

Appendix A10. Gas Development Projections

June 2026

Appendix to the 2026
Integrated System Plan for the
National Electricity Market





We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO is proud to have launched its Innovate [Reconciliation Action Plan](#) in June 2026. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation – a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

This is Appendix A10 to the 2026 Integrated System Plan (ISP) which is available at <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp>. AEMO publishes the 2026 ISP pursuant to its functions under section 49(2) of the National Electricity Law (which defines AEMO's functions as National Transmission Planner) and its supporting functions under the National Electricity Rules. This publication is generally based on information available to AEMO as at 20 April 2026 unless otherwise indicated.

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Version control

Version	Release date	Changes
1	25/06/2026	First release

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Executive summary

AEMO's *Integrated System Plan (ISP)* is a roadmap for the National Electricity Market's (NEM's) transition, and outlines an 'optimal development path' (ODP) for generation, storage and network investments to meet both consumer needs and government policies, at least cost, to 2050.

The 2026 ISP reaffirms that renewable energy, connected by transmission and distribution, firmed with storage and backed up by gas presents the least-cost way to supply secure and reliable electricity to consumers through to 2050, as coal plants retire and while meeting government policies.

Australia's electricity and gas markets are strongly coupled, with significant existing gas-powered generation (GPG) capacity connected to the NEM, providing an important role in maintaining the reliability and security of the power system. The demand for gas from GPG is also a material influence on the operation of Australia's East Coast Gas Market (ECGM) that services gas consumers in NEM jurisdictions, as well as in regions outside of the NEM, particularly the Northern Territory and central Australia.

The 2026 *Gas Statement of Opportunities (GSOO)* forecasts that with the level of existing, committed and anticipated¹ midstream gas infrastructure, and with the forecast level of gas production and demand across the ECGM, there is a risk of peak day shortfalls in southern Australia² from 2029 and risks that structural supply gaps emerge from 2030 under most weather conditions, unless new gas supplies are developed beyond that which is currently classified as committed or anticipated.

This appendix includes gas development projections which identify combinations of investments that may be developed by the gas industry in addition to those already progressing to address the investment opportunities highlighted in the 2026 GSOO and support the availability and operation of GPG in the NEM.

The gas development projections inform the ODP in the 2026 ISP; they do not provide an 'optimal development path' for gas, and the investments modelled are not actionable by the ISP framework in the National Electricity Rules (NER). Actual investment in gas infrastructure by the gas industry may differ from the gas development projections in this ISP.

The appendix provides insights into the potential limitations for gas to supply GPG, the impact these limitations would have on GPG development, and the role of secondary fuels such as diesel.

In particular, it recognises that:

- **The modelled gas development projections trend to a similar long-term outcome.** While the initial gas investments differ for all gas development projections, over the long term, all projections adapt to provide similar levels of gas availability for GPG.
- **Gas generators are a critical part of the current and future supply mix, and the role GPG plays is changing.** Gas usage for electricity generation is forecast to become peakier and more seasonal as GPG changes from more regular, mid-merit operations to a flexible, back-up role.

¹ Existing and committed' means gas developments that are already operating or have obtained all necessary approvals, with implementation ready to commence or already underway. 'Anticipated' means developers consider the project to be justified on the basis of a reasonable forecast of commercial conditions at the time of reporting, and reasonable expectations that all necessary approvals (such as regulatory approvals will be obtained and final investment decision ID made). 'Uncertain' projects are at earlier stages of development or face challenges in terms of commercial viability or approval.

² Southern Australia refers to the NEM regions of New South Wales, South Australia, Tasmania and Victoria.

- **Multiple gas development projections can meet forecast gas consumers' needs, including fuel needs for GPG.** These gas development projections influence the foundational assumptions for gas availability used to assess the investment needs of the NEM power system in the ISP, while also ensuring forecast gas demand for residential, commercial, and industrial consumers is met.

The modelled gas development projections trend to a similar long-term outcome

The 2026 ISP has modelled four alternate gas development projections, informed by analysis in the 2026 GSOO, to explore the impact of alternative initial gas investments to address gas supply shortfalls prior to 2030. While these initial gas investments differ, by around 2036 each projection has resulted in similar combinations of transport, storage and new gas supply developments, including regasification terminals, to meet the needs of gas consumers including GPG to support the NEM.

This demonstrates that while timely investment in new gas infrastructure is needed, the choice of project is less critical from a long-term gas supply adequacy perspective. The GPG requirements of the future power system may be met irrespective of which gas investment progresses first, if gas investment is sufficiently supported to deliver the required level of supply. Ultimately, it remains up to the gas industry to identify and progress projects, and alternative gas development projections could emerge as a result of the progression of actual projects by the gas industry.

AEMO acknowledges that different gas developments could result in variations in gas market dynamics that impact forecast gas prices, and this price expectation could impact the preferred developments by the gas industry, including gas consumers. The 2026 ISP has not included consideration of the impacts on gas price, cost recovery or other commercial aspects of individual gas developments. The gas development projections presented in this ISP – the first iteration to include gas development projections – represent potential developments and do not represent a preferred or optimal development path for the gas sector. The gas development options assessed were those published in the 2025 *Gas Infrastructure Options Report*, with updates from the 2026 GSOO. These options may not represent all gas infrastructure options being considered by the gas industry.

To simplify the analysis provided in this appendix, AEMO has focused most reporting on a single gas development projection. AEMO's alternative projections identify that only minor variations in the location of new gas generation may be needed if alternative gas investment paths occur.

Gas generators are a critical part of the current and future supply mix, and the role GPG plays is changing

Gas usage for GPG in the NEM is forecast to become peakier and more seasonal as GPG utilisation changes from more regular, mid-merit operations to a flexible, back-up role. The 2026 ISP reaffirms that renewable energy, connected by transmission and distribution, firmed with storage and backed up by gas, presents the least-cost way to supply secure and reliable electricity to consumers through to 2050 as coal plants retire and while meeting government policies. Over time, as more renewable generation and battery storage is connected and heating load switches from gas to electricity, GPG is also forecast to play an increasingly seasonal role, with gas increasingly needing to compensate for reduced renewable energy availability in winter and shoulder-season months.

GPG is forecast to be used less frequently through the year but will be critical to maintain reliability during less frequent periods of extreme demand, will provide operational flexibility during widespread low variable renewable energy (VRE)

output conditions, during longer ‘dark and still’ events³, and will also continue to provide essential power system services. From 2038-39, annual GPG consumption is forecast to stabilise, despite forecast electricity demand continuing to increase, as greater volumes of low-cost VRE and storage are forecast to be unlocked with the transmission developments in the ODP.

Multiple gas development projections can meet forecast gas fuel needs but, if gas investments are insufficient, secondary fuels may become essential to maintain NEM reliability and operability

The scale of GPG capacity required to support the NEM’s reliable operation in a high VRE future is broadly consistent, regardless of the specific gas development pathway. Most GPG new capacity is projected to be needed in New South Wales and Victoria, near the largest demand centres in the NEM, though GPG developers will need to consider the availability of gas when determining their specific locations.

The required gas infrastructure investment will depend heavily on the total volume and rate at which gas is required for GPG. Forecast daily gas demand remains highly uncertain, which will make it challenging for the gas industry to respond at the right time and deliver the right quantity. The commercial viability of gas investment to primarily support GPG is largely untested and may require a new approach to traditional infrastructure underwriting processes. It is therefore increasingly important that the right investment signals are in place, and that GPG developers and gas investors proactively engage with each other to ensure energy infrastructure is delivered effectively and efficiently, including appropriate consideration of lead times and commercial arrangements.

Modelling indicates that a future with an under-investment in gas developments would require the GPG fleet to have a much greater reliance on secondary fuels. While new GPG capacity in the NEM should be developed with multiple fuel capabilities, gas infrastructure under-investment may require additional capital investment in diesel storage and greater logistical arrangements for diesel refilling, and may pose higher reliability risks if diesel storages cannot be replenished quickly enough during extended VRE lulls.

With gas demand for GPG currently making up 17% of annual domestic east coast gas consumption, and this proportion is forecast to increase to become over 40%⁴ before the end of the ISP horizon, the development outlook for gas supply, storage, and infrastructure is closely linked to the developments in the NEM. If actual NEM developments diverge from the ODP, the scale and timing of gas demand for the NEM could shift materially, which would alter the gas development requirements for the ECGM. Likewise, if gas developments diverge materially, electricity investment alternatives to GPG, such as deep seasonal storages in the NEM, may be required to back up renewable generation.

³ Dark and still conditions affect the total generation that will be available from wind and solar generators. During extended periods of low renewable output, the power system must rely on energy production from other sources, such as hydro, storage, and GPG. The frequency of these conditions depends on the geographical and technical diversity of the future generation mix, and AEMO’s ISP models consider the expected availability across ‘weather years’ to determine the appropriate generation mix in the ODP.

⁴ These percentages exclude gas consumption within the Northern Territory, and only account for gas used in the NEM regions – Queensland, New South Wales, Victoria, South Australia and Tasmania.

A10.1 Introduction

Published every two years, AEMO's ISP is a roadmap for the transition of the NEM power system, with a clear plan for essential infrastructure that will meet future energy needs. The 2026 ISP is the first to investigate developments within the ECGM that help ensure energy system adequacy for both the gas and electricity sectors across the ISP horizon.

In early 2024, the Energy and Climate Change Ministerial Council (ECMC) finalised a review of the ISP⁵ and on 5 April 2024 published the Energy Ministers' *Response to the ISP Review*⁶. The response outlined a series of actions to enable the ISP to set a direction for the energy system as a whole, including expanded consideration of the influence of gas market developments on future power system needs.

On 19 December 2024, the Australian Energy Market Commission (AEMC) made rule changes to better integrate gas analysis into the ISP⁷. Changes to the National Gas Rules (NGR) enable AEMO to access, use and publish for ISP purposes certain gas information that has been provided to AEMO in the performance of its NGR functions, enhancing gas analysis in the ISP, increasing transparency and improving consistency across AEMO's reports. Changes to the National Electricity Rules (NER) require AEMO to produce gas development projections for inclusion in the ISP, to summarise the inputs, assumptions and scenarios used for the gas development projections, and explain where underpinning inputs are different to those in gas publications. The rule change stopped short of allowing co-optimisation of electricity and gas, reinforcing that the ISP remains an electricity planning tool, with gas analysis used to inform electricity infrastructure investments.

In December 2025, the Australian Government released its Gas Market Review Report⁸, which included a review of the Australian Domestic Gas Security Mechanism, Gas Market Code and Heads of Agreement, and consequently announced a domestic gas reservation scheme, which is aimed to come into effect during 2027⁹. As the detailed implementation of this policy is still under consultation at the time of publication, this 2026 ISP did not consider the impact of a domestic gas reservation scheme affecting the ECGM, or any other consequences related to this policy.

This appendix provides gas analysis which informed the development of the 2026 ISP ODP for the NEM:

- A10.2 highlights the need for developments in the gas sector as identified in the 2026 GSOO.
- A10.3 identifies four gas development projections, comprising of a series of potential gas infrastructure, storage and supply developments that will be required to meet forecast gas demand across the ISP outlook.
- A10.4 forecasts the changing role of gas-powered generation.
- A10.5 presents analysis across the gas and electricity systems, including the impact of different gas development projections on the ODP.

⁵ Australian Government, Department of Climate Change, Energy, the Environment and Water. *Review of the Integrated System Plan – Final Report*, January 2024. At https://www.aph.gov.au/Parliamentary_Business/Committees/Senate/Energy_Planning_and_Regulation_in_Australia/EnergyPlanning/Additional_Documents.

⁶ At <https://www.energy.gov.au/sites/default/files/2024-04/ecmc-response-to-isp-review.pdf>.

⁷ AEMC. Final report. National Electricity Amendment (Better integration of gas and community sentiment into the ISP) Rule 2024 and National Gas Amendment (Better integration of gas and community sentiment into the ISP) Rule 2024, December 2024. At <https://www.aemc.gov.au/rule-changes/better-integration-gas-and-community-sentiment-isp-0>.

⁸ See <https://www.dceew.gov.au/energy/markets/gas-markets/gas-market-review>.

⁹ See <https://minister.dceew.gov.au/bowen/media-releases/joint-media-release-affordable-gas-australian-homes-and-businesses>.

This appendix forms a new and important part of the 2026 ISP, recognising the influence of gas market developments on future power system needs and improving consistency across AEMO's reports. As AEMO's work to integrate gas into the ISP matures, future iterations of this analysis and the modelling supporting it will be refined.

The gas development projections inform the ODP for electricity network described in the 2026 ISP; they do not provide an 'optimal development path' for gas, and the investments modelled are not actionable by the ISP framework in the NER. Actual investment in gas infrastructure by the gas industry may differ from the gas development projections provided in this ISP.

Neither gas infrastructure capital costs nor operating costs have been passed to the electricity capacity outlook model and are not used in the ISP's cost benefit analysis (CBA) assessment of the NEM's ODP of electricity investments. In other words, gas and electricity infrastructure have not been co-optimised. Rather, a particular gas development projection has been used to set the gas fuel availability for the ODP. While a set of gas development projections was developed for each scenario, each candidate development path and the counterfactual development path used the same scenario-specific gas development projection.

Key changes from the Draft 2026 ISP

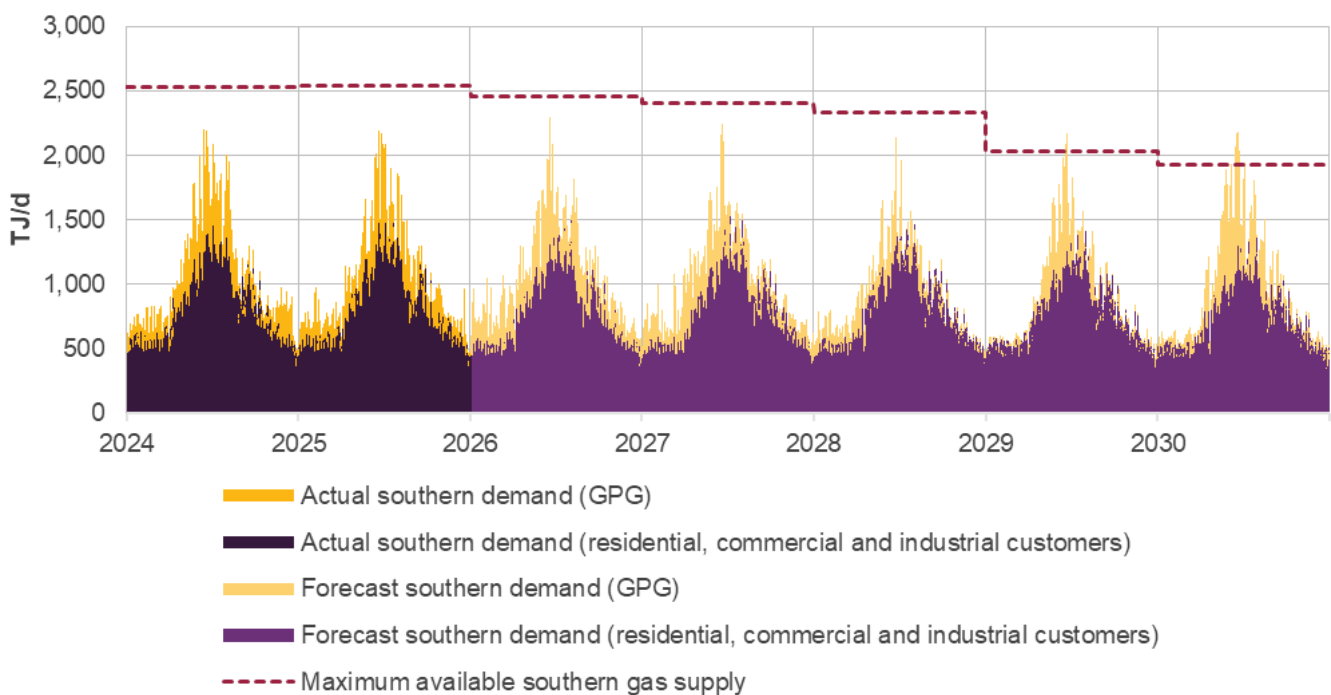
- Inputs for the gas modelling have been updated to be consistent with the 2026 GSOO. This includes:
 - residential, commercial, industrial and liquefied natural gas (LNG) gas demand forecasts,
 - gas production forecasts,
 - wellhead gas production costs, LNG regasification gas costs (inclusive of shipping and tolling costs), and pipeline tariffs, and
 - infrastructure and supply project status and details.
- Initial investments used as the starting point of the gas development projections are consistent with the project sets studied in Section 5 of the 2026 GSOO. This includes the reframing of the *Southern supply* project set into two distinct stages: first, the southern backfill production using existing gas plants, and second, the development of additional southern supply from all uncertain gas plants and further backfill of existing plants using prospective resources.
- Gas project details have been updated based on stakeholder feedback.
- Minor modelling improvements have been made to the gas model to reflect more realistic operation of the ECGM and behaviour of projected infrastructure developments.

A10.2 Gas system adequacy

The 2026 GSOO considered the availability of existing, committed and anticipated gas supplies, storage and pipeline infrastructure to meet forecast gas consumption, including as a fuel for GPG. The 2026 GSOO forecast that with the level of existing, committed and anticipated mid-stream gas infrastructure, and with the forecast level of gas production and demand across the ECGM, there is a risk of peak day shortfalls in southern Australia from 2029 (subject to prevailing conditions)¹⁰.

Figure 1 shows the maximum gas supply capacity (dotted red line) in terajoules per day (TJ/d) that is forecast to be available to meet southern daily gas demand, including GPG, based on existing, committed and anticipated gas supply and infrastructure. This indicates gas shortfall risks are forecast to emerge on some days in winter 2029 under extreme peak day demand conditions. While these peak day shortfalls vary in size depending on the forecast winter weather conditions and the degree of coincidence of electricity and gas demand, gas shortfalls are forecast under all extreme weather conditions studied.

Figure 1 Actual daily southern gas system adequacy since January 2024, and forecast to 2030 using existing, committed and anticipated supply projects, *Step Change*, (TJ/d)



Seasonal supply gaps may emerge from 2029 if conditions lead to sustained high gas usage and if gas investment remains limited to currently committed and anticipated projects. While gas demand remains highly seasonal and volatile, the scale of maximum southern daily demand is not forecast to be dissimilar to historical levels of peak gas usage. The difference is that southern regions will rely more heavily on storage withdrawals and north to south pipeline flows to meet winter peaks as forecast southern production continues to decline over time, and this gas infrastructure capacity is limited.

¹⁰ The 2026 GSOO did not consider the impact of recent geopolitical events in the Middle East.

From 2030, supply gaps are projected in all AEMO's scenarios under the majority of weather years simulated, even with the development of committed and anticipated gas supplies and expanded electricity developments that offset GPG needs. These supply gaps, which are most likely to occur during winter when gas consumption is highest, signal a need for structural investment in the gas industry. While several supply, storage and transport solutions are presently proposed by the gas industry, there remains uncertainty over which solutions will proceed and when.

The 2026 GSOO also considered the forecast gas supply available to meet northern Australian demand (in Queensland and Northern Territory¹¹), including to satisfy LNG export demand via Curtis Island in Queensland. According to current projections, uncertain supplies will need to be developed from 2029 to meet all gas demand in the north.

This 2026 ISP explores potential gas developments by the gas industry to address forecast supply gaps, and their influence on NEM development needs

This 2026 ISP includes gas development projections which identify combinations of investments that may be developed by the gas industry to address the investment opportunities highlighted in the 2026 GSOO. These gas development projections influence the foundational assumptions for gas available for GPG used to assess the ODP.

Differences between the assumptions used for the 2026 ISP and those used for the 2026 GSOO

- AEMO has applied consistent assumptions, inputs and scenarios from the 2026 GSOO to inform the gas supply development modelling and gas development projections in the 2026 ISP wherever possible. However, AEMO notes that:
 - The GPG forecast used for the gas development projections in the 2026 ISP reflects the generation, storage and network developments of the 2026 ISP's ODP. The GPG forecasts in the 2026 GSOO were aligned with developments in the Draft 2026 ISP ODP, with higher near-term consumption yet broadly similar in the longer-term.
 - Some production costs published with the 2026 GSOO are derived from a limited set of gas field developments, which may not represent full field infrastructure or operating conditions. Production costs for the Gunnedah basin were particularly impacted by this assumption so the production cost estimated for new gas supply in Narrabri in the 2026 ISP used alternative information for its basis¹², based on stakeholder feedback.
- Except as noted above, AEMO has maintained input consistency with the 2026 GSOO; any updated information provided on the Gas Bulletin Board since March 2026 is not reflected in this analysis.

¹¹ The ECGM includes the Northern Territory, and western Queensland locations outside of the NEM, including Mt Isa. The ECGM northern Australia region covers both Queensland and Northern Territory, excluding gas used for LNG exports out of Darwin.

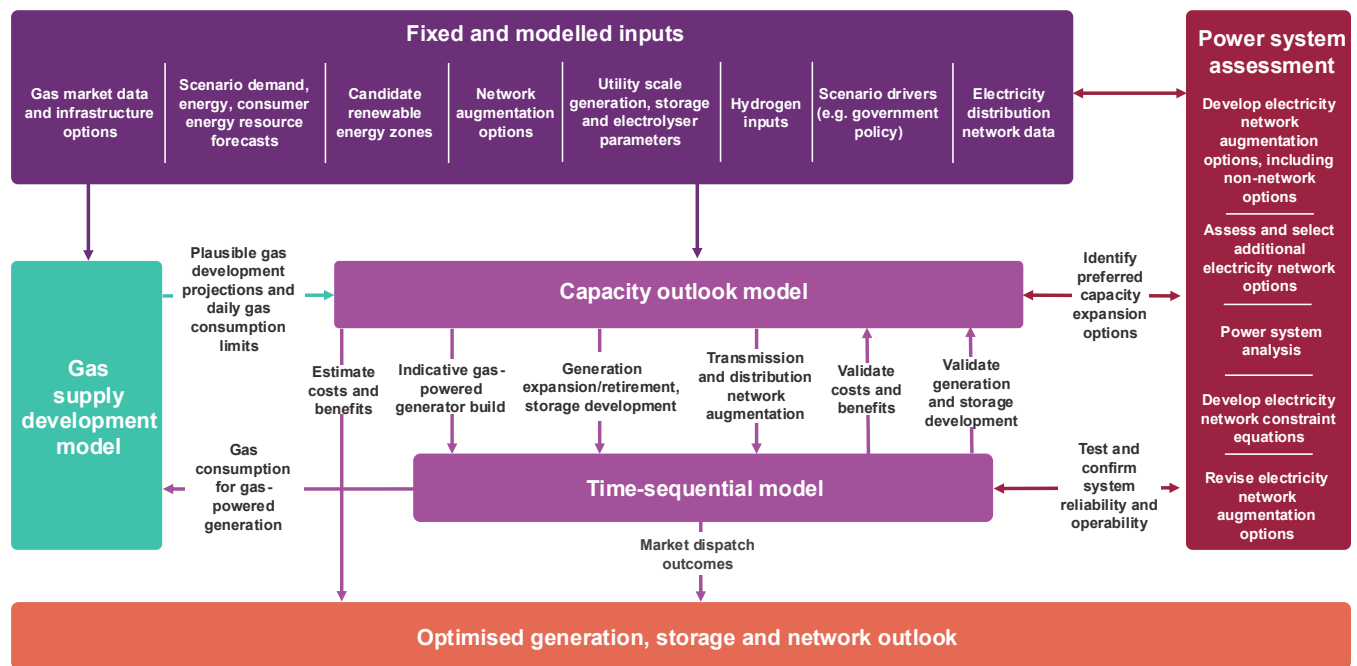
¹² From the EnergyQuest East Coast Gas Outlook report, as reported in the Australian Financial Review at <https://www.afr.com/companies/energy/gas-price-cap-would-rule-out-narrabri-beetaloo-study-20221103-p5bvgy>.

A10.3 Gas development projections

A gas development projection is a combination of gas supply and infrastructure options over the ISP planning horizon, including the timing of their development. For each scenario, AEMO has modelled four gas development projections, and each gas development projection has a unique set of daily gas fuel limitations for GPG. These gas fuel limitations are based on the capabilities of the existing, committed and anticipated ECGM supply developments, as well as supply available from the projection’s combination of gas infrastructure options, less supply needed to meet demands of residential, commercial and industrial gas consumers.

Figure 2 shows an overview of the ISP modelling methodology¹³ and illustrates how different ISP models interact with the gas supply development model to inform the NEM capacity outlook. It is an iterative process. The zonal daily gas limitations are a key output of the gas supply development model and are used by the ISP’s electricity models to constrain the operation of GPG in the NEM to levels that reflect forecast gas availability. The gas supply development model considered both capital costs and operating costs for each option, as well as the operating costs associated with secondary fuels (where applicable). Differences between gas development projections were introduced by assuming a different “initial investment” for each case, with the gas supply development model then determining the subsequent investments required to meet projected gas demand at lowest cost.

Figure 2 Overview of the ISP modelling methodology demonstrating the relationship between electricity and gas models



This 2026 ISP used the ODP’s GPG forecast as an input to the gas supply development model to generate the gas development projections in this appendix. As such, the gas development projections presented in this appendix are a refined version of those that informed the gas limitations for the ODP.

¹³ At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2026-isp-methodology/isp-methodology-june-2025.pdf?rev=e88a1f1bbeef447ba27692b785069a0a&sc_lang=en.

The gas development projections leverage analysis in the 2026 GSOO as starting points

The 2026 GSOO presented analysis that a number of uncertain gas developments exist that could meet the near-term gas consumption needs of the ECGM, and that a combination of investments would be required to service the 20-year horizon that the GSOO assesses.

The types of infrastructure and supply options considered can be divided into four categories:

- **transport options** – including options that expand the transportation capacity within the ECGM, including compression and pipeline options,
- **storage options** – including options that expand the gas storage inventory or injection capacity of the ECGM, including aboveground storage, underground storage and pipeline storage options,
- **production options** – including options that expand the gas production capacity or production supply of the ECGM, including natural gas processing plant, biomethane processing plant, and the extraction of gas from new wells that are classified as contingent (2C) or prospective¹⁴ resources (**Table 1** shows the classification of gas reserves and resources used by AEMO¹⁵), and
- **regasification options** – including options that expand the capacity of the ECGM to receive, store and process LNG back into its gaseous state before injecting the gas into the pipeline network.

The gas supply development model considered the entirety of the ECGM. This includes forecast supply and demand for Queensland and the Northern Territory, including demand for Queensland’s LNG exports via Curtis Island¹⁶. While new supply is required to meet forecast LNG export demand, outcomes associated with Queensland LNG export demand have been excluded from the 2026 ISP analysis to ensure that the focus remains on available gas supply for the NEM and other domestic gas consumers.

This 2026 ISP did not consider the impact of a domestic gas reservation scheme in the ECGM, as the detailed implementation of the policy is still under consultation at the time of publication.

The gas supply development model does not consider the existing or expected contracting arrangements for pipelines and, in reality, some developments may trigger a need for additional pipeline capacity for commercial reasons. An example of this could include the South West Pipeline in Victoria, if additional supply or storage is developed that utilises this pipeline.

Table 1 Classification of gas reserves and resources

Classification	Definition
Proven and probable (2P) reserves	Best estimate of commercially recoverable gas from known accumulations, with at least a 50% probability that the actual recovered volumes will meet or exceed these estimates. In general, 2P reserves are associated with production projects that are existing, committed, or anticipated.
Contingent (2C) resources	Discovered gas volumes that lack current commercial viability for development, requiring further appraisal and investment before they can be classified as reserves. In general, 2C reserves are associated with uncertain projects.
Prospective resources	Estimated gas volumes from undiscovered accumulations that remain highly speculative, as they have not been confirmed through drilling or exploration activities.

¹⁴ The development of prospective resources was restricted to the gas development projection aligned with the *Southern Supply* project set from the 2026 GSOO and the Domestic Supply Only gas development projection.

¹⁵ AEMO uses classifications of reserves and resources aligned with the Society of Petroleum Engineers – Petroleum Resource Management System (PRMS). For more details, see <https://www.spe.org/en/industry/reserves/>.

¹⁶ Northern Territory LNG exports are not considered part of the ECGM.

The production options for the gas development projections considered only known gas resources with contingent estimations of gas quantities, as well as prospective estimations for the *Southern Supply* and *Domestic Supply Only* gas development projections. Exploration for gas fields and the discovery of recoverable resources may materially change the gas supply outlook, however there is insufficient certainty for AEMO to include any undiscovered estimations in the gas development projections or prospective resources in any of the other gas development projections.

The ODP includes new gas-powered generation capacity

Table 2 shows how new entrant GPG in the electricity capacity outlook model are allocated to gas supply zones¹⁷, and **Figure 3** shows the timing and the capacity of these new GPG builds in the ODP for the *Step Change* scenario along with the retiring capacity for each year.

Currently, the NEM has 4 gigawatts (GW) of mid-merit and 8 GW peaking gas-powered generation capacity, of which 9 GW is forecast or announced to retire between now and 2050 as the plants reach end-of-life. As the mid-merit and some peaking plants retire, they would be replaced¹⁸, and the fleet expanded to a 17 GW fleet of flexible capacity able to deliver both generation and system security services. By 2049-50 in *Step Change*, the NEM is forecast to have built 13 GW of flexible GPG capacity, of which about 40% is in the Melbourne zone, which is the largest build for any zone.

Table 2 Gas supply zones and allocation of new entrant GPG builds in the Step Change scenario

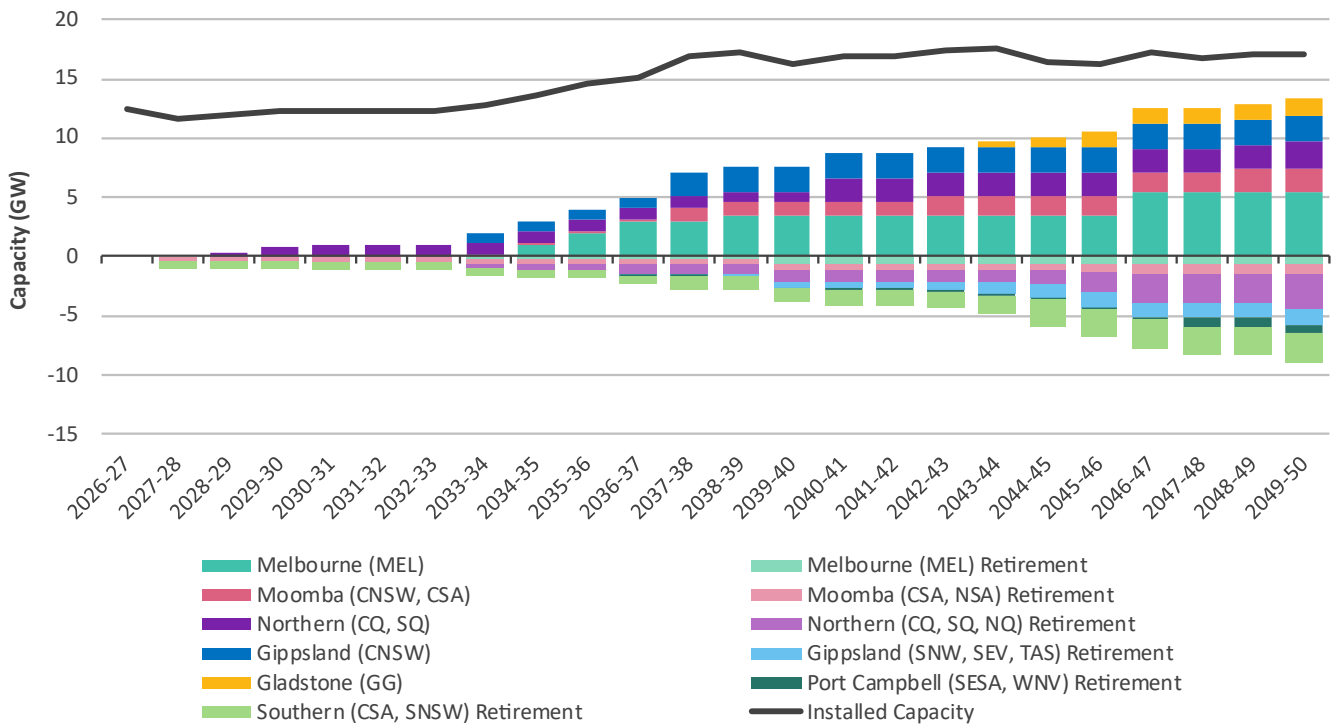
Supply zone	New NEM GPG development locations (ISP sub-regions bracketed, where appropriate)
Gippsland zone	Wollongong, Central New South Wales (CNSW)
Port Campbell zone	West and North Victoria (WNV)
Moomba zone	Including locations within Central New South Wales (CNSW) and Central South Australia (CSA) (excluding new dual-pipeline connected GPG in Adelaide) ^A
Newcastle zone	Specifically, only the Newcastle location within the Sydney, Newcastle and Wollongong ISP sub-region (SNW)
Melbourne zone	Greater Melbourne and Geelong (MEL)
Gladstone zone	New GPG in Gladstone Grid (GG)
Northern zone ^A	Central Queensland (CQ) and Southern Queensland (SQ)
Southern zone ^A	Including all ISP sub-regions within New South Wales (including the Australian Capital Territory), South Australia, Victoria and Tasmania

A. The Northern and Southern zones are aggregate areas that may include multiple supply or pipeline zones, allowing aggregate gas constraints to apply to multiple locations simultaneously.

¹⁷ To model the supply, demand and deliverability of gas in the ECGM for the purposes of the ISP, AEMO has applied a zonal representation of the ECGM, with 12 distinct gas zones. A daily gas limit was determined for each zone, reflecting the capability for GPG to operate given gas supply, storage and pipeline capacity constraints, and considering the residential, commercial and industrial gas demand that exists or is forecast within these zones.

¹⁸ For more information on the locational dynamics of capacity build and retirements, refer to Appendix A2 Generation and Storage Development Opportunities.

Figure 3 New entrant and retiring GPG capacity across different gas supply zones and ISP sub-regions in the ODP, and total GPG capacity, Step Change, 2026-27 to 2049-50 (GW)



Gas development projections

AEMO has developed four gas development projections for the 2026 ISP that explore alternative gas supply solutions to resolve the forecast supply gaps, three of which extend the analysis provided in Section 5 of the 2026 GSOO:

- **Option 1** – a gas development projection with an initial investment of currently uncertain southern supply,
- **Option 2** – a gas development projection with an initial investment of pipeline expansions and upgrades to improve north to south flow capacity,
- **Option 3** – a gas development projection with an initial investment of an LNG regasification terminal and associated pipeline infrastructure to expand the ability to deliver gas to load centres, and
- **Domestic Supply Only** – a gas development projection with domestic gas supply developments being the only new gas supply available in the ECGM. In this projection, LNG regasification terminals were not considered for meeting residential, commercial, industrial and GPG demand¹⁹. This gas development projection does not have any predetermined initial investments.

After any initial investment condition, each gas development projection sought to identify additional infrastructure required to meet ongoing gas needs, while minimising gas system costs.

¹⁹ While it is plausible for Australian LNG export facilities and LNG regasification terminals in southern Australia to create a ‘virtual pipeline’ to deliver LNG to southern markets, this was not considered, as the gas supply development model currently cannot distinguish between LNG supply from domestic and international supply sources.

In addition to these four gas development projections, AEMO also modelled a gas development projection which represented an under-investment in gas infrastructure. In this projection, the forecast gas developments meet residential, commercial and industrial demand but not additional developments required to meet forecast GPG demand.

Table 3 provides an overview of the gas infrastructure and supply forecast in each gas development projection for the *Step Change* scenario, with initial investment options shown in bold. **Figure 4** shows a map of the developments that have been included in the gas development projections.

The charts in **Figure 5** show the maximum available daily gas supply capacity in the Southern zone for each gas development projection, taking into account the pipeline transportation capacity from northern Australia to southern Australia, supply from regasification terminals, injection capacity from storage, and gas production capacity.

Available capacity in these figures includes both capacity from existing, committed and anticipated developments, and new or augmented capacity projected by AEMO's gas supply development modelling.

Table 3 Characteristics of different gas development projections in the Step Change scenario^A, with initial investment options shown in bold^B

	Option 1	Option 2	Option 3	Domestic Supply Only	Under-investment
Regasification options	<ul style="list-style-type: none"> Port Kembla Energy Terminal (2033-34) <ul style="list-style-type: none"> With Eastern Gas Pipeline reversal stage 2 Viva Energy Gas Terminal (2035-36) <ul style="list-style-type: none"> With Westernport Altona Geelong pipeline conversion 	<ul style="list-style-type: none"> Port Kembla Energy Terminal (2033-2034) Viva Energy Gas Terminal (2035-36) <ul style="list-style-type: none"> With Westernport Altona Geelong pipeline conversion 	<ul style="list-style-type: none"> Port Kembla Energy Terminal (2027-2028) <ul style="list-style-type: none"> With Eastern Gas Pipeline reversal stage 2 Viva Energy Gas Terminal (2035-2036) <ul style="list-style-type: none"> With Westernport Altona Geelong pipeline conversion 		<ul style="list-style-type: none"> Port Kembla Energy Terminal (2039-40) <ul style="list-style-type: none"> With Eastern Gas Pipeline reversal stage 2
Production options^C	<ul style="list-style-type: none"> 2C backfill southern production 2C new southern production <ul style="list-style-type: none"> Including 2C Gunnedah with Hunter Gas Pipeline (2030-31) Prospective backfill southern production New renewable gas production 	<ul style="list-style-type: none"> 2C backfill southern production New renewable gas production 	<ul style="list-style-type: none"> 2C backfill southern production New renewable gas production 	<ul style="list-style-type: none"> 2C backfill southern production 2C new southern production <ul style="list-style-type: none"> Including 2C Gunnedah with Hunter Gas Pipeline 2C new northern production <ul style="list-style-type: none"> Including 2C Beetaloo with North to East Australia Pipeline Prospective backfill southern production New renewable gas production 	<ul style="list-style-type: none"> 2C southern production New renewable gas production
Storage options	<ul style="list-style-type: none"> Golden Beach Energy Storage Project (2035-36) 	<ul style="list-style-type: none"> Golden Beach Energy Storage Project (2035-36) Heytesbury Underground Storage Project, Phase 2 (2039-2040) Generic underground storage – depleted field 	<ul style="list-style-type: none"> Golden Beach Energy Storage Project (2033-34) Heytesbury Underground Storage Project, Phase 2 (2035-36) Generic underground storage – depleted field 	<ul style="list-style-type: none"> Golden Beach Energy Storage Project (2035-36) Heytesbury Underground Storage Project, Phase 2 (2035-36) Generic underground storage – depleted field 	
Transport options (known expansions)	<ul style="list-style-type: none"> Port Campbell to Adelaide pipeline reversal Moomba to Sydney Pipeline to Eastern Gas Pipeline compression 	<ul style="list-style-type: none"> East Coast Gas Grid Expansion stage 3B (2028-29) <ul style="list-style-type: none"> With Riverina Storage Pipeline project (2028-29) Eastern Gas Pipeline reversal stage 2 (2028-29) Moomba to Sydney Pipeline to Eastern Gas Pipeline compression 	<ul style="list-style-type: none"> Port Campbell to Adelaide pipeline reversal 	<ul style="list-style-type: none"> East Coast Gas Grid Expansion stage 3B <ul style="list-style-type: none"> With Riverina Storage Pipeline project Port Campbell to Adelaide pipeline reversal Eastern Gas Pipeline reversal stage 2 Moomba to Sydney Pipeline to Eastern Gas Pipeline compression South West Pipeline expansion 	<ul style="list-style-type: none"> Port Campbell to Adelaide pipeline reversal Moomba to Sydney Pipeline to Eastern Gas Pipeline compression
Transport options (generic expansions)	<ul style="list-style-type: none"> Port Campbell Adelaide pipeline Queensland Gas Pipeline^D 	<ul style="list-style-type: none"> Port Campbell Adelaide pipeline Queensland Gas Pipeline^D 	<ul style="list-style-type: none"> Port Campbell Adelaide pipeline Queensland Gas Pipeline^D 	<ul style="list-style-type: none"> Moomba Adelaide Pipeline System Queensland Gas Pipeline^D 	

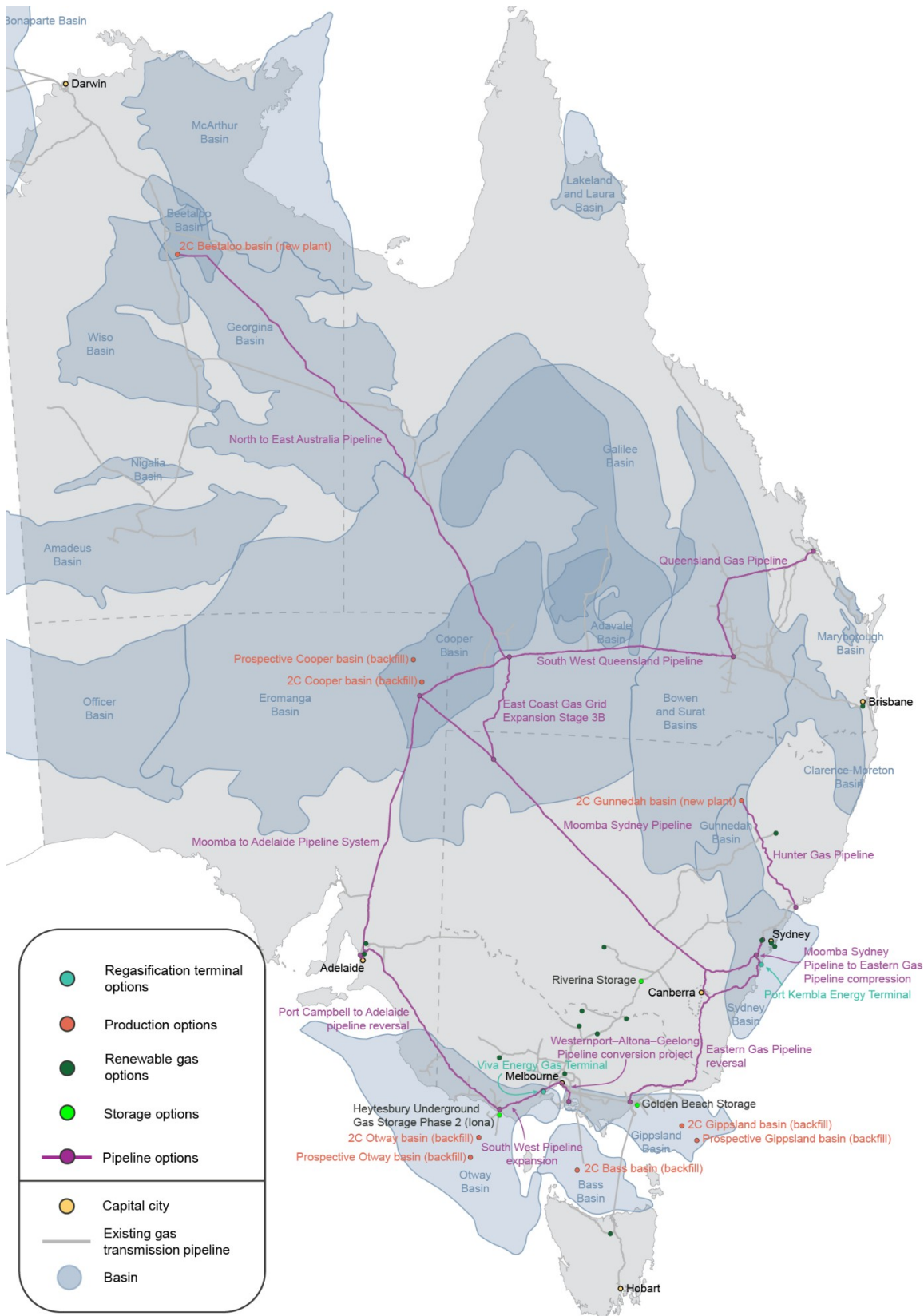
A. While new supply is required to meet forecast LNG export demand, developments associated with Queensland LNG exports have been excluded from this table.

B. The initial investments, also referred to as predetermined options, are as per the 2026 GSOO Section 5 project sets.

C. The initial build period is constrained using the predetermined options to align with the 2026 GSOO. Projects for additional supply from Southern 2C resources that are capable of backfilling existing production plants was available for the gas model to choose at any time, as these volumes can help maintain existing production rates or mitigate production declines as existing, committed and anticipated gas is extracted over time.

D. If pipeline transportation capacity is made available to new build GPG in the Gladstone sub-region on one of the existing LNG export pipelines, this expansion may not be required.

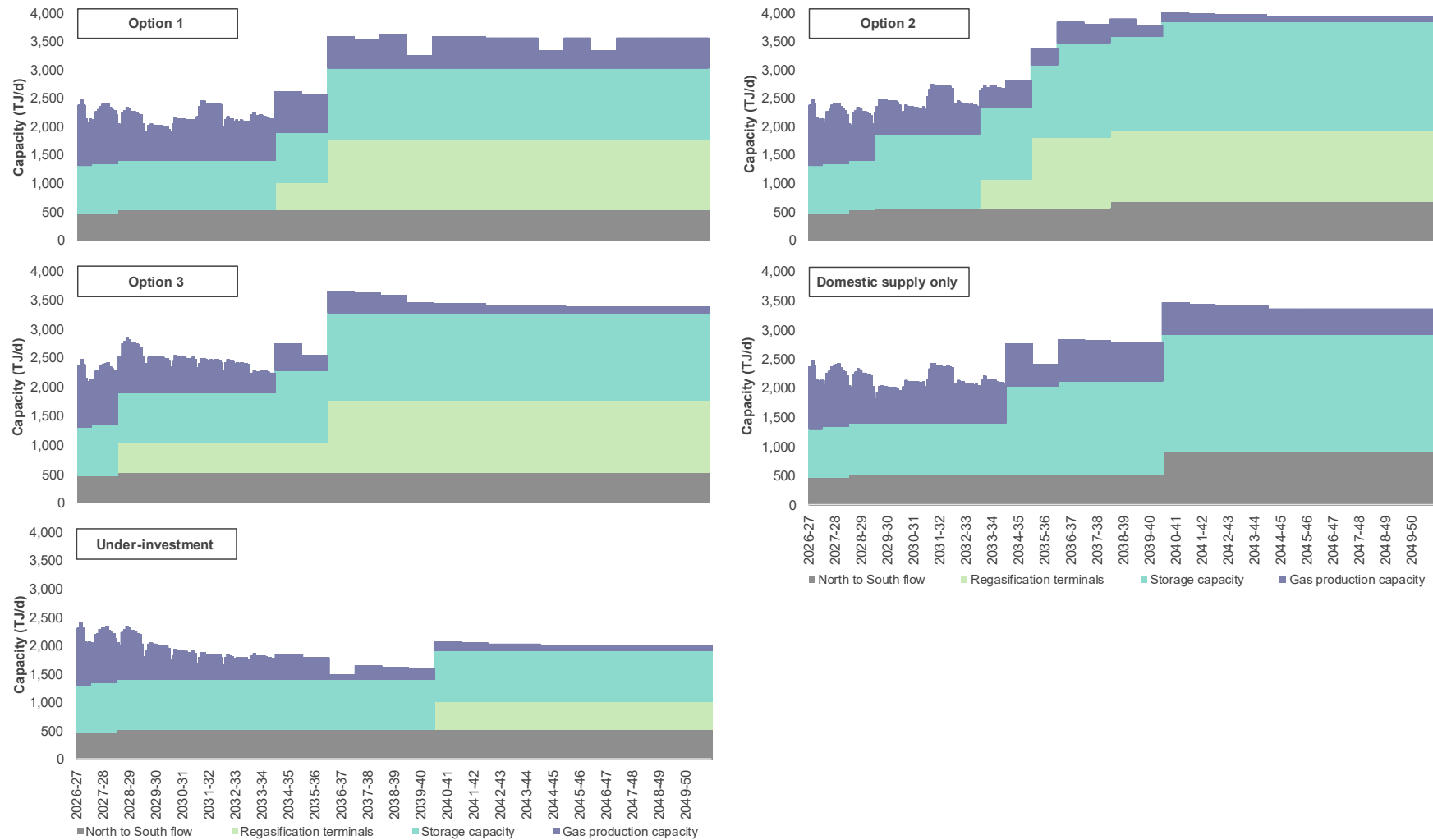
Figure 4 Map of developments included in the gas development projections, Step Change



Note: while new supply is required to meet forecast LNG export demand, developments associated with Queensland LNG exports have been excluded from this map.



Figure 5 Maximum available daily gas supply capacity in the Southern zone for different gas development projections, Step Change, 2026-27 to 2049-50 (TJ/d)



Notes: The degree of utilisation of gas infrastructure will vary depending on market conditions and supply/demand requirements on a daily basis. Later in the horizon, the gas supply development model may optimise natural gas field production on a year-to-year basis to meet the needs of the underlying weather sequence. This results in steps up and down in gas production capacity.

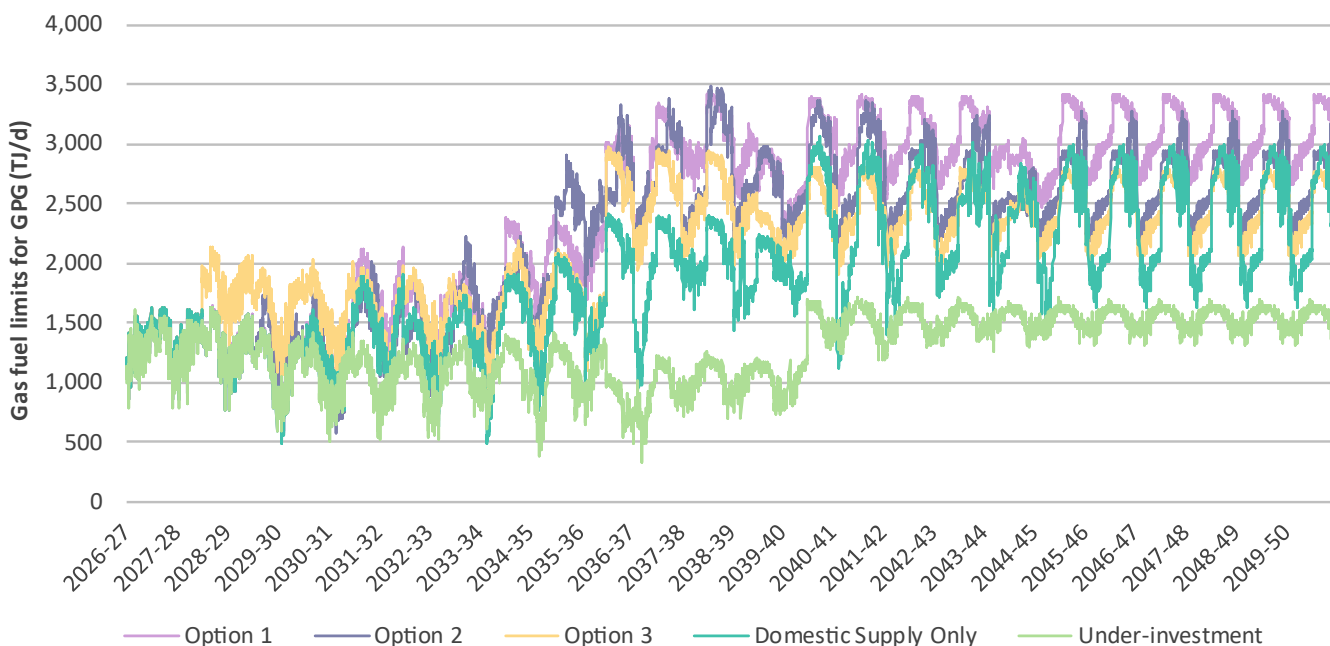


The gas development projections assessed in the 2026 ISP trend to a similar level of gas supply availability for GPG

Figure 6 shows the daily gas fuel limits for the Southern zone, across the four gas development projections studied and the under-investment projection for the *Step Change* scenario. While the initial gas supply capacity expansion is different for all four gas development projections, driven by differences in the predetermined initial investment, from 2040 they adapt to provide similar levels of gas availability for GPG, with the range of the highest daily gas fuel limits across the projections varying 20% across the projections.

Although there are common developments across the gas development projections, it remains up to the gas industry to identify and progress projects. The analysis indicates that the choice of initial investment does not materially constrain future gas development to support GPG, with no evidence that any initial investment ‘locks in’ a specific development pathway that is subsequently regretful. From a gas supply adequacy perspective, the sequencing of investments has limited long-term implications, and as described in the 2026 GSOO, as a combination of supply and infrastructure investments will be required over time to support gas consumers.

Figure 6 Daily gas fuel limits for GPG in the Southern zone for different gas development projections, *Step Change*, 2026-27 to 2049-50 (TJ/d)



Note: The gas fuel limits for GPG account for the underlying gas storage availability and gas development projections with a high proportion of gas storage in the supply capacity mix, such as the Domestic Supply Only projection, show greater fluctuations.

The under-investment projection shows much lower gas availability for GPG, but can still support some NEM GPG demand. In such circumstances, peak GPG operation may require some gas generators to transition over to on-site diesel storage. This under-investment projection therefore shows the NEM impacts if gas developments are insufficient to meet the largest gas demand peaks, instead relying on alternative fuels to service GPG needs. There is minimal reliance on diesel for the four gas development projections and while the under-investment projection requires a greater magnitude of diesel use, this is limited to a handful of days each year across winter.

Further discussion on the role of secondary fuels is in Section A10.5.



Gas development projections influence the gas available for GPG operation in the 2026 ISP

While multiple gas development projections may be able to fulfil the gas fuel requirements in the NEM, the 2026 ISP has selected one projection to represent gas availability in the electricity system modelling to determine the NEM's optimal development path.

Table 4 shows the qualitative criteria on which each gas development projection was evaluated.

Table 4 Gas development projection evaluation criteria

Criterion	Description
Feasibility	Build path's alignment with a basic assessment of project viability, particularly feasibility of delivery timeline. AEMO has not assessed the commercial feasibility of developments.
Supply adequacy	Ability to address potential gas shortfalls.
Fuel availability	Ability to provide suitable gas fuel for GPG in crucial supply zones.
Cost of gas developments	Infrastructure build and operating costs.
Utilisation	A basic assessment of whether the development appears to have a reasonable usage of the built gas infrastructure. AEMO has not done a thorough assessment of utilisation or commercial implications.

AEMO has determined that most of the projections are able to satisfactorily meet these criteria. The gas limits for GPG in the 2026 ISP's ODP assume that an initial investment occurs in a regasification terminal to support near-term gas adequacy, due to its relatively low build cost. This is partly due to the capital cost for the Port Kembla Energy Terminal being considered sunk²⁰, and the timing of all developments in this projection are delivered in a feasible timeframe.

While the gas development projection with an initial investment in a regasification terminal informs the gas limitations for the NEM capacity outlook modelling, any of the gas development projections assessed could be a reasonable and realistic outcome for the gas industry from a technical supply adequacy perspective. AEMO has tested the impact of changing these gas limitations to reflect different gas development projections in the NEM capacity outlook model, and marginal differences have been observed in the forecast GPG capacity for each NEM region (refer to Section A10.5 and Appendix A2 Generation and Storage Development Opportunities).

The gas development projections presented represent potential developments and do not indicate a preferred or optimal development path for the gas sector. The development options considered may not represent all gas infrastructure options being considered by the gas industry.

AEMO acknowledges that different gas developments could result in variations on forecast gas prices, and this price expectation could impact the preferred initial developments by the gas industry, including gas consumers. The 2026 ISP has not assessed the potential impact of each development projection on the domestic gas price. Additionally, AEMO has not included consideration of cost recovery or other commercial aspects of individual gas developments in the evaluation criteria or assessment.

As shown earlier in **Figure 2**, the process of deriving gas development projections and gas limitations to inform the 2026 ISP ODP was an iterative cycle. The gas development projections presented in this appendix are a refined version of those that

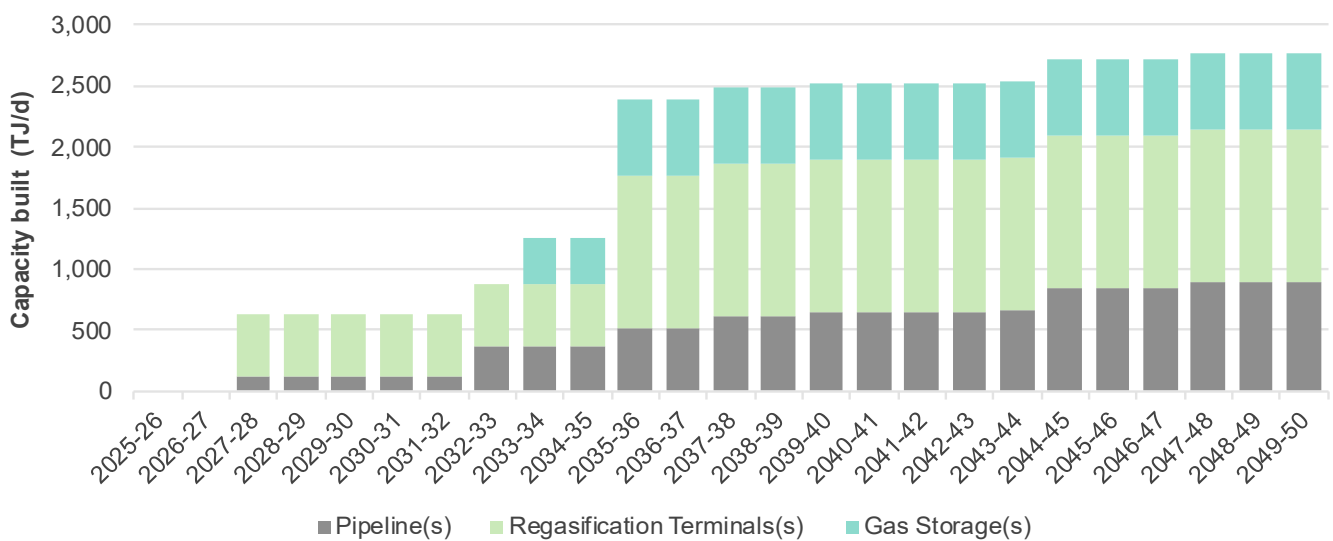
²⁰ Refer to the *2025 Gas Infrastructure Options – Consultation Summary Report* for stakeholder feedback and AEMO response regarding the treatment of the capital costs for the Port Kembla Energy Terminal as sunk, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-gas-infrastructure-options-report/final/2025-gas-infrastructure-options-report-consultation-summary-report.pdf?rev=be3bc9548b114fd1a4a4e141760f59fa&sc_lang=en.



informed the gas limitations for the ODP. Gas development projection Option 3 is the most similar to the earlier version of the gas development projection that informed the ODP, with build costs remaining relatively low compared to the other refined projections, and is therefore the central projection studied throughout the rest of this appendix.

Figure 7 shows the capacity build to meet domestic demand for gas development projection Option 3 in the *Step Change* scenario. As the figure shows, a combination of LNG regasification terminals, gas storage, and pipeline expansion developments was required to ensure gas supply adequacy for the ECGM and support gas fuel requirements in the NEM across the planning horizon. This chart includes pipeline expansions that increase transportation capacity within and around the ECGM, but do not increase net supply to the ECGM.

Figure 7 Capacity build to meet domestic demand for gas development projection Option 3, Step Change, 2025-26 to 2049-50 (TJ/d)



Note: The degree of utilisation of gas infrastructure will vary depending on market conditions and supply/demand requirements on a daily basis.

Figure 8 presents the available supply for gas development projection Option 3 and forecast domestic demand in the ECGM (excluding Northern Territory demand) under the *Step Change* scenario.

This includes supply from the total infrastructure capacity built as well as gas production capacity from existing, committed and anticipated supply and production capacity from 2C fields that are developed in Option 3. The figure demonstrates that as gas production declines, particularly in existing southern fields, supply adequacy is maintained largely with the support of LNG regasification terminals and storage capacity. The supply and infrastructure developed for gas development projection Option 3 takes into account a range of weather conditions²¹ that may cause demand to exceed what is shown in **Figure 8**.

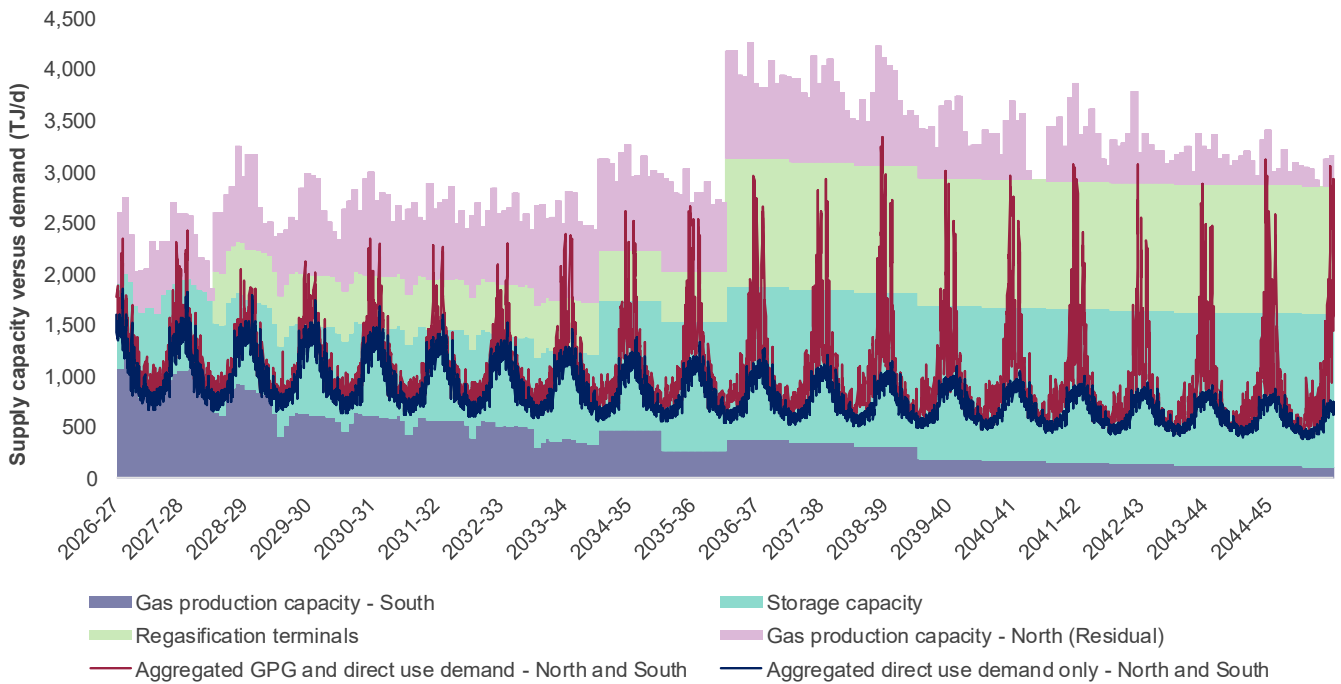
As noted earlier, gas production capacity to meet forecast LNG export demand has been excluded from the ‘Gas production capacity – North (Residual)’ totals, and LNG export demand has been excluded from the aggregated direct use demand, leaving the residual northern gas production capacity to meet domestic demand. AEMO assumed in the gas supply development modelling that the consumption of gas for LNG exports from Queensland that was forecast in the 2026 GSOO

²¹ The gas supply development model represents weather variability with a ‘rolling reference years’ approach that involves combing a diverse set of historical weather patterns throughout the planning horizon, similar to the approach in the electricity capacity expansion modelling. See the *ISP Methodology* for more information: https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2026-isp-methodology/isp-methodology-june-2025.pdf?rev=e88a1f1bbeef447ba27692b785069a0a&sc_lang=en.



will continue to be served by the LNG producers in Queensland, including expanded coal seam gas well developments to balance this forecast demand.

Figure 8 Supply capacity for gas development projection Option 3 and forecast direct use and GPG demand, Step Change, 2026-27 to 2044-45 (TJ/d)



Notes: In this figure, ECGM direct use demand excludes Northern Territory gas consumers, as well as LNG export facilities in Queensland. The degree of utilisation of gas infrastructure will vary depending on market conditions and supply/demand requirements on a daily basis.

Gas infrastructure is needed to support increased GPG reliance following coal closures

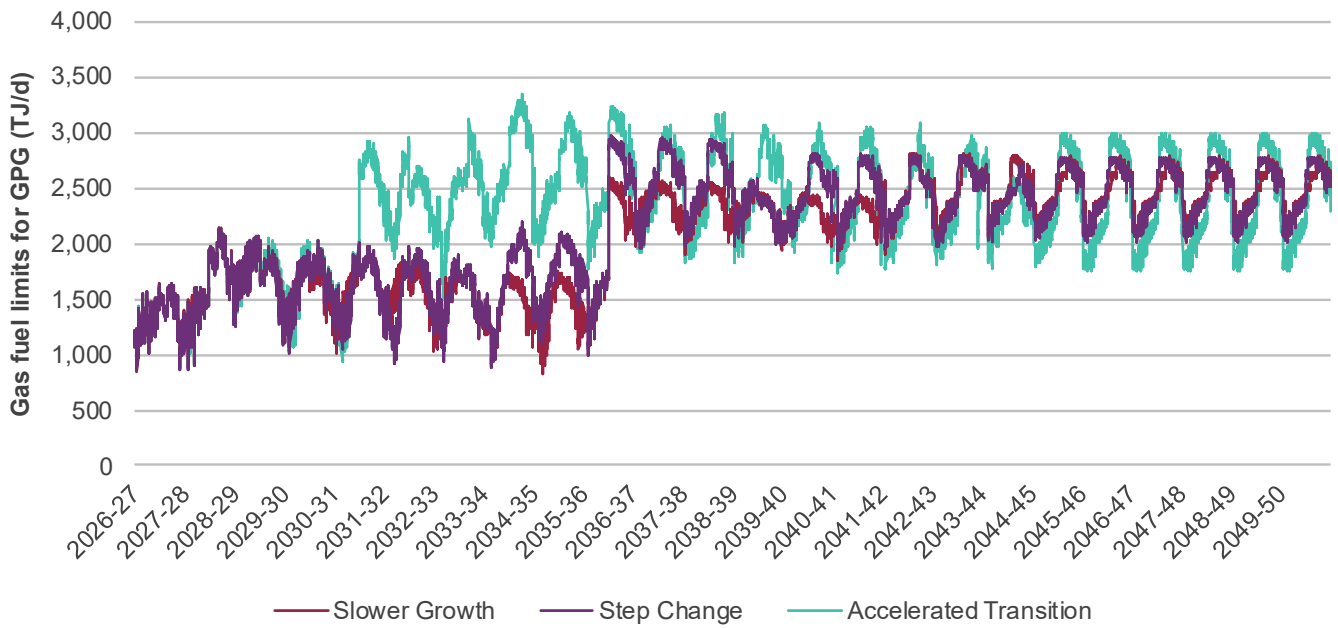
Figure 9 shows the daily gas fuel limits in the Southern zone for gas development projection Option 3 for each scenario, providing a comparison between *Slower Growth*, *Step Change* and *Accelerated Transition*.

The greatest variation in GPG needs between scenarios is the period from 2031-32 and 2039-40 when coal retirements vary most across the scenarios, leading to alternative investment needs for gas supply developments. The coal capacity replacement is a greater driver of GPG gas demand than either the economic growth or fuel-switching differences that exist between the scenarios, suggesting that major investments in gas infrastructure, particularly for GPG, will be clearly identifiable with the closure timings of existing coal generators.

Accelerated Transition is the scenario that faces faster coal retirements in the NEM, which drives up demand for GPG, leading to the greatest level of gas supply developments in this scenario. The model starts building for this higher GPG demand from 2030-31. As residential, commercial and industrial gas demand declines due to increased electrification, no further southern capacity is required in this scenario despite declining southern gas production capacity, resulting in reduced gas availability for GPG operation. As a result, all scenarios end up with very similar gas availability for GPG towards the end of the modelling horizon, despite different electricity demand outcomes across the NEM. This highlights the growing role of electricity storage in firming the NEM, with gas increasingly used sparingly to provide backup during renewable energy lulls or peak demand periods.



Figure 9 Daily gas fuel limits for GPG in the Southern zone for gas development projection Option 3, *Slower Growth, Step Change, and Accelerated Transition, 2026-27 to 2049-50 (TJ/d)*





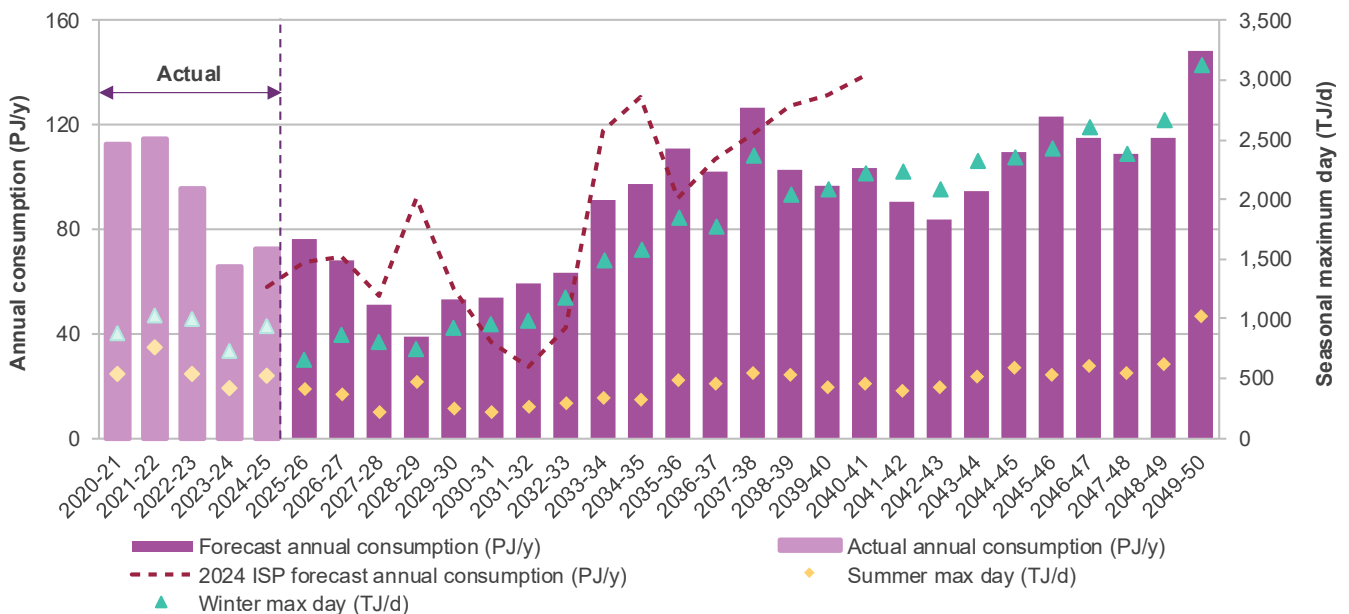
A10.4 Forecasting the role of GPG in the NEM

Gas usage for GPG in the NEM is forecast to become peakier and more seasonal, as GPG changes from more regular, mid-merit operations to a flexible, back-up role. The 2026 ISP reaffirms that renewable energy, connected by transmission and distribution, firmed with storage and backed up by gas, presents the least-cost way to supply secure and reliable electricity to consumers through to 2050, as coal plants retire and while meeting government policies. Over time, as more renewable generation and battery storage is connected and heating load switches from gas to electricity, GPG is also forecast to play an increasingly seasonal role.

GPG is forecast to be used less frequently during daily peak demand periods throughout the year, as electricity storages²² will provide a high level of intra-day and inter-day firming, but GPG will be critical to maintaining reliability during less frequent periods of more widespread renewable lulls, during longer dark and still events (see Appendix A4, Section A4.7), and will also continue to provide essential power system security services.

Figure 10 shows forecast annual consumption of gas for electricity generation returning to recent consumption levels during the mid 2030s, due to the combined effect of coal power station retirements, electricity consumption growth, and the need to backup high levels of VRE and storage.

Figure 10 Actual and forecast NEM GPG annual consumption (PJ/y) and seasonal maximum daily demand (TJ/d), Step Change, 2020-21 to 2049-50



Note: This forecast does not include the impact of sub-optimal management of storage technologies on GPG consumption.

Across the ISP horizon, the variability of annual consumption of gas used for electricity generation will depend on a number of factors, including the availability and operation of storage, and renewable resources. **Figure 10** shows that winter daily maximum demand for gas is forecast to increase significantly, as a result of electrification of heating loads and longer periods of lower VRE production in winter. While annual consumption may fluctuate depending on timing of coal closures and other investments (such as new renewable and network developments), importantly the maximum daily fuel used for

²² In this context, “storages” refers to systems that can store electrical or potential energy for later use (such as batteries or pumped hydro energy systems).



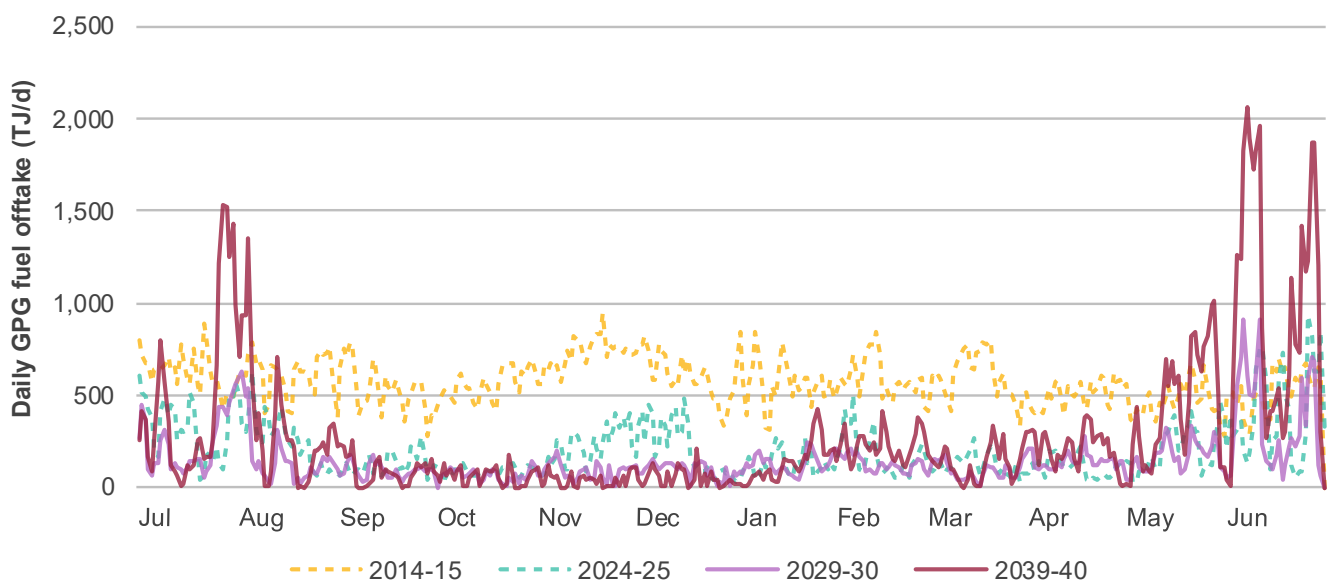
GPG remains relatively consistent from the mid-2030s over the long term to the end of the horizon, demonstrating the important back-up role that GPG will play to support reliability of supply.

Compared to the 2024 ISP, the ODP in the 2026 ISP has higher utility solar and storage over the ISP horizon. The impact of this has resulted in a lower forecast GPG consumption in the long term. The 2026 ISP ODP also has a slower phase out of coal-fired power plants to 2049-50, which also reduces forecast consumption of GPG, particularly for later years of the outlook period, as renewable lulls are less impactful while coal-fired generation remains present in the NEM.

Mid-merit generators (primarily combined cycle gas turbine [CCGT] technology) are expected to be gradually replaced as they retire by new flexible generators (primarily open cycle gas turbine [OCGT] technology)²³. OCGT technology is less fuel-efficient but has lower up-front capital costs and can operate more flexibly, so it is a more appropriate replacement technology both technically and economically when operating at lower annual utilisation factors. Gas turbines fitted with clutches (at design or retrofit) can act as synchronous condensers, providing security services even when not generating power. If fitted with self-start capabilities, these units can also support system restart.

Figure 11 shows the increasing role flexible gas is forecast to play in supporting winter peak electricity demand, with GPG generally increasing during winter (during non-peak demand events) when VRE generation is relatively low. This continuation of the trend observed in recent years to operate GPG more intensively in winter will increase demands on the ECGM to deliver higher volumes of gas over shorter periods of time. Winter is also the time when gas consumers traditionally demand the greatest level of gas for heating purposes, particularly in the colder southern regions.

Figure 11 Daily NEM-wide GPG fuel offtake, historical 2014-15 and 2024-25, forecast 2029-30 and 2039-40, Step Change, reference year 2020 (TJ/d)

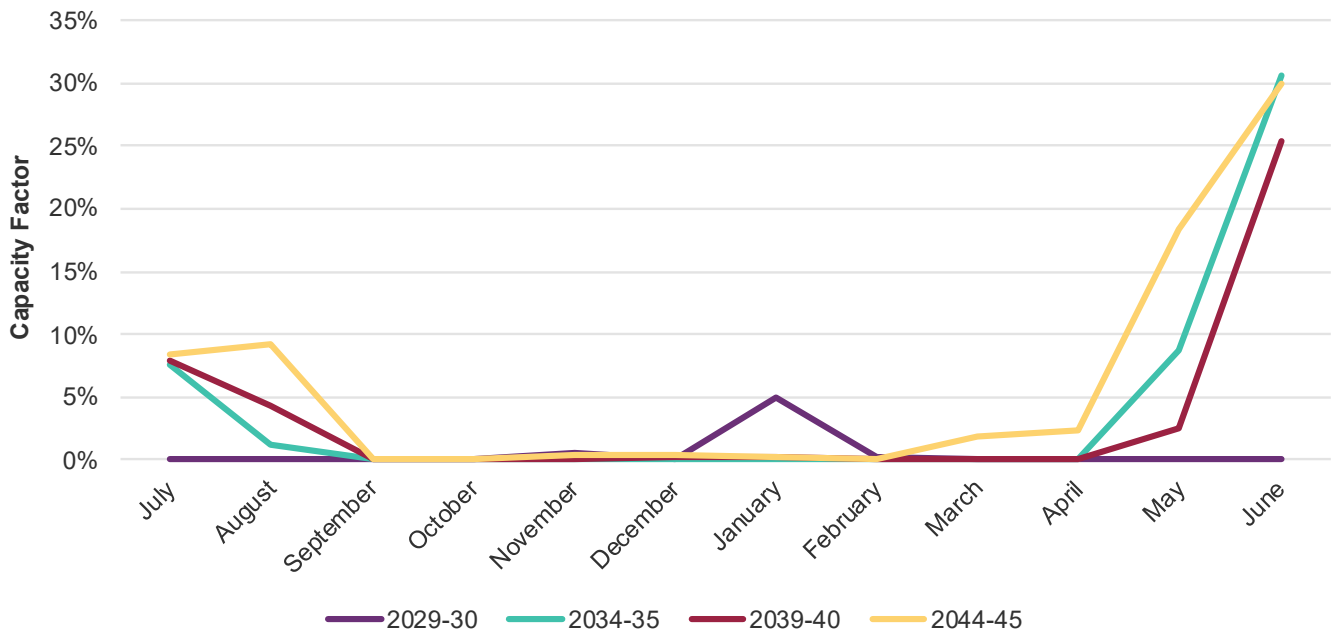


²³ In some cases, existing CCGT power stations such as the Tamar Valley Power Station in Tasmania may be taken out of service for extended periods, but generation capability is maintained if needed for power system reliability and security.



Figure 12 shows the forecast monthly capacity factor of new entrant GPG across the NEM for a snapshot of years over the ISP horizon. New entrant GPG are projected to be needed to provide back-up supply mainly in winter and in the months leading up to winter. The new entrant GPG are shown to both operate during peak demand events and also play a broader role in supporting system reliability across longer periods when renewable generation availability is low, highlighting the ability of GPG to respond flexibly to changing supply and demand conditions, particularly in a system with an increasing proportion of VRE.

Figure 12 Monthly capacity factor of new entrant GPG, 2029-30, 2034-35, 2039-40, 2044-45, Step Change, reference year 2020





A10.5 Impacts of different gas development projections on the electricity capacity outlook

There are a range of gas infrastructure developments that could shape the ECGM into different plausible gas development projections. Each projection AEMO has assessed in the 2026 ISP presents distinct infrastructure configurations and supply dynamics, particularly in the shorter term, yet all are capable of delivering sufficient gas volumes to support GPG across the NEM.

This section assesses the implications of these gas development projections on both the generation and storage development opportunities of the ODP and its operational performance.

The optimal development path is adaptable to different gas developments

AEMO's analysis indicates that there are few differences in the NEM's network, generation and storage developments when gas limits of different gas development projections are applied. If developers are aware of and account for fuel availability, the NEM is able to adapt its generation and storage developments given the availability of gas across the ECGM to service GPG needs.

Conversely, the assumed levels of gas demand for GPG drive the development of gas supply, storage and infrastructure capacity beyond that which is required to meet the needs of residential, commercial and industrial gas consumers²⁴. The need for these additional projects will be informed by the timing and scale of NEM GPG requirements. If actual NEM developments diverge from the ODP, the scale and timing of gas demand for GPG could shift materially, which would alter the need for gas investments in the ECGM. There may also be more economically efficient solutions for the energy transition if both the capital cost of new entrant GPG and the cost of new gas developments were compared against dispatchable capacity alternatives, potentially coupled with demand flexibility, but this would require co-optimisation of both the gas and electricity systems, which is beyond the scope the NER currently provide for the ISP.

The location of new entrant GPG is also important. For example, Queensland Gas Pipeline expansions were included in all gas development projections as a direct response to forecast GPG demand in the Gladstone sub-region²⁵. An alternative to this pipeline expansion could be the connection of new entrant GPG to one of the existing LNG export pipelines that run through the Gladstone sub-region, if capacity on these pipelines was made available to GPG.

If the future NEM features a higher GPG capacity than forecast by the ODP (see Appendix A2 Generation and Storage Development Opportunities) for a range of sensitivities to the ODP), peak daily GPG demand would likely be higher or include more periods of sustained GPG operation such that additional gas supply, gas storage or pipeline capacity beyond those assessed by AEMO in this appendix may be needed, else there will be a reliance on secondary fuels at these times.

Influence of gas development projects on GPG build

Figure 13 illustrates the projected GPG installed capacity across NEM regions under different gas development projections. The development trajectory and quantity of GPG capacity remains broadly consistent at a regional level, regardless of the

²⁴ Forecast industrial electricity demand in some locations drives the need for new entrant GPG; industrial expansions may also require increased gas supply to meet demand.

²⁵ The Queensland Energy Roadmap identified a tendering approach to support an additional 400 megawatts (MW) of GPG in the Central Queensland region. See <https://www.treasury.qld.gov.au/files/Queensland-Energy-Roadmap-2025-25-043.pdf>.



specific gas development projection. Most new entrant GPG capacity is forecast to be located in New South Wales and Victoria, where electricity demand centres and renewable energy penetration are among the highest in the NEM.

Figure 13 Forecast GPG installed capacity across different plausible gas development projections, Step Change, 2029-30 to 2049-50 (megawatts [MW])



Gas storages play a critical role in supporting GPG demand

Figure 14 shows the forecast daily gas offtake for southern GPG in 2042-43 using the 2011 weather reference year, which includes severe renewable lulls in winter. This chart shows that gas development projection Option 3 can supply sufficient gas during periods of extremely high GPG demand, although some GPG units might need to switch to secondary fuels and rely on onsite diesel storage for short periods. Relying on secondary diesel fuel for very short periods ensures that the gas supply development model does not overbuild capacity to meet peak GPG requirements when gas fuel is limited (that is, additional gas supply or infrastructure will not be needed if a secondary fuel to operate GPG is available). The chart also presents the forecast utilisation of gas storage capacity in the southern states, highlighting the critical role that gas storage plays in supporting extreme but infrequent peak GPG demand days.

Deep gas storage facilities, such as the Iona Underground Gas Storage facility, support seasonal supply deficits during the winter peak consumption period while refilling during periods of lower gas consumption in summer. Shallow gas storages, including the Newcastle and Dandenong LNG facilities, offer short duration supply flexibility and can deliver rapid gas injections to manage intraday peak demand fluctuations, for instance very high gas demand that arises from GPG operation in response to challenging electricity market conditions. Timely refilling of gas storage facilities is essential to ensure adequate supply is available ahead of the winter peak demand period. Transport of gas from the north to south via the South West Queensland Pipeline also supports higher gas use in winter, and the refilling of deep gas storage facilities in preparation for winter.

Gas use is expected to be increasingly variable as the role of GPG shifts to back up other firming resources provided by hydro generation and electricity storages. The resilience of the ECGM depends not only on long-term supply capacity and deep storages but also on its capability to manage rapid daily and intra-day demand swings, which is an ability that is



supported by the operational responsiveness of linepack and shallow gas storage facilities. The gas development projections do not consider linepack, and therefore additional shallow gas storages may be needed if intra-day gas use is greater than can be managed through linepack.

Figure 14 Forecast daily gas fuel limits for GPG in the Southern zone and southern NEM GPG daily demand, Step Change, reference year 2011, 2042-43 (TJ/d)

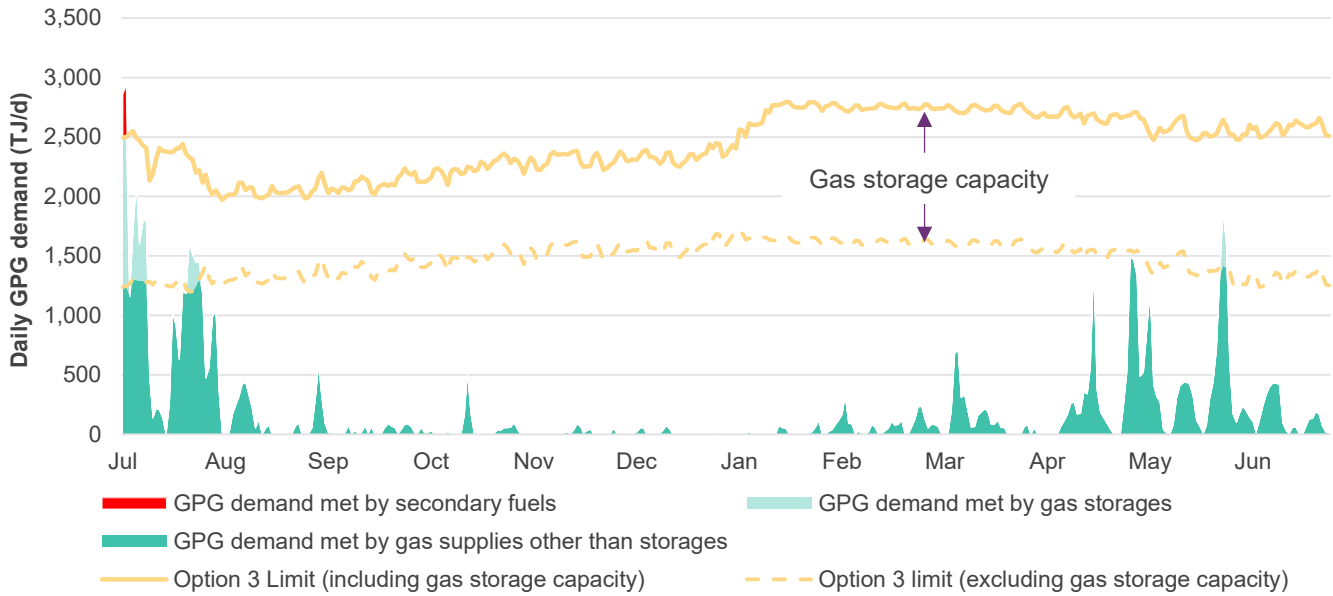
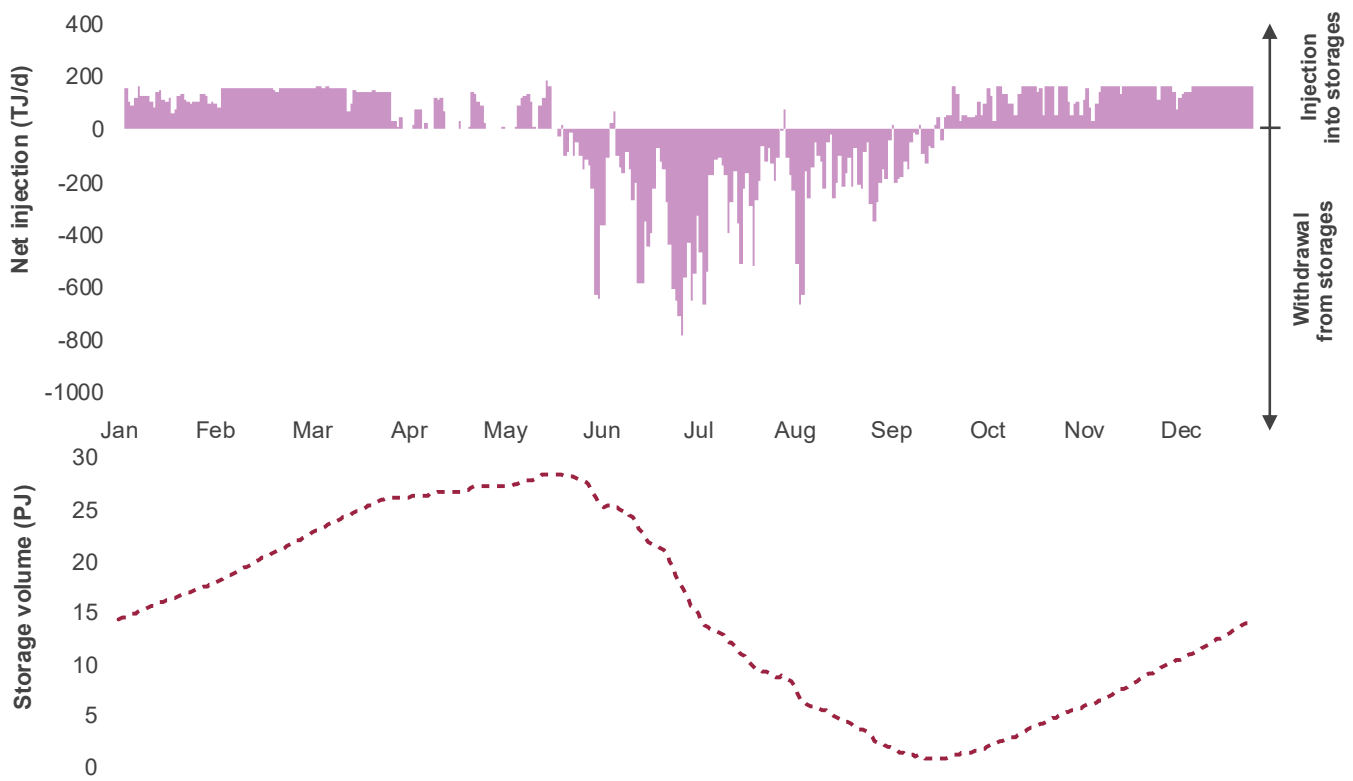


Figure 15 demonstrates the seasonal cycle of southern gas storages, with injections during warmer months to build storage reserves ahead of winter peak withdrawals. Appropriate storage management is required to ensure maximum withdrawal rates are available to supply gas on peak days or sustained across multiple high demand days when necessary.



Figure 15 Forecast southern gas storage profile for gas development projection Option 3, Step Change, calendar year 2031 (TJ/d and PJ)



Note: This chart is displayed as a calendar year, rather than financial year like other charts, to better highlight the entire winter period.

Gas under-investment will require alternative NEM firming solutions

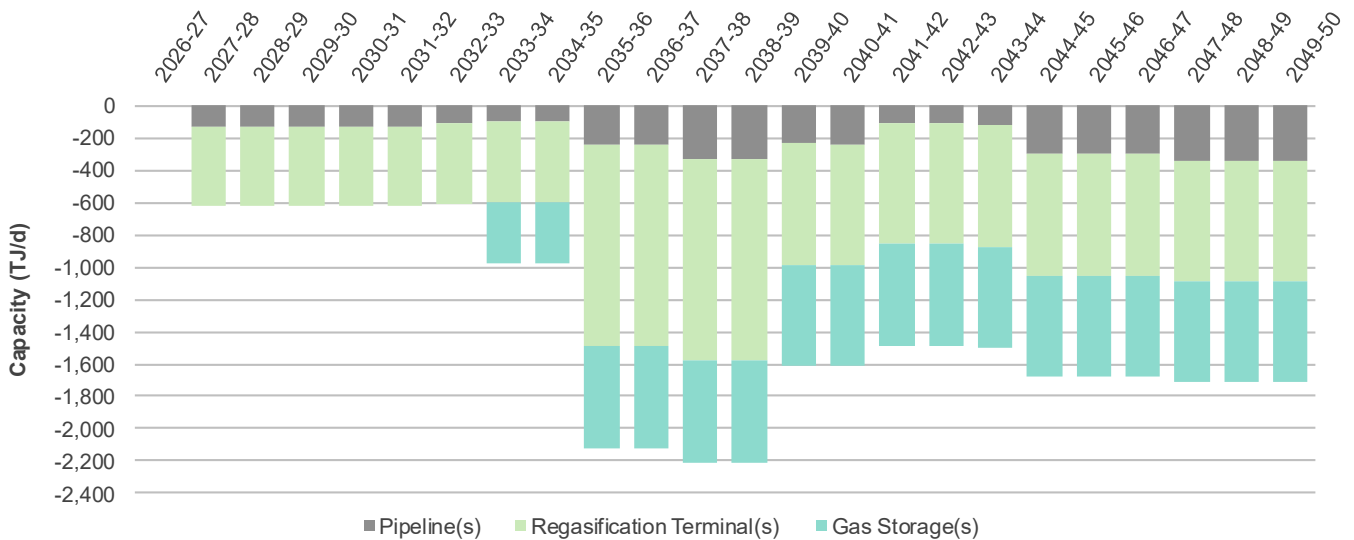
The options considered by the gas supply development model to produce the gas development projections include proposals from the gas industry that have not advanced sufficiently to be classified as committed or anticipated in the GSOO. Uncertainties such as cost, regulatory approvals, land use constraints, social licence, safety considerations, operational challenges, and market conditions may affect both the timing and successful delivery of the investments underpinning the gas development projections. Additionally, the commercial viability of gas investment to support GPG as the primary customer is largely untested and may require a new approach to traditional infrastructure underwriting processes. Alternatives to GPG that do not require gas infrastructure investment (such as long duration storage) may present more efficient solutions, from a whole-of-system view, in some circumstances, but would need to provide an equivalent capability to support reliability in various NEM conditions.

This section examines an alternative gas development projection – the under-investment gas development projection – where gas developments only respond to forecast residential, commercial, and industrial gas demand and therefore may not sufficiently provide gas under all conditions to service GPG needs. This analysis serves as a proxy for delayed or slow gas development, resulting in a significant reduction in available gas supply to the NEM GPG.

Figure 16 demonstrates the reduction in capacity development for each year under the under-investment projection compared to the gas development projection Option 3. It highlights that GPG demand is contributing to the build of up to 2,200 TJ/d of capacity in addition to other gas users, as demonstrated by the lower investment in this case relative to Option 3. The level of utilisation of this gas capacity will vary depending on daily conditions.



Figure 16 Capacity of the gas infrastructure developments in the under-investment projection relative to gas development projection Option 3, Step Change, 2026-27 to 2049-50 (TJ/d)



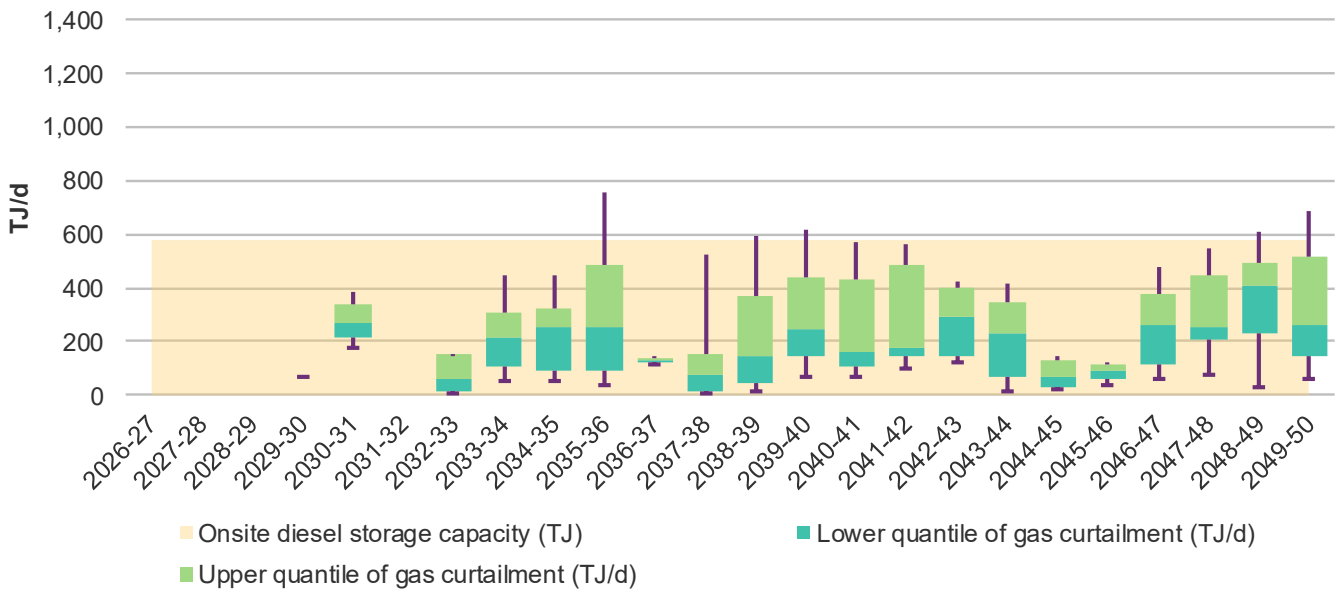
As shown earlier in **Table 3**, the under-investment projection does include the development of uncertain 2C southern gas production to backfill existing infrastructure, although at lower levels than developed in gas development projection Option 3.

In these circumstances, to operate the GPG fleet with reduced gas fuel availability, there would be greater reliance on secondary fuels. As shown earlier in **Figure 14** (during early July), the daily gas fuel available for GPG may be insufficient to meet extreme peak demands, which are most likely to occur during periods of sustained low VRE output. In such cases, dual-fuelled GPG units are expected to maintain operation, switching to locally stored diesel when gas supply is constrained.

Figure 17 illustrates the onsite diesel storage capacity for gas development projection Option 3, as well as the distribution of the forecast peak-day GPG demand for the ODP that cannot be met by gas across a range of simulated weather and market conditions. The capacity of existing diesel storages is sufficient to meet the forecast level of electricity generation that cannot be supplied by the ECGM, and GPG can operate to its required level at all times by fuel-switching to diesel as needed (assuming the diesel storage is sufficiently full). This is assuming that the total diesel storage capacity across the southern NEM is maintained at levels consistent with existing capacity. Risks of GPG interruptions from fuel limits (both gas and diesel) are heightened in the mid-2030s, coinciding with projections of major coal retirements in *Step Change*. This demonstrates that the gas development projection is not over-investing in new gas supply, but the small margin of remaining diesel storage capacity shows that contingency investments in diesel storages are important development considerations to ensure GPG can play the key back-up role that is needed.



Figure 17 Forecast range of peak-day GPG gas demand curtailment (TJ/d) and onsite diesel storage capacity (TJ) in southern NEM for gas development projection Option 3, Step Change, reference year 2011-2024, 2026-27 to 2049-50

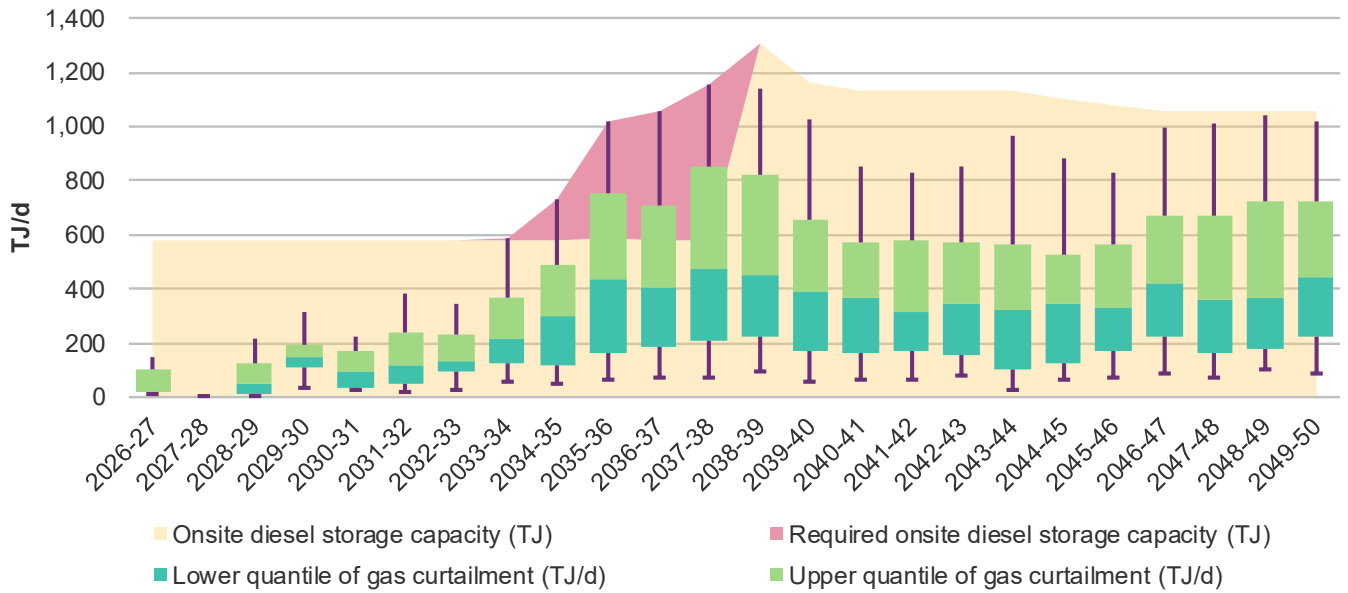


Compared to **Figure 17**, **Figure 18** shows that there is a much greater amount of peak-day GPG demand that cannot be met by gas when there is less gas supply capacity available under the under-investment gas development projection. This results in the need for additional on-site diesel storage, requiring further capital investment, increasing reliance on global fuel markets, and reducing Australia’s energy independence. It also introduces additional fuel management complexity and may increase reliability risks if diesel supplies cannot be replenished during extended renewable lulls. Diesel storage locations would need to be commensurately distributed across the NEM, in proportion with the scale of GPG developments, such that each region would have a high proportion of its GPG fleet with backup fuel arrangements.

The chart also shows that there are several forecast years under the under-investment projection when diesel reserves are fully depleted and the energy requirements of GPG cannot be met by gas or diesel. In 2035-36, for example, peak-day fuel shortfalls are projected to reach almost 450 terajoules (TJ), forcing approximately 1,700 megawatts (MW) of GPG offline. If alternative generation or demand response was not able to fill these gaps during these periods, reliability risks may present in the NEM. This highlights the NEM’s dependence on timely gas infrastructure development to support the important backup role of GPG, and reduce the reliance on secondary fuels which have a limited storage capacity.



Figure 18 Forecast range of peak-day GPG gas demand curtailment (TJ/d) and onsite diesel storage capacity (TJ) in southern NEM for the under-investment gas development projection, Step Change, reference year 2011-2024, 2026-27 to 2049-50



Glossary

This glossary has been prepared as a quick guide to help readers understand some of the terms used in this Appendix. Words and phrases defined in the National Electricity Rules (NER) and the National Gas Rules (NGR) have the meaning given to them in the NER and NGR, respectively. This glossary is not a substitute for consulting the NER, the NGR, the Australian Energy Regulator's (AER's) *Cost Benefit Analysis Guidelines*, or AEMO's *ISP Methodology*.

Term	Acronym	Explanation
Actionable ISP project	-	Actionable ISP projects optimise benefits for consumers if progressed before the next ISP. A transmission project (or non-network option) identified as part of the ODP and having a delivery date within an actionable window. For newly actionable ISP projects, the actionable window is two years, meaning it is within the window if the project is needed within two years of its earliest in-service date. The window is longer for projects that have previously been actionable. Project proponents are required to begin newly actionable ISP projects with the release of a final ISP, including commencing a RIT-T.
Actionable project progressing under a jurisdictional framework	-	A transmission project (or non-network option), other than an actionable ISP project, which optimises benefits for consumers if progressed before the next ISP, is identified as part of the ODP, and which will progress under a jurisdictional policy that AEMO considers under NER 5.22.3 (b) and includes in the ISP.
Anticipated supply	-	Gas facility projects that developers consider justified on the basis of a reasonable forecast of commercial conditions at the time of reporting, and reasonable expectations that all necessary approvals (such as regulatory approvals) will be obtained and final investment decision (FID) made.
Candidate development path	CDP	A collection of development paths which share a set of potential actionable projects. Within the collection, potential future ISP projects are allowed to vary across scenarios between the development paths. Candidate development paths have been shortlisted for selection as the ODP and are evaluated in detail to determine the ODP, in accordance with the ISP Methodology.
Committed supply	-	Gas facility projects that have obtained all necessary approvals, with implementation ready to commence or already underway.
Consumer energy resources	CER	Generation or storage assets owned by consumers and installed behind-the-meter. These can include rooftop solar, batteries and electric vehicles (EVs). CER may include demand flexibility.
Cost-benefit analysis	CBA	A comparison of the quantified costs and benefits of a particular project (or suite of projects) in monetary terms. For the ISP, a cost-benefit analysis is conducted in accordance with the AER's Cost Benefit Analysis Guidelines.
Counterfactual development path	-	The counterfactual development path represents a future without major transmission augmentation. AEMO compares candidate development paths against the counterfactual to calculate the economic benefits of transmission.
East Coast Gas Market	ECGM	Services gas consumers in all states and territories of Australia except for Western Australia. Excludes LNG exporters located in the Northern Territory.
Electrification	-	Fuel-switching to electricity, in this ISP this most often refers to switching from gas to electricity.
Expansion	-	The process of upgrading the capacity of a gas transmission (or distribution) pipeline.
Development	-	A development in the gas industry to support the use of gas by gas consumers, including gas usage for electricity generation purposes.
Gas consumption	-	Gas consumed over a period of time, usually a year but sometimes a month.
Gas demand	-	The amount of gas used on a daily basis. The maximum across a season is referred to as maximum demand or peak day demand.
Gas development projection	-	Projections of developments in the gas industry included in, and used by AEMO to develop, the ISP.
Gas-powered generation	GPG	Electricity generated from gas turbines (combined cycle gas turbine [CCGT] or open cycle gas turbine [OCGT]).

Term	Acronym	Explanation
Gas Statement of Opportunities	GSOO	Gas demand forecasts (over a 20-year horizon) and supply adequacy assessment for eastern and central Australia published annually by AEMO.
Gas supply and pipeline zones	-	Distinct zones within the ECGM reflecting the capability for GPG to operate given gas supply, storage and pipeline capacity constraints, and considering the residential, commercial and industrial gas demand that exists or is forecast within these zones.
Firming	-	Grid-connected assets that can provide dispatchable capacity when variable renewable energy generation is limited by weather, for example storage (pumped-hydro and batteries) and gas-powered generation.
Injection	-	The physical injection of gas into the gas transmission system or a gas storage facility.
Linepack	-	The pressurised volume of gas stored in the pipeline system. Linepack is essential for gas transportation through the pipeline network throughout each day, and is required as a buffer for within-day balancing.
Liquefied natural gas	LNG	Natural gas that has been converted to liquid for ease of storage or transport.
LNG regasification terminal	-	A facility that receives, stores, and processes LNG back into its gaseous state before injecting it into the gas transmission pipeline network.
Midstream gas infrastructure		The infrastructure that connects upstream gas facilities to end consumers. Including gas processing facilities, pipelines for gas transport, storage facilities and LNG regasification terminals.
Net market benefits	-	The present value of total market benefits associated with a project (or a group of projects), less its total cost, calculated in accordance with the AER's Cost Benefit Analysis Guidelines. The net market benefits of the ODP through to 2050 is the difference between the cost of the ODP and the cost of a 'counterfactual' development path which has no new transmission build.
Optimal development path	ODP	The development path identified in the ISP as optimal and robust to future states of the world. The ODP contains actionable projects, future ISP projects and ISP development opportunities, and optimises costs and benefits of various options across a range of future ISP scenarios.
Peak day shortfall	-	A peak day shortfall is driven by insufficient available gas production or transport capacity to meet extreme peaks in gas demand on a single day.
Pipeline	-	A pipe or system of pipes for or incidental to the conveyance of gas, including part of such a pipe or system.
Prospective resources	-	Estimated volumes associated with undiscovered accumulations of gas, highly speculative and not yet proven by drilling.
Reliable (power system)	-	The ability of the power system to supply adequate energy to satisfy consumer demand, allowing for credible generation and transmission network contingencies.
Renewable energy	-	For the purposes of the ISP, the following technologies are referred to under the grouping of renewable energy: "solar, wind, biomass, hydro, and hydrogen turbines". Variable renewable energy is a subset of this group, explained below.
Renewable lull	-	A prolonged period of very low levels of variable renewable output, typically associated with dark and still conditions that limit production from both solar and wind generators.
Rooftop and other small-scale solar	-	Solar photovoltaic (PV) generation assets that are not centrally controlled by AEMO dispatch. Examples include residential and business rooftop PV as well as larger commercial or industrial "non-scheduled" PV systems.
Reserves	-	Quantities of gas expected to be commercially recovered from known accumulations.
Resources	-	Less certain, and potentially less commercially viable sources of gas, than reserves.
Regulatory Investment Test for Transmission	RIT-T	The RIT-T is a cost benefit analysis test that TNSPs must apply to prescribed regulated investments in their network. The purpose of the RIT-T is to identify the credible network or non-network options to address the identified network need that maximise net market benefits to the NEM. RIT-Ts are required for some but not all transmission investments.
Scenario	-	A possible future of how the NEM may develop to meet a set of conditions that influence consumer demand, economic activity, decarbonisation, and other parameters. For this ISP, AEMO has considered three scenarios: <i>Slower Growth</i> , <i>Step Change</i> and <i>Accelerated Transition</i> .
Seasonal or annual supply gap	-	A seasonal or annual supply gap is driven by insufficient gas production or transport capacity to meet total seasonal or yearly gas demand.



Term	Acronym	Explanation
Storage facility	-	A facility for storing gas, including the Dandenong LNG storage facility and Iona Underground Gas Storage (UGS) in Victoria, and Newcastle Gas Storage Facility (NGSF) in New South Wales.
Uncertain supply	-	Gas projects that are at earlier stages of development or face challenges in terms of commercial viability or approval.
Underground gas storage	UGS	A storage facility which reinjects gas into depleted gas reservoirs, which can be withdrawn out at a later date.
Utility-scale or utility		For the purposes of the ISP, 'utility-scale' and 'utility' refers to technologies connected to the high-voltage power system rather than behind the meter at a business or residence.
Variable renewable energy	VRE	Renewable resources whose generation output can vary greatly in short time periods due to changing weather conditions, such as solar and wind.
Virtual power plant	VPP	An aggregation of resources coordinated to deliver services for power system operations and electricity markets. For the ISP, VPPs enable coordinated control of consumer-scale batteries.