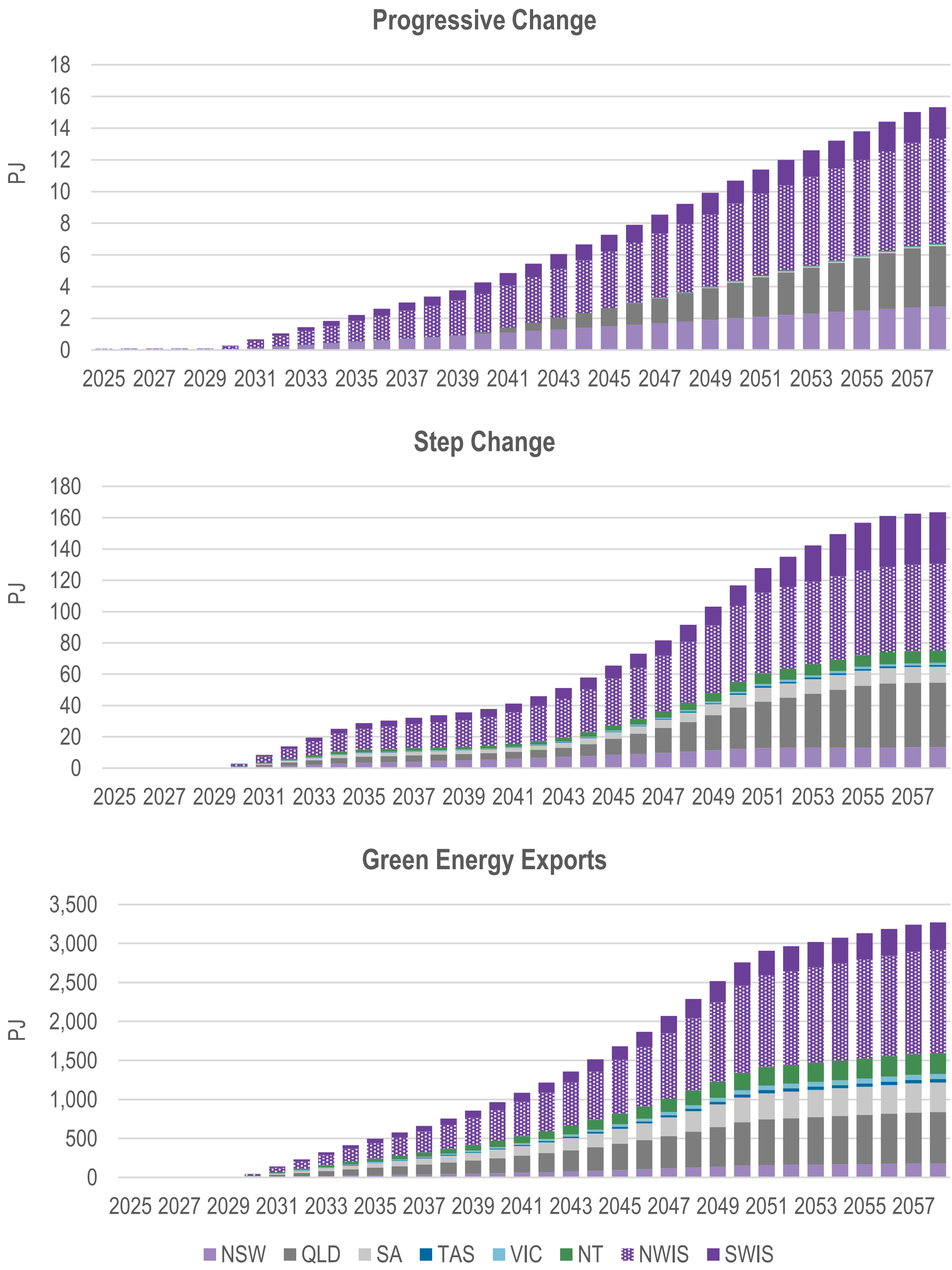
Figure 3.6 Hydrogen consumption by end use and scenario (PJ)



Source: ACIL Allen

Figure 3.7 presents the regional-level hydrogen consumption for each scenario, aggregated across all end-uses (regional-level breakdowns for each commodity are provided in Appendix B.3). The NWIS region (encompassing all of WA except the south-western SWIS region) is the largest hydrogen consuming region in all scenarios, with its established ammonia industry, large renewable energy resources and access to iron ore all contributing to significant production of the key green commodities in this analysis. Queensland and south-west WA (SWIS region) are also important hydrogen consumption locations across all scenarios.

Figure 3.7 Hydrogen consumption by region and scenario (PJ)



Source: ACIL Allen

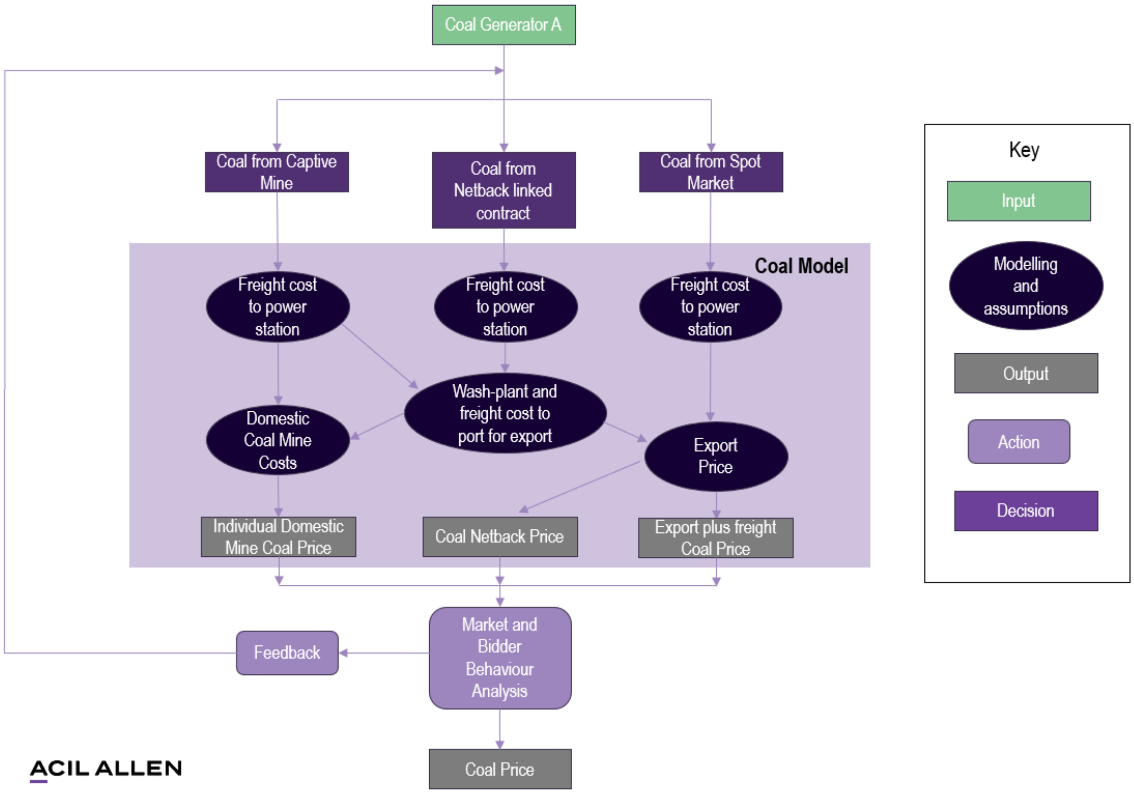
4 Coal prices

4.1 General approach and methodology

ACIL Allen maintains individual coal price projections for all incumbent coal generators in the NEM as a key input for our regular electricity market modelling. Our coal prices for AEMO are based on our regular analysis.

When determining coal prices, each generator's unique situation is modelled using our internal 'Coal model' which takes into account mining costs, unique mine operational processes (wash plant, open cut, underground etc.), export price, and freighting/handling costs. A summary of this model is illustrated below.

Figure 4.1 Coal price methodology



Source: ACIL Allen

Before coal prices can be formulated every coal generator must be classified into the distinct categories that exist in the NEM;

— NSW black coal generators largely with export exposure.

— Victorian brown coal generators with no export exposure and very low marginal mining costs.

— Queensland black coal generators with a number of different arrangements including own mine mouth (least export exposed), third party captive mine mouth, third party captive transported, and third party transported (most export exposed).

For those coal generators relying on own mine supply, the cost of coal is applicable to the mining costs of these operations over time. ACIL Allen tracks these costs for mines to ensure our coal prices for captive mines are accurate and reflective of trends in the industry.

A fundamental input into the NSW and some Queensland power station prices is the trajectory of the relevant coal export price (which is regarded as the Newcastle free-on-board (FOB) price). Out to financial year ending (FYE) 2031 these projections use the FOB forward curve as a starting point defined by the most up to date short term forecasts. Our assessment per scenario on where coal prices are likely to fall by FYE2031 defines how this curve declines over that period. The following table shows the export price assumptions per scenario beyond FYE2031 which are influenced by the IEA outlook and analysis of historical values.

Table 4.1 FOB coal price assumptions (US$/tonne)

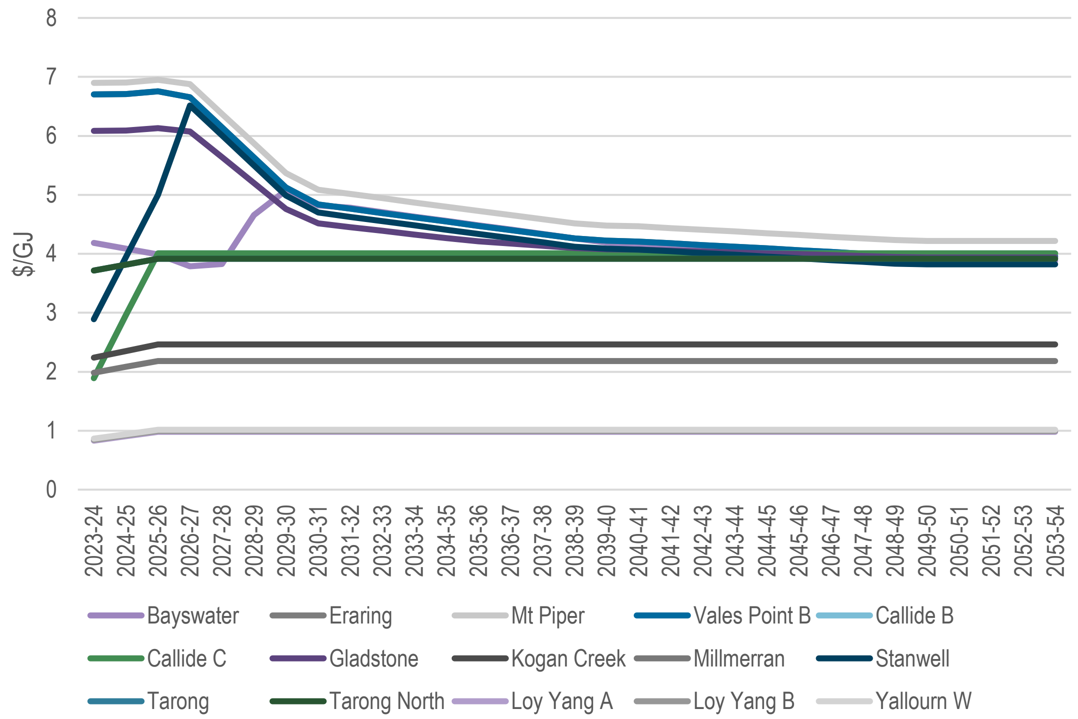
Scenario	FYE2031	FYE2041	FYE2051
Progressive Change	100	87	82
Step Change	80	66	66
Green Energy Exports	65	65	65

Source: ACIL Allen

4.2 Results

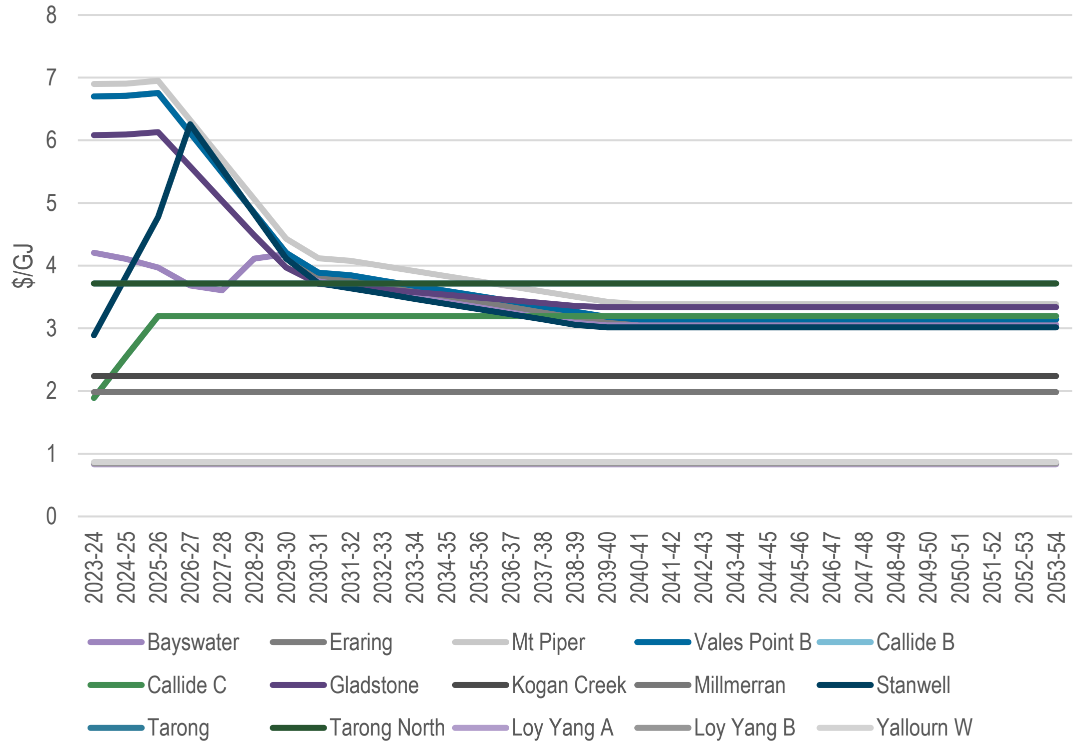
Delivered coal prices for each coal fired power station are shown in the figures below per scenario.

Figure 4.2 Coal prices by power station, Progressive Change scenario



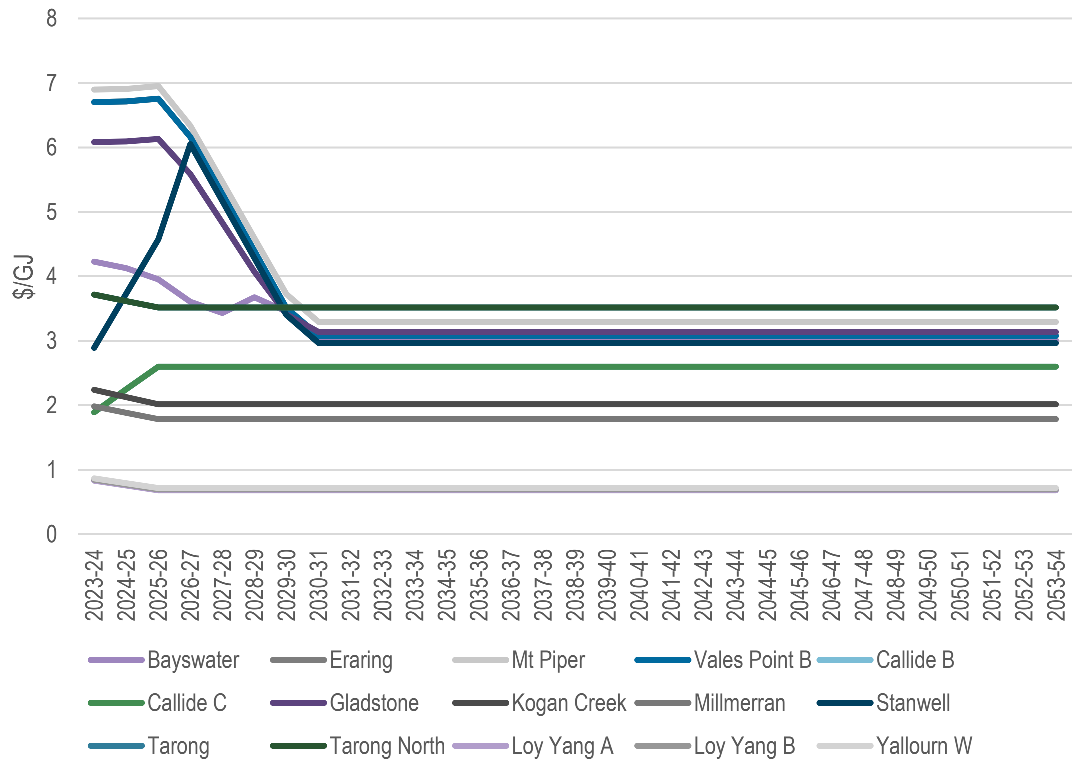
Source: ACIL Allen

Figure 4.3 Coal prices by power station, Step Change scenario



Source: ACIL Allen

Figure 4.4 Coal prices by power station, Green Energy Exports scenario



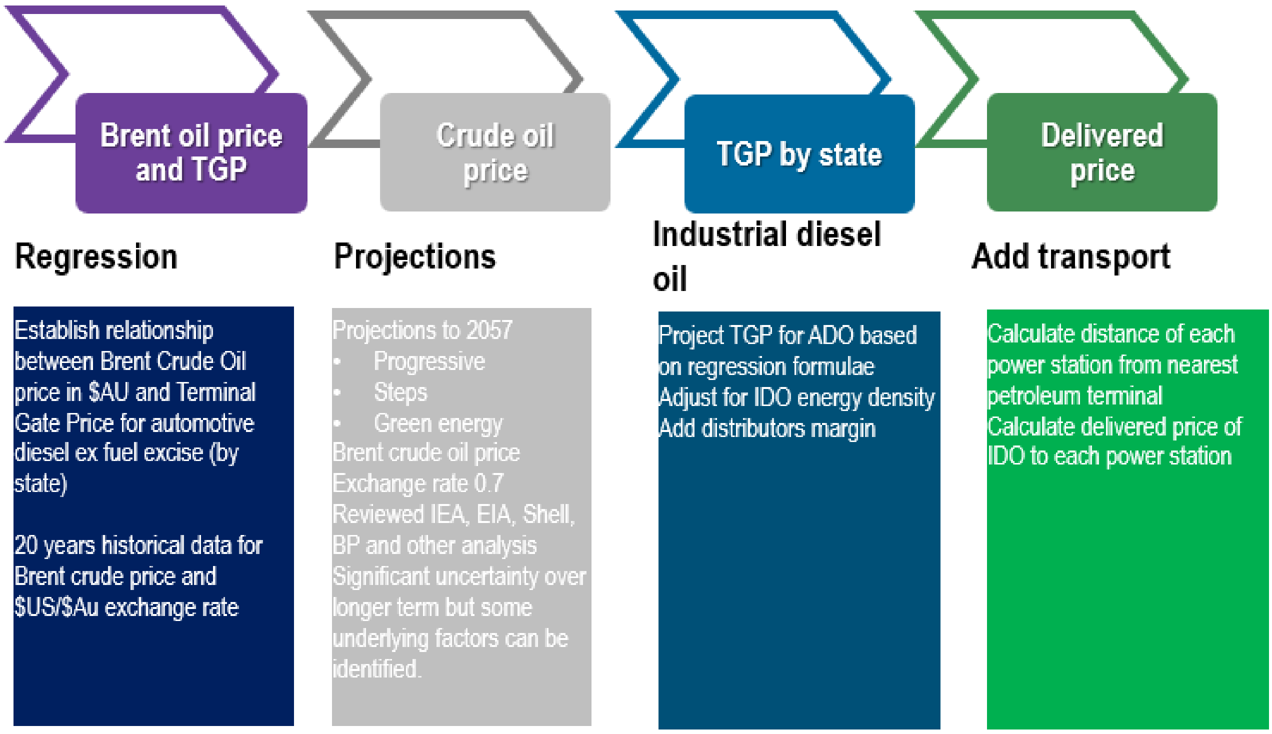
Source: ACIL Allen

5 Liquid fuel prices

5.1 General approach

The brief required the projection of diesel prices at power stations in the National Electricity Market (NEM) that can, or could, use diesel as a fuel. An overview of the general approach to preparing the projections of diesel prices for power stations is provided in Figure 5.1.

Figure 5.1 General approach



Source: ACIL Allen

The approach taken begins with projections of crude oil prices to provide projections of Terminal Gate Prices for automotive diesel oil. These prices are then converted to $/GJ for industrial diesel oil at the terminal. A distributors margin is added to the price and a charge for transport from the nearest petroleum terminal to the power station.

These steps are outlined below.

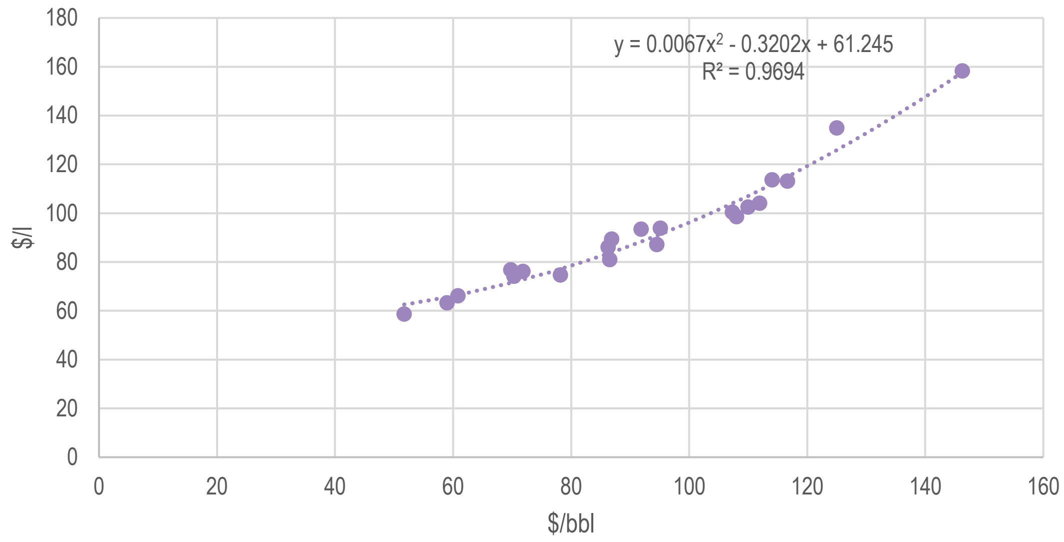
5.2 Terminal gate prices

The most relevant marker price for crude oil for Australian consumption is Tapis crude produced in Malaysia. However, there is not a good price series for Tapis crude and Brent crude is often used as a proxy.

Terminal gate prices for automotive diesel for the past 20 years are available by state from the Australian Institute of Petroleum[2]. A corresponding price series for Brent crude oi prices in US$/bbl is available from Thomson Reuters and published by the US Energy Information Agency[3].

The correlation between Brent crude oil prices and the terminal gate prices, after removing fuel excise, is strong ,as shown for example in Figure 5.2 for NSW. The relationship between the terminal gate price and the Brent crude oil price was similar for each state.

Figure 5.2 Terminal gate prices (excluding fuel excise) in NSW and the Brent Crude oil price in $AU/bbl (automotive diesel oil)



Source: ACIL Allen

5.3 Crude oil price projections

The next step was to devise projections of Brent crude oil prices from the period from 2024 to 2057.

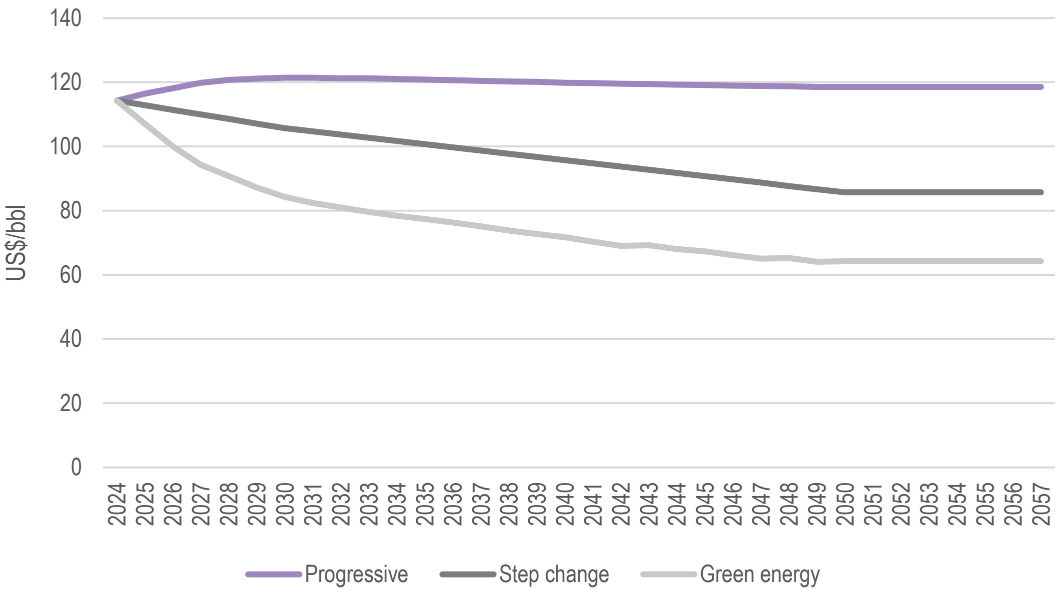
The crude oil market is in a period of transition with a decline in the rate of growth in demand for oil globally. This decline is characterised by a decline in demand growth in advanced economies, offset by growth in demand from emerging market and developing economies (IEA, 2024). This is complicated by ongoing geopolitical events arising from conflicts in central Europe and the middle east that is influencing the short to medium term outlook for supply.

Recent analysis by the International Energy Agency suggest that global oil demand will peak sometime around 2030 with the date of the peak varying depending on the assumed scenario outlook.

The projections of Brent crude oil prices are shown in Figure 5.3.

[2] https://www.aip.com.au/pricing/terminal-gate-prices accessed on 15 October 2024
[3] https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RBRTE&f=A sourced on 15 October 2024

Figure 5.3 Brent crude oil price (US$/barrel)



Source: ACIL Allen

5.4 Converting to prices at power stations

The process to convert the projections of Brent crude prices to prices at power stations involved the following steps:

- Calculating terminal gate prices for automotive diesel in cents per litre for each state in the NEM
- Converting the automotive diesel prices to prices for industrial diesel oil in $/GJ
- Adding a distributors' margin of 3%
- Adding the cost of transport from the nearest petroleum terminal to the power station.

5.5 Results

The following tables present delivered diesel prices for individual generators by scenario for each state in the NEM. The prices are for selected years and the full data set can be viewed in the accompanying workbook that supports this report.

Table 5.1 Delivered diesel price per generator ($/GJ), per scenario - NSW

	Generator	2030	2040	2050
Progressive Change	St George Leagues Club	31.56	31.03	30.60
	Hunter Economic Zone	31.56	31.03	30.61
	Nine network Willougby	31.59	31.06	30.63
	Bankstown Sports Club	31.59	31.06	30.63
	Revesby Workers Club	31.59	31.06	30.64
	Club Merrylands	31.63	31.10	30.67
	Smithfield	31.64	31.11	30.69
	Western Suburbs Leagues Club - Campbelltown, NSW	31.68	31.15	30.72
	West Illawarra Leagues Club	31.82	31.29	30.87
	Tallawarra	31.86	31.33	30.90
	Tallawarra B Power Station	31.86	31.33	30.90
	Colongra	31.95	31.42	30.99
	Eraring GT	31.97	31.44	31.01
	Hunter Power Project	32.11	31.58	31.16
	Broken Hill GT	33.21	32.68	32.25
Step Change	St George Leagues Club	26.65	23.97	21.64
	Hunter Economic Zone	26.65	23.97	21.65
	Nine network Willougby	26.67	24.00	21.67
	Bankstown Sports Club	26.68	24.00	21.67
	Revesby Workers Club	26.68	24.00	21.67
	Club Merrylands	26.72	24.04	21.71
	Smithfield	26.73	24.05	21.73
	Western Suburbs Leagues Club - Campbelltown, NSW	26.77	24.09	21.76
	West Illawarra Leagues Club	26.91	24.24	21.91
	Tallawarra	26.95	24.27	21.94
	Tallawarra B Power Station	26.95	24.27	21.94
	Colongra	27.04	24.36	22.03
	Eraring GT	27.06	24.38	22.05
	Hunter Power Project	27.20	24.52	22.20
	Broken Hill GT	28.29	25.62	23.29
Green Energy Exports	St George Leagues Club	21.34	18.97	17.82
	Hunter Economic Zone	21.34	18.97	17.83
	Nine network Willougby	21.36	18.99	17.85
	Bankstown Sports Club	21.37	19.00	17.86
	Revesby Workers Club	21.37	19.00	17.86
	Club Merrylands	21.41	19.04	17.90
	Smithfield	21.42	19.05	17.91
	Western Suburbs Leagues Club - Campbelltown, NSW	21.46	19.09	17.94
	West Illawarra Leagues Club	21.60	19.23	18.09
	Tallawarra	21.64	19.27	18.13
	Tallawarra B Power Station	21.64	19.27	18.13

Generator	2030	2040	2050
Colongra	21.73	19.36	18.22
Eraring GT	21.74	19.37	18.23
Hunter Power Project	21.89	19.52	18.38
Broken Hill GT	22.98	20.61	19.47

Table 5.2 Delivered diesel price per generator ($/GJ), per scenario - Queensland

	Generator	2030	2040	2050
Progressive Change	Southbank Institute of Technology - Unit 1 Plant	31.53	31.00	30.57
	Townsville	31.54	31.01	30.59
	Swanbank E	31.68	31.15	30.73
	Oakey	32.05	31.52	31.09
	Tarong GT	32.12	31.59	31.17
	Braemar 1	32.39	31.86	31.43
	Darling Downs	32.42	31.89	31.47
	Braemar 2	32.42	31.89	31.47
	Brigalow Peaking Power Plant	32.44	31.91	31.48
	Condamine	32.62	32.09	31.66
	Mt Stuart	32.74	32.21	31.79
	Yarwun	32.91	32.38	31.96
	Roma	33.12	32.59	32.16
	Barcaldine	33.49	32.96	32.53
	Cannington Recip	33.97	33.44	33.02
	Phosphate Hill CCGT	34.46	33.94	33.51
	Mica Creek	34.48	33.96	33.53
	Leichhardt OCGT	34.49	33.96	33.53
	Diamantina CCGT	34.51	33.98	33.56
	X41 OCGT	34.53	34.00	33.58
Step Change	Southbank Institute of Technology - Unit 1 Plant	26.64	23.97	21.65
	Townsville	26.65	23.99	21.67
	Swanbank E	26.79	24.13	21.81
	Oakey	27.15	24.49	22.17
	Tarong GT	27.23	24.57	22.25
	Braemar 1	27.49	24.83	22.51
	Darling Downs	27.53	24.87	22.55
	Braemar 2	27.53	24.87	22.55
	Brigalow Peaking Power Plant	27.54	24.88	22.56
	Condamine	27.73	25.06	22.74
	Mt Stuart	27.85	25.18	22.87
	Yarwun	28.02	25.35	23.04
	Roma	28.23	25.56	23.25
	Barcaldine	28.59	25.93	23.61
	Cannington Recip	29.08	26.41	24.10
	Phosphate Hill CCGT	29.57	26.91	24.59
	Mica Creek	29.59	26.93	24.61
	Leichhardt OCGT	29.60	26.93	24.62
	Diamantina CCGT	29.62	26.95	24.64
	X41 OCGT	29.64	26.97	24.66
Green Energy Exports	Southbank Institute of Technology - Unit 1 Plant	21.35	19.00	17.86
	Townsville	21.37	19.01	17.88
	Swanbank E	21.51	19.15	18.02
	Oakey	21.87	19.52	18.38
	Tarong GT	21.95	19.59	18.46
	Braemar 1	22.21	19.86	18.72

Generator	2030	2040	2050
Darling Downs	22.25	19.89	18.76
Braemar 2	22.25	19.89	18.76
Brigalow Peaking Power Plant	22.26	19.91	18.77
Condamine	22.44	20.09	18.95
Mt Stuart	22.57	20.21	19.08
Yarwun	22.74	20.38	19.25
Roma	22.94	20.59	19.46
Barcaldine	23.31	20.96	19.82
Cannington Recip	23.79	21.44	20.31
Phosphate Hill CCGT	24.29	21.93	20.80
Mica Creek	24.31	21.95	20.82
Leichhardt OCGT	24.31	21.96	20.83
Diamantina CCGT	24.34	21.98	20.85
X41 OCGT	24.36	22.00	20.87

Table 5.3 Delivered diesel price per generator ($/GJ), per scenario - Victoria

	Generator	2030	2040	2050
Progressive Change	Epworth Hospital - East Melbourne - Freemasons	31.40	30.87	30.44
	Newport	31.41	30.88	30.45
	Laverton North	31.43	30.90	30.47
	Somerton	31.50	30.96	30.53
	Hastings Generation Site	31.51	30.98	30.55
	Epworth Hospital - Geelong - Waurn Ponds	31.65	31.12	30.69
	Ballarat Base Hospital Plant	31.75	31.22	30.79
	Snuggery	31.87	31.34	30.91
	Jeeralang B	31.91	31.38	30.95
	Jeeralang A	31.91	31.38	30.95
	Valley Power	31.91	31.38	30.95
	Mortlake	32.10	31.56	31.13
	Bairnsdale	32.31	31.77	31.34
	Uranquinty	32.86	32.33	31.90
Step Change	Epworth Hospital - East Melbourne - Freemasons	26.46	23.77	21.42
	Newport	26.47	23.77	21.42
	Laverton North	26.49	23.79	21.45
	Somerton	26.55	23.86	21.51
	Hastings Generation Site	26.57	23.87	21.52
	Epworth Hospital - Geelong - Waurn Ponds	26.71	24.02	21.67
	Ballarat Base Hospital Plant	26.81	24.11	21.76
	Snuggery	26.93	24.23	21.88
	Jeeralang B	26.97	24.27	21.92
	Jeeralang A	26.97	24.27	21.92
	Valley Power	26.97	24.27	21.93
	Mortlake	27.15	24.46	22.11
	Bairnsdale	27.36	24.67	22.32
	Uranquinty	27.92	25.22	22.87
Green Energy Exports	Epworth Hospital - East Melbourne - Freemasons	21.11	18.72	17.56
	Newport	21.11	18.72	17.56
	Laverton North	21.14	18.74	17.59
	Somerton	21.20	18.81	17.65
	Hastings Generation Site	21.22	18.82	17.67
	Epworth Hospital - Geelong - Waurn Ponds	21.36	18.97	17.81
	Ballarat Base Hospital Plant	21.46	19.06	17.91
	Snuggery	21.58	19.18	18.03
	Jeeralang B	21.61	19.22	18.06
	Jeeralang A	21.61	19.22	18.06
	Valley Power	21.62	19.22	18.07
	Mortlake	21.80	19.41	18.25
	Bairnsdale	22.01	19.62	18.46
	Uranquinty	22.57	20.17	19.02

Table 5.4 Delivered diesel price per generator ($/GJ), per scenario – South Australia

	Generator	2030	2040	2050
Progressive Change	Port Lincoln GT	31.54	31.01	30.58
	Torrens Island B	31.55	31.02	30.60
	Barker Inlet Power Station	31.55	31.03	30.60
	Osborne	31.55	31.03	30.60
	Osborne Recip	31.55	31.03	30.60
	Quarantine	31.56	31.04	30.61
	Pelican Point	31.56	31.04	30.61
	Snapper Point Power Station	31.56	31.04	30.61
	Snapper Point	31.56	31.04	30.61
	Dry Creek	31.57	31.04	30.62
	Bolivar Power Station	31.58	31.05	30.62
	Port Stanvac 1	31.65	31.12	30.69
	Lonsdale	31.65	31.12	30.69
	Angaston	31.80	31.27	30.85
	Kingscote Power Station	31.95	31.42	31.00
	Mintaro	31.99	31.47	31.04
	Hallett	32.18	31.65	31.23
	Bordertown Power Station Gen	32.49	31.96	31.54
	Tatiara Meats	32.49	31.96	31.54
	Blue Lake Milling Power Plant	32.49	31.97	31.54
	Ladbroke Grove	32.91	32.38	31.96
	BHP Olympic Dam Backup Generation	33.52	32.99	32.57
Step Change	Port Lincoln GT	26.65	23.97	21.65
	Torrens Island B	26.66	23.99	21.66
	Barker Inlet Power Station	26.66	23.99	21.66
	Osborne	26.66	23.99	21.66
	Osborne Recip	26.66	23.99	21.66
	Quarantine	26.67	24.00	21.67
	Pelican Point	26.67	24.00	21.67
	Snapper Point Power Station	26.67	24.00	21.67
	Snapper Point	26.67	24.00	21.67
	Dry Creek	26.68	24.01	21.68
	Bolivar Power Station	26.68	24.01	21.68
	Port Stanvac 1	26.76	24.08	21.76
	Lonsdale	26.76	24.08	21.76
	Angaston	26.91	24.24	21.91
	Kingscote Power Station	27.06	24.39	22.06
	Mintaro	27.10	24.43	22.10
	Hallett	27.29	24.62	22.29
	Bordertown Power Station Gen	27.60	24.93	22.60
	Tatiara Meats	27.60	24.93	22.60
	Blue Lake Milling Power Plant	27.60	24.93	22.60
	Ladbroke Grove	28.02	25.35	23.02
	BHP Olympic Dam Backup Generation	23.33	20.95	19.80
Green Energy Exports	Port Lincoln GT	21.34	18.96	17.81
	Torrens Island B	21.36	18.98	17.83

Generator	2030	2040	2050
Barker Inlet Power Station	21.36	18.98	17.83
Osborne	21.36	18.98	17.83
Osborne Recip	21.36	18.98	17.83
Quarantine	21.37	18.99	17.84
Pelican Point	21.37	18.99	17.84
Snapper Point Power Station	21.37	18.99	17.84
Snapper Point	21.37	18.99	17.84
Dry Creek	21.37	19.00	17.85
Bolivar Power Station	21.38	19.00	17.85
Port Stanvac 1	21.45	19.07	17.92
Lonsdale	21.45	19.07	17.92
Angaston	21.60	19.23	18.08
Kingscote Power Station	21.76	19.38	18.23
Mintaro	21.80	19.42	18.27
Hallett	21.98	19.61	18.46
Bordertown Power Station Gen	22.29	19.92	18.77
Tatiara Meats	22.29	19.92	18.77
Blue Lake Milling Power Plant	22.30	19.92	18.77
Ladbroke Grove	22.71	20.34	19.19
BHP Olympic Dam Backup Generation	23.33	20.95	19.80

Table 5.5 Delivered diesel price per generator ($/GJ), per scenario - Tasmania

	Generator	2030	2040	2050
Progressive Change	Bell Bay Three	32.81	32.27	31.83
	Tamar Valley CCGT	32.83	32.29	31.85
Step Change	Bell Bay Three	27.82	25.12	22.78
	Tamar Valley CCGT	27.84	25.14	22.80
Green Energy Exports	Bell Bay Three	22.47	20.11	18.99
	Tamar Valley CCGT	22.49	20.13	19.01

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** with a maximum time horizon of 30 years. 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, Darwin and Karratha – 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

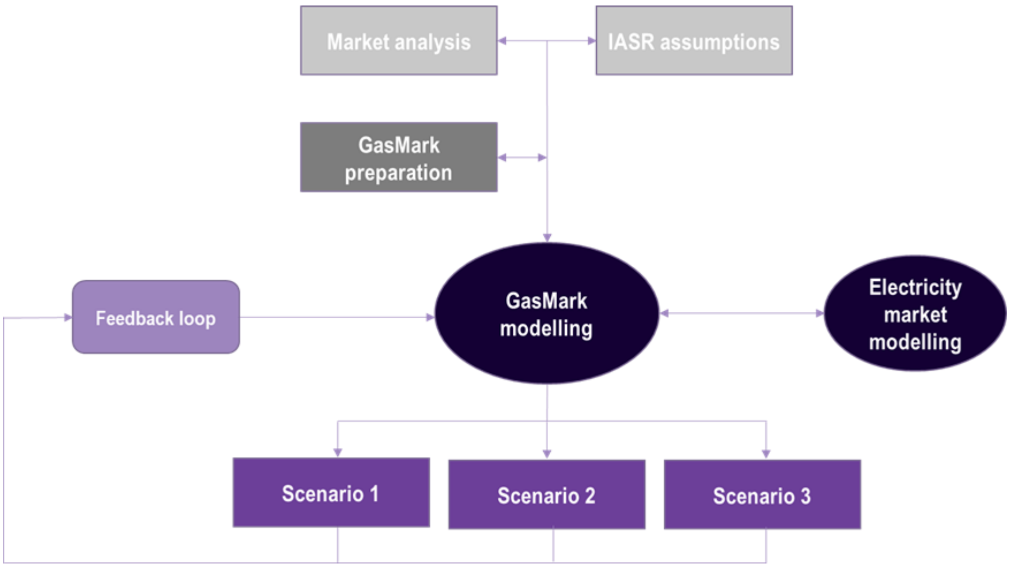
Model component	Key assumptions and data sets
Supply	– Supply assumptions include volume of reserves and resources, production profiles, cost of production, anticipated reserve and resource developments over life span of project and conversion rates for reserves and resources – any specific supply contracts 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, Northern Territory and Western Australia (expect AEMO to provide demand curves) – 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.

A.2.1 Formulation of residential and commercial prices

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

— Prepare demand forecasts and align with AEMO GSOO forecasts, per region, in the ECGM

— Run our GasMark model and produce an average annual wholesale price for each region in the ECGM

— Analyse whether adjustments need to be made based on policy such as the gas code.

A key assumption we make in the residential/commercial modelling is that all wholesale gas to be delivered to residential and commercial customers is sourced via contracts that gas retailers directly have with gas producers. This means that gas being supplied to the mass market throughout the ECGM will be subject to the wholesale price cap. While there may be situations where procurement of gas is different for some markets, the predominant method is certainly retailers having direct supply contracts with gas producers.

The wholesale price cap is assumed to influence domestic price setting in the short to medium term, and then in the longer-term, prices are influenced largely by demand-supply fundamentals. Recent evidence suggests that the price anchor is acting like a 'floor' in the market. We take note of this trend. However, in the long term our gas prices return to being set by demand-supply drivers and how the LNG netback trends. We expect in the future that domestic prices should drop below the $12/GJ mark during certain periods and this is certainly the case for scenarios such as the Green Energy Exports scenario.

The demand forecasts for each region are closely aligned with the 2024 GSOO results. AEMO's demand curves take into account the impact hydrogen and biomethane injection have on natural gas supply in the market. We do not assume any further influence by renewable gases for this sector.

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 the spot market.

A.2.2 Formulation of industrial prices

The key steps for modelling industrial prices are as follows:

— Prepare demand forecasts and align with AEMO GSOO forecasts, per region, in the ECGM and WA

— **Run 1**: Run GasMark model and produce an average annual wholesale price for each region in the ECGM and WA which is reflective of a contract price (and includes the operation of the price cap in the east coast).

— 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 (and if need be, WA)

— **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. 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 – we intend to make an assumption on the proportion of supply procured through contracts and via spot markets (which will 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 which spot markets reflect. Therefore, our forecasts long term will be more reflective of a long-term contract price and will not reflect a weighted price which accounts for short term factors.

We also account for the fact that industrial loads are much flatter loads than residential loads. Retailers typically will pay a premium to producers because of their significant load factor. Industrial users do not require this magnitude of flexibility and ACIL Allen will ensure the prices they paid are not influenced by the peakiness in market prices which are driven by residential and GPG loads.

A.2.3 Formulation of GPG prices

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

— Prepare demand forecasts (using AEMO's GPG data for the east coast and our own demand curves for WA)

— **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 (in relation to the east coast).

— **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 slide, 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 will be based on the type of generator (e.g. OCGT vs CCGT), the location of the generator, and the expected dispatch profile within a year.

We expect the weighted price for each generator to be variable, with some generators being highly skewed towards contracted gas supply and other generators (such as stations with OCGTs who act in a 'peaking' role) who will be skewed much more the other way towards procuring gas via the spot market. This analysis is particularly important given outcomes we are seeing in the market with respect to electricity market prices and how much we believe some generators are paying for gas. Short term prices are also likely to be well above capped prices, which is important to account for.

As we mentioned in respect to industrial prices, in the long-term our prices for generators will reflect a long-term price underpinned by demand and supply fundamentals, and not short-term factors. Therefore, forecasted 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 typically pay to source gas at short notice and at potentially high volumes. This is typically regarding pipeline capacity and the use of storage.

In WA, we don't assume the same gas sourcing/contracting trends. The market in WA is largely contracted and the seasonality and variability in demand and consumption is not like that of the east coast. Therefore, spot market purchases are less frequent. However, we still assume that a small premium for some generators might occur and this could be expected as GPG is likely to get peakier in the future.

A.3 Demand and supply assumptions

A.3.1 Scenario assumptions

Our overall assumptions for the east coast and WA natural gas price modelling is below. These assumptions are aligned as closely as possible to the narrative of each scenario of AEMO's. We have also aligned where we can to individual assumptions relating to demand and supply. This is particularly the case for demand which we highlight further below.

Figure A.2 Overall scenario assumptions – East coast

Assumption	Green energy	Step change	Progressive
Demand	Green Energy Exports scenario demand from 2024 GSOO	Step Change scenario demand from 2024 GSOO	Progressive Change scenario demand from 2024 GSOO
Reserves and resources	2P reserves + 2C resources	2P reserves + 2C resources	2P reserves + 2C resources
Production costs	Aligned with 2024 GSOO costs	Aligned with 2024 GSOO costs	Aligned with 2024 GSOO costs
New gas supply projects (NSW)	No Narrabri	Narrabri proceeds	Narrabri proceeds
New gas supply projects (VIC)	**Gippsland** - GBJV expansion (Kipper) **Otway** - Enterprise and Thylacine from 2024 **Bass** - No further development	**Gippsland** - GBJV expansion (Kipper, Turrum); Manta and Longtom are developed **Otway** - Enterprise and Thylacine from 2024 **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)	No new projects	Bowen Basin – Mahalo project (Santos/Comet Ridge)	Bowen Basin – Mahalo project and expansion of Moranbah Gas Project Galilee Basin (around 90PJ)
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 50 PJ for ECGM	Beetaloo – long term supply capacity of 100 PJ for ECGM	Beetaloo – long term supply capacity ramping up to 500-650 PJ for ECGM (mostly to LNG export)
New storage	No new storage	No new storage project Iona UGS expanded	No new storage project Iona UGS expanded
Pipeline development (greenfield/brownfield)	According to 2024 GSOO	Additional long-term expansion for Amadeus Pipeline, NGP, Carpentaria Pipeline, SWQP and MSP, to cater for increased northern supply	Similar to step change scenario assumptions plus a dedicated high-capacity export pipeline to connect Beetaloo and the ECGM
Pipeline tariffs	According to 2024 GSOO	According to 2024 GSOO	According to 2024 GSOO
Global long term oil price	Long term US$50 per barrel	Long term US$65 per barrel	Long term US$75 per barrel
Queensland LNG exports	Green Energy Exports scenario demand	Step Change scenario demand	Progressive Change scenario demand
LNG import terminals	Port Kembla online from 2027	Port Kembla online from 2027	Port Kembla online from 2027

Figure A.3 Overall scenario assumptions – Western Australia

Assumption	Green energy	Step change	Progressive
Demand	A similar path to AEMO until 2033; our demand then used to 2057	A similar path to AEMO until 2033; our demand then used to 2057	A similar path to AEMO until 2033; our demand then used to 2057
Decarbonisation (key for long term demand)	Limited use of CCUS and offsets, focus on direct emissions reduction; renewable electrification and renewable gas	Most likely mix including a mixture of CCUS, offsets, renewable gases, renewable energy electrification.	Emphasis on CCUS and offsets
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 (Carnarvon)	Scarborough developed	Scarborough developed	Scarborough developed Corvus developed
New gas supply projects (Perth)	West Erregulla Lockyer Deep Waitsia	West Erregulla Lockyer Deep Waitsia	West Erregulla Lockyer Deep Waitsia
New gas supply projects (Browse)	Browse project not developed	Browse project developed from late 2030s/early 2040s	Browse project developed from mid 2030s
New gas supply projects (Canning)	No new projects	No new projects	No New Projects
New storage	No new storage	No new storage	No new storage
Pipeline development (greenfield/brownfield)	According to 2023 GSOO	According to 2023 GSOO	According to 2023 GSOO
Pipeline tariffs	According to current published tariffs	According to current published tariffs	According to current published tariffs
WA LNG DMO/Domestic Commitments	Based on Low scenario LNG Projects	Based on Expected scenario LNG Projects	Based on High scenario LNG Projects

Source: ACIL Allen

A.3.2 East coast demand

Forecast demand in our model has been closely aligned with that of AEMO. AEMO have provided their latest demand forecasts for the Step Change, Progressive Change and Green Energy Exports scenarios. The model ensures consumption is aligned with these demand curves and the effect on consumption from price changes is managed by our supply assumptions. The only scenario which assumes significant green field development to meet demand is the Progressive case with its considerable and sustained LNG export task.

Demand in all scenarios mirrors AEMO's forecast demand with some minor deviation due to alignment with hydrogen assumptions we have made in regard to some industrial users across the east coast market (alumina and ammonia manufacturers).

The only significant difference and departure from the AEMO assumptions is in the Green Energy Exports scenario where the roll-off rate resulted in more demand falling away earlier. However, this is only for a brief period and then our demand curve re-aligns with AEMO's.

AEMO's domestic demand was supplied up until 2043, with LNG demand provided until 2053. ACIL Allen extrapolated domestic and LNG demand out to 2057.

Figure A.4 Gas demand alignment with AEMO assumptions – east coast gas market

Source: ACIL Allen

A.3.3 Western Australian demand

Given recent market developments, the limited forecast horizon of the GSOO, and the adjustments necessary for compliance with our renewable gas forecasts, ACIL Allen and AEMO have agreed to use the following demand traces for Western Australia. Deviations to the GSOO are broadly in line with industry (chiefly the shutdown of Alcoa's Kwinana alumina refinery) and long-run demand is broadly consistent with underlying assumptions for each scenario.

ACIL Allen prepared the following demand traces by projecting how each major gas consuming industry may trend over time in each scenario. The main gas consuming industries are power generation (including power generation for mining), mineral processing and large industrial.

— **Expected Case**
  Demand in the Expected case accounts for committed projects such as the Perdaman urea plant, some expansion of mining activity in line with the GSOO (which in the long run is offset by electrification of mining load using VRE), some coal-to-gas switching in alumina (Worsley) and no new Ammonia projects/expansions. Alumina and ammonia plant move away from gas consistent with our renewable gas forecasts.

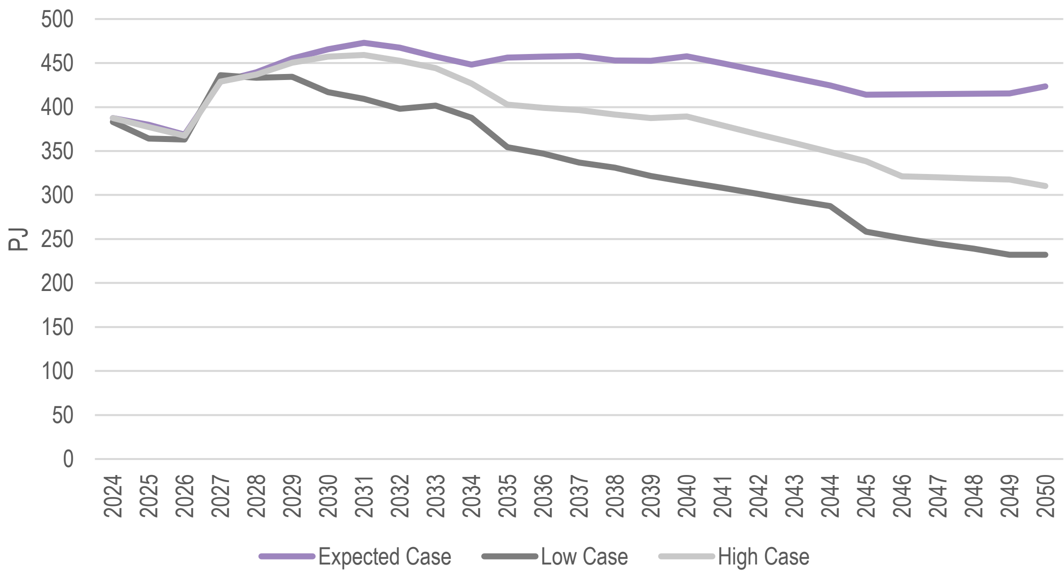
— **High Case:**

  Demand in the High case accounts for committed projects such as the Perdaman urea plant, a larger expansion of mining activity in line with the GSOO, some coal to gas switching in alumina (Worsley) and some expansions in the ammonia industry. Alumina plant do not move away from gas, and the transition for ammonia is consistent with our renewable gas forecasts for this scenario.

— **Low Case**

  Demand in the Low case also accounts for committed projects such as Perdaman Urea plant. However, limited expansion of mining activity occurs and greater movement away from gas occurs in the alumina and ammonia sectors. This movement away from gas begins earlier in the forecast period and is consistent with our renewable gas forecasts.

Figure A.5 Gas demand projections: – Western Australia



Source: ACIL Allen

B Renewable gas modelling methodology

B.1 Hydrogen supply

B.1.1 Overall approach

ACIL Allen has developed a detailed hydrogen cost model that builds on AEMO's Integrated System Plan (ISP) outputs to develop renewable hydrogen cost estimates at the Renewable Energy Zone (REZ) level. This approach captures differences in the inherent variability, seasonal patterns and overall resource quality for solar and wind in each REZ, to develop detailed REZ-level cost estimates.

Our hydrogen modelling capability builds on a range of assumptions from the ISP and other sources, as detailed below. For this assignment we have amortised capital costs using a real pre-tax discount rate of 7% to derive unit costs. This discount rate is consistent with that used as the core discount rate in the 2024 ISP.

Our estimation looked at 14 years of wind and solar data for each REZ, to include the impact of year-to-year variation in solar and wind variability. Solar, wind, electrolyser and storage volumes were calibrated to maintain reliable constant supply throughout these variations.

Not all NEM REZs were modelled. REZs with insufficient solar and wind capacity (excess to general grid requirements) were deemed unsuitable for large-scale hydrogen production and excluded.

As AEMO does not publish data for REZs in WA or the NT (due to the ISP not covering those jurisdictions), we created 'synthetic' REZs for these locations based on comparable NEM REZs.

Costs were modelled on a financial year basis. Costs were modelled based on five-yearly spot years (2024-25, 2029-30, 2034-35, 2039-40, 2044-45, 2049-50, 2054-55) and interpolated between to derive a yearly results series.

The storage and transport components of this cost modelling were extracted and used as inputs to CSIRO's multi-sector modelling, alongside CSIRO's own modelled estimates of the other cost elements of hydrogen production.

B.1.2 Hydrogen storage

Hydrogen storage acts as a buffer between variable solar and wind generation and the assumed flat consumption load profile modelled for this exercise. The size and cost of hydrogen storage is an important element of the hydrogen cost stack.

Storage volumes were calculated for each REZ and year based on the optimal wind, solar and electrolyser mix needed to serve the modelled demand, allowing for variability in wind and solar output while preserving a minimum level of hydrogen in storage ('cushion gas'). The key storage cost estimates are summarised in Table B.1.

Table B.1 Key hydrogen storage cost assumptions

	Capital cost ($/kg)	Cushion gas requirement	Fixed operations and maintenance costs
Pipeline storage	887	9%	3% of capex
Lined rock cavern	150	17%	3% of capex
Salt cavern	53	31%	3% of capex

Source: ACIL Allen based on Papadias and Ahluwalia (2021)

Due to uncertainty over the availability and viable scale of lined rock cavern and salt cavern storage, we adopted the conservative assumption of only using higher cost pipeline storage in our modelling.

B.1.3 Transport costs

Each REZ was matched to a consumption or export location to estimate the distance and costs associated with transporting hydrogen from the REZ to the point of consumption. The indicative REZ location and consumption location, and unit cost for each modelled REZ is summarised in Table B.2.

Table B.2 Spatial assumptions and REZ-level transport costs

REZ	Loca-tion	Indicative REZ location	Assumed consumption location	Indicative pipeline distance (km)	Unit transport cost ($/GJ)
Far North QLD	QLD	Lakeland	Townsville	710	$1.51
North Qld Clean Energy Hub	QLD	Hughenden	Townsville	460	$1.10
Northern Qld	QLD	Mingela	Townsville	180	$0.53
Isaac	QLD	Collinsville	Mackay	260	$0.71
Barcaldine	QLD	Barcaldine	Gladstone	780	$1.61
Fitzroy	QLD	Boulder Creek	Gladstone	200	$0.57
Wide Bay	QLD	Biggenden	Gladstone	330	$0.86
Darling Downs	QLD	Dalby	Gladstone	530	$1.23
Banana	QLD	Theodore	Gladstone	270	$0.73
North West NSW	NSW	Bellata	Newcastle	540	$1.24
Central-West Orana	NSW	Elong Elong	Newcastle	430	$1.05
Broken Hill	NSW	Broken Hill	Port Bonython	540	$1.24
South West NSW	NSW	Steam Plains	Geelong	540	$1.24
Wagga Wagga	NSW	Brookdale	Geelong	650	$1.42
Tumut	NSW	Gundagai	Port Kembla	510	$1.19
Ovens Murray	VIC	Benalla	Geelong	420	$1.03
Murray River	VIC	Kerang	Geelong	410	$1.01
Western Victoria	VIC	Horsham	Portland	300	$0.80
South West Victoria	VIC	Caramut	Portland	190	$0.55
South East SA	SA	Wattle Range	Portland	250	$0.69
Mid-North SA	SA	Hallett	Port Bonython	200	$0.57
Yorke Peninsula	SA	Minlaton	Port Bonython	330	$0.86
Northern SA	SA	Carriewerloo	Port Bonython	150	$0.45
Leigh Creek	SA	Leigh Creek	Port Bonython	370	$0.94
Roxby Downs	SA	Roxby Downs	Port Bonython	390	$0.97
Eastern Eyre Peninsula	SA	Kimba	Port Bonython	210	$0.60
Western Eyre Peninsula	SA	Poochera	Port Bonython	370	$0.94

REZ	Loca-tion	Indicative REZ location	Assumed consumption location	Indicative pipeline distance (km)	Unit transport cost ($/GJ)
North East Tasmania	TAS	Rushy Lagoon	Bell Bay	250	$0.69
North West Tasmania	TAS	Waratah	Bell Bay	330	$0.86
Central Highlands	TAS	St Patricks Plains	Bell Bay	280	$0.75
Northern NT	NT	Katherine	Darwin	370	$0.94
Barkly	NT	Tennant Creek	Darwin	1110	$2.03
Central NT	NT	Davenport	Darwin	1270	$2.20
Pilbara	WA	Pannawonica	Pt Hedland/ Dampier/ Point Samson	210	$0.60
Gascoyne	WA	Yandoo Creek	Carnarvon	150	$0.45
Mid-West	WA	Mullewa	Geraldton	130	$0.40
Wheatbelt	WA	Corrigin	Kwinana	360	$0.92
Eastern SWIS	WA	Kalgoorlie	Esperance	470	$1.12

Note: indicative pipeline distances include additional allowances to deal with travel through heavily-utilised urban and peri-urban areas, connection to suitable underground storage sites and a generic allowance to deal with irregularities in terrain and other constraints.
Source: ACIL Allen

Costs were estimated on a 2021 study for the Australian Pipelines and Gas Association with ACIL Allen adjustments for inflation (Table B.3).

Table B.3 Pipeline cost parameters

Pipeline distance	Cost (2021$ per inch-kilometer)	Cost (2024$ per inch-kilometer)	Fixed operations and maintenance (% of capex)
Under 100 km	70,000	80,448	3.5%
100 to 249 km	50,000	57,463	2.3%
250 to 499 km	40,000	45,970	2.1%
500 km and over	37,800	43,442	1.9%

Source: GPA Engineering (2021); inflation adjustments by ACIL Allen based on ABS CPI data.

B.1.4 Cost of hydrogen delivery to end consumers

We examined to elements of hydrogen delivery to end customers:

— blending hydrogen into existing gas distribution networks, to deliver a natural gas/hydrogen blend at up to 10% by volume (roughly equivalent to 3% by energy)

— delivering hydrogen via a new dedicated hydrogen pipeline to an industrial customer (assumed to consumer 10 TJ/day).

The hydrogen blending cost includes all costs associated with converting existing natural gas network equipment to be compatible with a 10% by volume hydrogen blend. We used estimates from access arrangement proposals for Australian Gas Networks (Victorian network) and Multinet (also in Victoria). These proposals examined options for capital expenditure to get these networks ready for hydrogen, including options where all relevant expenditure was incurred by 2028. These estimates summed to just under $20 million (2021 dollars), and we adjusted this estimate to January 2024 dollars and amortised these costs over 40 years at the current gas network regulated rate of return. This approach implies a cost of $0.42/GJ of hydrogen delivered.[4]

For dedicated pipeline delivery for a hypothetical industrial customer we assessed the cost of several pipeline distances:

— we assessed the cost of 25 km and 100 km pipeline, applying a 25% weighting to each

— we assessed the cost of a 50 km pipeline and applied a 50% weighting.

For all distances we assumed an 80% pipeline utilisation rate, and average demand of 10 TJ/day. We assumed a cost of just over $100,000 per pipeline inch-kilometre, and either a 4 inch (25 km) or 6 inch (50 km and 100 km) capacity (GPA Engineering, 2021). Amortising these costs over 40 years implied a weighted-average unit cost across the three distances of $1.26/GJ.

These costs are additional to transportation (bulk transmission) costs presented in section B.1.3.

B.2 Biomethane supply

B.2.1 Available volume

As noted in the body of the report, biomethane supply is limited in volume by the inherent limitation on feedstocks suitable for anaerobic digestion. There are also significant regional variations in feedstock availability, with some feedstocks being primarily driven by population (for example landfill gas and municipal organic waste) and others being driven by the location and extend of agriculture.

We have used a range of sources to estimate the potential scale of biomethane production. These sources provide detail on:

— the underlying or theoretically available level of feedstock suitable for biogas production

— locational aspects of this availability

— the effects of potential constraints on conversion of the theoretical biogas resource to production, including logistical and cost barriers to biomass collection and possible competing uses of these feedstocks.

Table B.4 summarises our key sources that form the basis of our estimate.

Table B.4 Key sources used to inform estimate of biomethane volumes

Source (s)	Usage
ENEA Consulting and Deloitte (2021), *Australia's Bioenergy Roadmap*	Total volume of biomass resource by state and feedstock category. Feedstock categories are organic wastes and residues, forestry and agriculture (p. 23) Volume of feedstock sub-categories at a national level (Appendix B, data file) Total volume of bagasse energy (Appendix A, p. 9)
Deloitte Access Economics (2017), *Decarbonising Australia's gas distribution networks*	Theoretical potential biogas production by feedstock category and state (p. 45)
ENEA Consulting (2022)*, 2030 emission reduction opportunities for gas networks*	Theoretical potential biogas production by feedstock category and state (p. 36)

[4] This cost is equivalent to $0.15 per GJ of natural gas delivered. While the cost of hydrogen blending is low when spread across the total network throughput, we consider the more relevant metric is the cost incurred to achieve hydrogen blending divided by the incremental volume of hydrogen delivered.

Source (s)	Usage
Australian Sugar Milling Council (2024), *Sugar industry summary statistics*	State share of biomass comprised of bagasse (sugar cane waste)
Australian Bureau of Statistics (2024), *Australian agriculture: broadacre crops*	State share of key broadacre crops providing biomethane feedstock (wheat, barley, canola, maize, sorghum)
ENEA Consulting (2019), *Biogas opportunities for Australia*	Existing biogas production used in power generation or other uses , to adjust estimates of available biomethane (p. 28)

Source: ACIL Allen using the sources cited

The theoretically available resource identified using the sources above is further reduced to reflect real-world logistical and commercial constraints on collecting the potential resource for biomethane production. These constraints include competing uses, the geographical dispersal of crop residues (creating logistical and commercial constraints on collection) and contamination of waste streams.

Following the Bioenergy Roadmap[5] we assume in our central (Step Change) scenario that 45% of crop residue resources will be feasible for use as a biomethane feedstock. Reflecting their concentrated nature, we assume higher collection rates are feasible for landfill gas and waste-based feedstocks. We vary the potential collection rate of waste-based feedstocks and crop residues across the scenario to reflect uncertainty about what is possible in practice, but hold the level of landfill gas utilisation at 90% across all three scenarios (Table B.5).

Table B.5 Assumed share of theoretical resource feasible for biomethane production

	Landfill gas	AD – wastes	AD – crop residues
Progressive Change	90%	40%	33%
Step Change	90%	70%	45%
Green Energy Exports	90%	90%	55%

Source: ACIL Allen

Table B.6 summarises the results of this analysis based on the above assumptions for the post-2030 period and Table B.7 shows the pre-2030 volumes. Pre-2030 volumes are lower than the long-run potential because the Australian Government's Large-scale Renewable Energy Target (LRET) scheme creates an incentive to continue to use biogas in power generation rather than upgrade this biogas to biomethane. Post-2030 this incentive will cease and we assume that biogas volumes currently used for power generation (primarily landfill gas) will be available for upgrading to biomethane.

Table B.6 Volume of potential biomethane production (PJ), by scenario, location and feedstock – post-2030

Scenario	Location	Landfill gas	AD – wastes	AD – crop residues	Total
Progressive Change	NSW	5.4	9.8	33.1	48.2
	QLD	3.3	6.5	10.3	20.1
	SA	1.1	5.8	18.3	25.1
	TAS	0.4	2.2	0.0	2.5
	VIC	6.7	9.1	17.6	33.4
	NT	0	0	0	0.0
	WA	1.7	9.3	41.6	52.6
Progressive Change	Australia	18.5	42.6	120.8	181.9
Step Change	NSW	5.4	17.1	45.1	67.6

[5] P. 15 in Appendix A of ENEA Consulting and Deloitte (2021)

Scenario	Location	Landfill gas	AD – wastes	AD – crop residues	Total
	QLD	3.3	11.4	14.0	28.7
	SA	1.1	10.1	24.9	36.1
	TAS	0.4	3.8	0.0	4.1
	VIC	6.7	15.9	24.1	46.6
	NT	0	0	0	0.0
	WA	1.7	16.3	56.7	74.7
Step Change	Australia	18.5	74.5	164.8	257.8
Green Energy Exports	NSW	5.4	22.0	55.1	82.5
	QLD	3.3	14.6	17.1	35.1
	SA	1.1	12.9	30.4	44.5
	TAS	0.4	4.8	0.0	5.2
	VIC	6.7	20.4	29.4	56.5
	NT	0	0	0	0.0
	WA	1.7	21.0	69.3	92.0
Green Energy Exports	Australia	18.5	95.8	201.4	315.7

Source: ACIL Allen

Table B.7 Volume of potential biomethane production (PJ), by scenario, location and feedstock – pre-2030

Scenario	Location	Landfill gas	AD – wastes	AD – crop residues	Total
Progressive Change	NSW	3.4	9.5	33.0	45.9
	QLD	2.0	6.3	10.3	18.7
	SA	0.7	5.6	18.2	24.5
	TAS	0.2	2.1	0.0	2.3
	VIC	4.2	8.8	17.6	30.6
	NT	0	0	0	0.0
	WA	1.1	9.1	41.6	51.7
Progressive Change	Australia	11.6	41.4	120.7	173.7
Step Change	NSW	3.4	16.6	45.0	65.1
	QLD	2.0	11.1	14.0	27.1
	SA	0.7	9.8	24.9	35.4
	TAS	0.2	3.7	0.0	3.9
	VIC	4.2	15.4	24.0	43.6
	NT	0	0	0	0.0
	WA	1.1	15.9	56.7	73.6
Step Change	Australia	11.6	72.5	164.7	248.7
Green Energy Exports	NSW	3.4	21.4	55.0	79.8
	QLD	2.0	14.2	17.1	33.4
	SA	0.7	12.6	30.4	43.7
	TAS	0.2	4.7	0.0	4.9
	VIC	4.2	19.9	29.4	53.4
	NT	0	0	0	0.0
	WA	1.1	20.4	69.3	90.7

Scenario	Location	Landfill gas	AD – wastes	AD – crop residues	Total
Green Energy Exports	Australia	11.6	93.2	201.2	306.0

Source: ACIL Allen

B.2.2 Cost

In practice the cost of biomethane will vary considerably between individual projects depending on a range of factors including:

— the size of the projects and associated plant (e.g. digester and upgrading plant)

— the quality and geographic concentration of the feedstock

— the local costs for avoided landfill levies

— the demand for and price of digestate in local markets

— commercial aspects of sourcing residues from farmers or other providers.

Given these range of factors and the lack of commercial biomethane plants in Australia it is not feasible to estimate precise locational costs for the purpose of this analysis. Rather, we estimated high-level cost curves for each of the three cost steps (landfill gas, AD from wastes and AD from crop residues) based on analysis in *Australia's Bioenergy Roadmap* (ENEA Consulting and Deloitte, 2021) and recent analysis of the levelised cost of biomethane supply by Blunomy (2024) for the Australian Gas Infrastructure Group.

Table B.8 summarises our use of each source to generate cost curves for each feedstock type and each scenario. We compared Blunomy's cost estimates for contemporary projects with time series estimates from the Bioenergy Roadmap and combined these sources to reflect a mix of potential cost outcomes across the scenarios, with Progressive Change having the higher cost outcomes and Green Energy Exports having he lower cost outcomes. We do not have sufficiently granular data to estimate different cost curves for each region although, as noted above, we do vary the potential volume of biomethane production to reflect feedstock availability.

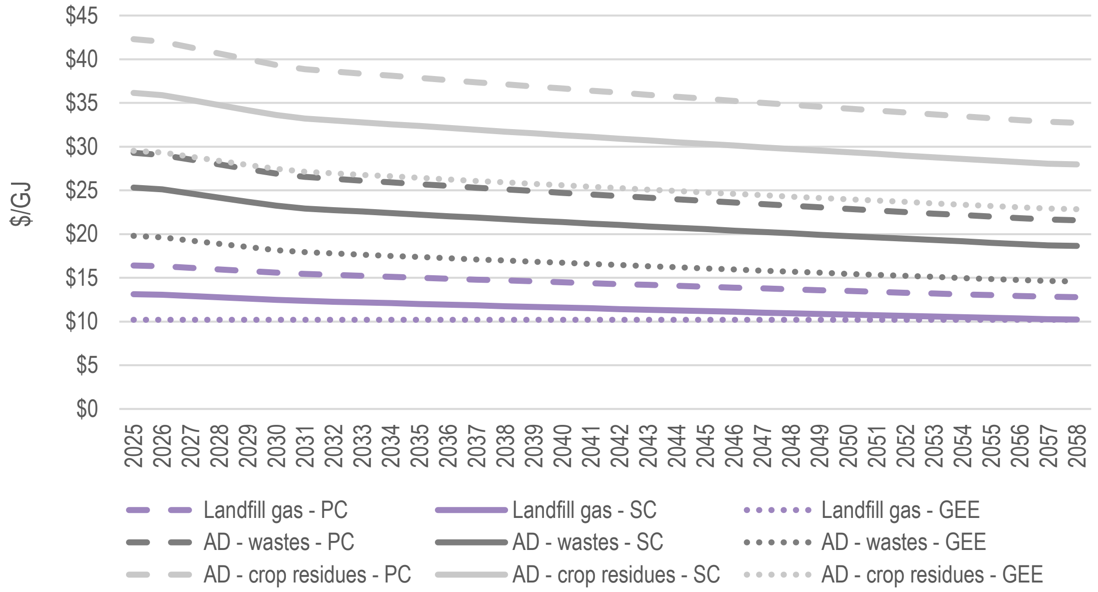
Table B.8 Derivation of cost assumptions

	Landfill gas	AD – wastes	AD – crop residues
Progressive Change	Bioenergy Roadmap, +25%	Blunomy high estimate for 2025, declining in line with Bioenergy Roadmap	Blunomy high estimate for 2025, declining in line with Bioenergy Roadmap
Step Change	Bioenergy Roadmap	Bioenergy Roadmap	Average of Blunomy low and high estimates for 2025, declining in line with Bioenergy Roadmap
Green Energy Exports	Blunomy, held constant in real terms	Average of Blunomy low and high estimates for 2025, declining in line with Bioenergy Roadmap	Bioenergy Roadmap

Source: ACIL Allen based on the sources cited

These assumptions result in the biomethane costs set out in Figure B.1.

Figure B.1 Biomethane cost by feedstock, scenario and year ($/GJ)



Note: PC = Progressive Change scenario; SC = Step Change scenario; GEE = Green Energy Exports scenario.
Source: ACIL Allen

B.3 Renewable gas demand assumptions and analysis

B.3.1 Green hydrogen for export

Description of hydrogen use case

Currently most hydrogen is produced from fossil fuels and used in chemical plants and oil refineries. Hydrogen production typically uses either 'steam methane reforming' (SMR) of natural gas or gasification of coal to produce a mixture of hydrogen and carbon monoxide known as 'syngas', which is then further transformed to a mix of hydrogen and carbon dioxide through a 'water-gas shift' reaction[6]. If fossil fuels are being used to make hydrogen, in general terms it is easier to transport the fossil fuels themselves than to transport hydrogen, and so hydrogen is most commonly-produced close to its point of use.

However, a range of stakeholders expect that hydrogen could become a widely-traded energy commodity as the world decarbonises. This is because abundant solar and wind energy could be used to produce 'green hydrogen' through electrolysis, and trading hydrogen or hydrogen-intensive commodities (such as green ammonia, green iron and methanol) would effectively transport energy from renewable-rich locations to locations with higher energy needs or less abundant resources.

Hydrogen could be transported from Australia to export markets in a range of ways including:

— conversion to ammonia (which is a widely transported in liquid form), with that ammonia either being used directly as a chemical or fuel, or being converted back to hydrogen in the importing country

— compressing or liquefying hydrogen to a density suitable for economic shipping (similar to the existing liquefied natural gas industry)

[6] Where steam reacts with carbon monoxide to create hydrogen and carbon dioxide.

— reaction of hydrogen to form a more transportable substance, and then reconverting that substance back to hydrogen in the importing country, with the primary options for this being:
  - reacting hydrogen with toluene to make methylcyclohexane (a liquid organic compound)
  - absorption of hydrogen with a metal to make a transportable metal hydride.

This section estimates the potential volume of demand for export hydrogen using any of the transportation methods discussed above, including ammonia (when the ammonia is converted back to hydrogen for end use). We analyse the volume of green ammonia used directly as a chemical or as a fuel in section B.3.2 below.

Export hydrogen volume

Global demand for export hydrogen is highly uncertain as it depends on a range of factors including global emissions policy settings, relative energy costs across countries, the viability of hydrogen against electric and other alternative options in a range of use cases (such as transport and heat), and technical and economic uncertainty about the viability of various hydrogen transportation approaches. This uncertainty is compounded by the immature state of the global hydrogen market, the rapidly changing economics of hydrogen production and the 'chicken-and-egg' problem of needing to scale up demand in order to reduce costs from current high levels in a market where demand is hard to stimulate due to high costs.

We have relied on the International Energy Agency's 2023 World Energy Outlook as our primary source for calibrating global traded hydrogen demand (Table B.9). This analysis indicates that the volume of hydrogen traded internationally is a very low share of total hydrogen demand, approximately 20% across all scenarios. Further, this estimate of traded hydrogen volumes includes pipeline-based trade between closely neighbouring countries, which is not a market available to Australia. As a result, we have assumed that in the Progressive Change and Step Change scenarios there is no dedicated export hydrogen production in Australia, due to the low levels of global demand and assumed weak global emissions reduction policies.

For the Green Energy Export scenarios we have calibrated Australia's share of this global demand based on its current share of global production and its share of surplus solar and wind resources[7], which broadly reflects Australia's comparative advantage in producing green hydrogen for export in a carbon-constrained world.

Table B.9 Key assumptions on global green hydrogen demand and Australian share of production

Assumption		Progressive Change scenario	Step Change scenario	Green Energy Exports scenario
Scenario alignment		IEA Stated Policies scenario (STEPS)	IEA Announced Pledges scenario (AP)	Aligned with IEA AP in 2025, transitions linearly to IEA Net Zero Emissions scenario by 2050
Key markets	Road transport	Aligned with IEA		
	Shipping fuel	Aligned with IEA		
	Power generation	Aligned with IEA		

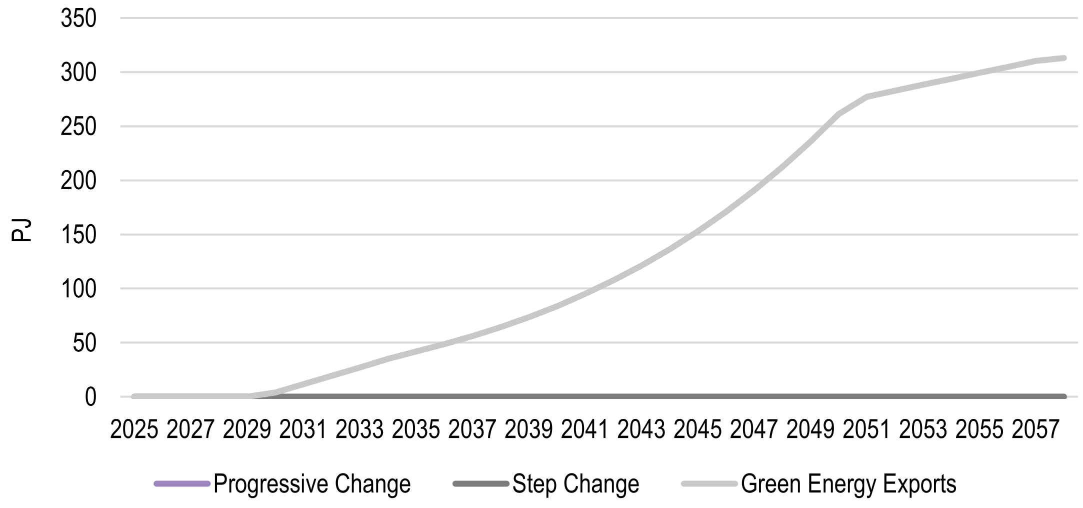
[7] Our estimate is based on Carbon Tracker Initiative (2021), which indicates that Australia has about 4.5% of global solar and wind resources, but the largest resource per capita. We have used the per capita measure to estimate a global share of about 9.8% of solar and wind resources excess to domestic needs (and therefore available for producing export commodities)

Assumption	Progressive Change scenario	Step Change scenario	Green Energy Exports scenario
Australian share of world market	0% (market is too small to support seaborne hydrogen trade)		2.1% (broadly reflective of Australia's share of VRE resources surplus to domestic needs, adjusted for the low-level of international hydrogen trade)

Source: ACIL Allen based on IEA (2023) and (2023); Carbon Tracker Initiative (2021).

Based on these assumptions, Figure B.2 presents the volume of hydrogen exported from Australia in the Green Energy Export scenario (expressed in terms of the hydrogen's energy content). In general, the cost and technical complexity of exporting hydrogen in the forms assessed here, and the level of uncertainty about the use cases for pure hydrogen, mean that the level of export hydrogen is significantly lower than the level of hydrogen embodied in Australia's ammonia and green iron production outlined in sections B.3.2 and B.3.4 below.

Figure B.2 Australian green hydrogen production, by scenario (PJ)



Source: ACIL Allen

We then broke Australian green hydrogen production down to the regional level with the split set out in based on the volume of proposed green hydrogen and green ammonia projects in each region[8], the level of solar and wind generation available in each region, and broad assessments of constraints around social licence, port infrastructure and workforce availability.

Table B.10 Share of Australian green hydrogen production by region

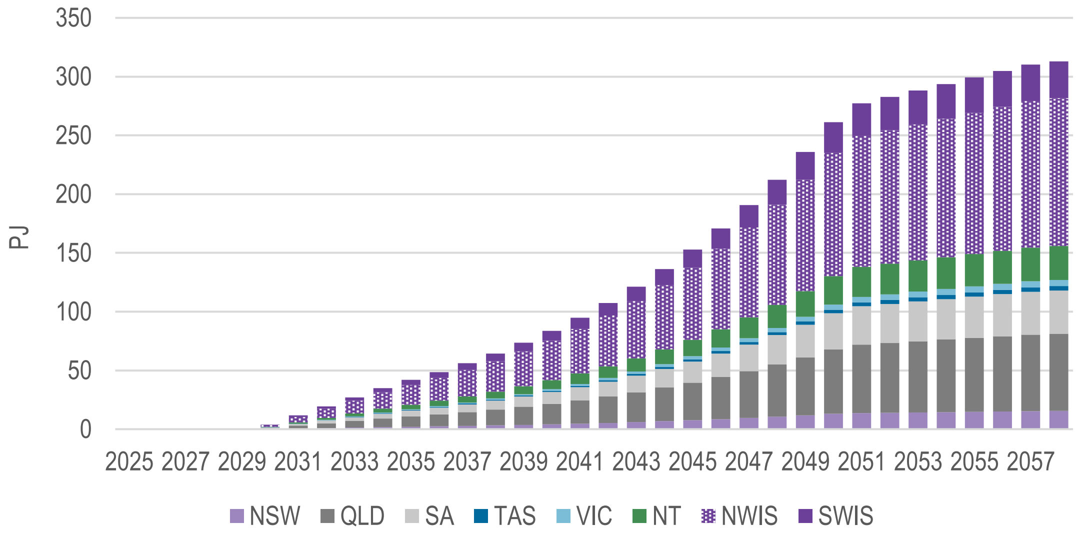
	NSW	QLD	SA	TAS	VIC	NT	NWIS	SWIS
Share of prod'n	5%	21%	12%	1%	2%	9%	40%	10%

Source: ACIL Allen

[8] We grouped both project types together for this purpose as a range of projects are considering a range of ways of exporting hydrogen, including ammonia and other carriers, or do not specify which carrier they plan to use.

Based on these assumptions, Figure B.3 presents our estimate of green hydrogen exports by region and year for the Green Energy Exports scenario (we assume no green hydrogen exports in the other two scenarios) .

Figure B.3 Green hydrogen exports by region, Green Energy Export scenario (PJ)



Source: ACIL Allen

B.3.2 Ammonia

Description of commodity

Ammonia is a globally-traded commodity used as the key chemical input to a range of products, such as nitrogen-based fertilisers and explosives. Ammonia's chemical compound is NH_3, meaning that it consists of one nitrogen atom and three hydrogen atoms. Nitrogen and hydrogen are combined through the Haber-Bosch process, which uses catalysts and high temperatures and pressures to drive the desired chemical reaction. The nitrogen in ammonia is sourced from the air, meaning that the main locational driver of ammonia investments is having a cost-competitive source of hydrogen.

Currently the hydrogen for most ammonia production is sourced from fossil fuels. This typically involves either gasification of coal or the decomposition of natural gas through SMR. In both cases, the production of hydrogen results in carbon dioxide as a by-product, and therefore ammonia is a major source of global greenhouse gas emissions.

Ammonia can also be produced without creating significant greenhouse gas emissions by either:

— capturing and storing the relatively pure carbon dioxide stream produced by the Haber-Bosch reactor
— electrolytically splitting water into hydrogen and oxygen using low-emissions electricity, and directly combining the hydrogen with nitrogen separated from the air.

As the world moves to reduce emissions, there is significant interest in low-emissions ammonia production, and particularly 'green ammonia' made with electrolytic hydrogen. Demand for green ammonia may both replace existing fossil fuel-based production, and also grow to serve new markets – for example, there has been some discussion of the potential for ammonia to act as a carbon-free fuel for activities such as shipping and power generation.

Australia currently produces about 1% of the world's ammonia, using natural gas as the feedstock to make hydrogen. The potential conversion of this established fossil-fuel based ammonia production to green hydrogen is considered in section B.3.7. This section analyses potential demand for Australian green ammonia production that commences operations using entirely electrolytic hydrogen, separately to the conversion of existing fossil fuel-based ammonia production.

Commodity volume

Global demand for green ammonia is highly uncertain as it depends on a range of factors including global emissions policy settings, relative energy costs across countries, trade policies and its competitive position against similar commodities. A key uncertainty for green ammonia demand is the potential, but highly uncertain, for it to be adopted as a shipping fuel. It is also possible that ammonia demand will remain close to currently levels, growing in its existing market segments broadly in line with global economic growth.

As for hydrogen exports, we have relied on the International Energy Agency's 2023 World Energy Outlook as our primary source for calibrating global green ammonia demand. We have calibrated Australia's share of this global demand based on its current share of global production and its share of surplus solar and wind resources[9], which broadly reflects Australia's comparative advantage in producing green ammonia in a carbon-constrained world (Table B.11).

The level of green ammonia production in Australia is then adjusted to avoid double-counting green ammonia produced by hydrogen blending in, or full conversion of, Australia's existing gas-based ammonia plants, which is covered in our analysis of feedstock hydrogen in section B.3.7. Our assumptions result in the estimated Australian green ammonia production levels shown in Figure B.4.

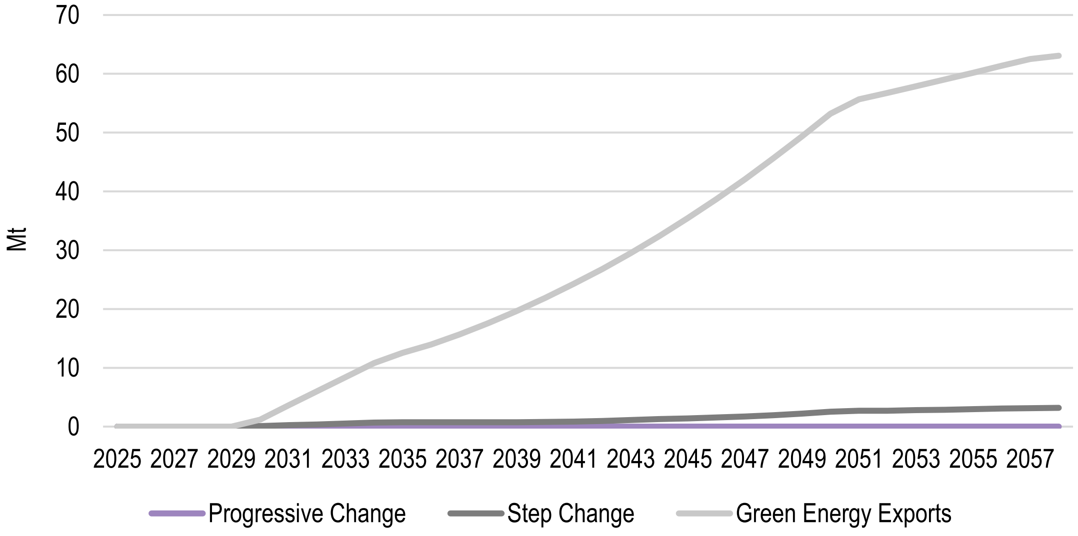
Table B.11 Key assumptions on global green ammonia demand and Australian share of production

Assumption		Progressive Change scenario	Step Change scenario	Green Energy Exports scenario
Scenario alignment		IEA Stated Policies scenario (STEPS)	IEA Announced Pledges scenario (AP)	Aligned with IEA AP in 2025, transitions linearly to IEA Net Zero Emissions scenario by 2050
Key markets	Chemical	Aligned with IEA		
	Shipping fuel	Ammonia and methanol demand as shipping fuel split evenly, rather than strong weighting to ammonia in IEA analysis		
	Power generation	Aligned with IEA		
Australian share of world market		1.1% (current share of global production)		9.8% (broadly reflective of Australia's share of VRE resources surplus to domestic needs)

Source: ACIL Allen based on IEA (2023) and (2023); Carbon Tracker Initiative (2021); US Geological Survey (2024).

[9] Our estimate is based on Carbon Tracker Initiative (2021), which indicates that Australia has about 4.5% of global solar and wind resources, but the largest resource per capita. We have used the per capita measure to estimate a global share of about 9.8% of solar and wind resources excess to domestic needs (and therefore available for producing export commodities).

Figure B.4 Australian green ammonia production, by scenario (Mt)



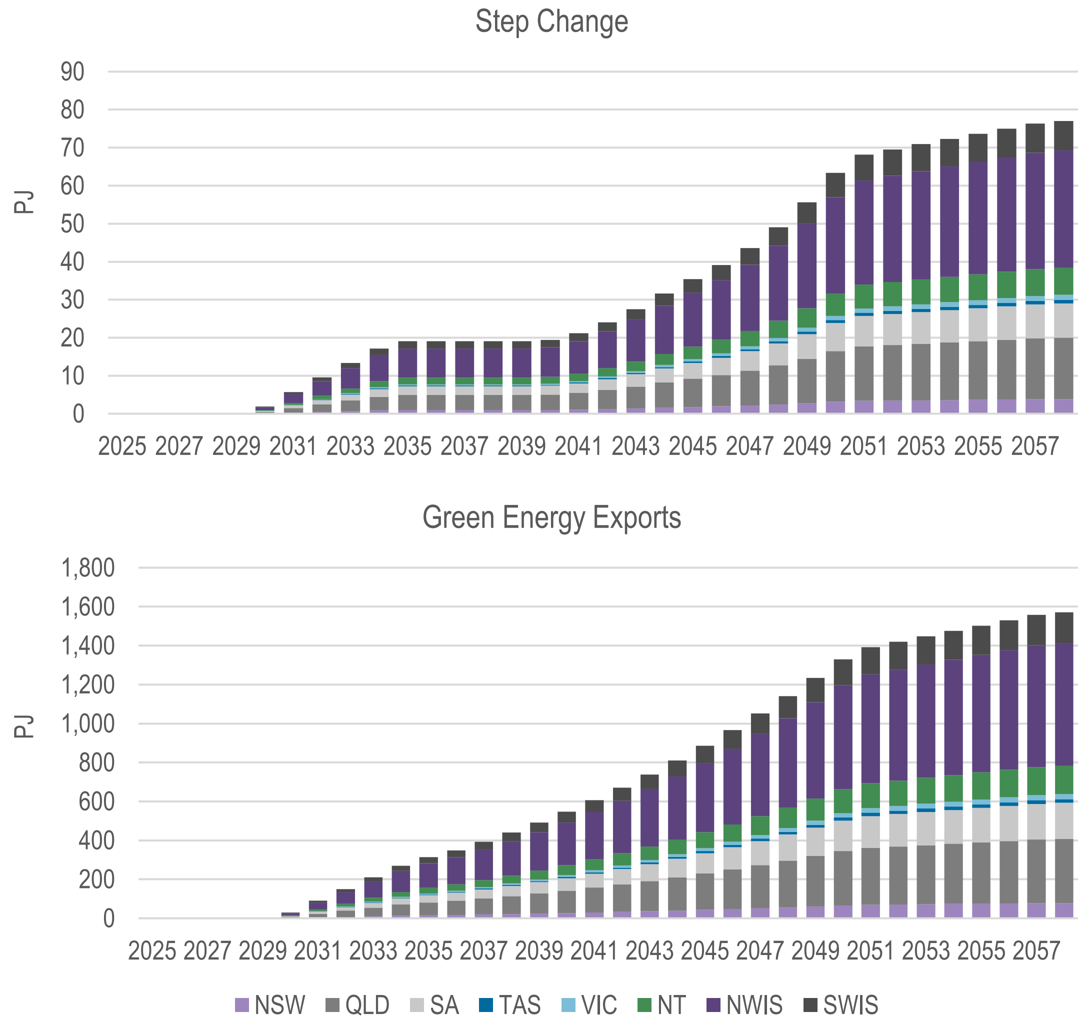
Source: ACIL Allen

We then broke Australian production down to the regional level using the same split used for green hydrogen projects (Table B.10). We adopted the same split for green hydrogen and green ammonia projects because a range of projects are considering a range of ways of exporting hydrogen, including ammonia and other carriers, or do not specify which carrier they plan to use.

Hydrogen consumption

Figure B.5 presents the volume of hydrogen used in green ammonia production in Australia at a regional level, expressed in equivalent energy terms (petajoules of energy content). These data are presented for the Step Change and Green Energy Exports scenarios only, as we assume that demand for green ammonia from Australia in the Progressive Change scenario will be served from green hydrogen blending at existing gas-based ammonia facilities, and this is covered in our analysis of feedstock hydrogen in section B.3.7.

Figure B.5 Hydrogen input to green ammonia production by region, Step Change and Green Energy Export scenarios (PJ)



Source: ACIL Allen

B.3.3 Methanol

Description of commodity

Methanol is a widely-traded chemical commodity most-commonly used as a feedstock or a solvent. It is most commonly made through SMR, which creates a mix of hydrogen and carbon monoxide, and then methanol synthesis.

Methanol production is similar to ammonia production in that it commonly starts with SMR of natural gas, but differs in important ways. Methanol's chemical formula is CH_3OH, and so it includes some carbon molecules from the natural gas feedstock, and does not include nitrogen. This means that making methanol without producing greenhouse gas emissions will require a non-fossil-based source of carbon. This favours locations with significant biomass resources.

As the world decarbonises, a number of stakeholders consider that methanol might be used as a low-emissions fuel, particularly for shipping. In this area methanol is in direct competition with ammonia .

Australia does not currently produce methanol. A plant in Laverton, Victoria, was closed in 2016.

Commodity volume

As for the other green commodities analysed here, global demand for green methanol is highly uncertain. Demand for methanol as a low-emissions shipping fuel is particularly uncertain. As for hydrogen exports and green ammonia volumes, we have relied on the International Energy Agency's 2023 World Energy Outlook as our primary source for calibrating global green methanol demand. As a low-emissions carbon source is a key element of methanol production, our assumptions on Australia's market share for this commodity are primarily driven by our estimate of Australia's share of global crop and livestock products (Table B.12).[10]

Table B.12 Key assumptions on global green methanol demand and Australian share of production

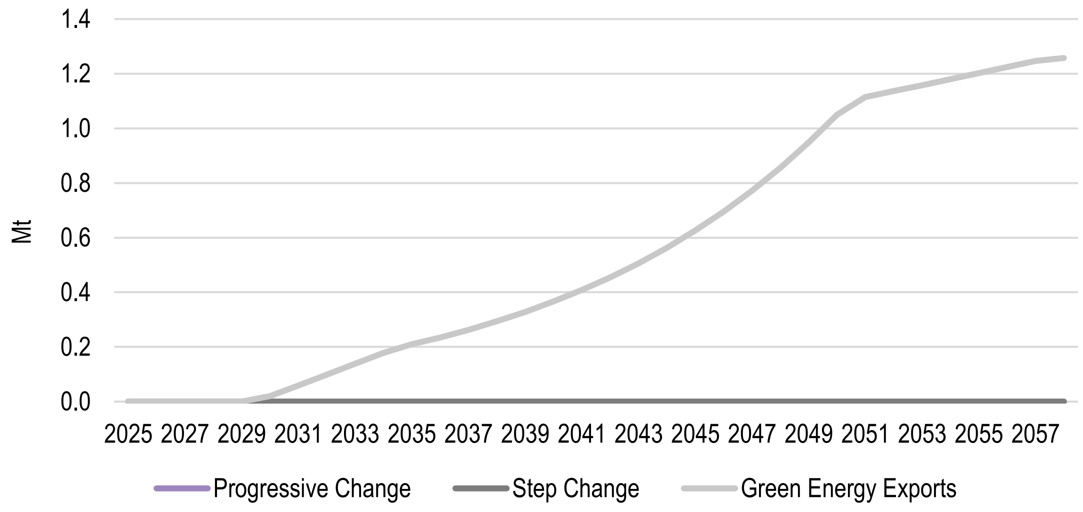
Assumption		Progressive Change scenario	Step Change scenario	Green Energy Exports scenario
Scenario alignment		IEA Stated Policies scenario (STEPS)	IEA Announced Pledges scenario (AP)	Aligned with IEA AP in 2025, transitions linearly to IEA Net Zero Emissions scenario by 2050
Key markets	Chemical	Aligned with IEA		
	Shipping fuel	Ammonia and methanol demand as shipping fuel split evenly, rather than strong weighting to ammonia in IEA analysis		
	Power generation	Aligned with IEA		
Australian share of world market		0% (reflecting current lack of Australian production)		1.4% (broadly reflective of Australia's share of global biomass resources)

Source: ACIL Allen based on IEA (2023) and (2023); UN Food and Agriculture Organization (2024).

[10] Based on UN Food and Agriculture Organization (2024) data over ten years (2013 to 2022) for world and Australian cereal, oil, fibre and sugar crop production.

These assumptions result in Australian green methanol production levels as shown in Figure B.6. The level of Australian methanol production is significantly lower than for green ammonia, reflecting the importance of biomass resources in methanol production (which is not a factor for ammonia production). This indicates that Australian producers will generally favour ammonia production over methanol, with other countries more likely to become globally significant green methanol providers.

Figure B.6 Australian green methanol production, by scenario (Mt)



Source: ACIL Allen

We then broke Australian production down to the regional level with the split set out in Table B.13, based on the volume of proposed green methanol production in each region, the level of biomass resources available in each region, and broad assessments of constraints around social licence, port infrastructure and workforce availability. Relative to green ammonia production, the regional split below is more strongly weighted to relatively biomass-rich regions such as Queensland and Tasmania.

Table B.13 Share of Australian green methanol production by region

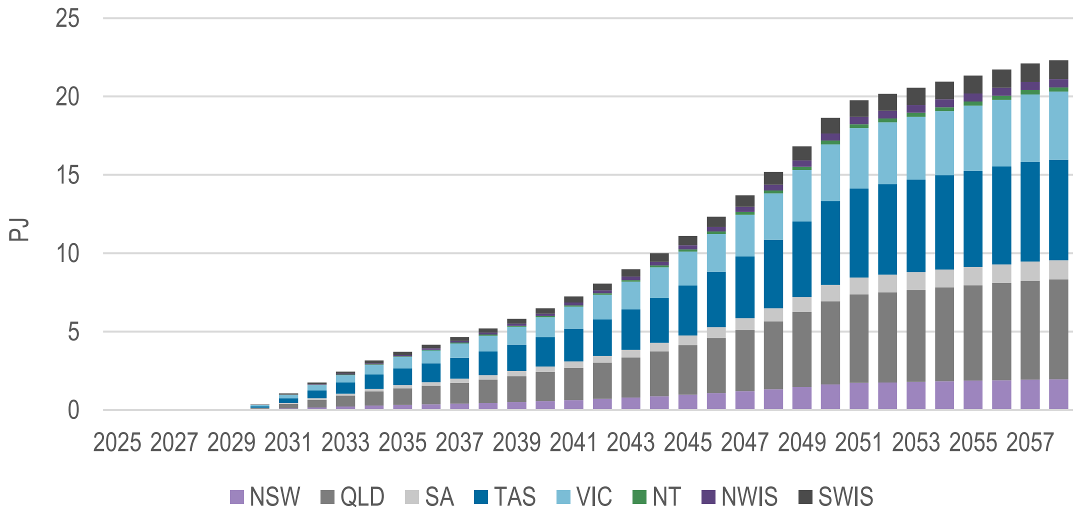
	NSW	QLD	SA	TAS	VIC	NT	NWIS	SWIS
Share of prod'n	9%	29%	6%	29%	19%	1%	2%	5%

Source: ACIL Allen

Hydrogen consumption

Figure B.7 presents the volume of hydrogen used in green methanol production in Australia in the Green Energy Exports scenario (there assume no green methanol production in the Progressive Change or Step Changes scenarios). This is presented at a regional level, expressed in equivalent energy terms (petajoules of energy content).

Figure B.7 Hydrogen input to green methanol production by region, Green Energy Export scenario (PJ)



Source: ACIL Allen

B.3.4 Green iron and steel

Description of commodity

Iron ore is converted to iron metal by removing oxygen from the ore. This is achieved using a reductant which reacts with the oxygen to remove it from the ore. The most common iron-making approach globally is using coke (made from coal) as the reductant, with the carbon in the coke reacting with oxygen to make carbon dioxide as a by-product. An alternate, low-emissions iron-making method is using hydrogen gas as the reductant, which results in steam as a byproduct and so avoids the greenhouse gas emissions associated with conventional iron-making. Iron metal is then refined to make steel either in a basic oxygen furnace or electric arc furnace.

Australia is a small steel producer by global standards, contributing about 0.2% of world production. This is despite it being a major supplier of both iron ore and coking coal. The economics of coal-based iron and steel-making favour shipping these resources to steelworks in large markets such as China, Japan and Korea, rather than making steel in Australia.

Efforts to reduce greenhouse gas emissions from the iron and steel industry may result in a move towards hydrogen-based iron-making. As hydrogen is more difficult and expensive to transport than coking coal, this may result in a move of iron-making to countries with abundant renewable energy with which to make green hydrogen, allowing hydrogen to be used locally in the iron-making process rather than incurring the significant expense of shipping hydrogen to energy-poor countries. For this reason, there are credible prospects for significant growth in iron-making in Australia in scenarios with strong global action to reduce emissions, which may in turn lead to growth in steel-making in Australia.

This projection focuses on green iron made through hydrogen direct reduction, and so does not include production from Australia's existing primary steelworks (at Port Kembla, NSW, and Whyalla, SA) or existing electric arc furnaces that produce recycled steel. We also do not include any direct reduction of iron that may occur using reformed natural gas or gasified coal as a reductant.

Commodity volume

As for the other green commodities analysed here, global demand for green iron and steel is highly uncertain. Important factors creating uncertainty over demand include both the overall strength of global emissions policy settings and technological uncertainty, with the potential for both CCS-based pathways and emerging electrolytic iron-making technologies to compete with hydrogen direct reduction. CCS-based pathways would favour iron-making in countries with existing blast furnaces (with CCS being retrofitted) or with abundant low-cost natural gas (suited to gas-based direct reduction, which produces a high-purity stream of carbon dioxide suitable for CCS[11]).

As for our analysis of other green commodity volumes, we have relied on the International Energy Agency's 2023 World Energy Outlook as our primary source for calibrating global green iron demand. We have calibrated Australia's share of this global demand (see Table B.14) based on its current share of global steel production, its share of surplus solar and wind resources (Carbon Tracker Initiative, 2021) and Australia's share of iron ore reserves (US Geological Survey, 2024).

Table B.14 Key assumptions on global green iron demand and Australian share of production

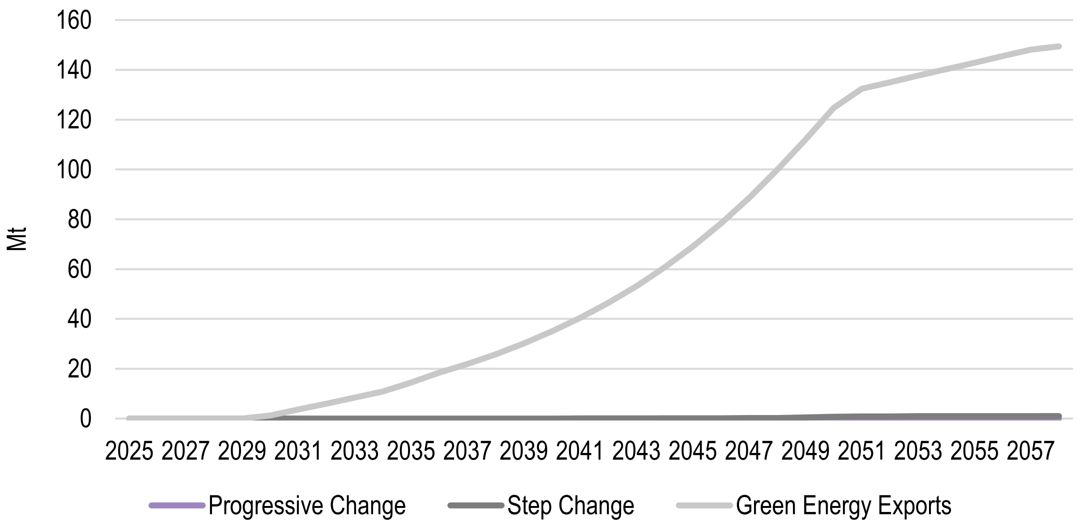
Assumption	Progressive Change scenario	Step Change scenario	Green Energy Exports scenario
Scenario alignment	IEA Stated Policies scenario (STEPS)	IEA Announced Pledges scenario (AP)	Aligned with IEA AP in 2025, transitions linearly to IEA Net Zero Emissions scenario by 2050
Australian share of world market	0.2% (reflecting current lack of Australian production)		15.2% (reflecting both Australia's share of global renewable resources (67% weighting) and iron ore resources (33% weighting))

Source: ACIL Allen based on IEA (2023) and (2023); Carbon Tracker Initiative (2021); US Geological Survey (2024).

Figure B.8 shows our estimated level of Australian green iron production levels by scenario based on these assumptions. Green iron production is very low in the Progressive Change and Step Change scenarios, but grows significantly in the Green Energy Exports scenario, representing a strong shift in global iron-making activity to Australia.

[11] Since 2016 about 0.8 Mtpa of CO_2 for CCS from Emirates Steel's gas-based direct reduction iron plant at Abu Dhabi (Global CCS Institute, 2017).

Figure B.8 Australian green iron production, by scenario (Mt)



Source: ACIL Allen

We then broke Australian production down to the regional level with the split set out in Table B.15 based on the level of solar and wind generation available in each region, the level of economically demonstrated iron ore resources in each region[12], and broad assessments of constraints around social licence, port infrastructure and workforce availability. While the assessment included iron ore resources as one factor in determining green iron production location, as the cost of transporting iron ore is small in the context of overall green iron production costs we assumed that iron ore could be moved to a location outside of the state in which it was mined for further processing to green iron. This might occur, for example, to take advantage of suitable energy resources, industrial infrastructure or workforce in other locations.

Table B.15 Share of Australian green iron production by region

	NSW	QLD	SA	TAS	VIC	NT	NWIS	SWIS
Share of prod'n	6%	18%	12%	1%	2%	7%	43%	10%

Source: ACIL Allen

If Australia produces significant volumes of green iron there is a possibility that some of this iron will be further refined to steel in Australia. However, it is also possible that most or all of the green iron produced in Australia will be exported as iron, and refined to steel closer to its end market. There is a high degree of uncertainty about whether Australia's likely energy cost advantage will outweigh its labour and capital cost disadvantages sufficient to justify further value-adding through Australian steel-making. Another factor that increases the likelihood of some steel-making in Australia is that there is an energy efficiency advantage in delivering direct reduced iron to an electric arc furnace while still hot, rather than cooling it for transport and re-heating it later for steel-making.

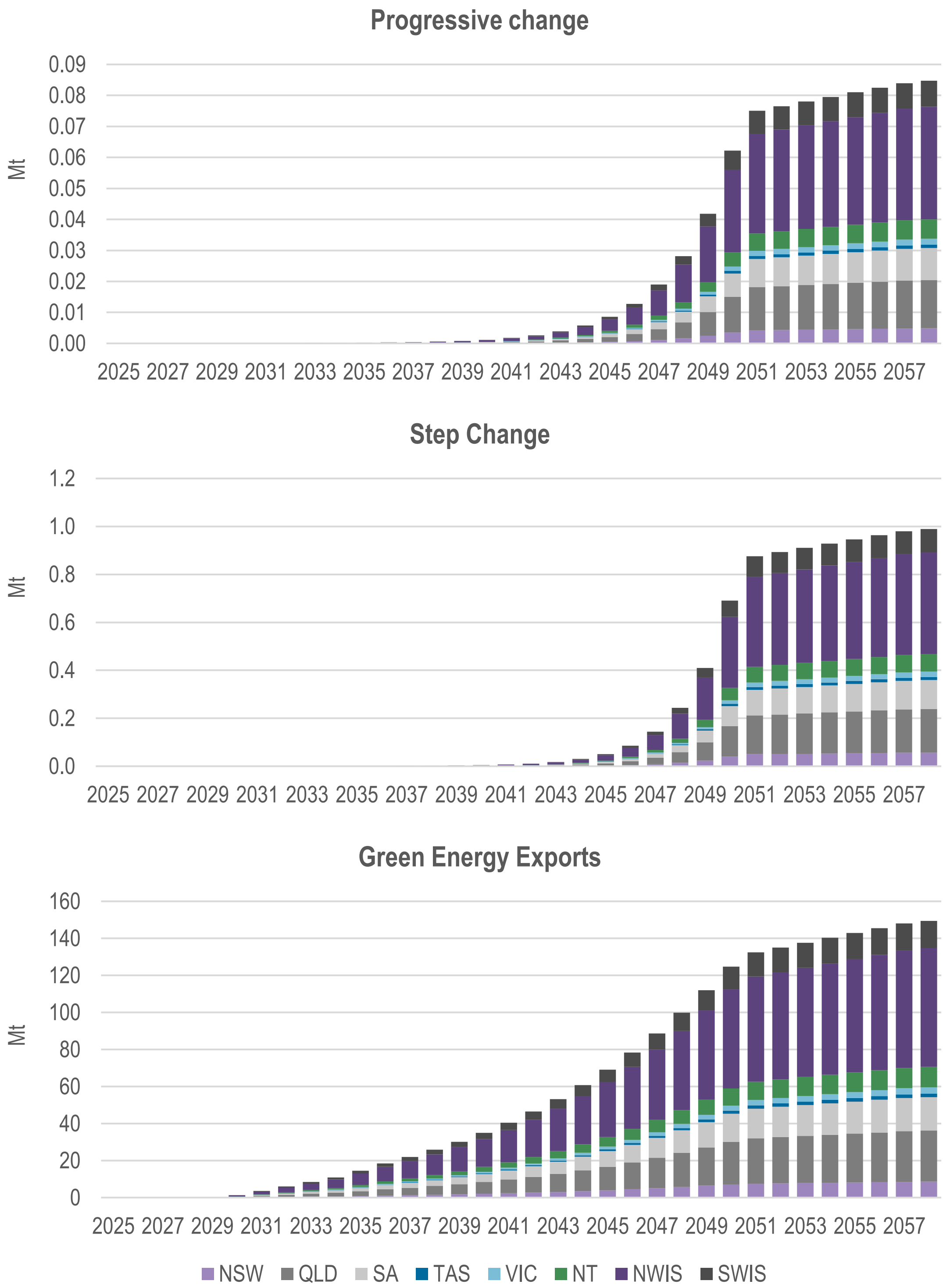
In broad terms, we estimate that about one-quarter of any green iron produced in Australia will be further converted into steel in Australia, and the remaining three-quarters will be exported as briquettes. However, as the level of hydrogen use in converting iron to steel is negligible, the level of green iron is far more important to our forecasts of hydrogen consumption in the iron and steel industry (see below). We do not make explicit forecasts of the volume of hydrogen consumed in converting iron to steel, as this is likely to be negligible and immaterial to the forecasts.

[12] Based on ACIL Allen analysis of Geoscience Australia (2020)and the SA Government's Department of Energy and Mines (2024).

Hydrogen consumption

Figure B.9 presents the volume of hydrogen used in green iron production in Australia at a regional level, expressed in equivalent energy terms (petajoules of energy content).

Figure B.9 Hydrogen input to green iron production, by region and scenario (PJ)



Source: ACIL Allen

B.3.5 Alumina

Commodity description

Alumina is a purified oxide of aluminium (chemical formula Al_2O_3) extracted from bauxite ores. Alumina is an intermediate product in the processing of bauxite ores to produce pure aluminium metal.

The primary energy consuming elements of alumina refining are:

— the low-temperature Bayer process, where bauxite is digested in a hot caustic solution to produce aluminium trihydrate crystals

— the high-temperature calcining process where aluminium trihydrate is heated in a kiln to produce dried alumina powder.

Australia is the world's second-largest alumina producer, with five operating refineries across south-west WA and Queensland (Table B.16).

Table B.16 Australia's alumina refineries

Refinery	Owner(s)	Location	Approximate annual production (Mt)
Pinjarra	Alcoa	WA	4.5
Worsley	South32	WA	4.4
QAL	Rio Tinto; Rusal	QLD	3.7
Yarwun	Rio Tinto	QLD	3.0
Wagerup	Alcoa	WA	2.7

Source: ACIL Allen

Commodity volume

We hold the volume of Australian alumina production constant across the projection under all scenarios. The level of production is lower than recent history due to the curtailment of Alcoa's Kwinana (WA) refinery during 2024, which we assume to be permanent. We assume the remaining five refineries continue to operate throughout the projection.

While hypothetically Australian alumina production could grow under certain circumstances, we consider this possibility to be too speculative to include in our projection, for a range of reasons:

— Australia is already the world's second largest alumina producer and processes a high proportion (about two-thirds) of its bauxite production to alumina

— Australia's bauxite production is under pressure and may decline in coming years due to:
  – the expected closure of Rio Tinto's Gove (NT) bauxite mine by 2030
  – concerns around the effect of Darling Scarp bauxite mining on WA's jarrah forests and water supply, which may create difficulties in expanding mining areas as operating resources are depleted.

Hydrogen consumption

Alumina production can be decarbonised in a range of ways. The approaches vary between the low-temperature Bayer process and the high temperature calcination process.

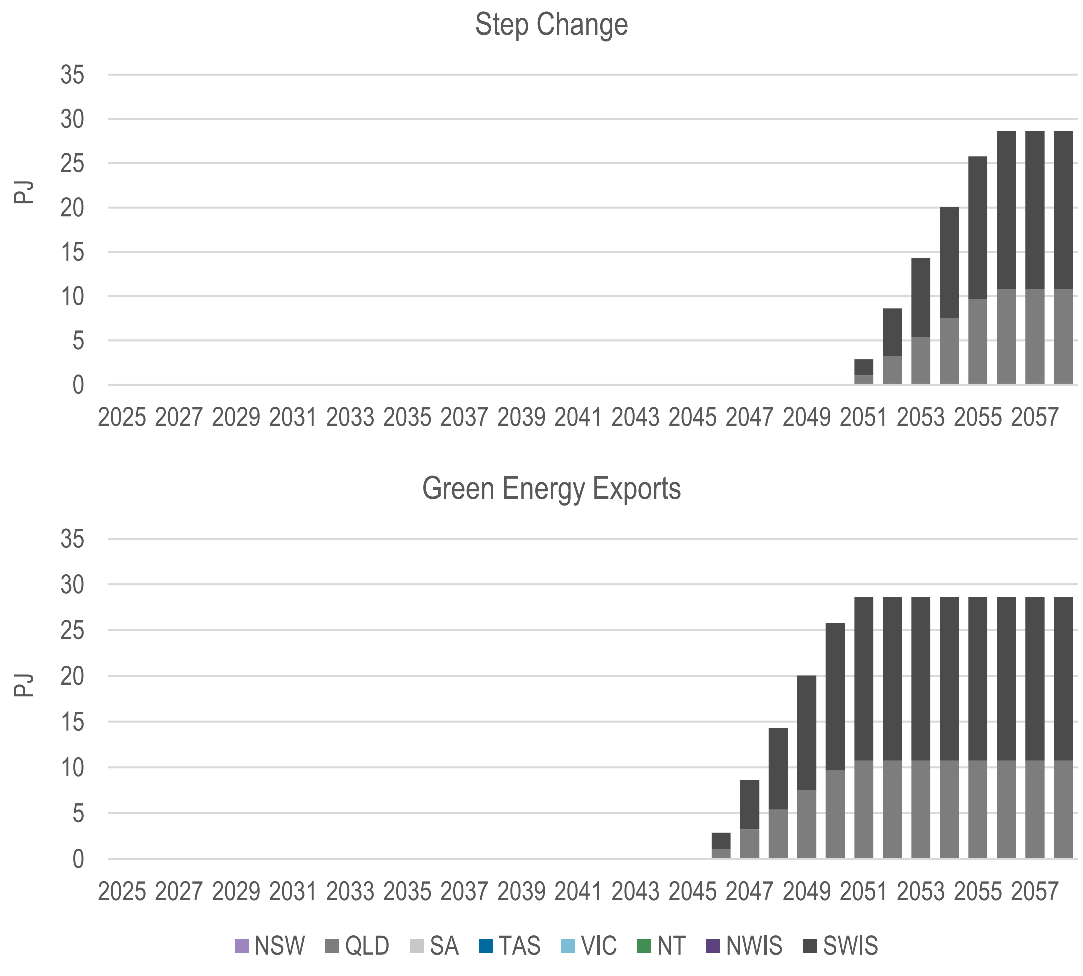
A range of energy sources can be used in the Bayer process, including coal, gas, biomass and electricity. In our view, the most likely transition pathway for this element of the alumina processing is electrification using a technology known as mechanical vapour recompression. This approach upgrades waste steam available from the digestion process for re-use in the process, and so is very energy-efficient and able to operate on firmed renewable electricity.

The most likely use of hydrogen is in calcination. Calcination requires a highly pure fuel, such as natural gas, biomethane, hydrogen or electricity. There are significant technical and economic uncertainties as to whether hydrogen or electric calcination will prove more effective. Accordingly we assume that up to half of the calcination energy demand moves to hydrogen by 2057. We consider the economics of moving from gas-based calcination to either electricity or hydrogen will be challenging, on so this switch will occur close to, or even after, 2040. This results in the following scenario-specific assumptions:

— Progressive Change: no move to hydrogen
— Step Change: hydrogen calcination commences progressively from 2051 and reaches 50% of calcination energy demand in 2055
— Green Energy Exports: hydrogen calcination commences progressively from 2046 and reaches 50% of calcination energy demand in 2050.

Figure B.10 presents the volume of hydrogen used in alumina production in Australia at a regional level, expressed in equivalent energy terms (petajoules of energy content). The Progressive Change scenario is not presented as we assume there is no hydrogen use in the Australian alumina industry in that scenario.

Figure B.10 Hydrogen input to alumina production by region, Step Change and Green Energy Export scenarios (PJ)



Source: ACIL Allen

B.3.6 Aluminium

Commodity description

Aluminium is produced by dissolving alumina in an electrolyte and electrolysing it in cells with a carbon-based anode (the Hall-Heroult process). The primary energy input to aluminium smelting is electricity, with world-scale smelters typically consuming between 13 and 15 MWh of electricity per tonne of aluminium metal.

Australia has four operating aluminium smelters (Table B.17)

Table B.17 Australia's aluminium smelters

Smelter	Owner(s)	Location	Production capacity (ktpa)
Tomago	Rio Tinto; CSR; Hydro Aluminium	NSW	590
Boyne Island	Rio Tinto; YKK Aluminium; UACJ Australia; Southern Cross Aluminium	QLD	570
Portland	Alcoa; CITIC Nominees; Marubeni Aluminium Australia	VIC	358
Bell Bay	Rio Tinto	TAS	186

Source: ACIL Allen

Commodity volume

While Australia is a globally-significant alumina producer (14% of the world total in 2022), it only produces about 2% of global aluminium. This implies that a significant portion of Australia's alumina is exported for smelting to aluminium in other countries.

Combined with Australia's abundant renewable electricity resources, this implies that Australia could increase its production of aluminium in a carbon-constrained world, with this growth being underpinned by local alumina production. Given these, we assume some degree of growth in our projections (as set out in Table B.18).

Table B.18 Aluminium production growth assumptions

Scenario	Cumulative global growth (2022-2050)	Australian cumulative growth (2022-2050)
Progressive Change	53%	No growth
Step Change	38%	Grows at half the global rate
Green Energy Exports	35%	Grows in-line with the global rate

Source: ACIL Allen

We assume that Australia's four operating smelters continue to operate through the projection. We assume that any growth in aluminium production occurs in states with established production capacity, rather than in 'greenfields' locations. Given Queensland's superior wind and solar resources, and limitations on growth in Tasmania's hydro resources, we assume that:

— Queensland captures 50% of Australian production growth

— NSW and Victoria capture 25% of the growth

— Tasmanian production does not grow.

Hydrogen consumption

Smelters use modest volumes of natural gas for anode baking (forming pitch and tar into carbon-based anodes) – indicatively about 2 GJ/tonne of aluminium. This implies total aluminium smelting gas consumption in the order of 3 PJ per year (ignoring any gas used in the power generation process).

Even if this gas converted to hydrogen it would be immaterial to the overall volume of hydrogen produced and consumed in Australia, particularly under the Green Energy Exports scenario. Further, we note that the aluminium industry is examining a shift to so-called 'inert anodes' that are not carbon-based, so as to avoid the emission of carbon dioxide from anode consumption in the smelting process. These inert anodes will have a different production process that is unlikely to involve the same baking process used in making traditional carbon anodes, and they may be produced at locations remote to the smelters. Therefore, the ultimate need for hydrogen to be used in Australia to support aluminium smelting is highly uncertain.

For these reasons, we have assumed zero hydrogen consumption in aluminium smelting.

B.3.7 Feedstock hydrogen

Description of hydrogen use case

Australian industry uses hydrogen as a feedstock at present. Overwhelming this hydrogen is made through steam methane reforming and converted into ammonia through Haber-Bosch synthesis, with ammonia then further converted into a range of transformed nitrogen-based compounds. Australia's existing and proposed gas-based ammonia plants are summarised in Table B.19.

Table B.19 Overview of Australian operating and proposed gas-based ammonia plants

Plant	Operator	Key products	Location	Ammonia production (kt)	Approximate annual gas use (PJ)	Approximate hydrogen feedstock need (PJ)
Plants operating and (*) under construction						
Pilbara	Yara	Ammonia	NWIS	840	27.2	21.0
Burrup*	Perdaman	Urea	NWIS	1,480	47.5	33.7
Kwinana	CSBP	Ammonium nitrate	SWIS	255	9.0	6.4
Moranbah	Incitec Pivot	Ammonium nitrate	QLD	150	6.0	7.1
Moura	QNP	Ammonium nitrate	QLD	95	2.7	23.5
Phosphate Hill	Incitec Pivot	Ammonium phosphates	QLD	274	7.8	3.8
Kooragang Island	Orica	Ammonium nitrate	NSW	360	12.6	2.4
Proposed plants						
Kwinana expansion	CSBP	Ammonia	SWIS	282	9.1	7.1
H2Perth	Woodside	Ammonia	SWIS	940	30.1	9.0

Source: ACIL Allen

All of these plants are either currently operating or will start operations primarily operating on natural gas feedstock. However, several have planned or implemented green hydrogen blending projects:

— Yara has implemented green hydrogen blending at its Pilbara plant, based on a 10 MW electrolyser and annual output of about 0.4% of the plant's hydrogen feedstock

— CSBP's proposed Kwinana expansion would operate with a 10 MW electrolyser from the start of operations, which would contribute about 3% of the plant's hydrogen needs

— Woodside's proposed H2Perth plant would combine a significant (250 MW) electrolysis capacity with its gas-based production, with green hydrogen contributing about 20% of feedstock at the start of operations.

These blending projects are considered in our projections of green hydrogen volumes at these gas-based ammonia plants, which is set out below. Green hydrogen used in dedicated green ammonia production facilities is discussed in section B.3.2.

Feedstock hydrogen volume

Our assumptions for each scenario on the use of green hydrogen as a feedstock at Australia's existing and proposed gas-based ammonia plants is summarised in Table B.20.

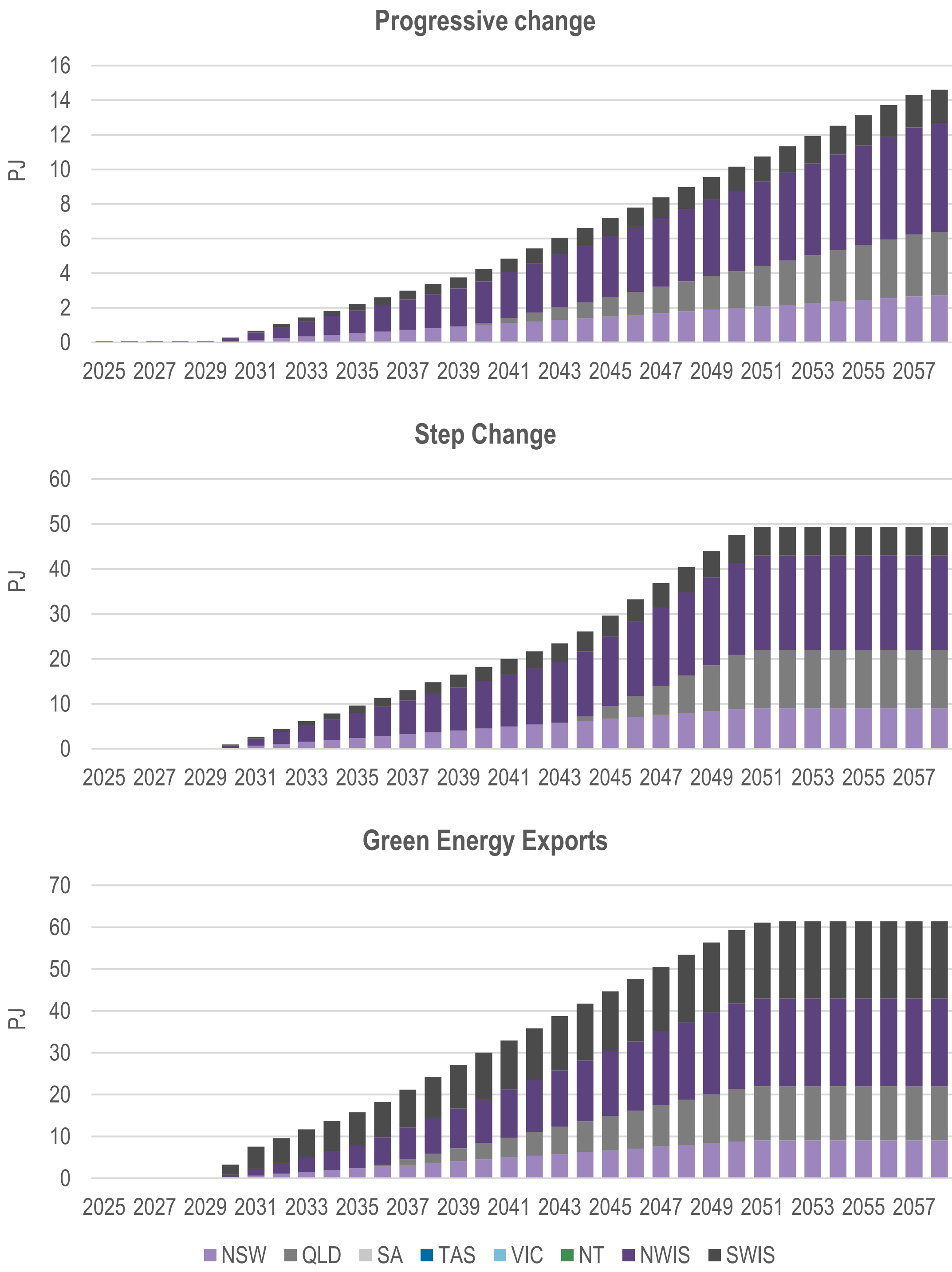
Table B.20 Green hydrogen blending and conversion assumptions at operating and proposed gas-based ammonia plants

Plant	Progressive Change scenario	Step Change scenario	Green Energy Exports scenario
Plants operating and (*) under construction			
Pilbara	Transitions to 30% blending between 2030 and 2057	100% conversion between 2030 and 2050	100% conversion between 2030 and 2050
Burrup*	No blending	No blending	No blending
Kwinana	Transitions to 30% blending between 2030 and 2057	100% conversion between 2030 and 2050	100% conversion between 2030 and 2050
Moranbah	Transitions to 30% blending between 2040 and 2057	100% conversion between 2044 and 2050	100% conversion between 2036 and 2050
Moura	Transitions to 30% blending between 2040 and 2057	100% conversion between 2044 and 2050	100% conversion between 2036 and 2050
Phosphate Hill	Transitions to 30% blending between 2040 and 2057	100% conversion between 2044 and 2050	100% conversion between 2036 and 2050
Kooragang Island	Transitions to 30% blending between 2030 and 2057	100% conversion between 2030 and 2050	100% conversion between 2030 and 2050
Proposed plants			
Kwinana expansion	Not constructed	Not constructed	Constructed by 2028, 100% conversion between 2030 and 2050
H2Perth	Not constructed	Not constructed	Constructed by 2030, retains proposed 250 MW electrolysis capacity

Note: blending refers to blending green hydrogen into the plant feedstock stream; conversion refers to progressively converting to full operation on green hydrogen.
Source: ACIL Allen

Based on these assumptions, Figure B.11 presents the volume of green hydrogen used as feedstock in operating and proposed gas-based ammonia plants at a regional level, expressed in terms of the hydrogen's energy content.

Figure B.11 Green hydrogen feedstock to gas-based ammonia production, by region and scenario (PJ)



Source: ACIL Allen

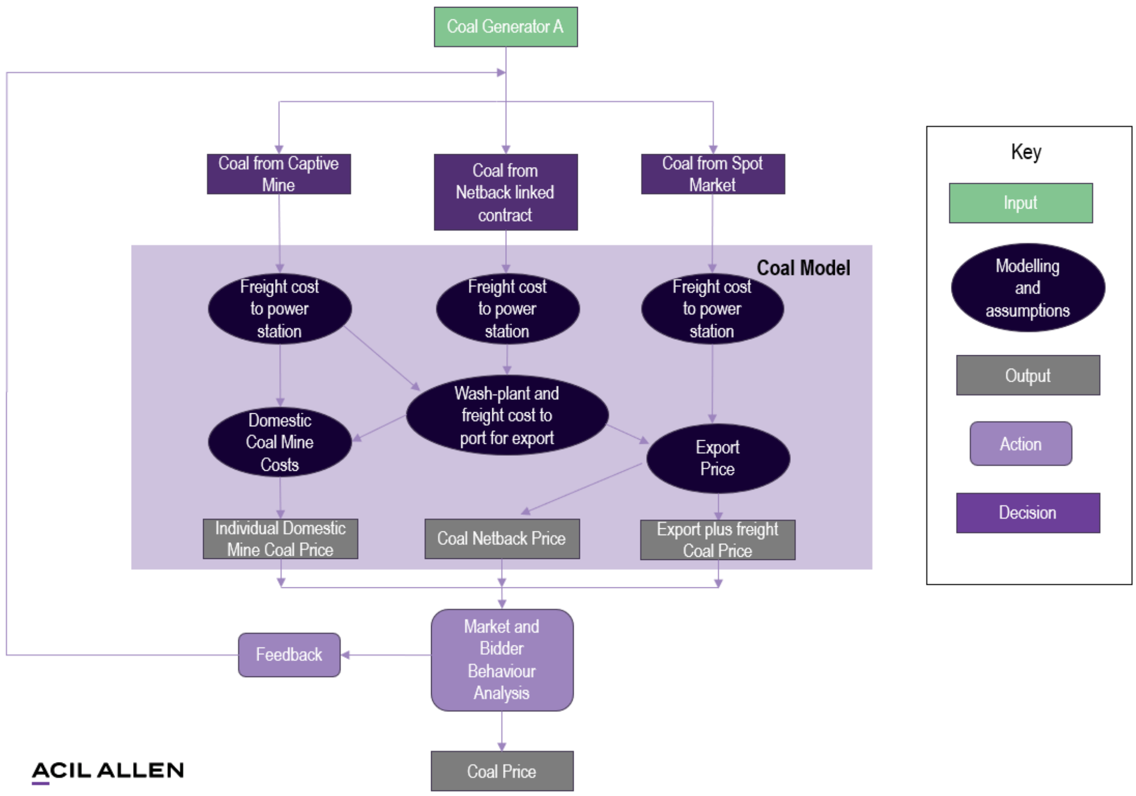
C Coal price modelling methodology

C.1 General approach and methodology

ACIL Allen maintains individual coal price projections for all incumbent coal generators in the NEM as a key input for our regular electricity market modelling. Our coal prices for AEMO are based on our regular analysis.

When determining coal prices, each generator's unique situation is modelled using our internal 'Coal model' which takes into account mining costs, unique mine operational processes (wash plant, open cut, underground etc.), export price, and freighting/handling costs. A summary of this model is illustrated below.

Figure C.1 Coal price methodology



Source: ACIL Allen

Coal plant across the NEM source coal in various ways. The three typical pathways are:

1. **Sourced from own mining supply**: this pathway covers captive generators such as many QLD and VIC plant. This stream relies on an understanding of the individual mine's operation as a key driver of price.
2. **Coal from netback linked contracts**: this pathway is useful for understanding coal supply contracts from third party mine operators which are not captive to the power station. Mine operating costs are combined with export prices to determine a netback price that the mines could otherwise achieve through selling the coal on the export market. This stream is important for some NSW and some QLD plant.

3. **Coal from the international spot market**: this pathway is useful for coal plants that have a proportion of their coal supply left uncontracted and sourced ad-hoc at export linked spot prices.

Coal prices for various coal plant in the NEM are essentially driven by two key pricing dynamics:

— mining costs for coal mines that support some coal plant

— spot market export prices for thermal coal.

C.2 Coal plant classification

Before we estimate coal prices for each coal generator, we classify them into categories which reflect how they source coal. Below is a broad summary for generators across the NEM.

NSW black coal generators

The delivered marginal coal prices into the NSW coal power stations are either linked to export parity coal prices or to the cost of production from supplying mines, whichever is the higher.

This is with the exception of Bayswater which has a long-term supply contract that is expected to expire in FYE2030, after which export-linked pricing is assumed to follow.

Victorian brown coal generators

Coal mined for generation in Victoria is not suitable for export and hence not affected by fluctuations in export prices. Extensive deposits of brown coal occur in the tertiary sedimentary basins of the Latrobe Valley coalfield, which contains some of the thickest brown coal seams in the world.

Mine mouth dedicated coalmines supply all the power stations. Except for the Loy Yang B power station, the coal mines are owned by the same entities that own the power stations. Loy Yang B is supplied by the adjacent Loy Yang Power mine (owned by the nearby Loy Yang A power station) under a coal supply agreement that expires around 2050.

The marginal price of coal for the Victorian power stations is generally taken as the marginal cash costs of mining the coal.

Queensland black coal generators

In Queensland there are four types of coal supply arrangement.

Mine mouth – own mine

Power stations in Queensland relying on their own mine-mouth coal supply are least likely to be affected by export prices, and it has been assumed that they will offer marginal fuel costs into the market. They are Tarong, Tarong North, Kogan Creek and Millmerran.

Mine mouth – captive third-party mine

Callide B and Callide C are power stations with a mine-mouth operation with a third-party supplier. Therefore, they are likely to be under pressure to accept higher prices more in line with export parity, particularly with price reviews and contract renewal. Due to the low export yield of Callide and Boundary hill mines, however, the ability of this operation to capture the export market is impaired. This is reflected in the price assumptions for these 2 power stations. Transport costs to the station are also very low: short conveyor run to stockpile.

Transported from captive third-party mine

Stanwell power station has been in a long-term supply arrangement with the Curragh mine since 2004. In 2018-19, Stanwell signed a new supply agreement that will extend its coal supply to 2038. We have assumed that Stanwell will transition to an export parity arrangement that imputes the coal netback price when the current agreement expires in the late 2020s.

Transported from third-party mine

Gladstone, which relies on transported coal from third party mines, is most exposed to pass-through of export prices. The Callide Boundary Hill mine is the lowest cost potential supplier of coal into Gladstone as this coal has poor yield for export. Gladstone is assumed to move to an arrangement where half its future coal supply will be at prices at export parity and the other half at prices from the lower cost Callide mine.

C.3 Captive mine costs

For those coal generators relying on own mine supply, the cost of coal is applicable to the mining costs of these operations over time. ACIL Allen tracks these costs for mines to ensure our coal prices for captive mines are accurate and reflective of trends in the industry.

Our coal model incorporates a dataset relating to all applicable mines when calculating a delivered cost for each coal generator. This includes:

- conveyor or rail costs if applicable
- government royalties
- tailored mining method costs; truck and shovel, dragline, wash plant and handling etc
- mining and pit services costs
- mine strip ratios
- administration costs

Recent trends suggest that some mines have experienced between 10-20% annual increases in production costs during the previous 4 years. As such ACIL Allen believes a variation of +-10% is of the appropriate magnitude to reflect changes in production costs.

C.4 Coal export prices

A fundamental input into the NSW and some Queensland power station prices is the trajectory of the relevant coal export price (which is regarded as the Newcastle free-on-board (FOB) price). Out to FYE2031 these projections use the FOB forward curve as a starting point defined by the most up to date short term forecasts. Our assessment per scenario on where coal prices are likely to fall by FYE2031 defines how this curve declines over that period.

The following steps define our process for developing an appropriate long term coal export price:

Historical FOB price - normal distribution

Historical prices were reviewed back to 2005 to understand how the FOB series trended during higher price and demand periods, and conversely with periods where demand is lower and prices are consequently lower. While this exercise doesn't mean future prices will follow this history, it gives us an understanding of how prices may track under different market conditions which we believe is important to account for in this process (given the different macroeconomic and industry conditions assumed in each of the scenarios).

This analysis shows that for most of the previous 20 years, excluding the recent spike in coal prices from 2022, prices have averaged between US$50 per tonne and US$100 per tonne. We chose the 75th, 50th and 25th percentiles to represent a price that broadly correspond to periods where coal prices are high, settling at a medium level price, and prices that are troughs in the market.

The percentile price outcomes are as follows:

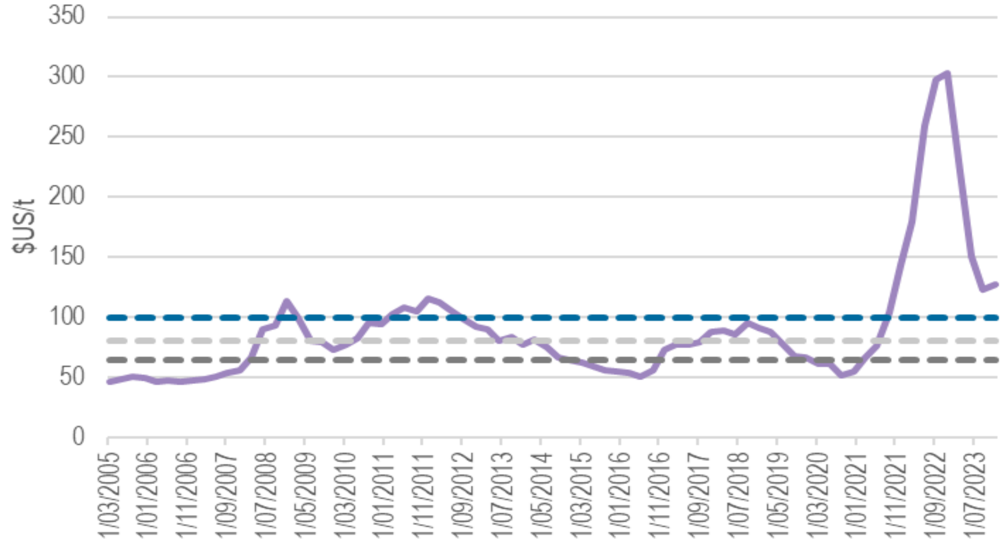
— Progressive Change scenario = 75th percentile, $US100/t

— Step Change scenario = 50th percentile, $US80/t

— Green Energy Exports scenario = 25th Percentile, $US64/t

These percentile prices track closely to the 2030 prices forecast by the IEA and in turn form the basis for the financial year 2030-31 export price assumption used in modelling.

Figure C.2 Thermal coal price analysis



Source: Department of Industry, Science and Resources, Commonwealth of Australia, Resources and Energy Quarterly, March 2024.

IEA 2024 World Energy Outlook

The second process in setting long run coal prices was to review the IEAs long term coal price forecasts for the region's most applicable to Australia. The IEA produces forecasts of Japanese and Coastal China prices for 'steam coal'. These are the most relevant to Australia and we have reviewed these two price series to help shape our understanding of how export prices are likely to trend long term.

The IEA produces coal forecasts under three scenarios which broadly align to AEMO's three scenarios

- **'Stated Policies' or 'STEPS' scenario** , which broadly aligns with AEMO's Step Change scenario
- **'Announced Pledges' or 'APS' scenario** , which broadly aligns with AEMO's Progressive Change scenario
- **'Net Zero Emissions' or 'NZE' scenario** , which broadly aligns with AEMO's Green Energy Exports scenario.

Figure C.3 IEA coal cost assumptions

Table 2.3 ▹ Wholesale fossil fuel prices by scenario

		STEPS			APS			NZE Scenario		
USD (MER, 2023)	2023	2030	2040	2050	2030	2040	2050	2030	2040	2050
IEA crude oil (USD/barrel)	82	79	77	75	72	63	58	42	30	25
Steam coal (USD/tonne)										
United States	57	51	42	40	42	31	27	28	23	23
European Union	129	68	69	64	64	51	48	57	43	39
Japan	174	105	86	82	81	66	61	66	53	49
Coastal China	150	101	88	82	78	67	61	64	54	49

Source: IEA 2024 World Energy Outlook, Table 2.3

The Australian coal prices based on the percentile analysis align well with the prices presented by the IEA for the year 2030 Japan and Coastal China. As such ACIL Allen determined to use the percentile analysis results for FYE2031 and the IEA prices as a basis for long term prices under the Progressive Change and Step Change scenarios. Our analysis and understanding of the Australian coal market does suggest that prices shown in the IEA's analysis for the NZE Scenario post-2030, and the APS scenario post-2040 are too low for many operators to bear under the assumed macroeconomic settings. As such, prices for the previous entry are held constant for the remainder of the price projection. The IEA NZE and APS scenarios reflect a lower demand for coal as well as lower mining costs. We do not expect prices to fall below this sort of level because experience shows us that when this happens the supply side responds accordingly.

Further, although international demand might be expected to fall, suppliers of thermal coal are likely to operate in a challenging environment. It is unlikely that the Australian thermal coal industry will experience the level of greenfield coal mine development we have had in the past 10-20 years. Thermal coal mine life extensions and/or expansions are also facing a much more challenging environment. This and other factors such as finance, the safeguard mechanism, wages and operating cost escalation, social license, make it increasingly likely that thermal coal production from Australia will become more expensive, and fall in volume moving forward.

Our final assumption for long term export coal prices per scenario is summarised below, with linear interpolation used between these points.

Table C.1 FOB coal price assumptions (US$/tonne)

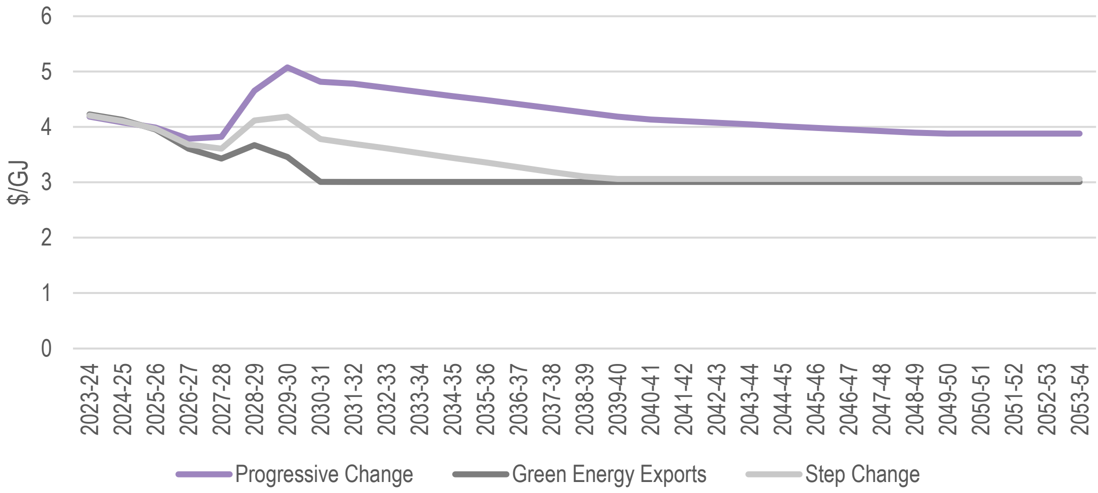
Scenario	FYE2031	FYE2041	FYE2051
Progressive Change	100	87	82
Step Change	80	66	66
Green Energy Exports	65	65	65

Source: ACIL Allen

C.5 Results

Delivered coal prices for each coal fired power station are shown in the figures below.

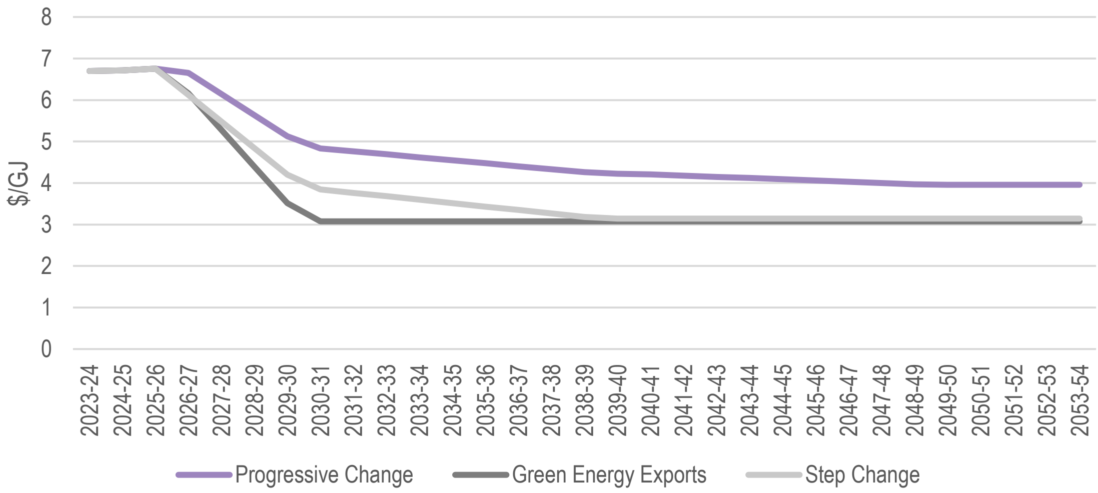
Figure C.4 Bayswater



Source: ACIL Allen

Bayswater is expected to transition from a lower contract price to 100 per cent export exposure from financial year ending 2028 to 2030. It is assumed to stay at this level of export exposure for the remainder of the projection period.

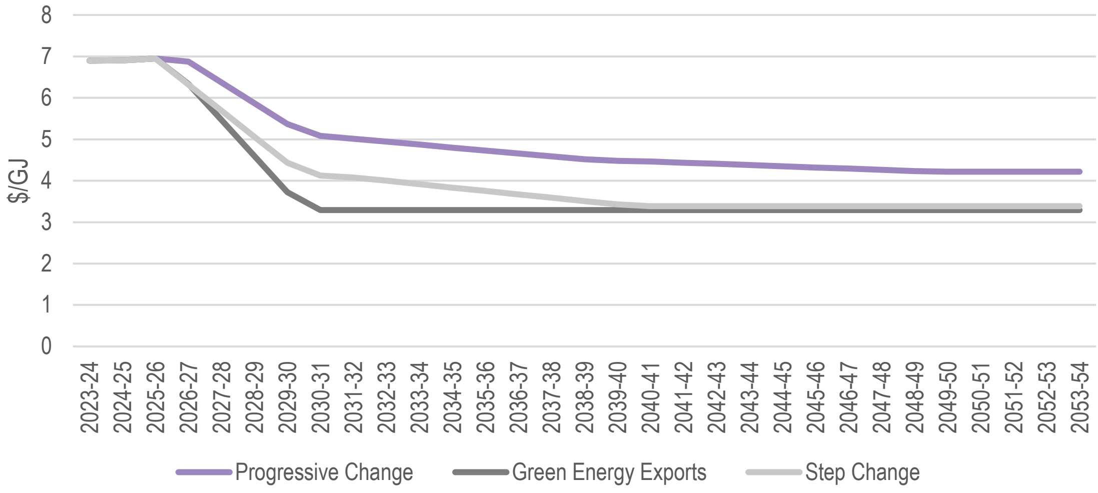
Figure C.5 Eraring



Source: ACIL Allen

Eraring is assumed to have export linked contracts with a starting point of around $6.70/GJ based on our analysis. Prices are expected to trend according to the behaviour of the export price series per scenario.

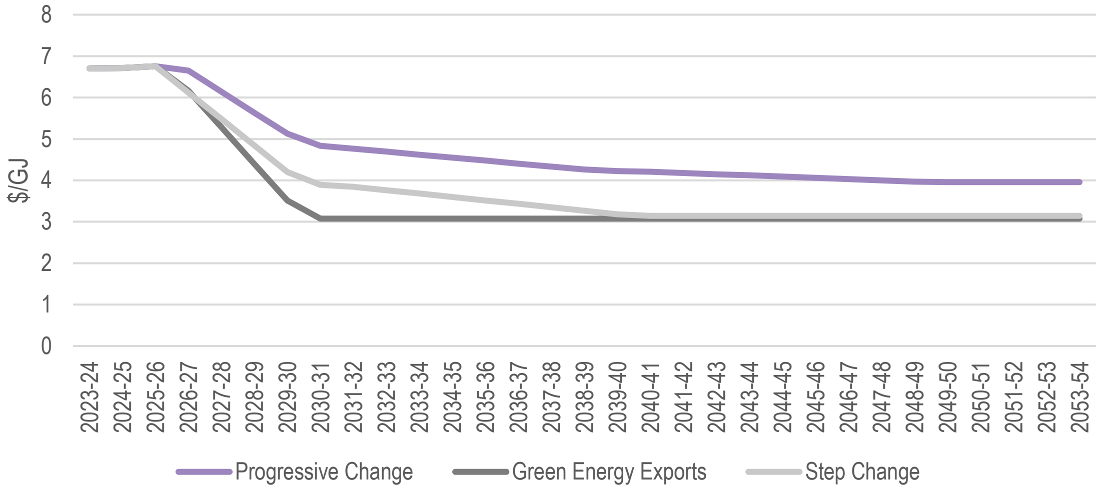
Figure C.6 Mt Piper



Source: ACIL Allen

Mt Piper is assumed to have export linked contracts with a starting point of around $6.90/GJ based on our analysis. Prices are expected to trend according to the behaviour of the export price series per scenario.

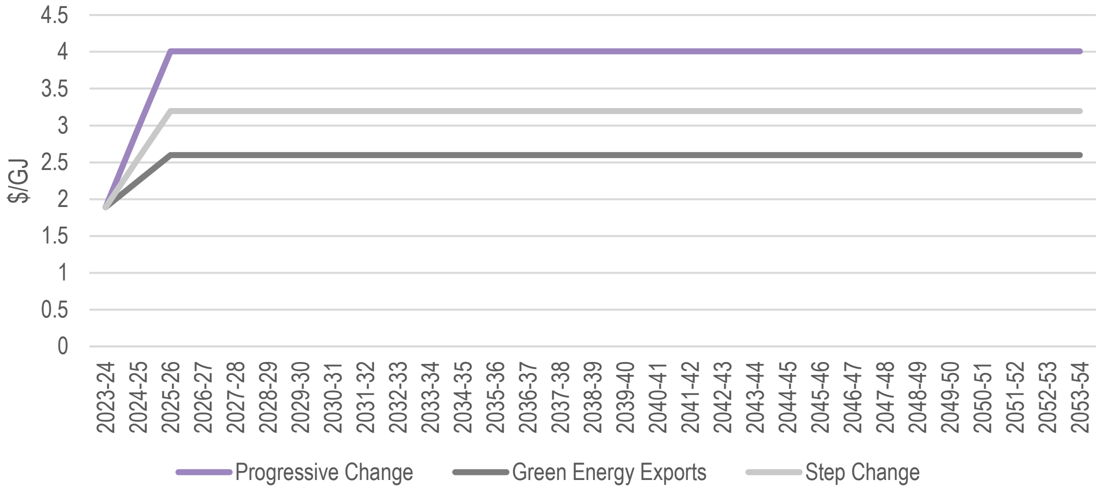
Figure C.7 Vales Point B



Source: ACIL Allen

Vales Point B is assumed to have export linked contracts with a starting point of around $6.70/GJ based on our analysis. Prices are expected to trend according to the behaviour of the export price series per scenario.

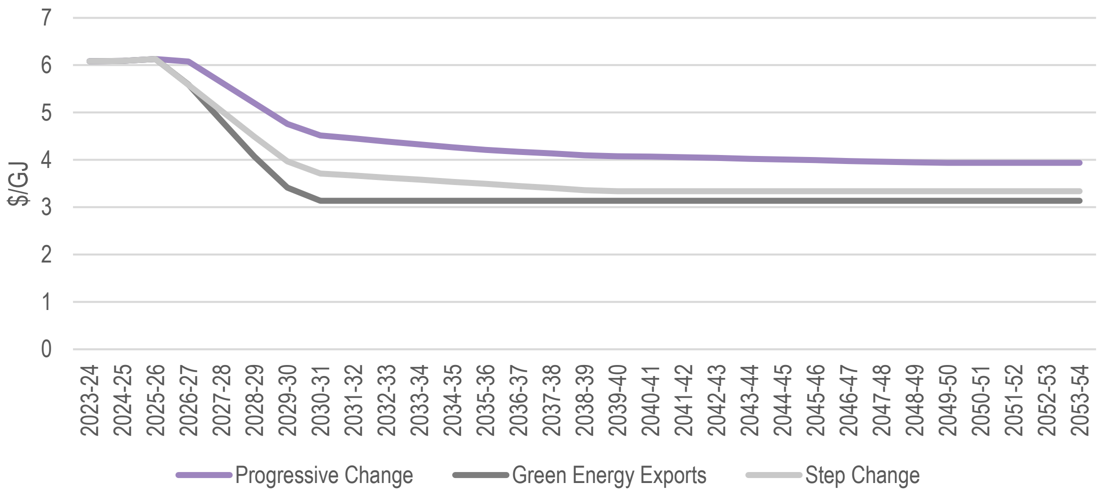
Figure C.8 Callide B and C



Source: ACIL Allen

Callide B and C have a coal supply agreement with the adjacent Callide and Boundary Hill coal mine. This agreement is expected to expire shortly, with prices moving to a new contract level estimated above. The Callide and Boundary Hill coal mine has access to the export coal market, however due to the low yield for export that this mine can achieve, it is anticipated that, as in the past, the contract price will be reflective of cost of production. We anticipate an increase in prices at this site due to changes in operating methodology, material costs, and labour costs. These increased costs will need to be reflected in the new coal supply agreement for the mining operations to remain viable.

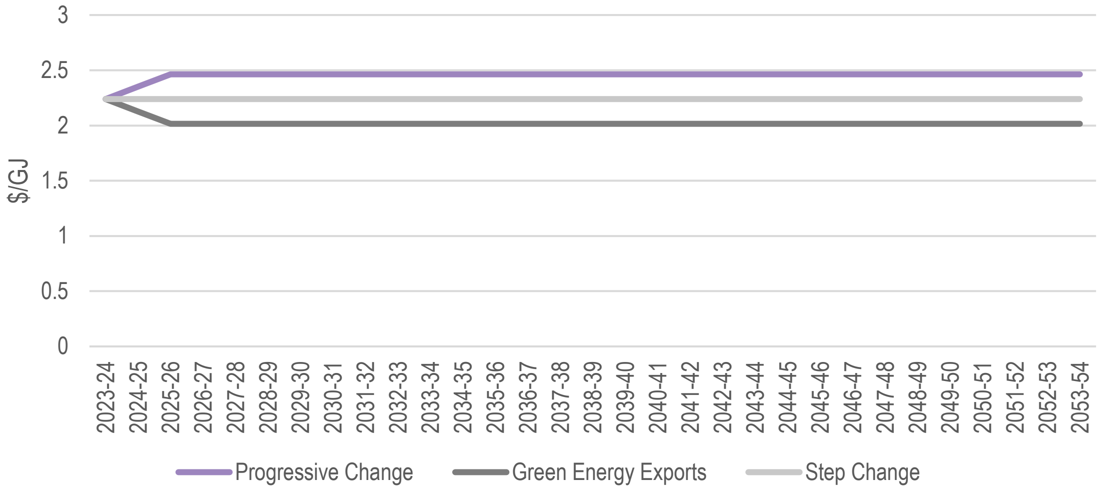
Figure C.9 Gladstone



Source: ACIL Allen

Gladstone power station is the most exposed of the QLD coal fleet to export prices. Gladstone is assumed to move to an arrangement where half its future coal supply will be at prices at export parity and the other half at prices from the lower cost Callide mine.

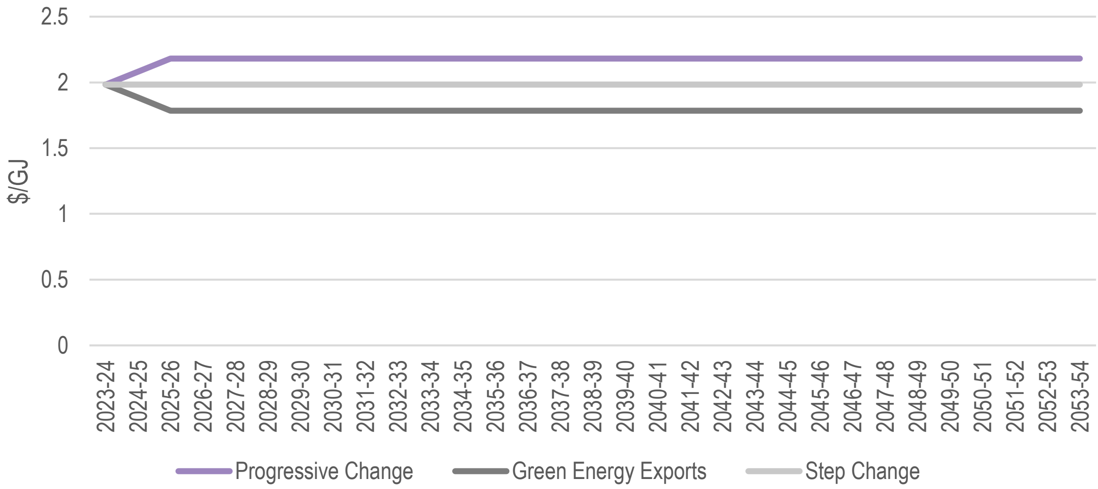
Figure C.10 Kogan Creek



Source: ACIL Allen

Kogan Creek has a captive mine that supplies coal exclusively to this plant. Mining cost estimates form the primary basis for this forecast.

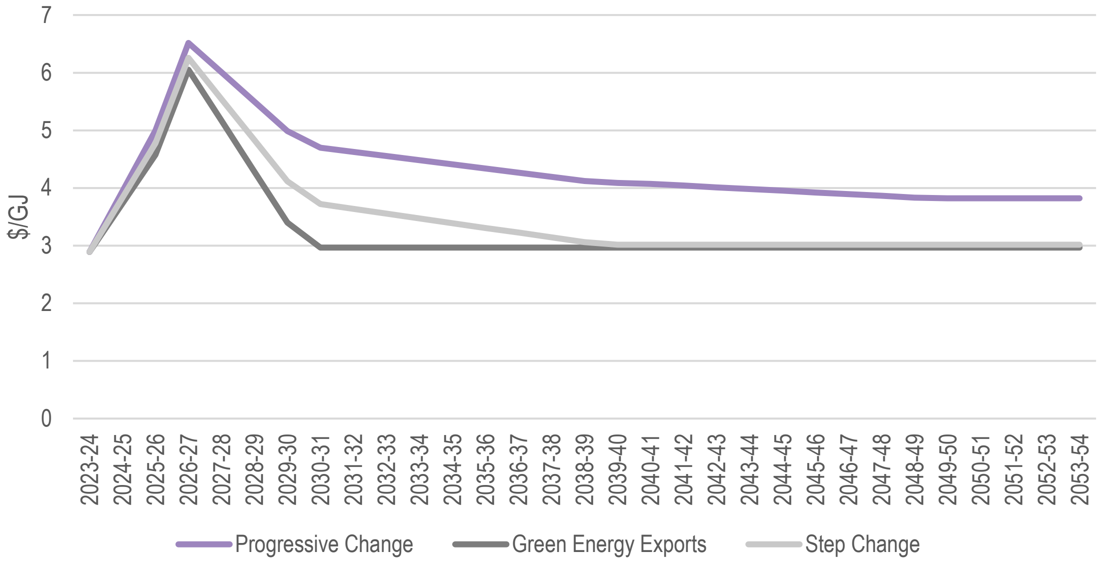
Figure C.11 Millmerran



Source: ACIL Allen

Millmerran has a captive mine that supplies coal exclusively to this plant. Mining cost estimates form the primary basis for this forecast.

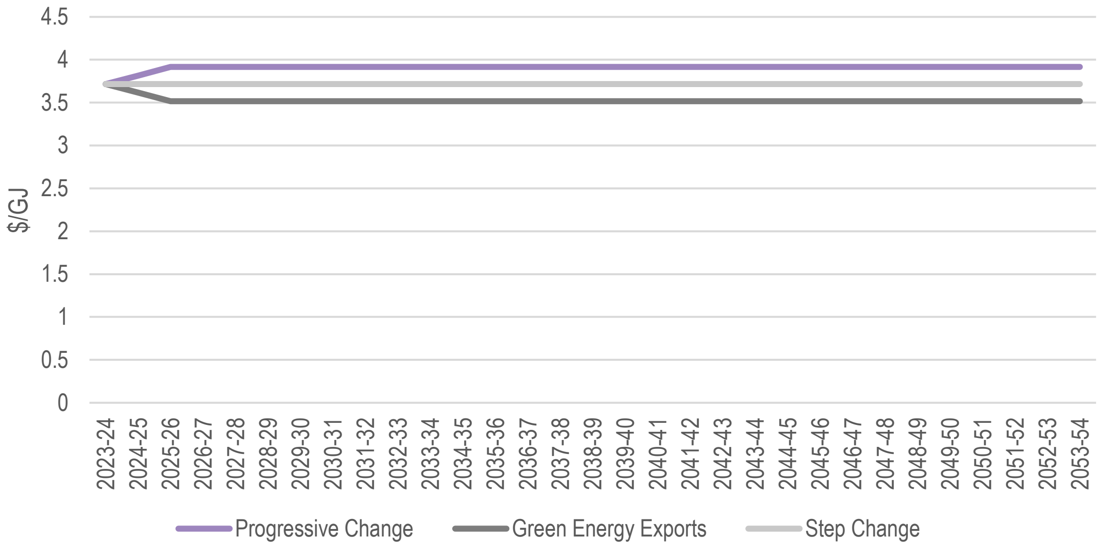
Figure C.12 Stanwell



Source: ACIL Allen

Stanwell power station has been in a long-term supply arrangement with the Curragh mine since 2004. In 2018-19, Stanwell signed a new supply agreement that will extend its coal supply to 2038. We have assumed that Stanwell will transition to an export parity arrangement that imputes the coal netback price when the current agreement expires in the late 2020s.

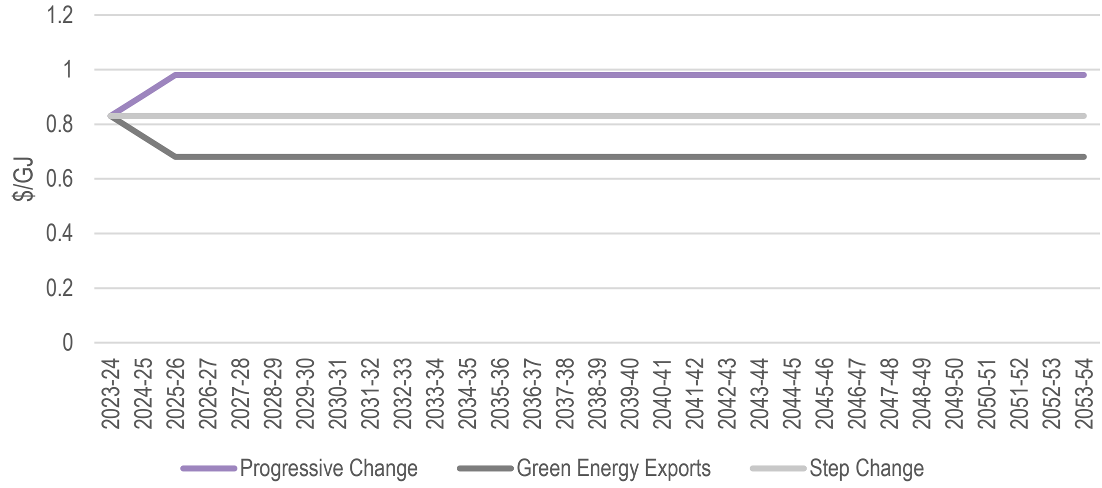
Figure C.13 Tarong and Tarong North



Source: ACIL Allen

Tarong and Tarong north have a captive mine that supplies coal exclusively to this plant. Mining cost estimates form the primary basis for this forecast. Costs are significantly higher for this generator than other captive mine costs due to the low grade of the coal produced and the requirement for washing.

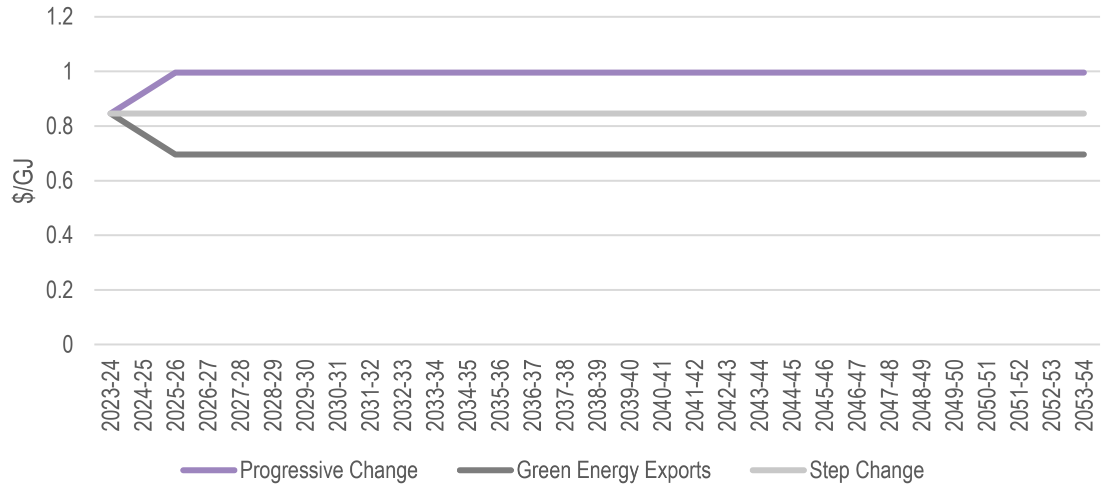
Figure C.14 Loy Yang A



Source: ACIL Allen

Loy Yang A has a captive mine that supplies coal exclusively to this plant. Mining cost estimates form the primary basis form this forecast. Costs for this plant are lower than other captive mines due to the simple mining process and low overburden removal required to access Victorian brown coal.

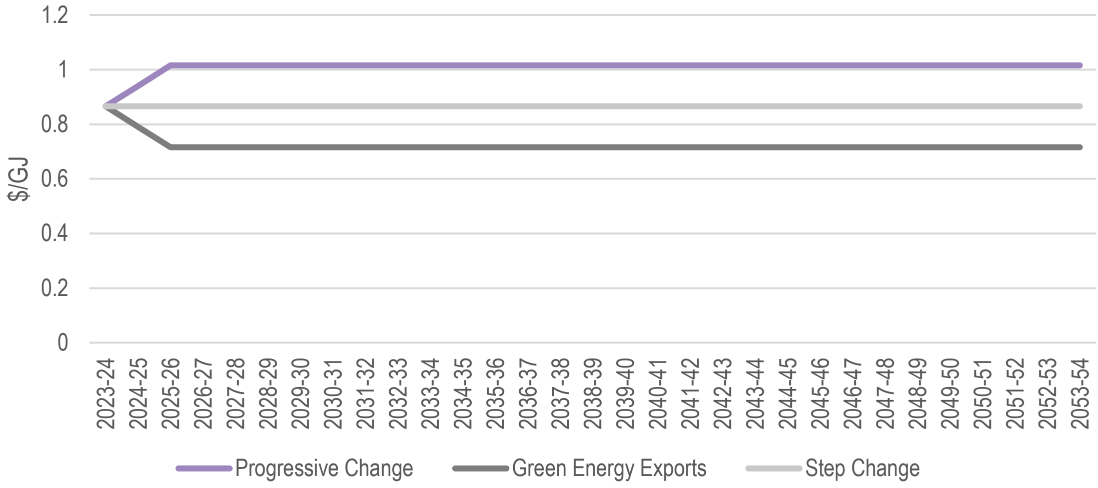
Figure C.15 Loy Yang B



Source: ACIL Allen

Loy Yang B sources coal from the same source that is owned and operated by Loy Yang A. As such prices are much the same plus an additional charge to reflect the additional handling and conveyor operation.

Figure C.16 Yallourn W



Source: ACIL Allen

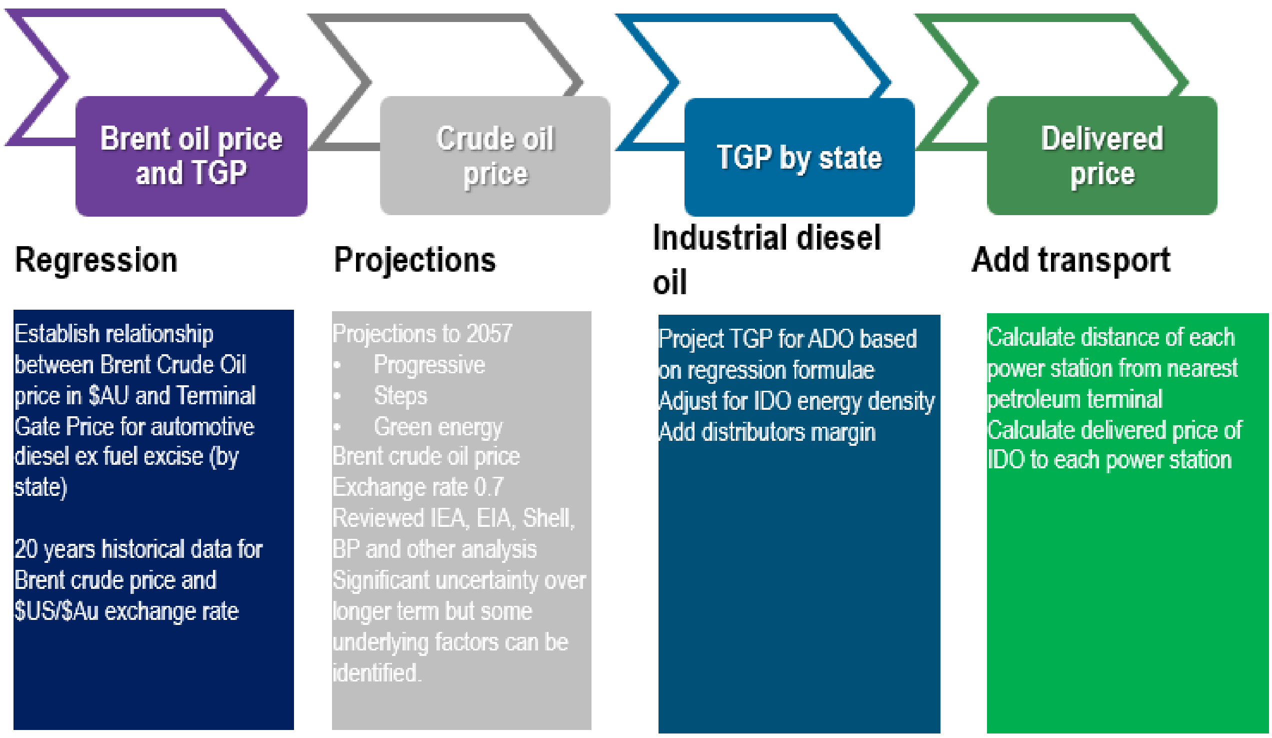
Yallourn W has a captive mine that supplies coal exclusively to this plant. Mining cost estimates for the primary basis form this forecast. Costs for this plant are lower than other captive mines due to the simple mining process and low overburden removal required to access Victorian brown coal

D Liquid fuel price modelling methodology

D.1 Approach

The brief required the projection of diesel prices at power stations in the National Electricity Market (NEM) that can, or could, use diesel as a fuel. An overview of the general approach to preparing the projections of diesel prices for power stations is provided in Figure D.1.

Figure D.1 Approach



Source: ACIL Allen

The approach taken begins with projections of crude oil prices to provide projections of Terminal Gate Prices for automotive diesel oil. These prices are then converted to $/GJ for industrial diesel oil at the terminal. A distributors margin is added to the price and a charge for transport from the nearest petroleum terminal to the power station.

These steps are outlined below.

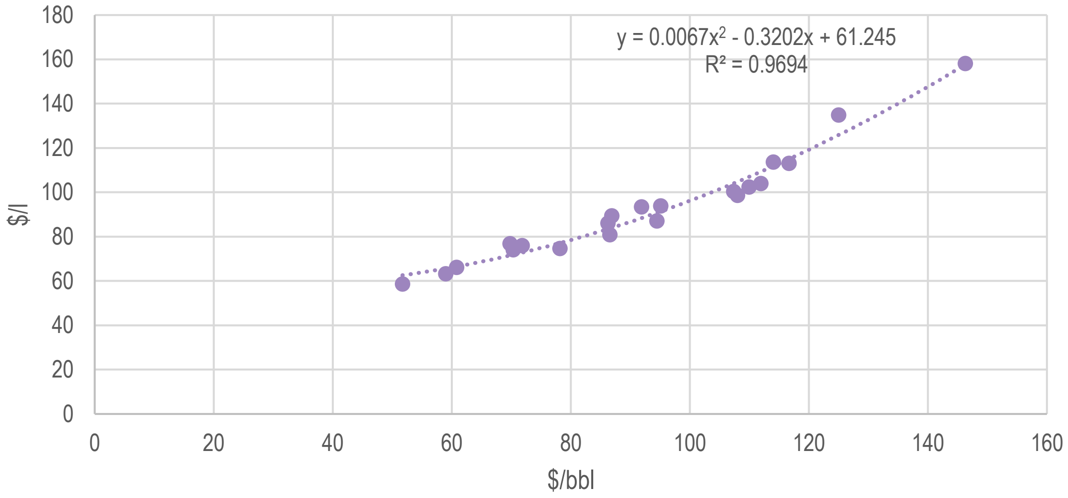
D.2 Terminal gate prices

The most relevant marker price for crude oil for Australian consumption is the Tapis crude produced in Malaysia. However, there is not a good price series for Tapis crude and Brent crude is often used as a proxy for Tapis.

Terminal gate prices for automotive diesel for the past 20 years are available by state from the Australian Institute of Petroleum[13]. A corresponding price series for Brent crude oi prices in US$/bbl is available from Thomson Reuters and published by the US Energy Information Agency[14].

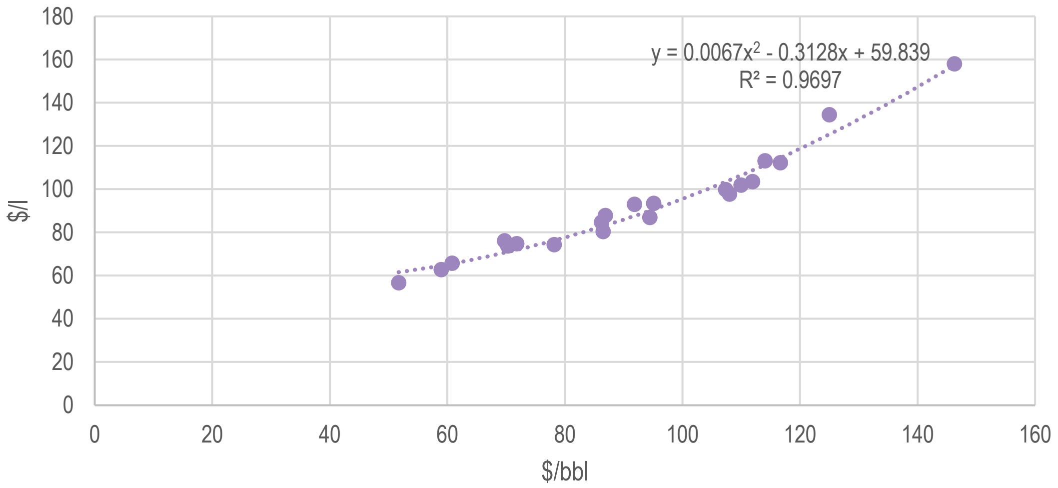
The correlation between Brent crude oil prices and the terminal gate prices after removing fuel excise is strong as shown in Figure D.2.

Figure D.2 Terminal gate prices (excluding fuel excise) in NSW and the Brent Crude oil price in $AU/bbl (automotive diesel oil)



Source: ACIL Allen

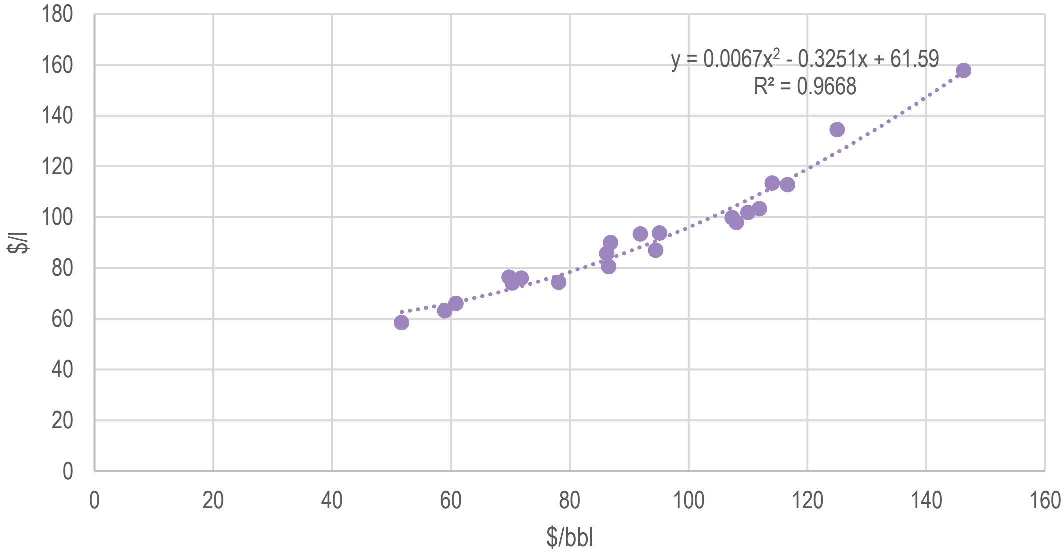
Figure D.3 Terminal gate prices (excluding fuel excise) in Victoria and the Brent Crude oil price in $AU/bbl (automotive diesel oil)



Source: ACIL Allen

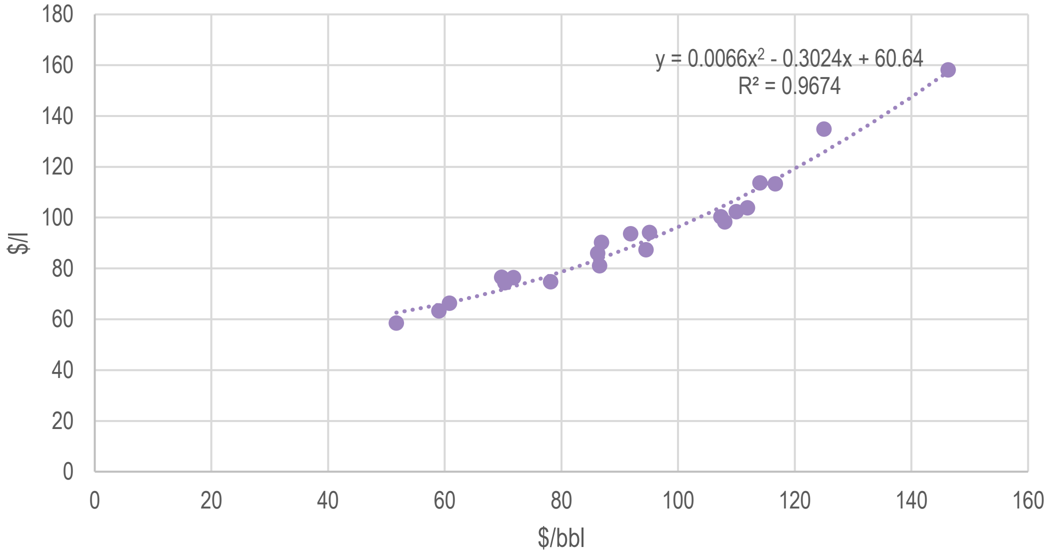
13 https://www.aip.com.au/pricing/terminal-gate-prices accessed on 15 October 2024
14 https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RBRTE&f=A sourced on 15 October 2024

Figure D.4 Terminal gate prices (excluding fuel excise) in Queensland and the Brent Crude oil price in $AU/bbl (automotive diesel oil)



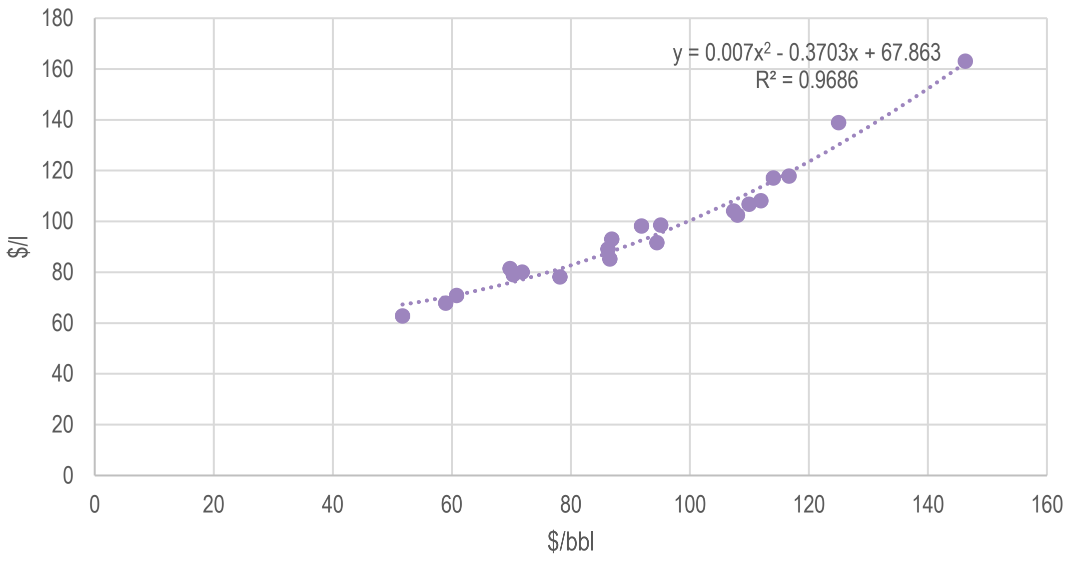
Source: ACIL Allen

Figure D.5 Terminal gate prices (excluding fuel excise) in South Australia and the Brent Crude oil price in $AU/bbl (automotive diesel oil)



Source: ACIL Allen

Figure D.6 Terminal gate prices (excluding fuel excise) in Tasmania and the Brent Crude oil price in $AU/bbl (automotive diesel oil)



Source: ACIL Allen

D.3 Projection of crude oil prices

The next step was to devise projections of Brent crude oil prices from the period from 2024 to 2057.

The crude oil market is in a period of transition with a decline in the rate of growth in demand for oil globally driven by a decline in demand growth in advanced economies offset by growth in demand from emerging market and developing economies (IEA, 2024). Over laying this transition are ongoing geopolitical events arising from conflicts in central Europe and the middle east that is influencing the short to medium term outlook for supply.

D.3.1 Macroeconomic context

The global macroeconomic context has significantly changed as a result of the Covid-19 epidemic and Russia's invasion of Ukraine. It has been further complicated by the events in the middle east commencing with the Israel-Hamas conflict and subsequent tensions spreading more widely to include Hezbollah and Iran. These events are affecting the immediate term outlook for the global oil market. While they will inevitably evolve, they illustrate the challenges in projecting crude oil prices over the longer term.

From a macroeconomic context, concerns over rising inflation central banks have been tightening interest rates. Inflation and interest rates remain higher than they have been over say the past 15 years. The recent impacts of energy prices on inflation illustrated their importance to inflation and economici growth. Ongoing concerns with conflict in the middle east and central Europe present near-term risks for global economic growth.

Global economic growth is a key driver of demand for petroleum fuels and ultimately on the price of crude oil.

For the purposes of these forecasts, we have assumed:

— The Progressive Change scenario is consistent with slower economic growth on average over the period of the projections
— The Step Change scenario is consistent with moderate economic growth over the period of the projections
— The Green Energy Exports scenario is consistent with higher economic growth over the period of the projections.

It is also important to bear in mind that the Middle Eastern producers of crude oil have national budgets to protect. Income from production of crude oil and petroleum products is important to their national budgets while they transition their economies to a more diverse industry structure as the demand for petroleum products declines. They can be expected to protect their budgetary interests over this period and seek to protect the crude oil price against significant price falls while this transition is underway. [15]For this reason, we have assumed that the price falls in the face of declining demand are not as great as is assumed by the IEA in their Net Zero Scenario in their 2024 World Energy Outlook.

D.3.2 Political uncertainties

Energy markets are particularly sensitive to political events and tensions. Factoring in political developments is particularly difficult when forecasting oil prices out to 2057. There are particularly high risks to oil prices arising out of any tensions or conflicts in the Middle East both from the perspective of the oil production that comes from this area, but also from the shipping arrangements particularly from shipping through the Strait of Hormuz. Around 75% of the oil shipped through the Strat of Hormuz goes to Asia where the strongest growth in demand for oil is expected.

For the purpose of these projections, we have assumed that political tensions will continue to affect the oil market that will to some extent prevent an extended collapse in the oil price over the projection period.

D.3.3 Rates of adoption of electric powered vehicles

The rate of adoption of electric powered vehicles is a key factor in assessing longer term oil demand particularly, but not solely, for the demand for petrol. The rates of growth in the sales of electric vehicles (EVs), Plug-in hybrid electric vehicles (PHEVs) and hybrid vehicles (HVs) are key factors in assessing the future demand for petroleum fuels globally.

Electric vehicles sales were growing by about 25% in the first half of 2024 driven in no small measure by sales in China. However, sales in Europe and North America have slowed somewhat at the same time.

For the purpose of our projections, we have assumed that sales of EVs and PHEVs grow more slowly than in the recent years for the Progressive and Step Change Scenarios and that the sales of EVs grows more strongly than PHEVs and HVs over the period to 2030 and beyond.

D.3.4 Fuel efficiency and fuel switching

Demand for petroleum fuels will also be influenced by continued improvements in fuel efficiency in vehicles and fuel switching to alternate fuels such as biofuels and hydrogen over the longer term. Of particular interest also is the rate of switching in the power sector in Middle Eastern countries over the medium to longer term.

[15] For a discussion of this issue see (Dale, 2015)

D.3.5 Demand and price outlook

Recent analysis by the International Energy Agency suggest that global oil demand will peak sometime around 2030 with the date of the peak varying depending on the assumed scenario outlook.

The main assumptions for the three AEMO scenarios are:

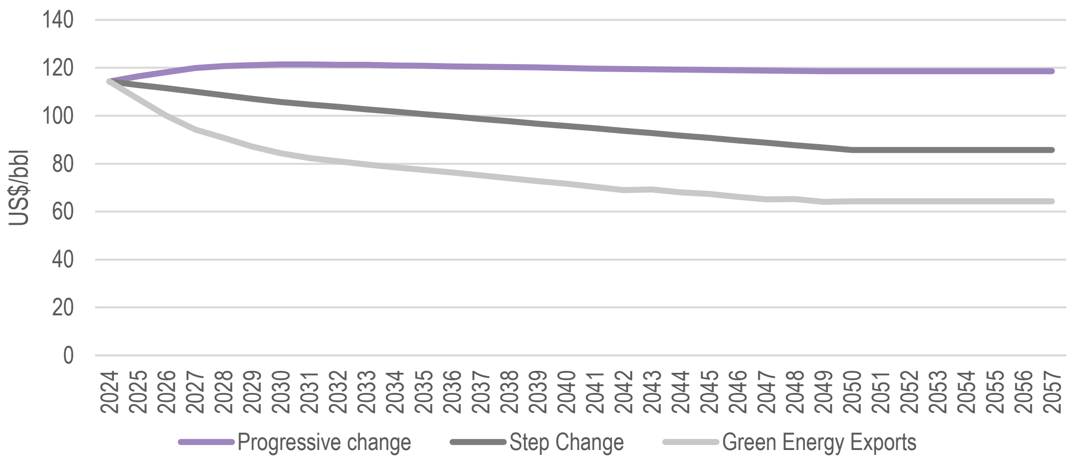
— Progressive Change - slower uptake in the transition to EVs and fuel substitution and slower economic growth

— Step Change – faster uptake of EVs and fuel substitution and moderate economic growth

— Green Energy Exports – fastest uptake of EVs and fuel substitution and higher economic growth.

The projections of Brent crude oil prices are shown in Figure D.7.

Figure D.7 Brent crude oil price



Source: ACIL Allen

D.4 Converting to prices at power stations

The process to convert the projections of Brent crude prices to prices at power stations involved the following steps:

— calculating terminal gate prices for automotive diesel in c/l for each state in the NEM

— converting the automotive diesel prices to prices for industrial diesel oil in $/GJ

— adding a distributors margin of 3%

— adding the cost of transport from the nearest petroleum terminal to the power station.

The price at the power station was calculated using the following formula:

$$P_{power\ station} = TGP_{IDO} + M_D + \mathrm{T}$$

where :

TGP_{IDO} = terminal gate price for industrial diesel oil

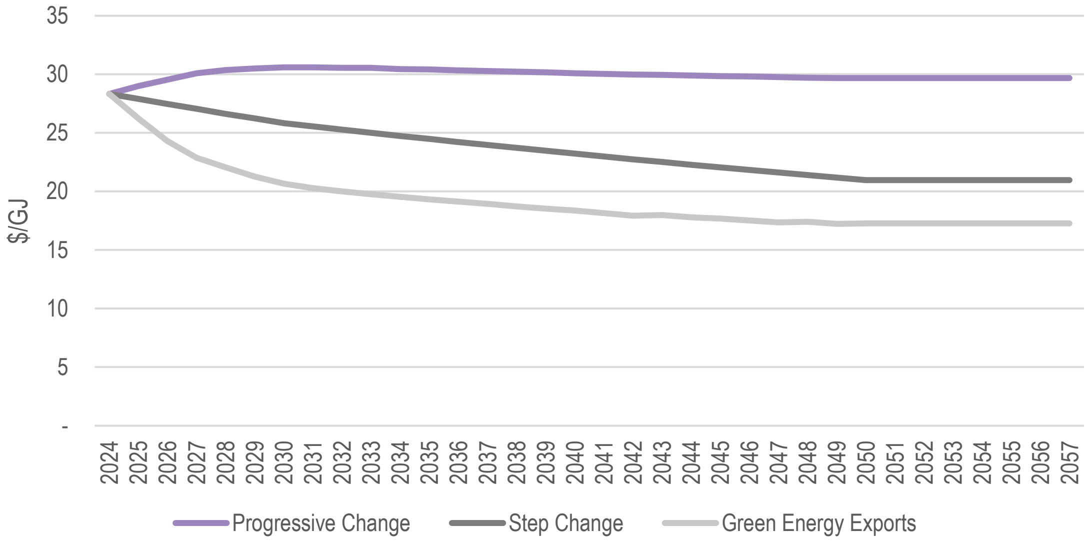
M_D = distributors margin

T = transport costs

D.4.1 Projections of terminal gate price for industrial diesel oil

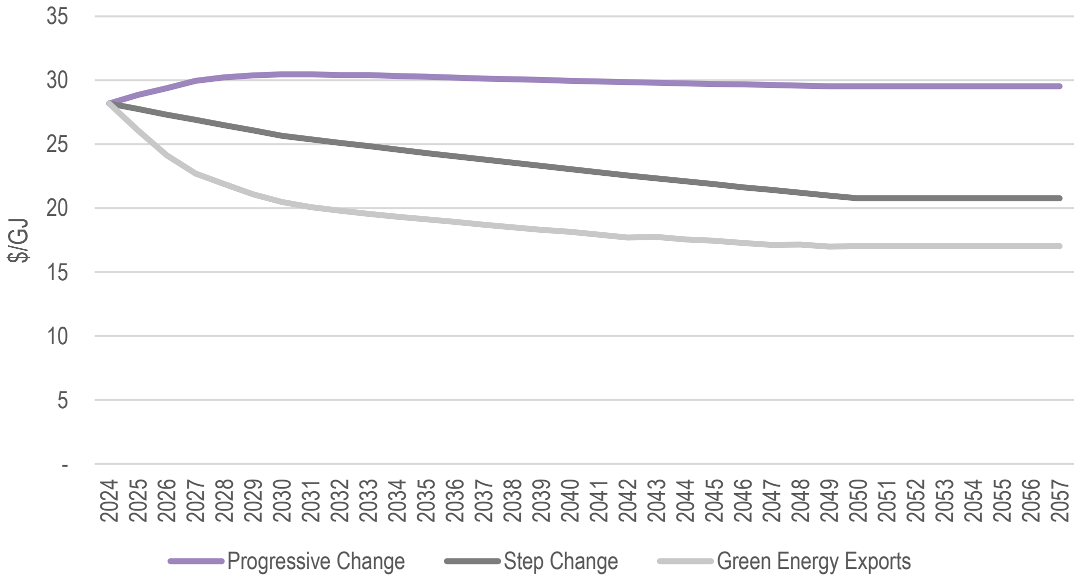
Projections of terminal gate prices in $/GJ are summarised in the following charts.

Figure D.8 Terminal gate price projections for the ISP scenarios ($/GJ) – New South Wales



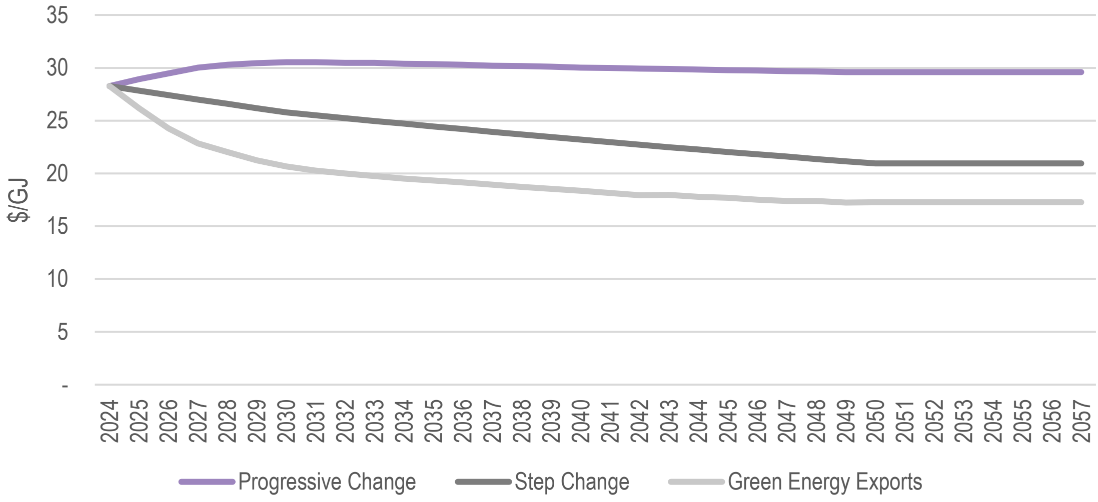
Source: ACIL Allen

Figure D.9 Terminal gate price projections for the ISP scenarios ($/GJ) - Victoria



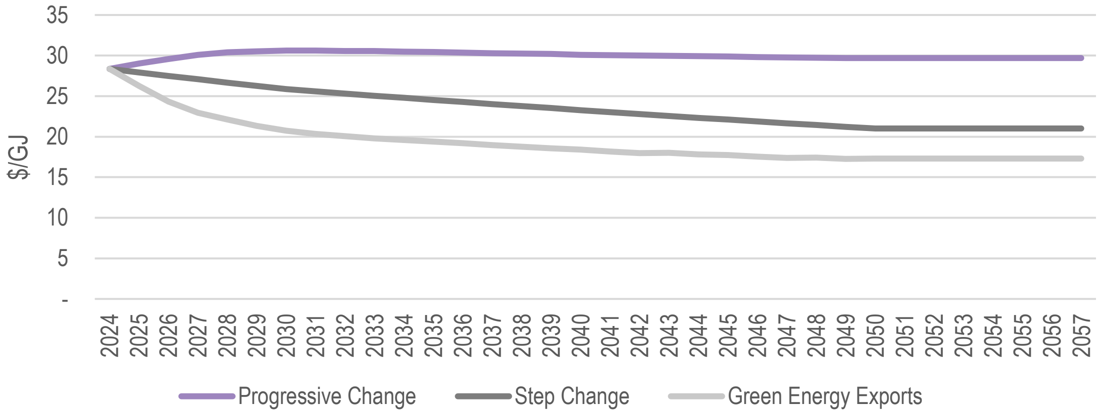
Source: ACIL Allen

Figure D.10 Terminal gate price projections for the ISP scenarios ($/GJ) - Queensland



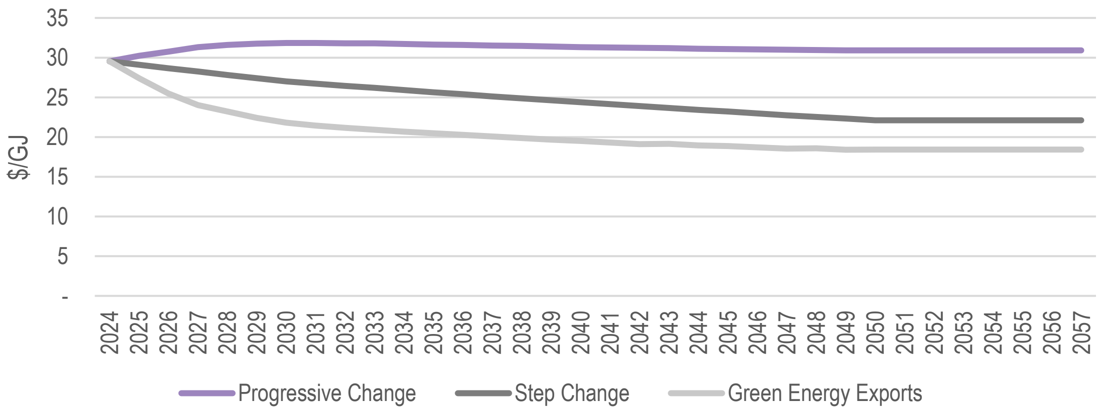
Source: ACIL Allen

Figure D.11 Terminal gate price projections for the ISP scenarios ($/GJ) – South Australia



Source: ACIL Allen

Figure D.12 Terminal gate price projections for the ISP scenarios ($/GJ) - Tasmania

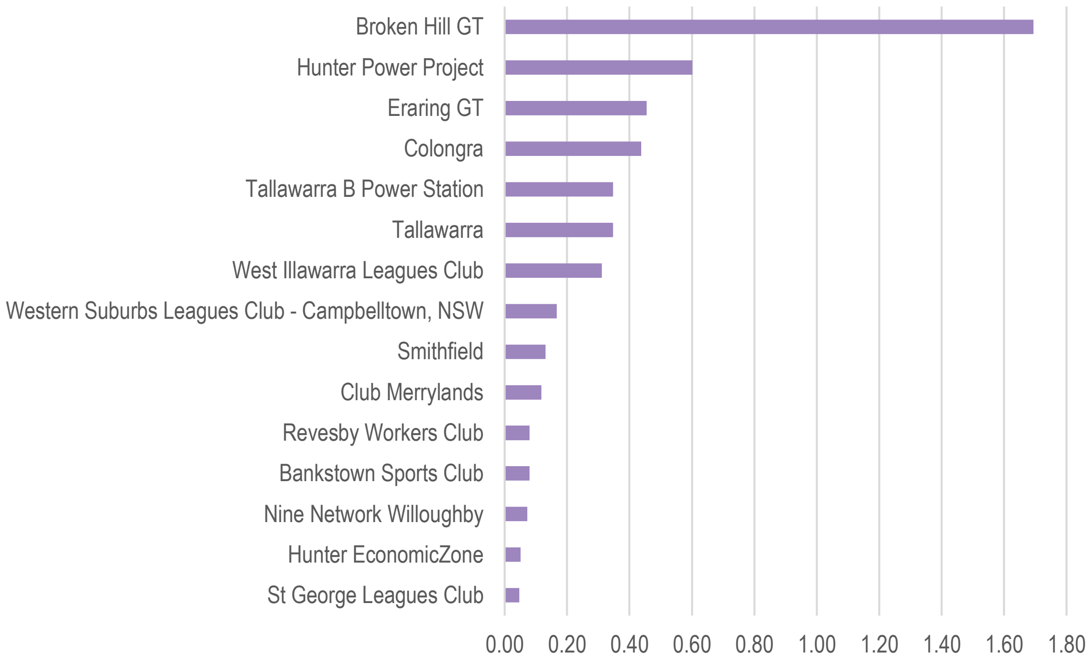


Source: ACIL Allen

D.4.2 Transport costs

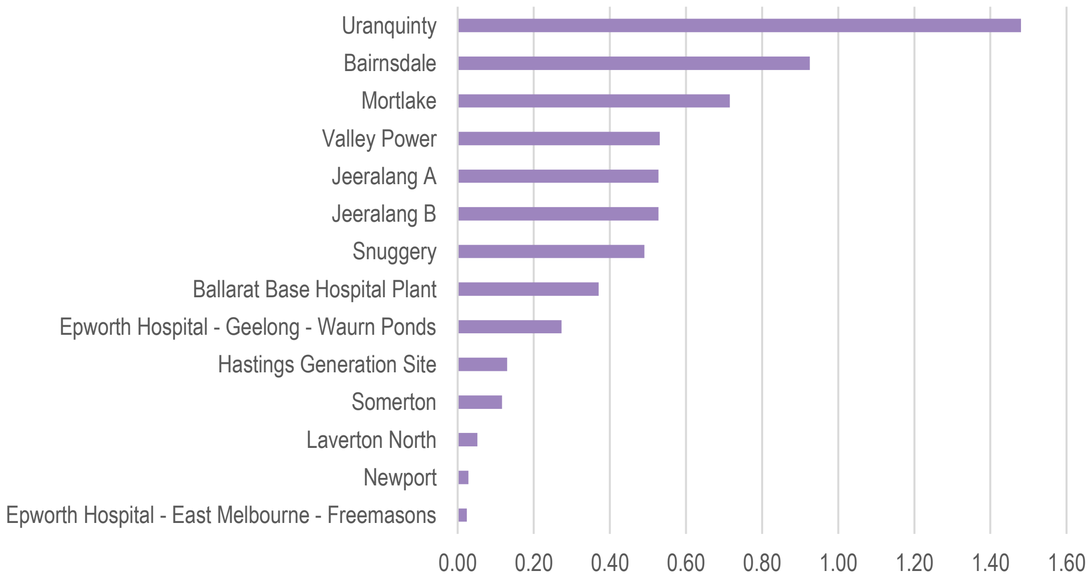
Transport costs have been calculated on cost per km and distance from the power station to the nearest petroleum terminal. Transport costs are based on an estimated cost of transport of $0.003341/GJ-km.[16]

Figure D.13 Generator transport cost, NSW ($/GJ)



Source: ACIL Allen

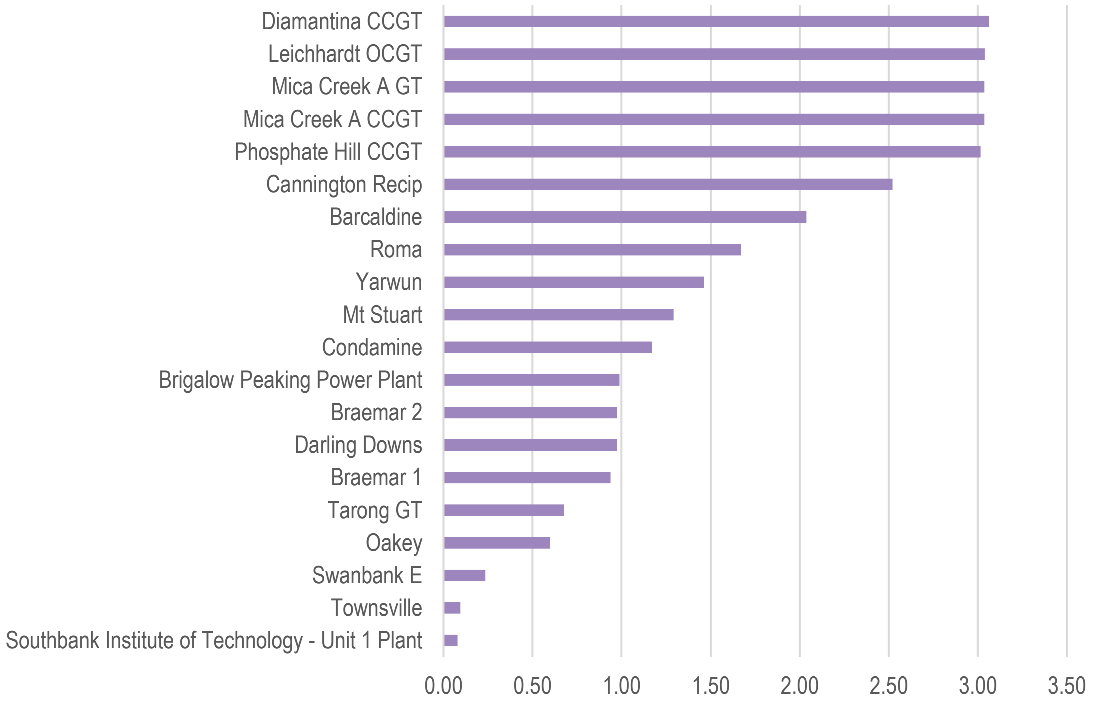
Figure D.14 Generator transport cost, VIC ($/GJ)



Source: ACIL Allen

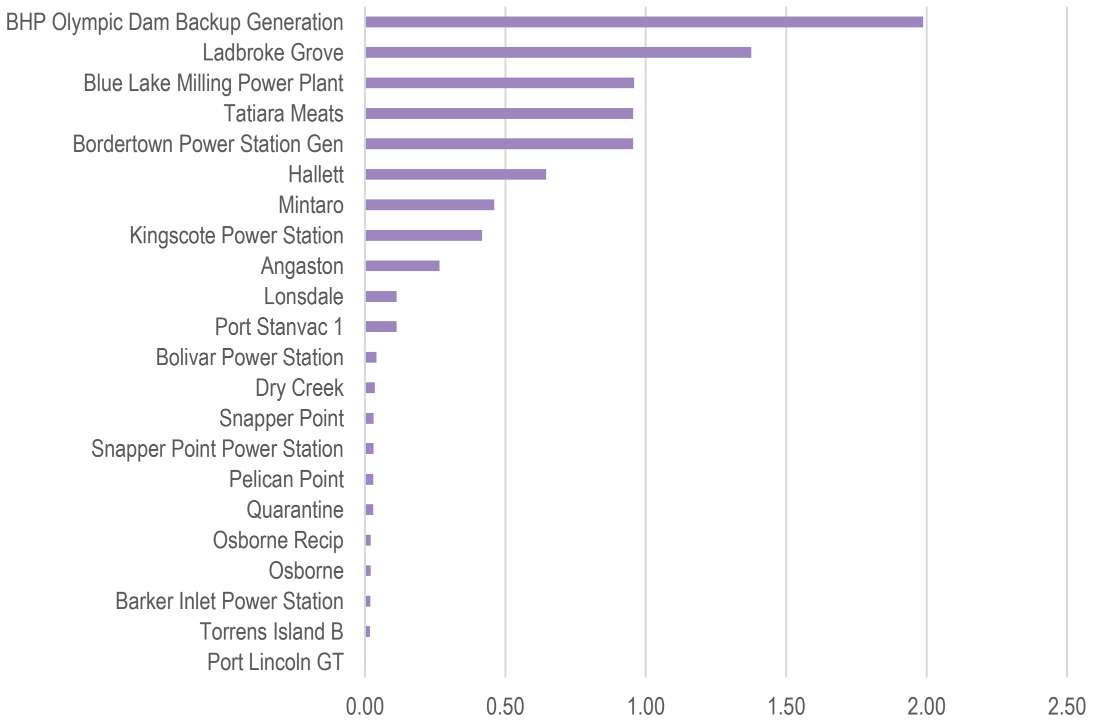
[16] Transport costs were based on a personal communication and (L.E.K, 2021)

Figure D.15 Generator transport cost, QLD ($/GJ)



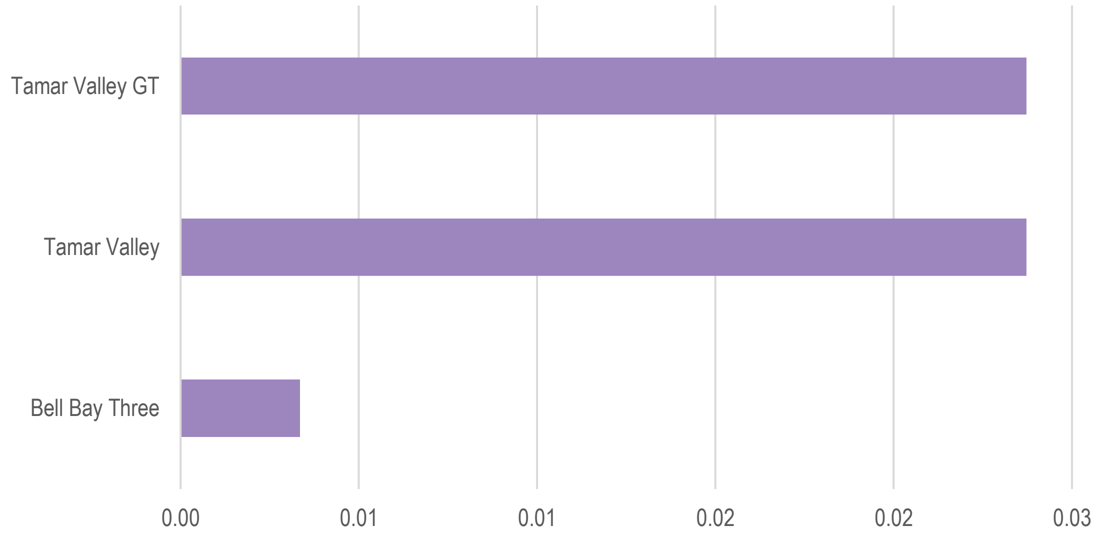
Source: ACIL Allen

Figure D.16 Generator transport cost, SA ($/GJ)



Source: ACIL Allen

Figure D.17 Generator transport cost, TAS ($/GJ)



Source: ACIL Allen

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