Jemena Gas Networks (NSW) Ltd

2025-30 Access Arrangement Proposal

Attachment 4.1

Achieving emissions reductions through our 2025 Plan

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Overview

Customers, communities, and investors are increasingly demanding swift and substantial action on climate change. Australia is party to the Paris Agreement which seeks to limit the rise in global temperature to below 2°C above pre-industrial levels and pursue efforts to limit the temperature increase to 1.5°C. Consistent with the Paris Agreement, the Australian and New South Wales (NSW) governments have set greenhouse gas emissions reduction targets.

We recognise that immediate action is required to reduce emissions to address the threat of climate change. This plan sets out how we will play our role over the 2025-30 period. This plan sets out the key initiatives we will implement as well as the associated expenditure required.

Achieving the Australian and NSW Government's legislated emission reduction targets will require significant change, akin to the industrial revolution but on a compressed timescale. As a gas network we must be at the centre of these changes. We emit 0.29 MtCO2e of emissions each year in providing services. Similarly, our customers, in consuming gas transported by us, produce 4.70 MtCO2e of emissions. Our customers' emissions make up 1.1% and 4.2% of total Australian (433 MtCO2e) and NSW (111 MtCO2e) emissions.

Over the past five years we have laid the foundation for substantial emission reductions. We have helped drive the development of the market for renewable gas, through undertaking biomethane and hydrogen pilots and working with GreenPower to launch a renewable gas certification scheme. We have also tested innovative direct emission measurement technology, changed our operating pressure philosophy and installed new equipment to reduce operational emissions.

Regulatory settings have evolved. The national gas regulatory framework now recognises that reducing Australia's greenhouse gas emissions – regardless of whether there are specific obligations for businesses to do so – delivers value for consumers. Changes to the National Gas Objective and the National Gas Rules mean that expenditure which reduces emissions (provided that the value of emissions reductions exceed the costs) can be recovered through regulated prices.

Recent technological advances, market developments, together with the changes in regulatory settings have created a window of opportunity for us to materially reduce Australia's greenhouse gas emissions. We propose to take advantage of this opportunity and play our role in helping achieve the Australian and NSW emissions reduction targets. We will:

1. **Reduce customer emissions by enabling access to renewable gas.** We will facilitate the introduction of 6.7 PJs of renewable gases into our network, decarbonising 8.3% of the energy we transport by 2030. This will support our customers achieve their emissions reduction goals and reduce greenhouse gas emissions by 390,000 tCO2e a year by 2030. This will deliver 0.4% and 1.0% of the reductions needed to achieve the Australian and NSW government's 2030 emission reduction targets.

2. **Move to direct emission measurement for our fugitive greenhouse gas emissions,** which account for 98.8% of our emissions, and away from generic and likely inaccurate benchmark factors. This will allow us to:

    - Report accurate emissions – by ensuring that reported emissions reflect measured emissions, rather than an estimate based on generic factors and high-level assumptions of our network performance.

    - Reduce actual emissions – as it provides sufficiently granular data to identify the size and location of leaks and development of an optimised repair program.

    Moving to direct emissions measurement is essential to enabling the achievement of emission reduction targets for our network, is consistent with global good industry practice as well as the goals of the Global Methane Pledge, which the Australian Government has committed to.

3. **Deliver no-regrets targeted actions to reduce our direct (scope 1) emissions.** This includes replacing deteriorating cast iron mains, reducing pressures across our network (to reduce leakage), and continuing to install low emissions and more efficient equipment alternatives (e.g. catalytic heaters).

To ensure that our programs are consistent with the National Gas Objective and National Gas Rules we have evaluated each project and have found that the value of these programs (which incorporates the value of emissions reduction) exceeds their costs. Together these strategies will provide $2.6 billion in consumer value, as shown in Table 0.1.

Table 0.1: Net Present Value (NPV) of our emissions reduction program ($2025 millions)

Element	Expenditure	NPV
Renewable Gas Facilitation	Capex	1,412.3
Direct Emissions Measurement (and leak repairs)	Opex	936.6
Reducing our direct emissions	Capex	237.2
Total	**Mix**	**2,586.1**

Our quantitative analysis does not capture all benefits. In particular, our plan to facilitate access to renewable gas will also:

- Unlock a gas decarbonisation pathway for our customers. This is particularly important for our customers who cannot electrify.
- Ensure that hard to abate manufacturing sectors can reduce or avoid emissions, rather than purchasing offsets, enabling continued economic viability.
- Avoid significant whole of economy consequences from a higher cost electricity only pathway to net-zero by supporting renewable energy choice.
- Avoid placing additional cost and operational pressures on the electricity system.
- Reduce gas network stranding asset risk and, in turn, constraining the overall higher level of accelerated deprecation required, given the reduced opportunity to recover at least our efficient costs. Without renewable gas, our proposal would need to assume that our network has a limited role to play to a decarbonised future and in turn seek a higher level of accelerated depreciation.

We will continue to refine our strategy and approach as technology advances and our understanding of our actual emissions deepens. In support of these strategies, and our overall commitment to net-zero by 2050, we will also take action to reduce emissions from the electricity we use (scope 2) and as well as emissions across our value chain (scope 3).

We are encouraged by the high levels of support from our customers for our plan and approach. However, we note that the AER's approval of our proposal is critical to ensuring that we can reduce emissions, support the achievement of Australian and NSW emissions reduction targets as well as unlock the customer, energy-system and economy wide benefits of renewable gas.

1. Policy context

1.1 Targets set to reduce Australia's greenhouse gas emissions

The Australian and New South Wales (NSW) Governments have set ambitious emission reduction targets, as set out in Table 1.1.

In addition to setting emission reduction targets, the Australian Government has joined the Global Methane Pledge. This pledge is a commitment to reduce methane emissions to a level consistent with the 1.5°C pathway (30% below 2020 levels by 2030) and to continuously work to improve the accuracy, transparency, consistency, comparability, and completeness of national greenhouse gas inventory reporting.

Table 1.1 NSW and Australian government greenhouse gas emission reduction targets (relative to 2005 levels)

	2030	2035	2040	2045	2050
NSW Government	50%	70%	TBD	TBD	Net-Zero (100%)
Australian Government	43%	65% – 75% (Expected)[1]	TBD	TBD	Net-Zero (100%)

Global Warming Potential and tCO2e tonnes of carbon dioxide equivalents

Global Warming Potential (GWP) is a metric used to compare the climate impact of different greenhouse gases relative to carbon dioxide (CO_2) over a specified period. Each gas's GWP is calculated based on its ability to absorb heat in the atmosphere, which contributes to the greenhouse effect, and its lifespan before breaking down.

The concept of carbon dioxide equivalent (CO_2e) is used to standardise the measurement of greenhouse gas emissions by converting amounts of various gases into the equivalent amount of CO_2 that would have the same global warming impact. This allows for a uniform way of expressing emissions and their effects on climate change, regardless of the specific gas. The CO_2e for each greenhouse gas is calculated by multiplying the amount of the gas emitted by its GWP, providing a clear measure to assess and compare the total impact of emissions from different sources.

The main component of natural gas is methane. When combusted methane mainly produces water vapor and carbon dioxide. Consuming 1GJ of natural gas emits 51.53 kg of CO2e of greenhouse gas into the atmosphere.[2] However, methane itself is a much more potent greenhouse gas. As a result, releasing 1GJ of methane to the atmosphere results in 437.8 kg of CO2e of greenhouse gas,[3] 80 times more than when it is combusted. Tonnes of CO2e is typically represented as tCO2e. These emission calculations are based on a 20-year time frame. Over a 100-year timeframe, methane emissions are only 28 times more potent than carbon dioxide as methane itself decays over time.

Net-zero targets encompass the reduction of all greenhouse gases, not just CO_2. The aim of achieving net-zero is to balance the amount of greenhouse gases emitted into the atmosphere with an equivalent amount removed or offset.

[1] The Australian Government has not yet set a 2035 emission reduction target for 2035. The Climate Change Authority (who is providing advice on the target) considers that the evidence suggests that a target in the range of 65% to 75% would be ambitious and achievable. See Climate Change Authority 2024, *Targets, pathways and progress, 2024 Issues Paper,* p. 6. Available here.
[2] Schedule 2 - Part 2—Fuel combustion—gaseous fuels of the National Greenhouse and Energy Reporting (Measurement) Determination 2008. Available here.
[3] Division 3.3.8 – Natural Gas Distribution (other than emissions that are flared) of the National Greenhouse and Energy Reporting (Measurement) Determination 2008. Available here.

1.2 Scale of change to achieve these targets

Reducing greenhouse gas emission reductions in line with Australian and NSW government targets will require urgent and fundamental change across Australian society and in every sector of the economy. As the Minister for Climate Change and Energy noted in February 2023:[4]

> *This is a big task. This is the biggest change in our economy since the Industrial Revolution and we are undertaking it at much greater speed. 2030 is important. Some sectors will reduce their emissions very substantially by 2030. Electricity, transport and others. What we do between now and 2030 is vital. It's 83 months away. That is a lot faster than it took the Industrial Revolution to occur. … We have to be all in to do it - governments, State, Federal, local, unions, industry, think tanks, universities, multilateral development banks, all in because this is not a whole of government effort. This fastest transition since the Industrial Revolution is and must be a whole-of-society effort.*

Since the Paris Agreement came into effect in 2016, and particularly in the last two years, we have seen growing momentum and urgency to reduce emissions. This has led to a series of substantial regulatory and policy reforms, including changes to the National Gas Objective and to the Safeguard Mechanism – both of which are outlined further below.

However, as the Minister emphasises, the change goes beyond government initiatives, encompassing a broader societal shift:

- Customers expect genuine action on climate change and have told us to act now, rather than delaying action to work towards a net zero future with renewable gas options. Customers have told us that reducing emissions via offsets is not genuine action.
- Investors are pushing for companies to align their operations and investments with the Paris Agreement. They are increasingly scrutinising companies for clear commitments to emissions reduction targets, including Scope 3 (up and downstream) emissions as a result of a business's activities. A growing number of financial institutions, at this stage predominately banks, are reviewing their involvement in providing equity and debt to oil and gas companies.[5]
- Good industry practice has evolved. Gas distribution businesses in Australia[6] and globally[7] are committing to ambitious emission reduction targets, deploying leak detection and repair technologies and facilitating the adoption of renewable gas.[8]

These changes extend to competition and regulatory bodies and their decisions. Recently, the ACCC placed considerable weight on the public benefit of emissions reductions in considering Brookfield and MidOcean's proposed acquisition of Origin Energy. While the ACCC found that it was not satisfied that the proposed acquisition would not be likely to substantially lessen competition, these public detriments were outweighed by the public benefits of a likely acceleration in the roll-out of renewable generation and storage and in turn a more rapid reduction in Australian emissions.[9]

As with all fundamental social and economic change the path forward will not be straightforward. As a country, Australia will need to innovate, adapt, and maintain flexibility to reduce risks and take advantage of opportunities which are unlocked.

[4] Minister for Climate Change and energy, Remarks at Australian Industry Energy Transitions Initiative (ETI) Pathways to Industrial Decarbonisation reports Release, 20 February 2023, See here.
[5] Australian Government 2024, *Future Gas Strategy Analytical Report*, pp 49-50. Available here.
[6] AusNet have committed to 50% reduction in emissions by 2030 (relative to 2022) (see here). AGIG and ATCO have committed to 2030 emissions reduction targets of 30% (see here and here). In addition to committing to a reduction of 30%, APA also set an operational methane emissions reduction of 30%, consistent with Australia's commitments to the Global Methane Pledge, and is developing a scope 3 emissions reduction goal. See here.
[7] See here
[8] AGIG has set the goal of 10% renewable gas by volume by 2030 and to transition their distribution networks to 100% renewable gas by 2040 as a stretch target and by no later than 2050. See here.
[9] See here.

1.3 Institutions have been created to ensure regulatory and policy settings evolve

The purpose of legislating emission reduction targets is to enable mitigation by signalling the direction of travel and enhance regulatory certainty.[10] The following legislation aims to establish frameworks specifically designed to adjust regulatory and policy settings to ensure that the targets are achieved:

- The Commonwealth Climate Change Act 2022 requires an annual ministerial statement to Parliament on progress towards the achievement of emission reduction targets (including the effectiveness of policies). It also gives the Climate Change Authority a role in providing advice to the Minister on the annual statement and in setting future emission reduction targets. The Australian Government has also since announced that a Net Zero Plan (supported by six sectoral plans) will be developed and will build on the Government's current emissions reduction policies.
- The NSW Climate Change (Net Zero Future) Act 2023 establishes an independent expert Net Zero Commission to monitor, review, report on and advise on progress towards emission reduction targets.

While overall emissions reduction objectives have been set, the associated regulatory and policy settings are not static. The opposite is the case. Regulatory and policy settings will continue to evolve to ensure that the goals of the Paris Agreement are achieved. This flexibility also extends to the carbon reduction targets themselves. Neither the Australian nor NSW governments have set 2040 or 2045 targets, while the Australian Government's 2035 targets are currently being developed.

Accordingly, we must not only consider current regulatory and policy settings but also anticipate how these may change and be adjusted to achieve emissions reduction objectives.

For example, an immediate policy action arising out of the Future Gas Strategy, is for the Australian Government to work with regulators and industry to reduce and, where possible, eliminate gas venting and flaring, unless required for safety purposes.[11]

Global Methane Pledge

While the Australian Government has joined the Global Methane Pledge, to date, there has been no direct policies implementing this commitment. However, methane emissions are in the spotlight and we expect regulatory and policy settings to be adjusted to ensure that commitments in the pledge are achieved.

For example, the Climate Change Authority's 2023 Annual Progress Report[12] recommended supplementary measures to the Safeguard Mechanism to target fugitive emissions in the oil and gas sectors. The Australian Government has responded by noting that it has already sent strong policy signals through the Safeguard Mechanism reforms and by joining the Global Methane Pledge. The Australian Government indicated that it will consider whether additional measures complementary to the Safeguard Mechanism could drive abatement in developing the Resources Sector Plan.

Similarly, in its 2023 Review of National Greenhouse and Energy Reporting (NGER) Legislation the Climate Change Authority made eight recommendations to improve how fugitive emissions are reported.[13] This includes establishing 'higher order' (more detailed and accurate) estimation methods for fugitive emissions. The Australian Government expects to provide a formal response to all recommendations by no later than mid-2024.

1.4 Changes to the National Gas Objective

In May 2023 Energy Ministers agreed to integrate emissions reductions objectives into the National Gas Objective. The purpose of this change is to provide greater clarity to Australia's energy market bodies, including the Australian Energy Regulator (AER), to explicitly consider emissions reduction in undertaking its functions.[14]

Energy Ministers also considered that the amendment sends a clear signal to wider industry, market participants, investors and the public of the Government's commitment to work together to transform and

[10] Climate Change Bill 2022 Revised Explanatory Memorandum. See here.
[11] Australian Government 2024, *Future Gas Strategy,* p.6 Available here.
[12] Australian Government 2023, *Annual Climate Change statement 2023,* p.78. Available here.
[13] Australian Government 2023, *2023 Review of the National Greenhouse and energy Reporting Legislation,* Section 3. Available here.
[14] Australian Government 2022, *Incorporating an emissions reduction objective into the national energy objectives,* p.1, Available here.

decarbonise the energy sector.[15] Or put another way, that policy and regulatory settings are not static and will change, if needed, to achieve the goals of the Paris Agreement.

The National Gas Objective (NGO) is now (with the recent changes in bold):

> to promote efficient investment in, and efficient operation and use of, **covered gas** services for the long term interests of consumers of covered gas with respect to:
>
> a. price, quality, safety, reliability and security of supply of covered gas; and
>
> **b. the achievement of targets set by a participating jurisdiction—**
>
> **i. for reducing Australia's greenhouse gas emissions; or**
>
> **ii. that are likely to contribute to reducing Australia's greenhouse gas emissions.**

The NGO now has two components. The first (a) relates to the supply of covered gas. The second (b) the achievement of emission reduction targets. This is a material change from the previous NGO which previously only focussed on the service-related attributes of the supply of covered gas (price, quality, safety, reliability and security of supply).

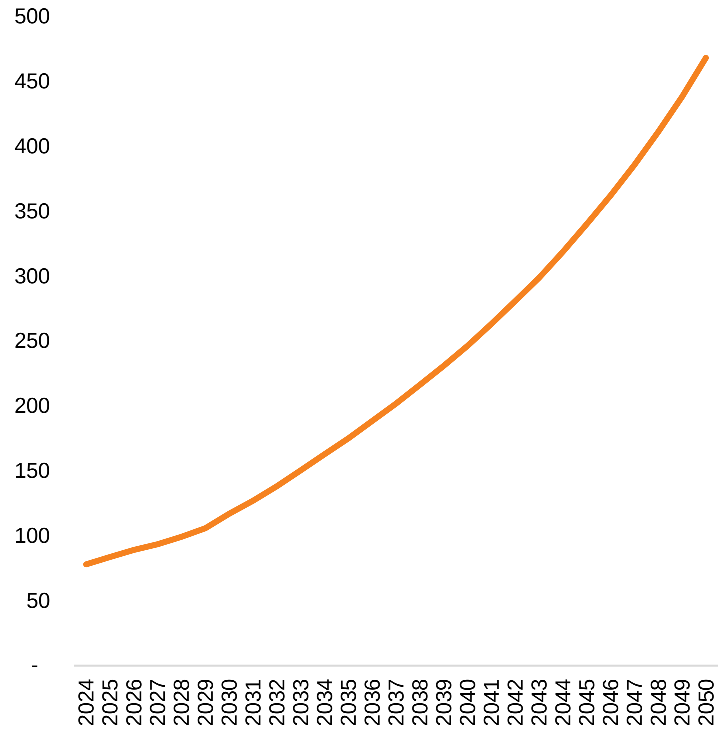
In making these changes, Energy Ministers explained that the intent was not to elevate one component above another but to provide a level playing field for both components to be considered within the current economic efficiency based regulatory framework.[16] As Officials articulated in consulting on the changes to the NGO:[17]

> With the inclusion of the emissions reduction component into the energy objectives, an approach would be to include a monetarised value of emissions in the calculation of the net benefits within the cost benefit analysis framework. This would allow the comparison of the overall estimated costs and benefits including those related to the emissions reduction objective. Having the emissions reduction objective as an input into a cost benefit analysis framework allows for the weighing up of the costs and benefits to ensure the most efficient way of meeting the national energy objectives, including the new emissions reduction objective.

These reforms have created a requirement for the AER to determine a value for emissions in applying the NGO. Given stakeholder support, the reforms included interim provisions in the National Gas Law which allows binding administrative guidance to be issued on the value of reducing emissions. To be binding the value set out in any administrative guidance must be consistent with the Energy Ministers Statement on the value of greenhouse gas emissions reductions, as set out in Figure 1.1.[18] The AER has indicated that it will apply guidance consistent with the Energy Ministers Statement. We support the AER's application of the interim value of emissions reduction set out in the Ministerial Council on Energy statement in considering and applying the new amended objective.[19]

[15] Australian Government 2022, *Incorporating an emissions reduction objective into the national energy objectives,* p.1, Available here.
[16] Energy Ministers 2023, *Incorporating an emissions reduction objective into the national energy* objectives, Information Paper, p.7 Available here.
[17] Energy Ministers 2023, *Incorporating an emissions reduction objective into the national energy* objectives, Consultation Paper, p.12 Available here.
[18] MCE Statement about the interim value of greenhouse gas emission reduction. Available here.
[19] Consistent with Schedule 3 Section 137(4) of the NGL.

Figure 1.1 Energy Ministers Value of Emissions Reduction ($2025/tCO2e)



Following the Energy Minister's decision to amend the NGO, the AEMC made a series of changes to harmonise the National Gas Rules (Rules) with the updated NGO.

The AEMC amended the Rules to be clear that pipeline service expenditure which contributes to the meeting of emissions reduction targets and is consistent with the NGO is to be recovered through regulated prices.[20]

For instance, Rule 79(1)(a) was changed so that it now reads (emphasis added):

> Conforming capital expenditure is capital expenditure that conforms with the following criteria:
>
> (a) the capital expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services **in a manner consistent with the achievement of the national gas objective**;

An equivalent change was made to the operating expenditure criteria.

This Rule previously ended with '*to achieve the lowest sustainable cost of providing services*.' The change ensures that the lowest sustainable cost is considered in the context of achieving emission reduction targets. This means that ignoring opportunities to efficiently reduce emissions through the delivery of pipeline service capex (or opex) would not achieve the NGO or be consistent with the Rules.

The AEMC also made two changes to the second part of the new capital expenditure criteria so that capex is justifiable:

- if it is necessary to contribute to meeting emission reduction targets through the supply of services.[21]

[20] AEMC 2024, *National Gas Amendment (Harmonising the national energy rules with the updated energy objectives) Rule 2024,* Rule Determination, p.29. Available here.
[21] Through the introduction of Rule 79(2)(c)(v)).

- if the overall economic value – including the value of emissions reductions within Australia - is positive. The assessment under this test includes consideration of:[22]

> …the economic value of changes to Australia's greenhouse gas emissions, whether or not that value accrues (directly or indirectly) to the service provider, producers, users or end users.

These rules provide clarity that expenditure which helps achieve Australia's emission reduction targets is justified even if there is no change to service-attributes or benefits which directly or indirectly impact end-users.

Notably, for expenditure to be justified it doesn't matter whether:

- A JGN specific obligation to reduce emissions is in place or not (although noting Jemena is subject to the Safeguard Mechanism).
- The expenditure delivers emissions reductions relating to JGN's activities or not, as long as the expenditure reduces Australia's emissions through the supply of services.

As outlined above, where there is a trade-off – for instance between price and emissions reductions – this can be considered through the cost benefit lens, with the value of emissions calculated in accordance with Energy Minister's guidance.

1.5 Reforms to the Safeguard Mechanism

In 2023, the Australian Government reformed the Safeguard Mechanism to ensure that large emitters reduce emissions in line with its emission reduction targets. The Safeguard Mechanism applies to around 215 facilities who emit more than 100,000 tonnes of carbon dioxide equivalent in a year (tCO2e), including JGN and some of our customers. Collectively, these facilities produce around 28% of Australia's emissions.

The Safeguard Mechanism requires that each facility keeps net emissions below a baseline. The baseline reduces each year to ensure that large facilities deliver a proportional share of Australia's 2030 and 2050 emission reduction targets.

Emission reductions can be achieved through reducing emissions or through the purchase of Australian Carbon Credit Units (ACCUs) or Safeguard Mechanism Credits (SMCs). SMCs are automatically issued to facilities with emissions below their baselines.

Baselines are set on a production-adjusted basis, which means they vary based on output. Over the period to 2030, baselines will transition from being set on a facility specific basis (based on a facility's historical emissions) to a 'default' approach (which represents the industry average).

Consistent with the Australian Government's 2030 emission reduction target, baselines will reduce by 4.9% each year to 2030. After 2030, decline rates will be set in five-year blocks in line with the Australian Government's emission reduction targets for 2035, 2040 and 2045.[23] Decline rates for 2030-35 will be set by 1 July 2027. An indicative decline rate of 3.285% has been set as a placeholder.

[22] New Rule 79(3)(b). The previous rule was limited the calculation of benefits to those in the gas supply chain (service providers, gas producers, users or end users).
[23] Consistent with Australia's Nationally Determined Contribution (a climate action plan) under the Paris Agreement.

2. Renewable gas

2.1 The opportunity

Our customers, in using gas transported through our pipeline, emit 4.70 MtCO2e a year.[24] This makes up about 4.2% of NSW (111 MtCO2e) and 1.1% of Australian emissions (433 MtCO2e).[25]

As shown in Table 2.1, most of these emissions are emitted by our larger industrial customers. This is because a large customers use most of the gas we transport.

Table 2.1 Customer emissions by segment per annum

	Residential	Commercial	Industrial	**Total**
Total emissions (MtCO2e)	1.46	0.69	2.55	**4.70**
Average emissions per customer (tCO2e)	1.00	19.88	6,697.38	**3.12**

Given the magnitude of these emissions, the potential value of reductions is immense. Applying the Energy Minister's value of emissions reductions, avoiding 4.70 MtCO2e of emissions in 2024 has a value of $366.5 million. This rises to $549.8 million in 2030 and to $822.1 million in 2035, due to the increase in the value of emissions reductions over time.[26]

2.2 The renewable gas solution

2.2.1 Not just the lowest cost pathway to net-zero

As recognised by the Australian Government's Future Gas Strategy,[27] renewable gases provide an opportunity to reduce emissions by displacing natural gas with low or zero emission renewable gas alternatives such as biomethane, green hydrogen and synthetic methane.

While there are two broad options to reduce emissions, electrification with renewable electricity or shifting to renewable gas, it is not a binary choice at the whole of energy system level. The best solution will differ on a customer-by-customer basis depending on their needs.

Renewable gas will be essential to unlocking the lowest cost pathway to net-zero and avoiding significant detrimental impacts to our customers and the wider economy. ACIL Allen has found that the theoretical least cost pathway to achieving net-zero involves a mix of renewable gas and renewable electricity. The 'Optimal Renewable Gas Target' scenario costs the economy $30 billion less than the alternative 'Electrify Everything Possible' pathway.[28] Frontier Economics similarly found that the scenario where almost all customers electrified (aside from some industrial use cases) was the costliest pathway to net-zero.[29]

In addition to being the lowest cost pathway, renewable gas also:

- Provides additional customer value through providing choice, access to gas cooking (which customers tell us is culturally important to some of the communities we service), and resilience through two sources of fuel.

[24] Calculated using throughput in 2022-23 (91 PJs) and applying emissions factors from the National Greenhouse and Energy Reporting Scheme measurement determination, Schedule 1, Part 2 - Fuel combustion - gaseous fuels available here. Calculation assumes all customers combust the gas they use.
[25] NSW and Australia emissions are from 2022, the most recent year available from Australia's National Greenhouse Accounts, available here.
[26] See Figure 1.1.Note figures are end of year 2025 dollars.
[27] Australian Government 2024, *Future Gas Strategy,* pp 29 - 30 Available here.
[28] ACIL Allen 2024, *Renewable Gas Target, Delivering lower cost decarbonisation for gas customers and the Australian economy.* Available here.
[29] Frontier Economics 2020, *The benefits of gas infrastructure to decarbonise Australia, A report for the Australian gas industry.* Available here.

- Provides options to customers where it is impossible or very expensive to electrify. This includes our high-rise customers with centralised hot water systems,[30] customers who do not have space for electric alternatives (such as those who live in smaller blocks or in townhouses), and our industrial customers who require a reliable source of high-temperature heat.

As the Australian Government's Future Gas Strategy notes,[31] industrial users have few options to switch away from gas. AEMO is only projecting small declines in industrial gas usage by 2035 and even an initial rise as industrial users shift away from coal. Access to renewable gases gives these customers a decarbonisation option, other than purchasing offsets and supports the achievement of NSW and Australian emissions reduction targets.[32]

2.2.2 Gas produces less emissions than the NSW electricity grid

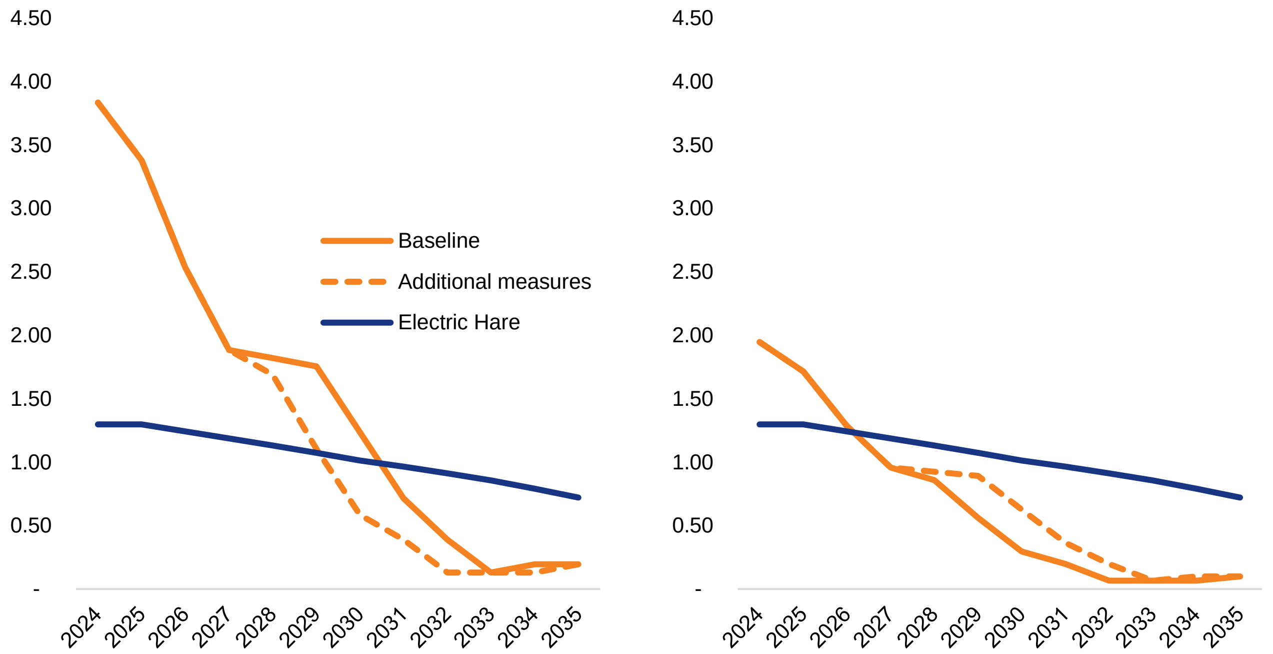
It is important to keep in mind that gas is starting with a head start with respect to emissions. While there have been large reductions in the emission intensity of grid electricity, due to increasing penetration of renewable electricity generation and closure of coal power stations, gas remains the lower emission option.

As shown in Figure 2.1, on an equivalent appliance-cost basis, gas will remain the lower emission option until around 2029 to 2031. Even if we compare gas hot water appliances to heat-pumps (which cost significantly more), gas will remain the lower emissions option until 2026.

These emissions forecasts are based on the Australian Government's emission projections. The baseline scenario includes all government policies implemented or where detailed design is well progressed. 'Additional measures' include policies announced but still under consultation. These projections assume that Eraring coal power station, which has produced 10-13 MtCO2e a year (10-12% of NSW emissions),[33] will close in August 2025. However, it has subsequently been announced that Eraring will stay open until August 2027. As a result, emissions are likely to be higher than in the baseline and additional measures forecasts (and gas will remain the lower emissions option in relative to NSW grid electricity for longer)

Figure 2.1 Annual residential hot water emissions (tCO_2e)[34]

Gas continuous versus Electric Storage (similar cost)	Gas continuous versus electric heat-pump (higher cost)



[30] Electrifying these loads is difficult due to the coordination issues across each *customer* which can be separate to the unit owners and strata as well as the physical constraints (the building may not have space for how water storage required with heat pumps)
[31] Australian Government 2024, *Future Gas Strategy,* p.20 Available here.
[32] Australian Government 2024, *Future Gas Strategy,* p.41 Available here.
[33] Origin Energy, *FY2023 Sustainability Performance Data,* p.12 Available here.
[34] Does not include scope 3 emissions. Emissions based on a gas continuous water heater using 30GJ of gas, electric storage water heater using 6.5 kWh, and a heat-pump water heater using 3.3KWh. Note that this level of gas consumption is much higher than the JGN

We note that the projected reduction in electricity emissions intensity does imply that an electric heat-pump hot water appliance will produce less emissions than a continuous gas hot water system over the life of the appliance. However, these heat-pump hot water systems are also more expensive. Evaluating the emissions reductions benefits against the additional appliance cost results in a cost per emission reduced of \$394/tCO2e to \$214/tCO2e depending on when the appliance is installed over the 2025-30 period. Or put another way, the emissions reduction benefits of a heat-pump hot water system are not justified by the value of Energy Ministers value of emissions reductions alone.[35]

Facilitating the roll-out of renewable gas is not just about reducing the emissions intensity of gas and achieving emissions reductions. It is also about reducing the pressure and additional load on the electricity system resulting in a lower cost pathway to net-zero for all energy users. By reducing the amount of load that electrifies, renewable gas not only supports the decarbonisation of gas but also supports the decarbonisation of the electricity grid.

Forms of renewable gas

Broadly, there are three kinds of renewable gas:

- Biomethane – A renewable form of gas produced by anaerobic digestion of organic waste materials such as food waste, agricultural residues, manure, and sewage sludge. Biomethane, when combusted, is a low emissions gas because the carbon it emits when burned was absorbed from the atmosphere by the organic materials it originated from, creating a closed carbon cycle. It has the same properties as natural gas and can be used in existing infrastructure and appliances.

- Renewable Hydrogen – Produced by using renewable electricity to split water into hydrogen and oxygen. When combusted, hydrogen produces no emissions except for water vapour. Currently, 10-20% hydrogen can typically be blended with natural gas in existing natural gas infrastructure or used by existing appliances, as higher concentrations may require infrastructure or appliance modifications.

- Synthetic Methane – Produced by combining hydrogen (typically green hydrogen) with carbon dioxide, which is captured from industrial processes or directly from the atmosphere. This process, called methanation, results in methane that is chemically identical to natural gas, enabling its use in existing infrastructure without modification while contributing to carbon recycling.

2.3 The growing role of renewable gas internationally

Renewable gases, particularly biomethane, are becoming increasingly critical in global efforts to reduce emissions. Globally, supply and production of biomethane is increasing by about 20 per cent per year.[36] We note that:

- The European Union has set ambitious targets to increase its biomethane production from 152 PJ to 1,330 PJ by 2030.[37]

- Denmark is aiming to replace natural gas entirely with biomethane by 2030, a significant leap from its already significant 25% share in 2021.[38]

- In the United States, California has set a biomethane target of 78 PJ, which will represent 12.2% of its natural gas throughput by 2030. [39]

residential average (19.33 GJ/year). Usage figures based on Grattan 2023, *Getting off gas: why, how and who should pay?* p.9. Available here.

[35] Key assumptions include: electricity emissions intensity consistent with the baseline scenario, gas mix consistent with our electric hare scenario, appliance life of 12 years, installed cost difference of gas and electric heat-pump appliances of \$1,726 (based on appliance costs used by the Grattan Institute escalated to \$2025) as well as annual energy consumption assumed by the Grattan institute of 30 GJ for gas (which is higher than our average residential 19GJ in 2022-23 usage) and 3.3 MWh for a heat-pump. This analysis does not consider the difference in the cost of energy which will vary depending on when electricity is used throughout the day.

[36] CEDIGAZ 2023, *Global Biomethane Market - 2023 Assessment*, p.4 Available here.

[37] European Biogas Association 2024, *Biogases towards 2040 and beyond, A realistic and resilient path to climate neutrality* p.3 Available here.

[38] European Commission 2021, *Biomethane Fiche – Denmark (2021).* Available here.

[39] California Public Utilities Commission *Decision implementing senate bill 1440 biomethane procurement program*, p.34 Available here.

- Italgas signed a Memorandum of Understanding with Coldiretti (an agricultural organisation) to replace a quarter of natural gas with biomethane. As part of this Italgas has committed to identify and implement actions aimed at reducing connection costs.
- Canada's natural gas utilities have set an aspirational target of 5% by 2025 and 10% by 2030.[40]
    - Enbridge, for example, has made a series of strategic investments in biomethane including the purchase of landfill to biomethane production facilities ($1.4 billion) as well as food-waste to biomethane partnerships and facilities. In May 2023 Enbridge had seven biomethane projects operating and in construction and had 50 additional projects in development.[41]
    - FortisBC, as of third quarter 2022, had entered into over 30 biomethane supply agreements which aim to supply 20 PJs per year.[42]

Relative to biomethane, hydrogen is still in its early stages, largely due to its higher current cost as well as infrastructure and appliance challenges for higher level blends. However, there is a broad consensus that costs will begin to fall and it could play a greater role in the 2030s.[43] Accordingly, we have seen:

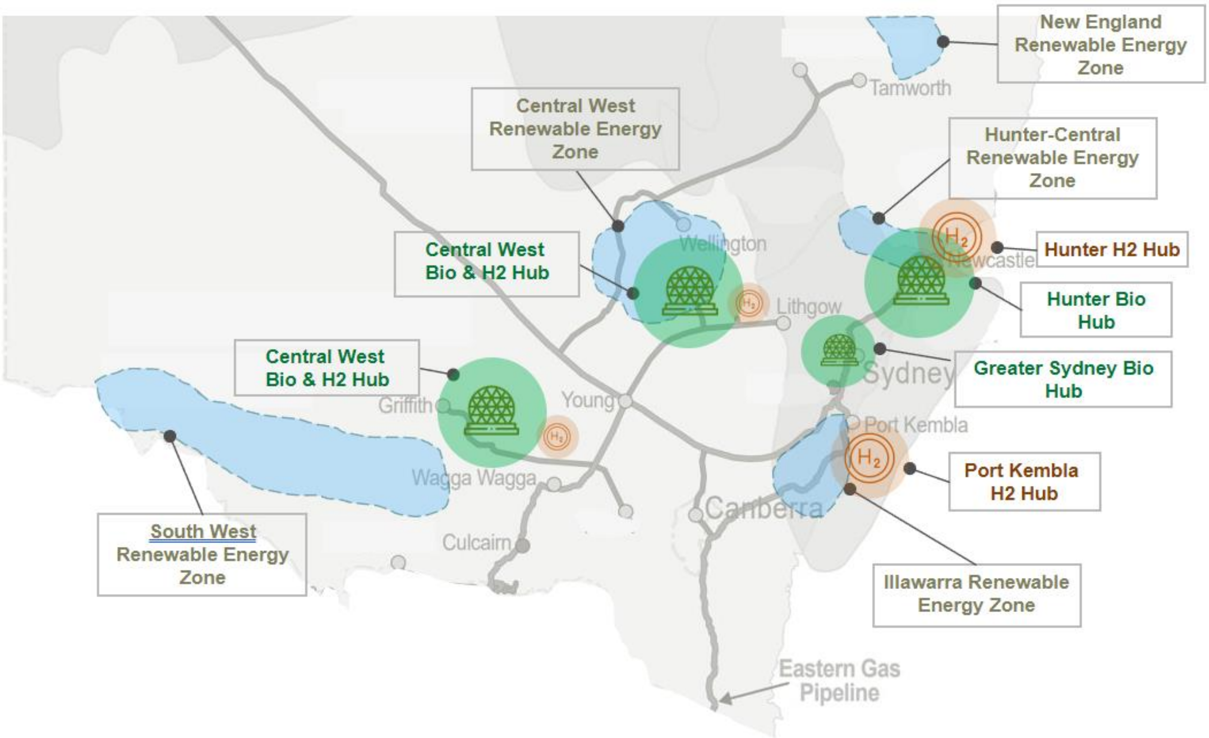
- A large number of hydrogen blending trials world-wide (Enbridge and Fortis BC in Canada, AGIG and Jemena in Australia, Engie in France, Cadent and Northern Gas networks in the UK, etc.).
- The UK Government making a policy decision to support hydrogen blending of up to 20% on the basis of potential strategic and economic value.[44]
- Portugal setting a 15% green hydrogen gas network injection target by 2030.[45]
- The NSW Government set a 2030 stretch target for 10% gas network blending (by volume).[46]

2.4 Renewable gas potential

Across the regions near our network, as shown in Figure 2.2, there are substantial local sources of biomethane. ACIL Allen estimates that maximum biomethane production volumes across NSW, from sources such as landfill gas and anaerobic digestion of feedstock and crop residue, are in the order of 70 PJ/year, of which at least 20 PJ/year is available now.[47] This finding is consistent with our understanding based on our confidential discussions with a range of project developers. We estimate that about 50PJ/year is near our network (of which 30 PJ/year is available now) and cost competitive to natural gas.

[40] See here.
[41] Enbridge 2023, *Net zero by 2050 Pathways to reducing our emissions,* p.11. See here.
[42] Fortis BC 2023, *Final argument to the British Columbia Utilities Commission*, p.17 See here.
[43] For example, ACIL Allen 2024, *Renewable Gas Target, Delivering lower cost decarbonisation for gas customers and the Australian economy.* p.7 Available here. and Fortis BC 2023, *Final argument to the British Columbia Utilities Commission*, p.18. Available here. 2024 Australian Government 2024, *Future Gas Strategy Analytical Report,* pp49-50. Available here.
[44] See here.
[45] See here.
[46] NSW Government 2021, *NSW Hydrogen Strategy: Making NSW a global hydrogen superpower,* p.7 Available here.
[47] ACIL Allen 2024, *Renewable Gas Target, Delivering lower cost decarbonisation for gas customers and the Australian economy.* p.9, Available here.

Figure 2.2 Renewable gas resources near our network



For context, total volumes on our network are about 90 PJs a year most of which are consumed by our large industrial customers as shown in Table 2.2.

Table 2.2 JGN 2022-23 Throughput (PJs)

Residential	Commercial	Industrial	Total
28.40	13.34	49.39	**91.13**

We have also received significant interest from hydrogen project developers in injecting into our network. At this stage this typically relates to unfirmed small-scale grid-connect projects which aim to opportunistically blend into the wider gas stream when the electricity wholesale market prices are low. Allowing up to 2% blending by energy (close to 10% by volume) would enable up to 1.8PJs to be injected per year.

2.5 The challenge

Looking ahead, as the Future Gas Strategy identifies[48] and international experience demonstrates scaling renewable gases is a critical opportunity for Australia. Renewable gas can replace natural gas and offer an additional pathway to reducing emissions.

While there is growing momentum and support from potential renewable gas producers and users, development has been hindered by regulatory, market and technological barriers. For instance:

- No certification of renewable gas – which means no mechanism enabling users to be recognised for their emissions reductions and no ability for project developers to earn a premium to compensate for the higher production costs relative to natural gas. This compares to much earlier establishment of the renewable electricity target and associated renewable electricity certificates in 2001.

[48] As outlined in the Future Gas Strategy, see Australian Government 2024, *Future Gas Strategy,* p.29, 30 and 34 Available here.

- A lack of clarity on whether and how the technical and economic regulatory frameworks apply to renewable gases.

- The industry, market, regulatory and commercial frameworks are premised on large-scale production from remote gas fields and high-pressure transmission pipelines to demand centres.

  In contrast, renewable gas is more decentralised involving a larger number of facilities producing small amounts of gas distributed across more locations. Changes are often required to the existing transportation and balancing arrangements (which can require physical, market and contractual change) where gas is not produced adjacent to a facilitated market. Although these challenges are surmountable these issues create additional costs and risk, primarily for the first mover in any particular location.

These barriers are gradually being resolved. Renewable gases are increasingly being recognised in regulatory frameworks. For instance, with our support, a Green Gas Certification scheme has been developed and is being implemented. Regulatory changes to bring renewable gases into the national gas regulatory framework have also been implemented. We (and others) have delivered pilot hydrogen and biomethane projects to demonstrate technical and commercial viability to the market.

In contrast to international experience (outlined earlier), there has been no large scale commercial renewable gas injections into any Australian gas network. Project developers tell us that while there is interest and opportunities to produce material levels of renewable gas, barriers and the lack of project precedents increase the project risk (and required rate of return[49]) creating challenges in projects obtaining the funding necessary to proceed.

2.6 Our strategy

Our strategy is to support, de-risk and reduce the project developer costs of potential projects to ensure that, where economic, renewable gas is supplied into our network to displace natural gas. Or put another way, to help overcome the barriers which are currently preventing the market from developing. We have identified four strategic pillars that will bring the greatest benefit to the acceleration of the renewable gas industry:

1. Support renewable gas demand – support gas users to understand their decarbonisation pathways.

2. Prove renewable gas viability – validate technical and commercial viability of renewable gas through demonstration projects.

3. Support renewable gas supply – facilitate renewable gas project developers to supply the market.

4. Ensure supportive policy settings – advocate for favourable policy and regulatory settings to encourage renewable gas supply.

We believe that it is possible to decarbonise our network by 2050. To achieve this goal our focus is:

- In the short term, on biomethane given markets are already operating around the world with a levelized cost of energy comparable with the current price of natural gas. We will also be open to low levels of hydrogen blending, to support its development and utilise periods of high availability of renewable electricity.

- In the medium term, the potential for converting some of the underutilised or industrial areas of the network into dedicated hydrogen networks and increasing blending hydrogen in the rest of the network.

- In the long-term, synthetic methane given its higher cost, but high potential due to it being a like-for-like solution with natural gas.

Overall, our strategy will deliver significant benefits, to consumers, the economy and to reduce emissions – as outlined in Table 2.3.

[49] Media reports indicate that green gas businesses are pitching returns of 30% to seek funding. See here.

Table 2.3 Renewable gas benefits

Customers	Economy	Climate Change	Other
• To provide a decarbonisation pathway for natural gas network customers. • Reduce the risk of falling demand and higher network prices. • Ensure ongoing energy choice and redundancy for our customers. • Reduce the risk and size of impact of natural gas shortfalls.[50]	• Avoid offshoring / closure of hard to abate manufacturing from Australia due to no access to renewable gas, including associated impacts on employment and local communities. • Avoid high-cost pathway to net-zero and significant economic losses to Australian domestic economy. • Circular economy benefits by reusing resources and reducing the need to produce and transport natural gas. • Reduced demand for (and in turn lower price of offsets) – reducing the cost to decarbonise the Australian economy.	• Support the achievement of NSW and Australian emissions reduction targets.	• To support the ongoing viability / competitiveness of the upstream market for renewable gas. • Reduce constraint and cost pressures on the electricity system.

2.7 Renewable Gas Program

2.7.1 Our 2025-30 Plan

Over the 2025-30 period, consistent with our strategy, we will support projects to overcome barriers and provide our customers with access to renewable gas. We will do this by incurring pipeline service expenditure and connecting projects through new mains to our pipeline.

We are forecasting to connect eight renewable gas projects to enable 6.7 PJs of biomethane to be injected into our network by 2030. We have only included projects in which we have a high degree of confidence. This has naturally resulted in less projects towards the back end of the 5-year period.

The level of support required to ensure each project will proceed differs depending on the circumstances of each project. This includes the forecast volumes, production costs and distance from our pipeline. In providing this support, we expect to incur and have included in our Access Arrangement Proposal $83.4 million in capex over the 2025-30 period. Project developers indicate that this support will enable their projects to proceed.

We note that there may be additional opportunities to connect an additional 10PJs of renewable gas, including some low-level hydrogen blending projects. These costs have not been included in our Access Arrangement forecast.

We will also monitor the development of the renewable gas market, to identify whether continued support will be required in the subsequent 2030-35 period and whether higher blends of hydrogen are likely. This will inform our

[50] As outlined in the Future Gas Strategy, see Australian Government 2024, *Future Gas Strategy,* p.39 and p.34 Available here.

asset management strategies and may trigger additional investment to prepare our network. These costs have also not been included in our 2025-30 Access Arrangement Proposal.

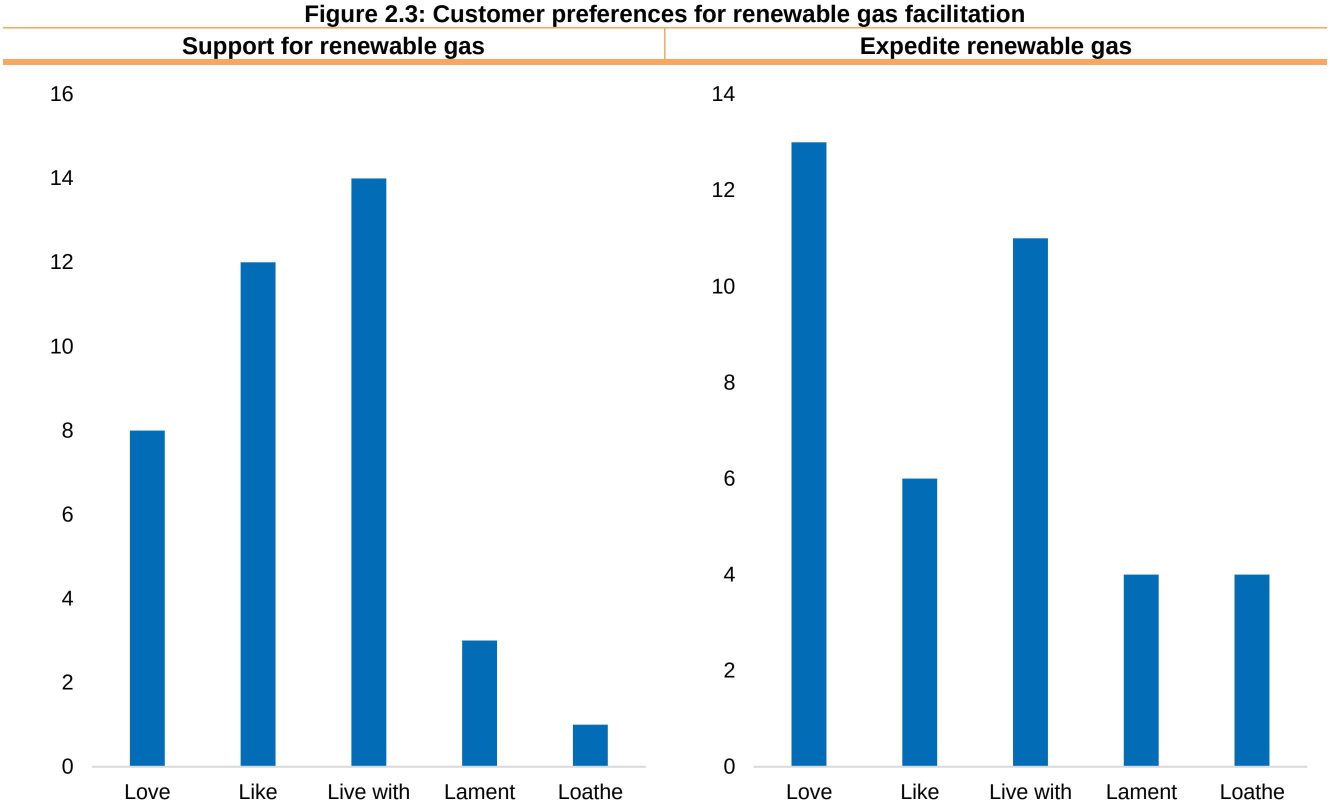
2.7.2 Customer feedback on facilitating renewable gas

In July 2023, during Customer Forum 5 of our customer engagement process, we provided customers with information about renewable gas blends and connections. We then asked for their recommendations on the role of renewable gas. After deliberating on the information provided, the majority of customers expressed their support for investing in renewable gas.

Customers provided several recommendations, including investing in building a reliable renewable gas network while avoiding unnecessary redundancies through effective management and cost control. They also emphasized the importance of continuing to invest in, and conduct, pilot studies and trials to thoroughly assess the safety of new and renewable gas networks, considering all aspects from supply and distribution to consumer usage and storage. Additionally, customers recommended benchmarking and developing consensus and industry standards for reliability and safety related to renewable gas networks.[51]

In the subsequent Customer Forum 7, held in September 2023, customers were asked to review their responses from the July forum. In the July forum, customers were presented with three options: do nothing, support connections, or expedite connections. The results showed that 90% of customers could either "live with," like, or "love" supporting renewable gas connections. When considering the option to expedite connections, 79% of customers expressed similar sentiments. These are demonstrated in the chart below. These findings demonstrate a strong customer preference for us to invest in and support the development of renewable gas connections while ensuring safety, reliability, and cost-effectiveness.

Figure 2.3: Customer preferences for renewable gas facilitation



[51] *JGN- bd Infrastructure-Att 2.2-Customer forum engagement report*, p. 19

2.7.3 Consistent with the NGO and the Rules

Our renewable gas program is consistent with the amended NGO and the updated conforming capital expenditure criteria,[52] as it is consistent with global and Australian good industry practice and will support the achievement of the NSW and Australian emission reduction targets.

The program will facilitate the uptake of 6.7 PJs of biomethane, reduce emissions by 0.35 MtCO2e per year and decarbonise 8.3% of the gas we transport by 2030. This contributes 1% and 0.4% of the reduction in emissions required to achieve the NSW and Australia 2030 emission reduction targets. [53]

The program is justified as the overall economic value of the expenditure is positive,[54] as demonstrated by the business cases for each of the eight renewable gas projects, and because they will contribute to meeting emissions reduction targets through the supply of services.[55]

Each business case assesses whether the overall economic value of the expenditure is positive taking into account the economic value of changes to Australia's emissions and as well as the economic value directly accruing to the service provider, producers, users and end users. The business cases show that the overall economic value is positive relative to no investment in renewable gas.[56] The net present value of our renewable gas facilitation projects sum to $1.4 billion.

Renewable Gas Business Cases

We engaged Frontier Economics to develop a business case for each of the eight renewable gas projects across the JGN.

This business cases demonstrate that our expenditure is justified under Rule 79(2)(a) as the overall economic value is positive, net present value (NPV) greater than 0 and a benefit cost ratio of greater than 1, relative to the 'no investment in renewable gas' (Base Case), calculated in accordance with Rule 79(3).

The CBA developed by Frontier Economics estimates the economic value, in monetary terms, of the incremental economic benefits and costs accruing to JGN (as service provider), gas producers, users and end users – including the economic value of changes to Australia's greenhouse gas emissions – calculated in accordance with Rule 79(3).

Frontier Economics developed the approach to the CBA to align with many of the broad principles and techniques in standard CBA guidelines, including the AER's cost-benefit analysis ISP guidelines[57]. This includes:

- Consideration of economic value from the perspective of the costs and benefits that accrue to a defined reference group: service providers, gas producers, users and end users[58], as per Rule 79(3), while ensuring no double-counting of costs or benefits, and excluding any 'financial or wealth' transfer of value between consumers and producers[59];
- Estimating the economic value, rather than financial value, of the costs and benefits (such as the economic value of changes to Australia's greenhouse gas emissions using the Energy Ministers' VER[60]);
- Comparing costs and benefits over a long-term (30 years) modelling period[61] in present value terms;

[52] See section 1.4 for further details on the change.
[53] As a result, the program is justified under Rule 79(2)(c)(v).
[54] Rule 79(2)(a).
[55] Rule 79(2)(c)(v).
[56] See RIN Attachments 4.3 for Lilli Pilli, Coolabah, Blue Gum, Iron Bark, Red Gum, Huon Pone, Kauri and Wollemi.
[57] AER 2020, *Cost benefit analysis guidelines - Guidelines to make the Integrated System Plan actionable*. Available here.
[58] Similar to the clause 5.22.10(d) of the NER, AER's cost-benefit analysis ISP guidelines require the inclusion of any measured cost to generators, distribution network service providers (DNSPs), TNSPs and consumers, and market benefits to those who consume, produce and transport electricity in the market. AER 2020, *Cost benefit analysis guidelines - Guidelines to make the Integrated System Plan actionable*, p18-20.
[59] AER 2020, *Cost benefit analysis guidelines - Guidelines to make the Integrated System Plan actionable*, p21, 36.
[60] Rather than the revenue stream that renewable gas suppliers may receive from the sale of ACCUs.
[61] Consistent with the AER's Cost-benefit analysis ISP guidelines, this involves the use of terminal values to reflect the option's expected cost and benefits over the remaining years (i.e. beyond the modelling period) of its economic life. AER 2020, *Cost benefit analysis guidelines - Guidelines to make the Integrated System Plan actionable*, p67.

- Using internally consistent and transparent input variables and parameters, while also accounting for uncertainty by creating “scenarios around the most likely scenario” [62];
- Identifying the option that maximises the present value of net economic benefit to service providers, gas producers, users and end users (i.e. maximises NPV>0, compared to the ‘no investment in renewable gas’ (Base Case)).

Our renewable gas program also complements our proposal to accelerate depreciation, with both initiatives reducing future asset stranding risk, and extending the life of the gas network for our customers which will help mitigate intergenerational equity concerns, which is in the long-term interest of customers. If our renewable gas program is not approved by the AER, our network will not be able to transition to renewable gas and we will need a higher level of accelerated depreciation to take into account that our network will be largely stranded by 2050.

2.7.4 Risks and opportunities

As highlighted above, the economic analysis in the business cases for each of the eight renewable gas projects demonstrates that there is a net positive economic value relative to the ‘no investment in renewable gas’ (Base Case).

This analysis also shows that the economic value of the costs and benefits that have been monetised in the CBA are primarily borne or received by end-users, and results in end-users (as a whole) being significantly ‘better off’ in that that the benefits received exceed the costs they ultimately incur.

Notably, the pipeline expenditure we incur, and renewable gas plant costs project developers incur, are complementary investments – both are required to enable the production and distribution of renewable gas to our customers.

If the AER does not approve our renewable gas program, we will not be able to proceed. This will mean renewable gas supply will not occur, stifling broader investment in the emerging renewable gas industry in New South Wales. This would not be in the long-term interests of customers (or consistent with the amended NGO) as it would mean:

- The $1.4 billion of net value we have identified (which is primarily received by end-users) will not be realised.
- No decarbonisation pathway for natural gas network customers.
- Increased stranding risk and in turn a higher level of accelerated deprecation will be required, given the reduced opportunity to recover at least our efficient costs.
- Substantial economic impacts, including the potential loss of hard to abate manufacturing in Australia.
- High-cost pathway to achieve emission reduction targets through electrification pathways only.
- Additional pressure on the electricity system.
- Foregone opportunity to reduce the risk and size of the impact of natural gas supply shortfalls in the gas market.

[62] AER 2020, *Cost benefit analysis guidelines - Guidelines to make the Integrated System Plan actionable*, p11.

3. JGN's emissions

In providing pipeline services, our activities result in direct (scope 1) emissions through:

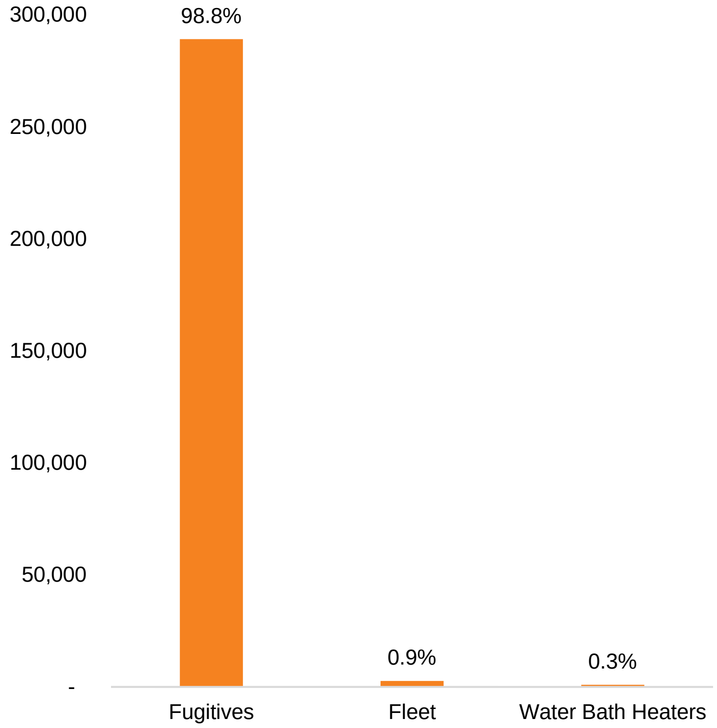
1. **Fugitive emissions** – The release of natural gas to the atmosphere from leaks and operational activities (venting, purging, and blowdowns etc.), the function of equipment (for example relief valves and the use of instrument gas[63]) and third-party damage. This occurs across the distribution and transmission components of our pipeline.[64]

2. **Our fleet** – Emissions are produced from the combustion of diesel or petrol used for our vehicles.

3. **Water Bath Heaters** – Emissions from the combustion of gas used in our 15 Water Bath Heaters, which pre-heat gas to counteract the temperature drop due to the Joule-Thompson effect.

As shown in Figure 3.1, 98.8% of our emissions are due to fugitive methane emissions. As noted in section 1.1, methane is a potent greenhouse gas with a global warming potential 80 times higher than carbon dioxide. Emitting 1 GJ of natural gas to the atmosphere results in about 80 times more emissions on a tCO2 equivalent basis.

Figure 3.1 JGN's 2022-23 Scope 1 emissions (tCO2e)



In addition to our direct emissions, we also emit a relatively small amount of emissions (1,045 tCO2e in 2022-23) from electricity consumption (scope 2).

We have also started an assessment to understand the source and scale of our other indirect emissions which occur outside of the boundary of our organisation but as a result of out actions (scope 3). Consistent with the Greenhouse Gas Protocol, emissions from the use of gas we transport does not form part of any of the 15 defined categories and are outside the Scope 3 boundary. This is because we do not own or sell the natural gas which is transported by our network.

[63] Instrument gas is a drawn from a pipeline's main flow to power equipment like valves and actuators. Unlike the gas used for combustion, instrument gas is directed solely for operational control and is released into the atmosphere after use. Instrument gas is typically a legacy approach to avoid the need for an electricity connection and air power system.

[64] For NGER purposes, distribution pipelines are those with a maximum design pressure of 1,050 kPa or less (our secondary, medium and low pressure mains) while transmission pipelines are those with maximum design pressure which exceeds 1,050 kPa (our trunk and primary mains).

3.1 Emission measurement and reporting

Fugitive emissions, largely due to many small leaks throughout our network, are not currently measured. Emissions are reported, using a 'lower order' method that relies on generic assumptions, in line with the NGER Scheme. The NGER Scheme is based on the historical assumption that fugitive emissions cannot be directly measured. Accordingly, there is no methodology currently included within the NGER Scheme which allows emissions to be reported based on direct measurement.

3.1.1 Measuring fugitive emissions

Fugitive emissions are measured and reported based on generic assumptions due to the historical lack of information on the location and extent of leaks across our 25,000 km of mains.

Although data on the number and size of leaks across our network is not currently available, we do measure unaccounted for gas (UAG). UAG is the difference between the gas measured entering our network at receipt points and the gas measured leaving our network at delivery points. UAG is driven by multiple factors such as:

- Measurement uncertainty, due to the accuracy of our gas meters. For instance, the meters for most of our 1.5 million customers are only accurate to about +/-2%. These meters generally under-record consumption as they age.
- Calculation uncertainty. Meters measure gas volumes, but we bill and report on an energy basis. This requires assumptions about the gas's composition (such as its 'heating value') and the environmental conditions (such as temperature) to convert gas volumes into a unit of energy. There are also timing factors due to the quarterly read cycle of our smaller meters.
- Theft.
- Fugitive emissions due to leaks, operational activities, and the equipment function (including venting) etc.

Historically, we have not had data which could allow us to split UAG by driver. Estimates on the size of the fugitive emission component of UAG have ranged from 80-90%, through to 50-60% and more recently 35-40%.[65] The NGER Scheme assumes that 37.3% of UAG is attributable to fugitive emissions, based on the midpoint of recent estimates.[66]

3.1.2 Distribution fugitive emissions

Our distribution fugitive emissions are currently based on:[67]

- the total amount of gas delivered through the distribution component of our network;
- a benchmark percentage to determine the proportion of delivered gas which is unaccounted for (2.2%);
- a benchmark percentage which represents the proportion of UAG which relates to fugitive emissions (37.3%); and
- emission factors used to convert GJs of gas into tonnes of carbon dioxide equivalent (tCO2e).

There is no link between network performance and reported fugitive emissions with the current approach.

From the 2023-24 reporting year, we will report emissions based on our actual UAG rather than a benchmark percentage.[68] This will increase reported emissions, as UAG is forecast to be 3.14%, compared to the generic assumption of 2.2% in the NGER Scheme. Despite this change, any link between network performance and

[65] Australian Government 2019, *National Inventory Report,* p.162. Available here.
[66] This proportion was changed from 55% to 37.3% in the 2022 version of the NGER. This is the primary reason JGN's emissions reduced from 26% from 400,018 tCO2e in 2021-22 to 292,825 tCO2e in 2022-23. See Australian Government 2022, *National Greenhouse and Energy Reporting Scheme – 2022 Proposed Amendments, Discussion paper*, p.9. Available here.
[67] Method 1.
[68] Method 2.

reported fugitive emissions will remain obscured due to uncertainties around the size and impact of the other drivers of UAG (which are not static).

3.1.3 Transmission fugitive emissions

Like distribution, transmission fugitives are based on generic factors. Our transmission fugitives are based entirely on the length of our pipeline. There is no relationship between network performance and reported emissions.

3.1.4 Fleet and Water Bath Heaters

Unlike distribution and transmission, our fleet and water bath heater emissions are calculated based on measured fuel usage and do not have the same issues as distribution and transmission fugitives.

3.2 Emission reduction targets

As outlined in section 1.5, the Safeguard Mechanism is designed so that covered facilities deliver a proportional share of Australia's emission reductions. Accordingly, reducing emissions consistent with Safeguard Mechanism baselines[69] will reduce emissions proportionally in line with the Australian Government's emission reduction targets (which are set in 5-year increments (2030, 2035, etc.)).

Relatively small reductions are required by JGN until 2030. This is because JGN's baselines will transition from being calculated using facility-specific to default emissions intensity values. For JGN, the default emission-intensity values produce a materially higher baseline. As a result, the transition mostly offsets the reduction in baselines due to the application of the 4.9% decline rate.

Baselines vary in line with production. If the amount of gas we transport falls, the emissions reduction target we need to achieve to avoid Safeguard Mechanism penalties increases. The only way to avoid penalties for emissions above our baseline is to reduce the emissions we produce on a per unit of gas transported basis. Reducing volumes alone is not an avenue to avoiding Safeguard Mechanism penalties.

While the decline rates post-2030 haven't yet been set, JGN's emissions will need to reduce at a much faster rate. This is because, by 2030 JGN will have fully transitioned to using default emissions intensity values. The full impact of the decline rates will apply (which is not the case for the period to 2030, as outlined above).

Emissions are currently legislated to decline at a rate of 3.285% after 2030.[70] However, as the 2035 interim target will likely be between 65% - 75%[71] the decline rate will need to be between 5.1% and 7.4% per year to align with this target.

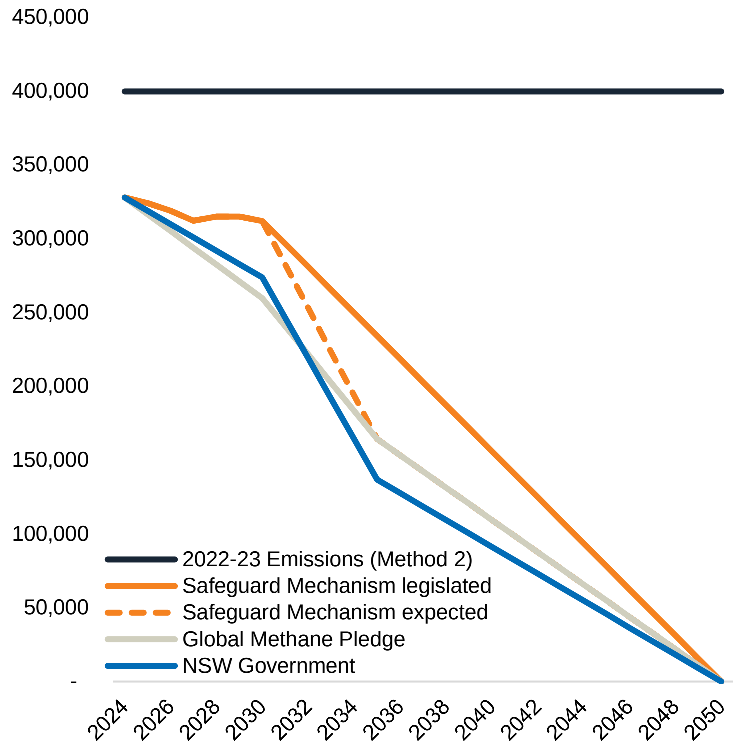
The NSW Government targets are more ambitious and will require steeper reductions. To achieve the 2030 NSW Government target, JGN's emissions will need to be 12.3% below the Safeguard Mechanism baseline. These reductions assume that JGN will be required to contribute a proportional share of the NSW emission reduction target.

Similarly, the emissions reductions required for JGN's emissions to be aligned with the Global Methane Pledge (30% reduction of methane emissions by 2030 relative to 2020 levels) are 17% below the Safeguard Mechanism 2030 baseline.

The implied emissions trajectories of each target, along with our 2022-23 emissions for comparison,[72] are shown in Figure 3.2. To prepare these trajectories we have held throughput and line length constant at 2022-23 levels. Using forecast throughput and line length would have shown *even lower* emission reduction targets. This is because, as discussed above, baselines are set on an emissions intensity basis and adjust for actual production.

[69] The Safeguard Mechanism only applies to Scope 1 emissions.
[70] National Greenhouse and Energy Reporting (Safeguard Mechanism) Rule 2025, section 32. Available here.
[71] Climate Change Authority 2024, *Targets, pathways and progress, 2024 Issues Paper,* p. 6. Available here.
[72] Emissions based on Method 2 reporting (which uses actual rather than benchmark UAG), to be consistent with our future reporting.

Figure 3.2 JGN emission reductions required to achieve Australian and NSW government targets[73] tCO2e



The key takeaway is that across all emission reduction trajectories, JGN will need to achieve significant emissions reductions to reduce emissions consistent with NSW and Australian government emissions reduction targets.

While these trajectories illustrate the reductions required to align with various targets they do not represent the efficient or optimal level of emissions reduction – which needs to balance the cost and value of reducing emissions.

3.3 Moving to direct emissions measurement and reporting is essential

In the absence of direct measurement and reporting, it is impossible for JGN to materially reduce:

- Reported fugitive emissions. Even if we found a way to reduce emissions without direct measurement, JGN would still report fugitive emissions as 37.3% of UAG. This has two implications:
    1. Reported emission will not align with our actual emissions.
    2. Reducing actual emissions by 1 tCO2e will only reduce reported emissions by 0.373 tCO2e.
- Actual fugitive emissions. Without data on the location and size of leaks, JGN will not be able to efficiently locate, prioritise and repair leaks to reduce fugitive emissions. We can only continue to reactively respond to leaks based on leaks reported to us by the public.

In turn without direct measurement and reporting, it is impossible to reduce greenhouse gas emissions to achieve emission reduction targets.

[73] Production variables held constant to isolate the impact of the decline rates.

3.4 Direct emission measurement technology

Fortunately, there have been significant developments in direct emissions reporting. The Oil & Gas Methane Partnership 2.0 (OGMP 2.0), the flagship reporting and mitigation programme of the United Nation's Environment Programme, has spearheaded the substantial shift from generic estimation to empirical measurements.

These changes have been enabled by the 'methane data revolution' and associated scientific and technological developments. Methane emissions are increasingly being measured using satellites with near-real time reporting, aerial surveys, vehicle mounted advanced sensors, optical gas imaging cameras, laser surveying and fluid tests.

These technologies have led to 'Leak Detection and Repair' (LDAR) programs.[74] This differs from the historical approach of reactive repairs based on community complaints – and provide the ability to measure and prioritise leak repairs based on the volume of gas being emitted.

Moving to direct emissions and adopting LDAR programs is good industry practice. 114 companies worldwide have joined OGMP 2.0 with more than half on the pathway to achieving 'Gold Standard' reporting.[75] This requires setting a methane reduction target, submitting OGMP 2.0 compliant reports and moving to higher level (more granular and more accurate) emissions measurement and reporting.

Given that gas network fugitive emissions occur across a large number of mains in various urban and rural locations, the technology of choice is the use of advanced vehicle mounted sensors referred to as Advanced Mobile Leakage Detection. Over 30 gas distribution businesses around the world have adopted this technology, including Cadent, GRDF, PG&E, National Grid, Snam and Italgas.

The use of vehicle mounted sensors and LDAR programs has enabled Snam to reduce fugitive methane emissions by 46% since 2015 and 30% since 2020 levels (consistent with the Global Methane Pledge).[76] Similarly Italgas has been able to reduce its fugitive emissions by 9% in 2021 and then by another 10% in 2022.[77]

We have recently started using advanced vehicle mounted sensors to undertake leakage surveys of our network, where we survey our entire distribution network over a 5-year timeframe. However, to move to direct emissions reporting we would need to expand our program to survey our whole network each year.

3.5 Developments in emission reporting

Under the NGER Scheme, there are typically four estimation methods. The first is the simplest based on default emissions factors. Method 2 and 3 use progressively higher levels of facility-specific information. Method 4 is the most sophisticated requiring direct measurement. For gas distribution or transmission fugitives there is no method 4. Emissions must be reported using generic benchmarks and emissions factors.[78]

There is widespread concern about the use of generic assumptions for estimating fugitive emissions, generally as they are considered to be under-estimates of actual emissions. These concerns have been raised by academics who have undertaken partial atmospheric methane mapping in Sydney[79] and thinktanks who have commissioned research to compare reported emissions against satellite observations.[80]

The Climate Change Authority, in reviewing the NGER Scheme found that many stakeholders consider that estimating fugitive methane emissions with simple generic assumptions is no longer appropriate. Less than a

[74] APA, for its gas transmission pipelines, are exploring enhanced methane reporting methods using both top-down and bottom approaches to ensure that reductions in methane emissions can be recognised. These include completing leak detection surveys and deploying aerial methane detection technology. See APA 2023, *Climate Report*, p4 & 16. See here.
[75] UN Environment Programme, *International Methane Emissions Observatory 2023 Report,* p.20 Available here.
[76] Snam 2013 *Consolidated non-financial Statement 2023*, p.304
[77] Italgas 2022, *Integrated Annual Report 2022,* p.144. Available here.
[78] See Division 3.3.8 – Natural Gas Distribution (other than emissions that are flared) and Division 3.3.7 – Natural gas transmission (other than emissions that are flared) of the National Greenhouse and Energy Reporting (Measurement) Determination 2008. Available here.
[79] O'Malley, N. (2020, September 13). *Sydney awash with leaks as research shows the climate cost of gas,* Sydney Morning Hearld. Available here. We note that one of the areas surveyed was an area of cast iron mains we have since replaced.
[80] The SuperPower Institute has funding to use satellites to monitor methane emissions from gas pipelines. See Potter, B. (2023, April 19). *How a 'superpower' Australia could snare greater share of green boom*, Australian Financial Review. Available here.

quarter of all submissions and less than half of those who report under the NGER Scheme consider current reported fugitive emissions as somewhat or very accurate.[81]

The Climate Change Authority made eight recommendations[82] in respect of fugitive emissions, including to phase out Method 1 and for the higher order estimation methodologies to be included so that direct measurement methods can be applied.[83] The Minister for Climate Change and Energy has already asked the Department of Climate Change, Energy, the Environment and Water to consider which of the recommendations can be practicably implemented by the end of 2023-24 with a focus on methane emissions and will respond to all recommendations in mid-2024.[84]

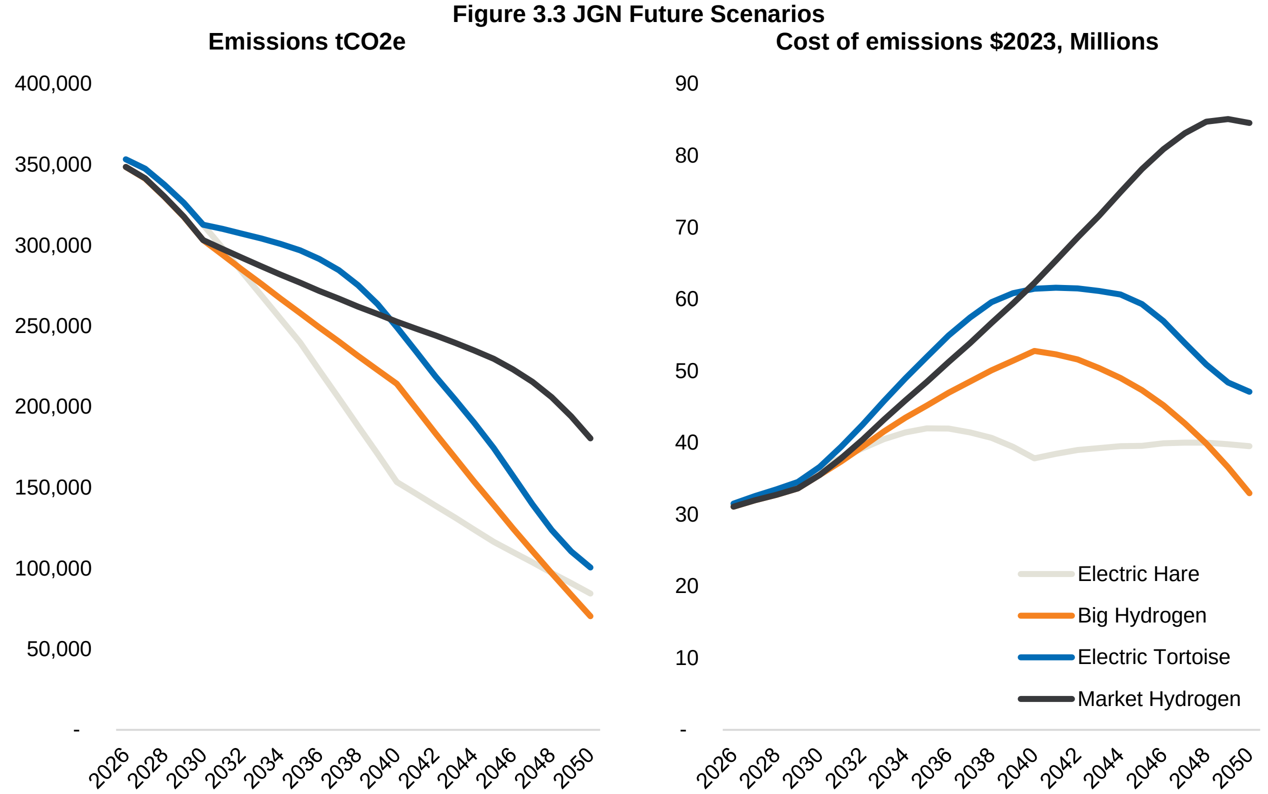
We are currently engaging with the Australian Government, and other stakeholders, on the development of a Method 4 for fugitive emissions for gas networks. This includes providing information, research and draft methods (consistent with OGMP2.0 protocols) to facilitate the move to direct emission measurement and reporting.

3.6 The economics of emission reductions and direct measurement

To help us navigate our uncertain future, we engaged an Expert Panel of seven independent energy industry leaders to co-design plausible scenarios for the NSW energy system.[85]

We have used these scenarios to forecast reported future emission trajectories – using the current generic assumptions.[86] In all the future scenarios identified, emissions reduce due to declines in volumes and to a smaller extent, the roll-out of hydrogen, as shown in Figure 3.3.

Figure 3.3 JGN Future Scenarios



[81] Australian Government 2023, *2023 Review of the National Greenhouse and energy Reporting Legislation,* p.79. Available here.
[82] The recommendations focus on further enhancements to the Scheme's data transparency; coverage; methane emissions measurement, reporting and verification; and administration.
[83] Australian Government 2023, *2023 Review of the National Greenhouse and energy Reporting Legislation,* p.80. Available here.
[84] See here.
[85] *JGN-KPMG-Att 2.3-KPMG Expert Panel Report*.
[86] We have also assumed that UAG stays constant at 3.14%. However, if volumes were to materially decline but mains were not decommissioned it would be plausible to expect that fugitive emissions (and in turn UAG) as a proportion of gas sales will rise. As a result, these forecasts are likely to understate future reported emissions.

Although emissions decline, the cost[87] of these emissions increases over time. This is because the value of emissions reductions increases over time, as shown in earlier in Figure 1.1. Table 3.1 shows the cost of JGN's emissions over the period to 2050 are substantial, ranging from $0.7 billion to $1 billion in present value terms.

This analysis indicates that, regardless of the plausible future which eventuates, there is significant value in reducing emissions.

Table 3.1 Future Scenario costs of emissions ($2025 millions, present value terms)

Electric Hare	Big Hydrogen	Electric Tortoise	Market Hydrogen
724.7	797.8	923.5	1,032.3

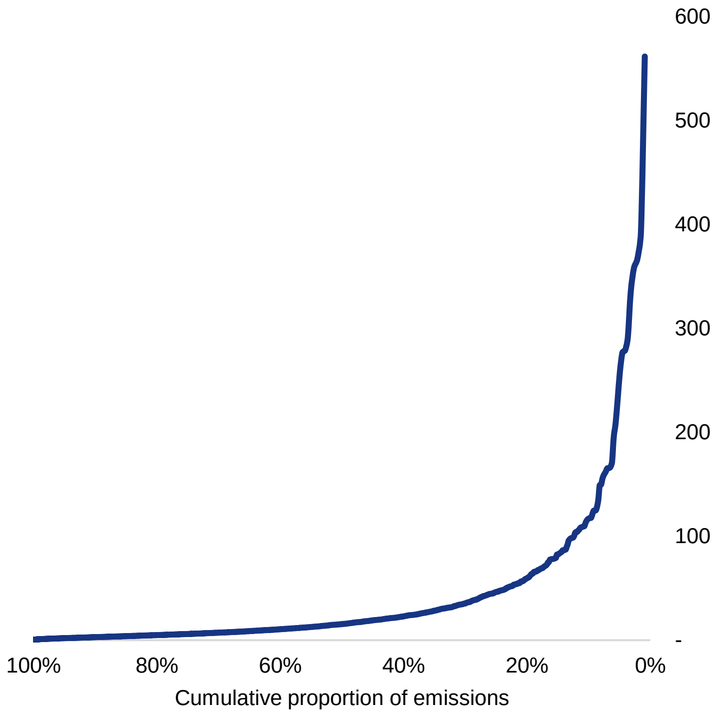
The efficient level of emissions reductions will differ to emissions reduction targets outlined in section 3.2. Given the value of reducing emissions, the efficient level is likely to be lower than implied by emission reduction targets.

Allocative efficiency is achieved when marginal cost equals marginal benefit. In this context this means where the marginal cost of reducing fugitive emissions (through leak repairs, mains replacement programs or other activities) equals the marginal benefit (value of reducing carbon emissions, reduced cost of lost gas and Safeguard Mechanism compliance costs).

Direct emissions measurement provides granular information on the size and location of each leak. We can then use this information to develop optimised repair and mains rehabilitation programs.

Figure 3.4 presents leak data collected so far across 20% of our network. It shows the size of each leak (vertical axis) against its cumulative share of total identified emissions (horizontal). We note that some leaks are very large. The largest emits gas at a rate of 562 tCO2e per year which has an annual cost of $43,838 using the Energy Ministers' 2024 value of emissions reductions. This cost is significantly higher than the cost of undertaking a repair (about $2,000 – although it depends on the material and location), especially given that the cost of a leak will be incurred every year until repaired while the cost of a repair is only incurred once.

Figure 3.4 Emissions per leak identified on our network using Picarro technology (tCO2e per year)



Importantly, this means that the efficient level of emission reduction (consistent with the NGO and the Rules) is not determined by the existence of a regulatory requirement, alignment with Safeguard Mechanism or another

[87] Based on the Energy Ministers Value of Emissions Reductions

target. The efficient level of emissions reduction is determined by the economics (cost and benefit) of addressing each leak. However, the information to reach this optimal level can only be obtained with direct emissions measurement.

Future Scenarios

The Expert Panel process resulted in four scenarios:[88]

- Electric Hare – where decarbonisation is supported by strong government policy driving electrification across industry and residential customers, with limited use of renewable fuels for hard to abate sectors.
- Big Hydrogen – where government policy support underpins a hydrogen export economy with a renewable gas target and certification, subsidies, and tax-offsets, driving down the cost of hydrogen production.
- Electric Tortoise – where residential customers slowly electrify and industrial users transition to biomethane, and in which hydrogen remains not commercially viable. Transition is driven by business and community investment.
- Market Hydrogen – where a near-term technological breakthrough driven by the market results in renewable gases becoming competitive with electrification, creating a diverse but fragmented energy mix.

Each Expert Panellist was invited to cast a vote on the relative likelihood of each scenario by allocating 100% across the four scenarios, based on their own assessment. The most likely outcome was Electric Tortoise (49%) followed by Electric Hare (27%), Market Hydrogen (15%) and Big Hydrogen (10%).

3.7 Customer feedback on direct emissions measurement

After our Draft Plan in March, we also asked our Customer Forum on whether we should whether we should invest further in emission-detection technology. We asked customers whether we should:

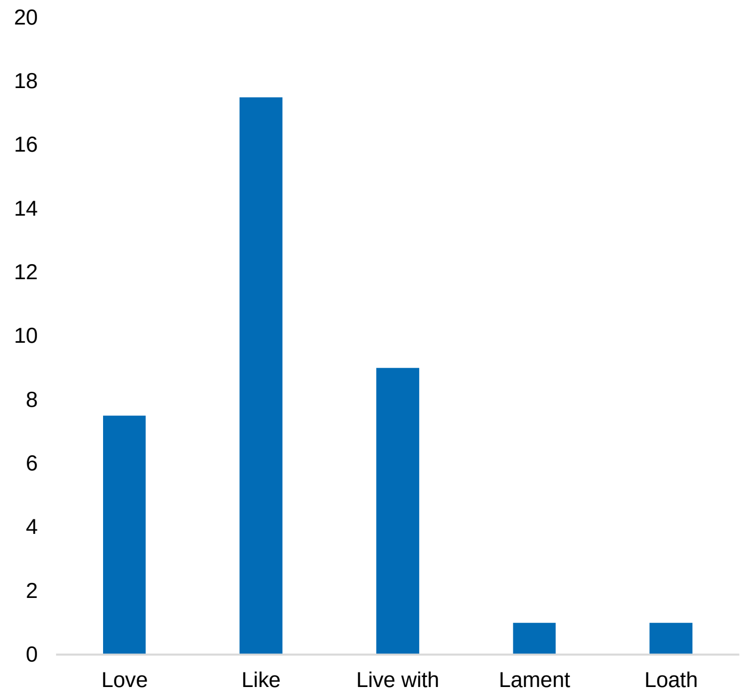
1. Survey 100% of the gas network annually. This would lead to proactive and planned mains repair and rehab, higher reduction in actual emissions and in the longer term rely less on offsets to reduce emissions. This option would have a bill impact of $2.40 per year.
2. Survey 20% of the network annually. This would result in minimal change to mains repair and rehab, minimal impact on actual network emissions and in the longer term greater reliable on offsets to reduce emissions. This option would have a bill impact of $1.50 per year.

While we indicated to customers that the 100% option was more expensive, our subsequent analysis has found that this option will be the lower cost option. This is because the reduction in emissions together with reporting on actual emissions (rather than estimates) reduces Safeguard Mechanism compliance costs which more than offset the additional costs involved (both in measurement and additional mains repairs).[89]

Customer Forum Participants were overall supporting of moving to direct emissions measurement. As shown in Figure 3.5, 94% of customers voted that they could "live with", "like" or "love" the initiative to directly and proactively address emissions.

[88] *JGN-KPMG-Att 2.3-KPMG Expert Panel Report.*
[89] See *JGN-RIN Att 4.4-Emissions Monitoring – Picarro*

Figure 3.5 Customer forum feedback on direct emissions measurement



3.8 Reducing JGN's emissions

3.8.1 The movement to direct emissions measurement and reporting

To facilitate future emissions reductions, we will move to direct emission measurement and reporting. We will do this by expanding the use of our Advanced Mobile Leakage Detection (vehicles with advanced sensors) technology from Picarro to survey 100% of our network each year. This will allow us to process the data collected consistent with OGMP 2.0 protocols.

While the NGER Scheme does not currently allow for direct emission reporting, we expect these regulatory changes will be in place within 2 years, given the Government's commitment to the Global Methane Pledge, community and stakeholder views as well as the recommendations from the Clean Energy Regulator.

We will move to direct measurement as:

1. We cannot reduce our reported emissions without moving to direct measurement.

2. The costs of direct measurement ($4.2 million) are substantially less than the potential benefits, given that JGN's emissions currently have a cost of $30 million per year (or more), as shown by Figure 3.3. While direct measurement will not reduce emissions in and of itself, international experience, indicates that reductions of about 10% per year are achievable.

3. Direct emission reporting will allow us to optimise our leak repair program on a leak-by-leak basis – and reduce emissions to the efficient level. Direct emissions reporting will allow us to evaluate repair, lost gas, Safeguard Mechanism compliance costs and the value of emissions on a leak-by-leak basis.

4. Our customers support taking action to move to direct emissions reporting through Picarro technology even if this option costs more (which we subsequently found it doesn't).

Notably, moving to direct emissions measurement is consistent with the NGO as it will reduce Australia's emissions and in turn meets the opex criteria.[90] While there are additional costs in moving to direct emissions, the value of emissions reductions will exceed these costs.

The program will commence in 2025-26 at a cost of $3.9 million per year. These costs have been included as a step change in our 2025-30 Access Arrangement.

We also expect that moving to direct emissions technology will lead to an increase in leak repair works and mains replacement costs, as we work to reduce emissions based on the data obtained. However, the extent of works is highly uncertain as it depends on the number, size and location of the leaks identified. We expect that we will incur around $3 million per year in additional leak repair costs and $1 million mains rehabilitation costs. It is also unknown whether our emissions will increase or decrease and at what rate. Accordingly, given this uncertainty we have not made any adjustment to the forecasts in our 2025-30 Access Arrangement to reflect increased leak repair costs or changes in our forecast emissions (although we note that any difference will be trued-up with 100% of any benefits realised flowing to customers).

3.8.2 Other no-regrets actions

In advance of shifting to direct measurement, we will undertake no-regrets actions to reduce emissions including:

1. $55.7 million in capex to replace cast iron mains in seven areas with known issues. These projects are no regrets as we know that leakage is high and undertaking reactive repairs are not efficient with cast iron mains.

2. $1.8 million to continue our catalytic heater program replacing water bath heaters to reduce gas usage at our facilities.

3. $2.0 million to continue to deliver our pressure reduction program where we reduce fugitive emissions by lowering the pressure in areas of our network.

All of these costs have been included in our 2025-30 Access Arrangement.

We will also explore other avenues to reduce emissions including:

- Changes to operational practices and procedures.

- Procuring biomethane for our water bath heaters.

- Strategies for the transmission component of our pipeline. For instance, leak detection surveys and new techniques to reduce fugitive emissions from venting etc, in line with the Methane Guiding Principles.[91]

- Changes to procurement and equipment standards, to deploy low emission technologies.

No specific funding has been sought for these strategies in our 2025-30 Access Arrangement.

3.8.3 Enabling projects

Supporting our two main strategies (to facilitate access to renewable gas and to reduce our emissions) we will also:

- **Provide climate-related financial disclosures.** We will provide information relating to governance, strategy, risk management, metrics and targets (including scope 1 and 2 emissions) as well as our scope 3 emissions (emissions which occur up and down our supply chain). This reporting is a regulatory

[90] Rule 91.
[91] See here.

requirement and a step change of $3.4 million over 5-years has been included in our 2025-30 Access Arrangement.[92]

- **Uplift our digital capability to support our emissions reduction program.** We will implement a new analytics platform, Asset Investment Planning System and Digital Work Order Management which will help us to efficiently reduce emissions. For instance, the Digital Work Order Management will improve our scheduling and dispatch capabilities and lower the cost of our lead detection and repair program we will need to implement after the shift to direct measurement. These projects have been included in our 2025-30 Access Arrangement.[93]

[92] *JGN-Att 6.2-Opex step change justification*.
[93] *JGN-Att 5.4-Technology Plan*, *JGN-RIN Att 4.3.5-ICT Investment Brief Asset Investment Optimisation Planning, Network Management Advanced Analytics, Work Management Extent Phase*.

Appendix A JGN's emission calculations

Distribution fugitives

The NGER Scheme is premised on the historical assumption that fugitive emissions cannot be directly measured and must be calculated using high-level benchmarks and estimates. While there are three methods, the broad methodology is to:[94]

a. Identify unaccounted for gas (UAG). UAG is the difference between the quantity of gas measured entering the network (receipt points) and the quantity of gas that is measured leaving the network (delivery points). UAG is due to measurement and calculation uncertainty[95] as well as physical losses due to leakage, theft and gas used for operational purposes.

b. Estimate the proportion of UAG which relates to fugitive emission. The NGER assumes that this is 37.3%.

c. Apply a composition factors. The NGER factors which reflect the composition of natural gas for carbon dioxide and methane. For NSW this is 0.8 tCo2e/TJ for Carbon Dioxide and 437 tCo2e/TJ for methane.

We currently calculate our emissions using Method 1 which deems that the UAG percentage to be 2.2%. As the UAG percentage is deemed and not calculated, our reported emissions vary year-to-year solely on the total amount of gas transported through the JGN.

Table 3.2 Calculation of distribution fugitive emissions 2022-23 (tCO2e)

Throughput (TJ)[96]	UAG%	Proportion of UAG assumed to be fugitive	Composition factors (tCO2e/TJ)	Emissions
74,432	2.2%	37.3%	437.8	267,404

Transmission fugitives

Similar to distribution fugitives, transmission fugitives are based on a deemed benchmark. We apply Method 1[97] where emissions are calculated based on the length of the pipeline and multiplied by the sum of the emissions length factors for carbon dioxide (0.02 tCO2e/km) and methane (11.60 tCO2e/km).

Table 3.3 Calculation of transmission fugitive emissions 2022-23 (tCO2e)

Pipeline length[98]	Composition factors (tCO2e/KM)	Emissions
1,873	11.62	21,768

Fleet

Fleet emissions are calculated on the number of litres of fuel used multiplied by emissions factors in the NGER.[99] In 2022-23 we incurred 2,723 tCO2e related to fleet.

[94] See Division 3.3.8 – Natural Gas Distribution (other than emissions that are flared) of the National Greenhouse and Energy Reporting (Measurement) Determination 2008. Available here.
[95] Due to meter accuracy (e.g. +/- 2% for our volume market customers), metrology errors (e.g. assumptions round the heating value of gas required as gas is measured on a volumetric basis but converted to energy for billing purposes), timing differences are we read meters quarterly and where we cannot access and must estimate consumption.
[96] Transmitted through our distribution pipelines. Excludes supply to customers supplied directly from the transmission pipelines which form part of JGN.
[97] See Division 3.3.7 – Natural gas transmission (other than emissions that are flared) of the National Greenhouse and Energy Reporting (Measurement) Determination 2008. Available here.
The NGER includes a higher-order method (method 2) where emissions are calculated on the basis of emissions factors for individual equipment types, number of units etc.
[98] Pipelines with maximum design pressure exceeding 1,050 kPa
[99] See Part 3 - Fuel

Water Bath Heaters

Water Bath Heater emissions are calculated using the emissions factors in the NGER. Specifically, item 17 in Part 2 of Schedule 1 which specifies emissions factors of:

1. 51.40 kg CO_2e/GJ for carbon dioxide (CO_2),
2. 0.10 kg CO_2e/GJ for methane (CH_4); and
3. 0.03 kgCO_2e/GJ for nitrous oxide (N_2O).

Our calculations for 2021-22 Water Bath Heater emissions are shown in Table 3.4.

Table 3.4 Water Bath Heater emissions 2022-23 (tCO2e)

Gas used (GJ)[100]	Emission factor (tCO2e/GJ)	Emissions
18,039	0.05153	930

If we were able to procure biomethane the emission factor would have been 0.00013 tCO2e/GJ and result in only 2.3 tCO2 emissions.

[100] Pipelines with maximum design pressure exceeding 1,050 kPa

Appendix B Safeguard Mechanism

Baselines

Baselines for each facility are determined using a three-step process:

- Using a production-adjusted (intensity) approach which allows baselines to grow and fall with production. For JGN, this means that the baselines vary depending on the amount of natural gas delivered and length of the pipeline.

- Using a hybrid model to apply emissions intensity values. Initially the baselines are weighted towards the use of site-specific emissions intensity values (based on a facility's historical emissions) and transition to a 'default' approach (which represents the industry average) values by 2030.[101] This is shown in Table 3.5.

- Decline by 4.9% per year until 2030 to achieve the aggregate emission reduction targets.

Table 3.5 Ratio of industry and site-specific emissions intensity factors

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Industry average: site specific	10:90	20:80	30:70	40:60	60:40	80:20	100:0

Calculating JGN's baseline

JGN's industry average and site-specific intensity factors are shown in Table 3.6. The industry average emissions factors are determined in the National Greenhouse and Energy Reporting (Safeguard Mechanism) Rule[102] while the site-specific factors are based on the middle three of the most recent five years of reported emissions data (between 2017-18 and 2012-22). For the transmission component of our network the factors are identical. However, for the distribution component the industry average emissions intensity factors are 44% higher, as JGN's emissions have been materially lower than the industry average emissions intensity factors.

Table 3.6 JGN's industry average and site-specific emissions intensity factors

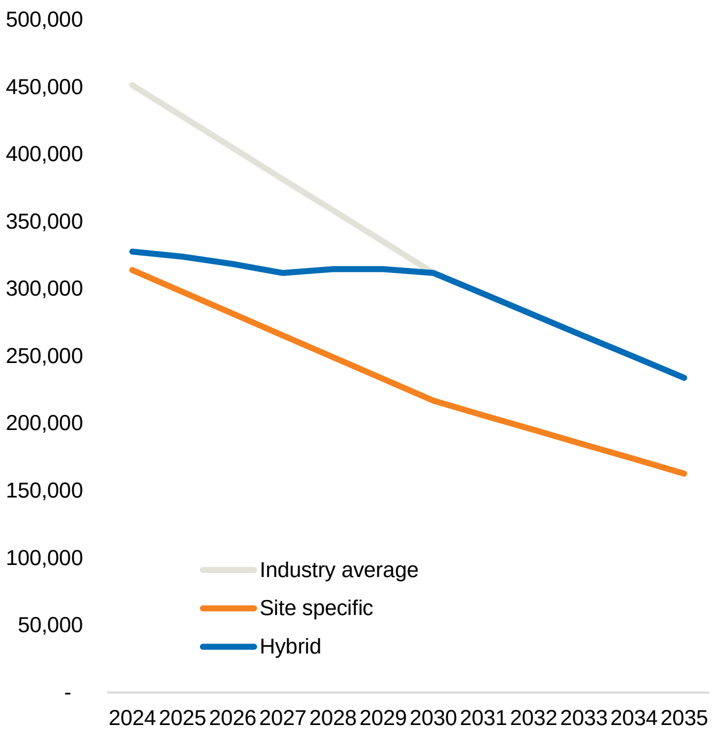
	Industry Average	Site Specific
Gas distribution (PJ.km)	0.254	0.173
Gas Transmission (km)	11.62	11.62

As shown in Figure 3.7, while the safeguard mechanism reduces baselines by 4.9% each year – a cumulative reduction of 34% by 2030 – these reductions are mostly offset for JGN due to the hybrid approach to setting the baseline. Shifting to an industry average (rather than site-specific average) increases the baseline by 44%. The net change to 2030 is a 6% reduction in the baseline (before forecast changes to the production factors – line length and throughput).

As the transition to the industry average emission intensity factors ends in 2029-30, the required reductions increase. We note that the default decline rate for the years after 2029-30 (3.285%) is a default rate to achieve net-zero by 2050 (i.e. the baseline goes to 0 in 2050).[103] The actual decline rates which will apply for the 2030-31 to 2034-35 period will be set by 1 July 2027.

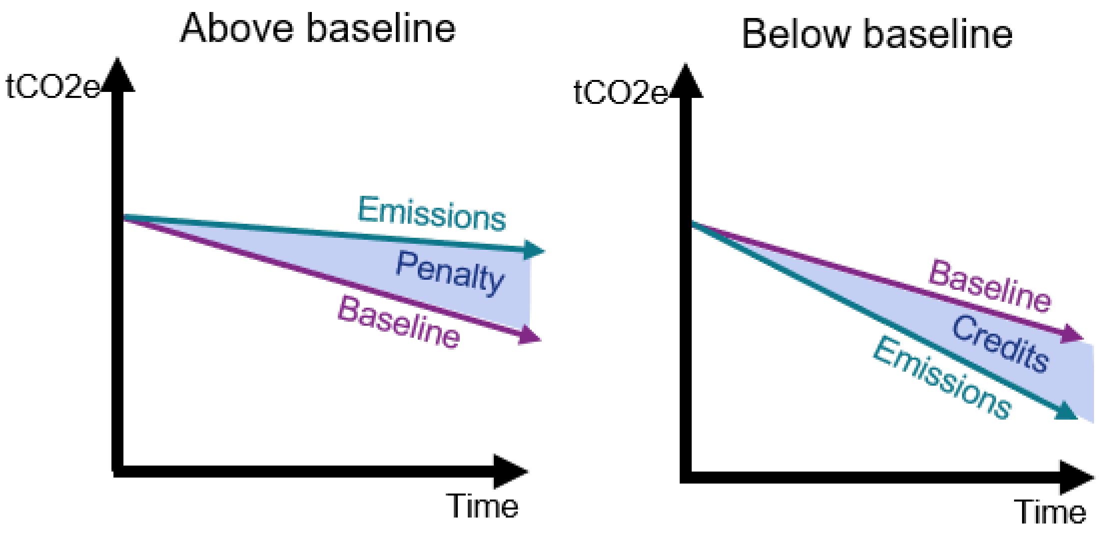
[101] The policy intention is to ensure long term policy settings are efficient (as the government considers industry average baselines provide an incentive for production to occur where emissions are lowest) while introducing obligations in manageable increments to give businesses sufficient time to plan and implement emission reduction projects See: 2023 Department of Climate Change, Energy, the Environment and Water, *Safeguard Mechanism Reforms Factsheet*, Available here.
[102] See Part 27 and 28 of Schedule 1 here.
[103] See Div 5 of the National Greenhouse and Energy Reporting (Safeguard Mechanism) Rule 2015

Figure 3.6 JGN's safeguard baseline (tCO2e)



From an economic point of view, whether total emissions exceed the baseline or not doesn't affect the incentive to reduce emissions. The baseline only determines whether this incentive is in the form of a penalty (and the need to buy ACCUs or SMC) or a credit (where an SMC is automatically granted and can be sold), as shown in Figure 3.7.

Figure 3.7 Application of the safeguard mechanism



ACCU / SMC price forecasts

Projecting the value of ACCU's (and SMCs) is challenging. As with all markets, prices will depend on demand (including businesses not captured by the Safeguard Mechanism who have set net-zero targets) and supply for ACCUs.

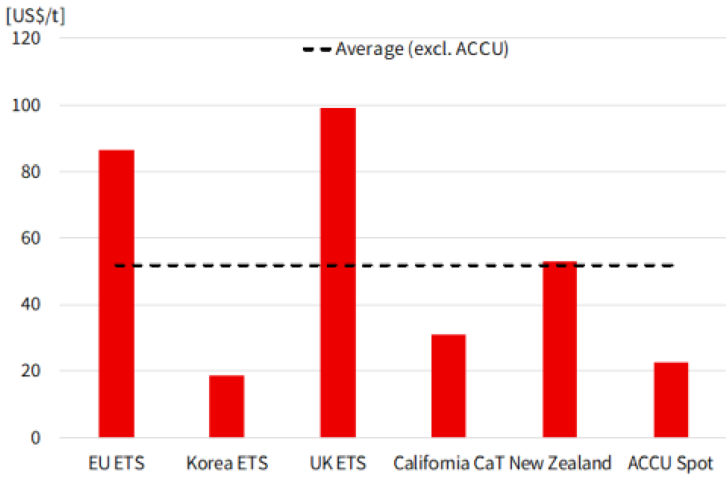
Both demand and supply will be affected by:

- Company specific emission reduction goals including the degree to which ACCUs are purchased relative to other measures such as emissions avoidance. This will be guided by feedback from shareholders, customers, and other stakeholders as business seek to meet public expectations around emission reduction.
- Carbon abatement cost curves. It is unclear how the costs to reduce carbon emissions will change over time as each facility adopts the most cost-effective measure first. This factor will play an increasing role as the baselines reduce each year, eventually down to zero in 2050.
- Technological advancements which could lower the cost of carbon abatement. Technological changes would reduce demand and increase supply of ACCUs.
- Regulatory changes including potential amendments to the Safeguard Mechanism (for instance the supplementary mechanisms to target methane flagged in section 1.3), changes to the post-2030 decline rates or changes to measurement and reporting methodologies.
- Broader economy market factors – for instance if the level of production increases this will result in a higher level of emissions and require sharper reductions to achieve net-zero.

Given these factors, the price of ACCU's has been volatile. The price of ACCU's peaked in January 2022 at a price of $57.[104] Over 2023 the price varied from an average of $36.42 over January to June, dropped to a low of $24.00 on 10 July 2023 then recovered to average $30.67 over July to December. ACCU prices in January 2024 were around $35.[105]

As the Department of Climate Change, Energy, the Environment and Water has noted ACCU price forecasts are highly uncertain.[106] Several forecasters expect ACCU prices to significantly rise due to tightening legislated limits, increasing abatement costs, increasing adoption of net-zero targets and the relative price of carbon in Australia relative to comparable carbon markets (as shown in Figure 3.8).

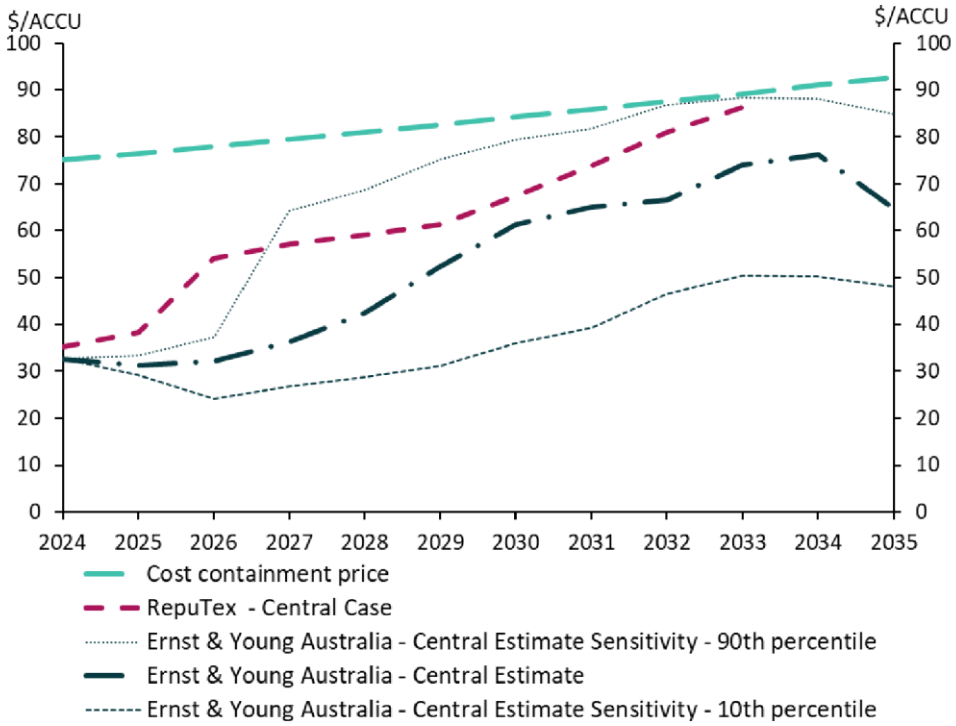
Figure 3.8 NAB Comparison of key carbon market prices in January 2023[107]



EY and Reputex have both forecast that the price for ACCU's will reach $60/tCO2e or higher by 2030[108] as shown in Figure 3.9 The cost containment price is the cap which limits the maximum price entities have to pay to meet compliance obligations under the Safeguard Mechanism.

[104] Clean Energy Regulator 2022, *Quarterly Carbon Market Report March Quarter 2022*, Available here.
[105] Clean Energy Regulator 2024, *Quarterly Carbon Market Report December Quarter 2023*, Available here.
[106] Department of Climate Change, Energy, the Environment and Water 2023, *Australia's emission projections 2023,* p.32 Available here.
[107] NAB 2023, *NAB Carbon Research: ACCU prices set to soar*. Available here.
[108] S&P Global Commodity Insights, *Australia's carbon credit demand to surpass issuances in 2028 as compliance tightens*, November 2023. Available here.

Figure 3.9 Forecast ACCU Prices by Market Analysts, 2024 to 2035 ($2024)[109]



For this submission, we forecast ACCU prices based on forward trade prices over the 2024 to 2027 financial years obtained in October 2023 as shown in Table 3.7.[110] To forecast prices beyond 2027 we assumed annual yearly linear growth interpolated between 2024 and 2027 to determine an annual growth rate of 2.65%. This was then applied to forecast prices to 2053.

Table 3.7 JGN's industry average and site-specific emissions intensity factors ($nominal).

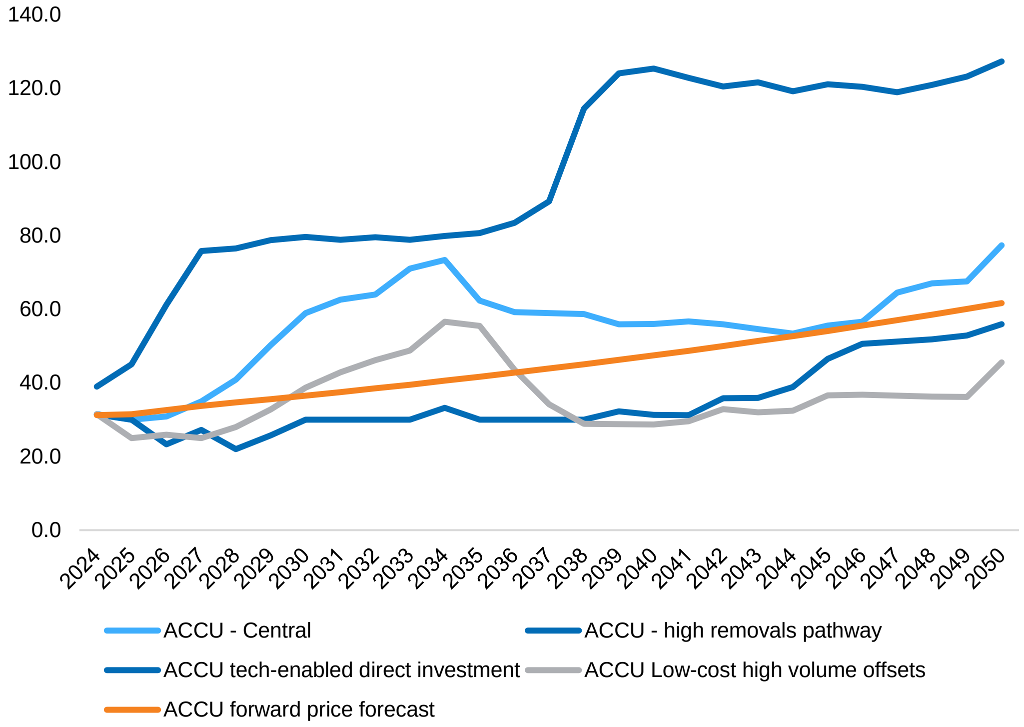
Financial year	Price ($nominal)
2024	31.25
2025	32.30
2026	34.25
2027	36.40

For reference, current spot prices for ACCU as of 20 June 2024 are $34.25.

A comparison of our forecast and EY's scenarios are shown in Figure 3.10. This illustrates how our forecast is lower than all but one of the EY scenarios (except the low-cost high-volume scenario) and in turn lower than the forecast produced by Reputex.

[109] Department of Climate Change, Energy, the Environment and Water 2023, *Australia's emission projections 2023,* Figure 17 Available here.
[110] This data was obtained from demand manager, see here.

Figure 3.10 ACCU price projections ($2025) [111]



[111] EY 2023, *Australia's carbon market is changing gears. Are you ready?* Available here.