

Appendix A10. Gas Development Projections

December 2025

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 first [Reconciliation Action Plan](#) in May 2024. '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 Draft 2026 Integrated System Plan (ISP) which is available at <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp>. AEMO publishes the Draft 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 10 December 2025 unless otherwise indicated.

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Version control

| Version | Release date | Changes |
|---------|--------------|---|
| 1 | 10/12/2025 | First release |
| 1.1 | 08/01/2026 | Updated Figure 5 to include Option 1 production. Corrected pipeline capacity built in Figures 9 and 18. |

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Executive summary

AEMO's ISP is a roadmap for the NEM's transition, and outlines an 'optimal development path' (ODP) for generation, storage and network investments to meet Australia's future energy needs.

The Draft 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 as coal plants retire, while meeting government policies through to 2050.

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 2025 *Gas Statement of Opportunities* (GSOO) forecast that with the level of existing, committed and anticipated 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 Australia¹ from 2028 and risks that structural supply gaps emerge from 2029, requiring new gas supplies to be developed.

This appendix 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 2025 GSOO and support the availability and operation of GPG in the NEM.

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

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

In particular, it recognises that:

- **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.
- **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.

¹ Southern Australia refers to the NEM regions of New South Wales, South Australia, Tasmania and Victoria.



- **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.

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

Three gas development projections were developed and modelled for each ISP scenario, each with different initial investments to address gas supply shortfalls prior to 2030 informed by analysis in the 2025 GSOO². While the initial gas investments differ for all gas development projections, by around 2037, all projections include very similar combinations of transport, storage and new gas supply developments, including regasification terminals.

This demonstrates that, in the near term, timely investment in new gas infrastructure is needed, but the choice of project is less critical from a gas supply adequacy perspective as long as a certain level of new supply is reached. The GPG requirements of the future power system may be met irrespective of which gas investment progresses first. Furthermore, the initial investment in the gas system will not materially restrict future gas developments to support GPG. 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 gas development projections presented represent potential developments and do not represent a preferred or optimal development path for the gas sector. The development options assessed were those published in the 2025 *Gas Infrastructure Options Report*, which may not represent all gas infrastructure options being considered by the gas industry. The Draft 2026 ISP has not included consideration of the impacts on gas price, cost recovery or other commercial aspects of individual gas developments.

To simplify the analysis provided in this appendix, AEMO has focused most reporting on a single gas development projection, while recognising that the NEM's ODP is supported by any one of the different combinations of gas developments, with only minor variations in the location of new gas generation, as long as an overall level of gas supply capacity is achieved. This gas development projection (gas development projection Option 3), assumed that initial investment occurs in a regasification terminal to support near-term gas adequacy, and this initial investment influences the gas limits for GPG in the Draft 2026 ISP's ODP.

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 Draft 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 as coal plants retire, while meeting government policies through to 2050. 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.

² See Chapter 5, 2025 GSOO, at https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2025/2025-gas-statement-of-opportunities.pdf?la=en.



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 VRE output conditions, during longer ‘dark and still’ events³, and will also continue to provide necessary power system services. From 2038-39, annual GPG consumption is forecast to decrease 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

Each gas development projection AEMO assessed in the Draft 2026 ISP presents distinct infrastructure configurations and supply dynamics, yet all are capable of delivering sufficient gas volumes to support GPG across the NEM and maintain supply to residential, commercial and industrial gas consumers.

For each gas development projection, daily gas supply availability (net of demand from direct-use gas customers) was calculated in specific locations within a NEM region and input to the electricity capacity outlook model.

The development trajectory and quantity of GPG capacity built by the electricity capacity outlook model remained broadly consistent, regardless of the specific gas pathway. Most new entrant GPG capacity is projected to be located in New South Wales and Victoria, where electricity demand centres are among the largest in the NEM. While GPG developers will need to consider the availability of gas when determining their specific locations, AEMO’s gas development projections broadly accommodate a consistent regional level of GPG investment across the forecast horizon.

If gas investments are misaligned with the fuel requirements of the NEM, secondary fuels may become essential to maintain NEM reliability and operability

The required gas infrastructure investment from the mid-2030s 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 GPG developers and gas investors proactively engage 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 developments 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.

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 investments may require alternative volumes and location of firming resources than forecast from GPG.

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.



A10.1 Introduction

Published every two years, AEMO's *Integrated System Plan* (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. For the first time, this Draft 2026 ISP investigates developments within the East Coast Gas Market (ECGM) that help ensure energy system adequacy for both the gas and electricity sectors across the ISP horizon.

Over 2023 and early 2024, the Federal Government undertook a review of the ISP⁴, and on 5 April 2024, the Energy and Climate Change Ministerial Council published the Energy Ministers' *Response to the ISP Review*⁵. 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 ISP⁶. 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.

This appendix provides gas analysis which informed the development of the NEM optimal development path (ODP):

- A10.2 highlights the need for developments in the gas sector as identified in the 2025 GSOO.
- A10.3 identifies three 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.

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 Draft 2026 ISP; they do not provide an 'optimal development path' for gas, and the investments modelled are not actionable in the same way as electricity transmission projects identified as actionable projects in the ODP. 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

⁴ 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.

⁵ At <https://www.energy.gov.au/sites/default/files/2024-04/ecmc-response-to-isp-review.pdf>.

⁶ 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>.



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 2024 ISP

- This Appendix 10 is a new appendix for the 2026 ISP, extending analysis provided in the 2024 ISP's Appendix 4 regarding the operation of GPG and the impacts of gas system adequacy on NEM market operability.
- This Draft 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 2025 GSOO and provide insight into the availability and potential limitations for gas to supply GPG in the NEM.
- The ISP's gas and electricity market modelling now includes access to gas information primarily provided for the GSOO. Gas supply development modelling produces gas development projections that inform zonal daily gas limits for GPG in the electricity capacity outlook model.
 - In the 2024 ISP, AEMO assumed new gas supplies would be developed but did not assess the options that could achieve that new supply or assess pipeline or gas storage developments. In the Draft 2026 ISP, AEMO modelled projections of gas developments which include infrastructure such as pipelines, storages, gas plants and LNG regasification terminals.
 - The 2024 ISP partially considered fuel availability limits for GPG by applying a single daily constraint across New South Wales, South Australia, Victoria and Tasmania (Queensland GPG were assumed to be unconstrained by gas fuel availability). In the Draft 2026 ISP, gas supply and pipelines zones have been developed to reflect the capability for GPG to operate given gas supply, storage and pipeline capacity constraints, and consider the residential, commercial and industrial gas demand that exists or is forecast within these zones.
 - The 2024 ISP did not consider the cost of gas infrastructure developments required to achieve the level of assumed new supply. The costs associated with the gas development projection that informs the ODP are reported on in Section 10.3 of the Draft 2026 ISP.

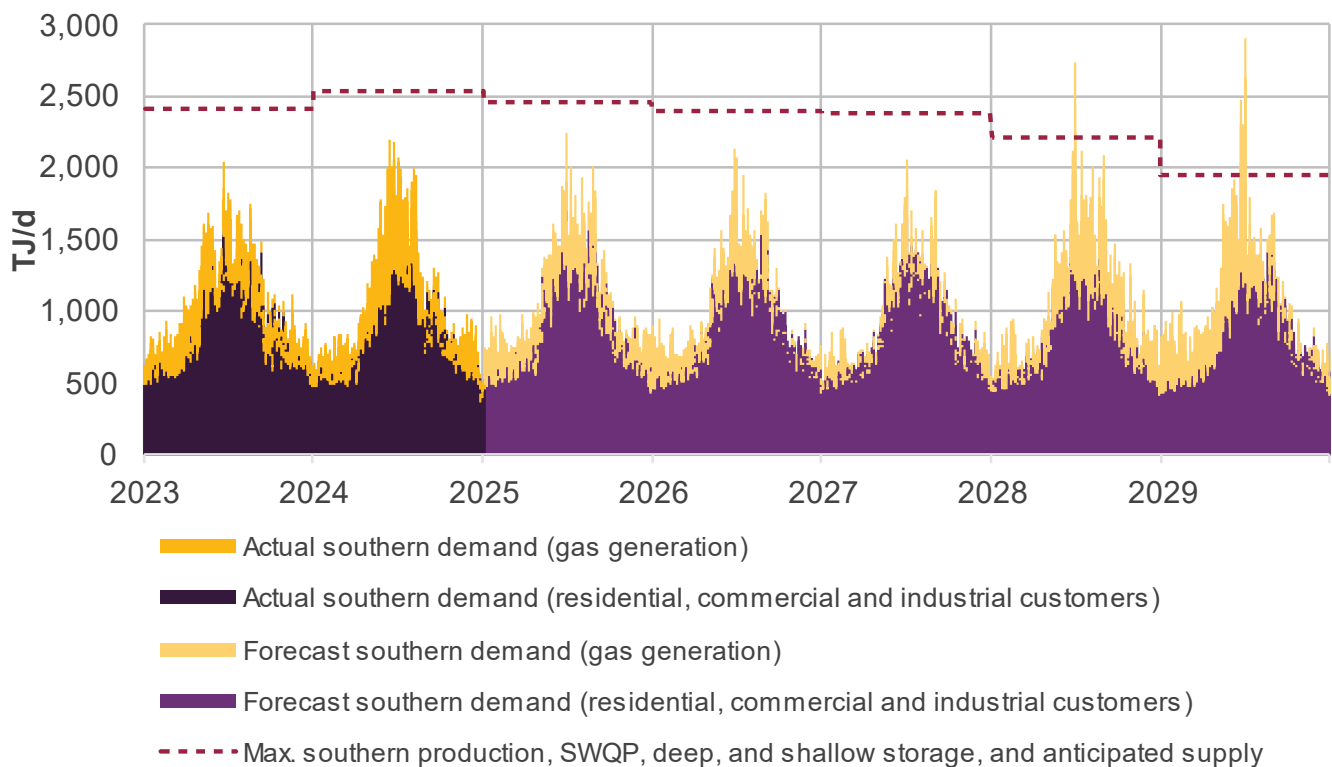


A10.2 Gas system adequacy

The 2025 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 2025 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 2028 (subject to prevailing conditions).

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 2028 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 2023, and forecast to 2029 using existing, committed and anticipated supply projects, *Step Change*, (TJ/d)



Note: SWQP in this chart represents the expected South West Queensland Pipeline flow available to transport gas from the north to the south.

Seasonal supply gaps may emerge from 2028 if conditions lead to sustained high gas usage. From 2029, the southern supply demand balance is forecast to continue to tighten and the 2025 GSOO forecast structural supply gaps emerging, requiring new gas supplies to be developed. While several supply, storage and transport solutions are presently proposed by the gas industry, which solution is developed, and the timing, is currently uncertain.



The 2025 GSOO also considered the forecast gas supply available to meet northern Australia demand (in Queensland and Northern Territory⁷), including to satisfy LNG export demand via Curtis Island in Queensland. According to current projections, uncertain supplies will need to be developed from 2028 to meet all gas demand in the north.

This Draft 2026 ISP explores potential gas developments by the gas industry to address forecast supply gaps

This Draft 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 2025 GSOO. These gas development projections influence the foundational assumptions for gas available for GPG used to assess the ODP.

Differences between the assumptions, inputs and scenarios used for the gas development projections in the Draft 2026 ISP and those used for the 2025 GSOO

- AEMO has applied consistent assumptions, inputs and scenarios from the 2025 GSOO to inform the gas supply development modelling and gas development projections in the Draft 2026 ISP wherever possible. However, AEMO notes that:
 - The 2025 GSOO was modelled using the scenarios from the Draft 2025 *Inputs, Assumptions and Scenarios Report (IASR)*, while this Draft 2026 ISP was modelled using scenarios from the 2025 IASR. The residential, commercial and industrial gas consumption and demand forecasts used in the gas supply development model are from the 2025 GSOO, which means the former *Green Energy Exports* scenario was used for the gas forecasts for the *Accelerated Transition* scenario.
 - The GPG forecasts in the 2025 GSOO align with the 2024 ISP. The 2026 GSOO will be aligned with this Draft 2026 ISP.
- AEMO has maintained consistency with the 2025 GSOO and not updated inputs for the gas development projections to align with any updated information published on the Gas Bulletin Board since March 2025.

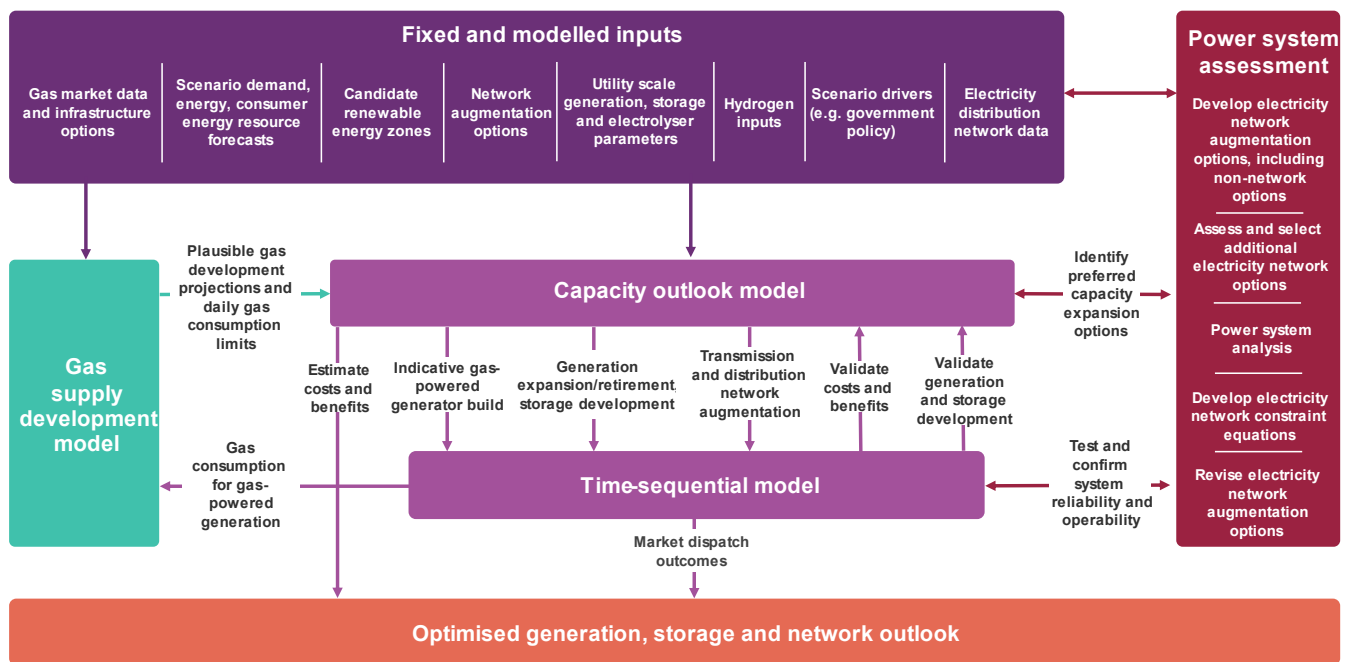
⁷ The East Coast Gas Market includes the Northern Territory, and western Queensland locations outside of the NEM, including Mt Isa. The ECGM northern Australia region covers both Queensland and Northern Territory, excluding gas used for LNG exports out of Darwin.

A10.3 Gas development projections

A gas development projection is a combination of gas supply and infrastructure options across the ISP planning horizon, including the timing for when different options are developed. For each scenario, AEMO has modelled three 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 methodology⁸ and illustrates how different ISP models interact with the gas supply development model to inform the NEM capacity outlook. 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. This Draft 2026 ISP used preliminary capacity outlook modelling of the ODP to inform the GPG forecast that was used as an input to the gas supply development model to generate the gas development projections.

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



The gas development projections leverage analysis in the 2025 GSOO as starting points

The 2025 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.

⁸ 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.



Each gas development projection has different predetermined initial development options based on the uncertain infrastructure development options considered in Section 5 of the 2025 GSOO. AEMO’s gas supply development model then determined a least-cost projection of remaining gas developments from a pool of known options⁹ and a set of generic options, to minimise gas supply adequacy risks. 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).

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

- **transport options** – including options that expand the transportation capacity of 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 plant 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) resources (**Table 1** shows the classification of gas reserves and resources used by AEMO¹⁰), 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 transmission 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 Island¹¹. While new supply is required to meet forecast LNG export demand, outcomes associated with Queensland LNG export demand have been excluded from the Draft 2026 ISP analysis to ensure that the focus remains on available gas supply for the NEM and other domestic gas consumers.

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. |

The production options for the gas development projections only considered known gas resources with contingent estimations of gas quantities. 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 undiscovered or prospective resources in the gas development projections.

⁹ Refer to the *Gas Infrastructure Options Report* for a full list of options available to the gas supply development model. At <https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-gas-infrastructure-options-report-consultation>.

¹⁰ 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/>.

¹¹ Northern Territory LNG exports are not considered part of the ECGM.



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.

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.

Table 2 shows how new entrant GPG in the electricity capacity outlook model are allocated to gas supply zones, and **Figure 3** shows the timing and the capacity of these new GPG builds in the ODP for the *Step Change* scenario. Currently, the NEM has 4 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 (see **Figure 4**). As the mid-merit and some peaking plants retire, they would be replaced¹², and the fleet expanded to a 14 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 11 GW of flexible GPG capacity, out of which about 40% of the capacity 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 | <ul style="list-style-type: none"> Wollongong, Central New South Wales (CNSW) |
| Port Campbell zone | <ul style="list-style-type: none"> West and North Victoria (WNV) |
| Moomba zone | <ul style="list-style-type: none"> Including locations within Central New South Wales (CNSW), Northern South Australia (NSA) and Central South Australia (CSA) (excluding new dual-pipeline connected GPG in Adelaide)^A |
| Newcastle zone | <ul style="list-style-type: none"> Specifically, only the Newcastle location within the Sydney, Newcastle and Wollongong ISP subregion (SNW) |
| Melbourne zone | <ul style="list-style-type: none"> Greater Melbourne and Geelong (MEL) |
| Gladstone zone | <ul style="list-style-type: none"> New GPG in Gladstone Grid (GG) |
| Northern zone ^A | <ul style="list-style-type: none"> Central Queensland (CQ) and Southern Queensland (SQ) |
| Southern zone ^A | <ul style="list-style-type: none"> Including all ISP subregions 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.

¹² For more information on the locational dynamics of capacity build and retirements, refer to Appendix A2.



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

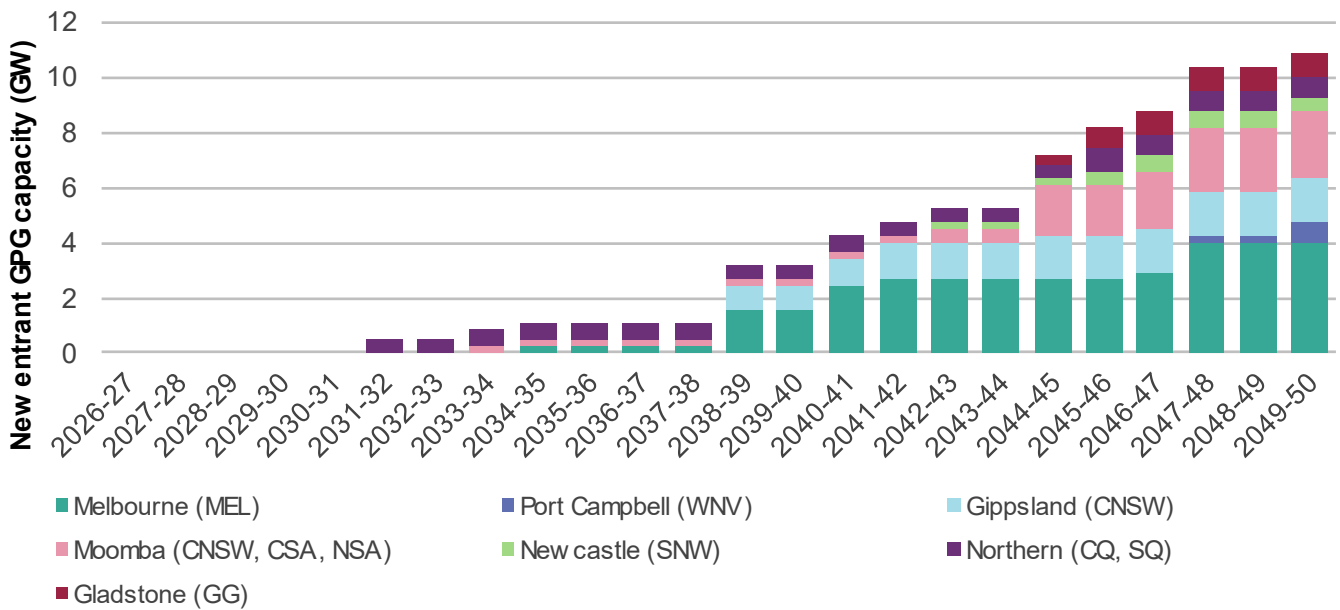
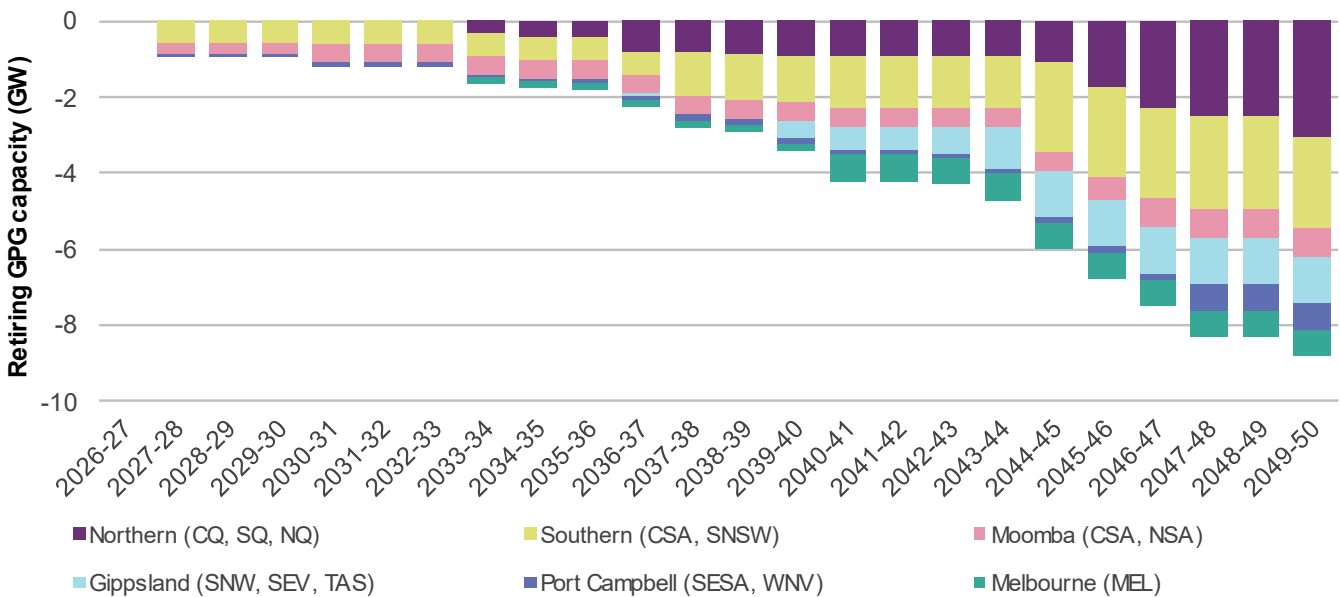


Figure 4 Retiring GPG capacity across different gas supply zones and ISP subregions in the ODP, Step Change, 2026-27 to 2049-50 (GW)



Gas development projections

AEMO used analysis from the 2025 GSOO to establish a predetermined starting position for three gas development projections until 2032-33: one with development of currently uncertain supply, one with pipeline expansions and upgrades to improve north to south flow capacity, and one with an LNG regasification terminal and associated pipeline infrastructure to expand the ability to deliver to load centres. The remainder of the horizon was optimised to minimise gas system costs.



Table 3 provides an overview of the infrastructure and supply forecast in each gas development projection for the *Step Change* scenario, with predetermined options shown in bold. **Figure 5** shows a map of the developments that have been included in the gas development projections.

In addition to the three gas development projections informed by the 2025 GSOO, AEMO also modelled a gas development projection which represents an under-investment in gas infrastructure. In this projection, the forecast developments meet residential, commercial and industrial demand but not additional developments required to meet forecast GPG demand.

Figure 6 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, with predetermined options shown in bold ^A

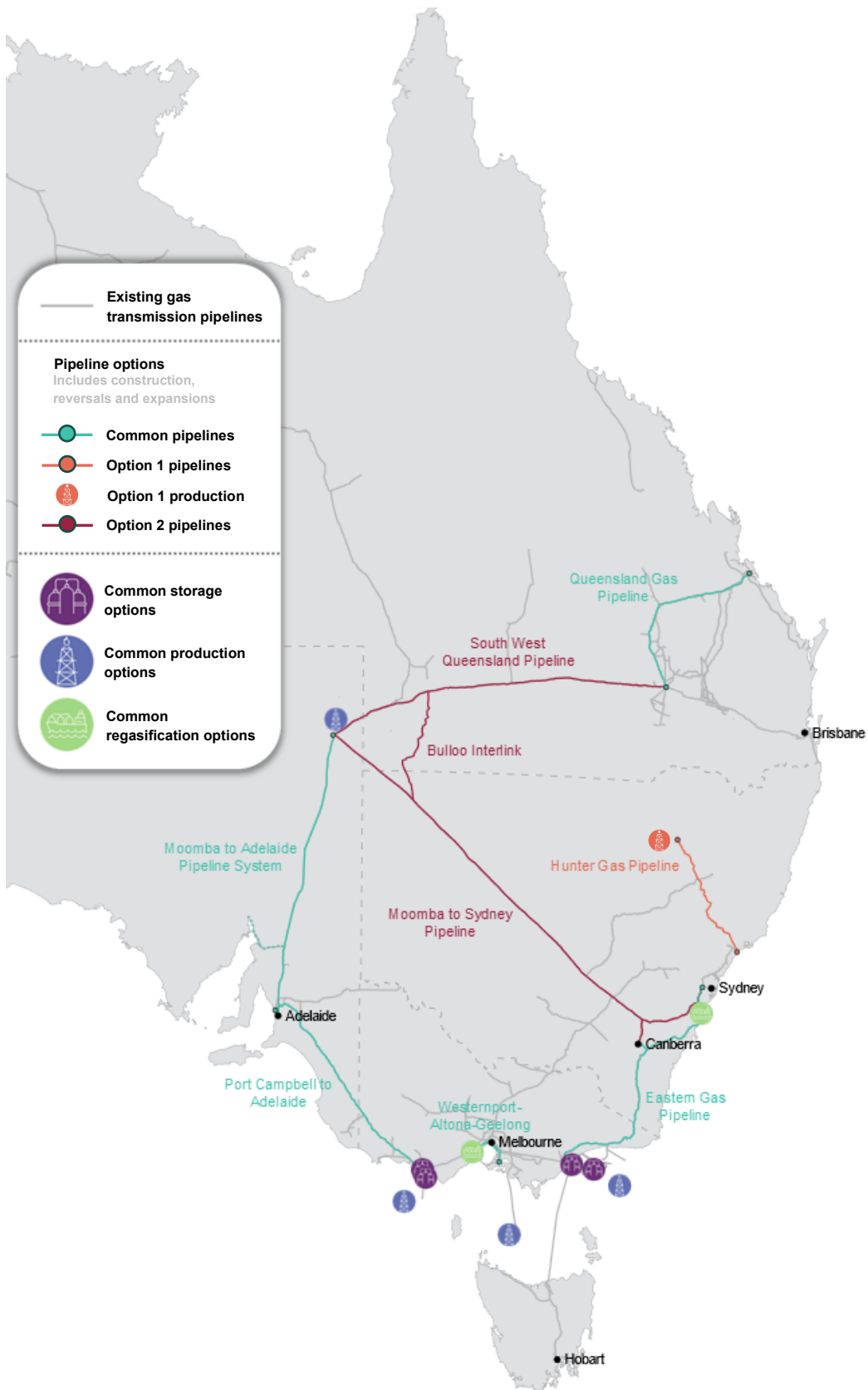
| | Option 1 | Option 2 | Option 3 | Under-investment |
|---|---|--|---|--|
| 2025 GSOO Chapter 5 option | Southern Supply | Pipeline Expansions and Upgrades | LNG Regasification Terminal | - |
| Regasification options | <ul style="list-style-type: none"> Port Kembla Energy Terminal (2033-34) <ul style="list-style-type: none"> With Eastern Gas Pipeline reversal stages 1 and 2 Viva Energy Gas Terminal (2036-37) <ul style="list-style-type: none"> With Westernport Altona Geelong pipeline conversion | <ul style="list-style-type: none"> Port Kembla Energy Terminal (2032-33) 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 (2026-2027) <ul style="list-style-type: none"> With Eastern Gas Pipeline reversal stages 1 and 2 Viva Energy Gas Terminal (2034-35) <ul style="list-style-type: none"> With Westernport Altona Geelong pipeline conversion | <ul style="list-style-type: none"> Port Kembla Energy Terminal (2035-36) <ul style="list-style-type: none"> With Eastern Gas Pipeline reversal stages 1 and 2 |
| Production options | <ul style="list-style-type: none"> 2C southern production <ul style="list-style-type: none"> Including 2C Gunnedah with Hunter Gas Pipeline (2030-31) | <ul style="list-style-type: none"> 2C southern production | <ul style="list-style-type: none"> 2C southern production | <ul style="list-style-type: none"> 2C southern production |
| Storage options | <ul style="list-style-type: none"> Golden Beach Energy Storage Project (2027-28) Heytesbury Underground Storage Project, Phase 2 (2041-42) Generic underground storage – depleted field | <ul style="list-style-type: none"> Golden Beach Energy Storage Project (2035-36) Heytesbury Underground Storage Project, Phase 2 (2029-30) ^B Generic underground storage – depleted field | <ul style="list-style-type: none"> Golden Beach Energy Storage Project (2035-36) Heytesbury Underground Storage Project, Phase 2 (2030-31) Generic underground storage – depleted field | <ul style="list-style-type: none"> Golden Beach Energy Storage Project (2033-34) Heytesbury Underground Storage Project, Phase 2 (2033-34) Generic underground storage – depleted field |
| Transport options (known expansions) | <ul style="list-style-type: none"> Eastern Gas Pipeline expansion of Sydney delivery Port Campbell to Adelaide pipeline reversal | <ul style="list-style-type: none"> East Coast Grid Expansion stage 3 (2027-28) Port Campbell to Adelaide pipeline reversal (2028-29) Eastern Gas Pipeline reversal stage 1 (2026-27) and stage 2 (2032-33) Eastern Gas Pipeline expansion of Sydney delivery Moomba to Sydney Pipeline to Eastern Gas Pipeline compression | <ul style="list-style-type: none"> Eastern Gas Pipeline expansion of Sydney delivery | <ul style="list-style-type: none"> Eastern Gas Pipeline expansion of Sydney delivery |
| Transport options (generic expansions) | <ul style="list-style-type: none"> Moomba Adelaide Pipeline System Port Campbell Adelaide pipeline Queensland Gas Pipeline | <ul style="list-style-type: none"> Moomba Adelaide Pipeline System Port Campbell Adelaide pipeline Queensland Gas Pipeline | <ul style="list-style-type: none"> Moomba Adelaide Pipeline System Port Campbell Adelaide pipeline Queensland Gas Pipeline | <ul style="list-style-type: none"> Port Campbell Adelaide pipeline |

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 build period (2026-27 to 2032-33) is constrained using the predetermined options to align with the 2025 GSOO. The expansion of Iona (Heytesbury Underground Storage Project, Phase 2) is a model-determined decision that can occur at any time.



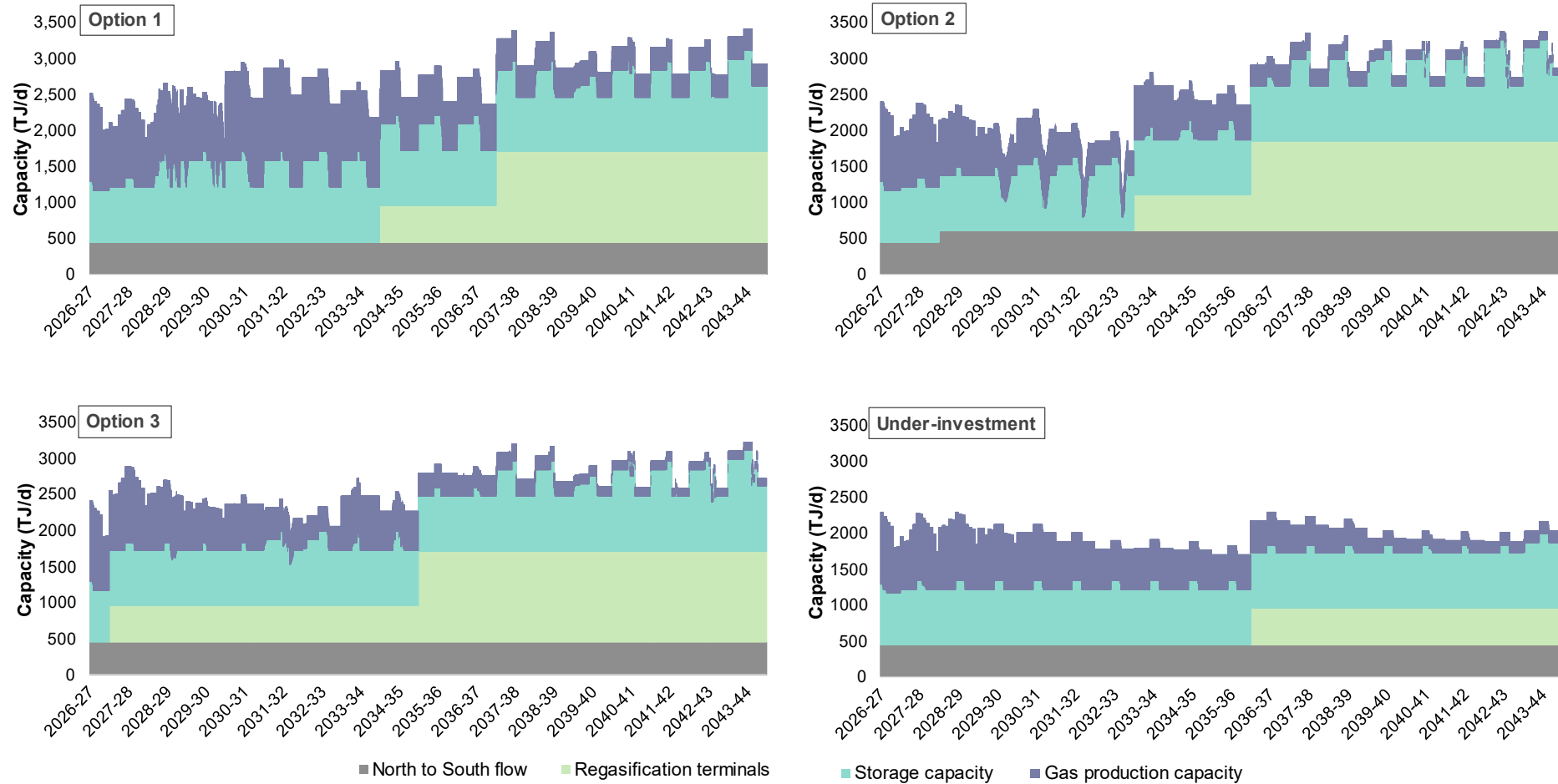
Figure 5 Map of developments included in the gas development projections, Step Change



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 6 Maximum available daily gas supply capacity in the Southern zone for different gas development projections, Step Change, 2026-27 to 2043-44 (TJ/d)



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

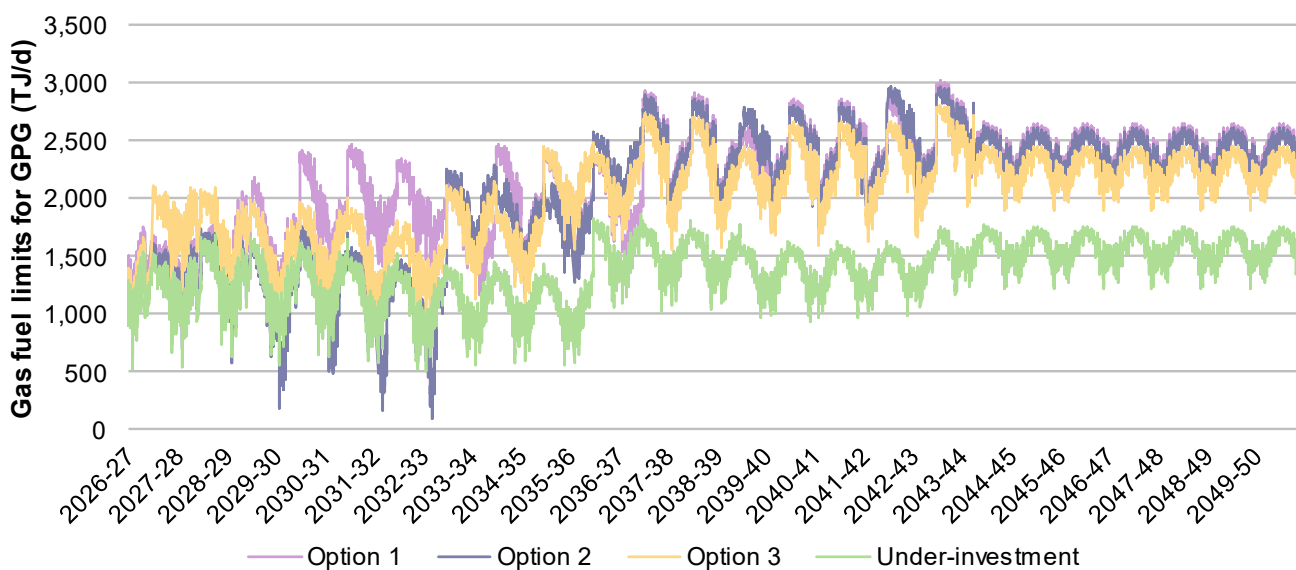


The gas development projections assessed in the Draft 2026 ISP trend to a similar series of developments

Figure 7 shows the daily gas fuel limits for the Southern zone, across the three gas development projections studied and the under-investment projection for the *Step Change* scenario. While the initial starting point for gas supply capacity expansion is different for all gas development projections, by around 2037, all projections (excluding the under-investment projection) adapt to provide similar levels of gas availability for GPG, and include similar combinations of transport, storage, production and regasification developments. This results in a tight spread of daily gas fuel limits for the Southern zone from the mid-2030s.

Although there are common developments across the gas development projections, it remains up to the gas industry to identify and progress projects. Analysis shows that the initial investment in the gas system will not materially restrict future gas developments to support GPG. From a gas supply adequacy perspective, there are few long-term implications of which investment progresses first, and as described in the 2025 GSOO, a combination of investments will be needed in the long term to support gas consumers.

Figure 7 Daily gas fuel limits for GPG in the Southern zone for different gas development projections, *Step Change*, 2026-27 to 2049-50 (TJ/d)



The under-investment projection shows much lower gas availability for GPG, but can still support some NEM GPG demand, even though the model has not been designed to explicitly build for all NEM GPG needs. During periods of peak GPG consumption, the gas supply development model allows some generators to switch to on-site diesel storage. This ensures that there is not an overbuild of gas developments to meet only the very largest of gas demand peaks when GPG gas demand could be reduced.

Figure 8 presents the forecast diesel usage in the Southern zone during peak GPG demand events. There is minimal reliance on diesel for the three gas development projections, while the under-investment projection requires a much higher frequency and greater magnitude of diesel use. Further discussion on the role of secondary fuels is in Section A10.5.

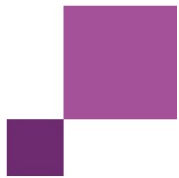
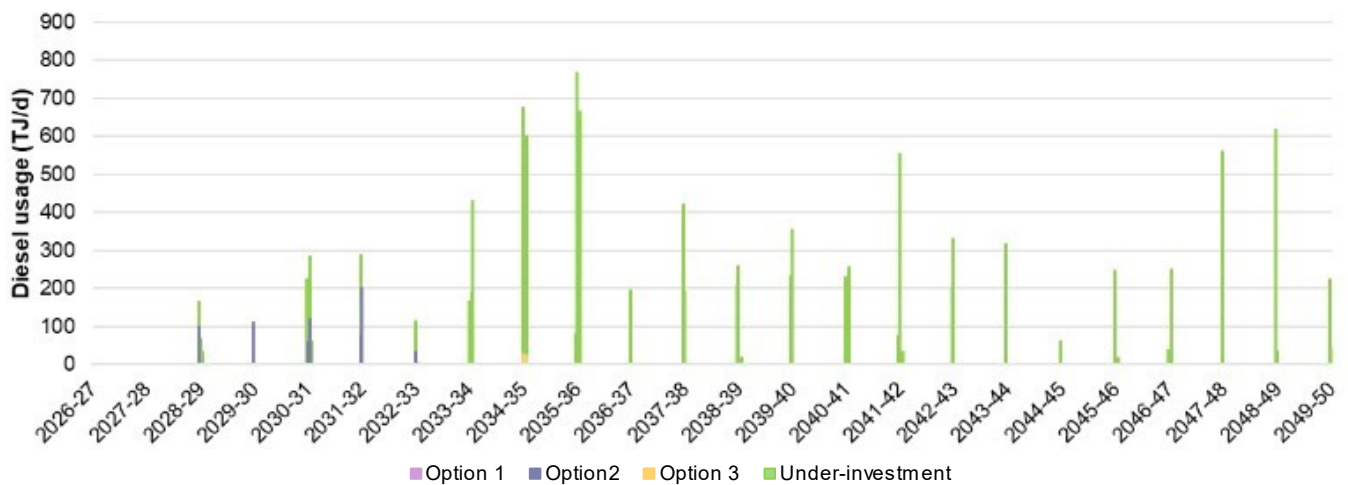


Figure 8 Forecast diesel usage for GPG in the Southern zone during peak GPG operations for different gas development projections, Step Change, reference year 2019, 2026-27 to 2049-50 (TJ/d)



Gas development projection Option 3 informs the daily gas fuel limits in the NEM capacity outlook for the Draft 2026 ISP

While multiple gas development projections may be able to fulfil the gas fuel requirements in the NEM capacity outlook modelling, the Draft 2026 ISP has been assessed after selecting one to represent gas availability. **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. Gas development projection Option 3 has been used to inform the gas limits for the ODP due to its relatively low build cost, partly as the capital cost for the Port Kembla Energy Terminal in the gas supply development model was considered sunk¹³, and the timing of all developments in this projection are delivered in a feasible timeframe.

While gas development projection Option 3 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

¹³ 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.



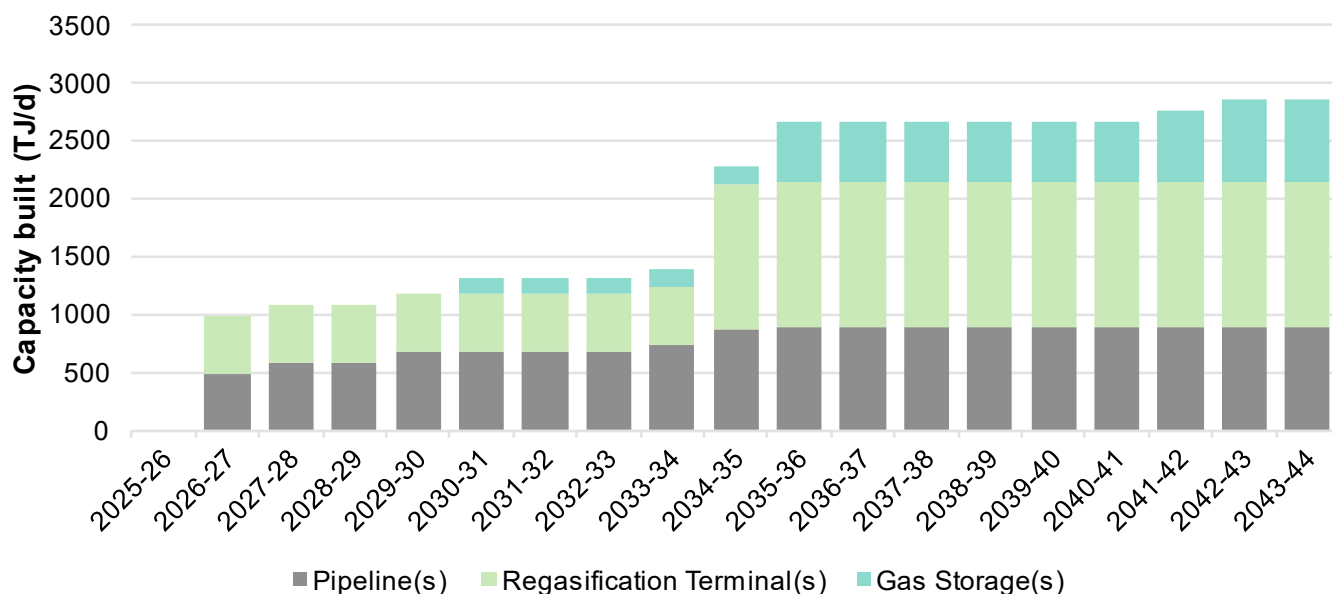
development projections in the NEM capacity outlook model, and marginal differences have been observed in the forecast GPG capacity for each NEM region (refer to Section 10.5 and Appendix A2).

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 initial developments by the gas industry, including gas consumers. The gas development projections presented represent potential developments and do not represent a preferred or optimal development path for the gas sector. The development options considered were those published in the 2025 *Gas Infrastructure Options Report*, which may not represent all gas infrastructure options being considered by the gas industry.

The Draft 2026 ISP has not assessed the potential impact of each development projection on the domestic gas price; AEMO may investigate price impacts in more detail for future publications. Additionally, AEMO has not included consideration of cost recovery or other commercial aspects of individual gas developments in the evaluation criteria or assessment.

Figure 9 shows the capacity built 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 9 Capacity built to meet domestic demand for gas development projection Option 3, Step Change, 2025-26 to 2044-45 (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 10 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.

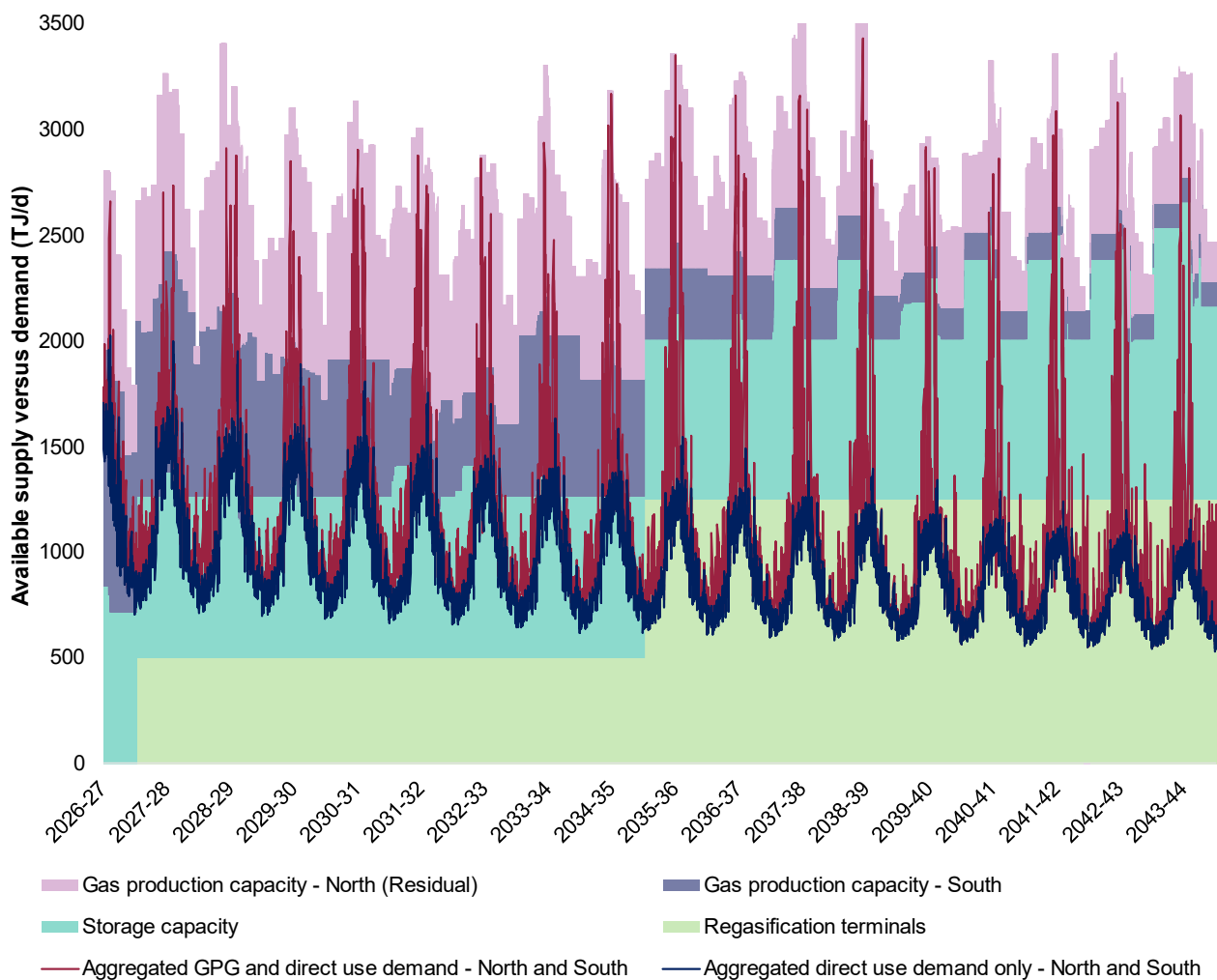
This includes supply from the total infrastructure capacity built as well as gas production capacity from existing, committed and anticipated supply and production capacity from 2C fields that are developed in Option 3. The figure demonstrates that as gas production declines, particularly in existing southern fields, supply adequacy is maintained largely with the support of



LNG regasification terminals and storage capacity. The figure also reflects the seasonal role that deep gas storage plays, with winter storage capacity increasing which provides seasonal capacity to meet peak winter gas demands.

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 2025 GSOO will continue to be served by the LNG producers in Queensland, including expanded coal seam gas well developments to balance this forecast demand.

Figure 10 Available supply for gas development projection Option 3 and forecast direct use and GPG demand, Step Change, 2026-27 to 2043-44 (TJ/d)



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

Gas development differences between scenarios are the greatest through the period of coal generation closures

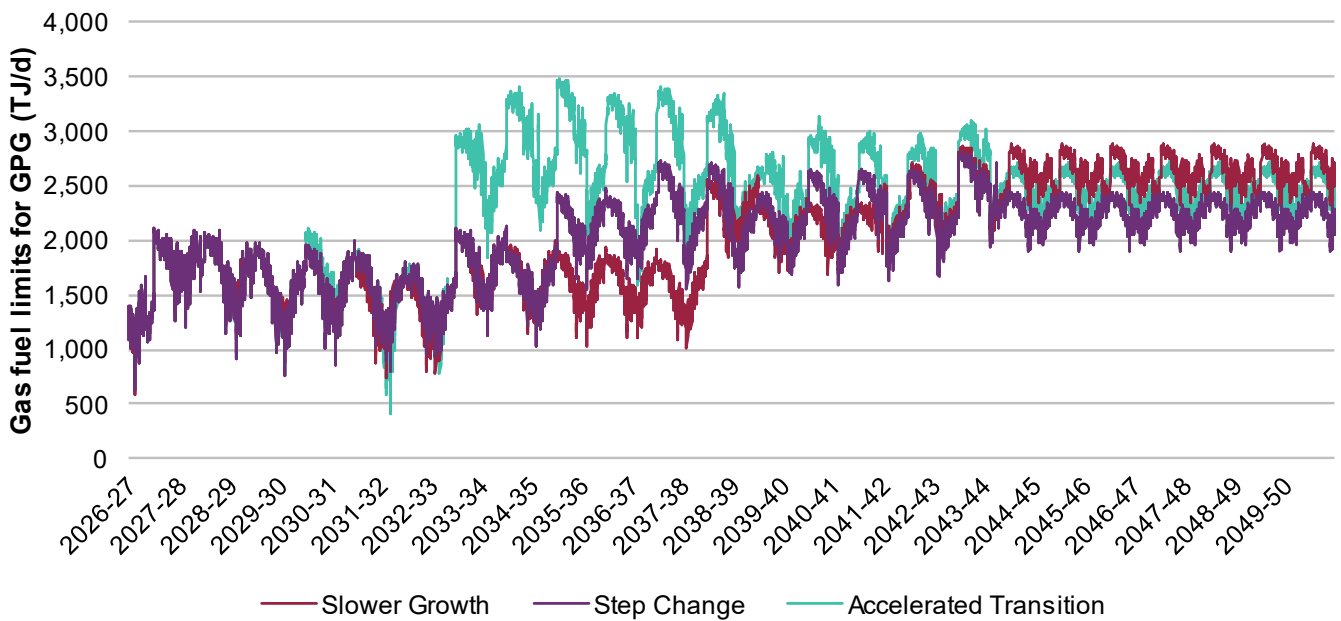
Figure 11 shows the daily gas fuel limits in the Southern zone for gas development projection Option 3 for each scenario, providing a comparison between *Slower Growth*, *Step Change* and *Accelerated Transition*.



The greatest variation in GPG needs between scenarios is the period from 2033-34 and 2039-40 as coal retirements vary most across the scenarios, leading to alternative investment needs for gas supply developments. The driver of coal capacity replacement has a greater impact than the economic growth and 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 has the highest gas supply developments, leading to the greatest availability of gas to service higher forecast GPG demand in this scenario. The model starts building for this higher GPG demand from 2033-34, based on the adopted modelling approach which relies on predetermined developments for the earlier period. As gas demand declines due to increased electrification, no further southern capacity is required 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, even though the NEM will experience greater, and lesser, electricity demand across the three scenarios, demonstrating that electrical storages will be a key technology to firm the NEM and that gas for GPG will need to be used sparingly at times to provide an important back-up role.

Figure 11 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)





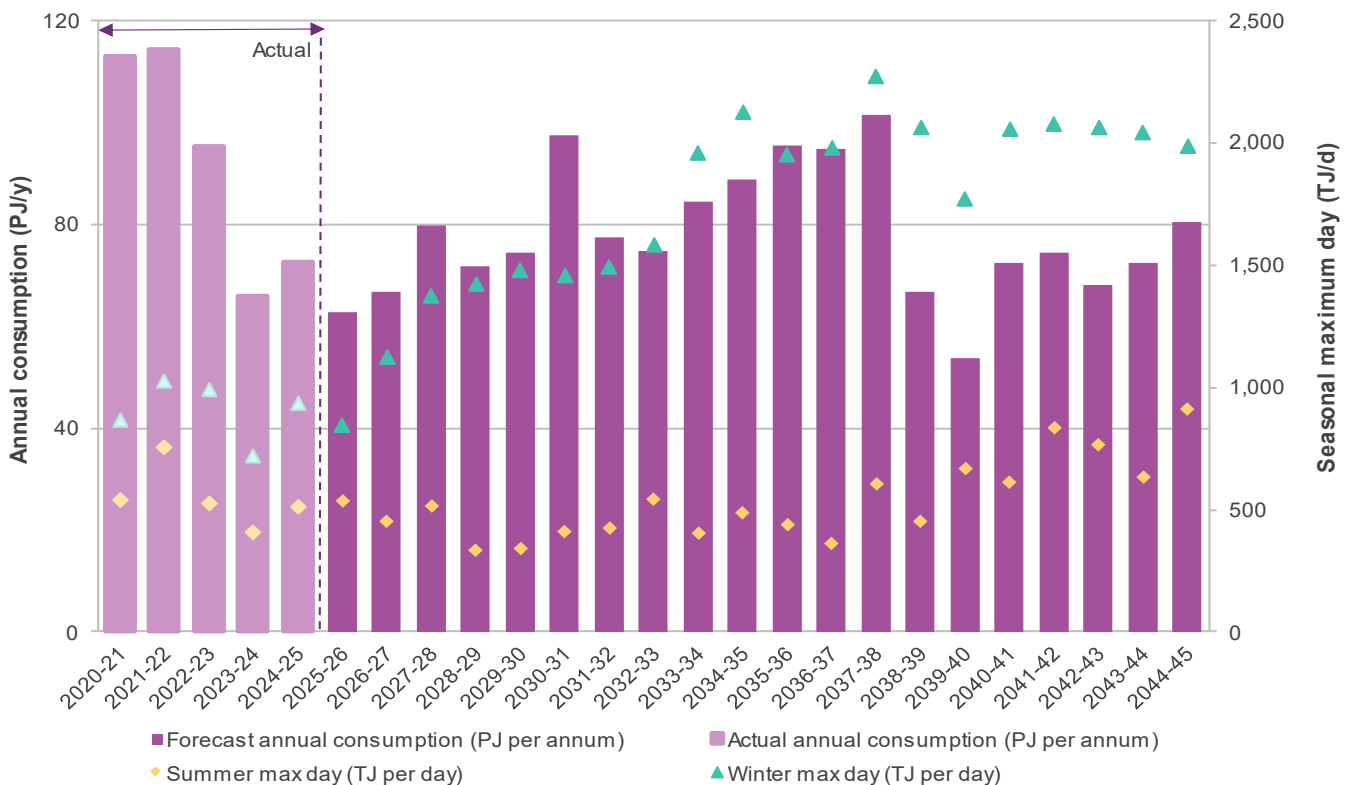
A10.4 Forecasting the role of GPG in the NEM

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 Draft 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 as coal plants retire, while meeting government policies through to 2050. 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 electrical storages will provide a high level of intraday and interday firming, but GPG will be critical to maintaining reliability during less frequent periods of more widespread low VRE output, during longer dark and still events (see Appendix A4, Section A4.5), and will also continue to provide critical power system security services.

Figure 12 shows forecast annual consumption of gas for electricity generation returning to recent consumption levels during the late 2030s, due to the combined effect of coal power station retirements, electricity consumption growth, and the need to firm high levels of VRE.

Figure 12 Actual and forecast NEM GPG annual consumption (PJ/y) and seasonal maximum daily demand (TJ/d), Step Change, 2020-21 to 2044-45



Note: This forecast does not include the impact of sub-optimal management of storage technologies on GPG consumption, which is discussed in Appendix A4 (Section A4.5).

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. The chart 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 other investments (such



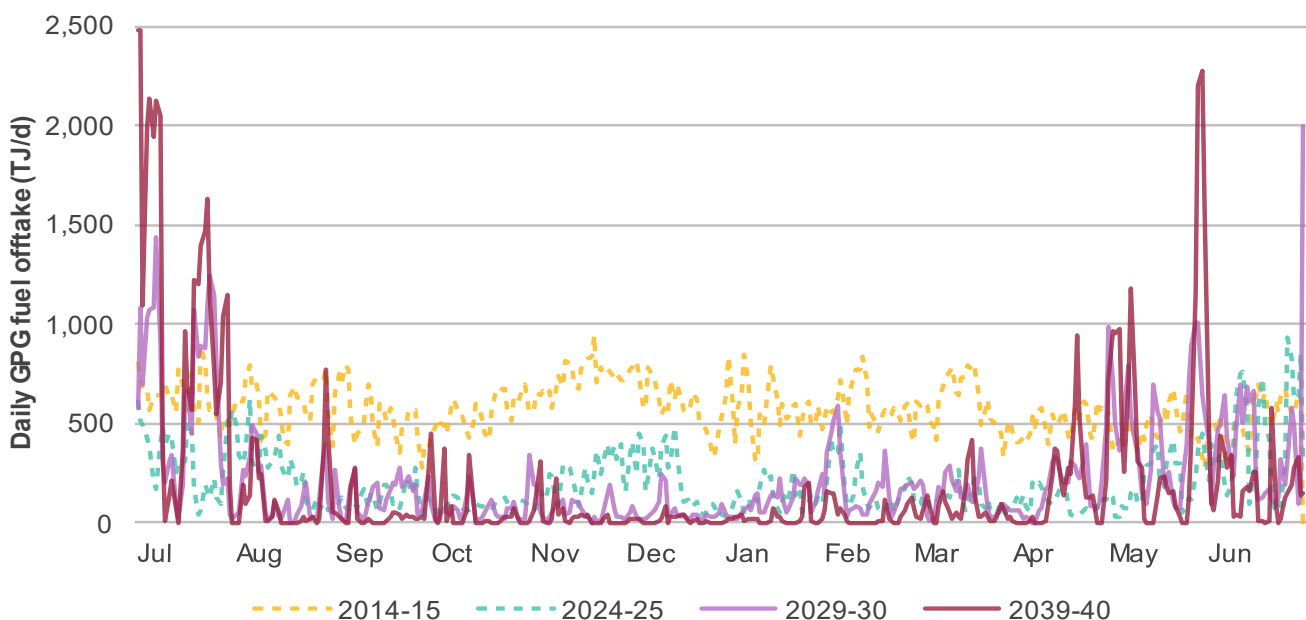
as new renewable and network developments), importantly the maximum daily fuel used for GPG remains relatively consistent over the long term, demonstrating the important back-up role that GPG will play to support reliability of supply.

Compared to the 2024 ISP, the proposed ODP in the Draft 2026 ISP has lower wind capacity in the short term (about 4-7 GW less). The impact of this, combined with the revised assumptions¹⁴ on the market operation of coal-fired power plants and storages, has resulted in higher forecast GPG consumption in the short term. The Draft 2026 ISP proposed ODP also has a slower phase out of coal-fired power plants to 2049-50, which reduces forecast consumption of GPG particularly for later years of the outlook period, as the VRE firming role is shared among coal-fired and gas-powered generation.

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)¹⁵. 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 13 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 13 Daily NEM-wide GPG fuel offtake, historical 2014-15 and 2024-25, forecast 2029-30 and 2039-40, Step Change, reference year 2011 (TJ/d)



¹⁴ The time sequential model underpinning the NEM GPG forecast in this section has been calibrated to reflect recent market bidding strategies and real operational behaviour of generators, such as the observed increased flexibility of the coal fleet. Additionally, the implementation of hydro generators and associated reservoirs has been improved. The 2025 IASR contains details of the improved hydro generation implementation, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/2025-inputs-assumptions-and-scenarios-report.pdf?rev=63268acd3f044adb9f5f3a32b6880c27&sc_lang=en.

¹⁵ 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.



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 Draft 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 development opportunities and the operational performance of the ODP.

The optimal development path is adaptable to different gas developments

AEMO's analysis indicates that the ODP is forecast to be operable under varying gas development sensitivities, with a high level of technology and geographical development consistency. As each gas development projection provides adequate supply to meet GPG requirements, there are only small differences in NEM-wide or regional outcomes. The ODP is able to adapt its generation and storage developments to different combinations of gas developments as long as an overall level of gas supply capacity is achieved. However, some sub-regional developments are preferred over others, depending on the gas development projection, such as if additional gas supply is available in Newcastle.

Conversely, some gas supply, storage and infrastructure developments are only required to support assumed levels of gas demand for GPG. The need for these 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.

If the future NEM features a higher GPG capacity than forecast by the ODP, such as in the *Faster Coal Retirement* or *Lower Energy Efficiency* sensitivities (see Appendix A2), GPG peak demand may be higher or include more periods of sustained GPG operation. Additional sources of gas supply, gas storage or pipeline capacity beyond those assessed by AEMO in this appendix may be needed to meet these higher GPG needs, without driving an over-reliance on secondary fuels.

Figure 14 illustrates the projected GPG installed capacity across NEM regions under different gas development projection sensitivities. The development trajectory and quantity of GPG capacity remains broadly consistent at a regional level, regardless of the specific gas pathway. 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 14 Forecast GPG installed capacity across different plausible gas development projections, Step Change, 2029-30 to 2049-50 (MW)



Figure 15 shows the forecast daily gas offtake for southern GPG in 2044-45 using the 2011 weather reference year, which includes severe VRE lulls in winter. This chart shows that each of the assessed gas development projections 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. The chart also presents the forecast gas storage capacity in the southern states, highlighting the critical role that gas storage plays in meeting 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. Shallow gas storages, including the Dandenong LNG facility, 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 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 demands in winter, and the refill of deep gas storage facilities in preparation for winter.

Managing operational dynamics becomes increasingly important as the role of GPG shifts to the strategic, back-up role as a response to short notice events in the NEM. This highlights that the resilience of the ECGM depends not only on long-term supply capacity and deep storages but also on its capability to manage rapid intraday demand swings, which is an ability that is supported by the operational responsiveness of linepack and shallow gas storage facilities. As the gas supply development model has no visibility of this intraday requirement, if linepack is insufficient, additional shallow gas storages may need to be developed compared to what was forecast by the gas development projections.

Figure 16 demonstrates the seasonal cycle of storage, with injection into storage during warmer months building 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 daily gas fuel limits for GPG in the Southern zone and southern NEM GPG daily demand, Step Change, reference year 2011, 2044-45 (TJ/d)

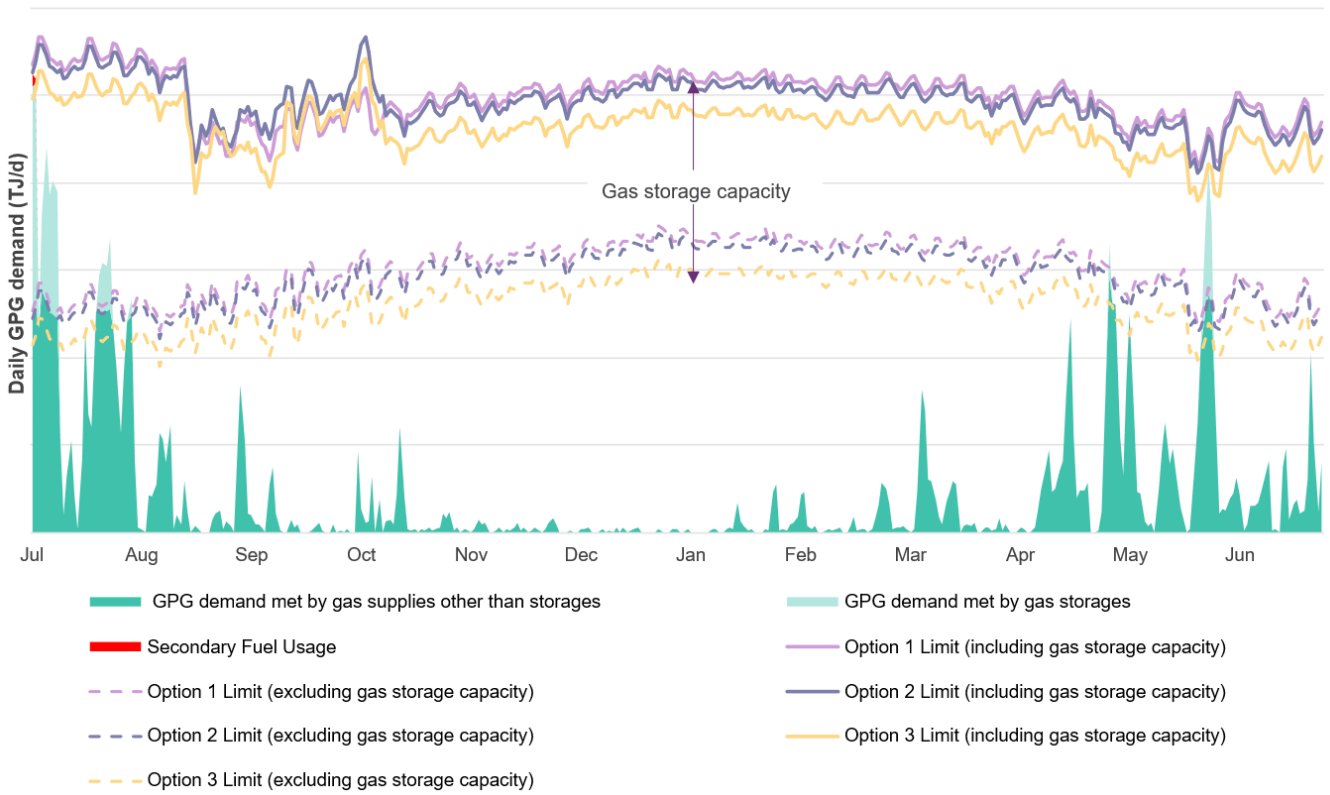
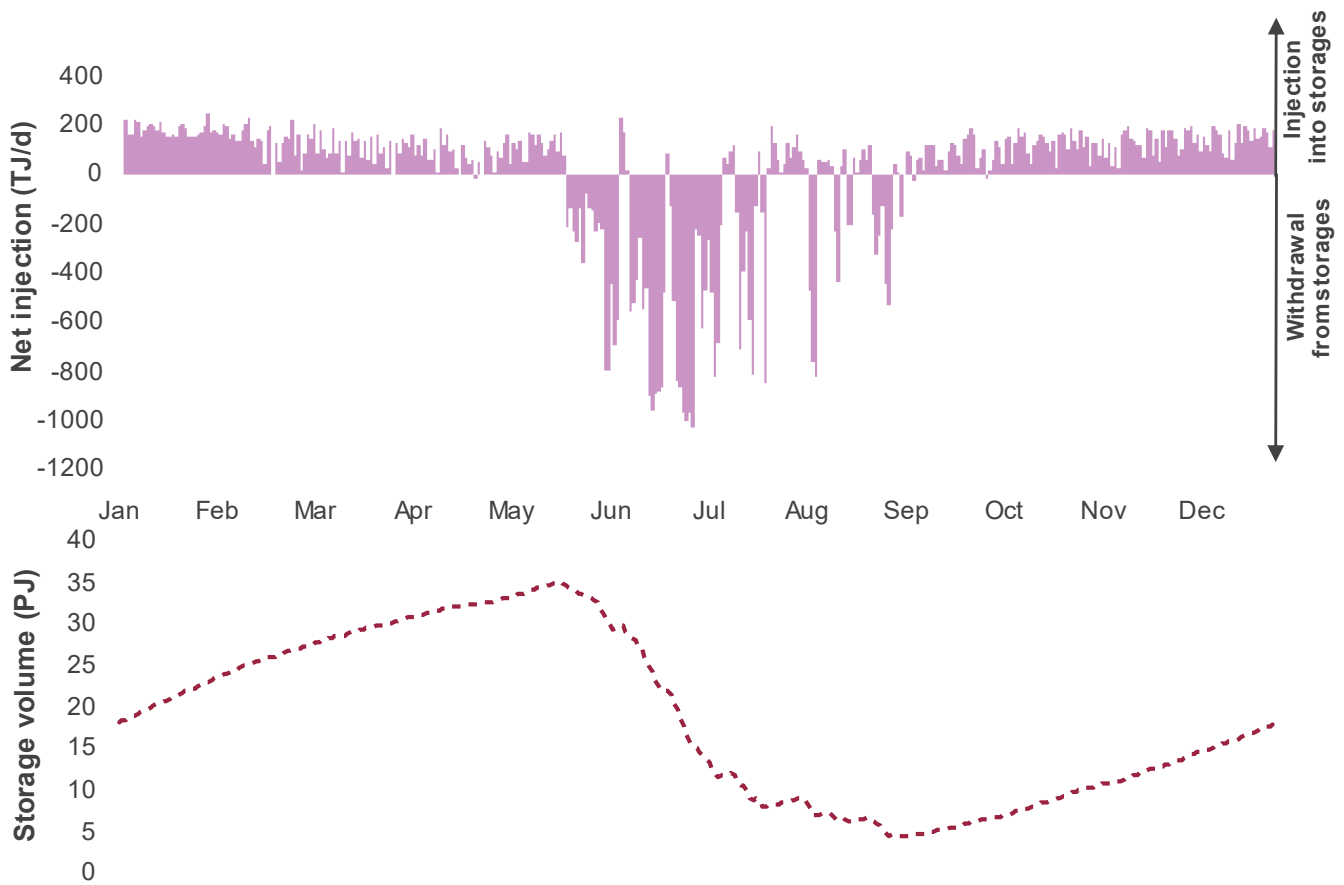




Figure 16 Forecast gas storage profile for gas development projection Option 3, Step Change, reference year 2015, calendar year 2031 (TJ/d and PJ)



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

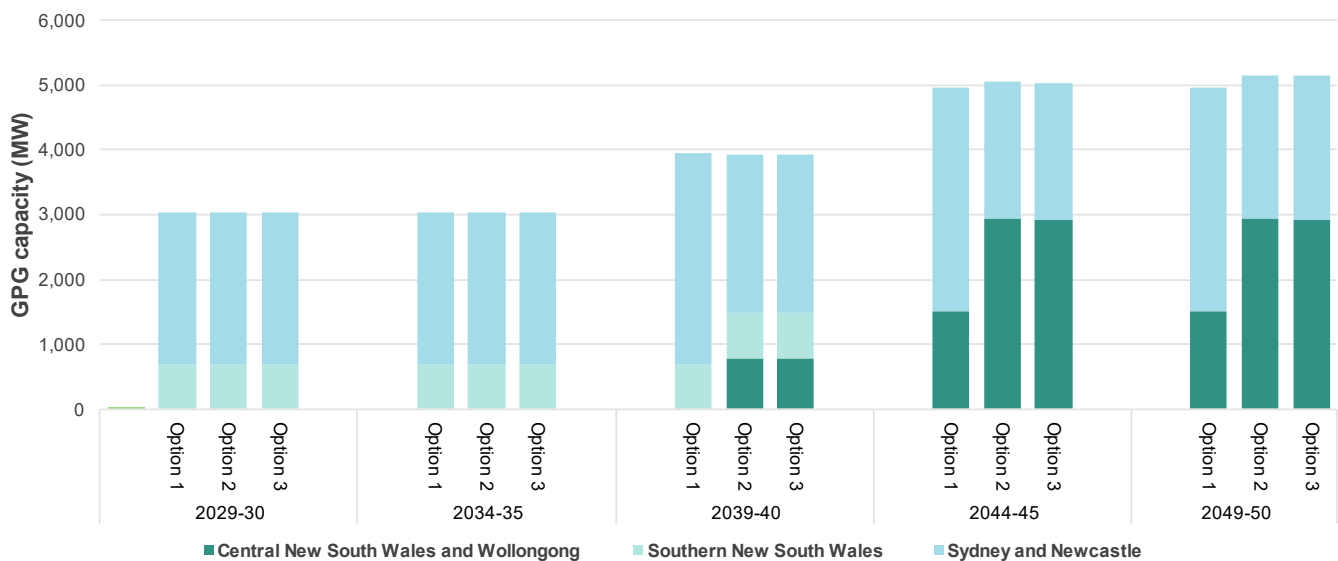
The location of new entrant GPG might need to adapt within a region as an outcome of different gas development projections

Within a region, the location of new GPG developments was modelled to be influenced by key gas developments which enable gas supply in specific locations. As an example, the existing Newcastle gas zone allows for very limited gas supply to new entrant GPG, and gas development projection Option 1 includes the development of gas production and a pipeline which increases gas supply availability in Newcastle. The NEM capacity outlook model favours new entrant GPG being located closer to Newcastle over Wollongong or areas of southern Sydney, as these are in the Gippsland gas supply zone which has higher daily gas fuel limits. With better electricity transmission access to the Sydney load centre, new entrant GPG in Newcastle would reduce congestion on network flows south of Sydney, freeing up electricity supplies from southern New South Wales and those transported from Victoria to be delivered into the Sydney ring network. Adding geographical diversity by locating more firming capacity north of Sydney and away from potential congestion between Sydney and Victoria (where critical deep storage assets exist with the Snowy and Snowy 2.0 generators) will reduce the potential need for electricity storages in other New South Wales locations. As gas and electricity developments were not co-optimised, AEMO has not assessed whether this would be a more efficient outcome overall.

Figure 17 illustrates this geographical diversity of GPG developments with more diverse fuel availability in the gas development projections.



Figure 17 Forecast GPG installed capacity in New South Wales for different gas development projections, Step Change, 2029-30 to 2049-50 (MW)



Some gas infrastructure developments are primarily driven by the forecast expansion of new entrant GPG in the NEM. 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-region¹⁶. Similarly, if new entrant GPG were required in the Northern South Australia (NSA) sub-region, as proposed by the ODP, a lateral connection to the Moomba – Adelaide Pipeline System would likely be needed to ensure adequate gas supply. 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.

If the level of gas investment is misaligned with the fuel requirements of the NEM, there are risks to the ODP

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 timing and successful delivery of the investments underpinning the gas development projections. Additionally, the commercial viability of gas investment to primarily support GPG 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, though would need to provide an equivalent capability to support reliability in various NEM conditions.

This section examines a ‘what-if’ analysis – the under-investment gas development projection – where gas developments only respond to forecast residential, commercial, and industrial gas demand. This analysis serves as a proxy for a delayed or slow gas development, resulting in a significant reduction in available gas supply to the NEM GPG.

¹⁶ The recently released Queensland Energy Roadmap identified a tendering approach to support an additional 400 MW of GPG in the Central Queensland region. See <https://www.treasury.qld.gov.au/files/Queensland-Energy-Roadmap-2025-25-043.pdf>.



Figure 18 demonstrates the reduction in annual capacity development under the under-investment projection compared to the gas development projection Option 3. It highlights that investment in southern gas supply capacity can be up to around 1,700 TJ/day lower in the under-investment projection than in Option 3; the utilisation of this gas capacity will vary depending on daily conditions.

Figure 18 Reduction in capacity development in under-investment projection as compared to gas development projection Option 3, Step Change, 2026-27 to 2044-45 (TJ/d)

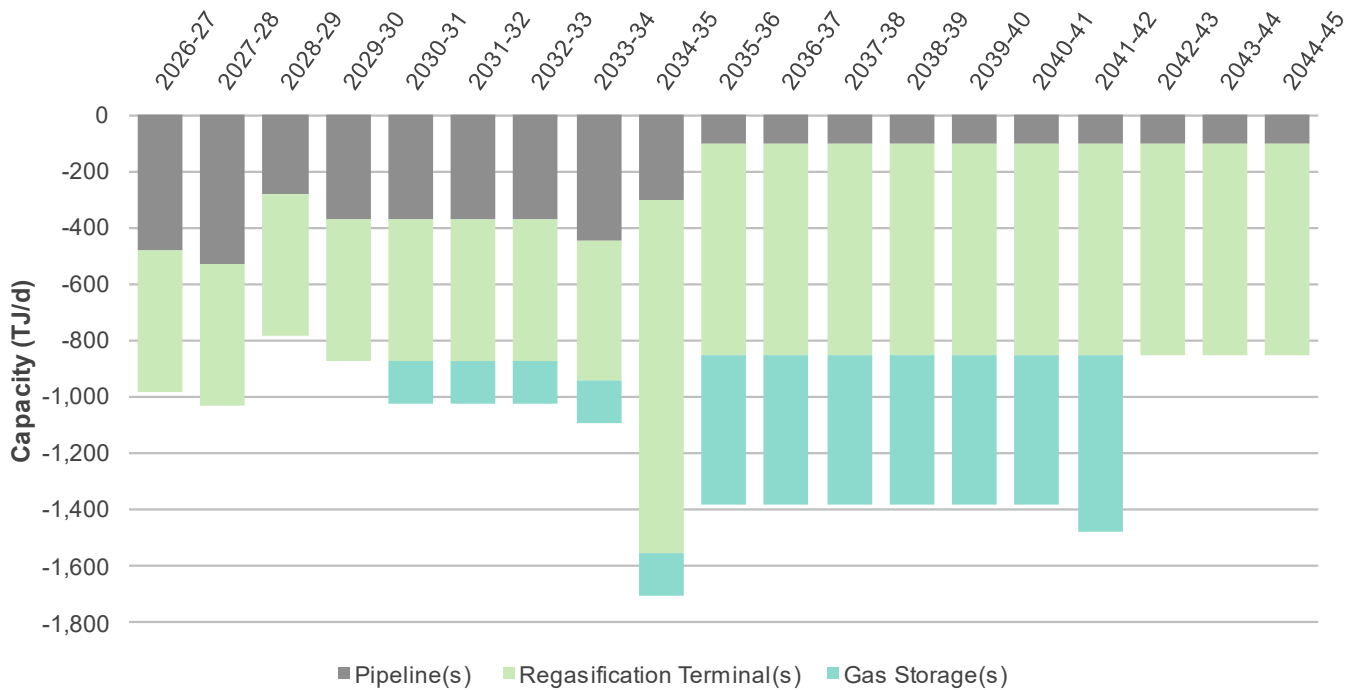


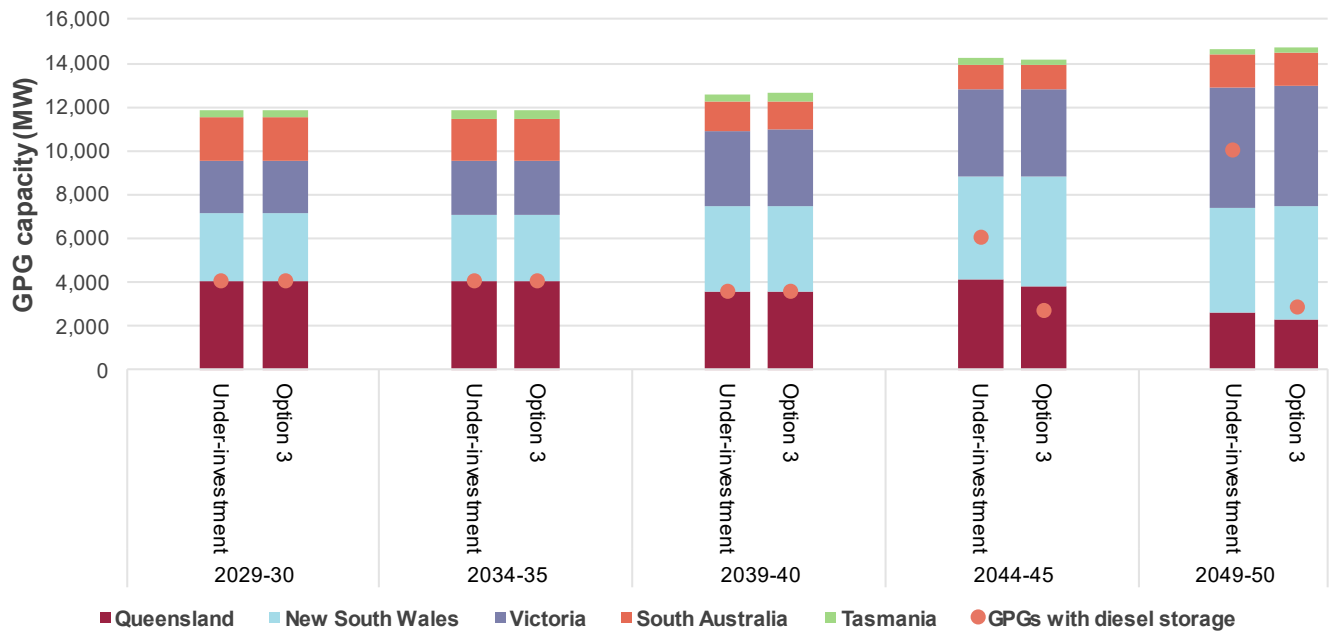
Figure 19 shows a similar level of GPG installed capacity between gas development projection Option 3 and the under-investment gas development projection. The only notable difference is the relocation of approximately 300 MW of new entrant GPG from New South Wales to Queensland, where gas supply remains more abundant.

This demonstrates the adaptability of the well-connected NEM under the ODP, enabling efficient and flexible resource sharing in the event of slower gas developments.

However, to operate the GPG fleet with reduced gas fuel availability, there would be a much greater reliance on secondary fuels. Nearly 10,000 MW, around 70% of the GPG fleet, would require 14-hour onsite diesel storage between 2039-40 and 2049-50 in the under-investment scenario. This would require additional capital investment, and potentially cause higher reliability risks if diesel storages cannot be replenished quickly enough during extended VRE lulls. Diesel storage locations will 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.



Figure 19 Forecast GPG installed capacity and GPG with diesel storage in gas development projection Option 3 and the under-investment gas development projection, Step Change, 2029-30 to 2049-50 (MW)



Both AEMO’s gas supply development model and NEM capacity outlook model considered that onsite diesel storages can be developed for all new entrant GPG to operate on secondary fuels. This ensured that there was not an overbuild of gas developments to meet only the very largest of gas demand peaks when GPG gas demand could be reduced. As shown earlier in **Figure 15** (during early July), the daily gas fuel limits 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, the GPG units that are capable of operating on secondary fuels are expected to maintain operation using onsite diesel storage when gas supply is constrained.

Figure 20 and **Figure 21** illustrate the distributions of the forecast peak-day GPG demand that cannot be met by the daily gas fuel limits for gas development projection Option 3, and by the under-investment gas development projection, respectively across a range of simulated weather and market conditions.

For gas development projection Option 3, the quantity of electricity that cannot be served by gas as a fuel remains within the capacity of existing onsite diesel storage, indicating that GPG can operate to its required level at all times, but only if primary and secondary fuels are managed within their expected limits. Risks of GPG interruptions from gas fuel limits and insufficient capacity of onsite diesel storages are heightened in the early to mid-2030s, coinciding with forecasts 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 onsite storages and dual-fuel capability are important development considerations to ensure GPG can play the key back-up role that is needed.

For the under-investment gas development projection, **Figure 21** shows there are several forecast years when onsite 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 575 TJ, forcing approximately 2,200 MW of GPG offline. If alternative generation, demand response, or accelerated investment in on-site diesel storage is not available, the power system would need alternative capacity such as long duration storage to maintain reliability during periods in the mid-2030s and early



2040s. This highlights the importance of timely gas infrastructure development to reduce the reliance on secondary fuels which have a limited storage capacity, and investing in onsite diesel storages and dual-fuel capability as a contingency, to mitigate reliability risks in the NEM during periods of tight electricity supply and demand balance.

Figure 20 Forecast range of peak-day GPG gas demand curtailment and onsite diesel storage capacity in southern NEM for gas development projection Option 3, Step Change, reference year 2011-2024, 2026-27 to 2044-45 (TJ/d)

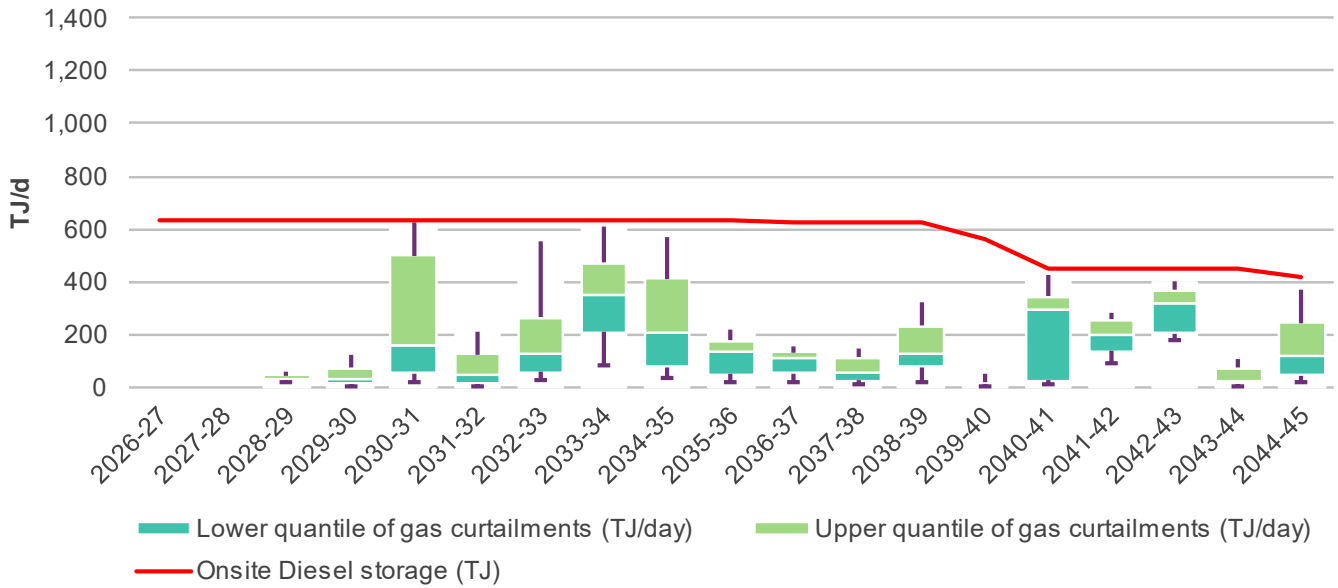
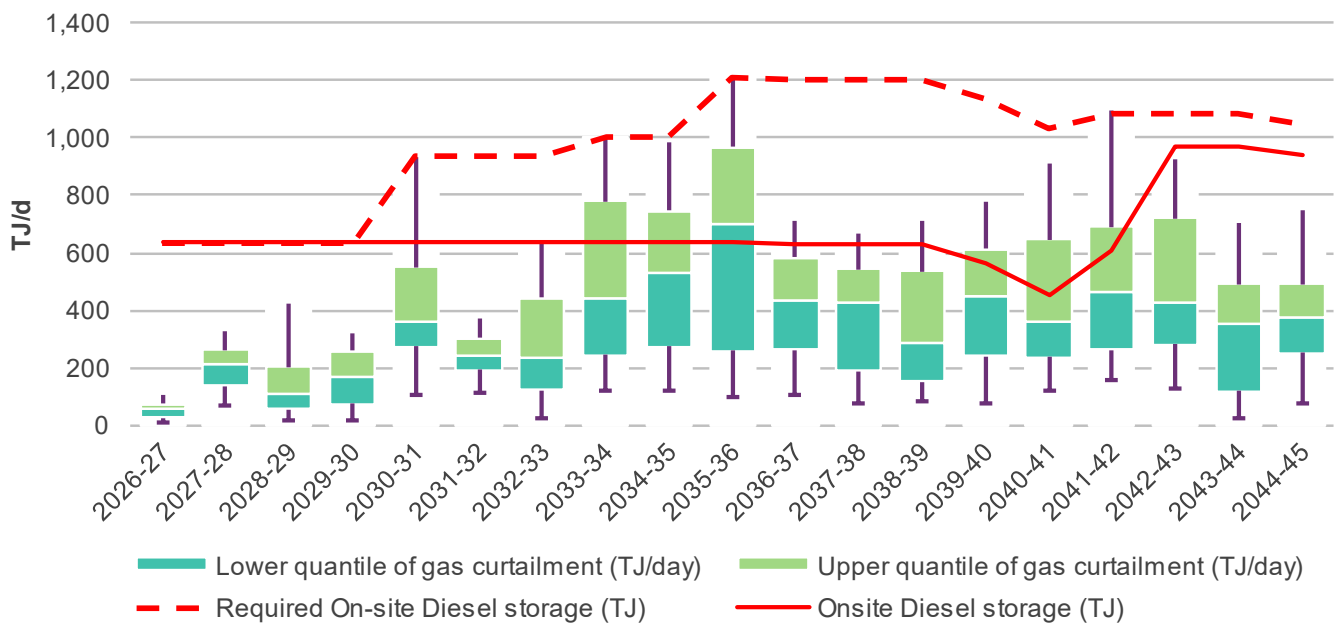


Figure 21 Forecast range of peak-day GPG gas demand curtailment and onsite diesel storage capacity in southern NEM for the under-investment gas development projection, Step Change, reference year 2011-2024, 2026-27 to 2044-45 (TJ/d)



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. |
| 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]). |
| 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. |

| Term | Acronym | Explanation |
|---|---------|---|
| 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. |
| Future distribution project | - | A distribution project that is part of the ODP and forecast to be needed in the future. The project is an ISP development opportunity and does not address an identified need specified in the ISP. The ISP cannot make a distribution project 'actionable' or require commencement of the Regulatory Investment Test for Distribution (RIT-D). |
| Injection | - | The physical injection of gas into the gas transmission system or a gas storage facility. |
| Lateral | - | A pipeline branch. |
| 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. |
| 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 power 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 the Draft 2026 ISP, AEMO has considered three scenarios: <i>Slower Growth</i> , <i>Step Change</i> and <i>Accelerated Transition</i> . |

| Term | Acronym | Explanation |
|--------------------------------------|---------|--|
| 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. |
| 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. |