

Strong reservations

How to design a domestic gas supply obligation

Alison Reeve, Tony Wood, Hamish McKenzie, and Ben Jefferson

Overview

For 50 years, the east coast of Australia enjoyed access to plentiful, cheap gas, mostly sourced from Bass Strait. As a result, gas became the fuel of choice to heat our homes, to cook, and to fuel industry. It also plays a small but important role generating electricity.

In the past decade, things have changed. Exports from Gladstone, Queensland, have linked east coast prices to higher international prices. At the same time, the Bass Strait fields have begun to run down.

The federal government has intervened sporadically since 2017 to try to increase supply and lower prices. It has now decided to undertake structural reform, establishing a gas reservation commencing in 2027.

The government's stated aim is for the reservation to 'cater for the domestic shortfalls that are forecast [and] to slightly oversupply the Australian domestic market'. It has committed to respect existing export contracts, but to require domestic demand to be met first, before any new gas can be exported.

A successful policy should restore the normal function of the gas market by giving certainty to users and producers of gas to invest or divest. It should avoid locking in production and demand that is inconsistent with emissions-reduction targets. It should be simple, easy to understand, fair, and flexible enough to respond to changing circumstances. And it should ensure domestic customers are well supplied, without creating over-reliance on exporters for domestic gas.

In this submission we outline a design that achieves these competing aims within the constraints of commitments already made.

Our design frames the scheme as a **domestic gas supply obligation**. This better reflects that the government's aim is to send extra supply to the domestic market. A 'reservation' implies setting aside a portion of gas reserves. But this would not guarantee that gas will reach

users. And a 'reservation' is harder to reconcile with the commitment to respect existing contracts.

The amount each exporter is obliged to supply to the domestic market should be calculated based on the total volume that they export, including current contracts. This is essential if the policy is going to deliver meaningful volumes of gas to the domestic market. Excising existing contracts from the base would mean very little new gas would reach the market before 2034, leaving prices high, and making shortages more likely.

The amount each exporter is obliged to supply should be calculated using a floating percentage based on the size of domestic supply gaps, but capped at 15 per cent of their exports. Capping the percentage provides certainty, but allowing it to float underneath the cap provides flexibility to adjust to changing demand.

The regulator should issue tradeable certificates for each unit of gas supplied to the domestic market by an exporter. Exporters would have to surrender certificates equal to their obligation each year in order to keep their export licence. Exporters can decide how to accrue certificates to meet their obligations – by increasing production, trading certificates, or diverting gas from contracted or uncontracted exports.

Oversupplying the market with gas is in direct tension with the government's emissions-reduction targets. Increasing supply of gas to lower prices is likely to induce higher demand for gas. To stay on track for its emissions-reduction targets, government will need to introduce new or expanded policies to reduce the use of gas.

The reservation is a once-in-a-generation chance to fix structural problems in the Australian gas market. This submission outlines how to seize that chance.

Recommendations

To make the domestic gas supply obligation work:

1. The gas reservation should be implemented as a domestic gas supply obligation on exporters of LNG.
2. The scheme should calculate domestic gas supply obligations based on each exporter's total volume of LNG production.
3. The domestic gas supply obligation should be set based on domestic supply gap forecasts, up to a cap of 15 per cent of total LNG production.
4. The regulator should issue exporters tradeable certificates for every petajoule of gas sold to the domestic market.
5. The domestic gas supply obligation should consist of two parts:
 - Exporters must surrender certificates equivalent to 80 per cent of their annual domestic gas supply obligation before the start of each year.
 - Exporters must surrender certificates equivalent to 100 per cent of their annual domestic gas supply obligation before the end of each year.
6. Exporters should be able to choose how they meet their obligations - by increasing production, trading certificates, or diverting contracted or uncontracted exports.
7. Exporters that meet their domestic gas supply obligation should be issued an export licence lasting one year.

8. Exporters that do not meet their domestic gas supply obligation should not be able to export gas except that required to service their pre-Reservation contracts. And the government should introduce additional proportionate sanctions sufficient to incentivise compliance with domestic gas supply obligations.
9. The government should build flexibility into the domestic gas supply obligation by enabling exporters to trade certificates and to bank and borrow certificates across time, up to a point.
10. The scheme should not allow exporters to export gas that is reserved for domestic customers under the domestic gas supply obligation.
11. The regulator should have the ability to adjust an exporter's domestic gas supply obligation up or down at short notice, in exceptional circumstances.

To avoid other problems:

12. To avoid derailing emissions-reduction targets, the government should establish new policies and programs to reduce demand for gas across the residential, electricity, and industrial sectors.
13. To avoid over-reliance on LNG exporters for domestic gas supply, the domestic gas supply obligation should not be used to address all future shortfalls.

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1 Introduction

This submission is by Alison Reeve, Tony Wood, Hamish McKenzie, and Ben Jefferson of the Grattan Institute, an independent think tank focused on Australian domestic public policy. Grattan aims to improve policy by engaging with decision makers and the broader community.

This submission responds to the report of the Gas Market Review released in December 2025, and the media release from Ministers Bowen, Ayres, and King announcing the domestic gas reservation.¹

We outline a design for a flexible domestic gas supply obligation that meets the commitments already made by government, and achieves its stated policy objectives, while also minimising the risk to Australia's emissions-reduction targets.

We would welcome the opportunity to engage further with the government on any of the matters raised in this submission.

1. Bowen et al (2025).

2 How we got here

For 50 years, the east coast of Australia enjoyed access to plentiful, cheap gas, mostly sourced from Bass Strait. And today, gas is essential to many parts of the Australian economy – we use it to heat our homes, to cook, to generate electricity, and to fuel heavy industry.

In 2015, three consortia began exporting gas from Gladstone, Queensland, as liquefied natural gas (LNG). This gas was largely drawn from new Queensland gas fields, but some of it drew gas from existing production. As a result, gas prices on the east coast increased.

Concerns about price and volume available to east coast users began to emerge almost immediately, and these increased as the Bass Strait fields began to run down and a potential supply gap emerged. Gas prices on the east coast also shot up at the start of the Russia-Ukraine war, and have not returned to previous levels.

The east coast still has vast quantities of gas, but most of it is in Queensland and controlled by the three LNG exporters. As production from Bass Strait declines, with the lion's share of production going straight to export, the east coast risks running out of gas.

According to the latest forecast, demand will outstrip supply as soon as 2029. From 2031, the gap widens quickly, peaking at nearly 160 petajoules – nearly a third of east coast demand – by 2034.²

Running out of gas is untenable. Domestic users unable to access gas at fair prices is unacceptable. A solution must be found.

There are three ways to do this, which are not mutually exclusive. First, government could implement policies to reduce demand. Second, domestic producers could increase production. The first is necessary

to meet emissions-reduction targets, but is difficult to do fast enough to close the supply gap. The second is unlikely to reduce prices, and may lock in production that becomes obsolete as demand falls.

The third option is for the LNG exporters that currently consume three quarters of east coast gas to contribute to meeting domestic demand. This is the premise of the gas reservation policy announced by the Federal Government in December 2025.

2.1 Today, gas is essential to the economy

Gas is used by Australian households and businesses to heat homes, to cook, to fuel industry, and to generate electricity.

Millions of Australians use gas to heat their homes and to cook. Most of this usage is in Victoria and NSW, with only small numbers of homes elsewhere using gas. This does not consume large volumes of gas – about 23 per cent of domestic gas demand.³ And, with households increasingly switching to electric cooking and space and water heating, the amount of gas used in buildings has started to decline.⁴

In industry, gas is used as a feedstock to produce fertilisers, explosives, and chemicals, and burned to generate heat for sectors such as mineral refining and food processing. Many industrial applications have clear non-gas alternatives – low-temperature heat can be electrified, and some uses of gas as a feedstock have alternatives such as green hydrogen. But currently, many industries that rely on gas have no immediate alternative.

2. Grattan analysis of AEMO 2025.

3. Grattan analysis of *ibid*, includes all use in buildings.

4. *Ibid*.

Gas plays a small but essential role in the electricity system. While just four per cent of east coast Australia's electricity was generated by gas in the last year, gas-powered generators are typically used as backup generation during periods of low renewable output and high demand.⁵ Because of the relatively high cost of gas-powered electricity generation, gas has historically been a major driver of electricity prices.⁶ About a quarter of Australia's domestic gas usage is for generating power.⁷

The vast bulk of gas production in Australia takes place in the large offshore basins off Western Australia, and in the coal seam fields of Queensland. The offshore gas fields in Bass Strait have historically been a major source of gas supply for eastern Australia, but these fields are rapidly depleting, with just 11 per cent of gas reserves remaining.⁸

2.2 Australia has three physically separate gas systems

While there is gas production in all states except Tasmania, there are three systems that connect this production to users.

The west coast gas system has no physical connection to the east coast – there are no east-west gas pipelines in Australia, and there are no facilities capable of regasifying LNG at scale in Australia. This means that currently, there is no physical way of getting WA gas to consumers on the east coast. This makes the two markets functionally separate.

The northern gas system, consisting of gas basins in the NT, and the two Darwin LNG exporters, is connected to the east coast by a single pipeline, the Carpentaria pipeline through Mt Isa. But most NT gas

is sent directly to Darwin for export, and minimal gas is sent from the east coast to the Territory. So, for the purpose of the reservation and east coast supply gaps, the northern gas system can be considered functionally separate.

The east coast gas system connects Tasmania, Victoria, South Australia, NSW, and Queensland. The three key gas-producing regions are Bass Strait, the Cooper Basin in South Australia, and the Bowen-Surat coal seam basins in Queensland. A single pipeline – the South West Queensland Pipeline – connects Queensland to the rest of the east coast gas system. This pipeline bottleneck creates a constraint on the reservation; additional gas delivered from Queensland will need to find a way to users in the south.

2.3 Australia has a large LNG export sector

Only a fraction of gas produced in Australia is used to meet domestic demand. Nationally, about three quarters is sent to large export terminals, where it is chilled to -160°C, at which point it forms a liquid, and is then loaded onto large tankers and exported as LNG. On the east coast, two thirds of all gas produced is exported (see Figure 2.1 on page 9).

Australia has exported gas as LNG since 1989, when the North West Shelf facility opened in WA. Today, there are 10 LNG export facilities across the country. Just three of these – the three LNG exporters in Gladstone – would initially be covered by the national reservation. These three – Australian Pacific LNG, Queensland Curtis LNG, and Gladstone LNG – are the focus of this submission (see Box 1 on the next page).

The key piece of infrastructure at an LNG export facility is the compression train – large production lines that liquefy natural gas. Each train uses large compressors and heat exchangers to progressively cool the gas, similar to a residential fridge but on an industrial scale.

5. Grattan analysis of OpenElectricity 2026.

6. Australian Energy Regulator (2025).

7. AEMO (2025).

8. Geoscience Australia (2025).

Typically, a single export terminal will have multiple trains, and each of the Queensland exporters has two trains. The capacity of compression trains creates an upper limit on how much gas can be exported.

2.4 The start of LNG exports on the east coast disrupted the market

The three Gladstone exporters – APLNG, GLNG, and QCLNG – were all opened in 2015 by consortia consisting of oil and gas majors and large Asian buyers of gas. Each of the exporters locked in large ‘foundation’ contracts, 20-year export agreements.

By the time these contracts expire in 2036, the Gladstone exporters are set to export 16,000 petajoules of LNG to service these contracts.⁹ Under a national reservation policy, the government has committed to respecting these contracts, meaning exporters will not be prevented from exporting gas to meet these contracts.

The opening of the Gladstone LNG facilities connected the east Australian gas market to global markets; and now, 5 per cent of worldwide LNG trade moves through this port. Connecting the east coast with the international market radically and rapidly limited the availability of gas for domestic east coast consumers, and linked the domestic price to the international price.

The first shipment of LNG left Queensland in January 2015. Two months later, the Productivity Commission published a report finding that the integration of the east coast system with global LNG markets was already ‘creating significant disruption for market participants and will lead to material costs for some gas users, including through higher prices’.¹⁰

9. ACCC 2025a, Chart 0.1.

10. Productivity Commission (2015).

Box 1: Should the reservation include WA and the NT?

Four of the five LNG exporters in WA (Wheatstone, Pluto, Gorgon, and the North West Shelf) are already covered by the WA reservation. The fifth, Prelude, does not have a domestic gas obligation because it processes all of its LNG offshore on a floating rig.

Including Prelude in the national scheme would be challenging because – as a floating LNG facility – it would require a scaled regasification facility to supply the mainland.

The government has indicated that the two NT LNG exporters – Ichthys and Darwin – could be included in the national reservation.

Obligations on the NT exporters would require different considerations to the Gladstone exporters because:

- The NT exporters source gas mostly from offshore fields in the Timor Sea so are not draining domestic gas fields.
- Moving gas from the Darwin LNG exporters to users in the east coast would require significant infrastructure investments.

There is merit in imposing standard national rules – not least to prevent exporters jurisdiction-hopping to states with lower reservation obligations. But government should proceed at pace to resolve the east coast supply gaps by targeting the east coast exporters.

For this reason, we focus this submission on the east coast exporters.

A year later, in April 2016, the ACCC conducted an inquiry into the east coast gas market. That inquiry found that the start of LNG exports on the east coast had caused a collapse in the availability and a spike in the prices of gas being offered to domestic industrial consumers:

The development and construction of the three liquefied natural gas projects in Queensland, starting in late 2010, triggered unprecedented changes in the east coast gas market. In the period from about 2012 to the end of 2014, domestic industrial gas users started to approach the market seeking new gas supply agreements (GSAs) in anticipation of many large, long-term GSAs coming to an end. Many industrial users reported that they either could not get offers for gas supply during this period for 2016 and beyond, or received few offers at high prices with less flexible terms and conditions, including shorter contract duration.¹¹

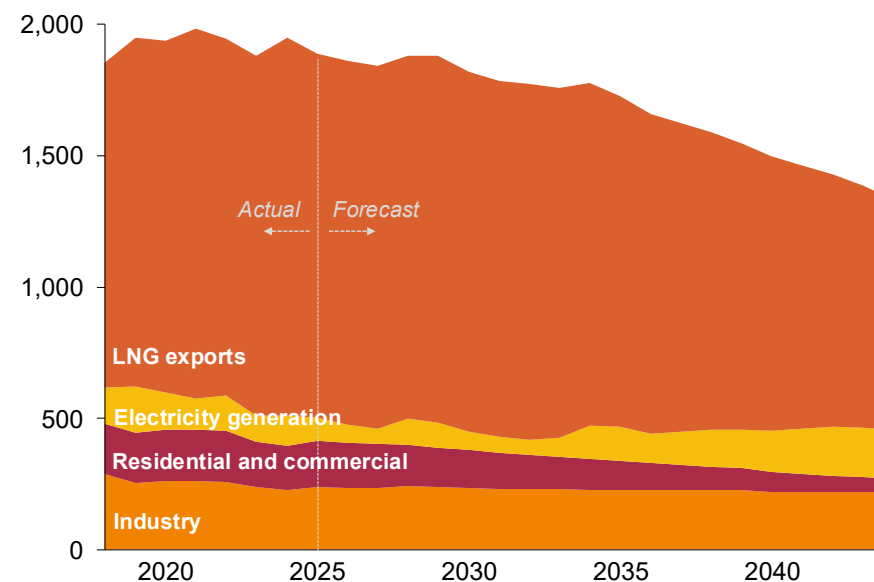
The ACCC found that by 2016, GLNG and QCLNG had already started purchasing large volumes of gas from Cooper Basin suppliers to meet their export demand. The Cooper Basin was historically a large source of supply for the southern market, so this redirection of supply reduced availability for domestic users.

This was not unexpected. At the start of 2016, GLNG and QCLNG had committed significantly more gas to export contracts than they controlled in their proven reserves. From the start, these two exporters clearly anticipated sourcing gas from the domestic market to service their export contracts.¹²

The Queensland LNG exporters control or influence almost 90 per cent of reserves on the east coast.¹³ They buy and sell gas into the domestic market, selling during times of excess production and low demand from the northern hemisphere, and buying gas from the

11. ACCC (2016).
 12. Ibid.
 13. ACCC (2025a).

Figure 2.1: About two thirds of gas produced on the east coast is exported, and only about one third goes to domestic demand
 Demand in the east coast gas system by domestic (industry, residential, commercial, and electricity) and LNG exports, 2018 to 2044 (petajoules)



Source: AEMO Gas Statement of Opportunities 2025, Figure 9.

domestic market to meet high export demand when domestic demand is low.

But the exporters' net contributions to the domestic market peaked in 2018 at 90 petajoules and have been declining ever since.¹⁴ Since 2023, the Queensland exporters have been net purchasers from the domestic market, taking out more than they put in. As their own production fields decline, they are forecast to withdraw more and more each year, rising to 77 petajoules in 2026.¹⁵ In fact, one exporter – the Santos-owned GLNG – is a net purchaser from the domestic market, while the other two – APLNG and QCLNG – are net contributors.¹⁶

About 90 per cent of the gas exported from Queensland is to meet the foundation export contracts. Between 2017 and 2024, the Queensland exporters sold a little more than 10,000 petajoules under contract and just 528 petajoules on the spot market.¹⁷ In 2026, Queensland exporters will require 1,297 petajoules of gas to meet their export contracts and will have a further 146 petajoules of uncontracted and spot gas.¹⁸

2.5 The risk of supply gaps are now a feature of the east coast gas market

As production in the southern fields declines, and the vast majority of supply in the Queensland fields is committed to export, the east coast is facing forecast gaps between supply and demand.

Each year, AEMO publishes a forecast of supply and demand, as a signal to the market about where and when further gas supply is needed.

14. Ibid.

15. Ibid, Chart 5.6.

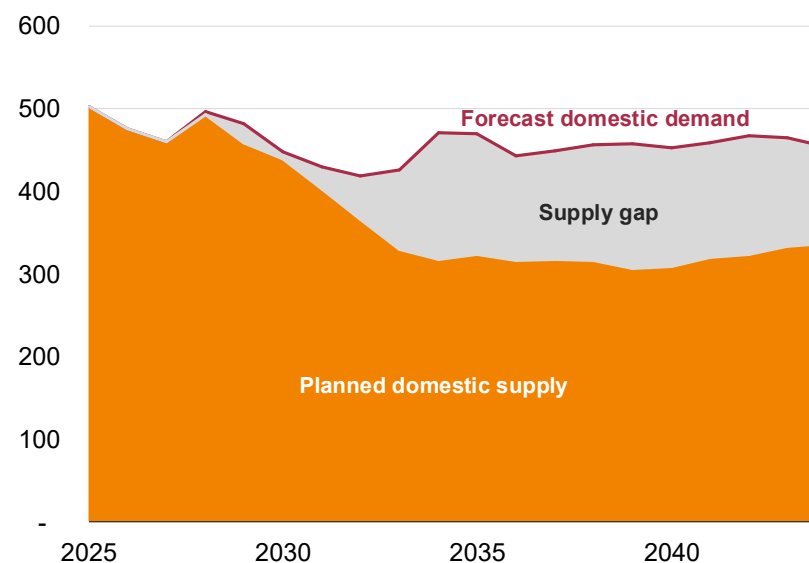
16. Ibid, Charts 4.2, 4.3, and 4.4.

17. Ibid, Chart 4.8.

18. ACCC 2025b, Chart 1.1.

Figure 2.2: On the east coast, an annual supply gap emerges in 2029 and grows rapidly into the 2030s

Gap between planned domestic production and forecast domestic demand in the east coast gas system, 2025 to 2044 (petajoules)



Source: Grattan analysis of AEMO Gas Statement of Opportunities 2025. Supply gap refers to southern supply gaps.

These forecasts are not predictions, they are warnings – they are designed to induce a market response. Year to year, the forecasts of supply gaps can change dramatically as market participants respond to fill the gaps.

In 2015, AEMO forecast a supply gap of about 15 petajoules per year from 2020. A year later, the forecast supply gap was pushed out to 2029.

In 2017, AEMO forecast an imminent supply gap of about 54 petajoules from 2018. But again, the following year, that supply gap failed to materialise as gas producers stepped up to fill the gap.

In the most recent forecast, from March 2025, annual supply gaps start to emerge from 2029 (see Figure 2.2). These supply gaps increase to about 150 petajoules by 2035. That forecast noted that from 2029, new supply will be required to meet demand in the east coast for both domestic and LNG export customers.

2.6 Since 2017, governments have tried many measures to secure domestic supply

Over the past decade, successive governments have introduced new rules and regulations aimed at increasing domestic supply and moderating domestic prices (see Figure 2.3):

- The **Heads of Agreement** is a voluntary agreement between the three Queensland LNG exporters and the federal government, which requires the exporters to offer uncontracted gas to domestic buyers at prices no higher than international prices, before exporting that gas.

It was first introduced by the Coalition government in 2017, and was renegotiated several times, most recently by the current Labor government in 2022.

- The **Australian Domestic Gas Security Mechanism** gives the federal Minister for Resources the ability to restrict the export of LNG if domestic supply gaps are forecast. It has never been triggered.

The ADGSM was first introduced by the Coalition government in 2017 and was reviewed multiple times, most recently by the current Labor government in 2022.

- The **Gas Market Code** is a mandatory set of rules requiring gas producers to offer gas to domestic consumers at fair prices.

The Gas Market Code commenced in 2023 under the current Labor government.

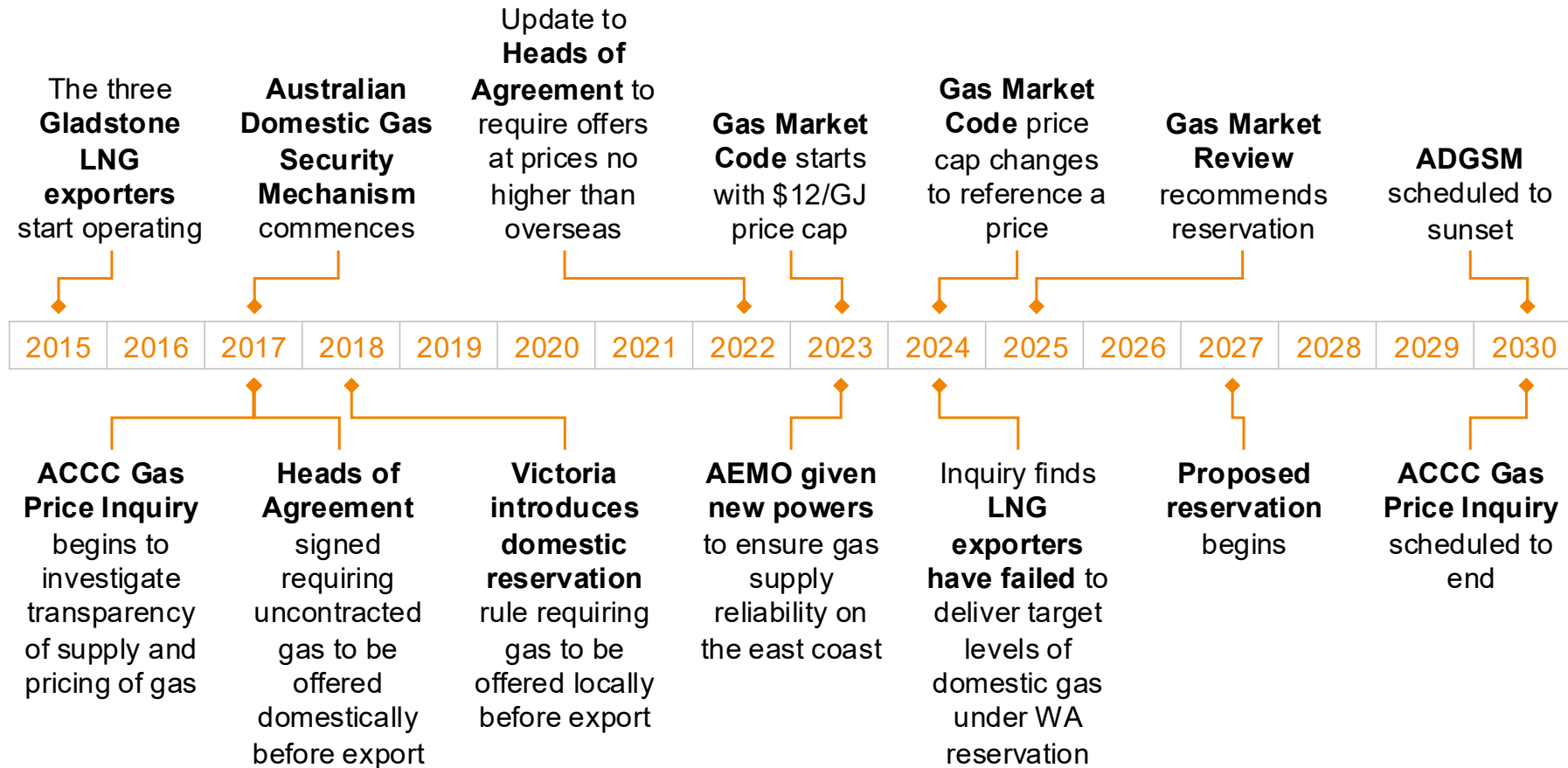
In 2025, the federal government announced a first-principles review of these mechanisms to ensure that the framework was fit to ensure domestic supply. That review found that while these instruments have contributed to averting shortfalls to date, they do not provide certainty of domestic supply, they have not placed continuous downward pressure on prices, and that ‘fundamental reform’ is needed.¹⁹

That review recommended the introduction of a gas reservation for the east coast.²⁰

19. DCCEEW (2025).

20. Ibid.

Figure 2.3: Since LNG exports began on the east coast, successive governments have attempted to manage the impact on price and supply
 Key developments in east coast gas policy since 2015



Source: Grattan analysis.

2.7 Three states have existing forms of gas reservation

Several states in Australia already have schemes to reserve gas for their local markets.

In 2011, the Queensland government introduced a law enabling it to designate individual gas fields for domestic supply only, with no exports allowed. This requirement is applied to specific acreages; it is not a blanket requirement across the state.

In 2018, the Victorian government introduced a law that requires offshore gas producers to offer gas to the local market on just terms before it can be sold to Queensland LNG exporters.

Western Australia has had a gas reservation scheme since 1979, when the state government struck a deal to develop the North West Shelf LNG export facility. In its agreement with the NWS, the state government placed three requirements on the project:

- A gas reservation – to reserve for the domestic market a volume equivalent to 15 per cent of the quantity of LNG approved for export.
- A marketing requirement – to market this gas to domestic consumers to achieve a stable supply profile.
- An infrastructure requirement – to procure and maintain facilities required to deliver this gas to the domestic market.

These principles still form the basis of the WA reservation today.

In 2024, the WA Parliament completed a two-year inquiry into the WA reservation. That inquiry found that WA was still facing significant forecast supply gaps from 2030, and that the scheme was failing to ensure exporters delivered their required domestic gas obligations.

The main loopholes identified by the inquiry were:

- the requirement to offer but not supply gas to domestic consumers.
- the presence of ‘commercial viability’ clauses that allow exporters not to supply the domestic market if it is uncommercial to do so.
- levying domestic gas obligations on a lifetime rather than annual basis.
- not requiring exporters to ensure sufficient infrastructure to get their gas to market.²¹

The WA scheme is implemented as a set of bespoke agreements between the state government and the LNG exporters. The terms of these agreements differ materially. This inconsistency, and a lack of reporting on performance against domestic gas obligations, makes it impossible to determine the extent to which exporters are meeting their obligations.

Moreover, a lack of material sanctions for non-delivery means exporters have little incentive to comply with their domestic gas obligations. Failure to do so does not affect their ability to continue exporting WA gas to overseas buyers.

21. WA Economics and Industry Standing Committee (2024).

3 Designing a domestic gas supply obligation

The federal government's proposed domestic gas supply obligation marks a shift from ad hoc intervention to structural reform. But the results will hinge on the design.

Get it right, and it can provide durable supply security while preserving competition and supporting the energy transition.

Get it wrong, and the scheme risks entrenching market power, dulling investment incentives, and delivering little new gas to domestic users.

This section lays out our approach to designing a workable domestic gas supply obligation.

First, our design meets three constraints outlined by the government:

- The scheme must be prospective.
- The scheme must meet domestic demand before exports are allowed.
- The scheme must be constitutional.

Second, we put forward a model for a domestic gas supply obligation that best meets a set of ten design principles. Inevitably, there will be trade-offs between design principles. Giving flexibility to exporters comes at the expense of certainty of supply for domestic consumers.

In the rest of the submission, we outline how our proposal balances these design principles.

3.1 The scheme should be framed as an obligation to make a contribution to domestic gas supply

'Gas reservation' refers to a wide range of policy instruments that can be used to increase the supply of gas to the domestic market, rather than the export market.

In a scenario in which exporters can attract higher prices for exporting gas than for delivering it to domestic consumers, some form of incentive or mandate is required to ensure that domestic consumers have access to sufficient supply, and to unlink domestic prices from international prices.

A reservation is the mechanism used to ensure domestic supply and break the link to international prices. It could be implemented in a variety of ways:

- A tax on LNG exports, to provide an incentive to supply to the domestic market.²²
- An acreage reservation, where supply from certain gas fields can only be sold domestically.²³
- A blanket reservation, where all LNG producers are required to offer or deliver a percentage of their output to the domestic market.²⁴

22. This is the model of reservation proposed by the Coalition before the 2025 federal election. The Coalition announced a gas reservation policy implemented as an export tax on Queensland LNG producers to be set at a level that makes domestic supply more attractive than LNG exports. The Coalition claimed the scheme would deliver up to 100 petajoules of additional gas to the domestic market in the first full year of operation.

23. Queensland uses this approach.

24. WA uses this approach.

- A preferential reservation, where uncontracted gas volumes must be offered to the domestic market first.²⁵

In the model being contemplated by the federal government, a gas reservation can best be thought of as a ‘domestic gas supply obligation’ placed on LNG exporters.

This is because the government has ruled out diverting gas from existing contracts, so there is little sense in which gas is actually being ‘reserved’ for the domestic market over the export market.

Instead, the government has framed its policy as creating a new obligation on the exporters to provide additional domestic gas supply, as a condition of being able to continue exporting gas beyond their existing contracts.

For this reason, in this submission we frame the reservation as a domestic gas supply obligation that places a requirement on LNG exporters to make a reasonable contribution to domestic gas supply. The gas required to be delivered to the domestic market is not ‘reserved’ from gas that would otherwise be exported, it is in effect additional to export gas.

3.2 The domestic gas supply obligation must meet three constraints

The government has outlined three policy commitments which we have taken as constraints on the design of our model.

The scheme must be prospective

When announcing the reservation scheme, federal Climate Change and Energy Minister Chris Bowen said:

25. The Heads of Agreement uses this approach.

This policy will apply only prospectively to new contracts – not existing contracts, not contracts that have been entered into in good faith by our trading partners and our gas companies, but to new contracts. No existing contract, domestic or international, would be disturbed or cancelled under this policy.²⁶

This is what we call the prospectivity constraint. In this submission, we have applied this constraint as follows:

- Gas exported to meet pre-Reservation contracts will not be subject to export licences.
- All other exported gas is subject to export licences. We call this ‘licensed gas’.
- Exporters will not be required to divert gas from pre-Reservation contract exports to fulfil domestic gas supply obligations²⁷

A failure by an obligation-holder to meet its domestic gas supply obligation cannot result in that exporter being prevented from exporting LNG to meet its pre-Reservation contracts.

Exporters can only be prevented from exporting licensed gas. Individual exporters will have different volumes of licenced gas. Some exporters may have none, only exporting the volume required to meet their foundation contracts.

Domestic demand must be met before exports are allowed

When announcing the reservation scheme, Minister Bowen said:

26. Bowen et al (2025).

27. However, exporters may choose to do this anyway, even though it is not required under the scheme. Bilateral agreements between exporters and their customers to reduce exports carry no sovereign risk as they do not involve government intervention. This type of deal is permitted by our design.

We've decided to support as a preferred model for further consultation the simplest, easiest to implement, easiest to understand model of not allowing gas exports into the future unless the government is satisfied that domestic demand is catered for first.²⁸

This is what we call the constraint of domestic supply first. In this submission, we have applied this constraint by ensuring that the domestic gas supply obligation must be met before, not after, receiving export licences.

The scheme must be constitutional

When announcing the reservation scheme, Minister Bowen said:

The reservation scheme should have capacity to be national in scope, working in tandem with federal, state, and territory gas market mechanisms.²⁹

This is what we call the constitutionality constraint. Any federal gas reservation must operate within the limits of the Australian Constitution. Unlike WA's policy – which relies on state powers over land and resource development – the Commonwealth cannot directly reserve gas at the wellhead or impose conditions on state production approvals.

Instead, a federal scheme must rely on the Commonwealth's power over trade and commerce, or the corporations power.³⁰

There are also limits on geographic targeting. Section 99 prohibits Commonwealth laws on trade and commerce which preference one state over another. And Section 92 guarantees freedom of interstate trade.

28. Bowen et al (2025).

29. Ibid.

30. Section 51(i) and Section 51(xx) respectively.

Together, these provisions mean a federal reservation cannot simply single out Queensland, even though the supply problem is concentrated on the east coast. Any obligation must be framed in nationally consistent terms, with differences justified on objective project characteristics, such as whether gas is exported as LNG.

Finally, several states already operate reservation-style policies, most notably WA. A federal scheme may need to treat projects already covered by state reservation differently, or effectively exempt them. Or, those states may decide to abolish their reservations or join the federal one. This helps explain why the federal proposal is framed as a domestic supply obligation on LNG exporters, rather than a blanket production-side reservation.

3.3 The domestic gas supply obligation should be designed against 10 principles

In addition to these constraints, the federal government has argued for a set of design principles.³¹ Other parties, such as the LNG exporters, have put forward different versions of design principles.

In this submission, we outline a set of 10 principles against which the domestic gas supply obligation should be designed. There will be trade-offs between these in any successful design:

- **Sufficient supply.** The domestic gas supply obligation should put downward pressure on gas prices for domestic consumers by slightly oversupplying the domestic market.
- **Domestic certainty.** The domestic gas supply obligation should provide domestic users of gas certainty to make investment and divestment decisions that rely on future availability of gas.

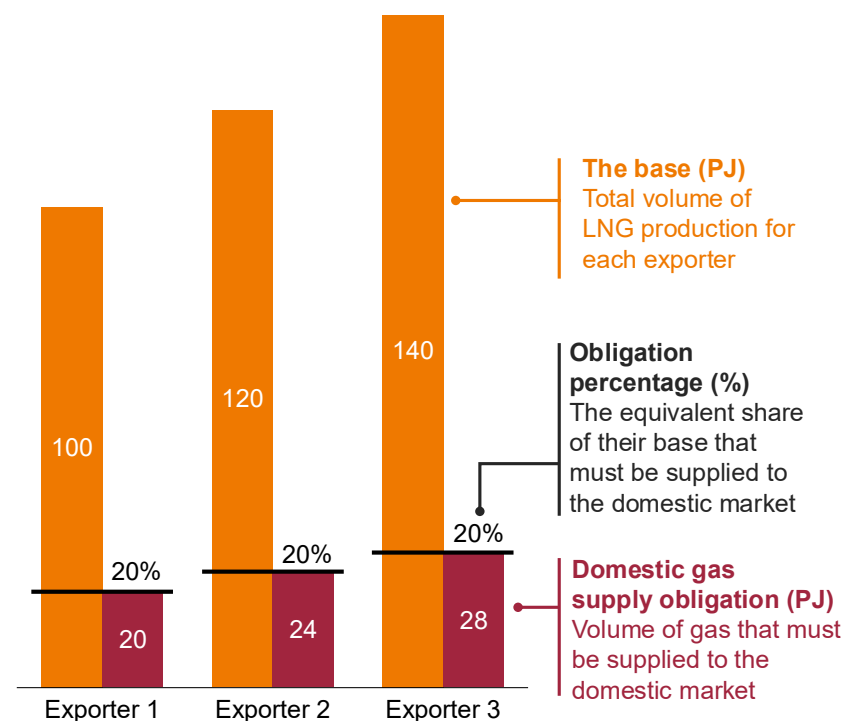
31. Bowen et al (2025).

- **Production certainty.** The domestic gas supply obligation should provide certainty for LNG exporters and domestic producers of gas to make long-term investment and divestment decisions.
- **Obligation to supply.** Exporters should have an obligation to supply, not just offer, gas to domestic consumers.
- **Flexibility.** Exporters should have flexibility to meet their domestic gas supply obligation through a variety of standard commercial arrangements.
- **Demand reduction.** The domestic gas supply obligation should avoid locking in high domestic demand for gas, and be consistent with other policies to reduce gas demand across the economy.
- **Upstream competition.** The domestic gas supply obligation should not reduce upstream competition in the supply of gas to the domestic market.
- **Simplicity.** The domestic gas supply obligation should be simple to implement and easy for the public to understand.
- **Fairness.** The domestic gas supply obligation should allocate responsibility for domestic gas supply between exporters fairly.
- **Emissions reduction.** The domestic gas supply obligation should not make it harder for Australia to meet its legislated 2050 and interim emissions-reduction targets.

In the rest of this submission, we outline the key challenges facing the federal government in designing the domestic gas supply obligation and we assess those challenges against our 10 design principles.

The key tasks for government (see Figure 3.1) are how to define the base against which a domestic gas supply obligation is calculated, and an obligation percentage – the equivalent share of the base that must be supplied domestically. The next two sections outline how to do this.

Figure 3.1: Grattan domestic gas supply obligation model overview
Under our proposal, exporters have a domestic gas supply obligation (in PJ) based on a percentage of their LNG production. Numbers are illustrative.



4 How to define the base

To calculate the domestic gas supply obligation, the government must define a base and a percentage. The base is the volume of gas used to calculate an exporter's domestic gas supply obligation. The percentage is then applied to that base to determine the domestic gas supply obligation volume that each exporter must deliver.

In this section, we outline how to define the base. We argue that the base of the domestic gas supply obligation should be set according to each exporter's total LNG export volumes.

The definition of what goes into the base is important for two reasons: it determines the total volume of gas that can be delivered to the domestic market under the domestic gas supply obligation, and it allocates responsibility for domestic gas between the exporters.

There are two broad models for defining the base:

Model 1: Total LNG defines the base as the full volume of LNG produced by the exporters. This includes gas being exported under contract today and in the future, and all spot cargoes.

Model 2: Uncontracted LNG defines the base as the volume of LNG production beyond that required to meet existing contracts. This includes gas exported as spot cargoes today and in the future, and gas exported under a contract signed after 22 December 2025.

Both models are consistent with the prospectivity constraint. But Model 2 is likely to deliver too little gas to cover supply gaps, and it fails to allocate domestic gas supply obligations between exporters based on their fair contribution to the problem.

The government should therefore adopt the Model 1 definition of the base, and use total LNG production volumes to determine the base of the domestic gas supply obligation.

4.1 To calculate the domestic gas supply obligation, government must define what gas is in the base

If a domestic gas supply obligation involves directing a given percentage of gas for the domestic market, the first question is: a given percentage of what?

To answer this, we define two types of gas:

- **The base:** gas that is used as the base of the domestic gas supply obligation calculation. This is the volume of gas to which an obligation percentage is applied.
- **Domestic gas supply obligation:** the volume of gas that must be supplied to the domestic market under the scheme. This is the product of the base and the obligation percentage.

For example, if an exporter has a base of 1,200 petajoules and a 20 per cent obligation percentage, they will have a domestic gas supply obligation to deliver 240 petajoules of gas.

The base will be a combination of these three types of LNG exports:

- **Contracted gas:** gas exported under a contract signed before the reservation scheme was announced on 22 December 2025.
- **Newly-contracted gas:** gas exported under a contract signed after the reservation scheme was announced on 22 December 2025.
- **Spot gas:** gas exported on the spot market.

4.2 Model 1 sets the base as total LNG production

Under the first model, the domestic gas supply obligation would be calculated based on the total LNG production of each exporter (see Figure 4.1).

Consider this scenario. An exporter produces annually:

- 1,000 petajoules of contracted gas,
- 100 petajoules of newly-contracted gas, and
- 100 petajoules of spot gas.

Under Model 1, a total of 1,200 petajoules would be the base.

With a 20 per cent obligation percentage, the exporter would have a domestic gas supply obligation to deliver 240 petajoules of gas.

4.3 Model 2 sets the base as only LNG production beyond pre-Reservation contracts

Under Model 2, the base would include only LNG production that was not under contract when the reservation scheme was announced on 22 December 2025.

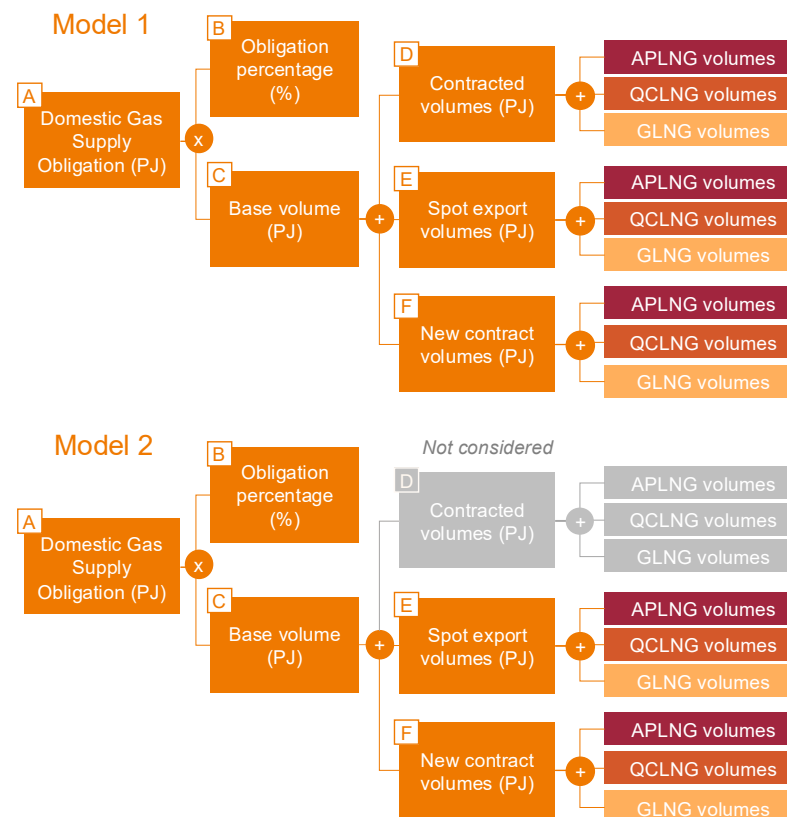
Consider an exporter that produces the same quantities of gas:

- 1,000 petajoules of contracted gas,
- 100 petajoules of newly-contracted gas, and
- 100 petajoules of spot gas.

Under Model 2, a total of 200 petajoules would be the base.

With a 20 per cent obligation percentage, the exporter would have a domestic gas supply obligation to deliver 40 petajoules of gas.

Figure 4.1: How to calculate the domestic gas supply obligation under Models 1 and 2 of the base



4.4 Both models meet the prospectivity principle

Both models are consistent with the prospectivity principle, because neither require exporters to divert gas from their existing contracts.

The definition of the base can be thought of as the mechanism for determining the overall size of the domestic gas supply obligation, and allocating it between the exporters.

Model 1 uses total LNG production volumes as the basis for calculating a domestic gas supply obligation. It does not require exporters to break those contracts. Exporters can choose to meet their domestic gas supply obligations however they like – increasing production, diverting spot exports, or diverting contracted exports if they choose to pursue agreements with their customers to do so.

Model 2 similarly does not require producers to break their export contracts. It simply uses a different base.

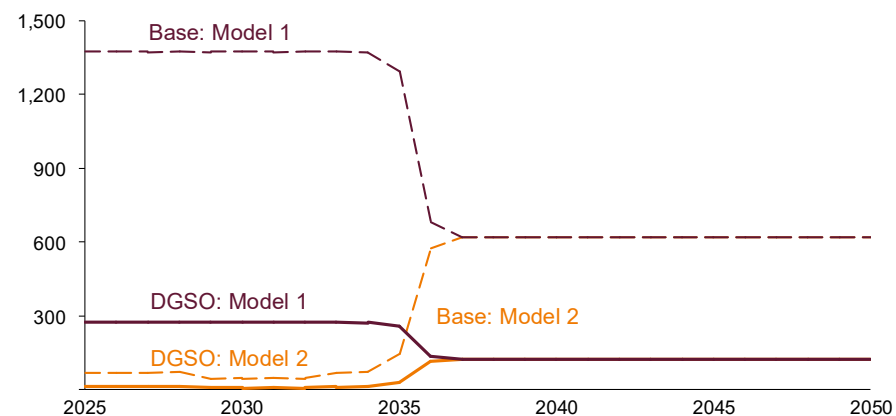
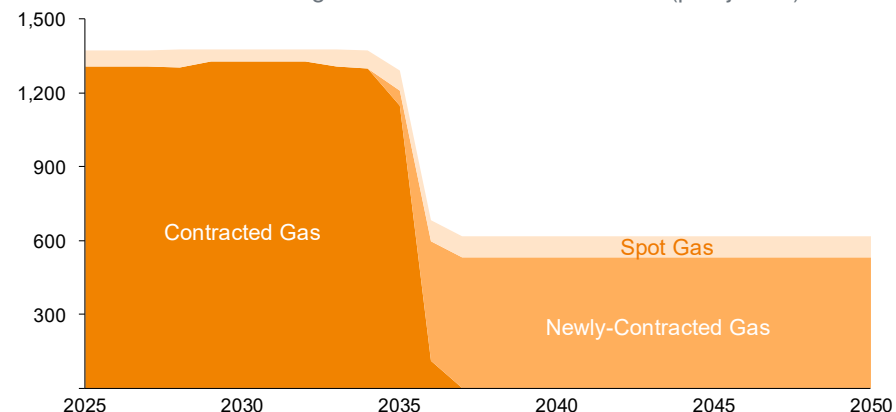
4.5 Model 1 delivers sufficient supply but Model 2 does not

Model 1 performs much better than Model 2 on the principle of delivering sufficient supply. This is because Model 2 is so narrowly defined that the volume of the base is not large enough to deliver sufficient volumes of gas under the domestic gas supply obligation to avert forecast supply gaps.

Figure 4.2 shows the different outcomes of these two models based on actual LNG production from the three east coast exporters. In Model 1, the base volumes are immediately equivalent to total LNG production at about 1,300 petajoules a year, and domestic gas supply obligation volumes are about 260 petajoules.³²

32. We have assumed a 20 per cent simple percentage to calculate the domestic gas supply obligation volumes for this example. The domestic gas supply obligation percentage can be set at any level to deliver the desired volume of domestic gas supply obligation.

Figure 4.2: Under Model 1, the volume of gas delivered under a fixed 20% obligation percentage declines when contracted volumes fall off
Forecast volumes of base gas and DGSO Models 1 and 2 (petajoules)



Source: Grattan analysis.

In Model 2, the base volumes start out low and climb from the mid-2030s as export contracts roll off. Under Model 2, the base volumes stay low until 2035 because there are low volumes of spot and newly-contracted gas. Such a low base means a low domestic gas supply obligation – just 14 petajoules of gas per year would be supplied domestically until the mid-2030s.

This happens because 94 per cent of LNG production capacity in Queensland is already used to meet export contracts. The production capacity of the six compression trains is a hard limit on total LNG production. So under Model 2, there is very limited scope to increase the volumes of the base until 2035.³³

Figure 4.3 shows the volumes of gas that would have been delivered under our proposed domestic gas supply obligation using Model 1 and 2 in 2025.³⁴

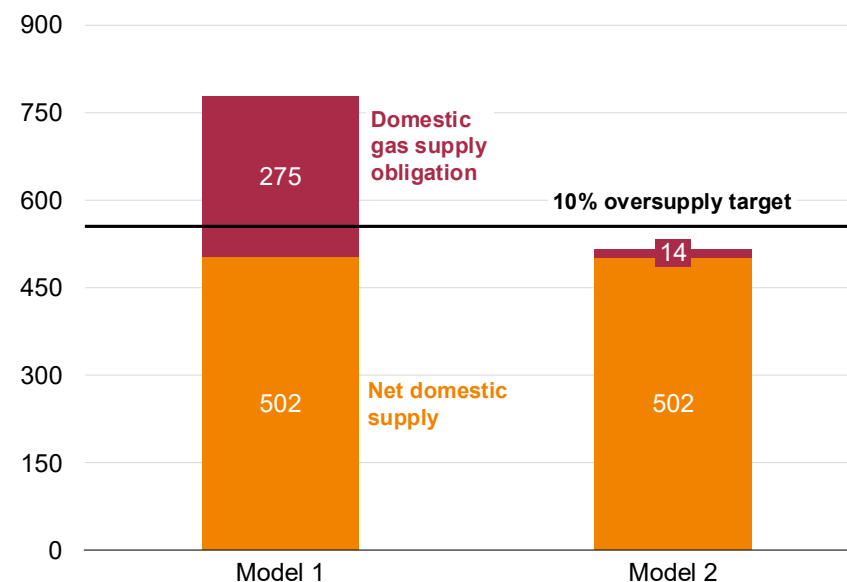
It shows that while Model 2 would have delivered just 14 petajoules of domestic gas, Model 1 would have delivered 275 petajoules. 275 petajoules would have been way too much gas for the domestic market to absorb in 2025. But it illustrates that a broad definition of the base as per Model 1 affords government much greater flexibility to deliver required volumes of gas under the domestic gas supply obligation than a narrow definition as under Model 2.

Given the goal of slightly oversupplying the domestic market, Model 2 would not have achieved this in 2025. In fact, at no point in the next two decades would Model 2 deliver sufficient gas to fulfil the principle of slightly oversupplying the domestic market (Figure A.2 on page 40).

33. One exception to this is the Kogas-GLNG contract. This contract is set to expire in 2031 unless it is extended. If the contract extension is considered a 'new contract' then under Model 2, an extension of the Kogas contract would significantly increase the volume of base gas in 2031. Under Model 1, the treatment of the Kogas extension is irrelevant to the size of the base - it is included either way.

34. Assuming a fixed 20 per cent domestic gas supply obligation percentage.

Figure 4.3: In 2025, Model 2 would not have delivered enough gas to meet the goal of slightly oversupplying the domestic market
Volume of gas delivered under a fixed 20% domestic gas supply obligation under Model 1 and Model 2 definitions of the base, 2025 (petajoules)



Note: This assumes a slight oversupply is 10%.

4.5.1 Setting a higher percentage risks eroding the base by disincentivising exports

One response to the flaws in Model 2 would be to set a higher obligation percentage and take more of the smaller base for domestic consumers.

This is unlikely to work because it requires the obligation percentage to be set so high it risks prompting exporters to stop exporting at all, which would erode the base.

Figure 4.4 shows the range of obligation percentages that would have been required to deliver a 10 per cent oversupply to the market across the past eight years.

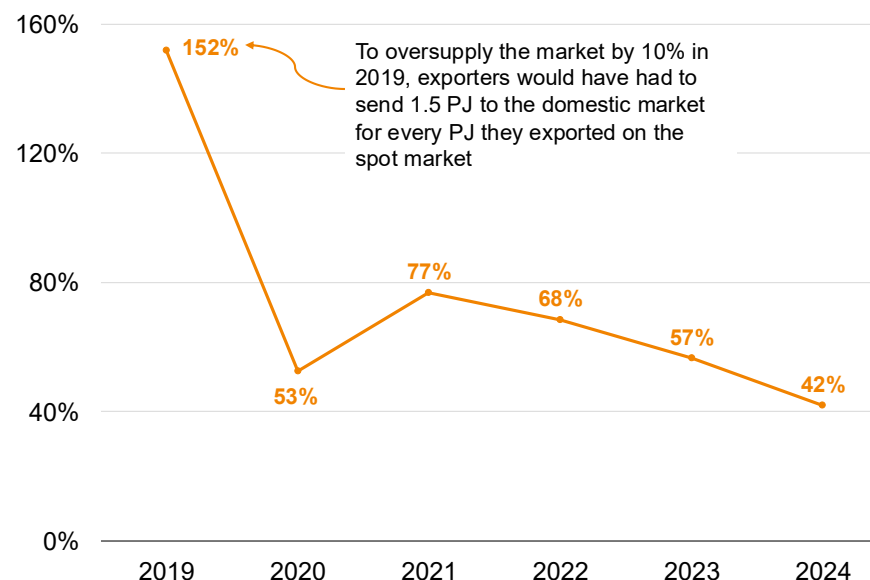
It shows that with the actual volumes of the base across that period, the obligation percentage would need to be set well above 50 per cent.

Setting the obligation percentage very high creates a higher marginal cost to export LNG. If exporters have to contribute 1 petajoule of domestic gas for every 1 petajoule of LNG exported beyond existing contracts (a 100 per cent obligation percentage under Model 2), they face higher disincentives to export than they would under Model 1. If the marginal costs of exporting become too high, exporters may simply decide to reduce their exports of spot gas, to avoid incurring a large domestic gas supply obligation. This would erode the base, meaning the domestic gas supply obligation would deliver less and less gas.

Conversely, setting a lower obligation percentage levied on a higher base reduces the distortionary impact on the decisions of LNG exporters. This retains the incentive for exporters to both keep exporting and supplying the domestic market.

Figure 4.4: Under Model 2, the obligation percentage would need to be set unreasonably high to deliver oversupply

Domestic gas supply obligation percentages required to deliver a 10% oversupply, 2019 to 2024



Source: Grattan analysis of AEMO 2025.

4.6 Model 1 allocates domestic gas supply obligation obligations fairly, Model 2 does not

Model 2 does not account for volumes of LNG for pre-Reservation contracts when calculating exporters’ domestic gas supply obligation.

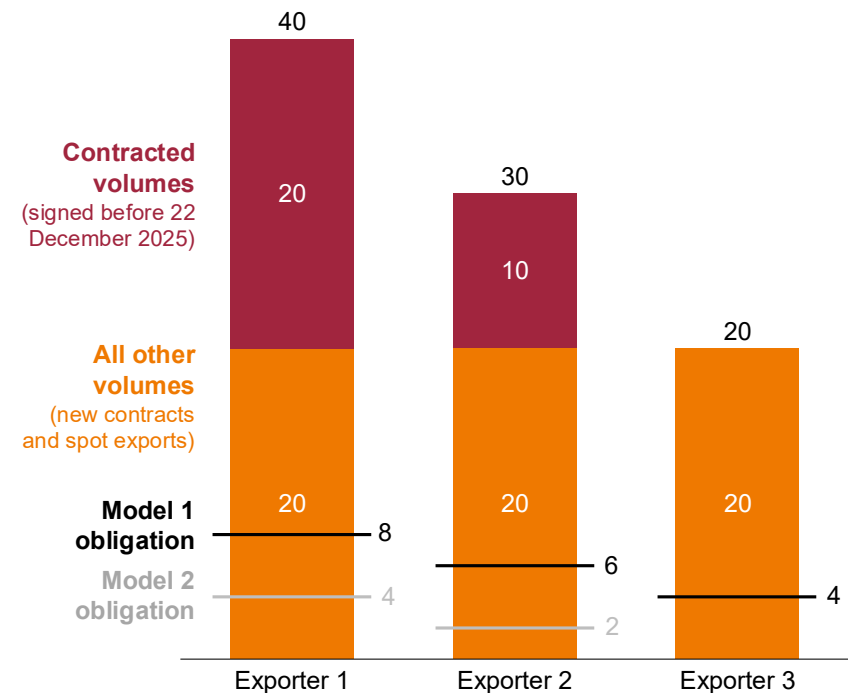
This means that an exporter with zero exports beyond its pre-Reservation volumes would incur a domestic gas supply obligation of zero petajoules. This would result in a perverse scenario whereby the three exporters could be exporting broadly similar volumes of LNG, but one exporter has no obligation to supply the domestic market.

Figure 4.5 illustrates one such scenario:

- Exporter 1 exports twice as much LNG as Exporter 3
- Under Model 1, Exporter 1 has twice the domestic gas supply obligation of Exporter 3
- But under Model 2, Exporter 3 avoids any domestic gas supply obligation

Figure 4.5: Model 2 fails to allocate responsibility for domestic gas supply obligations fairly

Domestic gas supply obligations (petajoules) under Model 1 versus Model 2 of the base, illustrative numbers (assumes a 20% obligation percentage)



5 How to set the obligation percentage

Once the base is decided, the next question for government is how to set the obligation percentage.

There are three options: a fixed percentage, a floating percentage, or a capped option where the percentage can float within a set range.

All three options have attractions and downsides. The government should approach this choice based on five of the design principles:

- How effectively would each option deliver sufficient supply?
- How does each option deliver certainty for exporters?
- Does each option deliver certainty for domestic consumers?
- How effectively does each model maintain upstream competition among domestic suppliers?
- How simple is each option to implement?

A fixed percentage would be easier to implement upfront, but it would not meet the key principle of delivering sufficient supply.

A fully flexible percentage would best meet domestic supply gaps, but it forces too much uncertainty onto exporters to make long-term decisions.

Overall, the capped percentage balances the design principles best (see Figure 5.1). Because it can flex, it better responds to forecast supply gaps than a fixed percentage. Because it has a ceiling, it gives similar degrees of certainty to exporters as the fixed model.

But it delivers more certainty for consumers, and is not unreasonably difficult to implement. Importantly, the cap ensures a continued role for domestic producers to supply the domestic market.

Figure 5.1: The capped percentage option performs best overall
Heat map comparison of options against design principles

	Fixed percentage	Floating percentage	Capped percentage
Sufficient supply	Cannot be adjusted based on changes in the base or supply gaps, so is unlikely to cover gaps reliably	Can be adjusted up and down to ensure domestic gas supply obligations cover supply gaps	Can be adjusted to cover supply gaps, but only up to a point (the cap)
Exporter certainty	Provides exporters certainty about their long-term obligations	Provides little certainty to exporters since it can fluctuate substantially based on supply gaps	Provides exporters certainty about their maximum long-term obligations
Consumer certainty	Provides low certainty to domestic consumers, 'release valve' means gas can still be exported	Provides high certainty that market will be consistently oversupplied	Provides high certainty that supply gaps will be met, but only up to the cap
Upstream competition	Provides moderate certainty for domestic producers given supply gaps are still likely to emerge	Reduces incentives for domestic producers due to 'whatever it takes' approach to setting obligation percentage	Provides more incentive to domestic suppliers to continue producing because of the cap on obligation percentage
Simplicity	Easy to implement upfront, but 'release valve' makes long-term implementation extremely difficult	Requires sophisticated forecasting capability, but avoids need for 'release valve monitoring'	Requires sophisticated forecasting capability, but avoids need for 'release valve' monitoring
Legend	Performs well	Performs moderately	Performs poorly

5.1 Floating and capped percentages consistently deliver domestic supply

The first test of each method of setting the obligation percentage is how well it delivers on the sufficient supply principle.

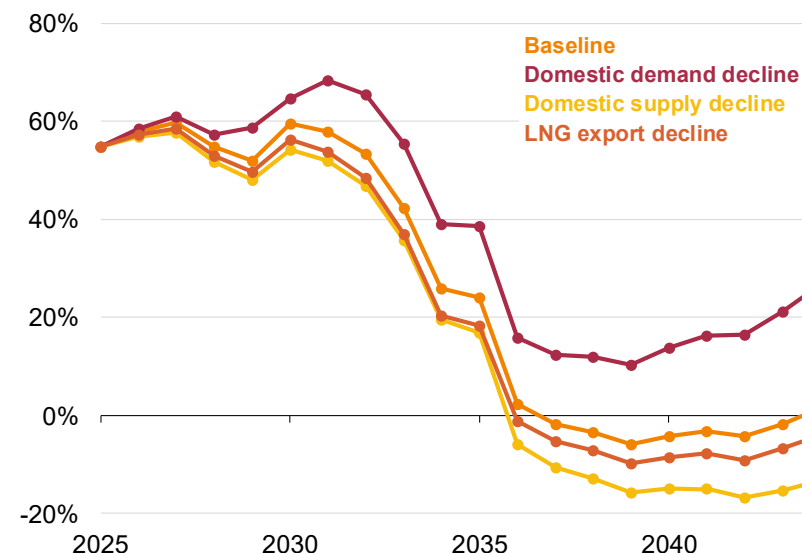
To test this, in this section we model four scenarios of future supply gaps:³⁵

- Baseline: current forecasts of southern supply-demand gaps out to 2044 and LNG exports
- Domestic demand decline: where domestic demand declines by 20 per cent below the baseline by 2044
- Domestic production decline: where production declines by 20 per cent below the baseline by 2044
- LNG export decline: where LNG exports decline by 20 per cent below the baseline by 2044

The obligation percentage should deliver enough supply consistently across these scenarios because the future of domestic demand, domestic production, and global LNG demand are inherently uncertain.

Against this principle, a fixed percentage performs poorly, whereas a floating or capped percentage performs well. Figure 5.2 shows that a fixed obligation percentage of 20 per cent would deliver vastly more gas than required in the early years, and not enough in the later years. Conversely, because a floating percentage can adjust to the size of supply gaps, it can cover supply gaps regardless of their size by adjusting the percentage. A capped percentage does the same thing, up to its cap.

Figure 5.2: Pursuing a fixed 20% obligation percentage delivers a significant variance in oversupply over time and across scenarios
Oversupply % delivered by a fixed obligation percentage of 20% under different scenarios



Source: Grattan analysis of data including AEMO 2025, ACCC 2025a.

35. See Appendix for full methodology behind these scenarios.

5.2 Capped and fixed percentages both offer certainty for exporters

Exporters with domestic gas supply obligations have a reasonable expectation that they will know how much gas they will be required to deliver to the domestic market into the future.

The obligation percentage should be set in such a way that it affords reasonable certainty to exporters to be able to enter into long-term contracts and plan their gas production to cover export and their domestic gas supply obligation.

The fixed and capped models perform equally well against this principle. Under either model, the precise volume that will be delivered is unknowable because it depends on domestic supply gaps in a given year. But both models involve a maximum amount that exporters can plan for. Conversely, the floating percentage provides no such certainty.

5.3 Floating and capped models deliver more certainty to domestic consumers than a fixed model

Exporters are not the only party that needs certainty. Domestic users of gas equally have a reasonable expectation that there will be sufficient supply of gas to meet demand into the future. Without this certainty, they cannot make long-term investment and divestment decisions.

If the domestic gas supply obligation fails to give domestic users of gas assurance that supply gaps will be averted, it will not have achieved its purpose.

Against this principle, a floating percentage performs best, a capped percentage performs reasonably, and a fixed percentage performs poorly. This is because a floating percentage adjusts to deliver the amount of gas required by the domestic market. The capped percentage also does this, but only up to a point. The fixed percentage

is unresponsive to changes in supply gaps, so cannot be relied upon to cover those gaps.

5.4 Capped and fixed percentages also guarantee a role for domestic producers

Setting a fully floating percentage runs the risk of discouraging domestic producers from investing in new supply to meet these shortfalls. A fully floating percentage means exporters can be compelled to supply 'whatever it takes' to the market to reach a targeted oversupply. In this scenario, domestic producers might rationally conclude that their own production risks being edged out of the market.

Setting a fixed or capped percentage ensures that there is a limit to what the exporters will be delivering to the domestic market. Domestic suppliers will continue to be motivated to invest in filling these gaps, ensuring the market does not become overly dominated by the exporters.

5.5 A fixed percentage requires a 'release valve' which reduces incentives to supply the domestic market

An alternative to capped percentage would be to set a fixed obligation percentage high enough to cover all plausible supply gap scenarios, combined with a 'release valve' that allows exporters to export any gas under the domestic gas supply obligation not taken up by domestic buyers.

In theory, this resolves the problem of choosing a single fixed percentage by allowing actual domestic deliveries to fall below the obligation level when demand is lower. But this would create two serious weaknesses in the scheme.

It means exporters are not required to actually supply gas

A fixed percentage with a release valve by definition means that exporters are not required to supply gas to domestic consumers, only to offer it.

In practice, this undermines the effectiveness of the entire scheme because it preserves the incentive (higher export prices) and creates the opportunity (release valve) for exporters not to sell gas to domestic customers.

Experience in both the east and west coast gas systems illustrates the fundamental weakness of an obligation to offer with a release valve.

- **On the east coast**, the Gas Market Review found that the obligation to offer (but not supply) gas under Heads of Agreement meant that producers had no incentive to reduce prices for gas offered to domestic consumers below international prices.³⁶ In practice, just 10 per cent of gas ever offered to domestic consumers under the HoA has been taken up. This reflects both the fact the market has never been in undersupply, and the fact that domestic buyers are not willing to pay international prices for gas.
- **On the west coast**, the parliamentary inquiry into the WA reservation found that because exporters only have an obligation to offer their gas, but not supply it, it is very difficult to determine if an exporter has met their obligation to source a domestic buyer for their gas. In practice, the substantial release valve in WA has led to exporters opting not to supply the domestic market.³⁷

An obligation to offer but not supply gas is very likely to lead to gas not being supplied to domestic consumers. This is why the Gas Market

Review recommended the obligation to supply, which we reflect as one of our design principles.

It would be complex and time-consuming to implement

Moreover, a release valve would make the domestic gas supply obligation as a whole extremely challenging to implement. This is because it would require a method of verifying when the release valve can be activated – the point at which the regulator is satisfied that exporters have executed their responsibilities to offer gas to domestic customers, and that excess gas can be exported.

This would require:

- Exporters to submit some form of compliance plan outlining how and when their domestic gas supply obligation volumes will be made available for purchase, providing ongoing revisions and updates to those plans, and providing evidence that they have complied with their plans.
- The regulator to execute a continuous process of assessing and approving plans, and monitoring compliance against those plans.
- A robust set of standards for exporters to have met to discharge their obligation to offer gas.

In short, because it drags the regulator into the day-to-day running of the export businesses, determining case-by-case when cargoes can be exported, the fixed percentage model risks being unworkable.

36. DCCEEW 2025, p. 42.

37. WA Economics and Industry Standing Committee (2024).

6 How to ensure compliance

The federal government has committed to a model of export permitting where exporters must meet domestic demand first before they are able to export licensed gas.

The design of this export permitting model is critical to ensuring that compliance with the scheme actually results in more domestic gas. This final section outlines a proposal for implementing export permits that will deliver on the promise of the reservation.

Export permits should be issued after obligation-holders meet two conditions. First, they should demonstrate they have met their current year's domestic gas supply obligation, and second, that they have pre-sold contracts representing at least 80 per cent of the next year's domestic gas supply obligation. If they demonstrate this, they earn an export licence for a year.

This model should be built on a system of tradeable certificates. Obligation-holders should earn a certificate for each petajoule of domestic gas sold. They could then either bank certificates for future years (up to a limit), or sell them to other obligation holders.

Exporters will resist this proposal because it requires them to meet their commitments before they can export. But this feature is necessary. The domestic gas supply obligation will only work if it severs the link between export and domestic price, and if exporters have an incentive to deliver domestic gas.

Government should not be cowed by exporters seeking to ensure there are loopholes in the design of the system. If the domestic gas supply obligation is to deliver sufficient domestic gas, it must be made strong. Here is how.

6.1 Export licences should be awarded for meeting the annual domestic gas supply obligation

In our proposal for an export permitting model, we assume that total LNG production is deemed the base (Model 1 in Chapter 4), and that the government will set the obligation percentage based on forecast supply gaps up to a cap of 15 per cent of LNG production (as recommended in Chapter 5).

To determine whether an LNG exporter gets a licence, the government would follow seven steps (see Figure 6.1 on page 30 for illustration of the process)³⁸:

- 1. Forecast gap.** Determine the size of the supply gap for the year ahead.
- 2. Calculate base.** Require gas exporters to submit their forecasts of base volumes for the forward period.
- 3. Determine obligations.** Set the obligation percentage based on the portion of base volumes required to cover the forecast supply gap, up to the cap of 15 per cent. Assign domestic gas supply obligations (in petajoules) to each exporter based on their forecast base volumes and the obligation percentage.
- 4. Award certificates.** Award exporters a certificate for every petajoule of gas sold to a domestic customer (certificates are awarded when contracts are signed).
- 5. Require certificates.** Require exporters to surrender:

³⁸ Domestic gas supply obligations could be set on any time-frame, for example, multiple years. For this submission, we have assumed that domestic gas supply obligations are set for the year ahead.

- Certificates equivalent to 80 per cent of their annual domestic gas supply obligation before the start of each year.
 - Certificates equivalent to 100 per cent of their annual domestic gas supply obligation before the end of each year.
- 6. Issue licences.** Issue export licences for the year ahead to exporters that meet their obligations.
- 7. Conduct reconciliation.** Require exporters to submit data at the end of each year on actual base volumes and actual domestic gas delivered.
- Issue additional certificates if exporters delivered *more* domestic gas than required based on their actual base volumes.
 - Require additional certificates to be surrendered if exporters delivered *less* domestic gas than required based on their actual base volumes.

Box 2: Why should export permitting use certificates?

Implementing the domestic gas supply obligation through tradeable certificates would deliver the additional domestic gas at lowest overall cost by allowing whichever party is best-placed to supply domestic gas to do so. Certificate schemes work well where governments:

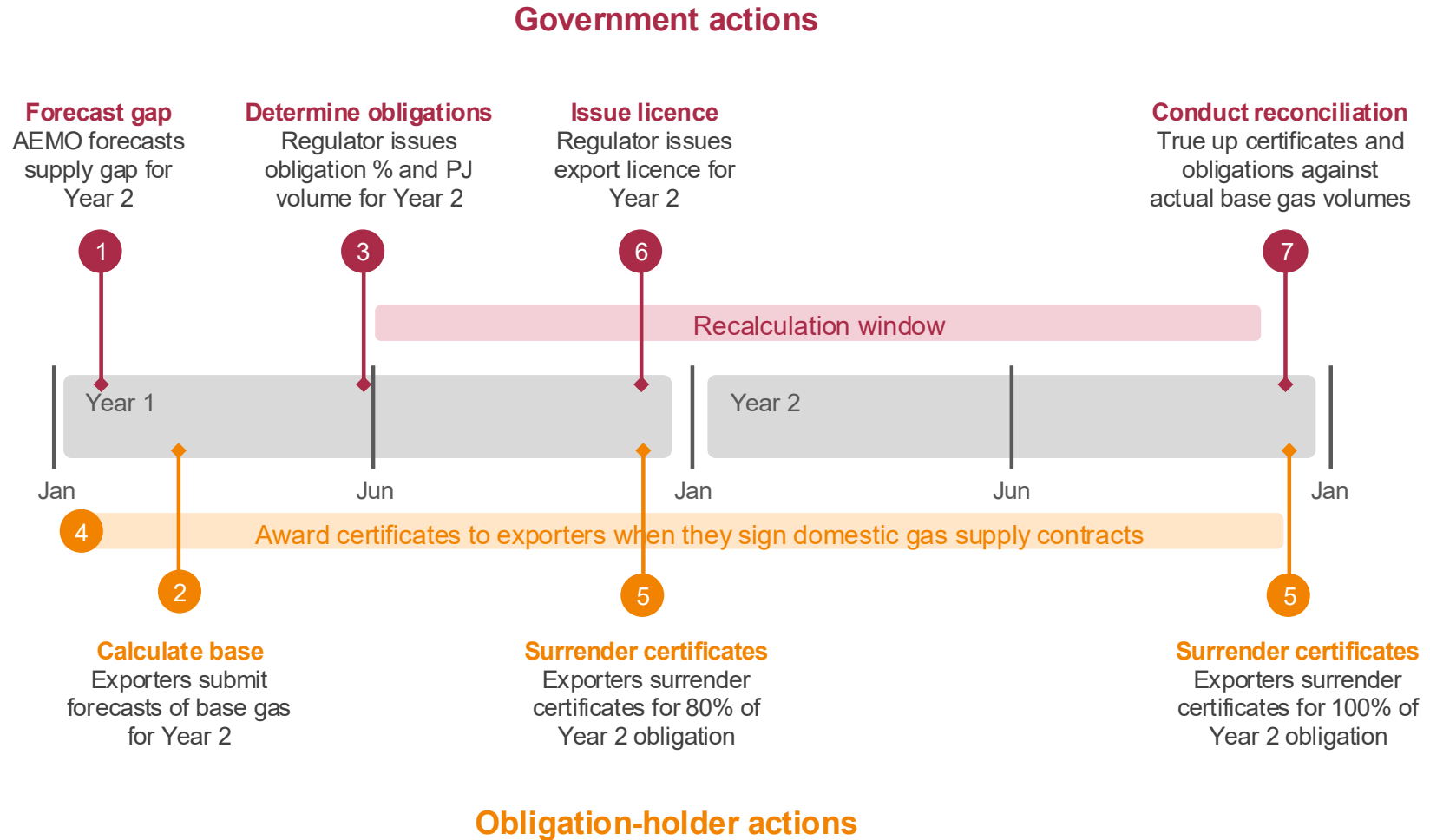
- Seek a specific overall outcome (in this case, additional domestic gas supply)
- Want the cost of achieving that outcome to fall on specific firms (in this case, LNG exporters)
- Want to minimise the overall cost of achieving the outcome (in this case, the cost of supplying additional gas)

In the case of domestic gas supply, a certificate-based system would deliver domestic gas supply through the producers able to deliver that supply at lowest cost. The three obligation-holders will face different costs of providing additional domestic gas supply. Without the ability to trade obligations, each exporter would be required to meet their obligations themselves, regardless of the cost. With trading, gas producers that are able to deliver extra domestic supply at lowest cost can sell certificates to firms that face higher barriers.

In the case of the east coast, APLNG and QCLNG (which already contribute to the domestic market) are likely to be in a position to sell excess certificates to GLNG (which does not) to enable it to meet its obligations. This would be a preferable outcome for all firms, creating a revenue stream for the sellers, and enabling the GLNG to choose between buying domestic gas certificates from the others, or developing its own domestic supply.

Figure 6.1: An illustration of the process for receiving gas export licences under our proposed model

In any given year, an exporter would be fulfilling obligations for multiple years. For example, at the end of Year 2, an exporter would need to surrender 100 per cent of certificates for its Year 2 obligation, and 80 per cent of certificates for its Year 3 obligation.



6.2 An export licence should only be granted after the exporter meets the obligation, not before

The regulator could issue export licences to exporters either before or after meeting their domestic gas supply obligation. The government has announced that a condition of the scheme is that domestic demand must be met before new gas can be exported, this is one of our design constraints. So, on the face of it, the export permitting model should reflect this.

But on top of this, issuing export licences before domestic gas supply obligations have been met is highly risky and would be difficult to enforce. It would require exporters to submit some form of plan for meeting their obligations, and require the regulator to monitor compliance with that plan ongoing.

This model also reduces the incentive for exporters to meet their obligations because they know that their right to export is not contingent on their meeting obligations. This may give more certainty to exporters, but because it reduces their incentive to actually deliver on their obligations, it comes at the cost of certainty for domestic consumers, and the risk of remaining supply gaps.

Conversely, requiring exporters to meet the obligation first gives them less certainty because their right to export is contingent, not absolute. But this approach is much more likely to meet the sufficient supply principle, because exporters are extremely motivated to meet their domestic gas supply obligation, given they are unable to export without having met it.

In general, the scheme should align the interests of the exporters with the delivery of their gas to the domestic market. Requiring the domestic gas supply obligation to be executed first (meaning the surrender of certificates representing confirmed sales), as under our proposal, achieves this.

6.3 Obligations should be met annually, not over the lifetime of the project

The domestic gas supply obligation could be calculated either as an annual amount or an amount to be delivered over the lifetime of an LNG project:

- **Annual obligation.** Obligation-holders would be required to deliver a certain volume of domestic gas supply obligation each year.
- **Lifetime obligation.** Obligation-holders would have to meet their overall domestic gas supply obligation over the course of the project's lifetime. This would enable them to defer domestic gas delivery based on market conditions.

This choice involves a trade-off between the principles of flexibility and certainty for exporters, against the principles of sufficient supply and certainty for domestic consumers.

A lifetime obligation grants obligation-holders maximum flexibility. For example, if they have insufficient production volumes one year to meet their domestic gas supply obligations, or if international prices are elevated, they could choose to defer domestic gas supply obligations until they have access to more supply, or until international prices fall.

There are clear downsides here though. Deferring domestic gas deliveries to end-of-field-life exposes domestic consumers to reserve risk (a field may have estimates of recoverable reserves downgraded) and operational risk (a field may become unviable towards the end of its life prompting a sudden shut down).

An annual obligation removes the ability of exporters to manage their domestic gas deliveries in response to production volumes or the opportunity cost of export. But it delivers much greater certainty for

domestic consumers that domestic gas will be delivered. For this reason the annual obligation is clearly preferable.

6.4 Obligation-holders should be able to discharge future obligations in advance

Under our proposed export permitting model, obligation-holders can receive and surrender certificates for future years in advance. For example, an obligation-holder could sign a 10-year gas supply agreement with a domestic consumer, and that obligation-holder could surrender those certificates to the regulator in advance to meet its future obligations.

Under our capped model, an exporter would know its maximum obligation into the future and would have an incentive to reduce its exposure to future domestic gas supply obligations by signing long-term agreements with domestic customers.

6.5 Obligation-holders should be able to bank and borrow certificates – up to a point

Banking and borrowing are features of many certificate systems because they give obligation-holders the flexibility to manage compliance costs over time, which reduces the overall cost of meeting a policy target.

Banking is saving surplus certificates for future use. Borrowing is using future certificates in the present, effectively holding a negative certificate balance.

The export permit model outlined above requires some level of banking and borrowing to manage differences between forecast and actual volumes of base gas. For example, if an exporter delivers their full domestic gas supply obligation and obtains their export licence, but

then exports less than they forecast, they are granted certificates for the difference, which can be banked against future years' obligations.

There are also other circumstances where obligation-holders might want to bank and borrow. For example, planned or unplanned equipment outages, spikes in demand, or changes in the domestic supply-demand balance could mean that domestic consumers and exporters would both benefit by deferring some volume of domestic gas supply obligation to a future year, or bringing future obligations forward to the present day.

However, unrestricted banking and borrowing involves all the same risks as a lifetime obligation instead of an annual obligation. With unlimited borrowing, an obligation-holder could simply defer delivery of gas to the future, which risks of supply gaps in the short-term, and risks of the obligation-holder never delivering gas in the long-term. On the other hand, unlimited banking means obligation-holders could flood the market with gas in the early years, bank the credits and then not deliver gas in future years. This again carries a risk of leaving supply gaps in the later years.

Banking and borrowing should therefore be allowed, but only up to strict limits on the number of certificates that obligation-holders can bank and borrow across years, and on how long domestic gas supply obligations can be deferred. Limits on banking and borrowing mean that compliance with the scheme actually results in gas delivered when it is needed.

One alternative to banking and borrowing would be to require obligation-holders to sell the domestic gas to domestic consumers who store the gas for use in future years. But the east coast has limited capacity to store significant volumes of gas (see Box 3 on the next page).

Box 3: Can excess gas delivered under the domestic gas supply obligation be stored?

Announcing the gas reservation policy, Minister Bowen suggested that domestic gas, not needed by the market in a given year, could be stored.^a

But storage is unlikely to play a meaningful role in absorbing excess gas delivered under our proposed domestic gas supply obligation.

The amount of gas the six major gas storage facilities on the east coast can store is constrained by:

- their capacity,
- the rate that gas can be injected into and withdrawn from storage,
- the physical location of the storage facilities, and
- the gas fields and pipelines to which they are connected.

The Dandenong facility in Melbourne stores gas as LNG and is used to manage peak day demand. With a capacity of 0.7 petajoules, it does not have capacity to store much gas.

The Moomba storage facility, in South Australia, is massive, with more than 60 petajoules of empty capacity. But Moomba is currently only operating in withdrawal mode. It would require upgrading to be able to store more gas.

The Iona storage facility in Victoria is large, at about 26 petajoules. But Iona already reaches capacity each autumn to be ready to supply bulk gas to Victoria in the cold months. It has no additional capacity to store more gas.

a. Bowen et al (2025).

Iona and Moomba are also on the 'wrong' side of the South West Queensland Pipeline. Getting more gas into these storage facilities would require moving it along that pipeline, which will soon be at capacity.

The Newcastle storage facility in NSW has a small capacity of 1.5 petajoules, and, because it stores gas as LNG, a relatively low injection and withdrawal rate. It is not suited to storing vast quantities of gas.

The Roma storage facility in Queensland has about 35 petajoules of excess capacity. But it is connected only to the Roma gas field, which exists for export, so it would not be able to store gas for the domestic market.

Finally, the Silver Springs storage facility in Queensland also has excess capacity of about 35 petajoules, and it is connected to the main domestic gas network. But Silver Springs has an extremely low rate of injection and withdrawal, meaning that over the course of a year it could store a maximum of 1 petajoule of additional gas, and contribute a maximum of 5 petajoules back to the domestic market.

The east coast is likely to need more gas storage capacity, regardless of the domestic gas supply obligation. And there are some significant new gas storage projects being built or planned.

But at present, the east coast has limited capacity to store significant volumes of new gas.

6.6 The government should retain the right to recalculate the domestic gas supply obligation in emergencies

There are some scenarios where the regulator may want to adjust the obligation percentage after it has been set.

For example, the regulator may want to increase the obligation percentage to cover circumstances where the domestic market faced a shortfall that was not forecast. This could be for any number of scenarios, including:

- A domestic producer stops operating.
- An LNG exporter shuts down its Australian operations and will not meet its domestic gas supply obligation.
- Unexpected damage has been caused to gas infrastructure.
- Simultaneous outages at coal generators have pushed up demand for gas.
- There is a significant error in the supply-demand and base volume forecasts.

Or, the regulator may want to decrease the obligation percentage to cover circumstances in which an obligation-holder was unable to surrender sufficient certificates to meet its obligation. This could similarly be for a range of reasons, including:

- A gas field with domestic gas supply obligations collapses.
- A major customer that was going to buy its domestic gas supply obligation volumes collapses.
- A seller of certificates is suddenly unable or unwilling to supply those certificates.
- There is a significant error in the supply-demand and base volume forecasts.

To allow for these emergencies, we propose that the domestic gas supply obligation should involve a recalculation power, allowing the regulator to adjust the domestic gas supply obligation once it has been set, under specific and extraordinary circumstances.

The recalculation window would run from the time the domestic gas supply obligation is set, to the time that obligation-holders must surrender their certificates for each year (see Figure 6.1 on page 30).

The recalculation power should only be invoked in one of two circumstances:

- **Catastrophic and imminent domestic shortfall:** a scenario in which the redirection of gas otherwise marked for export is necessary to avert an imminent shortfall of gas supply that would otherwise incur significant harm to domestic consumers.
- **Compliance failure without cause:** a scenario in which an obligation-holder is unable to meet their domestic gas supply obligation for reasons beyond their control and would otherwise lose their export licence.

The recalculation power should only be able to increase a domestic gas supply obligation in circumstances where the regulator has established that exporters have the ability to meet an increased obligation.

These scenarios are exceedingly unlikely and we do not anticipate the recalculation power ever being used. And because the integrity of our proposed scheme depends on the recalculation power being used only in extraordinary circumstances, the ability to invoke the power should sit with the Federal Minister for Resources, on the advice of AEMO (for the domestic shortfall scenario) or the regulator (for the compliance failure scenario).

Without an emergency power like this, eastern Australia risks running out of gas domestically even as we export hundreds of petajoules, or a

scenario in which an exporter is prevented from exporting despite there being no domestic shortfall. Either scenario would be a profound failure of policy. The domestic gas supply obligation should be flexible enough to prevent these unlikely but catastrophic events. A recalculation power is the best way to do it.

6.7 There should be significant sanctions for failing to meet domestic gas supply obligations

The domestic gas supply obligation will be effective only if the government has the power to withhold export licences from, and fine, firms that fail to meet their domestic gas supply obligations.

Financial penalties should be set higher than the value of exporting gas. For example, the penalty could be benchmarked to the Asian spot price, plus a percentage above this.

The government could also have a make-good option, which would require the exporter to supply the gas that they failed to deliver in one year in a future year.

Appendix

A.1 Scenarios we used to model domestic gas supply obligation volumes

In Section 5.1, we used four scenarios to model the volume of the domestic gas supply obligation under fixed, floating, or capped domestic gas supply obligation percentages:

- A baseline scenario using current forecasts of southern supply-demand gaps out to 2044 and LNG exports.
- A scenario where domestic demand declines by 20 per cent below the baseline by 2044.
- A scenario where domestic production declines by 20 per cent below the baseline by 2044.
- A scenario where LNG exports decline by 20 per cent below the baseline by 2044.

In each case, the overall trajectory was smoothly adjusted downwards to meet the new 2044 baseline, so the rate of decline was smooth throughout the whole period.

A.1.1 Approach to modelling the reservation

LNG liquefaction capacity for each exporter is taken from public information about the capacity of their LNG facilities, with the actual liquefaction capacity estimated as the maximum of forecast or historical production, and total nameplate capacity. This reflects that production can sometimes exceed nameplate capacity.

Historical **contracted and spot LNG export** data is drawn from ACCC Interim Gas Inquiry papers, summed across the three Gladstone exporters. The data was scraped using an online chart digitisation

tool as the data is not readily available from the ACCC website. Small transcription errors may apply.³⁹

Future contracted LNG export data is forecast based on the ACCC records of expected contracted gas volumes. The contract roll-off or renewal dates are based on the ACCC data. An assumption about recontracting rates is generated based on the Future Gas Strategy - the rate of recontracting is proportional to the rate of recontracting forecast in the overall LNG exports forecast from the Future Gas Strategy Analytical Report, 41 per cent.⁴⁰

Future spot exports are estimated by calculating the average spot cargo exports over the years 2019-2024, and splitting them three ways between the three exporters. The actual forecast spot cargoes of each exporter is the minimum of their uncontracted LNG liquefaction capacity, and their share of the average estimated spot cargoes. If they do not have enough uncontracted liquefaction capacity, they only export as many spot cargoes as they are able to. So the total forecast spot cargoes is the minimum of the sum of the uncontracted liquefaction capacity of the three exporters, or the average of the 2019–2024 spot cargo amounts.⁴¹

To forecast **domestic demand**, we used the 2025 GSOO forecasts of east coast domestic (non-LNG) final gas demand under the Step Change scenario.⁴²

To estimate **domestic supply**, we subtracted from domestic demand the 2025 GSOO forecasts of southern supply shortfalls under the Step

39. ACCC (2025a).

40. DISR (2024).

41. ACCC (2025a).

42. AEMO (2025).

Change scenario. This implicitly makes the assumption that shortfalls in Queensland will not materialise, which we think is reasonable. While it is likely that domestic producers will increase their supply in the coming years, in response to the forecast shortfalls, we avoid making any explicit assumptions about how much domestic supply might increase.⁴³

In general, unless otherwise stated we use a targeted oversupply of 10 per cent of domestic demand – so if domestic demand is 500 PJ, we calculate the required oversupply as 50 PJ.

Unless otherwise stated, we use a targeted reservation percentage of 20 per cent, as the midpoint of the government's stated target range.

A.2 LNG exports are a highly variable base on which to reserve gas

Basing gas reservation on LNG exports mechanically links domestic supply to export volumes. If exports rise, the reserved volume rises; if exports fall, so does supply to the domestic market. Any domestic oversupply is therefore driven by LNG exports; importing the uncertainty of LNG volumes.

LNG exports are hard to predict. They depend on global demand, competing supply, project economics, and climate policy. Small changes in assumptions lead to large swings in outcomes. Credible scenarios range from modest increases in exports to declines of 70-to-80 per cent over coming decades, implying very different volumes of reserved gas under an export-linked model.

There are also headwinds to Australia's LNG exports. Australian LNG is relatively costly to produce, while large new supplies are coming online from the US and Qatar over the next five-to-10 years. With

43. Ibid.

many importing countries also moving away from fossil gas, Australian exports face rising competitive pressure and a material risk of decline after the mid-2030s.

A.3 How a fixed obligation percentage would work

A fixed percentage applies a single percentage to the base to determine the obligation. Because it is fixed, the obligation percentage is set once, at the start of the scheme. After that, it is not responsive to changes in the underlying supply-demand balance, or the volume of the base.

In Figure A.1 on the next page we outline how domestic gas supply obligation volumes would be calculated under a fixed percentage.

A fixed percentage would not reliably deliver sufficient supply to cover supply gaps

Relative to domestic supply gaps, a single fixed obligation percentage delivers both too little and too much gas in different years.

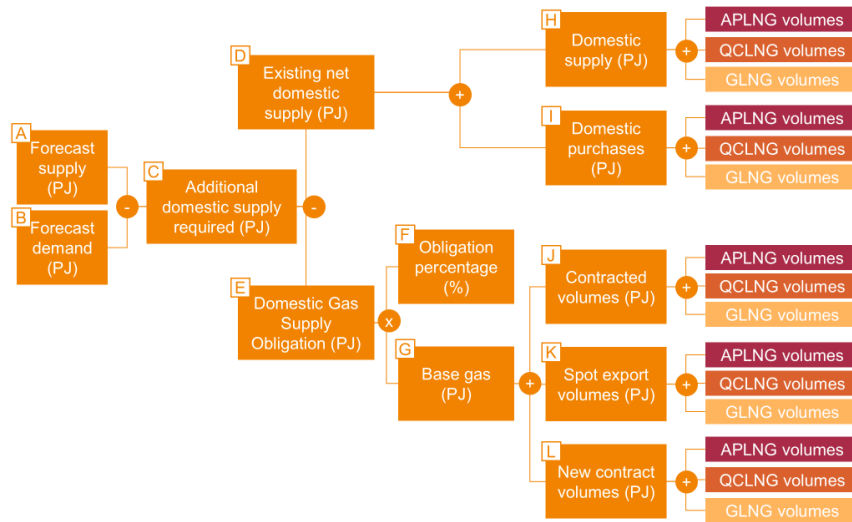
Take for example a fixed obligation percentage set in the middle of the range the government has proposed, 20 per cent. This fixed percentage model would deliver a substantial oversupply to the domestic market for the first 10 years (up to 60 per cent oversupply), and then a large undersupply beyond 2035 (up to 13 per cent undersupply).

Put simply, if the government insists on a fixed percentage, it is likely to be choosing to oversupply the market in the near-term and undersupply the market in the long-term.

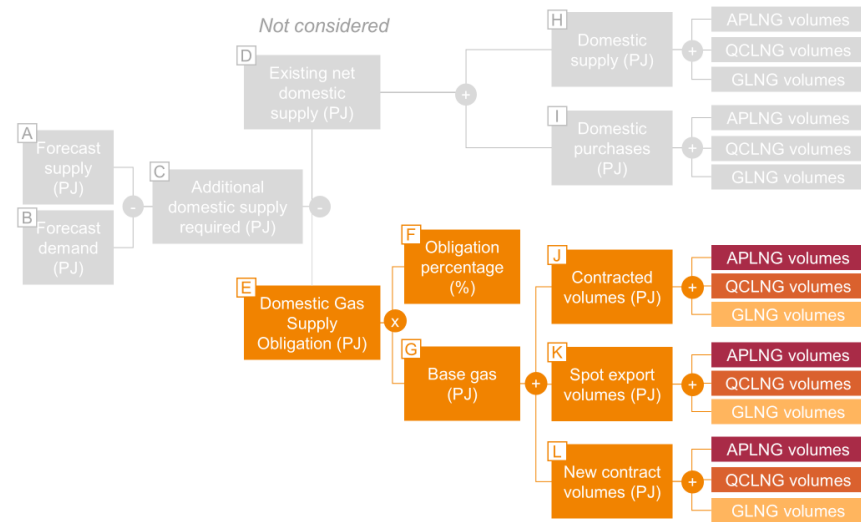
Our scenarios contemplate plausible changes in the domestic supply-demand balance and in LNG exports. But these scenarios will very likely be wrong. It is impossible in 2026 to pick a single percentage that will deliver the right amount of gas across time because a fixed percentage does not adjust to changes in the base or the supply gap.

Figure A.1: How to calculate domestic gas supply obligation volumes under a fixed or floating percentage
 Driver tree for DGSO volumes under a fixed or floating percentage

Floating



Fixed



A fixed percentage gives exporters certainty about their domestic gas supply obligation volumes, but the amount they actually deliver will vary

The fixed percentage delivers a clear indication to exporters about the percentage (but not the volume) of gas they would be required to deliver under the domestic gas supply obligation.

Under a fixed percentage of, say, 20 per cent, an exporter knows that to sign a new export contract of 100 petajoules, they need to produce a further 20 petajoules to meet their obligations.

On top of contracted volumes, there is a small volume of spot exports that are harder to predict. But these spot cargoes are typically less than 50 petajoules for a single exporter, and the exporters are required to forecast these volumes quarterly at the moment anyway. So a 20 percent obligation percentage levied on the base of spot exports would be only an extra 10 petajoules per exporter.

In practice, though, because the fixed percentage involves a release valve, exporters won't know in advance how much of their domestic gas supply obligation will be taken up by the domestic market and how much they can export as spot.

Under a fixed percentage, domestic consumers never know how much gas will actually be delivered

A fixed percentage provides limited certainty to domestic users because it does not respond to changes in the underlying supply–demand balance, and because the amount of gas actually delivered will differ from the domestic gas supply obligation volumes.

If the percentage is set too low, the domestic gas supply obligation will fail to cover emerging shortfalls, leaving users exposed to scarcity and high prices.

If the percentage is set high enough to insure against future gaps, most gas under the domestic gas supply obligation will be exported under a release valve. This would leave domestic buyers of gas with little certainty of the actual volumes that would be delivered under the scheme.

Domestic producers still have an incentive to supply the market under a fixed percentage

Keeping the domestic gas supply obligation relatively limited also retains important signals to domestic producers that there will be continued demand for domestic production. The risk of relying entirely on the domestic gas supply obligation to meet domestic demand is that domestic producers may get pushed out of the market. This risks resulting in less upstream competition in the supply of gas in Australian, not more.

A scenario in which the majority of domestic gas demand was met through the domestic gas supply obligation would also mean the east coast gas system would be heavily reliant on just three large exporters for its supply of domestic gas. Given the highly uncertain nature of LNG exports, this would leave domestic consumers highly exposed to shocks in the global LNG market.

A fixed obligation percentage hedges against these risks because it contains the role that the domestic gas supply obligation in the domestic market.

A.4 How a floating obligation percentage would work

Under a floating percentage, the regulator would adjust the obligation percentage periodically, for example yearly, based on the forecast balance between supply and demand.

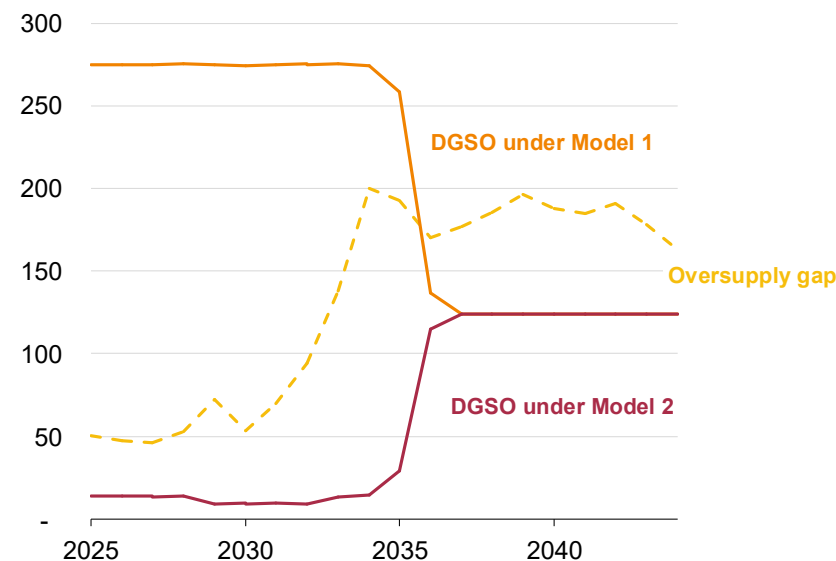
The amount of gas required to slightly oversupply the market will change year to year. Moreover, the size of the base from which the domestic gas supply obligation is calculated will also change. So to achieve a relatively stable oversupply delivered from a shifting base on a shifting supply-demand balance, the obligation percentage will also need to change.

In Figure A.1 on page 38 we outline how domestic gas supply obligation volumes would be calculated under a floating obligation percentage.

Because it is calibrated against supply-demand imbalances, a floating obligation percentage would start with forecasts of imbalances:

1. Determine for the year ahead **(A) forecast supply** and **(B) forecast demand**
2. Based on (A) and (B) determine the **(C) volume of additional domestic supply** required to slightly oversupply the market to achieve the desired price effect
3. Determine the **(G) volume of the base** according to exporters' forecasts of:
 - **(J) Contracted volumes**
 - **(K) Spot export volumes**
 - **(L) New contract volumes**
4. Determine the **(F) DGSO percentage** required to deliver (C) based on:
 - **(E) DGSO volume**
 - **(D) Existing net domestic supply**

Figure A.2: At a fixed percentage of 20%, Model 2 would not deliver enough gas to meet the supply gap as well as oversupply the market
Gas delivered under Model 1 and Model 2 and required gas to meet 10% oversupply and supply gaps



Source: Grattan analysis of data including AEMO 2025, ACCC 2025a.

A floating percentage would deliver the most effective amount of supply to the domestic market

A floating percentage would be much more robust at covering supply-demand imbalances because it allows the government to adjust domestic gas supply obligation volumes based on how much gas is required to cover shortfalls.

Figure A.3 shows how the obligation percentage would need to be adjusted year to year under different scenarios to achieve a 10 per cent oversupply into the future.

As the domestic supply-demand balance and the global LNG market fluctuate, so too can the obligation percentage.

In 2025, to achieve a targeted oversupply would required a fixed obligation percentage of just under 4 per cent - well below the range suggested by the government.

However, from 2030 onward, an obligation percentage of 4 per cent would substantially undersupply the domestic market relative to the supply gaps, so the percentage would be lifted.

In the baseline scenario, the obligation percentage required to meet forecast supply gaps and oversupply the market climbs to around 30 per cent by 2044.

Figure A.3 on the next page illustrates how a floating percentage could be adjusted in order to ensure the domestic gas supply obligation meets the sufficient supply principle.

Guaranteed oversupply would give greatest certainty to domestic consumers, at the cost of certainty for exporters

A floating model provides strong supply certainty for domestic users, because the obligation percentage is recalibrated each year to close forecast supply gaps and deliver a targeted level of oversupply.

Box 4: The volume of gas delivered to the market is not the same as the volume under the domestic supply obligation

The domestic gas supply obligation sets a volume of gas that must be delivered to the domestic market. But some exporters are already delivering a volume of gas to the domestic market, and some are taking more gas out of the domestic market than they deliver. So the amount of additional gas an individual obligation-holder must supply to the domestic market depends on the amount they are already contributing or taking.

For example, if an exporter has a domestic gas supply obligation to deliver 40 petajoules of gas, but they are already contributing 20 petajoules, then the 40 petajoule domestic gas supply obligation will only result in 20 additional petajoules being supplied to the domestic market. Conversely, if they have an obligation of 40 petajoules and are currently taking 20 petajoules, they will need to find 60 additional petajoules.

On Australia's east coast, Australia Pacific LNG is a significant net contributor to the domestic market whereas Gladstone LNG is a net buyer from the domestic market. If both consortia had the same domestic gas supply obligation volume requirement, GLNG would be required to secure far more gas than APLNG, because GLNG would first need to cover its existing net domestic purchases *and then* meet its domestic gas supply obligation volumes.

But this would come at significant cost to the exporters who could face large changes in their domestic gas supply obligation year to year.

The absence of a defined upper bound on the domestic gas supply obligation would provide little certainty to exporters because they risk being required to substantially change their production volumes in short timeframes. In many cases, rapid increases or decreases in production will be technically infeasible. And being able to sign long-term contracts requires some level of certainty over the size of domestic gas supply obligation volumes.

A floating percentage with no upper limit would not provide this certainty.

The floating model risks dulling investment incentives for domestic producers

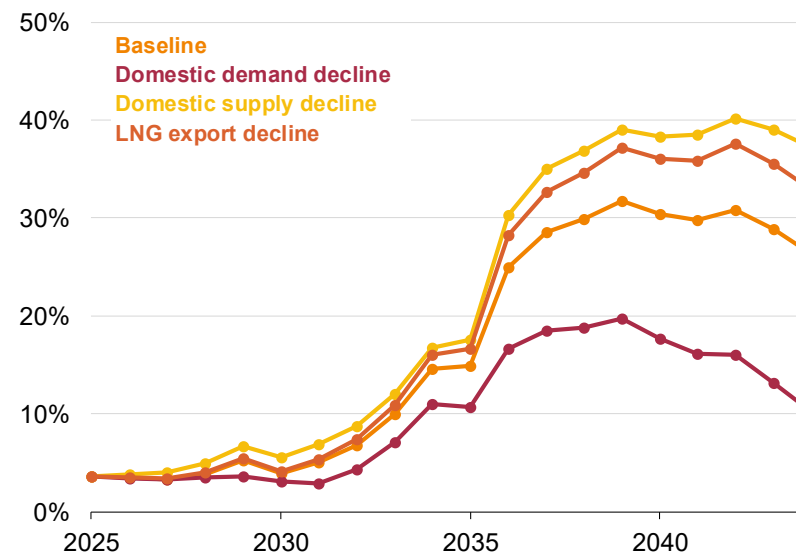
If domestic consumers know that the government has committed to ensuring an oversupply, they know the government will force exporters to sell them the amount of gas required to meet domestic demand. This puts buyers at an advantage - as is the intent of the policy.

Domestic producers face the unintended consequences of this strategic situation. Knowing that in the event of a potential shortfall, buyers will have a strong bargaining position with exporters, buyers will probably prefer to secure their marginal unit of gas from an exporter. This means domestic producers are less incentivised to produce more gas to meet those shortfalls.

The potential unintended consequences of consistently oversupplying the market just from the exporters, is that domestic producers contribute relatively less or exit the market earlier than they otherwise would have.

Figure A.3: Targeting a fixed oversupply of 10% with a completely floating DGSO percentage requires significant variation

Percentages required to deliver a 10% oversupply under current forecasts of supply-demand gaps and LNG exports



Source: Grattan analysis of data including AEMO 2025, ACCC 2025a.

A floating model would be challenging to implement upfront, but avoids administering a complex release valve

The key implementation challenge of a floating and capped obligation percentage is the requirement to accurately forecast the supply gap (domestic demand and domestic supply) and the base (LNG exports). The regulator would need access to credible data and use a transparent forecasting methodology to reliably estimate these each year.

However, the fixed and capped models avoid the requirement to monitor compliance with a release valve. This is because there is no release valve in the floating and capped models - the obligation percentage is set.

From the perspective of implementation, all three models have challenges. Government faces a choice between the challenge of developing accurate forecasting capability (floating and capped), or the challenge of implementing a complex compliance framework (fixed).

A.5 How a capped obligation percentage would work

In the capped model, the obligation percentage would be set within a range. This would follow the same process as a floating percentage, but the range of values for the obligation percentage would be constrained.

The capped model would deliver sufficient domestic supply up to a point; the cap could be set to ensure an acceptable amount

In a capped model, the obligation percentage would still adjust to target supply-demand imbalances but would do so within a limited percentage range.

Figure A.4 illustrates how a floating percentage could be adjusted under a 15 per cent obligation percentage cap.

As per the floating model, the obligation percentage starts low and climbs to 2035. However, unlike the floating model, the capped obligation percentage is constrained to 15 per cent.

This means that after 2035, the domestic gas supply obligation would not be delivering enough gas to cover the entire supply-demand gap. This implies either domestic demand would have to decline or domestic supply would have to increase to avert shortfalls. This is not a bad outcome: from 2035 onwards Australia will be trying to reach a very challenging net-zero target and will need to lean hard on squeezing gas demand to its lowest possible level. The threat of under-supply increases the incentive to do this.

A capped percentage gives exporters the same certainty as a fixed one

A capped model delivers meaningful certainty to exporters by placing a clear upper bound on exporters' obligations, while allowing the required obligation percentage to fall when domestic conditions improve.

Exporters know their maximum exposure in advance but may be required to supply less in years when domestic supply gaps are smaller — effectively a windfall relative to a fixed obligation. This preserves responsiveness to market conditions without introducing open-ended volume risk.

Moreover, under a low cap of, say 15 per cent, there is no meaningful difference in certainty for exporters relative to a fixed percentage. In both cases, the maximum amount of gas they could be required to deliver is somewhere between 0 and 15 per cent, dependent on the extent of domestic demand in a given year.

Under the fixed model, uncertainty in delivery of gas under the domestic gas supply obligation is managed by the 'release valve' whereas under the capped model it is managed upfront by setting a lower obligation percentage for a given year.

Domestic consumers would receive more certainty than in the fixed model

A capped model retains most of the supply certainty of a fully floating approach, while operating within a bounded range.

The domestic gas supply obligation still adjusts to domestic shortages, giving users confidence that additional gas will be made available when needed, but the cap limits how far obligations can rise.

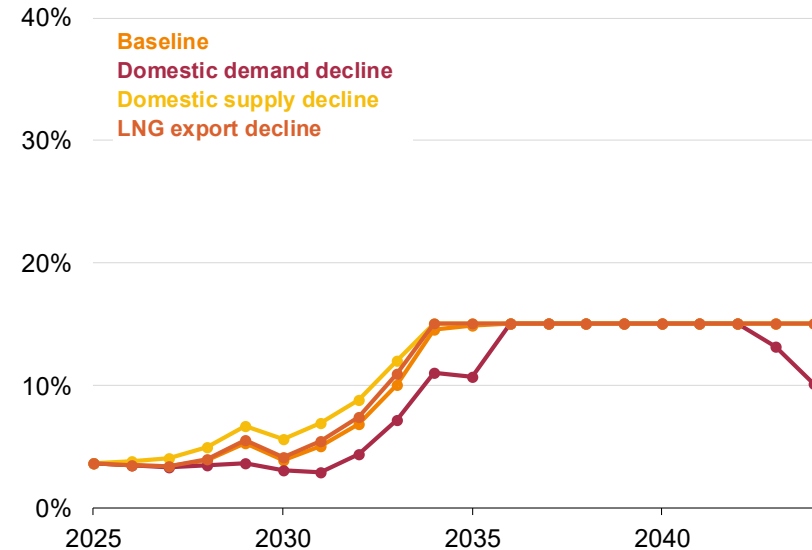
In practice, the capped model trades off a level of certainty for domestic users of gas against certainty for exporters of gas. The capped model preserves responsiveness to supply gaps and price pressures up to the cap, while protecting exporters from uncertainty beyond the cap.

The capped model would motivate domestic producers to continue to meet demand

For the same reasons as in the fixed percentage model, domestic producers would retain incentives to supply the domestic market under a capped percentage regime.

Figure A.4: A capped model allows obligation percentages to range up to 15%, putting an upper cap on exporters' obligations and maintaining incentives for domestic producers to supply

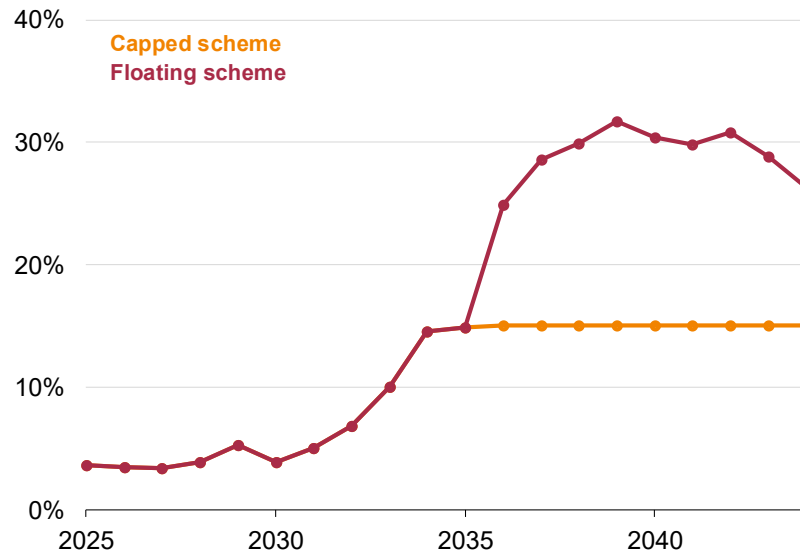
Percentages required to deliver a 10% oversupply under current forecasts of supply-demand gaps and LNG exports, capping obligation percentage at 15%



Source: Grattan analysis of data including AEMO 2025, ACCC 2025a.

Figure A.5: A capped model capped at 15% requires domestic producers to supply an equivalent of 10-15% of LNG exports more to the domestic market

Baseline scenario percentages required to deliver a 10% oversupply under current forecasts of supply-demand gaps and LNG exports, under the capped and fully floating model



Source: Grattan analysis of data including AEMO 2025, ACCC 2025a.

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