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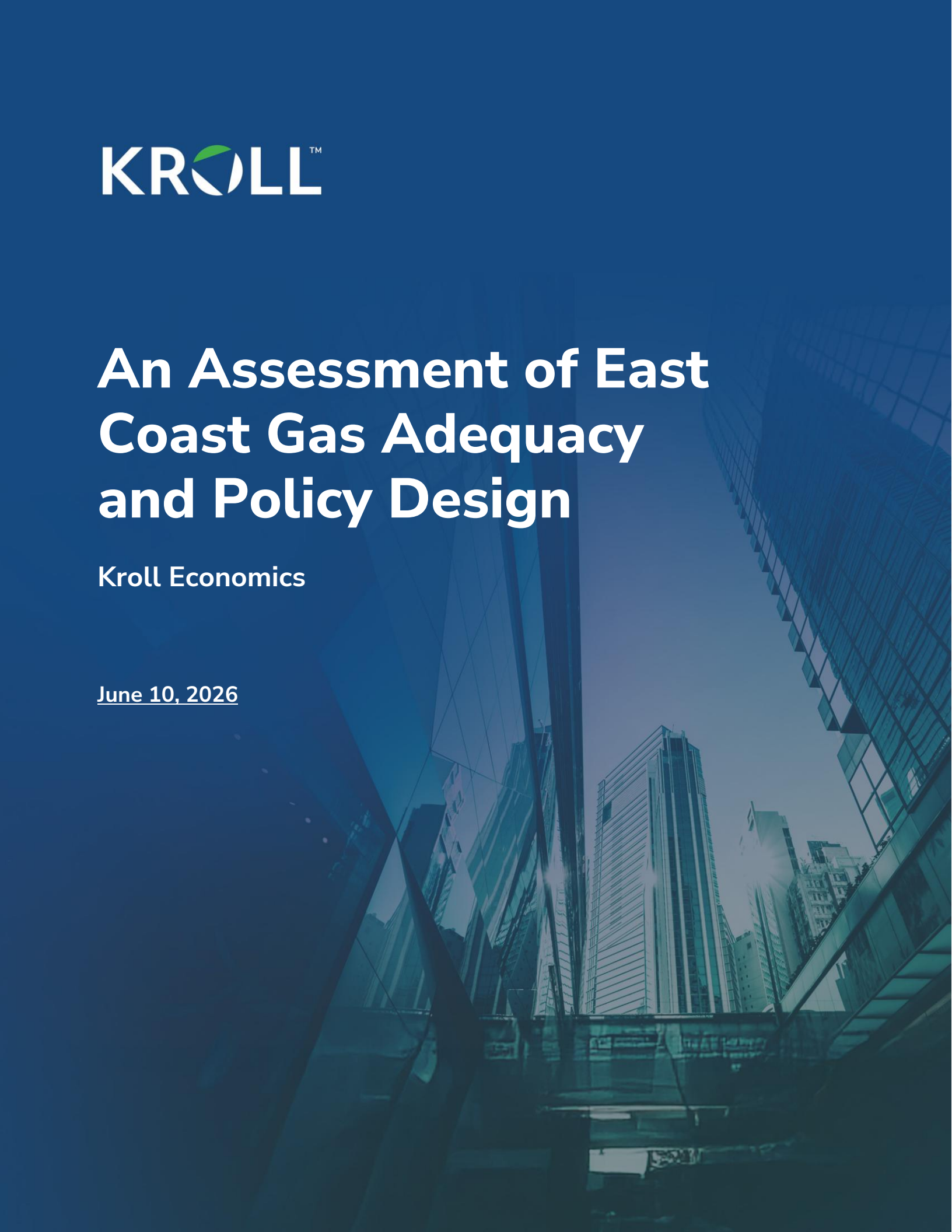
# An Assessment of East Coast Gas Adequacy and Policy Design

Kroll Economics

June 10, 2026



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**Transmittal of Kroll Report: An assessment of east coast gas adequacy and policy design**

Kroll Australia Pty Ltd ("**Kroll**") was engaged by Beach Energy Limited ("**Client**") to prepare the enclosed report titled **An assessment of east coast gas adequacy and policy design** dated 10 June 2026 ("**Report**") in accordance with the agreement between Kroll and the Client dated 20 May 2026 ("**Agreement**").

The Report was prepared based on, and is subject to, the assumptions, qualifications and limitations set out in it. This Report should be read in its entirety, including this transmittal letter, as well as those assumptions, qualifications and limitations.

No further work has been undertaken by Kroll since the date of the Report and Kroll is under no obligation to update this Report following that date to take account of events or circumstances arising after that date.

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# Executive Summary

The Commonwealth Government has announced a standing export-linked domestic supply obligation requiring entities intending to export LNG to supply the domestic market with a volume of gas equivalent to 20 per cent of their LNG exports on an annual basis, with obligations intended to commence from 1 July 2027. The scheme is intended to supersede the Australian Domestic Gas Security Mechanism and Heads of Agreement while enabling further reform to the Gas Market Code.

While the Government has clearly signalled its direction, the proposed mechanism remains subject to consultation and detailed design. The draft design framework provides greater clarity on the proposed export approval process, domestic supply obligation, compliance pathways and flexibility mechanisms, including the treatment of existing contracts, infrastructure constraints, annual DSO variation and the release of surplus DSO volumes. These features are important, but they also confirm that the practical operation of the scheme will depend on project-specific assessments, administrative judgement and how physical delivery constraints are managed.

This report, prepared by Kroll Economics at the request of Beach Energy, is aimed squarely at the consultation process. It assesses whether the proposed scheme is proportionate, workable and well calibrated to the market problem it is intended to solve, and where its design could be refined to better align with the underlying evidence.

## The diagnosis

The east coast gas market is not currently in broad structural annual shortage. The official evidence, drawn from AEMO's 2026 Gas Statement of Opportunities, the Victorian Gas Planning Report Update, the ACCC's reporting and the Government's own ADGSM decisions, points consistently to conditional near-term adequacy, not to a market in crisis or structural failure.

Three findings are central to this assessment.

First, the near-term market is conditionally adequate. AEMO's 2026 GSOO reports improved adequacy conditions through to 2029, with stronger peak-day supply capability, new infrastructure investment and lower consumption forecasts. The forecast year of first annual shortfall has been deferred consistently in GSOO vintage since 2019, from 2024 to 2030. That pattern does not eliminate longer-term risk, but it does underscore the danger of imposing standing obligations on the basis of long-range forecasts that may not materialise.

Second, the residual risk is not primarily volumetric. It is seasonal, regional and operational, concentrated in the southern system and most acute under winter peak-day conditions. Adequacy depends not on aggregate annual reserves, but on whether firm gas can be delivered into the southern system on the coldest winter days, when residential heating, industrial load and gas-powered generation coincide. That is a deliverability problem, not a shortage problem.

Third, the east coast does not face geological scarcity. Sufficient reserves and resources exist to meet projected domestic demand for at least the next decade. The challenge is converting those resources into timely, firm and accessible supply, a problem of investment timing, approvals, infrastructure and contracting, particularly in the southern basins where legacy production is declining fastest.

## Positioning the proposed obligation

The proposed standing export-linked domestic supply obligation represents the upper end of the intervention spectrum available to Government. It is, in effect, the most direct mechanism available to influence the allocation of gas between export and domestic markets.

There is therefore a clear logic in the Government seeking to develop such an instrument and have it available should circumstances warrant its use. The question is not whether such a tool should exist in the policy toolkit. The question is whether its design and application are proportionate to the conditions in which it would be used.

Precisely because the mechanism sits at this end of the intervention spectrum, its design should reflect that positioning. In our view, such an instrument is more appropriately framed as a tool that can be deployed, scaled or intensified in response to clearly identified market conditions, rather than as the default feature of the market architecture.

The current proposal incorporates elements of flexibility, particularly in how obligations may be met, the treatment of existing contractual arrangements, the ability to vary obligations and the possible release of surplus DSO volumes. However, the degree of flexibility does not yet fully align with the scale and potential impact of the intervention itself.

A more proportionate approach would retain the Government's ability to escalate to this level of intervention where necessary, but within a framework that is more explicitly linked to market conditions and capable of scaling in response to observable system stress.

## Why a standing reservation obligation is poorly matched to this problem

A standing export-linked domestic supply obligation starts from an annual volume requirement. That design may be justified where the problem is persistent aggregate scarcity or systematic diversion of gas away from domestic users. It is less well matched to a problem that is conditional, seasonal, regional and dependent on physical deliverability.

The structural heterogeneity of the east coast LNG export sector compounds this concern. The three LNG export projects occupy materially different upstream gas positions. One has substantial surplus and discretionary export capacity. One has a narrower margin. One is structurally short of gas and has limited practical capacity to contribute additional physical supply to the domestic market from its own portfolio. A uniform 20 per cent headline rate therefore does not translate into a uniform practical obligation.

The timing of the announced obligation adds a further concern. The scheme would commence at a point in the investment cycle when the market most needs commercial certainty to progress new southern supply, storage and transport investment. A standing obligation that lowers expected domestic prices through displacement of marginal southern production risks weakening the very investment conditions on which future adequacy depends. This risk applies not only to new projects, but also to sustaining capital decisions for existing assets, where continued expenditure is required to maintain deliverability, manage decline and support ongoing production.

## Implementation risks

While the proposed framework is conceptually straightforward, its practical implementation is likely to require a range of exceptions, carve-outs and judgement-based decisions, including in relation to legacy contractual arrangements, project-specific constraints, compliance pathways, infrastructure limitations and the release of surplus DSO volumes.

Experience in similar policy settings suggests that the accumulation of such provisions can materially increase complexity and uncertainty. This can, in turn, complicate contracting, reduce transparency in market outcomes and weaken investment signals at a time when new supply and infrastructure are most needed.

These implementation risks are not peripheral to the design; they are central to how the mechanism would operate in practice. The draft design framework's flexibility mechanisms may improve workability, but they also reinforce the need for transparent, evidence-led criteria governing when obligations apply, when they vary and when stronger intervention is warranted.

## What the modelling shows

This report presents purpose-built partial equilibrium modelling of the east coast gas market, linked to Kroll's global computable general equilibrium model (KGEM), to quantify the economic consequences of the proposed reservation.

The modelling shows that reservation can reduce domestic wholesale gas prices in the short term. However, it does so by reallocating gas rather than by creating new deliverable supply. Additional exporter gas enters the domestic market, lowers the market-clearing price and displaces marginal domestic production, including southern production that has particular value for winter deliverability. The initial price reduction is therefore a displacement effect: domestic users pay less, but exporters receive less for diverted gas and marginal domestic producers lose production and margin.

The partial modelling estimates annual welfare losses are approximately **$1.5 billion** under a 15 per cent effective reservation and **$2.9 billion** under a 20 per cent reservation. These costs arise from foregone export revenue, lost producer surplus and additional transport and infrastructure inefficiencies. They scale more than proportionately with the size of the obligation. These welfare costs should be weighed against a price benefit that is strongest in the first modelling year and may narrow over time if the policy weakens investment in firm, deliverable southern supply.

The economy-wide, CGE modelling reinforces this result. By 2030, the reservation is estimated to reduce Australian real GDP by approximately **$350 million** under a 15 per cent reservation and **$653 million** under a 20 per cent reservation, with Queensland absorbing the largest share of the impact through reduced LNG export activity.

An indicative peak-day stress test illustrates a further concern. If annual production displacement translates proportionately into reduced peak-day capability, the southern system's baseline peak-day surplus could shift to a material deficit under a 20 per cent reservation. A policy designed around annual domestic volume does not automatically increase firm peak-day capability. If it displaces local southern production, it can make the operational reliability problem worse rather than better.

## A proportionate alternative

The evidence does not support policy absence. It supports better-targeted intervention. This report proposes a policy architecture centred on three interlocking elements:

**Enhanced AEMO market intelligence.** A more granular, forward-looking gas market assessment, including named project-level supply tracking, infrastructure investment visibility, explicit modelling of major government decision impacts and a dedicated southern system adequacy view, updated regularly and published transparently.

**A Gas Market Impact Assessment process.** Major government decisions with material gas market consequences, including extensions of coal-fired generation, refusals of gas development approvals and significant new demand commitments, should be subject to a structured, published assessment of their gas market implications before and after they are made.

**A standing southern system adequacy assessment with a graduated response pathway.** A forward-looking assessment of southern system adequacy, maintained as a standing function, with a graduated escalation pathway: from market signal reinforcement, through targeted infrastructure and storage support, to export sequencing and, only where demonstrably required, time-limited or scaled domestic supply obligations. The key discipline is that more interventionist responses do not precede or bypass the earlier steps.

This architecture is better calibrated to the problem the evidence identifies. It preserves investment incentives, reduces the likelihood of false positives, reserves the most intrusive tools for circumstances in which they are demonstrably required, and aligns with the way the east coast gas market actually functions.

## Conclusion

The east coast gas market does not face an immediate, systemwide annual shortage that justifies a permanent, standing reservation obligation. It faces a conditional, southern-focused and operationally specific challenge that calls for precision, discipline and proportionality in policy design.

A standing export-linked domestic supply obligation is a high-impact policy instrument. The Government is right to consider it as part of the policy toolkit. However, its design and application should reflect its position at the upper end of the intervention spectrum.

If market conditions were to require sustained use of such an instrument, this would likely reflect a system under significant stress. In those circumstances, broader supply, infrastructure and investment constraints would remain the binding challenge.

Accordingly, the case is not to rule out this form of intervention, but to ensure it is appropriately framed, conditionally applied and supported by a policy architecture that is better aligned with the nature of the problem it is intended to solve. The consultation process should therefore be used to refine the proposed scheme in that direction: retaining the Government's ability to intervene strongly if circumstances warrant it, while embedding that intervention within a transparent, evidence-led and graduated architecture

SECTION 01

# Policy Context and Reform Task

## Purpose of this section

This section sets out the policy context, reform task and current evidence base that frame the analysis in this report. It describes the Commonwealth Government's proposed standing export-linked domestic supply obligation, outlines its stated objectives, and summarises the key elements of the draft design framework now under consultation.

It also explains how the current reform process has emerged. This includes the structural changes associated with LNG export development, the emergency and transitional interventions introduced in response to the 2022 global energy shock, and the limitations of the existing framework that led to the 2025 Gas Market Review.

Finally, the section sets out how current market conditions are being understood in official assessments, and why that matters for policy design. The purpose is to establish the analytical starting point for the report: what problem the policy is intended to address, how that problem is currently framed in the evidence, and whether the proposed approach should be assessed against a broad annual supply challenge or a more specific set of adequacy and deliverability risks.

## Current policy context and reform task

Following the 2025 Gas Market Review, the Commonwealth Government identified the need for a more enduring regulatory framework to support the operation and development of Australia's gas markets. The Review concluded that existing east coast gas market instruments were not sufficient to guarantee domestic supply, provide long-term investment certainty, or maintain downward pressure on prices in a tightly supplied market. The Commonwealth Government has framed its reform objectives around domestic energy security and affordability, while also emphasising investment certainty, respect for existing contracts and Australia's position as a reliable LNG exporter (DCCEEW 2026a; DCCEEW and DISR 2025).

At the centre of the reform package is a standing export-linked domestic supply obligation, proposed to commence on 1 July 2027. Under the announced design, entities intending to export LNG would be required to supply the domestic market with volumes equivalent to 20 per cent of their LNG exports on an annual basis. The measure was also referenced in the 2026–27 Federal Budget as part of the Government's broader fuel supply and energy resilience agenda (DCCEEW 2026a; Bowen, King and Ayres 2026; Australian Government 2026).

The Government has now released a draft design framework for consultation. This confirms the broad architecture of the proposed scheme, including an export approval process, an annual domestic supply obligation, the role of the Australian Energy Regulator in administration, monitoring and enforcement, and proposed flexibility mechanisms relating to existing contracts, infrastructure constraints, annual DSO variation and the release of surplus DSO volumes. It also confirms that feedback on the draft design framework is being sought before final policy settings are settled through legislation (DCCEEW and DISR 2026a; DCCEEW and DISR 2026b).

However, the scheme is not yet a fully specified regulatory regime. Important design questions remain, including the precise legislative mechanism, the treatment of existing and future contracts, the allocation of obligations across LNG exporters, compliance pathways, transition arrangements, interaction with state and territory gas policies, how physical delivery constraints will be managed, and the conditions under which flexibility mechanisms may operate (DCCEEW and DISR 2026a; DCCEEW and DISR 2026b).

This reform also needs to be understood in the context of the broader policy framework. Official Budget material states that the standing export-linked domestic supply obligation is expected to supersede the Australian Domestic Gas Security Mechanism and the Heads of Agreement, while enabling further reform to the Gas Market Code (Australian Government 2026; DCCEEW 2026a). The existing framework reflects a sequence of emergency and transitional interventions introduced in response to the 2022 global energy shock, and has resulted in a layered and, in some respects, internally inconsistent regulatory structure (DCCEEW and DISR 2025).

The introduction of a standing export-linked obligation therefore represents a shift from this emergency and transitional phase to a more durable, structural framework. While such a shift has the potential to provide clearer long-term investment signals, it also raises a central question of calibration. A standing scheme may improve certainty, but it may also embed a more continuous and rigid form of intervention than the underlying adequacy problem requires, depending on how it is ultimately designed and applied.

## Historical context to policy development

### Structural change: LNG exports and international linkage

The first major shift in the modern east coast gas market was the development of large-scale LNG export capacity in Queensland. In its 2016 east coast gas inquiry, the Australian Competition and Consumer Commission (ACCC 2016) concluded that the LNG projects "triggered significant structural changes" in the market, disrupting the prior supply–demand balance and exposing domestic gas outcomes more directly to international oil and LNG price signals.

The practical implication is that domestic outcomes are shaped not only by local supply and demand, but also by export optionality, contract structures and global price conditions. In this setting, producers may rationally seek to sell uncontracted gas into international markets where global prices exceed domestic returns. That does not, of itself, establish a market failure. It does, however, mean that any policy intervention operates in an export-linked, internationally exposed market rather than a closed national system.

That distinction is central to the current reform task. A standing export-linked domestic supply obligation is intended to alter the allocation of gas between export and domestic markets. Its effect will therefore depend not only on the headline reservation percentage, but also on how the obligation interacts with existing export contracts, prospective contracts, spot and uncontracted volumes, domestic contracting incentives and physical delivery constraints. The Government has announced a scheme requiring LNG exporters to supply the domestic market with a volume of gas equivalent to 20 per cent of LNG exports annually, but final legislative design and implementation details remain subject to further consultation (DCCEEW 2026a; Australian Government 2026; King 2026).

### Crisis shock: the 2022 global energy shock and emergency intervention

The second major catalyst for reform was the 2022 increase in local and global energy prices due to coal-fired powerplant outages coinciding with winter the months (which increased demand for gas fired generation) and Russia's invasion of Ukraine (RBA, 2022). In December 2022, the Commonwealth Government announced a package of emergency measures intended to limit the worst impacts of those pressures (Ministers for the Department of Industry, Science and Resources 2022).

That package included a 12-month emergency price cap on new domestic wholesale gas contracts by east coast producers, the introduction of a mandatory code of conduct for the gas market, and the fast-tracking of reform to the Australian Domestic Gas Security Mechanism (ADGSM), with the Commonwealth Government indicating that the cap was intended to be set at $12/GJ following a short period of consultation. The Commonwealth Government framed those measures as targeted intervention to protect households, industry and manufacturers, while supporting a more stable and well-functioning domestic gas market (Ministers for the Department of Industry, Science and Resources 2022).

The Gas Market Review Report describes those measures as part of a broader set of necessary responses to "market failures or emergency crises", including the extreme volatility associated with the 2022 global energy crisis. It also records that the Commonwealth Government strengthened the Heads of Agreement, reformed the ADGSM so that it could operate quarterly rather than only annually, and used the Gas Market Code to secure enforceable domestic supply commitments from producers. In that sense, the 2022–23 period is best seen as an emergency and transitional policy phase rather than the product of a settled long-run design framework (DCCEEW and DISR 2025).

This history is important because it explains why the current regulatory architecture is layered, reactive and in some respects internally inconsistent. The current reform process is not occurring in a vacuum. It is occurring because the Commonwealth Government now recognises that a framework assembled under crisis conditions is not necessarily fit for purpose as a durable long-run regime. The Gas Market Review concluded that, while the existing measures had been effective in responding to forecast shortfalls and near-term objectives, they were not sufficient to address the longer-term structural challenges facing Australian gas markets and that fundamental reform was needed (DCCEEW and DISR 2025).

The announced standing export-linked domestic supply obligation is therefore best understood as the Commonwealth Government's proposed shift from emergency and transitional intervention to a standing structural framework. Official Budget material states that the standing export-linked domestic supply obligation is expected to supersede the ADGSM and Heads of Agreement, while enabling further reform to the Gas Market Code (Australian Government 2026). The draft design framework confirms that this shift is intended to be implemented through a new export approval framework, an annual domestic supply obligation, AER administration and monitoring, and associated amendments to the Gas Market Code (DCCEEW and DISR 2026a). This makes the calibration of the new framework particularly important. A standing scheme may provide clearer long-term rules than the existing patchwork, but it also risks embedding intervention more permanently into market expectations if the obligation is broader, more rigid or more continuously binding than the underlying adequacy problem requires.

## The current official state of the market

Policy development is shaped not only by market conditions, but by how those conditions are understood at the time.

In the east coast gas market, perceptions of imminent shortage have become an important feature of the policy environment. Those perceptions have influenced public debate and sit in the background of the Commonwealth Government's 2025 review of gas market regulations and related instruments. They now also frame the announced standing export-linked domestic supply obligation and the draft design framework released for consultation, which present the proposed scheme as a mechanism to improve domestic supply security, place downward pressure on prices and reduce exposure to international gas market volatility (DCCEEW 2026a; DCCEEW and DISR 2026a).

That matters because the form of intervention should be calibrated to the problem identified by the evidence. If the official evidence points to a broad and persistent annual supply shortage across the east coast market, that may support one type of policy response. If, instead, the evidence points to more specific risks around timing, location, winter peak demand, storage adequacy, infrastructure constraints and the behaviour of LNG exporters with uncontracted gas, that points to a different design problem.

The distinction is important for assessing the announced 20 per cent export-linked domestic supply obligation. A standing reservation obligation may increase domestic availability in aggregate, but it may not be the most direct or proportionate instrument if the binding risk is concentrated in particular periods, locations or delivery pathways. Conversely, where export incentives are contributing to domestic adequacy risks, the policy question is how to design any obligation so that it addresses those risks without unnecessarily weakening incentives for new production, storage and transport investment.

## The official evidence base, read chronologically

The official record over the past year points to a more qualified position than a simple shortage narrative suggests. Table 1 steps through four key documents: the DISR Q4 2025 gas supply decision, the AEMO Victorian Gas Planning Report Update, the AEMO 2026 Gas Statement of Opportunities and the ACCC March 2026 interim report.

The official short-term outlook changed materially in 2026 relative to the position reflected in the 2025 planning material. The 2025 GSOO identified risks of peak-day shortfalls in the southern states from 2028 and annual supply gaps from 2029. Those forecasts reflected declining southern production and the need for additional supply, storage and transport investment to maintain adequacy.

AEMO's 2026 GSOO presents a less acute near-term picture. AEMO reports improved near-term supply conditions, with risks of extreme peak-day shortfalls in southern Australia now expected to emerge one year later than previously forecast and new investment required from 2030 onwards. AEMO attributes this improvement to increased peak-day gas supply, new infrastructure investment and reduced consumption forecasts, while also emphasising that timely delivery of committed and anticipated production, storage and pipeline projects remains important. AEMO also notes that gas production from legacy fields in the southern states is forecast to decline materially over the next five years, reinforcing that the medium-term adequacy challenge has not disappeared (AEMO 2026a).

The ACCC points to a tighter and more immediate winter risk (ACCC 2026a, ACCC 2026c). The ACCC's focus is on Q3 2026, including the role of gas storage, LNG producer export decisions and domestic contracting conditions. In particular, the ACCC indicates that east coast supply-demand balance in Q3 2026 could range from a shortfall to a small surplus depending on LNG producer behaviour, and that the southern states face a material July 2026 supply gap requiring storage support (ACCC 2026a).

Read together, these official assessments do not support a simple characterisation of the east coast market as either adequately supplied or structurally short in all periods. They point instead to a more specific and dynamic problem: near-term conditions have improved relative to earlier forecasts, but the market remains exposed to southern winter deliverability risks, declining southern production, storage dependence, infrastructure constraints, contracting behaviour and the availability of timely new investment.

That is the relevant evidentiary context for assessing the announced standing export-linked domestic supply obligation and the draft design framework now released for consultation. The policy design question is not only

whether additional domestic gas should be made available, but whether a standing 20 per cent export-linked obligation, even with the flexibility mechanisms proposed in the draft framework, is the best calibrated instrument for the particular risks identified in the official evidence base (DCCEEW and DISR 2026a).

*Table 1: Chronology of official assessments of east coast gas market conditions, July 2025 to March 2026*

| | DISR Q4 2025 gas supply decision (1 July 2025) | AEMO Victorian Gas Planning Report Update (March 2026) | AEMO GSOO (March 2026) | ACCC interim report (March 2026) |
|---|---|---|---|---|
| **Key themes** | The Commonwealth Government judged that domestic demand could be met without reducing exports in Q4 2025, drawing on the ACCC, AEMO and the availability of mitigants such as storage and operational powers. | Victoria remains adequate but tight over the five-year outlook. Supply is expected to exceed 1-in-2 and 1-in-20 year demand, but Victoria is projected to become a net importer from 2029 as production declines. | The east coast outlook has improved in the near term relative to 2025, with stronger adequacy to 2029, but declining southern production means new investment is still required from 2030. | A tight east coast gas supply–demand outlook for winter 2026, heavy reliance on storage (particularly Iona) and LNG producer behaviour, rising but stabilised domestic contract prices, and the ACCC's decision to retain the LNG netback price series as a transparency tool amid prospective gas market reforms. |
| **Risks emphasised** | Risks are acknowledged, but treated as manageable through mitigants: uncontracted LNG gas, storage drawdown and AEMO's emergency response powers. | The key risk is increasingly operational and locational: supply into the Victorian DTS remains tight, support from Culcairn and Dandenong LNG is likely to be required on peak days, and unexpected conditions could still produce shortfalls. | The key remaining risk is increasingly southern winter peak-day adequacy rather than immediate broad annual scarcity. AEMO also stresses reliance on timely delivery of committed and anticipated production, stora ge and pipeline projects. | The ACCC highlights material risks of winter shortfalls, driven by low surplus supply, limited responsiveness to shocks once storage is drawn down, uncertainty around LNG export decisions following the expiry of the HoA, and congestion or timing risks in storage and pipeline utilisation. |
| **Near-term adequacy signal / first stress marker** | Q4 2025 ADGSM not activated. Government states the east coast market will have enough supply for the quarter and that domestic demand can be met without reducing exports. | 2026–30: expected supply exceeds both 1-in-2 and 1-in-20 year system demand across the five-year outlook; Victoria becomes a net importer from 2029. | Peak-day stress from 2029; new investment required from 2030 under most weather conditions. | The first clear adequacy stress signal is July 2026, when southern states face a projected 16 PJ monthly supply gap that would require large, timely withdrawals from Iona storage, leaving little margin to absorb unexpected demand spikes or supply disruptions. |

*Sources: ACCC 2026a, DISR 2025c, AEMO GSOO 2026a, AEMO 2026b.*

## Key policy design considerations

As this paper moves on to consider policy and market design issues, the starting point is no longer whether the Commonwealth Government intends to intervene in the east coast gas market through a standing export-linked domestic supply obligation. The Government has now released a draft design framework that sets out the proposed architecture of that obligation, including an export approval process, annual compliance plans, AER administration and monitoring, and mechanisms for varying or releasing DSO volumes in defined circumstances (DCCEEW and DISR 2026a; DCCEEW and DISR 2026b). The relevant question is therefore whether the proposed instrument is proportionate, workable and well calibrated to the market problem it is intended to solve.

That question matters because the official evidence does not point to a single, undifferentiated shortage problem. It points to a more complex set of adequacy and deliverability risks, including southern winter peak-day pressures, declining southern production, storage dependence, infrastructure constraints, domestic contracting conditions and the behaviour of LNG exporters with access to export markets. A standing export-linked obligation may increase domestic availability in aggregate, but its effectiveness will depend on whether the obligation addresses the timing, location and deliverability dimensions of the problem.

Proportionality is therefore the key discipline. In this context, proportionality means ensuring that the scale, intensity and duration of intervention are no greater than necessary to address the specific problem the policy is intended to solve. Where policy measures are not proportionate to the problem they seek to address, they risk generating unintended consequences that undermine investment incentives and market functioning.

This is particularly important because the proposed obligation sits at the upper end of the intervention spectrum available to Government. It directly links LNG export approval to domestic supply obligations and is intended to become part of the enduring regulatory architecture of the gas market. That does not mean such a tool should be ruled out. It does mean that its use should be closely aligned with observable market conditions and the severity of the adequacy or deliverability risk it is intended to address.

The draft design framework recognises this issue to some extent by including flexibility mechanisms. These include the ability to vary an individual DSO to account for existing contracts, infrastructure constraints or other relevant matters; annual DSO variation to manage expected domestic demand plus a buffer; and a release valve mechanism for surplus DSO volumes where domestic market conditions are assessed as well supplied and specified conditions are met (DCCEEW and DISR 2026a; DCCEEW and DISR 2026b). These features are important because they acknowledge that a uniform headline obligation may not operate uniformly in practice.

However, the existence of flexibility mechanisms does not remove the core calibration question. It reinforces it. A framework that requires variations, exceptions, carve-outs and judgement-based decisions may be more workable than a rigid obligation, but it may also increase complexity and uncertainty. The practical operation of the scheme will depend on how Ministers, the AER and AEMO assess compliance plans, existing contracts, infrastructure constraints, market liquidity, surplus volumes and supply adequacy over time. These matters will determine how the obligation operates in practice, which market participants bear the obligation, whether domestic gas is available when and where it is needed, and whether the scheme supports or discourages new investment.

The risk of unintended consequences therefore remains central to the design problem. A standing obligation may bind even when the relevant adequacy or deliverability stress is not present. In a sector characterised by long lead times, high capital intensity and heavy reliance on future contracting conditions, a rule that binds more

often, more broadly or more rigidly than necessary can do more than alter short-run price outcomes. It can weaken incentives to commit capital to the new supply, storage and infrastructure the market may later depend on.

This also points to the importance of assessing major government decisions, including in adjacent markets such as electricity, for their gas market implications before and after they are made. Gas market adequacy is increasingly shaped by interactions between gas production, storage, pipelines, LNG export behaviour, electrification, renewable generation, coal retirement and gas-fired power demand. A durable gas market framework therefore needs not only a mechanism for intervention, but also a disciplined process for testing whether policy decisions across the energy system are increasing or reducing future gas market risks.

## Structure of this report

This report starts with the Commonwealth Government's stated objectives and asks a practical design question: what form of intervention is best aligned with the problem the Commonwealth Government is seeking to solve?

- **Section 2** examines how the east coast gas market functions to determine whether the main challenge is aggregate supply, physical deliverability, timing, or a combination of these.
- **Section 3** considers how the problem should properly be framed, including the distinction between gas resources in aggregate and gas that can be brought to market when and where it is needed.
- **Section 4** reviews the available evidence. It draws on planning assessments, price data, and commercial market signals. The section assesses whether this evidence indicates a broad annual shortage or points to a more nuanced situation.
- **Section 5** turns to the areas in which adequacy risks appear most likely to emerge, particularly in the southern system, and what that may imply for the kinds of mechanisms or responses that may be most relevant.
- **Section 6** examines the design complexity and calibration problem, including whether the east coast gas market has experienced a market failure that justifies permanent intervention, how the proposed draft design framework would operate, and whether its flexibility mechanisms are sufficient to align the scheme with the risks identified in the evidence.
- **Section 7** quantifies the economic costs of applying a standing reservation mandate through a purpose-built partial equilibrium model and a whole of economy Computable General Equilibrium (CGE) model.
- **Section 8** sets out a proportionate policy architecture, built on enhanced market intelligence, a recommended Gas Market Impact Assessment process, and a standing southern system adequacy assessment with a graduated response pathway, and explains why this architecture is better calibrated to the problem the evidence identifies.

Much of this report refers to the southern states, which includes New South Wales, South Australia, Victoria and Tasmania. References to the east coast include all southern states plus Queensland and the Northern Territory, excluding Northern Territory LNG.

SECTION 02

# East Coast Market Characteristics and the Southern System

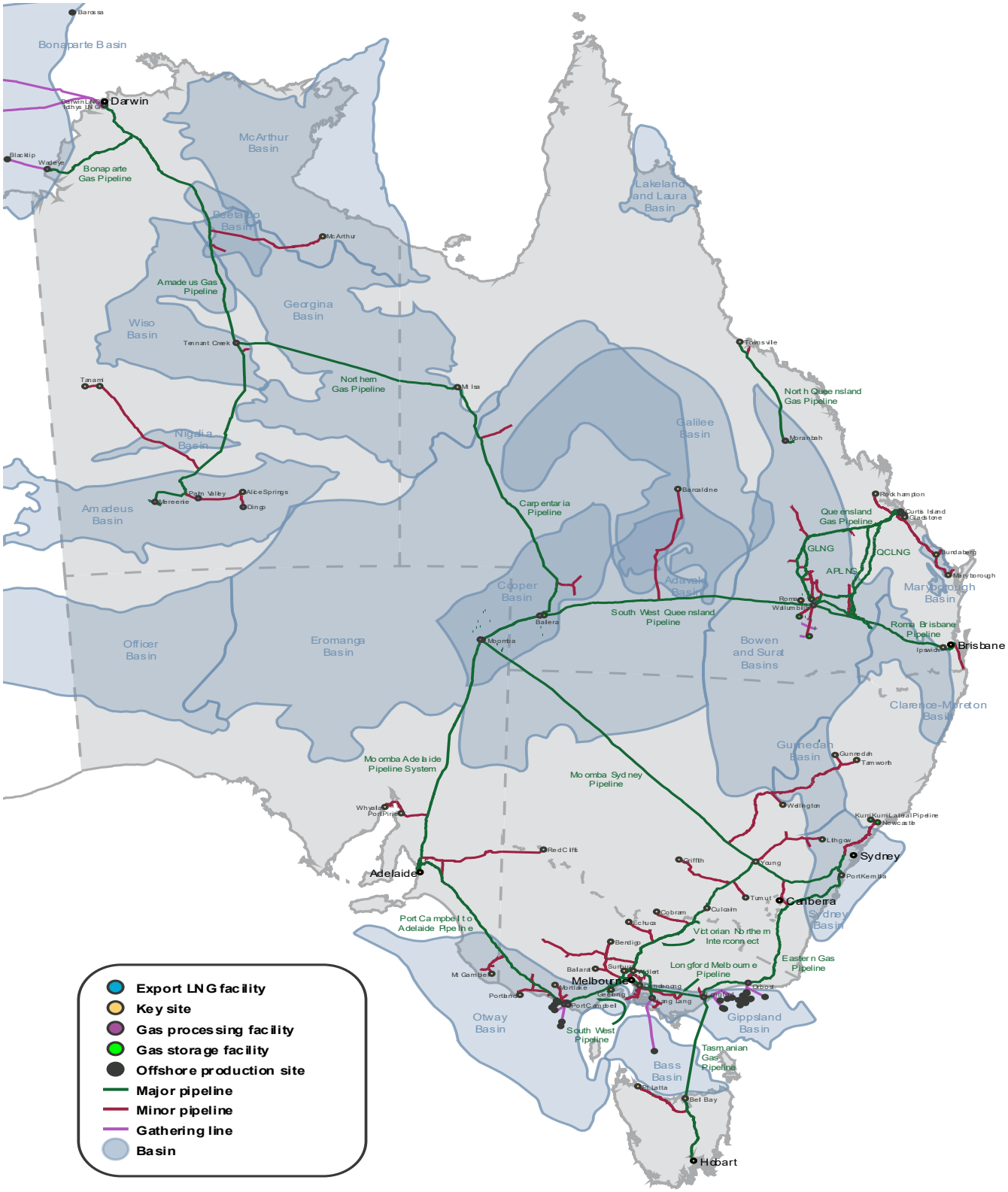
## Purpose of this section

The east coast gas market has transformed over the last decade and is now characterised by the export-linked production in the north, local demand centres in the south, transport, storage and winter peak demand. The geographic span and interconnected nature of these features are illustrated in Figure 1, which maps the east coast gas market and its major system components.

This section focuses on the market characteristics that matter most for assessing whether the announced standing export-linked domestic supply obligation, now elaborated through the draft design framework, is proportionate and well calibrated. It explains how the east coast market differs from a more isolated domestic market, why the southern system has become the operational centre of gravity for adequacy risk, why transport and storage are part of the adequacy question rather than peripheral infrastructure details, and why price is an important diagnostic but not a sufficient trigger on its own.

Recent market analysis indicates that north–south price differentials are relatively limited in the near term and become more pronounced only in later years, where they are broadly consistent with transportation costs. This suggests that emerging regional price differences are better understood as evidence of increasing dependence on transport from Queensland to southern markets, rather than as a fundamental difference in upstream resource availability. That distinction is central to policy design: if the emerging problem is one of deliverability, infrastructure and timing, a policy focused only on aggregate annual domestic volume may be poorly targeted.

*Figure 1: Map of the East Coast gas market*




*Source: AEMO GSOO 2026a.*

## The nature of the east coast gas market

The east coast gas market is no longer a self-contained domestic system. Two structural changes explain why. The first was the development of the Queensland LNG export industry, which linked domestic outcomes more directly to international LNG and oil-linked pricing. The second was the evolution of the eastern Australian pipeline system into a more interconnected network through which gas can move across regions in response to changing demand and price signals (ACCC 2016; AEMC 2016).

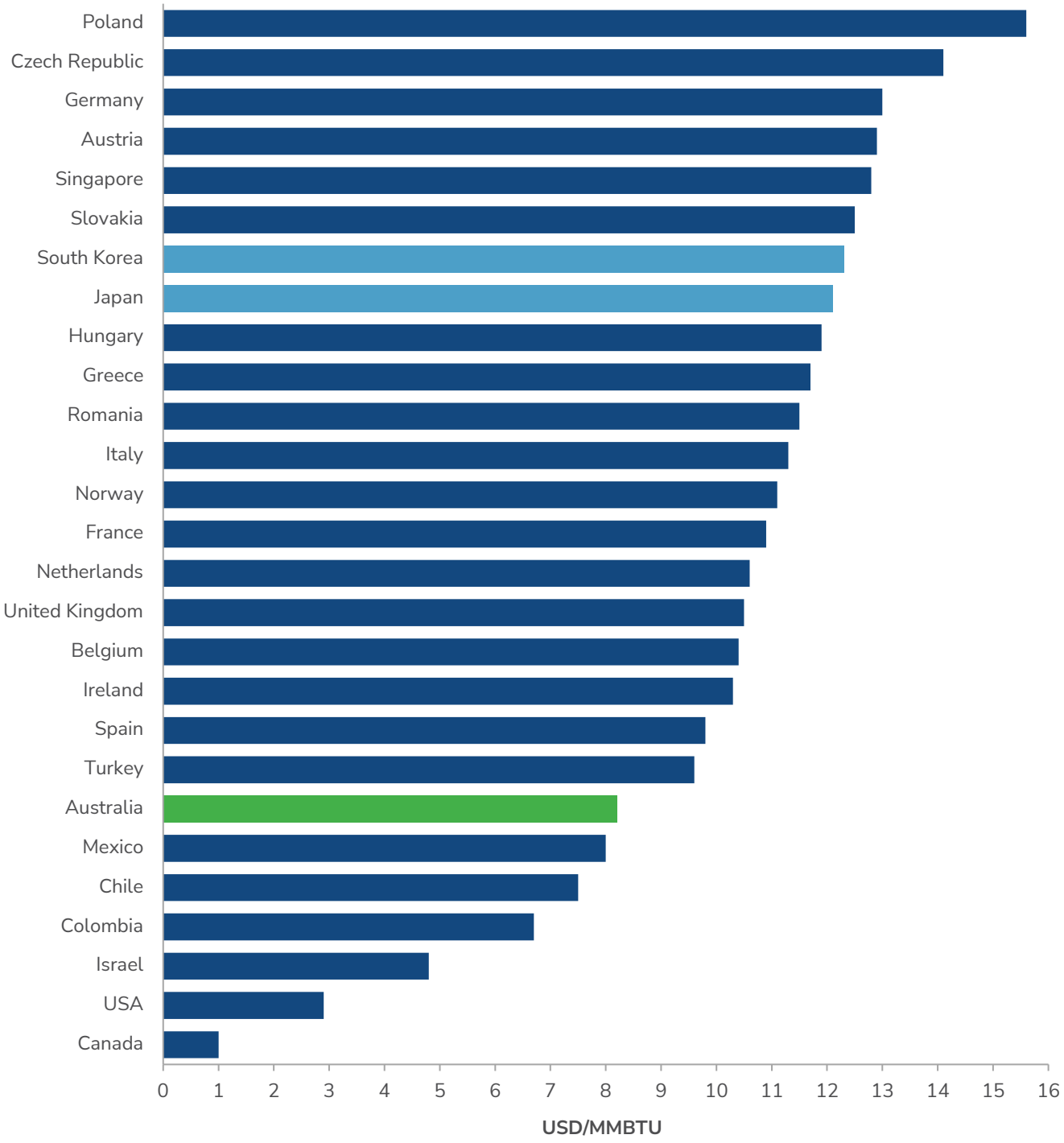
Those changes were identified clearly in the foundational market reviews. The ACCC concluded in 2016 that LNG developments had triggered significant structural changes in the east coast market, disrupted the previous supply and demand balance, and exposed domestic users more directly to international pricing conditions (ACCC 2016; AEMC 2016).

The Commonwealth's 2025 Gas Market Review adopts the same framing. It states that domestic and international gas markets have become linked, notes that the east coast market spans multiple jurisdictions, and highlights the absence of any nationally consistent producer obligation to ensure domestic users have access to sufficient gas at more affordable prices (DCCEEW and DISR 2025; DCCEEW 2026a).

At the same time, international comparisons indicate that Australian wholesale gas prices remain competitive. Figure 2 shows that when compared across a selection of OECD countries, Australian prices are among the lower tier, ranked seventh lowest in 2024 and materially below prices in many European markets. This suggests that while international linkages have some impact on price formation, domestic prices have not simply converged to the average global benchmarks. Export exposure has increased volatility and sensitivity, but it has not eliminated regional price differentiation.

The policy implication is that price outcomes alone are an incomplete description of market performance in an export-linked and interconnected system. The central issue is not simply whether enough gas exists in aggregate, but whether gas can be delivered to where it is needed, when it is needed, and on terms compatible with both system adequacy and investable commercial conditions. Those outcomes are shaped as much by transport capacity, storage availability, timing and regional configuration as by headline price levels, making these factors intrinsic features of the market rather than secondary constraints.

*Figure 2: Annual average wholesale gas prices across a selection of OECD nations, 2024 (USD/MMBTU)*




*Source: IGU Wholesale Gas Price Survey 2025.*

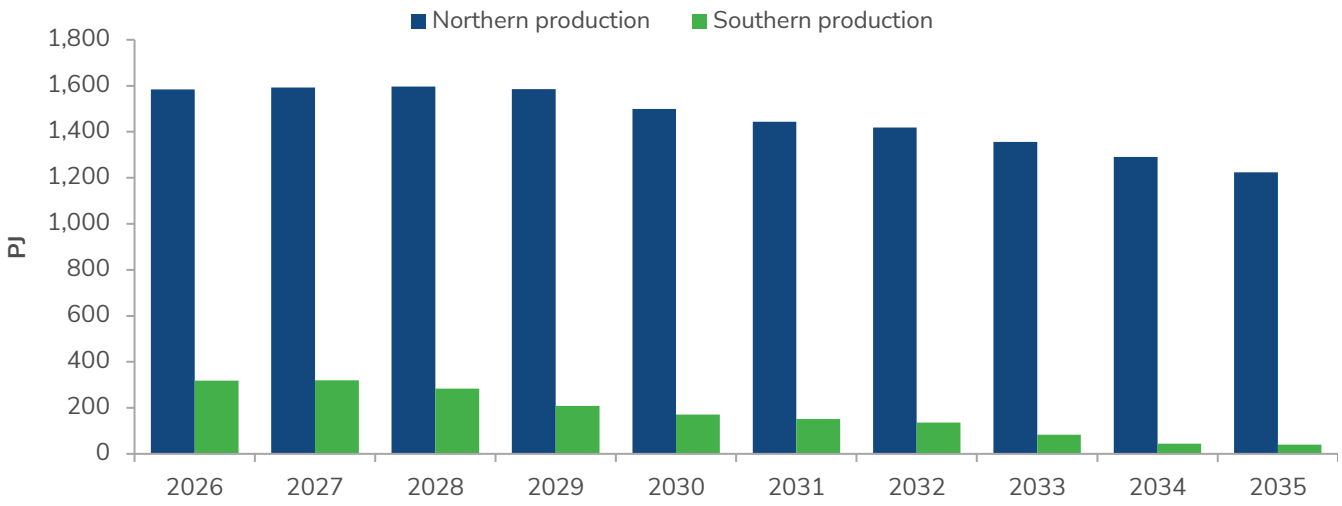
## The southern system is where risk often binds

The official outlook points consistently to the south as to where system risk is most prominent. The 2026 Gas Statement of Opportunities as produced annually by AEMO indicated improved extreme peak-day shortfall risk in southern Australia from 2029 and new investment needs from 2030 onwards (AEMO 2025; AEMO 2026a).

Australia is not running out of gas in aggregate. The issue is that legacy southern production is declining (Figure 3) while winter demand and gas-powered generation can still create periods of intense local stress (Figure 4). In that setting, adequacy depends not only on reserves and production somewhere on the east coast, but on whether the southern system can successfully increase supply and draw sufficiently on northern inflows, storage and backstop facilities when those peak conditions arise (AEMO 2026a; AEMO 2026b).

Further, Victorian production is forecast to decline sharply over the outlook period, and Victoria is projected to become a net importer of gas from 2029 as local consumption exceeds local production. Effective maximum daily supply into the Victorian Declared Transmission System is also materially lower than total Victorian supply capacity because of transport constraints (AEMO 2026b).

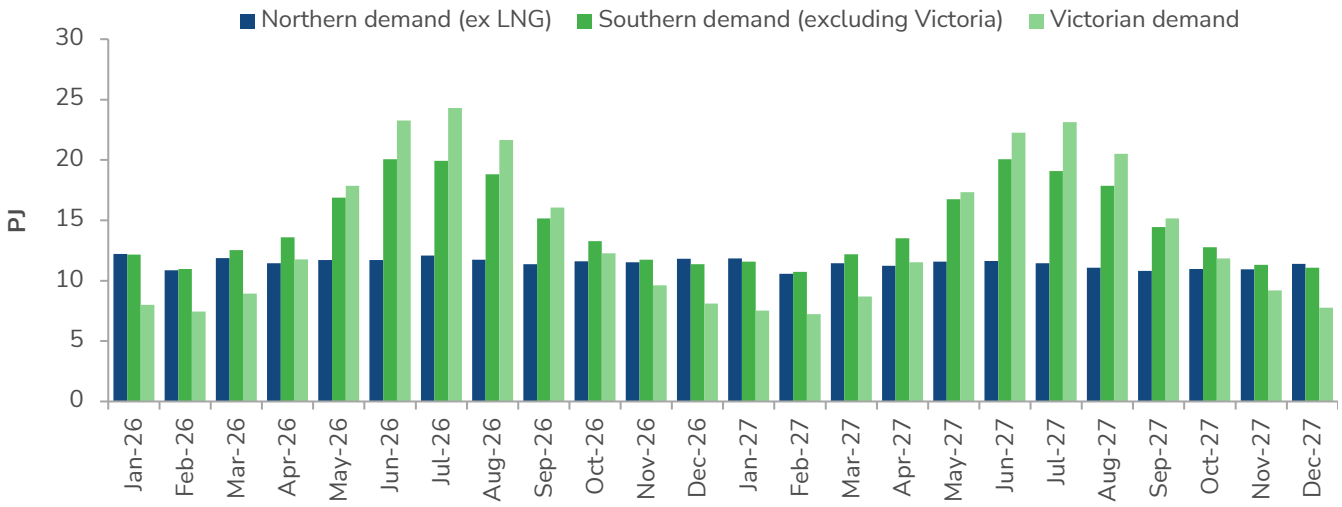
*Figure 3: Forecast annual gas production by region - existing, committed and anticipated supply (PJ)*




*Source: AEMO GSOO 2026a.*

That is why recent AEMO and ACCC work repeatedly returns to the southern system as the operational centre of gravity for the adequacy question. The risk is concentrated where production is declining fastest and where winter peak-day deliverability matters most, as shown by the large increase in winter demand in Figure 4 (AEMO 2026a; AEMO 2026b; ACCC 2023). The evidence therefore points to regional concentration rather than uniform east coast scarcity.

*Figure 4: Forecast monthly gas demand by region, 2026–27 (PJ)*




*Source: AEMO GSOO 2026a.*

## Transport and storage

If the southern system is where risk is most prominent, the next question is what levers determine whether that risk can be managed. The ACCC made the point in its January 2023 interim report "that transport and storage is becoming increasingly important to address shortfalls in the southern states" and highlighted the growing importance of infrastructure to Victorian system security (ACCC 2023).

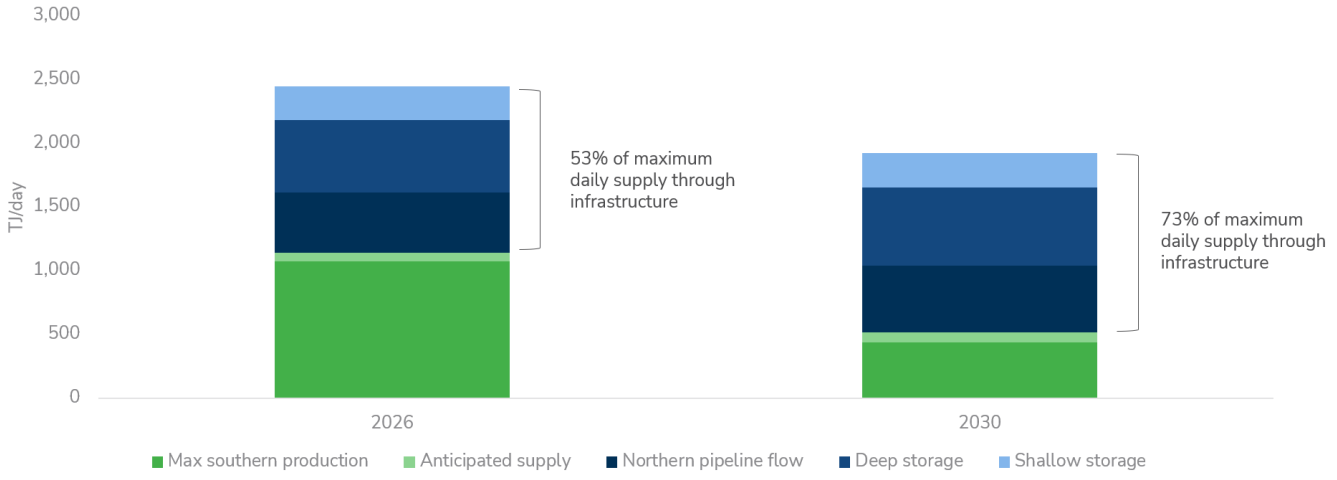
The market response to this tightening southern position is also increasingly infrastructure-led, reflecting a growing dependence on transport and storage to meet peak demand, which increases exposure to constraints, operational risk and price volatility. APA's East Coast Gas Grid Expansion Plan says Stage 3A is intended to increase north-to-south capacity for winter 2028 (APA Group 2026a, APA Group 2026b). This shows that market participants are responding to a deliverability problem as much as to a pure upstream supply problem.

This matters for policy design because it means the adequacy problem cannot be reduced to annual domestic volume alone. In the east coast market, adequacy is partly a question of logistics, optional capacity and system flexibility. A policy framework that ignores transport and storage would mis-specify the problem it is trying to solve (ACCC 2023; AEMO 2026b).

Purely increasing production in Queensland does not ensure supply into southern markets when it is needed most due to transport and storage constraints. While pipeline expansion remains part of the solution, the most direct and lower-cost pathway to addressing southern adequacy risk is to strengthen southern production and storage, which targets the location and timing of the challenge without compounding transport dependence.

Figure 5 shows that if there is no further conversion of uncertain projects in the southern basin then by 2030 73 per cent of peak daily supply will be provided by infrastructure in the form of storage and pipelines, up from 53 per cent today. This highlights the increasing importance of infrastructure to meet peak-day supply in the southern regions.

*Figure 5: Forecast maximum daily supply in the southern states, 2026–30 (TJ/day)*




*Source: Kroll analysis of AEMO GSOO 2026a.*

## Implications for the design problem

The east coast gas market is not simply a large domestic annual gas balance. It is an export-linked, interconnected and multi-jurisdictional system in which risks increasingly emerge through southern deliverability, storage and transport constraints, particularly under winter peak conditions.

The central issue is therefore not simply whether enough gas exists in aggregate, but whether gas can be delivered to where it is needed, when it is needed, and on terms compatible with both system adequacy and investable commercial conditions. This is directly relevant to the announced reservation scheme. An export-linked domestic supply obligation may increase domestic availability in aggregate, but its effectiveness will depend on whether it increases deliverable supply into the parts of the system where risk actually binds.

That distinction matters because the physical structure of the market can make aggregate volume a poor proxy for adequacy. Gas reserved in one part of the system does not necessarily resolve stress in another if transport capacity, storage levels, contractual arrangements or peak-day deliverability are binding constraints. Similarly, additional gas made available on an annual basis may not address risks that arise over short winter periods, on peak days, or in specific locations where local production is declining and system flexibility is limited.

This changes the terms of the policy design problem. If risk emerges through specific combinations of production decline, transport limits, storage position, contracting behaviour and peak demand, the relevant question is not simply whether more gas should be reserved in principle. It is whether a standing export-linked obligation, including the flexibility mechanisms proposed in the draft design framework, is calibrated to the physical and commercial conditions under which the system comes under stress.

A well-designed framework would therefore need to do more than increase domestic availability in aggregate. It would need to support deliverable supply where it is needed, preserve incentives for new production, storage and transport investment, and avoid creating obligations that bind more broadly or more frequently than the underlying adequacy risk requires. The existence of flexibility mechanisms in the proposed framework is relevant

to that assessment, but does not remove the underlying question of whether a standing obligation is the right default instrument for a conditional, regional and deliverability-focused risk.

SECTION 03

# Resource Abundance versus Deliverable Supply

## Purpose of this section

The preceding sections established two related propositions. First, the current official outlook does not point to an immediate, systemwide annual shortage of gas supply. Rather, it identifies a risk profile that becomes more pronounced over time, is concentrated in southern markets, and peaks during winter demand periods. Second, these risks arise in an export-linked and highly interconnected market, where transport capacity, storage availability, contracting behaviour and timing are integral to supply adequacy.

This section takes the next step by examining a distinction that sits at the centre of the policy design problem: the difference between gas that exists as a resource and gas that is deliverable to the market when and where it is needed. This distinction is directly relevant to the standing export-linked obligation, now elaborated through the draft design framework, which may increase domestic availability in aggregate but will not necessarily resolve adequacy risk if the binding constraint is the conversion of resources into timely, firm and accessible supply.

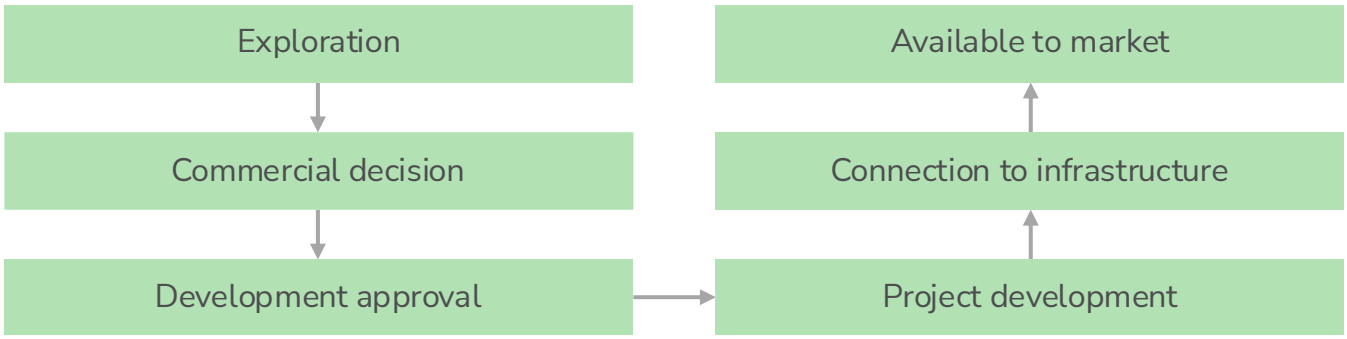
The central issue is therefore whether the presence of substantial reserves and resources is sufficient to address the risks identified in the preceding sections, or whether the real challenge lies in the barriers that prevent those resources from being approved, financed, developed, connected, contracted and delivered within the relevant timeframe.

In considering this issue, this section seeks to answer four questions:

- Why can a market with substantial gas resources still experience tightness or shortfalls?
- What must occur for a resource to become deliverable supply?
- What factors commonly delay or prevent that conversion?
- What does this imply for the design of a domestic supply framework, particularly where the proposed instrument is an annual export-linked obligation but the adequacy risk is locational, seasonal and dependent on investment?

Figure 6 shows that even once a resource is found there are multiple stages that take time for that resource to be approved, developed and then made available to the market. The time required to move from resource identification to production is therefore critical to policy design.

*Figure 6: Pathway from gas resource discovery to deliverable supply*



## Aggregate abundance does not guarantee timely supply

A central theme in recent official material is that the east coast can hold substantial gas resources in aggregate and still face supply stress. The ACCC's June 2025 gas inquiry report states that sufficient reserves and resources exist to meet projected domestic demand for at least the next decade, but that much of this supply is not yet developed because of policy, technical and commercial factors. Structural shortfalls can therefore still emerge if new supply is not brought to market in time.

The Future Gas Strategy analytical material similarly distinguishes between resource potential and the technical and contingent risks that affect whether new supply can reach domestic and international markets. It characterises the challenge not as one of total endowment, but as whether supply and infrastructure can be delivered within the relevant timeframes (DISR 2024b).

A resource base describes what gas exists in geological or commercial terms. It does not indicate whether that gas is approved, financed, developed, connected to infrastructure, contracted, or physically capable of being delivered into the area experiencing stress. In practice, supply adequacy depends not on the existence of resources, but on the ability of the market and regulatory framework to convert those resources into deliverable supply on the required timeframe.

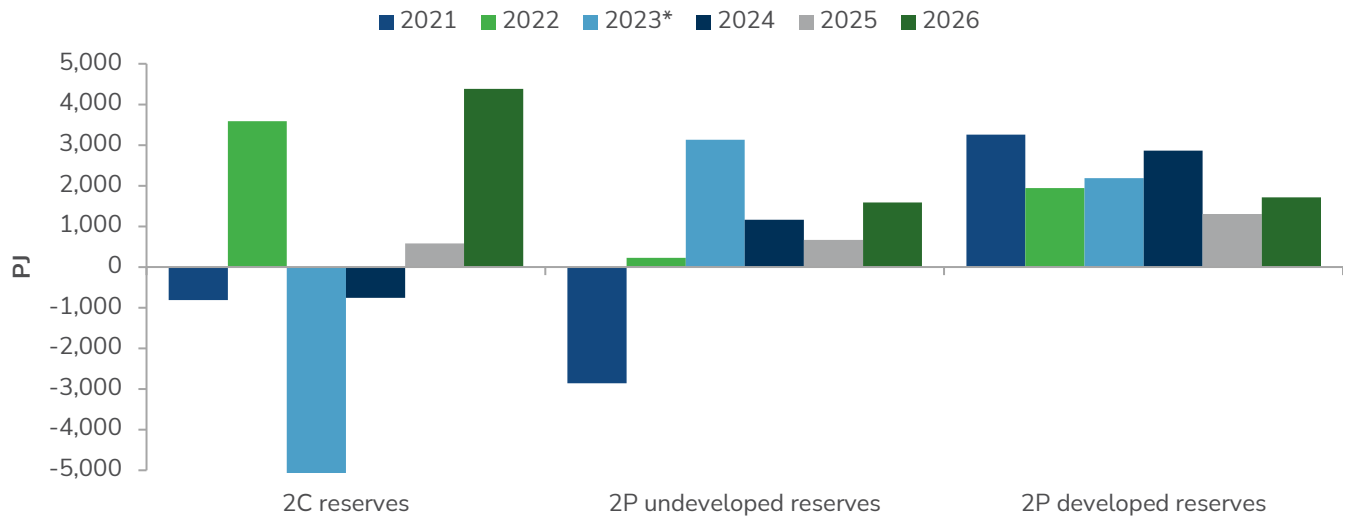
To distinguish these concepts, this section uses two different categories. The first is existing and committed supply, which represents current production and projects that are approved or expected to come online. The second is the underlying resource and reserve base, shown using 2C and 2P classifications, which reflects future potential supply at different stages of development.

A key issue for the east coast gas market is whether declining production from legacy fields can be replaced in time. In the southern states, existing and committed supply is forecast to decline from approximately 290 PJ in 2026 to around 27 PJ by 2034 (AEMO 2026a), implying that roughly 260 PJ of current supply must be replaced through new development, inter-regional flows or demand adjustment within a relatively short timeframe.

Figure 7 places this challenge in an east coast context. It shows the annual change in gas resources and reserves across three categories: 2C resources, 2P undeveloped reserves, and 2P developed reserves. The figure demonstrates that there is a substantial pipeline of gas at the aggregate level, with significant volumes entering both the 2C and 2P categories over time. This supports the conclusion that the east coast market is not constrained by geological scarcity.

However, these categories should not be interpreted as a smooth or automatic progression from resources to production. Movements between 2C and 2P reserves reflect reclassification, appraisal and commercial decisions, and do not guarantee timely development. The conversion of resources into production depends on commercial conditions, regulatory settings, technical constraints and infrastructure availability.

*Figure 7: Annual change in east coast gas reserves and resources by category (PJ)*




**2023 is an outlier in the change of reserves due to different reporting. The figure represents the flow of new reserves into each category by adding back previous years production*

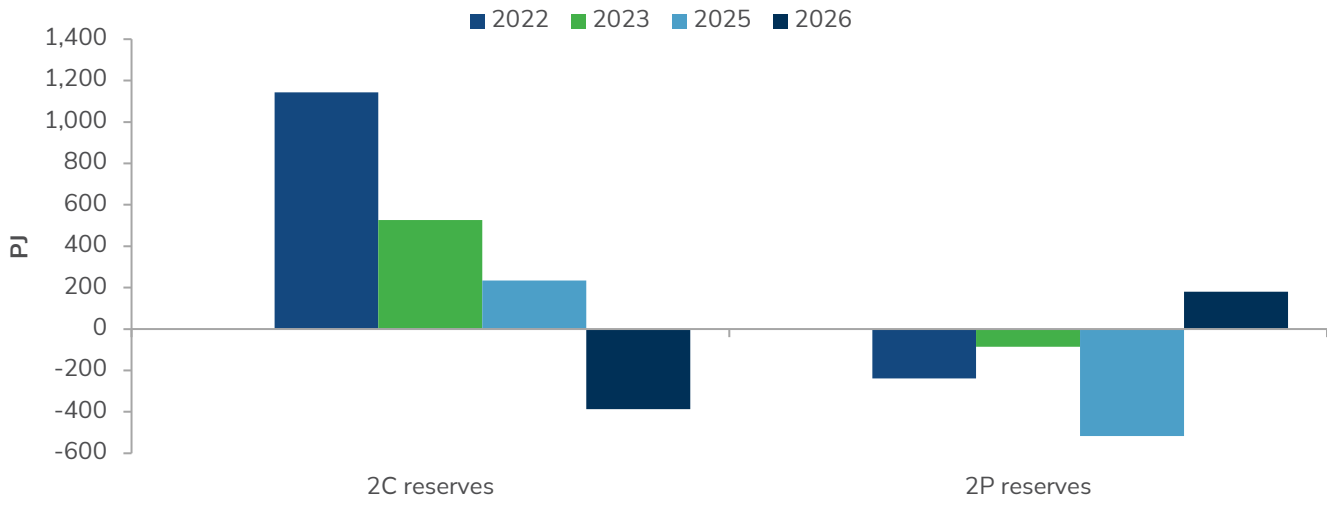
*Source: AEMO GSOO various years.*

Figure 8 provides the more relevant policy signal by focusing on the southern states, where adequacy risks are most pronounced. It compares annual changes in 2C resources and 2P reserves. The key result is that additions to 2C resources have not translated into a consistent or sustained increase in 2P reserves in the southern market. In other words, while potential supply is being identified, it is not being converted into commercially developed reserves at a pace sufficient to offset declining legacy production.

This distinction is critical. Southern adequacy depends not on the existence of potential gas in the ground, but on whether that gas can be converted into investable, approved and connected production in time to meet demand. If that conversion does not occur, the gap between declining existing supply and future deliverable supply will widen.

This is where the distinction between reservation and deliverability becomes central. Reserving additional gas for the domestic market may change how available gas is allocated, but it does not, by itself, create new southern production, expand transport capacity, increase storage availability or accelerate project approvals. If the underlying problem is the decline of existing southern production combined with the slow conversion of resources into firm supply, then policy must be assessed not only on its effect on short-term prices, but on its impact on investment incentives and the development of new supply.

*Figure 8: Annual change in southern gas reserves and resources by category (PJ)*




*Source: AEMO various years, Gas Statement of Opportunities, Geoscience Australia (various years).*

## The conversion from resource to supply

Potential supply issues are therefore fundamentally about conversion rather than geology. Resources must be appraised to commercial reserves, progress through approvals and financing to final investment decision, and then be developed with the necessary production, processing, transport and storage infrastructure in place.

Planning frameworks reflect this logic. AEMO distinguishes between existing, committed, anticipated and uncertain supply, emphasising that committed and anticipated projects must be delivered on time if forecast shortfalls are to be mitigated.

This distinction matters because only a subset of the resource base can be relied on for adequacy planning. Existing and committed supply can be treated with relatively high confidence. Anticipated supply depends on projects progressing as expected. Uncertain supply may be material in resource terms, but cannot be assumed to be available when the system comes under stress.

Resource abundance alone therefore does not indicate how much supply will be available in a given period, how firm that supply will be, or whether it will reach the part of the system under stress. A policy framework that treats all potential gas as equivalent risks overstating the market's ability to respond to shortfalls in the relevant timeframe. This requires a more operational concept: deliverable supply.

DISR planning data summarised in Figure 9 shows that since 2017 far more projects have been committed in Queensland than in the southern states. This indicates that supply risk often arises not because gas does not exist, but because projects are unable to progress to the committed stage in the regions where future adequacy risk is most acute.

*Figure 9: Committed gas projects by region, 2017–2025*

| | | | |
|---|---|---|---|
| **Queensland** | **24** new proposals | **16** committed proposals | **9** new projects, **7** expansions |
| **Southern States** | **17** new proposals | **9** committed proposals | **3** new projects, **6** expansions |

*Source: Department of Industry, Science and Resources (Office of the Chief Economist), Resources and Energy Major Projects reports (various years).*

The implication for policy design is that a domestic supply framework should be assessed by whether it improves the conversion pathway from resource to deliverable supply, not merely by whether it increases the amount of gas notionally reserved for domestic use. In the southern states, this means preserving incentives for appraisal, approvals, financing, contracting, infrastructure connection and timely development. A framework that increases domestic availability in the short term but weakens the commercial conditions required to bring forward new supply could leave the market more exposed to the same adequacy risks it is intended to address.

## What delays or prevents conversion into deliverable supply?

The ACCC has consistently identified barriers that can slow the conversion of resources into market supply. These include regulatory and approvals barriers, such as multi-layered approval pathways, environmental assessment requirements, litigation risk and uncertain timelines; commercial and investment barriers, including capital requirements, price uncertainty, contracting conditions and hurdle rates; and physical or technical barriers, including geological risk, infrastructure access and connection timelines.

The ACCC reiterated this diagnosis in its June 2025 report, noting that while sufficient reserves and resources exist in aggregate, longstanding policy, technical and commercial impediments continue to delay development and investment in domestic supply.

As a result, adequacy cannot be assessed by reference to reserve tables alone. It depends on the interaction between approvals, investment incentives, infrastructure access, project economics and commercial contracting conditions.

## Deliverable supply depends on physical access and commercial access

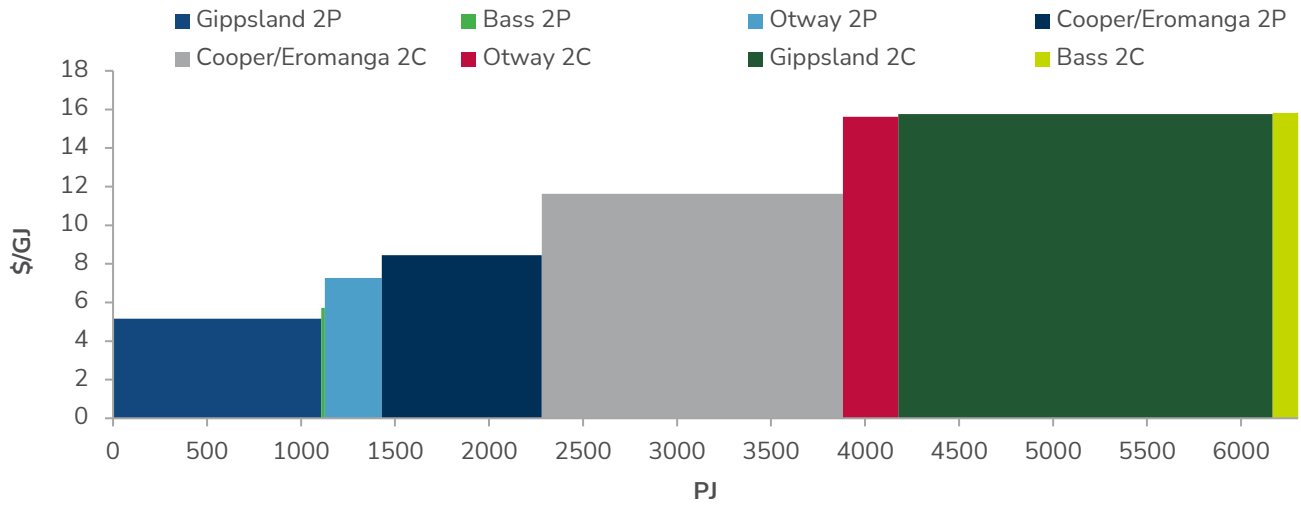
Even once a project is developed, the gas is not necessarily equivalent to deliverable supply. Physical access still matters. With legacy southern production expected to decline over the next five years, southern adequacy increasingly depends on new developments, transport capacity, storage availability and peak-day capability.

Figure 10 illustrates the indicative supply curve for gas reserves in the southern states and highlights that a substantial share of potential future supply sits toward the higher-cost end of the curve.

As legacy southern production declines, meeting southern demand increasingly relies on the commercial viability of these developments. For 2C resources to transition into deliverable supply, investors must have confidence that realised prices and contracting conditions will be sufficient to support development, connection and operating costs on a sustained basis. Policy interventions that materially reduce expected returns, without regard to cost structure, transport constraints or regional deliverability, may discourage investment in marginal supply and tighten conditions in the very parts of the system where future adequacy pressures are most acute.

In this sense, the figure reinforces the central distinction in this section. Reserves alone do not guarantee supply outcomes. Price signals, contracting conditions, approvals and infrastructure access all affect whether potential supply is converted into gas that can actually be delivered to southern markets.

*Figure 10: Southern states gas supply curve, 2026 ($/GJ)*




*Source: AEMO GSOO 2026a, Rystad 2026.*

## Policy and approvals barriers can slow the conversion of resources into supply

The east coast gas market's adequacy challenge is not one of geological scarcity, but of the timely conversion of resources into deliverable supply. While sufficient reserves exist in aggregate, the pace at which new projects progress from resource appraisal to production has been slower in recent years, particularly in the southern basins where adequacy risks are most acute.

State and federal policy and approvals processes appear to have been one material factor in this outcome. New gas developments can face complex, multi-layered approval pathways, including Commonwealth environmental approval under the EPBC Act, state environmental impact assessments and, for some projects, water-related assessment requirements and litigation risk. These processes can introduce extended and uncertain timelines, elevate development costs, and increase the risk that projects are deferred, staged or cancelled.

The cumulative effect is that the conversion of resources into firm supply can be slower and less reliable than reserve estimates alone might suggest. This reinforces the central point of this section: adequacy depends not only on the existence of resources, but on whether those resources can be approved, financed, developed, connected and contracted in time to meet the needs of the system. In the southern basins, where adequacy risks are most acute, slower conversion of potential resources into deliverable supply is a material policy concern.

Table 2 provides selected illustrative examples of gas and gas-related infrastructure projects that have experienced extended approval, regulatory sequencing or legal-contestation risks. These examples are not intended to provide a comprehensive project history or to attribute delay to a single cause. Rather, they illustrate

how regulatory and legal pathways can affect the timing and certainty with which potential supply becomes deliverable supply.

*Table 2: East coast gas projects delayed or litigated under EPBC triggers*

| Project Name / Basin | Status / Outcome | Delay / Litigation Details | Key EPBC/Policy Triggers | Notes / Sources |
|---|---|---|---|---|
| **Narrabri Gas Project (NSW)** | Approved 2020, delayed | Long approvals pathway; project approvals and related infrastructure have been subject to judicial review proceedings and ongoing legal contestation, alongside extended regulatory sequencing and stakeholder opposition. | EPBC Act (including contested application of the water trigger to associated works), state EIS processes, and judicial review pathways. | Final approval 2020, FID delayed. |
| **Golden Beach Gas Storage (VIC)** | Approved, delayed | Schedule extended due to multi-stage environmental assessment and regulatory sequencing (including offshore environment plan and related approvals), rather than a single discrete approval event. | Commonwealth and state environmental approvals (including offshore regulatory requirements), with EPBC pathways applicable depending on activity scope and referral outcomes. | Project timeline extended; now targeting late 2026. |
| **Otway Basin Expansion (VIC/SA)** | Ongoing, delayed | Timing risk driven by offshore approvals sequencing and contested environmental impacts; proposals and environment plans have attracted objections and, in some cases, formal challenges/appeals. | EPBC Act (marine, threatened species), state EIS | Incremental expansions only; major new supply slow. |
| **Gippsland Basin (VIC)** | Legacy fields declining | New developments face multi-year lead times and complex Commonwealth/state environmental pathways (including marine and coastal sensitivities), increasing schedule uncertainty. | EPBC Act, state EIS | Southern supply risk persists due to slow conversion. |
| **Arrow Energy Surat Gas (QLD)** | Approved, delayed | Extended approvals and land access/engagement processes, with heightened scrutiny for groundwater and cumulative impacts; community and landholder objections have increased timing risk. | State EIS and approvals; EPBC Act pathways may apply (including the water trigger where relevant) depending on referral determinations and project scope. | FID delayed; staged development. |
| **Beetaloo Basin (NT)** | Early stage, delayed | Proposals have progressed through multiple review stages and have attracted strong scrutiny and legal challenge risk, contributing to extended and uncertain timelines. | EPBC Act, NT approvals | Not east coast, but indicative of national pattern. |

*Sources: Selected examples compiled from public AEMO and ACCC publications, government and regulator portals, and project proponent disclosures (publicly available at the time of writing). These include: Narrabri Gas Project - NSW Independent Planning Commission determination (30 September 2020) and Mullaley Gas and Pipeline Accord Inc v Santos NSW (Eastern) Pty Ltd [2021] NSWLEC 110; Golden Beach - EPBC Act Approval 2019/8513 and Victorian Government Environment Effects Statement process; Otway Basin - NOPSEMA Offshore Project Register and Australian Government offshore petroleum approvals processes; Gippsland Basin - AEMO Victorian Gas Planning Report (2025) and Commonwealth/state environmental approval frameworks; Arrow Surat Gas Project - EPBC Act Approval 2010/5344 and Queensland Government EIS assessment; Beetaloo Basin - Northern Territory hydraulic fracturing inquiry (Pepper Inquiry, 2018) and Federal Court proceedings relating to EPBC Act "water trigger" application.*

Several common features emerge from this evidence. First, major new gas projects in the southern basins have frequently experienced approval timelines measured in years rather than months, particularly where water or threatened species triggers apply. Second, litigation risk and community opposition have been most pronounced for unconventional gas and projects near sensitive water resources, increasing both delay risk and development costs. Third, ongoing policy and regulatory uncertainty has compounded these effects by raising the hurdle rate for investment and encouraging proponents to defer or stage development.

The net result is a slower conversion of resources to deliverable supply, reinforcing the conditional adequacy and winter peak-day risk identified elsewhere in this report. Recent reforms aimed at streamlining approvals and clarifying environmental standards may reduce these frictions over time, but their impact on project timelines has yet to be demonstrated. The existing evidence supports the conclusion that policy and regulatory settings have been a material factor in delaying new gas supply, particularly in the southern system where future adequacy challenges are expected to bind most sharply.

## Why this matters for the policy design question

The distinction developed in this section has a direct implication for policy design. If the adequacy problem is one of converting gas resources into timely, firm and accessible supply, then it cannot be solved coherently by focusing only on aggregate resource abundance or on a nominal reservation percentage. The relevant question is whether the policy framework addresses the actual constraints that prevent gas from becoming deliverable supply.

That is particularly important in the east coast market, where official sources identify later-dated southern shortfalls, winter peaks, transport and storage constraints, declining legacy production and the need for new investment in production and infrastructure. A standing export-linked obligation, even with the compliance pathways and flexibility mechanisms proposed in the draft design framework, may increase the amount of gas notionally available to the domestic market. However, it will only improve adequacy to the extent that it supports gas being delivered to the right locations, at the right times, and through commercial arrangements that sustain investment (DCCEEW and DISR 2026a; DCCEEW and DISR 2026b).

The presence of large reserves and resources therefore tells policymakers that the issue is not simply running out of gas. It is how to get the market to deliver the right gas to the right place at the right time, while preserving the incentives needed to develop future supply. The section that follows examines what the available evidence, including planning assessments, price data and observable commercial behaviour indicates about whether that conversion is occurring at the pace and in the locations the market requires.

SECTION 04

# What the Evidence Shows about Current Market Conditions

## Purpose of this section

The preceding sections established three propositions. First, the Commonwealth Government has announced a standing export-linked domestic supply obligation, equivalent to 20 per cent of LNG exports annually, and has now released a draft design framework setting out the proposed architecture for implementation. Second, the east coast gas market is not a single annual gas balance, but an export-linked, interconnected and multi-jurisdictional system in which adequacy risk increasingly emerges through southern deliverability, storage and transport constraints. Third, the relevant supply challenge is not geological scarcity, but the conversion of resources into timely, firm and accessible supply.

This section tests those propositions against the current evidence. It draws on planning assessments, forecast revisions, price data and observable commercial behaviour to assess whether the evidence supports a diagnosis of broad, immediate annual shortage, or a more qualified position: conditional near-term adequacy, with residual risk concentrated in southern winter deliverability and longer-term investment. This matters because the proposed obligation, even with the flexibility mechanisms identified in the draft design framework, should be assessed against the market conditions it is intended to address.

## The 2026 outlook is materially improved

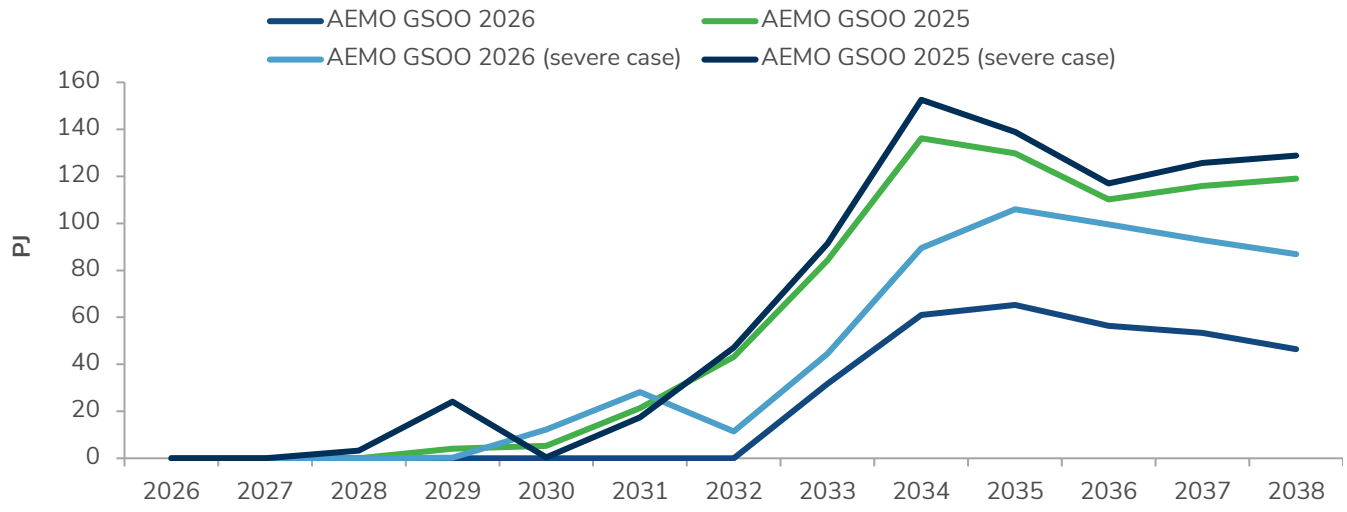
The official short-term outlook changed materially in 2026 relative to the position reflected in the 2025 planning material.

The 2025 GSOO identified risks of peak-day shortfalls in the southern states from 2028 and annual supply gaps from 2029. Those forecasts reflected declining southern production and the need for additional supply, storage and transport investment to maintain adequacy.

AEMO's 2026 GSOO presents a less acute near-term picture. It reports improved supply conditions in the near term, with risks of extreme southern peak-day shortfalls now expected to emerge one year later than previously forecast and with stronger adequacy expectations through to 2029. AEMO attributes that improvement to increased peak-day supply capability, new infrastructure investment and lower consumption forecasts.

Figure 11 provides the clearest summary of that shift. It shows how the projected southern supply gap is both later and materially smaller in the 2026 outlook than in the 2025 planning vintage.

*Figure 11: Forecast southern system gas supply gap, 2026–38 (PJ)*



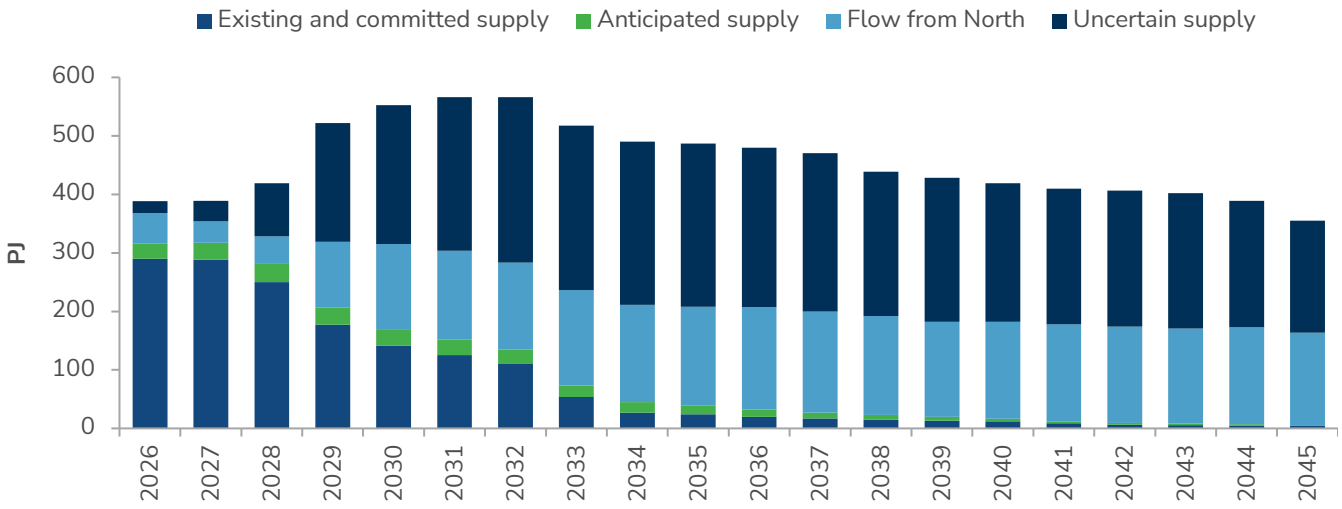

*Source: AEMO various years, Gas Statement of Opportunities.*

*The severe case uses the AEMO adequacy assessment demand, which is based off a one in 20 year demand case. The other projections use AEMO core demand forecast.*

That shift is important because it changes the factual setting in which the current market should be assessed. It does not mean that longer-term adequacy concerns have disappeared. The 2026 GSOO still points to a material decline in production from legacy southern fields, states that new investment will be required from 2030 under most weather conditions, and notes that several additional supply, storage and transportation projects remain uncertain.

Figure 12 shows why this matters. Southern market adequacy increasingly depends on northern transfers and uncertain new supply, rather than enduring local production. Existing and committed southern supply declines over time, anticipated supply remains limited, and adequacy becomes more conditional on project development, inter-regional flows, storage and supporting infrastructure performing as expected.

*Figure 12: Forecast annual gas supply by source in the southern states, 2026–30 (PJ)*




*Source: AEMO GSOO 2026a.*

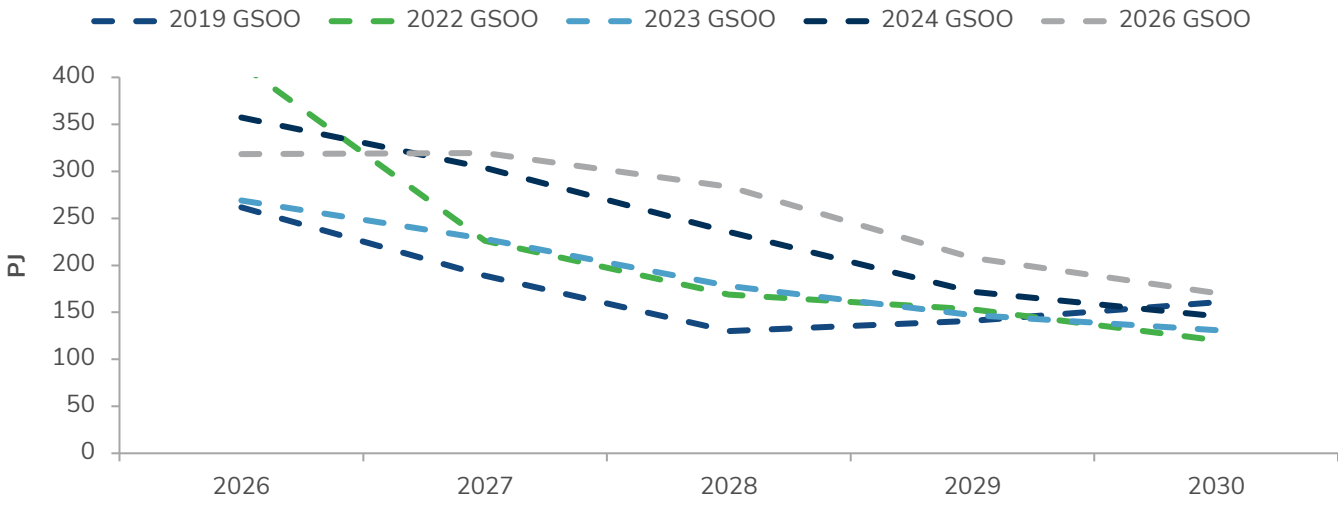
## Planning assessments have consistently deferred the forecast shortfall

The official planning materials continue to show that southern supply gaps remain a feature of the medium- and longer-term outlook as legacy production declines and additional supply, storage and transport investment becomes necessary. But long-term planning outputs perform a different function from near-term market assessments.

The risk in interpretation is that these longer-term planning results can be read too quickly as evidence of an immediate market condition. That is not what they show. They identify where future stress is expected to arise if investment does not keep pace. They do not establish that the market is already in broad structural annual shortage today.

Figure 13 shows that projected southern supply risk remains a persistent feature of the planning outlook, but that its timing and scale have shifted across successive GSOO reports. Earlier forecasts pointed to a steeper and earlier decline in available southern supply, while the 2026 GSOO shows a higher supply profile through the late 2020s.

*Figure 13: Evolution of AEMO southern supply forecasts across planning vintages (PJ)*



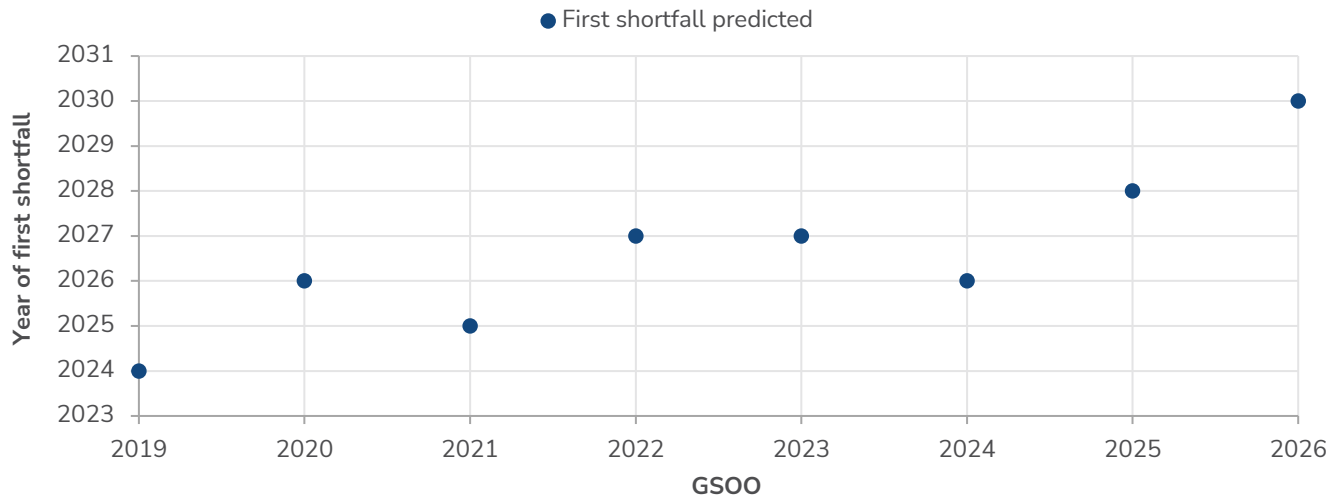

*Source: AEMO various years, Gas Statement of Opportunities.*

Figure 14 provides the clearest summary of what long-run planning evidence can and cannot tell us. The forecast year of first annual shortfall has been deferred in successive GSOO vintages since 2019. In 2019, the first shortfall was projected for 2024. In the 2026 GSOO, it has moved to 2030.

This is not evidence that the problem has disappeared. It is evidence that planning outputs are sensitive to assumptions, that markets respond to signals, and that the timing of stress is genuinely uncertain at long horizons.

This does not diminish the value of long-term planning assessments. Their purpose is to identify emerging risks early enough for market participants and governments to respond. But it does mean that long-dated projections should be used carefully as policy triggers. A framework that applies binding obligations on a standing basis, or that mechanically activates obligations on the basis of long-range forecast shortfalls, may intervene too early, too broadly or too often where market responses, demand changes or project developments subsequently defer the risk.

*Figure 14: Forecast year of first annual shortfall across AEMO GSOO vintages*



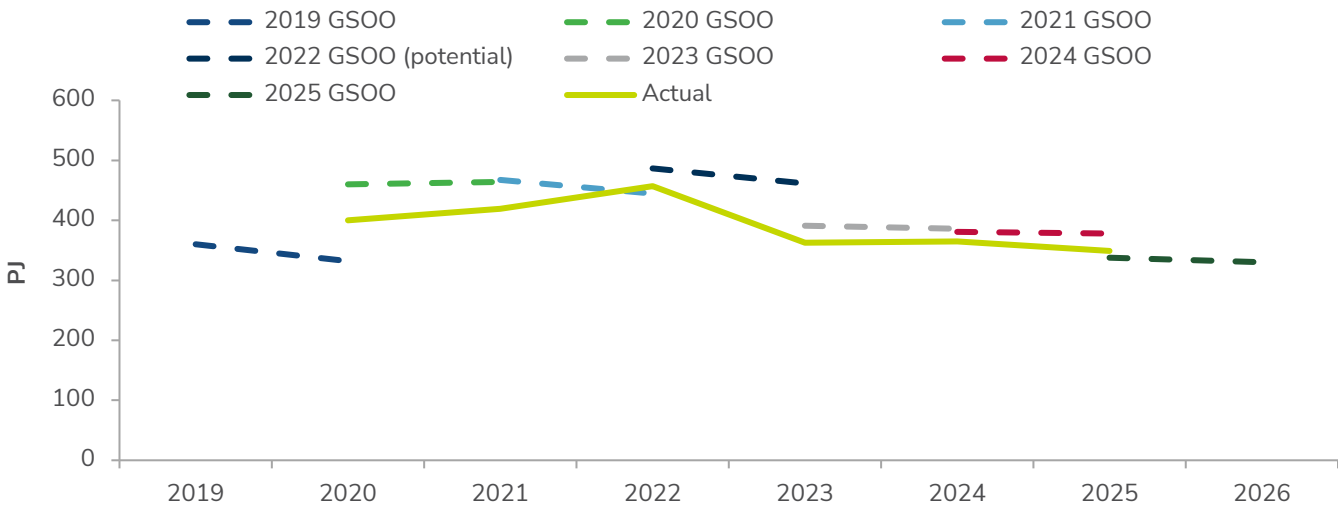

*Source: AEMO various years, Gas Statement of Opportunities Adequacy Assessment.*

## Near-horizon supply forecasts have been broadly accurate

Figure 15 compares successive AEMO GSOO forecasts for southern states gas supply with subsequent outcomes over a two-year horizon. The figure shows that AEMO's short-term supply projections have been broadly informative and reasonably consistent across reports.

That is important for policy design. It suggests that the market already produces useful forward-looking information on regional gas availability, and that emerging adequacy risks can be identified before they become binding. This supports a policy architecture that uses market intelligence and adequacy assessment to inform whether, when and how intervention should escalate, rather than relying only on a fixed annual obligation that applies regardless of whether stress is present.

*Figure 15: Forecast gas supply in the southern states, 2019–26 (PJ)*



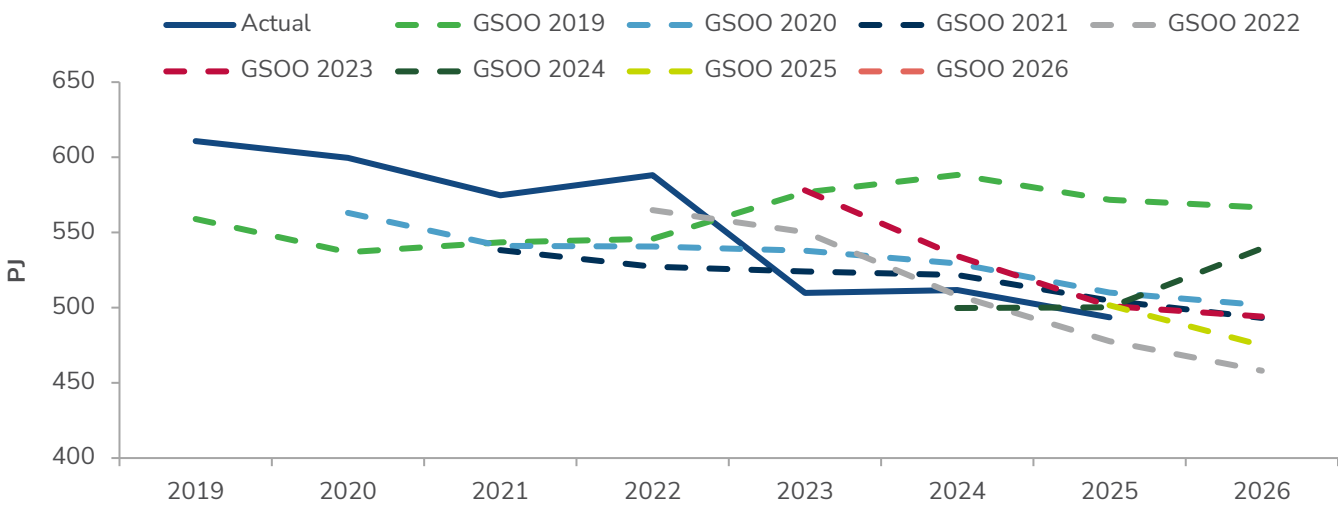

*Source: AEMO various years, Gas Statement of Opportunities.*

## Demand has been systematically overstated

Successive AEMO GSOO forecasts for domestic gas demand in the southern states have tended to sit above realised outcomes over relevant forecast horizons. This does not mean the forecasts were unreasonable when made. Rather, it highlights the sensitivity of demand projections to policy-contingent and system-level factors, including electrification, gas-powered generation requirements, coal retirement timing and electricity market decisions.

Figure 16 demonstrates this limitation directly. Realised demand has generally come in below earlier medium-term projections, while updated forecasts have adjusted as market and policy conditions have changed.

*Figure 16: Forecast domestic gas demand in the southern states, 2019–26 (PJ)*

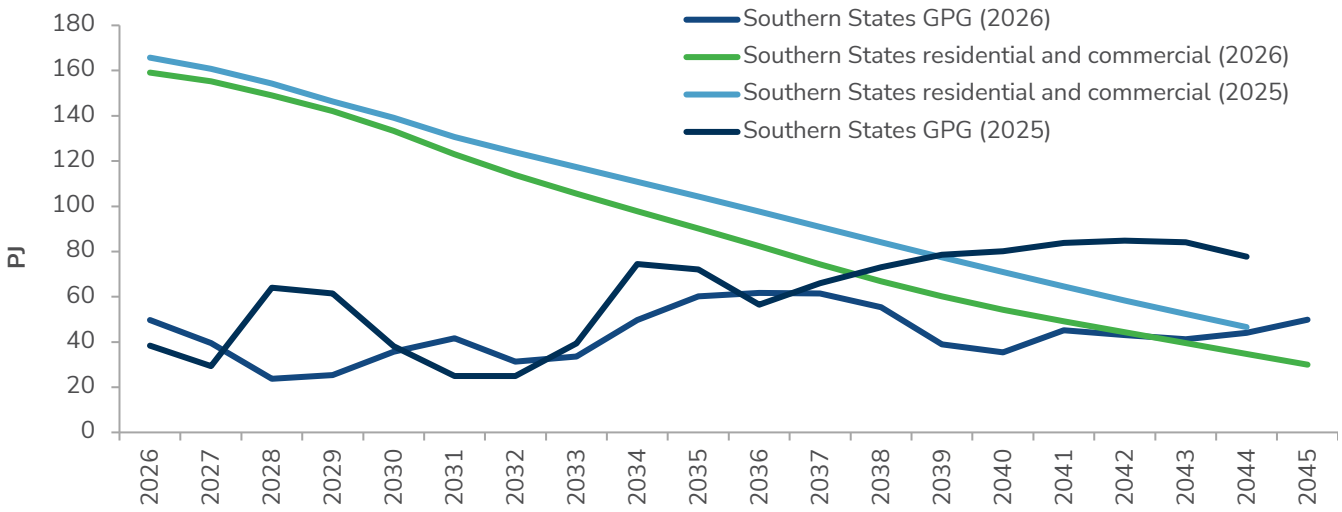



*Source: AEMO various years, Gas Statement of Opportunities.*

Figure 17 extends this point by showing how gas demand pathways diverge materially across scenarios. The divergence is driven by factors including electrification rates, gas-powered generation requirements, household and commercial gas demand, and electricity market decisions such as the extension of coal-fired capacity at Eraring.

These are not factors that gas market modelling can resolve on its own. They are partly exogenous to the gas system and subject to policy choices that may change over time. For policy design, the implication is that demand uncertainty should be explicitly recognised rather than converted too quickly into a fixed annual supply obligation.

*Figure 17: Forecast total gas demand in the southern states, 2026–45 (PJ)*




*Source: AEMO various years, Gas Statement of Opportunities.*

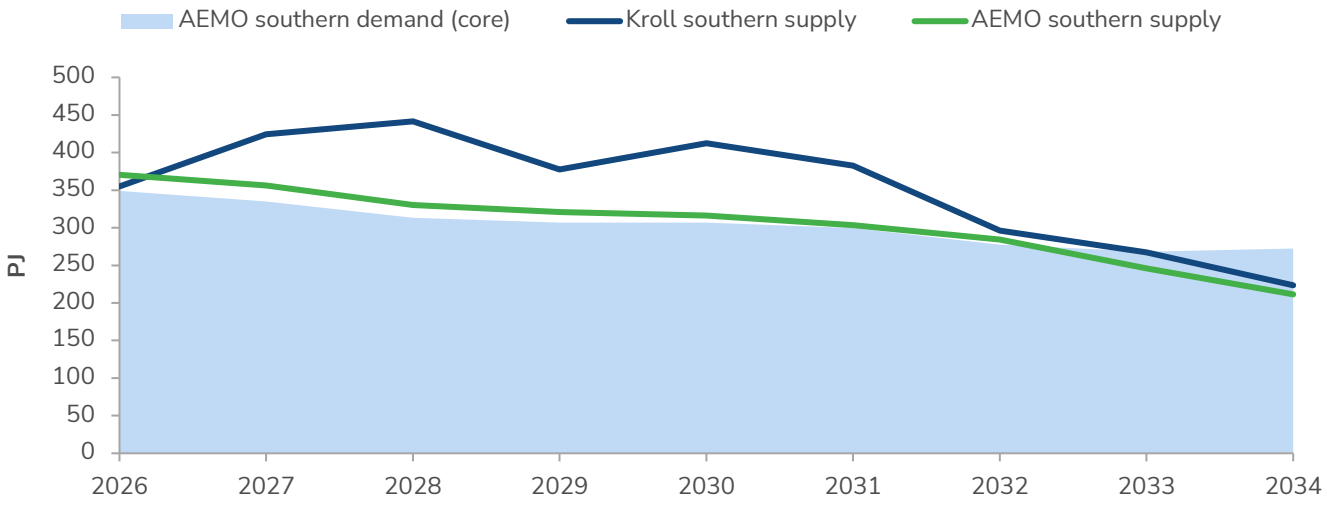
## The uncertain supply wedge is not a permanent gap

Figure 18 reinforces this point from the supply side. AEMO's uncertain supply category should not be read as gas that will never be developed. It is a planning category that identifies supply that cannot yet be relied upon with the same confidence as existing, committed or anticipated projects.

The Kroll southern supply forecast shown in Figure 18 incorporates a project-by-project assessment of likely southern development (using supply data from Wood Mackenzie), including projects that AEMO classifies as uncertain. The resulting supply profile exceeds AEMO's base case through 2029, suggesting that the uncertain wedge is not a single homogeneous category. Some projects within it are more likely to proceed than others, and independent commercial assessments may treat a portion of that supply as probable.

The implication is not that uncertain supply should be assumed to materialise. It is that uncertain supply should be assessed probabilistically and updated as projects move through the development pathway. The uncertain wedge is therefore best understood as a planning signal about where investment, approvals and infrastructure delivery are needed, not as evidence that the market has already failed to deliver.

*Figure 18: Forecast gas supply and demand in the southern states, 2026–34 (PJ)*




*Source: Kroll analysis of AEMO GSOO 2026a, Wood Mackenzie 2026. Kroll supply is supply available for the south after northern demand (including exports) is filled.*

## Price behaviour confirms a market decoupling from international extremes

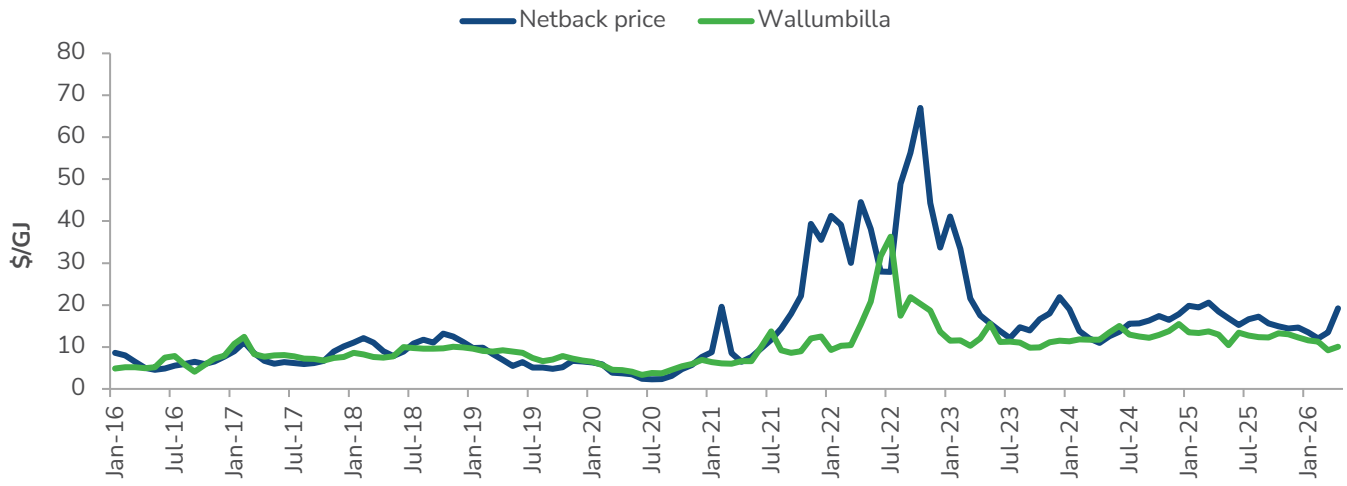
Figure 19 shows that over the last decade east coast wholesale gas prices have moved broadly with international LNG prices, but have not replicated them one-for-one. The price evidence is best understood in three broad periods.

**From 2016 to 2021**, the market was adjusting to LNG linkage. Local prices were closely aligned with netback prices, with the Wallumbilla monthly price averaging around 8 per cent above netback over the period. This reflected the structural adjustment that followed the development of LNG exports in Queensland.

**From 2021 to 2023**, the international energy crisis placed strong upward pressure on LNG netback prices. Domestically, falling availability of coal-fired generation increased reliance on gas-fired generation. This combination saw Wallumbilla prices rise, but remain below netback in most months. During this period, higher domestic prices reflected both international export parity signals and short-run domestic pressures, including increased reliance on gas-fired generation during periods of electricity system stress.

**From 2023 to 2026**, the domestic pricing wedge persisted. Wallumbilla prices remained below netback in most months, with discounts generally stabilising in the 12 to 25 per cent range. This indicates that the domestic market remains linked to international prices, but does not simply transmit international extremes one-for-one.

*Figure 19: Average monthly gas prices, eastern Australia, 2016–2026 ($/GJ)*




*Source: ACCC 2026b, AER 2026a, AEMO GSOO 2026a.*

Table 3 summarises the relationship between Wallumbilla wholesale prices and LNG netback prices over time. The evidence shows that export linkage remains relevant to price formation, but also that domestic outcomes have not simply converged to international LNG parity. This is important because price outcomes alone do not support a simple conclusion that domestic users are fully exposed to global LNG pricing, or that the market is already in broad structural shortage.

*Table 3: Wallumbilla–netback price differential by period*

| | Average price difference from netback | Months above netback | Proportion of months above netback |
|---|---|---|---|
| **2016 -2020** | 8% | 35 | 58% |
| **2021** | -33% | 3 | 25% |
| **2022** | -50% | 2 | 17% |
| **2023** | -36% | 0 | 0% |
| **2024** | -12% | 3 | 25% |
| **2025** | -24% | 0 | 0% |
| **2026** | -25% | 0 | 0% |

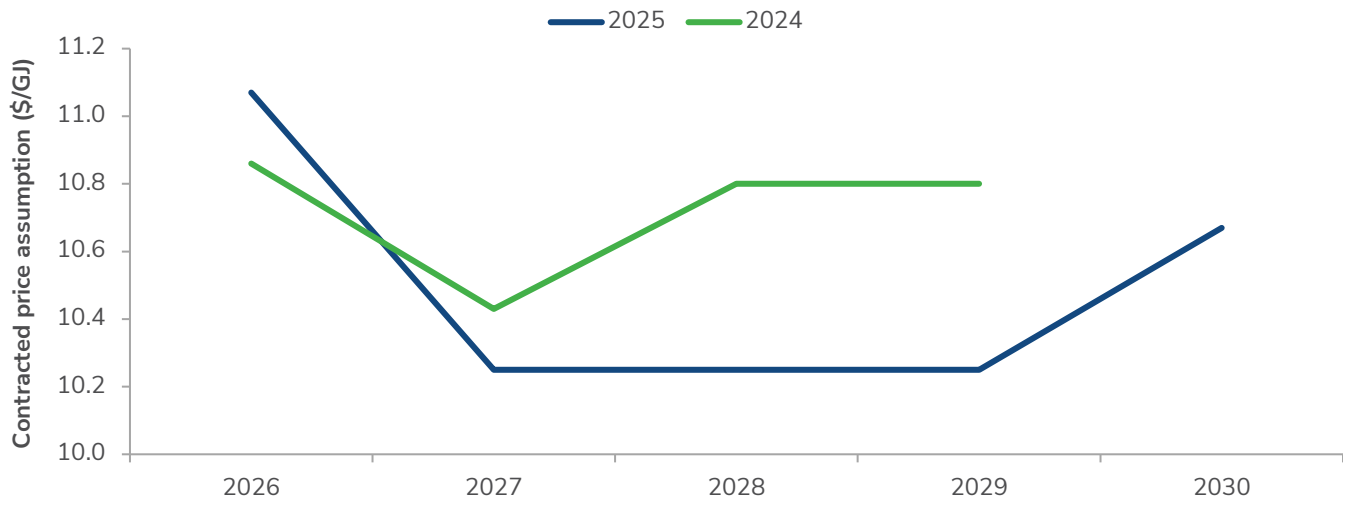
*Source: ACCC 2026b, AER 2026b.*

## Forward price assumptions also point to stability rather than escalating scarcity

The Australian Energy Regulator's 2026 Wholesale Gas Reserves Price Assumptions Report provides a useful cross-check on the price evidence. Based on mandatory disclosures from gas field owners covering calendar year 2025, the AER finds a downward shift in contracted gas price assumptions relative to the

previous year, alongside a narrowing of price dispersion across both contracted and uncontracted reserves as shown in Figure 20.

*Figure 20: AER contracted gas reserve price assumptions, 2026–2030 ($/GJ)*




*Source: AER 2026.*

This pattern is more consistent with stable forward price expectations than with market participants pricing in escalating scarcity or sustained volatility. Importantly, these assumptions underpin reserve development decisions, meaning they are relevant not only to current prices but also to the commercial conditions under which future supply may be developed.

## Commercial market signals point to a tight but functioning market

Planning assessments and price data should be cross-checked against observable market behaviour. If the east coast market were already in broad structural shortage, that would be expected to appear in contracting conditions, infrastructure decisions, storage management and prices.

Recent commercial signals point instead to a market that is tight but functioning.

Producers have continued to offer and contract gas into the domestic market through EOIs and Gas Market Code-related processes. Beach Energy has published an EOI for firm domestic gas supply from 2027 to 2029, while APLNG has also continued to market domestic gas volumes and related services (Beach Energy Limited 2026, APLNG 2026a). These processes are not the same as executed gas supply agreements, but they are evidence that wholesale gas continues to be made available through commercial channels rather than withdrawn from the domestic market.

The expiry of the LNG exporters' Heads of Agreement on 1 January 2026 also does not appear to have coincided with an absence of observable commercial market activity. In early 2026, producers continued to market volumes through published EOIs and Code-related offers, while the ACCC's March 2026 interim update observed that buyers were seeking to secure supply for 2027 and that storage remained central to meeting southern winter demand.

Infrastructure investment is also proceeding in direct response to the southern deliverability challenge. APA Group reached final investment decision on Stage 3A of its East Coast Gas Grid Expansion in February 2026, committing capital to increase north-to-south capacity for winter 2028. This is a market-led infrastructure response directed at the same southern deliverability issue identified throughout this report.

Contract prices have stabilised below the extreme levels observed during the 2022–23 crisis period. Recent ACCC reporting indicates contracted gas prices in the broad range of $13–15/GJ, while short-term contracting activity suggests buyers are managing exposure through rolling procurement rather than being locked out of supply altogether.

The Government's decision not to activate the ADGSM for Q4 2025 is also relevant. The ADGSM has existed since 2017 but has not been formally activated to restrict LNG exports. The decision not to activate it for Q4 2025 indicates that existing contractual, voluntary and regulatory arrangements were judged sufficient to manage near-term supply risk without resort to export controls. That judgement was based on the official assessment of domestic demand, uncontracted LNG availability, storage positions and AEMO's emergency response powers.

Storage is being actively managed within design parameters. The ACCC's April 2026 reporting indicated that Iona underground storage was on track to be full ahead of winter, while also noting that the southern states may require substantial storage withdrawals during July 2026 (ACCC 2026c). This reinforces the operational importance of storage, but also shows that the near-term response is being channelled through storage management and deliverability planning rather than through evidence of market failure.

Taken together, these signals, producer EOIs, infrastructure FIDs, stabilised contract pricing, managed storage cycles and the Government's non-activation of the ADGSM, describe a market responding to tightening conditions through commercial and investment decisions. They do not describe a market free of risk. But they also do not describe a market in broad structural failure or one that has stopped functioning.

## What the evidence does not show

The evidence examined in this section supports a diagnosis of conditional near-term adequacy, not a finding that the east coast gas market is free of risk.

Three conclusions follow.

First, the market is not currently in broad structural annual shortage. Planning assessments have improved materially in the 2026 vintage, near-horizon supply projections have been broadly informative, demand forecasts have tended to sit above realised outcomes, domestic prices remain below LNG netback, and commercial behaviour is consistent with a market that is tight but functioning.

Second, longer-term adequacy risks remain real. Southern production is declining materially, the system is becoming more dependent on northern flows, storage, infrastructure and uncertain new supply, and AEMO continues to identify the need for new investment under most weather conditions. The deferral of forecast shortfalls does not remove the underlying structural challenge.

Third, the remaining risk is increasingly operational, seasonal and regional. The key issue is not simply aggregate annual volume, but whether gas can be delivered into the southern system under winter peak conditions and during periods of electricity system stress.

These conclusions narrow the policy question. They do not eliminate the case for government involvement. They indicate that any intervention should be calibrated to conditional adequacy, southern deliverability and longer-term investment, rather than assuming a settled, systemwide annual shortage.

That matters for the announced reservation scheme and the draft design framework now released for consultation. A standing export-linked domestic supply obligation may increase domestic availability in aggregate, and the draft framework includes flexibility mechanisms intended to recognise existing contracts, infrastructure constraints and surplus domestic volumes. However, the evidence in this section suggests that the binding risks are more specific: southern, seasonal, operational and dependent on continued investment. The central question is therefore whether the proposed framework is sufficiently conditional and flexible to respond to those risks without imposing a standing obligation more broadly or more frequently than the evidence warrants. The section that follows therefore examines where the remaining risk actually binds, winter peak-day adequacy in the southern system, and what that implies for the design of a proportionate policy response.

SECTION 05

# Winter Peak-day Adequacy and the Southern System

## Purpose of this section

The preceding sections established that the east coast gas market is not currently in broad structural annual shortage. The evidence points instead to conditional near-term adequacy, with longer-term residual risk concentrated in the southern system and increasingly operational in character.

This section examines where that residual risk actually binds. The key issue is not whether the east coast has enough gas in aggregate over a year, but whether the southern system can access enough firm, deliverable gas on the coldest winter days, when residential heating demand, industrial load and gas-powered generation can coincide. Under those conditions, declining local production, finite storage capacity and constrained transport infrastructure are tested most acutely. This distinction is directly relevant to the proposed domestic supply obligation: an annual volume obligation may increase gas available to the domestic market in aggregate, but adequacy ultimately depends on whether firm gas can be delivered into the southern system when operational stress occurs.

## Where system stress emerges

On the highest-demand winter days, the southern system must draw simultaneously on local production, pipeline inflows from the north, and storage withdrawal to meet demand from residential heating, industrial users and gas-powered generation. If the combined capacity of those sources is insufficient to meet demand on a given day, the system operator must curtail supply, meaning industrial customers may lose gas, gas-powered generators may be unable to run, and in severe cases residential supply may be affected (AEMO 2026b). This is not an abstract planning risk: it is an operational constraint that binds on specific days under specific conditions, and it is the reason that annual volume adequacy and peak-day deliverability are fundamentally different questions.

The official materials point increasingly away from a broad annual scarcity problem and toward a more concentrated operational challenge in the southern system. Unexpected conditions, such as higher demand or unplanned supply restrictions, could still produce shortfalls (AEMO 2026b).

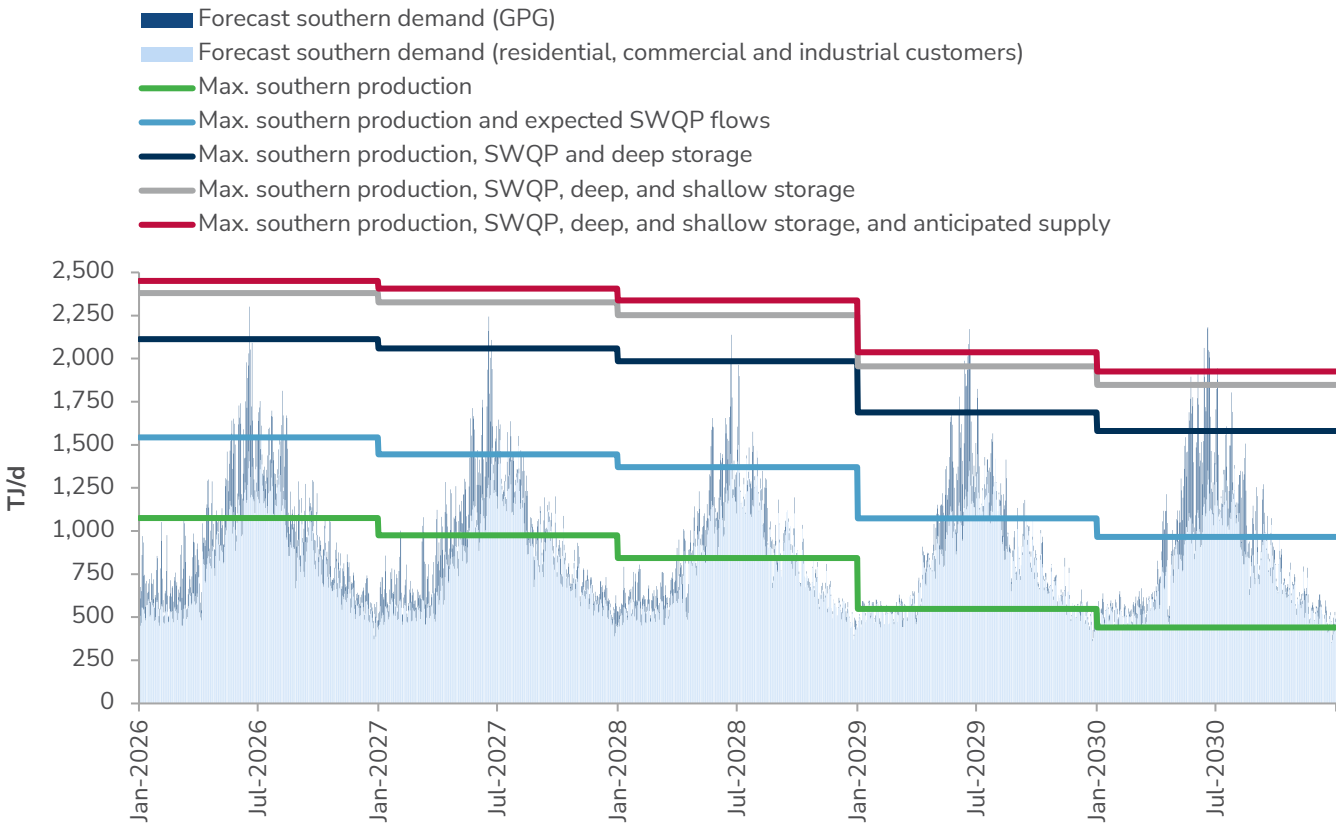
The ACCC's reporting provides the most concrete near-term illustration of this risk. It projects a 16 PJ monthly supply gap in the southern states for July 2026, the first winter month, that would require large and timely withdrawals from Iona underground storage to clear (ACCC 2026a, ACCC 2026c). At that rate of drawdown, the margin available to absorb an unexpected demand spike or unplanned supply disruption is narrow. This is not a hypothetical long-horizon planning scenario. It is a specific, dated and quantified stress point in the immediate outlook. It also illustrates why annual volume adequacy and peak-day deliverability are different policy problems. A standing annual reservation obligation, even with flexibility mechanisms, may increase the amount of gas notionally available to the domestic market, but it does not by itself ensure that firm gas can be delivered into the southern system on the days it is needed most.

AEMO's 2026 GSOO reaches a similar conclusion at the broader east coast level. While annual demand is expected to moderate as electrification continues and battery development reduces gas-powered generation relative to earlier expectations, gas is still expected to play a critical role during winter peak demand periods. At the same time, production from legacy southern fields is projected to decline materially, which means that adequacy increasingly depends not simply on the existence of gas in aggregate, but on whether gas can be delivered where it is needed, when it is needed, under peak conditions (AEMO 2026a).

Figure 21 shifts the focus from annual balance to daily winter adequacy in the southern system. The chart shows pronounced seasonal demand peaks, with winter gas use rising sharply above average daily levels each year. Against that profile, maximum southern production declines steadily over time, and even when combined with expected SWQP flows the available margin against peak-day demand narrows materially across the outlook. Additional support from deep and shallow storage remains important, but the headroom it provides is finite.

The significance of Figure 21 is that the residual risk is increasingly operational rather than purely volumetric. Annual balances may appear manageable, but the system can still be exposed if peak-day demand approaches or exceeds the combined capability of local production, northern inflows and storage withdrawal. As southern production declines, the margin for error becomes more dependent on transport availability, storage inventory, storage withdrawal capability and the timing of demand spikes. This is the operational test against which any domestic supply framework should be assessed: not only whether it increases aggregate domestic availability, but whether it improves firm deliverability into the southern system under peak conditions.

*Figure 21: Forecast daily gas supply and demand in the southern states, 2026–30 (TJ/day)*




*Source: AEMO 2026a.*

Storage and transport are therefore not secondary infrastructure details. They are central to the adequacy problem. Storage provides the flexibility to meet short-duration winter spikes, while transport determines whether gas from outside the southern system can physically reach load centres when local production is insufficient. A policy framework that focuses only on annual domestic volumes risks underweighting both constraints.

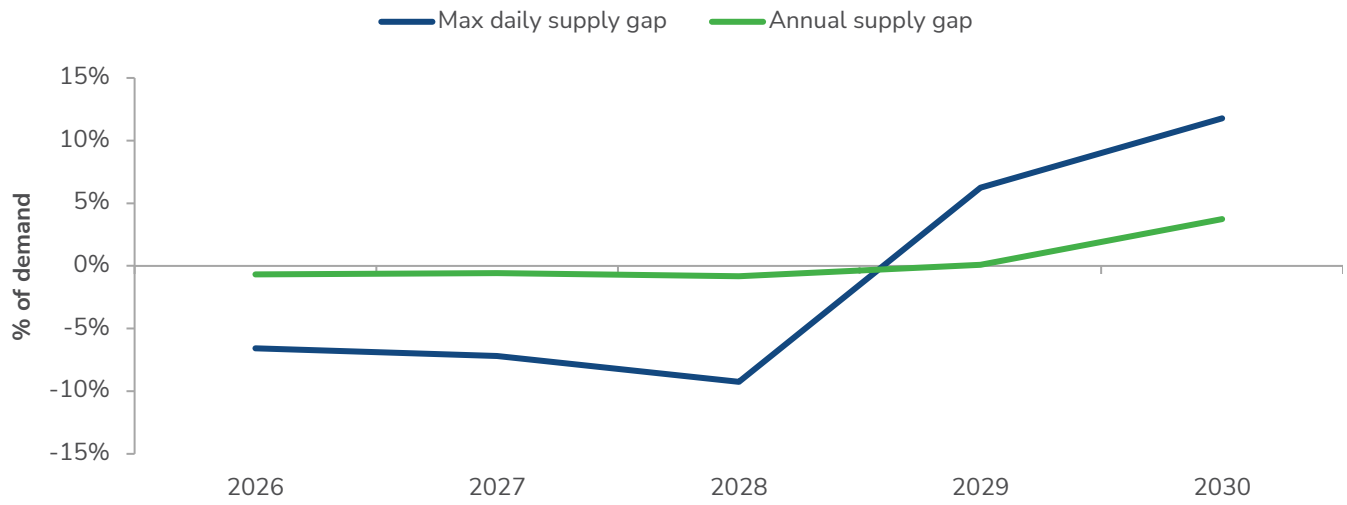
## Peak-day deliverability in the southern system

The official planning material is clear that the remaining southern risk is not best understood as a broad annual supply crisis. The 2026 Victorian Gas Planning Report Update states that expected Victorian supply exceeds both 1-in-2 and 1-in-20 year system demand over the five-year outlook period, but that adequacy remains tight (AEMO 2026b). AEMO's 2026 GSOO is consistent at the east coast level: improved peak-day supply, new infrastructure investment and reduced consumption forecasts have strengthened near-term adequacy, delaying extreme peak-day shortfall risk in southern Australia to 2029, while still requiring new investment from 2030 onwards (AEMO 2026a).

Figure 22 compares the projected annual supply gap with the maximum daily (peak-day) supply gap in the Southern States as a percentage of demand. Annual adequacy remains broadly balanced through the late 2020s, with only a small and gradual shortfall emerging toward 2030. By contrast, peak-day conditions tighten earlier and more sharply, with maximum daily demand exceeding deliverable supply by a materially wider margin well before any sustained annual deficit appears.

The divergence matters because a gas system can appear manageable in aggregate over the year while still facing acute operational stress during peak demand periods when storage, transport capacity and supply flexibility become binding. The solution set depends on which problem is actually present. If the challenge is winter peak-day firmness and deliverability, as the official evidence consistently indicates, then storage, transport, operational flexibility and targeted supply responses are the natural first-order levers, not annual volume obligations.

*Figure 22: Forecast daily and annual supply gap as a share of demand, AEMO 2026 GSOO (%)*




*Source: Kroll analysis AEMO GSOO 2026a,*

## The role of storage in providing winter firmness and optionality

Storage sits at the centre of the southern adequacy problem because winter stress is not simply a matter of annual gas availability. It is a matter of being able to inject gas into the system at the right time and in the right location.

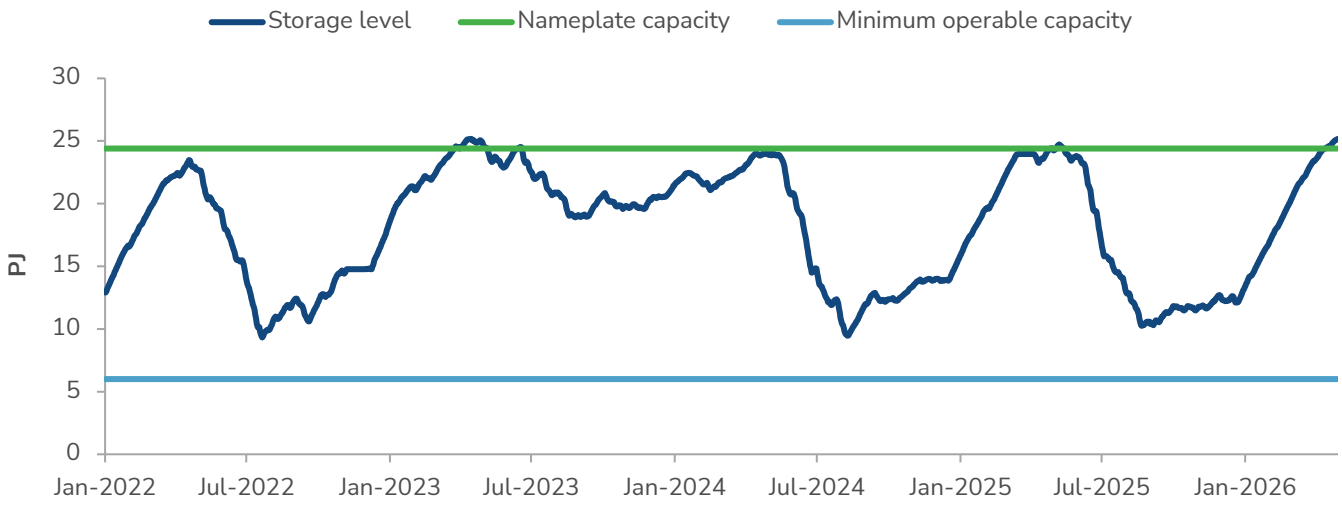
The Victorian Gas Security Statement makes the same point in broader system terms. It combines upstream supply, storage and network measures with gradual demand reduction, and presents storage as central to maintaining resilience as electrification reduces long-term gas demand while winter spikes and firming needs remain (Victorian Government 2025).

A fixed annual reservation rule cannot distinguish between a system that needs more winter optionality and a system that merely has a lower annual average buffer. Storage, by contrast, directly targets the timing problem. It is therefore a more natural part of the solution set for a peak-day reliability challenge. That does not mean storage alone is sufficient but that any serious response to the winter problem must treat storage as a first-order variable.

Figure 23 shows historic gas inventory levels at the Iona underground storage facility relative to both nameplate capacity and minimum operable capacity. The chart highlights a consistent seasonal cycle: inventories are drawn down sharply during winter periods, when southern system demand and peak-day stress are highest, and replenished during lower-demand months. This confirms Iona's role as an actively utilised seasonal balancing asset. Currently, it shows that storage levels are at a historic maximum highlighting the current strength of the gas market.

Importantly, the figure also shows that storage levels have repeatedly operated above minimum operable thresholds, indicating that while winter reliance on storage is high, the facility has not yet been fully exhausted. This remaining headroom matters because it demonstrates that storage is already alleviating peak-day constraints and retaining some ability to respond to additional winter stress. The figure therefore illustrates why storage directly addresses the need for timely, flexible and rapidly deliverable supply during short, high-impact winter peaks.

*Figure 23: Historical Iona gas storage levels, 2022–2026 (PJ)*




*Source: ACCC 2026a, Lochard Energy.*

## The role of transport in location-specific adequacy

Transport is the second major lever because the southern market increasingly depends on gas moving from other regions as Bass Strait production declines. The 2026 Victorian Gas Planning Report Update notes that

effective supply into the Victorian DTS is lower than total Victorian supply capacity because of transport constraints. It also notes the contribution of APA's Stage 3A expansion to additional southern capacity toward Victoria (AEMO 2026b).

APA's East Coast Gas Grid Expansion Plan provides the clearest currently public example of this response. Stage 3A includes three new compressors designed to increase north-to-south capacity for winter 2028, expanding the South West Queensland Pipeline, the Moomba to Sydney Pipeline and the Young–Culcairn lateral. APA says this would increase Young–Culcairn capacity by around 39 TJ/day and help ensure pipeline capacity is not the constraint to solving projected shortfalls (APA Group 2026).

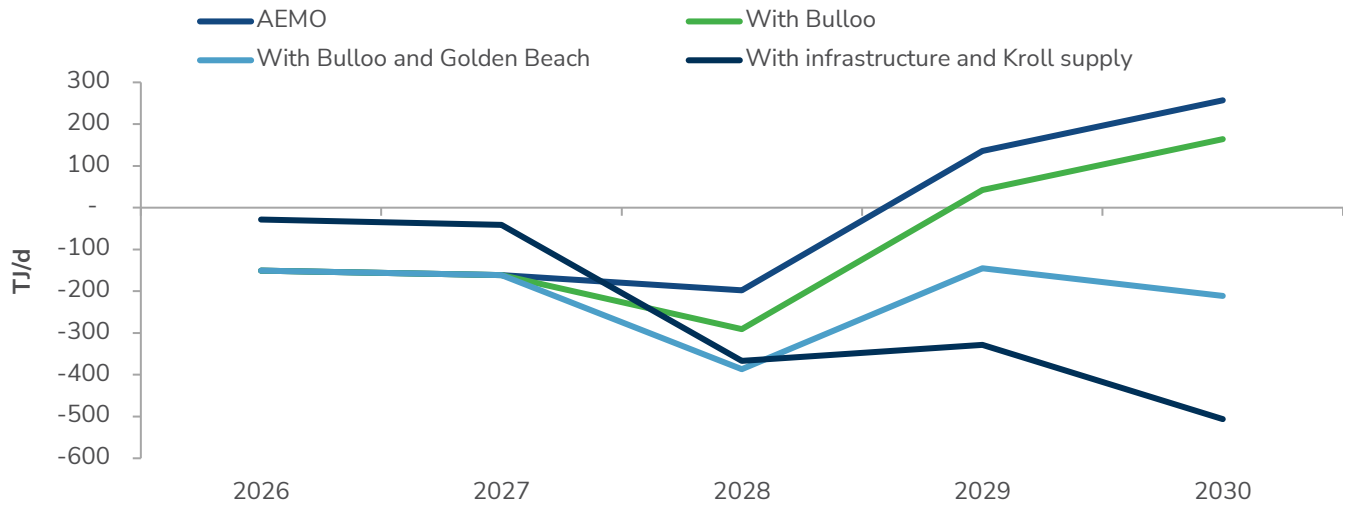
The AER's April 2026 Wholesale Gas Reserves Price Assumptions report provides independent confirmation that transport costs are already embedded in the market's forward pricing of southern supply. The report found that uncontracted gas reserves price assumptions for southern basins consistently exceed those for northern basins, with the differential widening from 2028 to reach $2.45/GJ by 2030, a gap the AER attributes to pipeline transportation costs given the south's increasing reliance on northern gas (AER 2026b). Firm pipeline transportation contracts to move gas from Wallumbilla to Culcairn or Wilton currently cost between $2.45 and $3.30/GJ. This means the delivered cost of northern gas into the southern system already carries a material transport premium that will only grow as southern production declines, further reinforcing that the adequacy challenge is one of deliverability and logistics, not aggregate volume.

The Victorian Gas Security Statement also confirms that the State is working on network and storage measures intended to improve resilience and to ensure gas is available to businesses, industry and gas-powered generation when required. The point is that the winter adequacy problem is partly a logistics problem, supply is only valuable to the southern system if it can physically reach the load centre at the time of stress (Victorian Government 2025; AEMO 2026b; APA Group 2026).

Figure 24 illustrates how southern peak-day supply gaps evolve under different assumptions about infrastructure expansion and supply development. The figure shows that, under AEMO's base assumptions, maximum daily shortfalls emerge before 2030, reflecting the interaction of declining local production and transport constraints into the southern system. When uncertain infrastructure developments are included, peak-day adequacy improves more materially.

The scenario that combines infrastructure expansion with Kroll supply assumptions shows the largest improvement, with peak-day shortfalls deferred well into the next decade. This progression demonstrates that the binding constraint on southern reliability is increasingly the ability to physically move gas into the market at times of peak demand, rather than the existence of gas volumes elsewhere in the system. The figure therefore reinforces that new supply only improves southern adequacy if sufficient pipeline capacity exists to deliver gas south during winter stress events. As a result, the southern adequacy challenge is fundamentally locational and operational, and solutions must prioritise transport capacity, timing and deliverability alongside upstream supply.

*Figure 24: Indicative southern peak-day supply gap under alternative infrastructure and supply scenarios (TJ/day)*




*Source: Kroll analysis of AEMO GSOO 2026a, APA Group 2026b, Wood Mackenzie 2026, Victorian Government 2019–2026.*

## The role of demand and firmness in managing adequacy

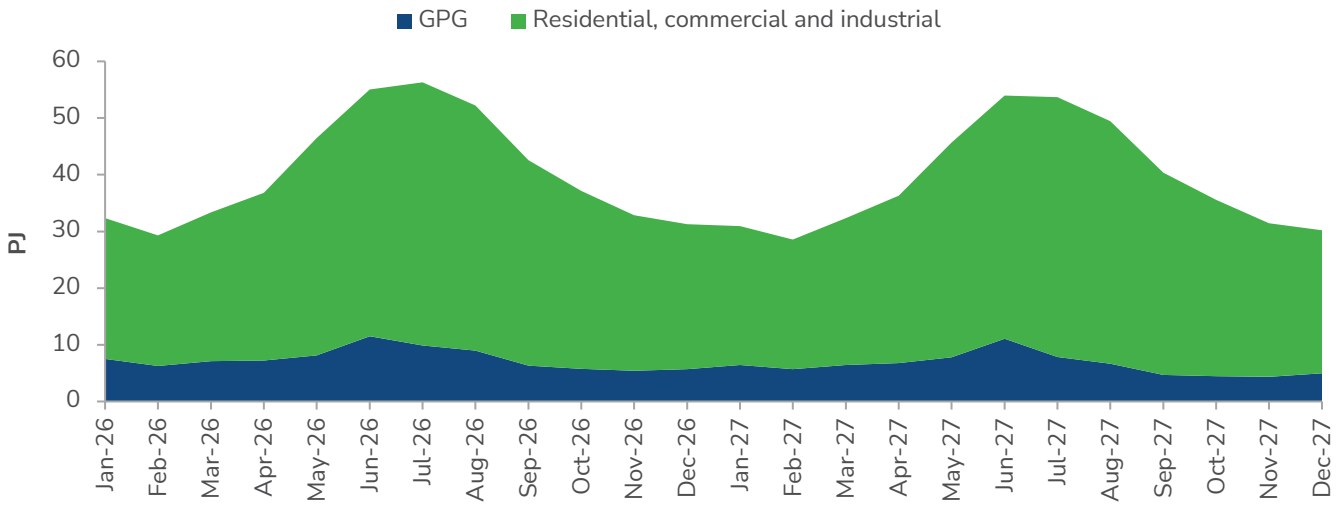
A well-designed response to winter adequacy should not look only at physical supply additions. It should also test the demand and operating assumptions that determine how much firm gas is actually needed on stress days. The 2026 Victorian Gas Planning Report Update explicitly links future peak-day pressure to gas-powered generation and states that gas-powered generation units may need to rely on secondary fuels during the most significant demand periods if additional infrastructure is not available (AEMO 2026b).

The Victorian Gas Security Statement adopts the same broader logic. It combines upstream supply and storage actions with gradual demand reduction, energy efficiency and electrification, arguing that these reforms can conserve gas for industry and for system firming. In that sense, the Statement treats avoided demand as effectively part of the supply-security response (Victorian Government 2025).

For the purposes of this report, the peak-day adequacy problem is partly defined by how much firm gas demand persists under stress, especially from gas-powered generation and household heating. This means the relevant design comparison is not simply reservation versus no reservation. It is reservation versus the best available package of storage, transport, supply and demand-side firmness assumptions (AEMO 2026b; Victorian Government 2025).

Figure 25 and Figure 26 illustrate why winter adequacy in the Southern States depends not only on physical supply additions, but also on how much firm gas demand is assumed to persist during stress periods. Figure 25 shows that southern gas demand remains strongly seasonal, with winter peaks dominated by residential, commercial and industrial heating load, while GPG constitutes a smaller but still material component.

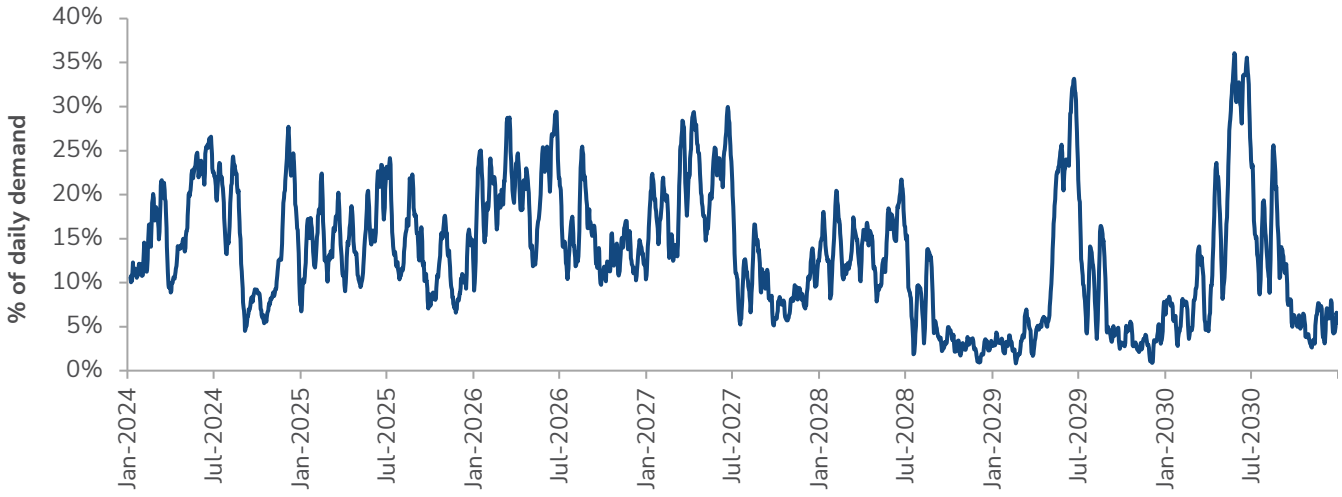
*Figure 25: Forecast monthly gas demand by consumer type, 2026–27 (PJ)*




*Source: AEMO GSOO 2026a.*

Figure 26 adds an important operational dimension by showing that GPG demand is highly volatile on a daily basis, with sharp episodic spikes that can account for a substantial share of total daily gas demand during specific stress events. Together, the figures demonstrate that peak-day firmness requirements are sensitive to assumptions about generator behaviour, fuel-switching capability and demand-side responses. Measures that reduce or reshape winter heating demand, improve energy efficiency, or enable GPG to rely on secondary fuels during extreme periods can materially lower the volume of firm gas the system must carry. The figures therefore reinforce the importance of a broader package that optimises supply, storage, transport and demand-side firmness to minimise peak-day risk.

*Figure 26: Gas-powered generation demand as a share of total daily demand (%)*




*Source: AEMO GSOO 2026a.*

## Conclusion

The evidence in this section shows that the remaining adequacy risk is concentrated in the southern system and is most acute under winter peak-day conditions. The issue is not simply whether enough gas exists across the east coast over a year. It is whether enough gas can be delivered into the southern system on the days when local production, northern inflows, storage withdrawal and gas-powered generation requirements are all tested at once.

That diagnosis matters for policy design. If the binding risk is operational, seasonal and locational, then the policy response must be assessed against those same dimensions. A standing export-linked domestic supply obligation may increase aggregate domestic availability, and the draft design framework includes flexibility mechanisms intended to recognise practical constraints in how obligations are met. However, the central question remains whether the framework supports firm, deliverable supply into the southern system when stress actually emerges.

The implication is not that government should be passive. It is that intervention should be targeted to the risk the evidence identifies: winter peak-day adequacy, storage readiness, transport deliverability, timely investment in southern supply and infrastructure, and clear operational triggers for response. This provides the basis for the later assessment of whether a standing reservation obligation is proportionate, or whether a more conditional adequacy framework would better match the problem.

SECTION 06

# Design complexity and calibration problem

## Purpose of this section

The preceding sections established that the east coast gas market is not currently in broad structural annual shortage. The evidence points instead to conditional near-term adequacy, with residual risk concentrated in the southern system and increasingly operational in character. The binding challenge is winter peak-day deliverability, declining legacy southern production, storage and transport constraints, and the timing of new investment, not a simple shortage of annual gas volume.

This section examines why a standing export-linked domestic supply obligation is difficult to calibrate to that problem, and why the headline reservation rate alone does not determine the policy's practical effect. This task is now informed by the draft design framework released for consultation, which provides greater detail on the proposed export approval process, domestic supply obligation, compliance pathways and flexibility mechanisms (DCCEEW and DISR 2026a; DCCEEW and DISR 2026b).

The analysis is directly relevant to the proposed standing export-linked domestic supply obligation. A standing obligation may increase the amount of gas notionally available to the domestic market in aggregate. However, the key question is whether the proposed framework, including its flexibility mechanisms, improves deliverable supply into the southern system when stress actually emerges, or whether it displaces local production, increases reliance on constrained transport infrastructure, weakens investment incentives and imposes broader economic costs.

## The market failure question

Before turning to design, it is important to address the framing that has underpinned successive interventions in the east coast gas market. The Gas Market Review and ministerial statements have described recent policy measures as responses to "market failures or emergency crises" (DCCEEW and DISR 2025; DCCEEW 2026a; Bowen, King and Ayres 2026). That language is important because, in economic terms, durable intervention is usually justified by a clear diagnosis of the problem the intervention is intended to correct. A persistent market failure, such as market power, externalities, information failures or coordination failures, points to a different policy response from a temporary shock, a transitional adequacy risk or a deliverability constraint.

The evidence reviewed in this report suggests that the east coast gas market's recent problems are better understood as a combination of structural exposure, external shocks and investment-delivery challenges, rather than as a simple case of persistent market failure requiring permanent volume control. The development of large-scale LNG export capacity in Queensland linked the east coast market more directly to international LNG and oil-linked pricing. The 2022 global energy shock then amplified that exposure under exceptional conditions. More recently, the evidence points to conditional near-term adequacy, with residual risk concentrated in southern winter peak-day deliverability as legacy production declines and the system becomes more dependent on storage, transport and timely new investment.

This distinction matters for policy design. If the problem is a durable market failure that prevents efficient allocation in normal conditions, then a standing structural intervention may be warranted. If the problem is instead episodic disruption, international exposure, uncertain investment timing and location-specific deliverability risk, then the appropriate policy response should be more targeted: improving market information, strengthening adequacy assessment, supporting timely investment, managing operational risks and intervening only where credible adequacy or deliverability risks are present.

This is not an argument for policy absence. The evidence clearly indicates that government has a legitimate role in monitoring adequacy, improving transparency, reducing barriers to timely supply, coordinating infrastructure planning and protecting consumers from acute disruption. The question is whether a standing export-linked domestic supply obligation is the right instrument for that task. A measure designed around annual domestic volume may be poorly matched to a problem that is conditional, seasonal, regional and dependent on physical deliverability.

The supply picture reinforces this point. The east coast does not face a geological scarcity problem. Official and market evidence indicates that substantial reserves and resources exist, but not all of that potential supply is approved, financed, connected, contracted or deliverable when and where it is needed. The core challenge is therefore converting resources into timely, firm and accessible supply. That is a problem of investment timing, infrastructure development, approvals, contracting and operational readiness. A policy framework that weakens those conditions may worsen the very adequacy risk it is intended to address.

The relevant policy test is therefore not whether government should intervene in the gas market at all. It is whether the form of intervention is proportionate to the market problem identified by the evidence. On the evidence developed in this report, the case is stronger for a targeted adequacy and deliverability framework than for a standing obligation that applies more broadly or more continuously than the relevant system stress requires.

## The intervention spectrum - where reservation sits and where the problem points

Policy intervention in the east coast gas market can be understood across a spectrum. At one end are market-enabling measures that improve transparency, information, liquidity and coordination while preserving market-based allocation. At the other end are market-replacing measures that administratively allocate supply, mandate fixed volumes or override market signals on an ongoing basis.

This spectrum is useful because the appropriate form of intervention depends on the nature of the problem being addressed. Where the problem is poor information, weak transparency or uncertainty about future adequacy, market-enabling measures may be most appropriate. Where the problem is a credible but conditional adequacy risk, market-shaping measures may be justified, such as mechanisms that strengthen monitoring, require early supply commitments, or condition specific obligations on evidence that deliverability risk is likely to bind. Where the problem is acute crisis or persistent failure of market allocation, more direct market-constraining measures may be warranted.

A standing export-linked domestic supply obligation sits toward the more interventionist end of this spectrum. It does not merely improve information or coordination. It links LNG export approval to the satisfaction of a domestic supply obligation, defined by reference to annual LNG export volumes. The draft design framework recognises that this architecture requires flexibility, including mechanisms to account for existing contracts, infrastructure constraints, annual DSO variation and the release of surplus DSO volumes (DCCEEW and DISR 2026a; DCCEEW and DISR 2026b). However, those mechanisms operate within a framework whose starting point remains a standing annual obligation. That design may be appropriate if the problem is persistent aggregate scarcity or systematic diversion of gas away from domestic users. It is less clearly matched to a problem that is conditional, seasonal, regional and dependent on physical deliverability.

The evidence developed in this report points to the latter characterisation. The official record does not indicate a broad structural annual shortage in the near term. It points instead to conditional adequacy, residual risk concentrated in the southern system, winter peak-day deliverability constraints, declining legacy southern production, storage and transport dependence, and the need for timely new investment. A policy response calibrated to that diagnosis would focus on the conditions under which risk actually binds, rather than applying a standing obligation as if the market were in continuous annual deficit.

The Western Australian reservation model is often cited as a reference point, but the east coast market is structurally different. Western Australia is more geographically contained and less interconnected with other domestic gas regions. The east coast market spans multiple jurisdictions, is physically interconnected through a long-distance pipeline network, is linked to international LNG markets through Queensland, and faces its most acute adequacy risks in the southern system, where local production, storage and transport constraints determine winter deliverability. These differences do not mean that reservation is irrelevant as a policy option, but they do mean that the east coast policy test must be specific to east coast market structure.

The implication is that the evidence points more naturally toward market-enabling and market-shaping interventions than toward an inflexible, standing market-constraining obligation. A proportionate framework would improve information, strengthen adequacy monitoring, identify credible southern deliverability risks early, preserve incentives for new supply, storage and transport investment, and activate stronger measures only when the evidence shows that adequacy or deliverability risk is likely to bind.

This does not rule out targeted obligations in all circumstances. It means that obligations should be tied to the problem being solved. If the relevant risk is winter peak-day deliverability in the southern system, then the policy mechanism should be capable of testing and responding to that risk directly. A broad annual export-linked obligation may increase domestic availability in aggregate, but it is not well targeted if it does not improve firm, deliverable supply where and when the system comes under stress.

## Complexity and uncertainty in the design of standing export-linked domestic supply obligation

Even setting aside the question of whether a standing reservation is the appropriate instrument, the practical operation of an export-linked obligation depends critically on its detailed design. Small differences in policy specification, including scope, unit of obligation, compliance mechanism, treatment of contracts, timing and flexibility, can materially alter outcomes, distributional effects and feasibility.

The 7 May 2026 announcement confirmed a headline reservation rate of 20 per cent applied to LNG export volumes through an export approval-based scheme (Bowen, King and Ayres 2026; DCCEEW 2026a; King 2026). The draft design framework now provides further detail on how the scheme is proposed to operate, including annual domestic supply obligations, export approvals, compliance plans, AER monitoring and enforcement, and flexibility mechanisms for existing contracts, infrastructure constraints, DSO variation and surplus DSO volumes (DCCEEW and DISR 2026a; DCCEEW and DISR 2026b).

However, the release of the draft design framework does not remove the calibration problem. It makes that problem more concrete. The framework shows that the scheme will require a series of administrative and judgement-based decisions about who carries the obligation, how compliance is demonstrated, when obligations can be varied, when surplus volumes can be released, and how project-specific constraints are treated. These matters will determine the practical effect of the scheme more than the headline 20 per cent rate alone.

## Scope of the obligation

A primary source of complexity concerns which LNG volumes are practically affected by the obligation. The headline rate is expressed against LNG exports, but the practical effect of the scheme depends on the treatment of existing contracts, exempt or grandfathered volumes, spot cargoes, uncontracted gas and project-specific export approval conditions. Where existing LNG commitments are preserved, the volume of gas that can be influenced in the short term may be materially smaller than the volume implied by applying the headline rate to total exports. This means that the headline 20 per cent rate may overstate the volume of gas that is practically available for redirection to the domestic market in any given year.

## Unit of obligation

A second area of complexity relates to the unit at which the obligation is assessed and enforced. In practice, the effect of the scheme will depend on whether obligations are calculated, varied and monitored at the level of individual LNG projects, project participants, related entities or the export approval holder. Even where a framework appears neutral at a system level, it can produce highly uneven effective burdens in practice. Structural differences across LNG projects, particularly in upstream gas availability and contractual commitments, mean that some projects may have limited practical capacity to contribute additional physical gas to the domestic market, regardless of the formal obligation.

## Source of reserved gas

There is also complexity around how reserved gas would be sourced in practice. Compliance could rely on physical delivery from upstream production, contracting with third parties, swaps, commercial arrangements with other producers, or other approved compliance pathways. These options may improve workability, but they also change the economic incidence of the scheme. For projects that are structurally short of gas or fully contracted, physical compliance may not be feasible, shifting the burden onto domestic markets and introducing new price and liquidity effects. In such circumstances, a reservation mechanism may reallocate existing gas rather than create incremental deliverable supply.

## Temporal structure

The timing of compliance matters. Annual accounting frameworks may not align well with seasonal demand profiles, export scheduling, storage cycles, or the lead times required to bring new gas supply to market. Short-term domestic tightness can coexist with annual adequacy, while annual domestic supply obligations may not ensure firm gas is available in the southern system under winter peak conditions. Flexibility mechanisms such as annual DSO variation or release of surplus DSO volumes may reduce some risks, but they also increase the importance of administrative judgement, information quality and transparent adequacy assessment (DCCEEW and DISR 2026a; DCCEEW and DISR 2026b).

## Contractual and institutional interactions

Export-linked reservation policies necessarily interact with existing long-term LNG contracts and established market institutions. Commitments to honour existing contracts constrain the volumes that can be practically influenced in the short term. At the same time, interaction with the ADGSM, Heads of Agreement, Gas Market Code and proposed export approval framework raises questions about policy hierarchy, transition and durability. The draft design framework moves toward a more integrated export approval regime, but the practical interaction between contract protection, compliance plans, AER monitoring and Ministerial decision-making will be central to the scheme's effect on contracting and investment decisions.

### Investment incentives and long-run adequacy

Finally, reservation design has implications for investment incentives. If the compliance burden falls disproportionately on exporters that have invested in upstream surplus, the commercial case for incremental exploration and development is weakened, a dynamic that becomes particularly acute when applied to the structurally heterogeneous east coast export sector, as examined below.

### Overall assessment

Taken together, the impacts of a standing export-linked domestic supply obligation are highly sensitive to detailed design choices. While the policy can be framed in simple proportional terms, its practical operation depends on project-level gas balances, contractual structures, compliance pathways, the distribution of discretionary export capacity and the operation of flexibility mechanisms. The draft design framework reduces some uncertainty by setting out the proposed administrative architecture, but it also confirms that the scheme will rely on variations, release mechanisms and project-specific assessments. System-wide obligations do not automatically translate into system-wide compliance in practice, and policy outcomes may be concentrated on a subset of projects irrespective of intent. These uncertainties raise a more concrete question: whether the structural characteristics of the east coast LNG export sector permit any uniform standing export-linked domestic supply obligation to operate as intended.

## Structural heterogeneity among east coast LNG exporters

The preceding discussion identified a number of design dimensions along which the practical operation of a standing export-linked domestic supply obligation is sensitive to specification. Those dimensions were discussed in general terms. This section applies that framework to the specific structural characteristics of the east coast LNG export sector, which reveal a further and more fundamental source of policy complexity: the exporters themselves occupy qualitatively different positions in the gas market, and a uniform reservation obligation will not produce uniform outcomes.

Three LNG export projects operate on the east coast. While they share a common regulatory and geographic context, their upstream gas positions, contractual structures and capacity to redirect gas to the domestic market differ markedly. These differences are not marginal. They are structural, reflecting the geological endowments, investment histories and commercial arrangements that underpin each project. Understanding them is essential to any realistic assessment of how a reservation mechanism would operate in practice.

The assessment that follows is based on Kroll analysis of ACCC gas inquiry material, Wood Mackenzie 2026 project-level supply data and publicly available LNG project disclosures. It distinguishes between each exporter's upstream gas position, contracted LNG export commitments, domestic supply position and discretionary or uncontracted export capacity. These factors are central to practical compliance capacity under any standing export-linked domestic supply obligation. A uniform reservation rate applied to total LNG exports may therefore produce materially different outcomes across projects, because the ability to contribute additional domestic gas depends on each project's physical gas position and contractual commitments, not simply on its share of total exports.

### Three distinct structural positions

The first exporter maintains substantial upstream gas production that materially exceeds its LNG export commitments. This project is a net contributor to the domestic gas market and has been for some time. It holds the largest share of discretionary, that is, spot and uncontracted, LNG export capacity among the three projects. In practical terms, this means it is the exporter with the greatest physical ability to comply with a domestic

reservation obligation. It has gas available beyond its contracted export commitments, and it has the operational flexibility to redirect volumes to domestic buyers. Under any plausible interpretation of a standing export-linked domestic supply obligation, this exporter would bear the largest share of the compliance burden, not because of any policy intention, but because it is the only project with sufficient surplus to absorb a material obligation.

The second exporter also produces more gas upstream than it ships as LNG, but the margin is narrower. Its upstream surplus, while positive, is modest relative to its total export volumes, and its exposure to the spot LNG market is limited. This project could contribute to a domestic reservation, but its capacity to do so is constrained. Under an aggregate standing export-linked domestic supply obligation, it would bear a moderate share of the compliance burden, meaningful but substantially less than the first exporter, and disproportionately small relative to its share of total exports.

The third exporter occupies a fundamentally different position. Its upstream gas production falls well short of its contracted LNG export obligations. This project is structurally short of gas: it does not produce enough to meet its own export commitments, let alone divert volumes from its own portfolio to the domestic market. It has limited or no discretionary LNG export capacity, and it sources additional gas from third parties to fulfil contracted commitments. Under a standing export-linked domestic supply obligation, this exporter may have limited practical capacity to contribute additional physical gas from its own resources. Compliance through third-party purchases or other commercial arrangements may be possible, but such compliance would not necessarily increase net domestic supply if it simply reallocates gas already available within the domestic market.

## The mechanical concentration of burden

These three structural positions produce a striking distributional consequence under an aggregate or collective standing export-linked domestic supply obligation. When the obligation is expressed as a system-wide requirement, for example, 20 per cent of total LNG exports, the arithmetic of compliance does not distribute evenly across exporters. The structurally short exporter has limited capacity to contribute additional physical gas from its own portfolio, because it does not hold surplus gas available for redirection. The exporter with a narrow surplus contributes modestly. The exporter with substantial surplus and discretionary capacity absorbs the residual which, in practice, is the majority of the obligation.

This concentration is not a policy choice. It is a mechanical outcome of applying a uniform rule to a heterogeneous sector. The burden falls where the gas is, and the gas is not evenly distributed. Publicly available data on project-level production, export volumes and upstream balances confirm that the effective compliance burden under an aggregate framework would be heavily concentrated on one, or at most two, of the three east coast LNG projects.

The corollary is equally important: the headline reservation rate substantially overstates the effective rate for the sector as a whole, because a significant share of total exports is produced by a project that cannot participate in compliance. As documented in the scenario analysis that follows, this is the primary reason the effective reservation rate can fall from 20 per cent at the headline level to as little as 15 per cent, or lower, once structural constraints are accounted for.

## Implications for investment and long-run supply adequacy

The concentration of compliance burden on exporters with upstream surplus creates a perverse dynamic for investment incentives. Projects that have invested in upstream gas development, and that currently produce more gas than they export, are precisely the projects that would bear the cost of a reservation obligation. Projects that have not invested in upstream surplus, or that have structured their operations around third-party gas purchases, face no incremental cost under the same policy.

Over time, this asymmetry weakens the incentive to invest in the upstream gas production that would improve long-run domestic supply adequacy. If the reward for building upstream surplus is an increased reservation burden, the commercial case for incremental exploration and development is diminished. This is not a theoretical concern. The east coast gas market faces well-documented challenges in attracting new upstream investment, and policy settings that penalise existing surplus production risk compounding those challenges rather than alleviating them.

The implication is that a reservation mechanism designed to improve domestic gas availability in the short term may, if poorly specified, reduce the investment that would improve domestic gas availability over the medium and longer term. This tension is inherent in any standing, uniform reservation obligation applied to a structurally heterogeneous sector.

## A design problem, not a compliance problem

The structural heterogeneity of east coast LNG exporters presents the Government with a genuine design problem. A uniform reservation rate applied across all exporters, whether at the project level or in aggregate, does not produce uniform compliance, uniform burden-sharing, or uniform incentive effects. The sector's diversity means that the Government faces a difficult trade-off among three objectives:

- **Uniformity**: applying the same reservation rate to all exporters
- **Contract sanctity**: honouring existing long-term LNG contracts
- **Supply adequacy**: generating meaningful additional domestic gas volumes

The draft design framework seeks to manage this trade-off through flexibility mechanisms, compliance pathways and administrative discretion. However, the underlying tension remains. Honouring contracts and applying a uniform rate may limit the effective domestic supply gain, because many export volumes are contracted and structurally short exporters may have limited capacity to contribute additional physical gas. Achieving meaningful supply gains while honouring contracts may concentrate the burden on exporters with surplus. Achieving both uniformity and meaningful supply gains may require interference with existing contractual positions, which the Government has indicated it does not intend to pursue.

## The path toward differentiated arrangements

The combination of structural heterogeneity, contractual protection and the flexibility mechanisms in the draft design framework suggests that the practical implementation of a standing export-linked domestic supply obligation may evolve toward differentiated arrangements across exporters. This would not necessarily occur through explicit bilateral agreements alone. It could occur through compliance plans, project-specific variation decisions, recognition of existing contracts, infrastructure-constraint assessments, release of surplus DSO volumes or export approval conditions. The announced export approval mechanism creates an administrative interface through which project-specific circumstances can be taken into account (DCCEEW and DISR 2026a; DCCEEW and DISR 2026b).

If the scheme does move in this direction, the effective reservation rate for the sector as a whole would depend not on the headline 20 per cent, but on the specific terms agreed with each exporter. That would be consistent with the structural reality documented in this section: a uniform rule applied to a heterogeneous sector produces concentrated, uneven outcomes, and the natural resolution is to tailor obligations to the compliance capacity and contractual position of each project. It would also mean that the range of economic outcomes modelled in this

section, from a hard mandate benchmark to a feasibility-constrained lower bound, captures not only different policy designs, but also different negotiated endpoints.

This may be a pragmatic response to the structural heterogeneity of the LNG exporters, but it also creates a governance and transparency problem. If compliance obligations are determined through project-specific negotiations, exemptions, licence conditions or bespoke undertakings, the effective operation of the scheme may become less visible to the wider market. Domestic buyers, upstream producers, storage providers and infrastructure investors may find it difficult to assess how much gas will actually be available, when it will be available, which projects are carrying the obligation, and how future obligations may change. That uncertainty matters because the core adequacy challenge identified in this report depends on timely investment in production, storage and transport capacity. A framework that relies heavily on firm-specific negotiation may therefore solve one implementation problem while creating another: weaker transparency and less predictable investment signals.

The broader implication is important. Whether the reservation operates as a uniform rule, a system of formal exemptions, or a set of bespoke bilateral agreements, the economic outcomes will fall somewhere within the range defined by the structural constraints documented above. The headline rate sets an upper bound. The structural capacity to comply sets a lower bound. The distance between the two is large, and the point at which the policy settles within that range is a matter of detailed design and negotiation, not of headline policy announcement. That is why the modelling in this section considers a range of effective reservation rates rather than a single number.

### Implications for the analysis that follows

This structural heterogeneity, and the design uncertainty it creates, means that the proposed scheme cannot be assessed by reference to the headline 20 per cent rate alone. The relevant question is whether reservation, as it may operate in practice, improves deliverable domestic supply at a cost that is proportionate to the problem being addressed. The available literature provides useful guidance on the likely mechanisms and trade-offs, but it does not answer that east coast-specific question directly.

## What the literature tells us

The available public-domain economic literature on domestic gas reservation points to a consistent conclusion: reservation can lower domestic prices for some users, but it does so by reallocating gas away from higher-value uses and by weakening investment incentives. The central policy question is therefore not whether reservation can reduce prices in the short term. It is whether those price effects are large enough, durable enough and well targeted enough to justify the broader economic costs.

The benchmark Australian study is Neill, Hartley, Tyers and Adams (2019), which assessed the Western Australian domestic gas reservation using a detailed gas-market model linked to a multi-regional computable general equilibrium framework. The study found that reservation imposed a net national welfare cost, reduced household welfare and did not confer a lasting net benefit on Western Australian workers or consuming households. The welfare loss arose because gas was redirected from higher-value export use to lower-value domestic use, while lower domestic prices changed the distribution of income rather than creating a net national gain.

Other Australian studies have reached a similar directional conclusion. Deloitte Access Economics, ACIL Allen, the Grattan Institute and the Western Australian Economic Regulation Authority have each raised concerns that reservation policies can impose economy-wide costs, distort investment incentives and reduce the efficiency of gas market allocation (Deloitte Access Economics 2013, ACIL Allen 2014, Grattan Institute 2013, Economics

and Industry Standing Committee, Legislative Assembly of Western Australia 2024). The specific estimates differ across studies because the policy settings, modelling frameworks and market assumptions differ. However, the broad conclusion is consistent: reservation is not a costless affordability measure. It creates benefits for some domestic users, but those benefits must be weighed against foregone export income, weaker producer returns, lower investment and broader efficiency costs.

The international evidence reinforces this mechanism (OECD 2022). Countries that have used domestic reservation, export restrictions or below-export-parity pricing to hold down domestic gas prices have often experienced weaker upstream investment, reduced export reliability and tighter supply over time. The precise institutional settings differ across jurisdictions, so these examples should not be read as direct analogues for the east coast market. Their relevance is narrower but important: where policy suppresses realised prices or constrains access to higher-value markets without preserving investment incentives, the result can be lower future supply and a less resilient system.

Competition concerns also need to be considered. A standing export-linked domestic supply obligation does not automatically increase competition merely because it increases the volume of gas notionally available to domestic users. If obligations are administered through incumbent LNG exporters, or if reserved volumes are allocated through compliance-driven processes rather than competitive contracting, the policy may reinforce the position of large incumbents rather than support new entry. This matters in the east coast market because the residual adequacy risk is concentrated in the southern system, where smaller domestic-focused producers, storage operators and infrastructure providers are central to future deliverability.

This point is particularly important for policy design. A standing reservation obligation may reduce domestic prices in the short term by increasing domestic availability. But if that lower price displaces marginal southern production or weakens the business case for new supply, storage or transport investment, the policy can reduce the diversity and resilience of supply over time. In that case, a measure intended to improve domestic security can make the system more dependent on a smaller number of large producers and on constrained long-distance transport pathways.

The wider economic literature on energy market regulation points in the same direction. Regulatory intervention can be justified where markets are exposed to shocks, information failures, coordination problems or genuine security risks. But persistent or poorly calibrated intervention can increase regulatory risk, delay investment, reduce entry incentives and favour incumbents with existing assets. These effects are particularly important in capital-intensive sectors such as gas, where investment decisions are long-lived and depend on expectations about future prices, contracting conditions and regulatory stability (OECD 2022; Eyre and Pollitt 2016; Gowrisankaran et al. 2024).

Taken together, the literature supports three propositions relevant to this report. First, reservation can lower domestic prices, but primarily through redistribution and reallocation rather than by creating new supply. Second, the long-run cost of reservation depends critically on its effect on investment incentives, competition and infrastructure requirements. Third, the design of any intervention matters: a targeted mechanism linked to credible adequacy or deliverability risk is likely to have a different economic profile from a standing obligation whose default application is not closely tied to whether the system is under stress.

However, the existing literature does not answer the specific question addressed in this section. Most existing Australian studies either focus on Western Australia or assess reservation at a relatively high level of aggregation. They do not estimate the cost of applying an export-linked domestic supply obligation to the contemporary east coast market, with its existing domestic price discount, two-region north–south structure,

southern deliverability risk, finite pipeline capacity and potential displacement of southern production. That is the gap this section fills.

## Conclusion

This section has examined the design problem created by applying a standing export-linked domestic supply obligation to a market whose binding challenge is not broad annual scarcity, but conditional, regional and infrastructure-dependent adequacy risk. The central point is that the headline reservation rate does not determine the practical effect of the policy. Its impact depends on scope, compliance design, treatment of existing contracts, timing, source of reserved gas, flexibility mechanisms and the structural position of individual LNG exporters.

The draft design framework provides greater clarity on the proposed architecture of the scheme, including export approvals, domestic supply obligations, compliance plans, AER monitoring and flexibility mechanisms. Those features are important and may improve workability. However, they also confirm that the scheme will require project-specific assessments, variations, release mechanisms and administrative judgement. The calibration problem is therefore not removed; it becomes the central design task.

The east coast LNG sector is not homogeneous. The three export projects occupy materially different positions in relation to upstream gas supply, contracted LNG commitments, domestic supply activity and discretionary export capacity. A uniform reservation rate applied to total exports may therefore produce uneven compliance burdens. In practice, the obligation is likely to fall most heavily on projects with upstream surplus and discretionary export capacity, while structurally short or fully contracted projects may have limited practical capacity to contribute additional physical gas from their own portfolios.

This creates a calibration problem rather than a simple compliance problem. If the scheme is applied uniformly while existing LNG contracts are honoured, the effective domestic supply gain may be materially smaller than the headline rate implies. If the scheme is designed to generate meaningful additional domestic supply while honouring contracts, the burden is likely to be concentrated on a subset of exporters. If the scheme seeks both uniformity and meaningful supply gains, it may require interference with existing contractual positions, which the Government has indicated it does not intend to pursue.

The literature reinforces the need for careful calibration. Domestic gas reservation can lower prices for some users in the short term, but it does so by reallocating gas and changing investment incentives, rather than by automatically creating new deliverable supply. The relevant policy question is therefore not whether reservation can reduce domestic prices, but whether the price effect is large enough, durable enough and well targeted enough to justify the broader costs and risks.

The next section quantifies those trade-offs. It applies a purpose-built partial equilibrium model and Kroll's global computable general equilibrium model to assess how reservation scenarios affect domestic prices, southern production, export value, peak-day deliverability and economy-wide outcomes in the contemporary east coast market.

SECTION 07

# Modelling and Economic Impacts

## Purpose of this section

The preceding analysis shows that the proposed standing export-linked domestic supply obligation cannot be assessed by reference to its headline rate alone. Its practical effect depends on scope, compliance design, contractual treatment, exporter heterogeneity, flexibility mechanisms and the extent to which a nominal obligation translates into additional deliverable domestic supply. The draft design framework released for consultation provides greater detail on the proposed export approval process, domestic supply obligation and compliance pathways, but it also confirms that the effective operation of the scheme will depend on administrative decisions, project-specific constraints and mechanisms for varying or releasing DSO volumes (DCCEEW and DISR 2026a; DCCEEW and DISR 2026b).

This section therefore quantifies the consequences of applying reservation scenarios to the contemporary east coast gas market, including the effects on domestic prices, southern production, export value, peak-day deliverability and economy-wide output. The scenarios should be understood as policy impact tests rather than forecasts. They illustrate how costs and risks scale depending on whether the scheme operates close to the headline 20 per cent obligation or is reduced in practice by exemptions, contractual protections, project-specific feasibility constraints or flexibility mechanisms.

To test that question, this section draws on two modelling frameworks. The first is a purpose-built partial equilibrium model of the east coast gas market. The model represents the market as two interconnected regions, north and south, linked by a pipeline with finite capacity, and is constructed from project-level supply data, forward LNG price projections and AEMO planning assumptions. The second is Kroll's global computable general equilibrium model, KGEM, which is used to assess how the direct gas market effects flow through the broader economy.

The partial equilibrium model isolates the direct market effects of a reservation obligation: changes in domestic prices, displacement of production, foregone export revenue, producer impacts and transport or infrastructure costs. KGEM then captures economy-wide effects that the partial equilibrium model cannot, including sectoral reallocation, investment responses, trade effects and changes in gross state and domestic product.

Full model specifications, methodology and data sources are set out in Appendices A and B. This section focuses on the results and their implications for policy design.

## How we modelled the market

The partial equilibrium model is designed to test the direct market effects of a standing export-linked domestic supply obligation in the east coast gas market. It is not intended to be a detailed market forecast. Rather, it is a controlled analytical framework for isolating how a reservation obligation affects prices, production, exports, transport requirements and welfare under clearly defined assumptions.

This distinction is important in light of the draft design framework. The framework includes flexibility mechanisms and project-specific compliance pathways, meaning that the final policy may not operate as a simple uniform 20 per cent reservation in practice. The modelling therefore tests the economic mechanisms that would be engaged under different effective reservation rates, rather than assuming that the headline rate alone determines the practical outcome.

The model represents the east coast gas market as two interconnected regions. The northern region comprises Queensland and the Northern Territory and is characterised by large-scale gas production and LNG export

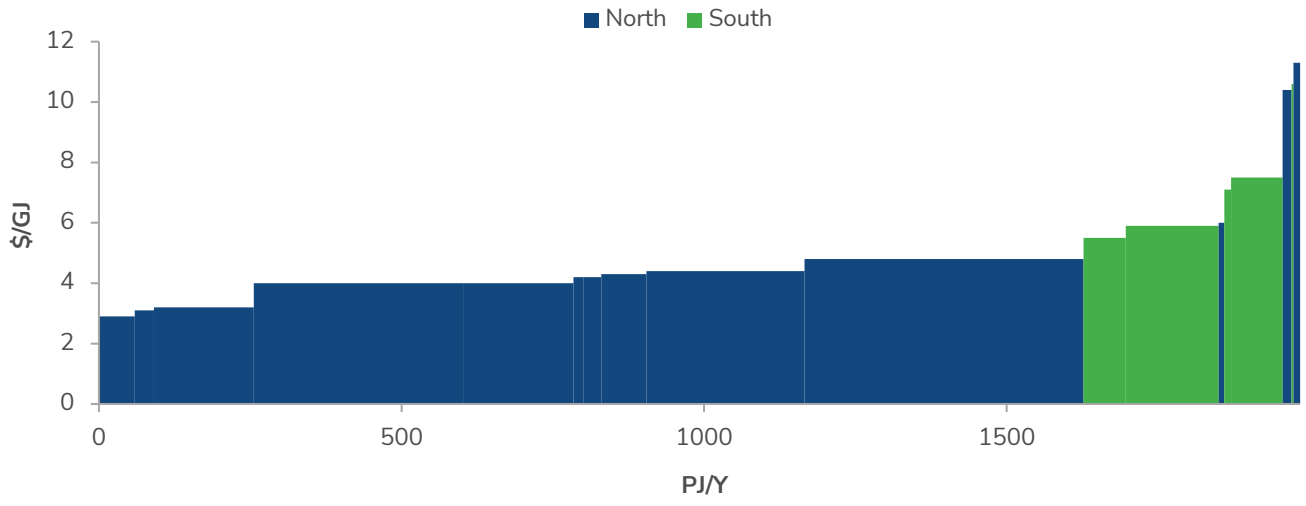
linkage. The southern region comprises Victoria, New South Wales, South Australia and Tasmania and is characterised by declining legacy production, major demand centres, winter peak demand, storage reliance and increasing dependence on north–south transport.

The two regions are connected by a pipeline with finite southbound capacity. This is central to the model because the preceding sections show that the relevant adequacy challenge is not simply whether enough gas exists across the east coast in aggregate, but whether gas can be delivered into the southern system when it is needed. The model therefore allows a reservation obligation to affect not only total domestic supply, but also the regional pattern of production and the extent to which southern demand is met by local production or by gas transported from the north.

Supply in each region is represented through step-function supply curves constructed from project-level and basin-level cost and production data. Each supply tranche is available if the realised market price is sufficient to cover its breakeven cost. This structure captures the central investment and displacement mechanism relevant to this section: if reserved exporter gas is supplied into the domestic market at lower cost than marginal southern production, it can displace southern supply that would otherwise be commercially viable.

Figure 27 illustrates this supply-curve structure for 2027. The figure orders available supply by cost and shows how progressively higher-cost supply is brought into the market as demand increases. This is central to the modelling results because the effect of a reservation obligation depends on where additional exporter gas enters the domestic supply stack and which existing supply it displaces. If the additional gas reduces the market-clearing price below the breakeven cost of marginal southern production, those projects are displaced first. The model therefore captures not only the price effect of reservation, but also its effect on the regional composition of supply.

*Figure 27: East coast gas supply curve, 2027 ($/GJ)*




*Source: Kroll modelling based on Rystad Energy 2025 and Wood Mackenzie 2026.*

Domestic gas demand is held fixed in the model, which is the same assumption used for the gas market modelling produced in the GSOO reports. In reality, any reservation that reduces domestic prices will have a marginal impact on demand. For 2027, total domestic demand is set at 469 PJ, comprising 135 PJ in the north

and 335 PJ in the south, based on AEMO planning assumptions. This assumption is deliberately conservative for welfare estimation. It means lower domestic prices do not generate additional domestic consumption benefits in the model, nor additional deadweight costs associated with the effective subsidisation of gas. Instead, lower prices redistribute income between producers, exporters and consumers while the real economic costs arise from foregone export value, displaced producer surplus and additional transport or infrastructure requirements.

The baseline case represents the market without an additional reservation obligation. Under this calibration, domestic demand is met through the least-cost combination of northern and southern supply, subject to the north–south pipeline constraint. The southern market-clearing price is set by the marginal southern producer. This baseline provides the counterfactual against which the reservation scenarios are assessed.

The reservation scenarios then impose an additional domestic supply obligation on LNG exporters. The obligation is modelled at 15 and 20 per cent to reflect the range canvassed during the policy development process and to show how costs scale as the obligation increases. The 20 per cent scenario is the central case for assessing the announced policy position. In each case, the model calculates the additional gas that LNG exporters must supply domestically, determines how that gas is absorbed in the domestic market, and solves for the new market-clearing prices and production pattern.

The key mechanism is displacement. Because domestic demand is fixed, additional exporter gas supplied into the domestic market must replace other domestic supply. The model identifies which production is displaced first, based on relative cost and regional deliverability. This is critical for the policy question because displacement is not neutral: if lower-cost exporter gas displaces higher-cost southern production, the policy may reduce domestic prices while weakening the local production base that supports southern winter deliverability.

The model then decomposes the direct economic effects into three categories. First, it estimates export revenue foregone when gas that would otherwise earn export-linked value is redirected into the domestic market. Second, it estimates producer surplus lost when domestic production, particularly southern production, is displaced. Third, it estimates transport and infrastructure costs associated with replacing local southern supply with gas transported from the north.

These cost categories are outputs of the model, not assumptions. They arise from the interaction between the reservation obligation, the supply curves, domestic demand, export values and the north–south transport constraint. The results should therefore be interpreted as a policy impact assessment under stated assumptions, rather than as a forecast of market prices or production in any particular year.

The partial equilibrium model is then linked to Kroll's global computable general equilibrium model, KGEM, to assess broader economy-wide impacts. The direct gas market results are translated into shocks to LNG exports, upstream gas investment, southern gas production and gas distribution productivity. KGEM is then used to estimate the effects on industry output, investment, trade, gross domestic product and gross state product.

Full details of the partial equilibrium model, data sources, assumptions and KGEM implementation are provided in Appendices A and B. The remainder of this section focuses on the model results and what they imply for the design of a proportionate domestic gas policy framework.

## What the reservation does

The reservation scenarios model the effect of requiring LNG exporters to supply additional gas into the domestic market. The Government's announced position is a 20 per cent export-linked domestic supply obligation, and

the draft design framework now provides further detail on the proposed export approval, compliance and flexibility architecture. However, the effective operation of the policy remains uncertain because the practical obligation may be affected by existing contracts, project-specific compliance constraints, infrastructure limitations, DSO variation mechanisms, release of surplus DSO volumes and other implementation decisions. For that reason, the modelling considers two scenarios that bracket a plausible range of policy outcomes.

- **Headline obligation case: 20 per cent of total exports.** This scenario assumes the 20 per cent reservation rate is applied broadly to LNG export volumes, with limited practical reduction for contracted volumes, structurally constrained projects or feasibility limitations. It represents an upper-bound case for assessing the economic effects of the announced headline obligation.
- **Feasibility-constrained case: effective rate of 15 per cent of total exports.** This scenario assumes the 20 per cent headline obligation is materially reduced in practice by contractual protections, project-specific compliance constraints, infrastructure limitations, release mechanisms, exemptions, carve-outs or negotiated implementation outcomes. The effective rate applied to total exports falls to approximately 15 per cent.

The 15 per cent scenario is not intended to represent an alternative announced policy. It is a feasibility-constrained case designed to reflect the possibility that a 20 per cent headline obligation is reduced in practice by the flexibility mechanisms and implementation constraints now recognised in the draft design framework, including contractual protections, infrastructure constraints, project-specific compliance limits, release mechanisms or negotiated arrangements with individual exporters (DCCEEW and DISR 2026a; DCCEEW and DISR 2026b).

For modelling purposes, LNG exports are assumed to be approximately 1,330 PJ in 2027. Exporters are assumed already to supply approximately 104 PJ to the domestic market. On that basis, the incremental domestic supply required under the reservation scenarios is approximately 95 PJ at a 15 per cent obligation and 161 PJ at a 20 per cent obligation.

Domestic demand is fixed at 469 PJ in 2027, comprising 134 PJ in the north and 335 PJ in the south. The additional gas supplied by LNG exporters under the reservation scenarios therefore does not create new domestic demand in the model. It has to be absorbed within an already supplied domestic market. In practical terms, that means it must either displace existing domestic production, change the use of transport and storage, or be released from the obligation through the policy's flexibility mechanisms.

This is the central mechanism in the modelling. Because the east coast market is forecast to have sufficient annual supply to meet domestic demand in 2027, the key question is not whether the reservation adds more gas to the domestic market in aggregate. It is which gas is displaced when the reserved volumes enter the market. A policy designed around annual domestic volume can increase the amount of gas notionally available to domestic users, but where demand is fixed, that additional gas necessarily changes the composition of supply.

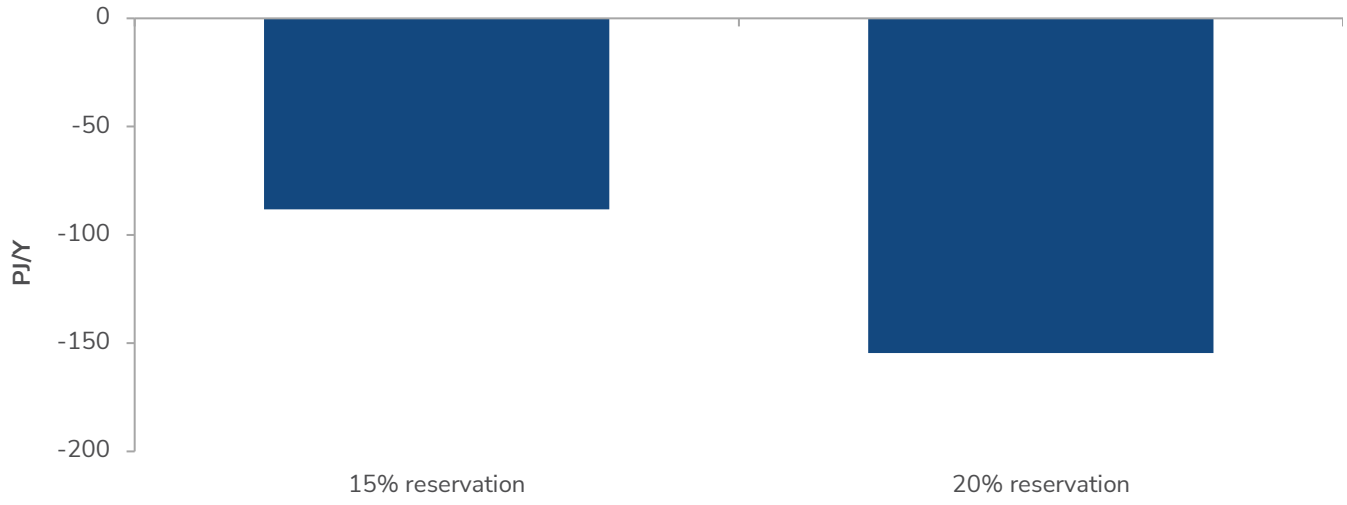
The displacement effect follows from the supply curve shown in Figure 27. Additional LNG-linked gas enters the domestic supply stack and reduces the volume required from higher-cost domestic producers. As those higher-cost sources are displaced, the marginal source of supply shifts down the cost curve. This is the mechanism through which reservation can reduce the modelled wholesale price.

That price effect, however, is inseparable from the production effect. The gas displaced by reservation is not necessarily irrelevant to system adequacy. In the east coast market, some of the marginal higher-cost production is located in the southern system, where local supply has particular value for winter deliverability and peak-day

resilience. If reserved LNG-linked gas displaces southern production, the policy may reduce average domestic prices while weakening the local production base that supports adequacy during periods of system stress.

In the model, reserved exporter gas first serves northern domestic demand. The remaining reserved volumes then flow south, subject to pipeline capacity, and enter the southern market. As this additional gas enters the southern supply stack, it displaces marginal southern production. Figure 28 shows the estimated reduction in southern production under the two reservation scenarios.

*Figure 28: Estimated reduction in southern production under reservation scenarios, 2027 (PJ/Year)*

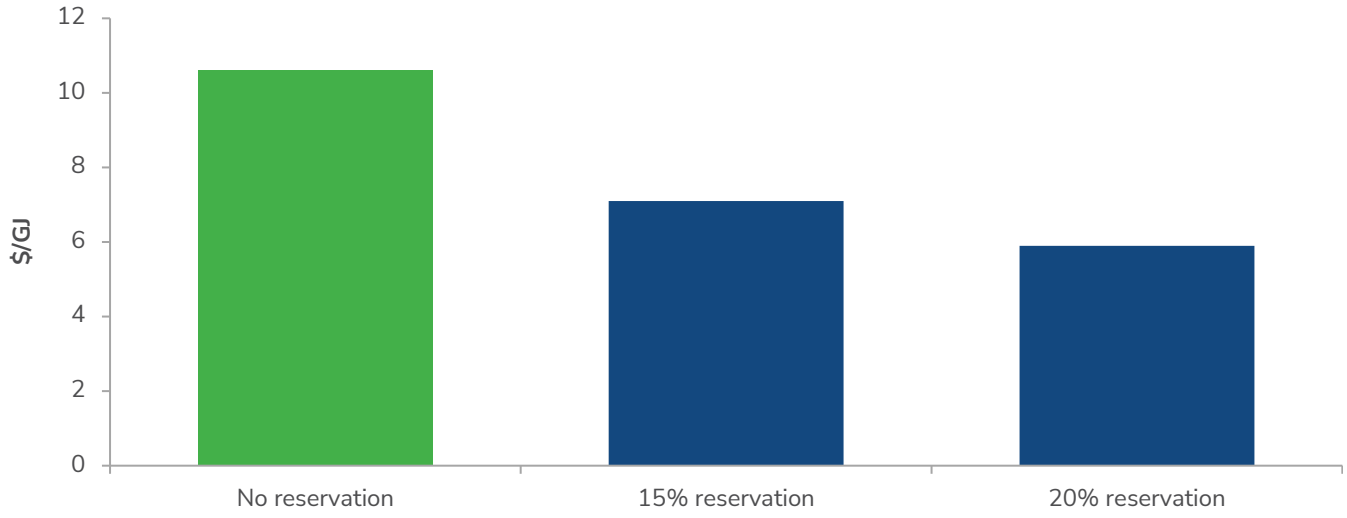



*Source: Kroll modelling.*

Figure 28 highlights an important policy trade-off. A reservation mechanism designed around annual domestic volume can reduce the domestic price by displacing higher-cost supply. However, where that displaced supply is located in the southern system, the price reduction may come at the cost of weakening the local production base that supports winter deliverability and peak-day resilience. Flexibility mechanisms may reduce this risk if they prevent unnecessary displacement, but they do not remove the underlying trade-off between lower prices, producer viability and local deliverability.

The price effect follows directly from this displacement. Under each reservation scenario, the marginal producer in the southern market shifts to a lower-cost basin. At 15 per cent, the marginal cost of production moves from $10.60/GJ to $7.1/GJ. At 20 per cent, the marginal basin moves further down the supply curve to $5.90/GJ. The southern domestic price falls accordingly, as shown in Figure 29.

*Figure 29: Estimated southern wholesale gas prices under reservation scenarios, 2027 ($/GJ)*




*Source: Kroll modelling.*

The model therefore shows why a reservation can produce lower domestic prices in the short term. It also shows why that price effect should not be interpreted as a pure efficiency gain. With domestic demand fixed, lower prices are achieved through redistribution and displacement: consumers pay less, but exporters receive less for diverted gas and marginal domestic producers lose production and margin. The policy question is whether those price reductions justify the associated loss of export value, producer surplus, investment incentives and deliverability resilience.

The modelling does not treat lower gas bills as irrelevant. Rather, it distinguishes between a transfer from producers and exporters to domestic users, which changes the distribution of income, and a real resource cost, which reduces economy-wide welfare.

## What a standing export-linked domestic supply obligation costs

The welfare impact of a standing export-linked domestic supply obligation can be understood in two parts: real economic costs and distributional transfers.

Real economic costs are costs that reduce national welfare. They include foregone export value where gas is redirected from higher-value export use to lower-value domestic use, lost producer surplus where otherwise viable domestic production is displaced, and additional transport or infrastructure costs where gas must be moved longer distances to replace local supply.

Distributional transfers, by contrast, change who receives income within the economy. Lower wholesale gas prices benefit domestic users, but under the model's assumption of fixed domestic demand, those lower prices do not generate additional gas consumption or a new efficiency gain. They transfer income from producers and exporters to consumers. That transfer can be commercially and politically important, but it should not be treated as a net gain to national welfare unless it is accompanied by additional efficiency benefits.

The first real economic cost is export revenue foregone. Each gigajoule redirected from export to domestic supply earns less than its export-equivalent value. At a 15 per cent reservation, the model estimates foregone

export value of approximately $851 million in 2027. This cost increases to $1,638 million as the reservation obligation rises to 20 per cent because more gas is diverted from export-linked use into the domestic market.

The near doubling of the impact is driven by two factors. First, the incremental volume diverted increases from 95 PJ to 161 PJ, a rise of around 70 per cent. Second, domestic prices fall by a further $1.20 per GJ. Together, these effects amplify the economic cost well beyond what the headline increase in the reservation rate alone would suggest.

The second real economic cost is lost southern producer surplus. As shown in Figure 28, reserved exporter gas displaces marginal domestic production, including southern production. Where this occurs, the producer surplus associated with that production is lost. This is not simply a transfer from producers to consumers. It reflects the loss of economic value from production that would otherwise have occurred at a price above its breakeven cost. At a 20 per cent reservation, the model estimates this loss at approximately $603 million.

The third real economic cost is transport and infrastructure substitution. When southern production is displaced, replacement gas must be transported from the north. That increases reliance on north–south pipeline flows and can create additional transport costs or, where capacity is insufficient, the need for new pipeline investment. At a 20 per cent reservation, the model estimates transport and infrastructure inefficiencies of approximately $617 million.

Together, these three real cost channels generate an estimated annual welfare loss of approximately $1,455 million under a 15 per cent reservation or $15.3 million per PJ reserved. The cost rises to approximately $2,858 million under a 20 per cent reservation or $17.7 million per PJ reserved, as shown in Table 4.

In practical terms, export revenue foregone is calculated as the difference between the export-equivalent value of diverted gas and the domestic price received for that gas. Lost producer surplus reflects the margin on southern production that is displaced when the market-clearing price falls below the breakeven cost of marginal supply. Transport and infrastructure inefficiencies reflect the additional cost of replacing local southern supply with gas transported from the north, including the cost implications of using finite north–south pipeline capacity. The calculations are set out in detail in Appendix A.

*Table 4: Estimated economic costs under reservation scenarios, 2027 ($ million)*

| | 15% reservation | 20% reservation |
|---|---|---|
| Exporter loss ($m) | 851 | 1,638 |
| Southern foregone production ($m) | 296 | 603 |
| Transport inefficiencies ($m) | 309 | 617 |
| **Total ($m)** | 1,455 | 2,858 |
| **Cost per PJ reserved ($m)** | 15.3 | 17.7 |

*Source: Kroll modelling. Figures may not sum due to rounding*

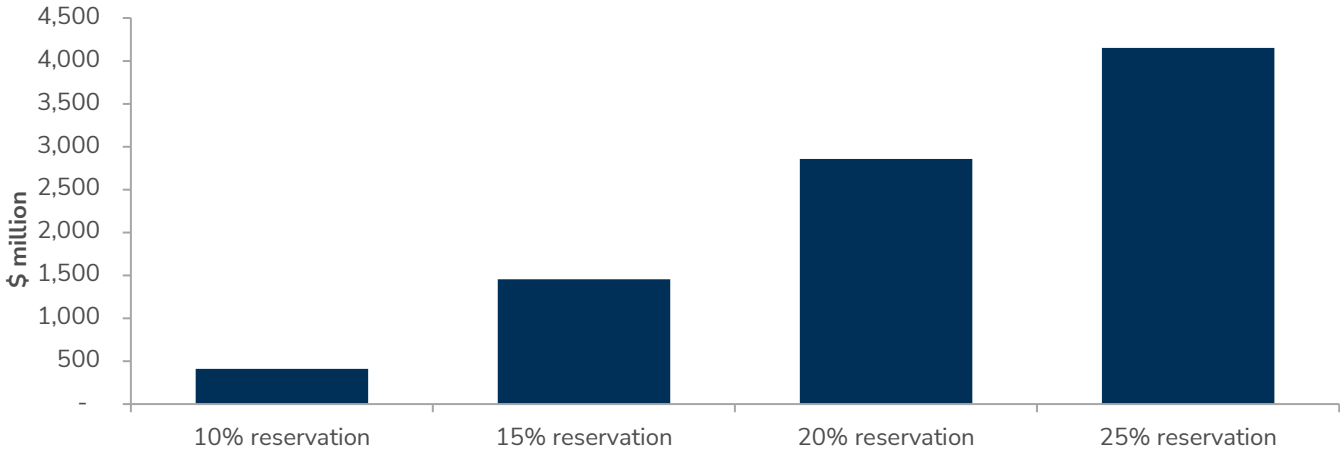
These results should be interpreted as effective-rate results rather than predictions of a single final policy outcome. If the draft design framework's flexibility mechanisms materially reduce the effective obligation, outcomes may sit closer to the 15 per cent scenario. If the framework operates closer to the headline obligation,

outcomes may sit closer to the 20 per cent scenario. The modelling therefore shows how the economic cost scales as the effective reservation rate increases.

The results indicate that the cost of reservation rises more than proportionately as the obligation increases. Figure 30 illustrates this effect across different reservation scenario sensitivities (as shown in Appendix A). This non-linear outcome reflects the fact that larger reservation volumes do more than simply depress domestic prices. They also displace domestic production, divert greater volumes away from export markets, and increase reliance on north–south transport infrastructure. As the policy expands, the marginal cost of each additional unit of reserved gas increases.

This result is particularly important for the east coast market because the displacement is not regionally neutral. The southern states rely on domestic-focused producers whose investment decisions depend primarily on domestic prices and contracting conditions. These producers do not have the same export optionality as LNG-linked producers in Queensland. A standing export-linked domestic supply obligation that lowers southern prices by displacing marginal southern production therefore has consequences beyond the immediate price effect. It can weaken the commercial conditions required to maintain and develop local supply in the part of the system where deliverability risk is most acute.

*Figure 30: Estimated economic costs under reservation scenarios, 2027 ($ million)*




*Source: Kroll modelling*

The model does not fully capture these longer-term dynamic and competition effects. It estimates the direct annual welfare cost associated with the reservation scenarios under stated assumptions. If lower expected prices also delay future investment, reduce entry by smaller producers, discourage storage or infrastructure development, or increase reliance on a smaller number of large producers, the true economic cost could be higher than the static estimates reported here.

As a cross-check, the direction of these results is consistent with previous Australian modelling of gas reservation. Neill, Hartley, Tyers and Adams (2019) estimated that the Western Australian gas reservation imposed a net welfare cost by redirecting gas from higher-value export use to lower-value domestic use and weakening investment incentives. The east coast results are not directly comparable because the market structure is different, but the mechanism is similar: reservation lowers domestic prices by reallocating gas, while imposing real costs through foregone export value, lost producer surplus and weaker investment signals.

The key policy implication is that lower domestic prices should not be assessed in isolation. A reservation can reduce the wholesale price paid by domestic users in the short term, but those price reductions come with economic costs. In the east coast market, those costs are amplified by the two-region structure of the market and by the fact that displaced southern production has value for winter deliverability. The question is therefore not simply whether reservation lowers prices, but whether the price reduction is worth the loss of export income, producer surplus, investment incentives and system resilience.

On the modelling presented here, that trade-off is unfavourable. The reservation reduces domestic prices by reallocating gas and displacing marginal supply, rather than by creating new deliverable supply. It therefore provides a short-term price benefit to some domestic users while imposing real economic costs and weakening the production base that supports southern system adequacy. That is why the welfare cost identified in this section is central to the policy design question: if the underlying risk is conditional, regional and peak-day in nature, a standing annual volume obligation is a costly and poorly targeted instrument.

## The potential impacts on peak-day supply

The partial equilibrium results show that reservation lowers domestic prices by displacing higher-cost domestic supply, including southern production. That displacement has a further implication that is not captured by annual welfare measures alone: it can weaken peak-day supply capability in the part of the market where adequacy risk is most acute.

This is also the key test for the draft design framework. Flexibility mechanisms, compliance plans and release mechanisms may affect the volume of gas ultimately supplied under the obligation, but they do not by themselves convert annual domestic supply into firm peak-day deliverability. The relevant question is whether the framework preserves or strengthens the local production, storage and transport capability required to meet southern winter peak demand.

This matters because the southern system's reliability challenge is not simply an annual volume problem. On a winter peak day, adequacy depends on how much gas can be physically delivered in a single day from local production, storage withdrawals and pipeline inflows from the north. Pipelines have finite daily capacity, storage withdrawal rates are limited, and local production provides firm deliverability close to the major southern demand centres. A policy that increases annual domestic availability but displaces local southern production may therefore reduce, rather than improve, peak-day resilience.

The reservation creates this risk because it substitutes export-linked northern gas for some southern production. On an annual basis, that gas can help meet domestic demand. But on a peak winter day, the relevant question is whether the gas can be delivered into the southern system at the required rate. If local production has been displaced and the replacement gas must travel through constrained north–south infrastructure, the system becomes more dependent on pipeline capacity and storage performance precisely when those assets are under greatest stress.

To illustrate this mechanism, an indicative peak-day assessment has been undertaken using assumptions aligned to AEMO's 2026 GSOO 1-in-20 year peak-day adequacy test for 2027. The assessment is deliberately stylised: it is designed to show the direction and potential scale of the peak-day risk if annual production displacement reduces local peak-day capability. These assumptions are:

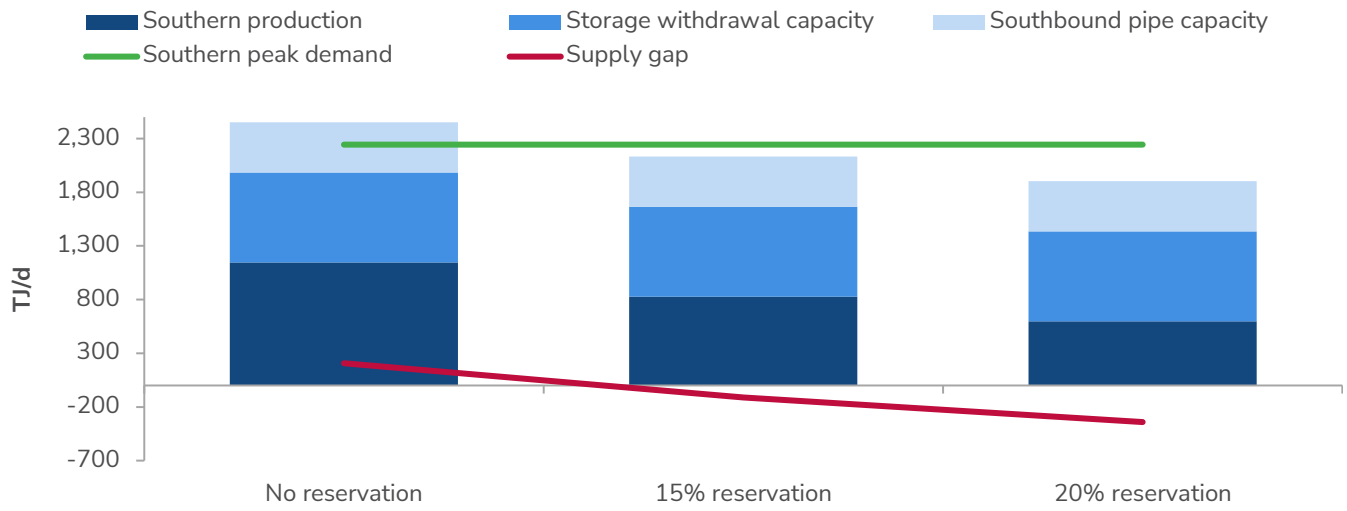
- peak southern daily demand of 2,244 TJ/day;
- maximum southern production of 1,146 TJ/day;
- maximum storage withdrawal capacity of 837 TJ/day; and
- maximum pipeline import capacity from the north of 468 TJ/day.

Under the baseline scenario, these sources provide aggregate peak-day capability of 2,451 TJ/day. Against peak demand of 2,244 TJ/day, this implies a surplus of approximately 207 TJ/day.

The reservation scenarios change this result by reducing southern production. Under the partial equilibrium modelling, a 20 per cent reservation displaces around 48 per cent of southern production in 2027. If that annual displacement translated proportionately into reduced peak-day production capability, maximum southern production would fall from 1,146 TJ/day to approximately 598 TJ/day. Holding storage withdrawal capacity, pipeline import capacity and peak demand constant, the baseline surplus would become a deficit of approximately 341 TJ/day.

The result becomes less acute at lower reservation levels. Under the 15 per cent scenario, the indicative peak-day deficit is approximately 112 TJ/day.

*Figure 31: Indicative southern peak-day supply balance under reservation scenarios, 2027 (TJ/day)*




*Source: Kroll modelling based on AEMO GSOO 2026a peak-day adequacy assumptions.*

This analysis should be interpreted as an illustrative stress test, not as a forecast. It assumes that annual production displacement translates proportionately into peak-day production capability. In practice, some displaced producers may be able to retain wells, processing facilities and connection infrastructure in a state of

operational readiness, allowing them to provide peaking supply during winter stress events even if they lose baseload production volumes during the year.

However, that qualification does not remove the policy concern. Maintaining peak-only production capability without sufficient baseload revenue may be commercially difficult, particularly for smaller southern producers with limited balance-sheet flexibility. If a standing export-linked domestic supply obligation lowers prices and displaces production for most of the year, it may weaken the commercial case for maintaining the very assets that provide local peak-day deliverability.

The direction of the result is therefore important. A reservation designed around annual domestic volume can reduce domestic prices while increasing reliance on constrained transport infrastructure and storage. It does not automatically increase firm peak-day capability. If it displaces local southern production, it may make the system less resilient under winter stress conditions.

This is the second major risk identified by the modelling. The first is that reservation can lower prices by displacing marginal southern production. The second is that this displacement can reduce the local production capability that supports winter peak-day adequacy. In a market where the binding risk is operational, seasonal and regional, that is a material calibration problem.

The broader implication is that infrastructure constraints, storage readiness and local production capability must be central to policy assessment. Measures that increase annual domestic volume without strengthening local production, storage withdrawal capability or peak-day transport deliverability risk addressing the wrong problem. They may leave the southern system more dependent on constrained infrastructure and less resilient during the periods when reliability matters most.

## Capturing economy wide impacts

The partial equilibrium results measure the direct welfare effects within the gas market. They show how a reservation affects domestic prices, export revenue, producer surplus, southern production and transport requirements. However, those direct gas market effects do not capture how the impacts flow through the broader economy.

To assess those wider effects, the partial equilibrium results are linked to KGEM, Kroll's global computable general equilibrium model. KGEM captures the broader channels through which the reservation affects the economy, including changes in LNG exports, upstream gas investment, domestic gas production, transport intensity, downstream industry costs, household income, trade and state economic activity.

The partial equilibrium and CGE results should be interpreted as complementary, not additive. The partial equilibrium model estimates direct gas-market welfare effects under stated assumptions. KGEM then traces how selected gas-market impacts flow through the wider economy. The CGE results are therefore not an additional cost to be added to the partial equilibrium welfare estimates; they provide a separate economy-wide perspective on the same policy shock.

Four shocks derived from the partial equilibrium modelling are imposed in KGEM. First, LNG exports are reduced to reflect gas diverted from export markets into the domestic market. Second, upstream gas investment falls as lower expected returns weaken the commercial case for new production. Third, southern domestic gas production contracts as reserved exporter gas displaces marginal southern supply. Fourth, gas distribution

productivity declines to reflect greater reliance on long-distance pipeline transport and associated infrastructure costs.

The CGE results show that the reservation generates gains for some downstream gas users, but that these gains are outweighed by broader losses across the economy. Lower wholesale gas prices reduce costs for some gas-intensive sectors, including gas-fired generation and selected manufacturing industries. However, those benefits are offset by reduced export income, weaker upstream investment, lower gas production, higher transport intensity and lower income flowing through the economy.

The largest direct industry impacts occur in the upstream gas sector. Under a 20 per cent reservation, Australian upstream gas output contracts as export-linked production is redirected and southern production is displaced. The effects are concentrated in the gas-producing states. Queensland is affected through lower LNG export revenue, while Victoria and South Australia are affected through reduced southern production and weaker investment in domestic supply.

The fiscal impacts are also material. Lower gas production and export revenue reduce royalty income for state governments. Under a 20 per cent reservation, the modelling indicates annual royalty revenue losses of up to approximately $90 million for South Australia and $293 million for Queensland. These losses are not incidental: they reflect the same underlying mechanism identified in the partial equilibrium model. Reservation lowers domestic prices by reducing producer and exporter revenue, and part of that revenue loss flows directly through to state government income.

The investment channel is particularly important because it links the economic modelling back to the adequacy problem identified in earlier sections. Under a 20 per cent reservation, aggregate upstream gas investment is around $2.8 billion lower by 2030 relative to the no-reservation baseline. This effect compounds over time because weaker investment incentives reduce the future capital stock available to support production. The impact is especially relevant in the southern system, where future adequacy depends on timely investment in new supply, storage and infrastructure as legacy production declines.

The timing of the announced obligation is particularly important. Southern production is forecast to decline materially over the next five to eight years, and AEMO's 2026 GSOO identifies the need for new supply, storage and transport investment from 2030 under most weather conditions. The decisions that will determine whether that investment occurs are being made now and over the next two to three years. A standing obligation that commences in 2027 and lowers expected domestic prices through displacement of marginal southern production risks disrupting investment decisions at the point in the cycle when commercial certainty matters most. If new southern supply, storage and infrastructure projects are deferred or cancelled because expected returns have fallen below investment thresholds, the system may be less able to meet the adequacy challenge when it becomes binding.

Table 5 summarises the estimated economy-wide impacts by reservation rate. At the macroeconomic level, the reservation reduces real GDP by approximately $350 million in 2030 under a 15 per cent reservation. The loss increases as the reservation rate rises, reaching approximately $653 million under a 20 per cent reservation.

The state impacts vary according to each state’s exposure to gas production, exports and consumption. Queensland experiences the largest decline, with gross state product falling by approximately $685 million in 2030 under a 20 per cent reservation, reflecting its exposure to LNG export revenue. Victoria also records a material decline, with gross state product falling by approximately $206 million, while South Australia falls by approximately $67 million as southern production and investment are reduced. New South Wales records a gain

of approximately $288 million, reflecting its position as a major gas-consuming state that benefits from lower wholesale gas prices. However, those gains do not offset the national losses.

*Table 5: Estimated economy-wide impacts under reservation scenarios, 2030 (2026 $ million)*

| | | 15% reservation | 20% reservation |
|---|---|---|---|
| Real GSP (2026 $m) | Australia (Real GDP) | -350 | -653 |
| | New South Wales | 154 | 288 |
| | Queensland | -367 | -685 |
| | Victoria | -110 | -206 |
| | Tasmania | 9 | 16 |
| | South Australia | -36 | -67 |
| Royalty losses (2026 $m) | Queensland | -213 | -293 |
| | South Australia | -90 | -90 |

*Source: Kroll modelling.*

The CGE results reinforce the core finding from the partial equilibrium modelling. Reservation does not create new economic value. It reallocates gas from export markets and marginal domestic producers toward domestic users, while reducing export income, weakening investment and increasing transport intensity. Some downstream sectors benefit from lower gas prices, but the economy as a whole is smaller because the policy reduces higher-value production and investment.

This matters for policy design because the economy-wide losses are not separate from the adequacy problem. The same investment effects that reduce GDP also weaken the future supply response in the parts of the market where adequacy risk is most acute. In other words, the reservation does not merely impose a static welfare cost. It also changes the future investment environment in a way that may make the southern system more dependent on constrained transport infrastructure and less able to develop new local supply.

The economy-wide modelling therefore confirms the broader policy conclusion. A standing export-linked reservation obligation may deliver lower prices for some domestic users, but it does so at the cost of lower export revenue, weaker upstream investment, reduced state government income and lower national economic output. Flexibility mechanisms may affect the scale and distribution of these impacts, but they do not change the underlying economic mechanism: the policy lowers prices by reallocating gas and changing investment incentives, rather than by automatically creating new deliverable supply. Where the underlying problem is conditional, regional and peak-day in nature, those costs are difficult to justify unless the policy can be shown to materially improve deliverable supply under stress.

## Conclusion

This section has examined the consequences of applying a standing export-linked domestic supply obligation to a market whose binding challenge is not broad annual scarcity, but conditional, regional and infrastructure-dependent adequacy risk.

The modelling produces a clear result. A reservation can reduce domestic wholesale gas prices in the short term, but it does so by reallocating gas rather than by creating new deliverable supply. In the partial equilibrium model, additional exporter gas enters a fixed domestic market, lowers the market-clearing price and displaces marginal domestic production. In the east coast market, that displacement is not neutral. It falls on southern production that has particular value for winter deliverability.

This is the first major policy concern. The reservation lowers prices by weakening part of the local supply base that supports the southern system. That may appear beneficial if the policy objective is assessed only through average annual domestic prices. But it is problematic if the relevant adequacy risk is winter peak-day deliverability, declining southern production and the need for timely investment in local supply, storage and transport.

The second concern is that the reservation increases infrastructure dependence. By displacing southern production, the policy increases reliance on gas transported from the north through finite pipeline capacity. That substitution imposes transport and infrastructure costs and can leave the southern system more exposed during peak winter periods. A policy designed around annual domestic volume does not automatically increase firm peak-day capability. If it reduces local production capability, it can make the operational reliability problem worse rather than better.

The third concern is the scale of the economic cost. The partial equilibrium modelling estimates annual welfare losses of approximately $1.5 billion under a 15 per cent effective reservation and $2.9 billion under a 20 per cent reservation. These costs arise from foregone export value, lost producer surplus and additional transport or infrastructure inefficiencies. They are real economic costs, not merely transfers between producers and consumers.

The economy-wide modelling reinforces this result. The reservation reduces LNG export revenue, weakens upstream investment, lowers state royalty income and reduces national economic output. Some downstream gas users benefit from lower wholesale prices, but those gains do not offset the broader losses. At the national level, the policy makes the economy smaller, while also weakening the investment conditions required to support future supply.

The draft design framework's flexibility mechanisms may reduce the effective obligation in some circumstances and may improve workability relative to a rigid mandate. However, they do not change the central economic mechanism identified in this section. To the extent the scheme increases domestic supply by reallocating export-linked gas into a fixed domestic market, it lowers prices by displacing existing supply and changing investment incentives. The critical question is therefore whether the final framework improves firm, deliverable supply into the southern system when stress actually emerges.

Taken together, the results show that a standing reservation obligation is a poor fit for the east coast gas market as diagnosed in this report. The policy is designed around annual domestic volume, while the evidence points to a problem of deliverability, timing, location and investment. It may lower prices for some users in the short term, but it does not directly address the conditions under which the southern system comes under stress. In doing so, it risks imposing large economic costs while weakening the very supply and infrastructure response needed to manage future adequacy risk.

The policy implication is not that government should stand back from the gas market. The evidence supports a continuing role for government in monitoring adequacy, improving transparency, reducing barriers to timely supply, coordinating infrastructure planning and acting where credible deliverability risks emerge. But the

modelling suggests that intervention should be calibrated to the actual risk. A framework focused on conditional adequacy, winter peak-day deliverability, storage readiness, transport capability and investment incentives is more likely to improve system resilience at lower economic cost than a standing annual reservation obligation.

The central conclusion is therefore straightforward. If the objective is to improve domestic gas security on the east coast, the relevant test is not whether a policy can increase annual domestic gas availability in aggregate. It is whether it improves firm, deliverable supply into the southern system when the system is under stress. On the modelling presented in this section, a standing export-linked reservation obligation does not meet that test unless its final design can demonstrate that it preserves or strengthens, rather than displaces, the local supply and infrastructure capability on which southern peak-day adequacy depends.

SECTION 08

# A Proportionate Policy Architecture for East Coast Gas

## Purpose of this section

Section 7 quantified the consequences of applying a standing export-linked domestic supply obligation to the east coast gas market. The modelling showed that reservation can reduce domestic wholesale gas prices in the short term, but that those price reductions are achieved by reallocating gas rather than by creating new deliverable supply. In the partial equilibrium model, additional exporter gas enters a fixed domestic market, lowers the market-clearing price and displaces marginal domestic production, including southern production that has particular value for winter deliverability.

The economic costs are material. The modelling estimates annual welfare losses of approximately $1.5 billion under a 15 per cent effective reservation and $2.9 billion under a 20 per cent reservation. These losses arise from foregone export value, lost producer surplus and additional transport or infrastructure inefficiencies. The economy-wide modelling reinforces the result: a standing reservation obligation reduces export income, weakens upstream investment, lowers state royalty income and reduces national economic output.

The release of the draft design framework does not remove this policy design problem. The framework includes flexibility mechanisms, compliance pathways and administrative processes that may improve workability relative to a rigid mandate. However, those mechanisms operate within a framework whose starting point remains a standing annual export-linked obligation. The question is therefore whether the final design should go further by making stronger intervention conditional on the evidence that adequacy or deliverability risk is actually likely to bind (DCCEEW and DISR 2026a; DCCEEW and DISR 2026b).

The policy design problem is therefore not whether government should be involved in the east coast gas market. The evidence developed in this report supports a continuing role for government in monitoring adequacy, improving transparency, reducing barriers to timely supply, coordinating infrastructure planning and acting where credible deliverability risks emerge. The question is whether the form, timing and intensity of intervention are proportionate to the problem the evidence identifies.

This section sets out that alternative. It does not argue against intervention. It argues that intervention should be matched to the problem. Where the evidence points to conditional adequacy, southern winter peak-day deliverability risk and the need for timely investment in supply, storage and transport, the first-order response should be a richer information and governance architecture that enables better decisions by market participants, regulators and governments closest to the source of risk.

## What the market already knows

The east coast gas market already generates a substantial and regularly updated body of evidence relevant to adequacy assessment. This evidence base is not perfect, but it is not thin. It already informs real policy decisions, including ADGSM assessments, market monitoring, infrastructure planning and near-term supply risk management.

AEMO's Gas Statement of Opportunities and Victorian Gas Planning Report Update provide structured assessments of annual and peak-day adequacy, committed and anticipated supply, demand conditions, storage, transport and the timing of emerging risks. These assessments are particularly important because they distinguish between different planning horizons and identify where risks are expected to emerge as southern production declines and the system becomes more dependent on storage, transport and new investment.

The ACCC's gas inquiry reports provide a complementary near-term view. They assess quarterly supply-demand balance, uncontracted LNG gas, market behaviour, contracting conditions and the role of storage. This evidence has been central to actual government decisions, including quarterly ADGSM assessments. Its value lies in its proximity to current market conditions: it is closer to operational reality than long-horizon planning forecasts.

The Gas Market Code and associated reporting obligations have also improved transparency over uncontracted gas volumes and timing. That matters because earlier policy concerns were amplified by uncertainty over how much gas would be available to domestic buyers, on what terms and when. Greater visibility over uncontracted gas reduces the information asymmetry that previously made near-term adequacy assessment more difficult.

Recent AEMC rule changes requiring AEMO to report gas infrastructure closures through established planning frameworks (AEMC 2025a) also improve the evidence base. Infrastructure closures, storage availability and pipeline capability are increasingly central to southern system adequacy. Bringing those issues into regular planning processes improves the lead time available for market and policy responses.

The significance of this evidence base is not simply that information exists. It is that the east coast market already produces evidence capable of supporting conditional policy decisions. Near-term adequacy assessments, uncontracted gas information, storage positions, infrastructure updates and observable market behaviour can all help determine whether a risk is credible, imminent and location-specific.

The current gap is therefore not a complete absence of information. It is that the information is fragmented across institutions, not always sufficiently granular, and not yet embedded in a transparent policy architecture that links evidence to graduated responses. A proportionate framework should build on the existing evidence base, not bypass it with a standing annual obligation that applies as the default instrument before the relevant system stress has been demonstrated.

The section proceeds in three steps. First, it examines what the east coast market already knows about adequacy conditions, and why the reliability of that evidence differs across near-term, medium-term and long-term horizons. Second, it sets out a preferred policy architecture built on three interlocking elements: enhanced AEMO market intelligence, a Gas Market Impact Assessment process for major government decisions, and a standing southern system adequacy assessment with a graduated response pathway. Third, it explains why this architecture is better calibrated to the problem identified in this report than a standing annual reservation obligation, even where that obligation includes flexibility mechanisms.

The core proposition is that policy should be evidence-led, conditional and proportionate. Better information is the starting point because it allows risks to be identified early and gives market participants, infrastructure investors and governments the opportunity to respond before more intrusive intervention is required. But the architecture is not limited to information provision. It also creates a disciplined pathway for targeted infrastructure support, storage and transport responses, export sequencing and, if necessary, time-limited obligations where credible adequacy or deliverability risks are demonstrated.

This is the key distinction from a standing annual obligation. The proposed architecture does not remove stronger intervention from the policy toolkit. It reserves stronger intervention for circumstances in which the evidence shows it is warranted, and sequences that intervention so that broader obligations do not precede lower-cost, better-targeted responses.

## How reliable is the evidence across different horizons?

The evidence base examined in Section 4 shows that reliability varies materially across planning horizons. That matters because evidence should not be used in the same way at every point in time. Near-term evidence can support operational and conditional policy decisions. Medium-term evidence is useful for planning and investment signalling. Long-term evidence is best understood as an early-warning device rather than a settled prediction of market failure.

Near-term evidence is the most reliable and most decision-relevant. AEMO's short-term supply projections have been broadly informative over a two-to-three year horizon, and actual government decisions, including recent ADGSM assessments, have been made using near-term balance evidence, ACCC analysis, AEMO advice, information about uncontracted gas and storage positions. At this horizon, committed and anticipated supply can be tracked against forecast demand with reasonable confidence, and observable market behaviour can be used to corroborate whether modelled risk is translating into real-world stress. This is the horizon at which conditional policy decisions can most credibly be anchored.

Medium-term evidence is useful, but increasingly conditional. Over a three-to-five year window, adequacy assessments depend more heavily on whether anticipated projects are delivered on schedule, whether infrastructure investments proceed as planned, whether storage remains available, and whether demand assumptions around electrification, gas-powered generation and industrial use hold. This evidence should influence planning, investment signalling and preparedness. However, it should not be treated as conclusive evidence of a present market failure unless corroborated by near-term indicators and observable market behaviour.

Long-term evidence is a warning device, not a mechanical trigger. At horizons beyond five years, planning outputs are necessarily sensitive to assumptions about technology, policy, project delivery, electricity market outcomes and demand behaviour. Section 4 showed that forecast shortfalls have been repeatedly deferred across successive planning vintages, while demand has tended to be overstated relative to realised outcomes. That does not mean long-term planning is unimportant. It means long-term projections should be used to identify where preparedness and investment may be needed, not to justify standing obligations that apply regardless of whether the risk has become credible, near-term and deliverability-specific.

The policy implication is straightforward. A proportionate architecture should give greatest weight to near-horizon evidence, use medium-term evidence to support preparedness and investment signalling, and treat long-term planning as an early-warning system. A standing annual obligation does not naturally make that distinction. Even where flexibility mechanisms are available, the starting point remains an obligation defined annually rather than a response calibrated to the confidence, timing and location of the risk. That is why a graduated framework tied to evidence quality and proximity is better matched to the way the market's own information base works.

## What does market behaviour add?

Planning evidence is essential, but it does not capture the full state of the market. Observable market behaviour provides a complementary source of evidence about whether modelled adequacy risk is translating into real-world stress.

This includes contracting conditions, producer offers, LNG export decisions, storage positions, pipeline utilisation, price movements and the behaviour of large users. These indicators matter because they reveal how

market participants are responding to current and expected conditions. A modelled shortfall that is accompanied by tightening contract availability, unusual storage drawdown, reduced domestic offers or increased reliance on emergency mechanisms should be treated differently from a modelled shortfall that is not corroborated by market behaviour.

The ACCC has repeatedly emphasised the importance of LNG producers' decisions about uncontracted gas in shaping near-term domestic balances. This is a useful example of why market behaviour matters. A projected shortfall can become a surplus depending on whether uncontracted gas is offered domestically or exported. Gas Market Code reporting has improved visibility over these volumes and therefore strengthens the capacity of policymakers to distinguish between genuine near-term adequacy risk and modelled risk that may be resolved through commercial decisions.

Storage behaviour is another important signal. If storage is being replenished ahead of winter and withdrawal capability is available, the system may be able to manage a short-term southern supply gap without broader intervention. If storage is unusually low, withdrawal capability is constrained, or refill behaviour is inconsistent with expected winter demand, the same planning outlook would carry greater policy significance.

Contracting behaviour also matters. The continued availability of producer offers, expressions of interest and negotiated supply agreements indicates that the market is still functioning, even if conditions are tight. Conversely, a sustained deterioration in contract availability, shorter contract tenors, rising risk premia or evidence that buyers cannot secure firm supply would provide a stronger basis for intervention.

Market behaviour should not replace planning evidence. It should be used to corroborate, qualify and interpret it. A near-term planning assessment that identifies a potential adequacy concern carries more weight if observable market behaviour points in the same direction. It carries less weight if market participants are behaving as if conditions remain manageable.

The policy implication is that decisions about intervention should not rely on any single indicator. A credible adequacy concern should be assessed using both forward-looking planning evidence and contemporaneous market behaviour. This reduces the risk of over-reacting to long-range modelled shortfalls, while also reducing the risk of waiting until physical shortfalls have already emerged. In practical terms, planning evidence should identify where and when risk may arise, while market behaviour should help determine whether that risk is becoming sufficiently concrete to justify further policy action.

This approach supports a more disciplined basis for policy judgement. A stronger case for further policy action would exist where near-term planning evidence points to a credible adequacy or deliverability risk and that risk is corroborated by market signals such as tightening contract availability, unusual storage drawdown, constrained transport availability, reduced domestic offers or changes in LNG export behaviour. Conversely, where planning risks are longer-dated, uncertain or not corroborated by market behaviour, the appropriate response should be preparedness, monitoring and investment signalling rather than immediate mandatory intervention.

## What does a multi-indicator approach add?

The three categories of evidence examined above, near-horizon planning assessments, long-run planning outputs as warning signals, and observable market behaviour, each have strengths and limitations when considered in isolation.

A price-only approach is vulnerable to export linkage effects, as Section 2 established. Elevated prices can reflect international parity rather than domestic adequacy stress, making price alone an unreliable indicator of when intervention is warranted.

A planning-only approach is vulnerable to conservative assumptions and long-run uncertainty. Standalone reliance on planning data could have supported intervention in circumstances where forecast shortfalls were later deferred or did not materialise.

A market-behaviour-only approach is reactive, it captures stress that has already emerged rather than identifying it in advance.

The evidence base is therefore most useful when these categories are considered together. Near-horizon adequacy evidence provides the primary signal. Long-run planning outputs provide context and early warning. Observable market behaviour provides corroboration. Together, they offer a more complete and more defensible picture of adequacy conditions than any single indicator can provide.

## Governance, transparency and the conditions for credible evidence use

The value of the evidence base described in this section depends critically on how it is used. Evidence that is selectively cited, mechanically applied, or insufficiently transparent will not support disciplined policy decisions, regardless of its technical quality.

This is particularly important while the draft design framework remains subject to consultation. The consultation process should be used not only to refine implementation details, but to test whether the proposed framework contains the right governance disciplines to ensure that intervention is proportionate to the conditions it is intended to address.

Several governance disciplines are essential to credible evidence use in this context.

**Publication cadence and accessibility.** Evidence that informs policy decisions should be publicly available, regularly updated and methodologically transparent. AEMO's GSOO and the ACCC's gas inquiry reports already meet this standard in important respects. Recent AEMC rule changes requiring AEMO to report gas infrastructure closures through established planning frameworks are a further step in the right direction, improving the lead time available for both market and policy responses.

**A hierarchy of evidence.** Not all evidence should carry equal weight in policy decisions. Near-horizon adequacy evidence, which is more reliable and more directly observable, should carry greater weight than long-run planning projections, which are sensitive to structural assumptions. Market behaviour evidence should be used to corroborate or qualify planning-based assessments rather than to substitute for them.

**Explicit acknowledgement of uncertainty.** The evidence base reviewed in this section is valuable but imperfect. Demand projections have tended to overstate realised outcomes across successive planning vintages. Supply projections have repeatedly deferred forecast shortfalls. Any policy framework that uses this evidence should be explicit about what it knows and what it does not, and should be designed to accommodate revision as new information becomes available.

**Institutional judgement alongside quantitative signals.** The evidence reviewed here supports judgement, not mechanical rule-following. A framework that applies fixed thresholds without institutional discretion risks both

over-activation and under-activation. The governance architecture should preserve space for expert judgement, periodic review and transparent communication of decisions and their rationale.

## The preferred architecture: enhanced market intelligence as the first-order response

The most proportionate and effective first-order policy response to the problem the evidence identifies is not a mandated volume obligation. It is a richer, more dynamic information environment, one that enables better investment decisions, better contracting, better infrastructure planning, and better regulatory and government choices, closest to the source of risk. Information-based policy sits at the market-enabling end of the intervention spectrum and, if designed well, can mobilise private sector responses that are more targeted, more timely, and less economically costly than any administratively imposed solution.

The foundation of this architecture is an enhanced mandate and capability for AEMO's market intelligence function. AEMO's GSOO and Victorian Gas Planning Report Update are already valuable tools, and this report has drawn heavily on them. However, in their current form, these publications have important limitations. They present a conservative, system-level view of supply and demand that does not readily distinguish between committed, anticipated, and uncertain projects by name; does not explicitly model the gas market implications of major government decisions; and does not provide the project-level granularity that market participants need to make investment and contracting decisions with confidence.

The proposed architecture has three interlocking elements.

### Element 1 - Enhanced AEMO market intelligence

The Commonwealth should enhance AEMO's mandate to require a more granular, forward-looking, and decision-relevant gas market assessment, updated at regular intervals and published transparently. The enhanced assessment should incorporate:

- **Named project-level supply tracking** - identifying committed, anticipated, and uncertain projects by name, status, and expected timeline, so market participants can see where supply is coming from and on what schedule, rather than relying on aggregate categories.
- **Infrastructure investment visibility** - including pipeline expansions, storage developments, and interconnection projects, with their modelled contribution to southern system adequacy under peak-day conditions.
- **Government decision impacts** - explicitly modelling the gas market implications of major government decisions, including approvals, refusals, moratoriums, and decisions in adjacent markets such as electricity (for example, the extension of coal-fired generation capacity at Eraring and its effect on gas-powered generation demand). These effects are currently absorbed by the market without being formally assessed or published.
- **Southern system adequacy as a standing priority** - a dedicated southern-system adequacy view, updated at least annually, that tracks peak-day deliverability risk with the specificity that the nature of the problem requires, rather than treating it as a sub-component of an east coast annual balance.

This is not a proposal to create a new bureaucracy. AEMO already has the analytical capability and institutional standing to perform this function. What is proposed is a clearer mandate and a higher standard of transparency, one that gives market participants, infrastructure investors, and state governments the information

they need to respond to emerging adequacy risks through private decisions, before government intervention becomes necessary.

This enhanced market intelligence function would also improve the operation of any flexibility mechanisms in the Government's proposed framework. Decisions about DSO variation, release of surplus volumes, infrastructure constraints or escalation to stronger measures will only be credible if they are anchored in transparent, granular and regularly updated evidence about actual adequacy conditions.

## Element 2 - A Gas Market Impact Assessment process

Major government decisions that carry material gas market consequences should be subject to a structured Gas Market Impact Assessment (GMIA) - a formal, published analysis of how the decision will affect supply, demand, storage, pricing, and adequacy in the east coast gas market, with particular attention to southern system conditions.

The GMIA process is recommended for significant decisions, including but not limited to: the extension of coal-fired power station life beyond previously assumed retirement dates (AEMO 2026a); the refusal or deferral of major gas development approvals; significant changes to environmental or planning frameworks that affect exploration or development timelines; and major new demand commitments (such as large-scale industrial or export facilities) that alter the system's supply-demand balance.

The purpose of a GMIA is not to veto government decisions. It is to ensure that gas market consequences are explicitly assessed, publicly reported, and available to market participants and policymakers before and after significant decisions are made. Decisions that carry material gas market costs should be made with those costs visible, not absorbed invisibly through higher risk premia, delayed investment, tighter contracting conditions or greater reliance on later intervention.

The GMIA process is recommended rather than mandatory, recognising that governments retain policy discretion across a wide range of decisions. However, for decisions of the scale and consequence described above, the expectation of a published GMIA would represent a meaningful governance discipline — one that improves the quality of decision-making and supports market confidence in the regulatory environment.

The GMIA should be conducted by, or with substantive input from, an institution with relevant analytical capability and sufficient independence from the decision-maker. AEMO is the most natural candidate, given its existing role in gas market planning and its institutional standing. Where a GMIA relates to a decision outside AEMO's current mandate, the assessment could be commissioned by the relevant Commonwealth or state department but published transparently, with AEMO providing the technical gas-market analysis. The key discipline is that the assessment should be publicly available and methodologically transparent, regardless of which institution produces it.

## Element 3 - A southern system adequacy assessment with a defined, graduated response pathway

The enhanced AEMO intelligence function provides the informational foundation. The third element of the architecture is a clear process for translating that information into proportionate policy responses when adequacy concerns are identified.

This is distinct from a reactive mechanism that activates only when a crisis has materialised. The proposal is a standing, regular assessment, anchored in AEMO's enhanced reporting, that monitors southern system adequacy conditions on a forward-looking basis and identifies, at the earliest opportunity, whether the supply, storage, and infrastructure pipeline is sufficient to meet projected peak-day demand in the southern system over the relevant planning horizon.

When that assessment identifies a credible and near-horizon adequacy risk, a graduated response pathway is available. The pathway moves from least to most interventionist, and each step should be exhausted - or credibly assessed as insufficient - before the next is taken:

1. **Market signal reinforcement** — ensuring the information from the enhanced AEMO assessment is clearly communicated to market participants, infrastructure investors, and state governments, so private decisions can respond.
2. **Targeted infrastructure and storage investment** — government support for, or coordination of, storage capacity, pipeline augmentation, or other physical infrastructure responses directly targeted at the southern system peak-day problem.
3. **Sequencing and export conditionality** — export approval conditions that ensure domestic adequacy is demonstrated before uncontracted or discretionary gas is exported, applied at the margin and for the period required.
4. **Broader intervention, including volume obligations** — a more interventionist response, potentially including time-limited or scaled domestic supply obligations, available as a last resort if the preceding steps have demonstrably failed to resolve a credible adequacy or deliverability risk.

The key design discipline is that broader intervention does not precede or bypass the earlier steps. A standing reservation mandate that effectively begins at step four, even if accompanied by flexibility mechanisms, risks being disproportionate to the problem the evidence identifies unless the earlier steps have been exhausted or credibly assessed as insufficient. This is the central difference between the architecture proposed here and an always-on annual obligation: the proposed architecture allows escalation to stronger measures, but only after the evidence demonstrates that less intrusive responses are unlikely to manage the relevant adequacy or deliverability risk.

The criteria for escalation should be anchored in the enhanced AEMO adequacy assessment. For example, movement from Step 1 to Step 2 might be triggered where the standing southern adequacy assessment identifies a credible peak-day shortfall risk within a two-to-three year horizon that is corroborated by observable market signals such as tightening contract availability, unusual storage drawdown or constrained pipeline utilisation. Movement to Step 3 might be triggered where the assessment identifies a near-term adequacy risk within twelve months that has not been resolved by infrastructure or storage responses. Movement to Step 4 would require a demonstrated failure of the preceding steps to resolve a credible and imminent adequacy or deliverability risk. The precise thresholds should be developed in consultation with AEMO, the ACCC, relevant state governments and industry, and published transparently.

## Why information-led policy is better calibrated than mandated volumes

The case for information as the first-order policy response rests on a straightforward economic logic. The east coast gas market has sufficient reserves and projects in the pipeline to address its adequacy challenges. The barriers to resolution are not geological, they are informational, commercial, and investment-timing problems. Market participants do not invest in storage or new supply because the forward information environment is not

rich enough or certain enough to support the business case. Infrastructure developers do not commit capital because the regulatory and policy environment is uncertain. Contracting parties do not sign long-term agreements because the price and volume outlook is opaque.

A richer, more transparent information environment directly addresses these barriers. If AEMO's assessment credibly signals a southern system adequacy risk on a defined timeline, private investors have the information they need to make storage, pipeline, and supply investment decisions. If government decisions that affect gas supply are formally assessed and published, producers and consumers can incorporate those impacts into contracting and investment plans. If the adequacy assessment is regularly updated and publicly available, the market can respond continuously rather than waiting for a crisis to prompt emergency intervention.

Section 7 demonstrated this directly. A standing reservation that displaces southern production, increases pipeline dependence, and achieves its price effects through redistribution and displacement rather than through new supply does not address the underlying information and investment-timing barriers. It shifts the adequacy problem forward in time rather than resolving it. The draft design framework's flexibility mechanisms may reduce the scale of these effects in some circumstances, but they do not replace the need for a transparent architecture that identifies when intervention is needed, what form it should take and when it should be withdrawn. Where intervention is judged necessary, the most transparent approach would make the cost and rationale explicit rather than embedding costs in market distortions absorbed by producers, exporters and the wider economy. The information architecture proposed here comes closer to meeting that standard.

The proposed architecture does not remove volume obligations from the government's toolkit. It retains them as a last-resort measure, available where the evidence demonstrates that earlier steps have failed to resolve a credible adequacy risk. The difference from the announced standing export-linked domestic supply obligation is one of sequencing and conditionality: obligations follow the evidence rather than preceding it.

## Design disciplines for the proposed architecture

The architecture proposed in this section is only as good as its implementation. Four design disciplines are essential to its credibility and effectiveness.

### Transparency

AEMO's enhanced assessments must be publicly available, methodologically clear, and regularly updated. Market participants, infrastructure investors, and state governments must be able to rely on the information as a credible basis for commercial and policy decisions. Opacity in the assessment process, whether in methodology, assumptions, or project-level data, undermines the entire architecture.

### Prospectivity

The southern system adequacy assessment must be forward-looking and maintained as a standing function, not activated only when a crisis has already emerged. The value of the architecture lies precisely in its ability to identify risks early enough for private decisions to respond. A reactive assessment that is only commissioned when conditions have already tightened is too late to support the investment and contracting decisions that would have prevented the tightening.

### Jurisdictional sensitivity

The evidence developed throughout this report consistently points to the southern system, Victoria, South Australia, New South Wales, as the operational centre of gravity for east coast adequacy risk. The architecture should reflect that geography. A national framework that treats the east coast as a uniform system will systematically mis-specify the problem and mis-calibrate the response. Southern system adequacy should be a standing, explicit priority in AEMO's enhanced mandate, not a sub-component of a national annual balance.

### Graduated discipline

The response pathway set out above is only credible if each step is genuinely exhausted before the next is taken. A government that defaults to volume mandates without first ensuring the information environment is rich, the infrastructure pipeline is supported, and export sequencing has been applied is not following a proportionate architecture, it is using the architecture as cover for a predetermined intervention. The discipline of graduation must be embedded in the governance of the framework, with clear published criteria for moving from one step to the next.

### Reviewability and reversibility

A proportionate framework should include clear review points and mechanisms for scaling intervention down as well as up. If adequacy conditions improve, if investment is delivered, or if market behaviour indicates that risks have receded, the framework should be capable of withdrawing or reducing intervention. This is particularly important for high-impact tools such as domestic supply obligations. The credibility of a conditional framework depends not only on government's capacity to escalate when risk increases, but also on its willingness to de-escalate when the evidence no longer supports intervention.

The credibility of a graduated framework depends on governments being willing to follow the evidence rather than defaulting to the most visible intervention. This is a genuine implementation risk. However, the alternative, a standing reservation obligation that applies regardless of market conditions, does not eliminate political pressure. It simply embeds a permanent intervention that may be poorly calibrated to actual risk. A graduated framework at least provides a transparent, evidence-based process for determining whether intervention is warranted. If governments are unwilling to follow such a process, the problem is not the framework, it is the governance environment in which gas policy is made.

## Conclusion

The evidence and modelling presented in this report point to a clear conclusion. The east coast gas market's binding challenge is not broad annual scarcity. It is conditional adequacy, southern winter peak-day deliverability and the timing of new investment in supply, storage and transport. A standing export-linked domestic supply obligation is not well matched to that problem. It lowers prices by displacing production rather than by creating new deliverable supply, and it imposes material economic costs while weakening the investment conditions the southern system depends on.

The draft design framework recognises some of the practical complexity of implementing such a scheme by including compliance pathways and flexibility mechanisms. Those features are important and should be acknowledged. However, they do not remove the central calibration problem. A framework whose starting point is a standing annual obligation remains less well matched to a problem that is conditional, regional and operational than a framework that escalates intervention only where the evidence shows that adequacy or deliverability risk is likely to bind.

The architecture proposed in this section offers a more proportionate alternative. It would enhance the market's information environment, make the gas market consequences of major government decisions visible, and establish a standing southern system adequacy assessment with a graduated response pathway. The framework does not preclude government action. It ensures that action is evidence-led, conditional and targeted to the risk the evidence identifies.

The central policy choice is therefore not between intervention and inaction. It is between a standing obligation that treats the market as if it is in continuous annual deficit, and a conditional framework that responds to the market as it actually operates. On the evidence in this report, the conditional framework is better calibrated, lower cost and more likely to support the investment and infrastructure the east coast gas market needs.

The consultation process should therefore be used to refine the proposed scheme in that direction: retaining the Government's ability to intervene strongly where circumstances warrant it, but embedding that intervention within a transparent, evidence-led and graduated architecture that better matches the nature of the risk.

SECTION 09

# Conclusion

This report set out to test whether the Commonwealth Government's proposed standing export-linked domestic supply obligation, equivalent to 20 per cent of LNG exports and intended to commence from 1 July 2027, is aligned with the problem the available evidence actually identifies. The answer is not that intervention is unwarranted. It is that the form, timing and calibration of intervention matter profoundly.

The east coast gas market faces genuine and evolving challenges. Legacy southern production is declining, the system is increasingly reliant on transport and storage to meet winter demand, and new investment will be required over time to maintain adequacy. However, the evidence does not support a diagnosis of an immediate, systemwide annual shortage requiring permanent, standing intervention.

Instead, the official record, across successive AEMO planning vintages, ACCC reporting, observed price outcomes and commercial market behaviour, points consistently to conditional near-term adequacy. The near-term outlook improved materially between the 2025 and 2026 planning cycles, with forecast annual shortfalls repeatedly deferred and peak-day risks emerging later than previously anticipated. That deferral does not eliminate longer-term risk, but it does underscore the sensitivity of long-run projections and the danger of imposing standing obligations on the basis of long-range forecasts that may not materialise.

Crucially, the residual risk that remains is not primarily volumetric. It is seasonal, regional and operational in character, concentrated in the southern system and most acute under winter peak-day conditions. Adequacy depends not simply on aggregate reserves or annual production, but on the ability to convert resources into firm, deliverable supply at the right time and in the right location. A policy framework calibrated to an assumed broad annual shortage therefore risks mis-specifying the problem it seeks to solve.

Market behaviour corroborates this assessment. Producers continue to market gas domestically through commercial processes; infrastructure investment has proceeded in direct response to deliverability constraints; storage is being managed within expected seasonal parameters; and both realised prices and forward-looking price assumptions indicate stabilisation well below crisis peaks. These signals are not consistent with a market in structural failure or imminent collapse. They are consistent with a market that is tight, navigable and responsive to incentives.

Taken together, the evidence implies that policy intervention should escalate when credible, near-term deliverability risk in the southern system is demonstrated, rather than being applied permanently on the basis of long-dated projections.

Against this backdrop, the economic analysis in this report highlights the cost of mis-calibrated intervention. A standing export-linked domestic supply obligation may lower wholesale gas prices for some domestic users in the short term, but it does so by reallocating gas rather than by creating new deliverable supply. Modelling results indicate that such a policy would impose material and escalating welfare losses, estimated at approximately $1.5 billion per year under a 15 per cent effective reservation and $2.9 billion under a 20 per cent reservation, driven by foregone export revenue, lost producer surplus and additional transport and infrastructure costs.

The modelling recognises that reservation would lower wholesale gas prices for some domestic users. However, under the model's fixed-demand assumption, those lower prices represent a distributional transfer from producers and exporters to consumers rather than a net increase in national welfare. Importantly, these costs arise even in periods when the market is conditionally adequate, meaning the policy imposes costs now to address risks that are conditional, regional and later-dated. A framework that binds too early risks imposing

economic and investment costs that cannot be easily unwound. A conditional framework, by contrast, preserves the ability to intervene rapidly if risk materialises.

The draft design framework released for consultation recognises some of the practical complexity of implementing a standing export-linked domestic supply obligation. Its proposed compliance pathways and flexibility mechanisms are important and should be acknowledged. However, they do not remove the central calibration problem. A framework whose starting point is a standing annual obligation remains less well matched to a problem that is conditional, regional and operational than a framework that escalates intervention only where the evidence shows that adequacy or deliverability risk is likely to bind.

The core policy choice, therefore, is not between action and inaction. It is between a standing obligation that applies as the default instrument, and a proportionate framework designed for conditional risk.

This report argues for the latter. The preferred policy architecture presented here is centred on evidence-led, conditional intervention. It recognises that much of the information required to identify emerging adequacy risk already exists, and that the most effective role for policy is to organise, sharpen and act on that information in a disciplined way. The architecture has three interlocking elements: enhanced AEMO market intelligence with a standing southern system adequacy focus; a Gas Market Impact Assessment process for significant government decisions; and a graduated response pathway that escalates from market signal reinforcement, through targeted infrastructure and storage support, to export sequencing and, only where demonstrably required, time-limited or scaled domestic supply obligations.

By strengthening near-horizon market intelligence, applying structured assessment to major policy decisions with gas market implications, and establishing a graduated escalation pathway focused on the southern system, the framework targets intervention to the timing, location and operational character of the risk. It also gives the Government the ability to deploy stronger intervention where circumstances warrant it, while avoiding the costs of applying the most intrusive tool before the evidence shows it is required.

Such an approach preserves investment incentives, reduces the likelihood of false positives, and reserves the most intrusive tools for circumstances in which they are demonstrably required. It also aligns more closely with the way the east coast gas market actually functions: as an export-linked, interconnected system in which adequacy challenges increasingly arise through deliverability rather than aggregate scarcity alone.

On the evidence presented in this report, a standing export-linked domestic supply obligation in its announced form would be a disproportionate response to a risk that is conditional, regional and operational rather than persistent and systemwide. The consultation process should therefore be used to refine the proposed scheme in that direction: retaining the Government's ability to intervene strongly if circumstances warrant it, but embedding that intervention within a transparent, evidence-led and graduated architecture. A conditional framework is not only more credible economically, but better aligned with the evidence and more robust to the risks the market is likely to face over time.

SECTION 10

# Appendix A – Partial Equilibrium Modelling

This appendix documents the methodology used to estimate the welfare impacts of a domestic gas standing export-linked domestic supply obligation on the east coast gas market, and the methodology used to estimate peak-day reliability impacts. Both modules sit on a common modelling framework: a partial equilibrium representation of east coast supply and demand, calibrated to 2027 conditions and extended to 2030 and 2035.

## Geographic and product scope

The model represents the Australian east coast gas market as two regions. The northern region comprises Queensland and the Northern Territory, dominated by the three Gladstone LNG projects (APLNG, QCLNG, GLNG) which together produce approximately 1,400 PJ/yr of coal seam gas. The southern region comprises Victoria, New South Wales, South Australia and Tasmania, supplied predominantly by conventional offshore and onshore gas from the Otway, Gippsland, Cooper-Eromanga and Bass basins. The two regions are physically connected by the South West Queensland Pipeline (SWQP) and Moomba-Sydney Pipeline (MSP) infrastructure, with effective southbound capacity of approximately 468 TJ/d today.

## Data sources

Three primary data sources underpin the model. Each is used for a distinct purpose and the source for each parameter is documented alongside the parameter in the model file.

- **Rystad Energy (December 2025 vintage).** Used for the supply curve specification, including project-level long-run breakeven prices. This is the data which was used in the ACCC's 2025 supply review.
- **Wood Mackenzie Lens (Upstream).** Used for the potential annual production volumes by basin.
- **AEMO GSOO 2026.** Used as the public-source basis for all demand assumptions.

## Partial equilibrium baseline

The model is a partial equilibrium representation: it solves for prices and quantities in the gas market while taking input prices, demand schedules, and macroeconomic conditions as exogenous. Demand is modelled as perfectly inelastic at total east coast levels, reflecting the short-run inflexibility of gas demand from industrial users, gas-powered electricity generation, and residential heating systems.

The zero demand-elasticity assumption is conservative for welfare analysis. Real-world demand response - particularly through electricity-sector substitution and industrial fuel-switching - would moderate price impacts in either direction. Imposing zero elasticity isolates the supply-side effects of reservation, which is the primary policy question.

Supply is modelled as a step-function merit order: each project (or aggregated tranche for CSG) contributes a fixed quantity at a fixed breakeven price, with the system clearing at the price of the marginal project required to meet demand. Capacity is binding at the project's nameplate.

## Policy pricing

The central methodological choice in the welfare analysis is the pricing rule: the equation that determines the domestic clearing price under a standing export-linked domestic supply obligation. The choice matters because a standing export-linked domestic supply obligation is fundamentally about the relationship between domestic prices and the international LNG export market, and different pricing rules produce materially different welfare results.

Price determination occurs as follows:

- **Competitive marginal-cost pricing.** Domestic price is the breakeven cost of the marginal domestic project, with the export market and domestic market effectively treated as delinked under the reservation where there is supply from domestic only producers. Under a competitive equilibrium rule, LNG netback effectively operates as the upper bound on the domestic clearing price.

## Welfare decomposition

Under competitive marginal-cost pricing, the welfare impact of reservation decomposes into three real economic costs and three distributional flows. The real costs represent genuine resource losses to the economy; the distributional flows are transfers between agents.

### Real economic costs

These three components are independent of the pricing rule and reflect genuine resource costs:

- **Export revenue foregone.** Reserved gas displaced from LNG export markets earns less than its export-equivalent value. Calculated as the incremental reserved volume above current voluntary domestic supply multiplied by the difference between the northern domestic price and the international LNG price.
- **Displaced production rent destroyed.** Southern projects displaced by northern gas flowing south earn no rent on production they no longer make. Calculated as displacement (PJ) × (old market price minus project breakeven). Concentrated in the marginal southern projects.
- **Infrastructure and transport real costs.** Two components. First, transport tariffs paid for the additional gas flowing south. Second, pipeline annualised capex if the additional flow requires new infrastructure investment, calculated using the model's pipeline capacity threshold and a regulated rate of return assumption (8% WACC).

### Distributional flows

These three flows transfer welfare between consumers, exporters, and southern producers. Their magnitude depends critically on the pricing rule:

- **Consumer surplus gain.** Domestic consumers benefit from lower prices. This is the principal channel through which reservation creates value for non-exporting stakeholders. Calculated as the price reduction (old minus new) multiplied by demand quantity, summed across regions.
- **Exporter loss.** Two sub-components. First, the loss on the existing voluntary volumes of domestic supply, which now sells at a lower domestic price rather than the previous netback-implied price (covering existing contractual flexibility). Second, the loss on the incremental reserved volume, where exporters lose the differential between LNG netback and the new domestic clearing price.
- **Southern producer loss.** Continuing southern producers receive a lower price on their ongoing production (margin compression).

## Limitations and caveats

The methodology described above has several material limitations. They are documented here in approximate order of analytical importance.

### Static rather than dynamic equilibrium

The model is solved separately for each reference year (2027, 2030, 2035) without intertemporal feedback. In reality, reservation that suppresses prices in 2027 would likely reduce investment in CSG sustaining drilling, leading to lower production and higher prices in 2030-2035. This 'investment feedback' channel is the most important missing element in the welfare analysis. The investment module documents the magnitude of capex placed at risk, but does not feed this back into supply curves for later years. A genuinely dynamic model would solve this iteratively.

### Zero demand elasticity

Demand is treated as perfectly inelastic. In practice, gas-fired electricity generation has substantial elasticity through dispatch substitution with renewables and storage. Industrial demand has slower-moving but real elasticity through fuel switching and process changes. Residential heating has near-zero short-run elasticity but material long-run elasticity through electrification. The zero-elasticity assumption produces larger price impacts than would be observed in practice, biasing welfare estimates upward in absolute magnitude. The direction of the bias is conservative for arguments against reservation (it overstates harm) and aggressive for arguments for reservation (it overstates benefit).

## Assumptions table

*Appendix table A: Partial model assumptions*

| Parameter | 2027 | 2030 | 2035 |
|---|---|---|---|
| Total domestic demand (PJ) | 469 | 449 | 414 |
| Northern domestic demand (PJ) | 134 | 142 | 141 |
| Southern domestic demand (PJ) | 335 | 307 | 273 |
| Already supplied domestically (PJ) | 104 | 99 | 35 |
| Exporter production base (PJ) | 1431 | 1432 | 1289 |
| Pipeline fee | $2.7 | $2.7 | $2.7 |

*Source: Kroll modelling.*

## Economic costs over time

*Appendix table B: Economic costs to Australia, $ million*

| | 2027 | 2030 | 2035 |
|---|---|---|---|
| 15% reservation ($m) | 1,455 | 1,626 | 2,067 |
| 20% reservation ($m) | 2,858 | 3,080 | 3,199 |

*Source: Kroll modelling.*

## Sensitivity test of economic costs of different reservation scenarios

*Appendix table C: Economic costs to Australia, 2027 $ million*

| | 10% reservation | 15% reservation | 20% reservation | 25% reservation |
|---|---|---|---|---|
| Exporter loss ($m) | 245 | 851 | 1638 | 2312 |
| Southern foregone production ($m) | 89 | 296 | 603 | 915 |
| Transport inefficiencies ($m) | 77 | 309 | 617 | 925 |
| **Total ($m)** | 412 | 1,455 | 2,858 | 4,152 |
| **Cost per PJ reserved ($m)** | 14.4 | 15.3 | 17.7 | 18.2 |

SECTION 11

# Appendix B – CGE Modelling Method

The CGE modelling is intended to capture the economy-wide consequences of the reservation that the partial equilibrium (PE) model cannot - specifically, sectoral reallocation, labour market effects, terms-of-trade adjustments, fiscal impacts, and the net effect on Australian household welfare.

## Shock design overview

The reservation's economic effects operate through three distinct channels, each requiring a separate shock in the CGE model:

- Shock 1: Export restriction - the primary allocation effect. Gas is diverted from export to domestic use, reducing LNG export volumes and revenue. These values are taken from the partial model.
- Shock 2: Gas system efficiency loss - the real resource cost of shipping gas further and building pipeline infrastructure. Southern production is replaced by northern gas transported 2,000 km via pipeline. These values are taken from the partial model.
- Shock 3: Gas sector investment reallocation - the dynamic investment deterrent. Production investment is lost (north and south) while pipeline investment is forced (partially offsetting). The investment loss is based on partial modelling outcomes of displaced supply and WoodMac data on the investment needed for the production that is lost.

Two reservation rates are modelled - 15% and 20% - corresponding to the government's announced range. Each shock is calibrated at both rates.

The PE results are translated into KGEM as follows. The LNG export reduction is imposed as a volume shock to the LNG export sector. The upstream investment reduction is imposed as an investment shock to the Australian economy. The gas distribution productivity shock is imposed as an input productivity shock into users of the gas distribution sector. Southern production contraction is imposed endogenously by the model. The following table summarises the model shocks in 2027:

| | 15% reservation | 20% reservation |
|---|---|---|
| LNG export reduction (PJ) | 95 | 161 |
| Upstream investment reduction ($m) | 473 | 804 |
| Gas distribution productivity shock ($m) | 239 | 547 |

## Baseline

The CGE baseline is based on a no reservation scenario and takes assumptions on GDP and population growth from S&P forecasts.

## CGE results tables

*Appendix table D: GDP impacts to Australia, $ million*

| Australian GDP ($m) | 2028 | 2029 | 2030 |
|---|---|---|---|
| 15% reservation | -205 | -273 | -350 |

| Australian GDP ($m) | 2028 | 2029 | 2030 |
|---|---|---|---|
| 20% reservation | -416 | -525 | -653 |

*Source: Kroll modelling.*

*Appendix table E: GSP impacts to the States of a 20 per cent reservation, $ million*

| | | 2028 | 2029 | 2030 |
|---|---|---|---|---|
| Real GSP (2026 $m) | New South Wales | 184 | 231 | 288 |
| | Queensland | -437 | -550 | -685 |
| | Victoria | -131 | -165 | -206 |
| | Tasmania | 10 | 13 | 16 |
| | South Australia | -43 | -54 | -67 |

*Source: Kroll modelling.*

*Appendix table F: GSP impacts to the States of a 15 per cent reservation, $ million*

| | | 2028 | 2029 | 2030 |
|---|---|---|---|---|
| Real GSP (2026 $m) | New South Wales | 90 | 120 | 154 |
| | Queensland | -215 | -286 | -367 |
| | Victoria | -65 | -86 | -110 |
| | Tasmania | 5 | 7 | 9 |
| | South Australia | -21 | -28 | -36 |

*Source: Kroll modelling.*

## Kroll Geo-Economic Model (KGEM)

The KGEM model is a computable general equilibrium (CGE) model that provides a dynamic, internally consistent economic framework for analysing policy, trade and investment impacts. It simulates how economies respond to shocks by capturing interactions across regions, sectors and agents, thereby supporting strategic decision-making for both government and industry.

The model is grounded in economic theory and represents the behaviour of key agents: households, firms, governments and international investors. These agents interact through markets for goods, services and factors of production (labour, capital and natural resources). All relationships are solved simultaneously, ensuring that economic outcomes reflect general equilibrium conditions across the entire system rather than partial or isolated effects.

KGEM generates projections of macroeconomic aggregates including GDP, employment, consumption, investment and trade balances. It also produces detailed sectoral results such as output, input demand, trade flows and price changes, enabling the assessment of structural adjustment and supply chain impacts.

## Model structure

The model is multi-region and multi-sector, with coverage of 161 regions and 74 production sectors. Regions can represent individual countries or subnational economies, allowing for analysis at different geographic levels. The structure explicitly incorporates global trade linkages such that changes in one region can affect outcomes in others through trade, capital flows and price adjustments.

At a high level, each regional economy comprises the following interacting components:

- A representative household
- Producers (firms)
- Government
- Investors (domestic and global)
- The international sector

These components are linked through flows of goods, services, income and financial capital. A shock, such as a policy change, demand shift or productivity improvement, affects relative prices and incomes, triggering adjustments across all components until a new equilibrium is reached.

## Database and calibration

KGEM is underpinned by the GTAP database, a detailed global database describing economic transactions between sectors and regions. The dataset captures:

- Input-output relationships between industries
- Household consumption patterns
- Bilateral trade flows between regions
- Tax structures and government accounts
- Factor use (labour, capital and natural resources)

The database is calibrated to a base year equilibrium, ensuring that the model reproduces observed economic activity in that year. This calibration provides a consistent starting point for simulations, from which counterfactual scenarios can be analysed.

## Behavioural foundations

## Households

Each region contains a representative household that receives income from wages, returns to capital and natural resources, and income transfers. Household income is allocated between consumption, savings and taxes.

Consumption behaviour is derived from utility maximisation subject to a budget constraint. Households allocate expenditure across composite goods based on relative prices and preferences. Substitution between domestic and imported goods is modelled using an Armington structure, allowing goods to be differentiated by origin.

## Firms (producers)

Firms produce goods and services by combining intermediate inputs and primary factors. Production technologies are represented using nested functional forms:

- An input-output structure combines intermediate inputs and value-added in fixed proportions
- Value-added is composed of labour, capital and other factors using a constant elasticity of substitution (CES) function
- Intermediate inputs are sourced from domestic and imported suppliers based on relative prices

Firms are assumed to minimise costs subject to these production technologies. As relative prices change, firms adjust their input mix and sourcing decisions, creating substitution effects across sectors and regions.

## Government

Government consumption is typically linked to national income and allocated across goods and services to maximise utility subject to a budget constraint.

Tax instruments include indirect taxes on production and consumption, as well as direct taxes on income. Government balances are maintained.

## Investment and capital accumulation

Investment is driven by expected rates of return. A global investment pool allocates capital across regions based on relative returns, risk and economic conditions. This structure allows capital to flow toward regions with higher productivity or favourable policies.

Within each region, investment is used to build capital stock through the production of capital goods. Over time, capital accumulation affects productive capacity and long-run economic growth.

## International trade

Trade is modelled using the Armington assumption, whereby goods are differentiated by country of origin. This allows for imperfect substitution between domestic and imported goods, as well as between imports from different regions.

Export demand depends on relative prices and income in trading partner regions. Changes in exchange rates, production costs or global demand conditions therefore influence trade flows and competitiveness.

## Market clearing and equilibrium

Prices in the model are determined through competitive market-clearing conditions. For each commodity and factor, supply equals demand across:

- Household consumption
- Government demand
- Intermediate use by firms

- Investment demand
- Exports and imports

Simultaneously solving these conditions ensures that all markets clear and that the model reaches a consistent equilibrium following any shock.

## Dynamics and adjustment

KGEM is dynamic, allowing it to capture both short-term responses and long-term structural adjustments. In the short run, some factors (such as capital) may be relatively fixed, while over time investment and capital accumulation enable the economy to adjust more fully.

The model captures:

- Immediate (direct) effects of shocks
- Indirect effects through supply chains
- Induced effects from changes in income and consumption
- Long-term structural changes in production and trade patterns

This dynamic framework enables the analysis of policy impacts over time, including transition paths between equilibria.

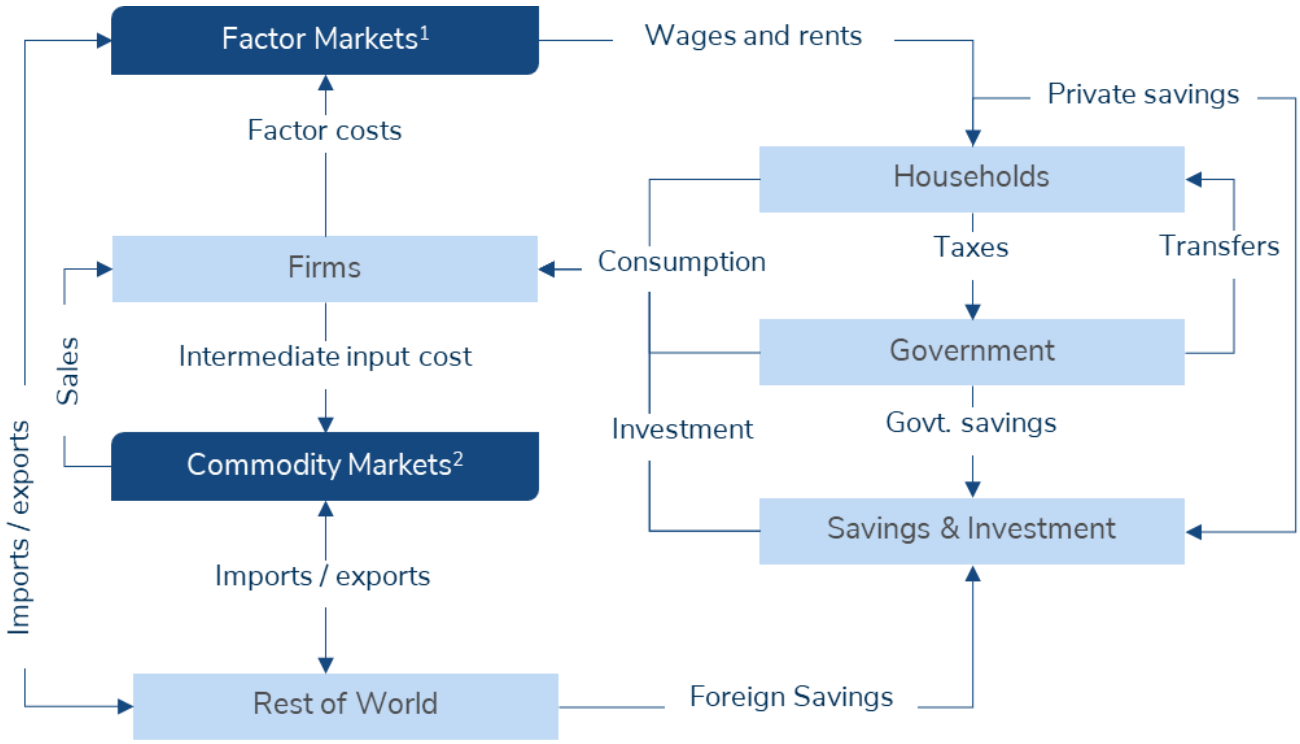
**Model outputs**

The model produces a comprehensive set of outputs, including:

- Macroeconomic indicators (GDP, employment, consumption, investment)
- Sectoral output and value-added
- Trade flows and terms of trade
- Factor prices (wages, returns to capital)
- Government revenues and fiscal balances
- Price indices and inflation measures

These outputs provide a detailed picture of how shocks propagate through the economy and affect different industries, regions and stakeholders.

The diagram below is a stylised version of how the model operates.




1. Factor markets represent inputs needed to produce goods and services (e.g., land, labour and capital)
2. Commodity markets represent raw materials and primary goods (e.g., oil or grains and crops)

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