Jemena Gas Networks (NSW) Ltd

Revised 2025-30 Access Arrangement Proposal

Attachment 4.2

Renewable gas expenditure

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Overview

Jemena welcome the opportunity to help enable the decarbonisation of the energy sector. Whilst many technology improvements and innovation will occur to support this migration, the easiest and quickest solution involves minimal retrofitting and capital by simply replacing the existing natural gas with renewable gas. This will ensure customer cost impact is minimised, whilst benefit realisation timelines are short and efficient in deployment. Our customers, in consuming gas, 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.

The Federal and State Governments are showing support for renewable gases at a rapid rate. Since the Initial 2025-30 Proposal was submitted, the NSW Renewable Fuel Strategy and the VIC Government's Renewable Gas Directions Paper have all been released and all show support for renewable gases now and into the future.

Our Initial 2025 Plan proposed to facilitate 6.7PJs of renewable gas into our network, decarbonising 8% of the energy we transport by 2030. This will support our customers in achieving their emission reductions goals and reduce emissions by 0.35 MtCO2e a year by 2030. Our innovative approach will deliver 0.4% and 1.0% of the reductions needed to achieve the Australian and NSW government's 2030 emission reduction targets.

Our proposal is consistent with the recent changes to the NGO and NGR that enables expenditure which reduces emissions to be recovered through regulated prices. In particular we justified our projects on the basis that they contribute to meeting emission reduction targets *and* that the overall economic value was positive (NPV of $1.34 billion).

In its draft decision, the AER noted that this was a new and complex area and at this stage indicated that it was not satisfied that the projects provided a net benefit. The AER indicated that it required further information and analysis before it could consider that the projects were justified on the basis of providing an overall positive economic value. Accordingly, the AER set a placeholder decision of zero. The AER also recommended that due to the renewable gas market uncertainty we should consider whether renewable gas capex is added to a speculative capex account in the revised proposal and the need for JGN to highlight the cohort of customers who will be the beneficiaries of renewable gas.

We acknowledge that this is a new and complex area and appreciate the AER's engagement to date on this critical initiative.

Our renewable gas projects are essential to unlocking a gas decarbonisation pathway for our customers. As recognised by the Australian Government and the ACCC,[1] there are no technically or commercially feasible alternatives to gas for some manufacturing and chemical processes (70% of our industrial load). For example, electricity cannot currently provide an economical solution for high heat industrial processes and cannot replace gas as a feedstock for chemical processing. As noted by the ACCC, reducing emissions in these areas requires technological advancements – such as our innovative proposal to facilitate the production of renewable gas. Accordingly, our proposal has material implications for the Australian economy as a whole. Our renewable gas projects avoid placing additional cost and operational pressures on the electricity system and will reduce the economy-wide demand for (and in turn lower the price of) offsets required to achieve net-zero.

We also note that the facilitation of renewable gas into JGN will provide wider market benefits. The ACCC has found the east coast gas market needs to be well supplied to support reliable energy and an orderly transition to a lower emissions environment. However, over the next two decades gas demand is expected to remain at high levels while east coast supply will be in decline and new supply is not being brought online fast enough. Renewable gas can help close this supply gap. We have considered the feedback provided by the AER and updated our analysis to address the concerns raised. For instance, to assess whether biomethane production is the most efficient use, we now take into account the counterfactual, where feedstock is used for electricity generation.

The outcome is unchanged. Our Revised 2025 Plan seeks to retain $79 million ($2025) renewable capex for the 2025-30 period. Our updated analysis continues to show that our projects deliver substantial economic benefits, increasing the total NPV to $3.35 billion. Accordingly, our projects continue to be justified – on the basis of *both*

[1] Australian Government 2024, Future Gas Strategy, p.20 Available here and ACCC 2024 *Gas inquiry 2017-2030* Interim update on east coast gas market, *December 2024.* p.4 Available here.

contributing to emissions reduction targets and providing an overall economic value – in turn meeting the conforming capex criteria in the Rules. This is unsurprising given that emissions reduction benefits of using biomethane feedstock for electricity generation is low, given the projected reduction in emissions intensity of our electricity system.

Our Revised 2025 Plan also addresses the AER's concern around uncertainty of projects proceeding by putting forward a fixed principle, as an alternative approach to the speculative capex account. We are committing to adjusting our 2030-35 building block revenue to return to customers the revenue difference between our actual renewable gas project capex spend and the AER's capex allowance.

We have addressed the AER concerns around the assumptions and inputs of the business cases and consider that our proposed renewable capex is prudent and efficient and demonstrates:

- The economic value of the renewable gas connection projects of $1.34 billion for the original base case and $3.35 billion for our projects when using renewable electricity generation as the counterfactual base case, substantially outweighs the proposed $79 million ($2025) capex (see section 5.1).
- We consider the difference between the cost of producing biomethane compared to the production and transportation of natural gas to take a society wide view consistent with Rule requirements and best practice cost benefit analysis. We note that these benefits (of avoided natural gas production and transport costs) are likely to flow through to consumers, especially given it will result in additional supply in the currently tight and volatile east coast gas market.[2] (see section 5.2).
- There is a reliable, long-term availability of feedstock. Our projects will require less than 5% of total NSW feedstock available (see section 5.4).
- Byproduct valuations were carefully tailored to each project's unique production capabilities, with conservative pricing reflecting emerging market conditions (see section 5.5).
- Customers do not absorb project risk (see section 2 and 5.6).

As our renewable gas projects will deliver substantial economic benefits, help achieve emissions reduction targets and meet the conforming capex criteria, and are consistent with the NGO, we have made no changes to our proposed projects.

Our proposed approach to renewable gas connection capex for the 2025-30 period is set out with a focus on the following areas:

- Section 1: Compliance and justification under the NGR and NGO.
- Section 2: Fixed principle to alleviate risk to consumers of projects not progressing.
- Section 3: JGN customers best served by renewable gas.
- Section 4: The evolving international, federal and state government policy environments in favour of renewable gas.
- Section 5: Response to the AER feedback on the inputs and assumptions in the business cases.
- Section 6: Response to stakeholder submissions.
- Section 7: Proposed revisions to the Initial Proposal AA to incorporate the fixed principle.

[2] ACCC 2024 *Gas inquiry 2017-2030* Interim update on east coast gas market, *December 2024.* p.7 Available here.

What is biomethane?

Biomethane is a sustainable alternative to natural gas.

It is described by the Clean Energy Regulator as "a methane-rich net-zero carbon emissions natural gas substitute produced from waste methane generated by organic waste"[3]. Biomethane has a chemical composition very close to natural gas and is often referred to as a drop-in fuel. This means it can be injected directly into the gas network without requiring upgrades of the gas infrastructure or consumer appliances. Whilst the biomethane industry is in its infancy in Australia it is widely used in international markets to displace fossil natural gas, leading to emissions reduction benefits, and supporting hard-to-electrify customers to remain economically viable and transition to net zero fuel sources, and reducing reliability on natural gas exports.

Australia's Bioenergy Roadmap[4] (The Roadmap) published by the Australian Renewable Energy Agency (ARENA) states that with targeted deployment, by the 2030s, Australia could see gas pipelines incorporating up to 105PJ per annum of renewable gas, accounting for 23 per cent of the total pipeline gas market[5]. JGN's proposal to connect 6.7PJ per annum of biomethane into the network by 2030 would constitute part of such a targeted deployment.

[3] Clean Energy Regulator, 2022 Biomethane Method Package Variations under the Emissions Reduction Fund | Clean Energy Regulator2022 biomethane method package variations under the Emissions Reduction Fund (17 March 2024)

[4] australia-bioenergy-roadmap-report.pdf

[5] note 13 at 10

1. Compliance and justification under NGR and NGO

As the AER is aware, clause 28 of the NGL requires that the AER must perform or exercise an economic regulatory function or power in a manner that will or is likely to contribute to the achievement of the NGO. The AER's draft decision states that the AER considers that JGN did not provide sufficient information to enable the AER to determine that the proposed renewable gas connections capex is 'justifiable'.

This section explains why the proposed renewable gas capex meets the 'justifiable' criteria and, in the event that the project proceeds, will be conforming capex under the NGR, as well as why it is consistent with the NGO.[6]

Rule 79(1) of the NGR provides that conforming capex is capex that:

- 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" (Rule 79(1)(a)); and
- is "*justifiable on a ground stated in subrule (2)"* (Rule 79(1)(b)); and
- must be "*for expenditure that is properly allocated in accordance with the requirements of subrule (6)*" (Rule 79(1)(c)).

Rule 79(2) sets out a number of elements used to determine whether capex is justifiable. Significantly, r79(2)(c)(v) specifically states that capex is justifiable if it is necessary "*to contribute to meeting emissions reduction targets through the supply of services*". The term 'emissions reduction targets' is defined to mean targets set by a participating jurisdiction for reducing Australia's greenhouse gas emissions or that are likely to contribute to reducing Australia's greenhouse gas emissions, including the targets stated in the 'targets statement' (set out by the Australian Energy Market Commission).[7]

The criteria in Rule 79(2)(c)(v) reflects the changes to the NGO made in 2023 to include the new emissions reduction objective in addition to the existing economic efficiency framework.

JGN's renewable gas projects facilitate network connection of renewable energy projects and supports the achievement of the targets for reducing Australia's greenhouse gas emissions set by both the Commonwealth and NSW jurisdictions, including by facilitating the production of 6.7PJ of biomethane for our customers, reducing emissions by 0.35 MtCO2e[8] per year and decarbonising 8.3% of the gas we transport by 2030. This is expected to contribute 1% (for NSW) and 0.4% (for Australia) of the reduction in emissions required to achieve the NSW and Australian 2030 emission reduction targets.

The capex required for JGN's renewable gas projects is therefore 'justifiable' under r79(2)(c)(v) as this spending is necessary to contribute to meeting emissions reduction targets through the supply of services. It is relevant to note that many industrial customers are unable to electrify, so the renewable gas connections provide them with a decarbonisation pathway.

In relation to the 'justifiable' criteria, r79(2)(a) also states that capex is justifiable if the overall economic value of the capex is positive, subject to subrule (3). Rule 79(3) states that in deciding whether the overall economic value of capex is positive, it is necessary to consider the sum of the economic value, other than of changes to Australia's greenhouse gas emissions, and 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.

[6] We also set out the changes to the NGO and the conforming capex criteria in section 1.4 of our emissions reduction strategy.

[7] National Gas Rules, r 3 (as at 19 December 2024) (Version 83).

[8] National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Schedule 1) biomethane Scope 1 Emissions Factor of 0.13kg CO2-e/GJ) vs Natural gas distributed in a pipeline Scope 1 Emission Factor 51.53 kg CO2-e/GJ.

The updated business cases for each of the eight renewable gas projects demonstrate that the capex is 'justifiable' under the criteria set out in r79(2)(a) as the overall economic value is positive relative to no investment in renewable gas and against the counterfactual use of the feedstock at each of the eight sites to generate renewable electricity.[9] The NPV of our renewable gas facilitation projects sums to $1.34 billion for the original base case assumptions and $3.35 billion for our projects when using renewable electricity generation as the counterfactual base case with the details of the NPV summarised in section 5.1.

Renewable Gas Business Cases

We engaged Frontier Economics to develop business cases for each of the eight renewable gas connection projects across the JGN network.

These business cases demonstrate that our proposed capex is justified under Rule 79(2)(a) as the overall economic value is positive, the NPV is greater than zero, and the benefit cost ratio is greater than 1, relative to the ‘no investment in renewable gas’ (Base Case), calculated in accordance with Rule 79(3).

In order to address the comments made by the AER in its draft decision, we have now also tested the counter-factual use of the feedstock at all eight of the facilities to generate renewable electricity.

The cost-benefit analysis (CBA) scenarios developed by Frontier Economics estimate 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[10]. 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[11], 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[12];
- 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[13]);
- Comparing costs and benefits over a long-term (30 years) and shorter term (24 years) modelling period[14] in present value terms;
- Using internally consistent and transparent input variables and parameters, while also accounting for uncertainty by creating “scenarios around the most likely scenario” [15] and testing different sensitivities for inputs that could have typical market variations;
- 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’ and electricity generation counter-factual scenarios).

[9] See JGN - Frontier - RP - Att 4.7M - Revised renewable gas project CBAM - 20241220.
[10] AER 2020, *Cost benefit analysis guidelines - Guidelines to make the Integrated System Plan actionable*. Available here.
[11] 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.
[12] AER 2020, *Cost benefit analysis guidelines - Guidelines to make the Integrated System Plan actionable*, p21, 36.
[13] Rather than the revenue stream that renewable gas suppliers may receive from the sale of ACCUs.
[14] 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.
[15] AER 2020, *Cost benefit analysis guidelines - Guidelines to make the Integrated System Plan actionable*, p11.

2. Fixed principle to alleviate customer risk of projects not progressing

> JGN proposes a balanced approach to renewable gas connection projects through ex-ante capex approval rather than using the speculative capex account. To address the AER's concerns about customer protection, JGN has introduced a fixed principle that would return revenue to customers if projects don't proceed. This approach provides crucial investment certainty to project developers whilst protecting customer interests, helping to unlock broader economic benefits and foster the development of the renewable gas market.

In its draft decision, the AER expressed concerns that if it approves capex on an ex-ante basis, customers may end up paying for renewable gas connection projects that do not proceed. It suggested that JGN could use the speculative capex account for these projects in lieu of it approving an ex-ante capex allowance.

We have concerns with this approach—the speculative capex account provides little regulatory certainty as it effectively defers the AER's assessment of this capex until the next price review process. As the ACCC identified, long-term regulatory certainty and investment is essential for gas security in the energy transition. The ACCC recommended that State and Commonwealth Governments reduce regulatory barriers to investment to ensure that new supply can be delivered in a timely fashion.[16] Applying the speculative capex account would delay a decision on whether the AER considers our innovative program meets the conforming capex criteria and in turn create a regulatory barrier to investment and prevent 6.7 PJs of gas being supplied to the east coast gas market.

Furthermore, we submit that in our businesses cases we have provided strong evidence that this expenditure is capable of meeting the capex criteria within the NGR, and is consistent with the NGO. Noting that the renewable gas industry is still in its infancy, it is imperative that the right investment signals are provided to customers, JGN, and the proponents of these projects, that this type of expenditure, when demonstrated to be prudent and efficient and consistent with rule requirements, will be approved within the regulatory framework.

The proposed renewable gas connections capex will facilitate renewable gas projects' connection to the network and bolster certainty of market access for project developers. By having this offtake certainty, project developers have informed JGN that this will lower their cost of capital and unlock significantly more economic benefits than just the cost of the JGN connection alone. Accordingly, AER approval of the renewable gas connection capex would assist to provide investment certainty to the project developers and to derisk their capex, giving them access to a diverse offtake market. Without AER approved connections to our network, the project developers will not have any certainty around market access, impeding their ability to obtain long term offtake agreements. This will continue to stifle the renewable gas market and the development of all the associated emission reduction product markets.

To address AER concerns that customers may end up paying for renewable gas projects that do not proceed, we have proposed a fixed principle within our 2025-30 Access Arrangement as an alternative approach to the speculative capex account. The fixed principle requires us to adjust our 2030-35 building block revenue to return any 2025-30 building block revenue relating to any renewable gas connections projects capex not incurred by us (i.e. the return on capital, return of capital, and tax allowance). If we spend more capex on renewable gas connections projects than provided for in the AER's allowance, then the fixed principle would not apply and the AER's general incentive mechanisms would apply as normal to the capex spend as part of our total capex spend. Refer to section 7 for further details.

[16] ACCC 2024 *Gas inquiry 2017-2030* Interim update on east coast gas market, *December 2024.* p.8 Available here.

3. JGN customers best served by renewable gas

More customers than just the “hard-to-electrify” will be the beneficiaries of renewable gas. Those that are hard-to-electrify, costly-to-electrify and who have a desire for gas have all indicated wanting access to a decarbonisation pathway using renewable gas and therefore will be the beneficiaries and best served by the renewable gas connections. The demand from this cohort far exceeds the 6.7PJ of biomethane JGN proposes to connect to the network in the 2025-30 period.

The AER in its draft decision and feedback to the Initial 2025 Plan noted that:

> *JGN needs to address which cohort(s) of customers are best served by renewable gas connections. As noted in section B.2.1, submissions stated that the most suitable market for biomethane gas would be hard-to-electrify consumers. The size of this cohort is uncertain, and JGN would need to quantify it in its revised proposal.*

JGN delivers services to over 1.5 million customers that utilise natural gas for a multitude of end-use applications including heating, cooking, hot water, industrial heat, feedstock and gas-fired electricity generation. These customers vary in size and are commonly referred to as demand market or volume market customers.

Our customers, in using gas transported through our pipeline, emit 4.31MtCO2e a year.[17] This makes up about 4% of NSW (111MtCO2e) and 1% of Australian emissions (433MtCO2e).[18]

JGN categorises customers into Industrial, Commercial and Residential. These customer types, estimated connection numbers, and total demand are outlined in Table 3.

Table 3: Jemena customer overview

Customer Type	Total Customers	Volume (PJ)
Residential	1,490,490	26.8
Commercial	34,214	13.0
Industrial	379	44.1
Total	**1,525,083**	**83.8**

Note: Totals may not sum due to rounding.

As can be seen in **Error! Reference source not found.**, whilst residential customers represent our largest c ustomer base, the consumption of natural gas by these customers is significantly less than the industrial customer demand which typically contains our hard-to-electrify customers. Whilst this cohort of customers need renewable gases to decarbonise, we do not see this cohort of customers as the only beneficiaries of renewable gas. We also consider the costly-to-electrify and the desire for gas customers as likely offtakes of the biomethane. The 6.7PJ of biomethane generated by the eight renewable gas projects could be utilised across multiple sectors, and the demand in this regulatory period and beyond will outstrip the supply potential as outlined in the following sections.

3.1.1 Hard-to-electrify customers

JGN internal research estimates that of the 44.1PJ of industrial gas demand, around 70% of these customers (30.9 PJ) are classified as hard-to-electrify as they require a gaseous molecule to either combust for high heat processes (such as the production of steel, cement, glass, ceramics, bricks), utilise as a feedstock in the creation of their product (such as fertiliser, ammonia, explosives, petrochemicals), or for gas fired electricity generation. If renewable gases are not made available to hard-to-electrify customers connected to the gas network, there is no

[17] Calculated using throughput in 2023-24 (83.5PJs) 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.
[18] NSW and Australia emissions are from 2022, the most recent year available from Australia's National Greenhouse Accounts, available here.

alternate viable decarbonisation pathway currently identified and therefore their continued operation in NSW and more broadly Australia will be limited. Many of these companies are covered by the Safeguard Mechanism[19] and other mandated disclosure and voluntary scope 1 decarbonisation frameworks. Without renewable gases they will be forced to pay penalties, and in turn this could lead to non-viable economic outcomes.

The federal governments Future Gas Strategy acknowledges this, stating that to achieve net zero globally, Australia will need gas to:

- Support renewable generation.
- Process critical minerals.
- Help lower emissions in steel and cement.
- Produce fertiliser.
- Manufacture the products we need to build a net zero economy.

The 6.7PJ of biomethane that the renewable gas connection projects would deliver will ensure that the above forementioned industries can continue to have a reliable, decarbonised gas future. As these customers have government mandated emissions reduction targets they will likely have the highest willingness to pay and therefore will be the first adopters of biomethane.

As outlined in Attachment 8.1 Pricing of our Revised 2025 Plan, we are proposing to gradually increase the revenue proportion we recover from our demand customers to enhance the cost reflectivity of our tariffs. Increasing the revenue that we recover from demand customers means that they will pay for a greater share of the costs associated with the renewable gas connection projects.

3.1.2 Costly-to-electrify

There is a large cohort of JGN customers that theoretically have an electrification pathway, however, it is extremely cost prohibitive. These customers are therefore not considered hard-to-electrify as there is a potential pathway for them to electrify, but currently this is not an economically feasible pathway. These customers will also be the beneficiary of the biomethane distributed using existing natural gas infrastructure. Examples of customers that fall into this category are food manufacturers, hospitals, universities, dry-cleaners, bakeries and crematoriums. The barriers are not only financial for these customers, but also practical, such as competing needs for space (e.g. for storage hot water systems in apartments and townhouses), new electricity infrastructure requirements such as substations and transmission lines adding to cost, and their usage patterns not being matched with renewable electricity generation sources.

Our internal research with this customer cohort suggests that a decarbonisation pathway using renewable gas is far more cost effective for these customers, and can have more immediate emissions reduction benefits, than alternate decarbonisation pathways identified. As their gas demand is often a small portion of their overall energy costs, and the benefits they receive from having decarbonised products can be high, they likely have a high willingness to pay for renewable gas and could also be early adopters of the biomethane market. These customers fall into both our demand and volume customer markets depending on their end use application and volume requirements.

3.1.3 Desire for gas

The customer category that has a desire for gas into the future are those that the Future Gas Strategy defines as *"having a choice in how their energy needs are met"*. These customers have a defined electrification pathway; however they have a preference for gas. An example of these customers are commercial businesses and residential households that could convert to induction cooking appliances but have a preference for gas e.g. Chinese and Italian restaurants, or households that want to continue to have access to unlimited hot water.

[19] Safeguard Mechanism | Clean Energy Regulator

During our engagement with our customers, we heard that they value diversity in their energy supply, and the ability to choose gas. As there are currently no policies in place in NSW that mandate the electrification of gas in any sector or for any end user, it is likely that this part of our customer base will continue to have a requirement for gas, although likely have a lower willingness to pay, so will be later adapters of renewable gas.

Furthermore, biomethane injected into gas networks could also unlock new demand from market customers who want to decarbonise using renewable gas, such as those switching from coal to gas to meet emissions reduction targets (as identified by the Future Gas Strategy[20]), or biorefineries that could use biomethane to produce other renewable fuels such as Synthetic Aviation Fuel (SAF). The development of new long-term demand customers on the network will assist with reducing stranding asset risk into the future.

[20] Australian Government 2024, Future Gas Strategy, p.15 Available here

4. The evolving international, federal and state government policy environments support renewable gas

Since the Initial 2025-30 Proposal was submitted there has been significant policy announcements that demonstrate support for renewable gases and highlight that they will be required now and into the future. This fast paced political traction along with the exponential growth experienced in the international market all help to promote the renewable gas market in Australia and derisk investments. With added regulatory certainty this will give the industry the green light to indicate that Australia is open for business.

4.1 Australian policy landscape

> Both the NSW and Federal governments are actively shaping policy to support renewable gases (biomethane and hydrogen) as crucial elements in Australia's energy future. Through the 2024 Future Gas Strategy and NSW's Renewable Fuel Strategy, there's clear policy direction towards maintaining flexible gas infrastructure whilst enabling decarbonisation. This policy landscape supports JGN's proposal to connect renewable gas projects and aligns with the NGO for efficient, consumer-focused investment in gas services.

Feedback received to the Initial 2025-30 Plan called for the NSW Government to "*give clear policy direction in NSW as to the future of the domestic gas networks*"[21] and that "*the AER have indicated that they both explicitly look to the NSW government for leadership in shaping this access arrangement*"[22].

The renewable gas policy landscape in Australia is constantly evolving to be more supportive of renewable gases. Since our Initial 2025-30 Plan there have been multiple government announcements in support of renewable gases and promoting the necessary role gas will play in the energy transition.

The ACCC Gas Inquiry 2017-2030 was released in January 2025 and states: [23]

> *Natural gas will play a critical role in Australia's transition to lower emissions. As we increasingly rely on renewables for electricity generation, gas will be required to support energy security, reliability and affordability, while remaining an important source of energy and feedstock for residential, commercial and industrial users (C&I) ,*

The NSW Renewable Fuel Strategy consultation occurred in August 2024. This strategy included both biomethane and hydrogen and contained a myriad of possible government policies that would aim to achieve NSW's emissions reduction targets, decarbonise hard-to-electrify sectors, drive economic development and improve fuel security in NSW[24]. The possible policies consulted on included the introduction of a renewable gas target, utilising the existing Renewable Fuel Scheme currently for hydrogen and expanding it to include biomethane, contracts-for-difference and feed-in-tariffs to close any gaps there might be in the commercialisation of renewable fuels, and utilising governments buying powers to procure the first renewable fuels developed.

The Victorian government, whose policy previously was all aimed at the electrification of gas demand, in December 2024 released Victoria's Renewable Gas Directions Paper[25]. This highlights the need for biomethane and hydrogen now and into the future. The discussion paper proposes a renewable gas target aimed at the decarbonisation of hard-to-electrify sectors.

These recent policy announcements all align with the Federal Governments Future Gas Strategy (Strategy)[26] released in May 2024. The Strategy states:

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[21] Justice and Equity Centre – Advice to the AER – Jemena Gas Networks access arrangement 2025-30: Issues paper – September 2024

[22] Rewiring Australia - Jemena Gas Networks' (NSW) access arrangement proposal – September 2024

[23] Australian Government 2024, Future Gas Strategy, p.20 Available here and ACCC 2024 *Gas inquiry 2017-2030* Interim update on east coast gas market, *December 2024.* p.4 Available here.

[24] Building a thriving renewable fuel industry in NSW | NSW Climate and Energy Action

[25] Victoria's Renewable Gas Directions Paper | Engage Victoria

[26] Department of Industry, Future Gas Strategy (Report, May 2020)

> *continued gas development and more flexible gas infrastructure is needed to increase the resilience of Australia's energy system and that whilst gas supply will gradually support a shift towards higher-value and non-substantiable gas uses, households will continue to have a choice of how their energy needs are met". It also acknowledges that "decarbonising natural gas use in Australia will need the replacing of natural gas with low emissions gases such as biomethane.*

These strategies and consultation papers demonstrate that low emissions gases such as biomethane and hydrogen are central to the decarbonisation of gas use. It is clear that both Federal and State governments are supportive of renewable gas projects and will continue to advance renewable gas when making energy policy into the future. This supports JGN's proposal to connect renewable gas projects to the network.

We consider that the introduction of renewable gas into gas networks is consistent with the NGO and will promote efficient investment in covered gas services for the long term interests of consumers, being aligned with the energy forecast outlook and policies expected of both Federal and State governments now and into the future.

JGN concludes that there is policy support for both natural gas and renewable gases into the future and that this is what is giving project developers the investment confidence to develop renewable gas projects to connect into the JGN network. This confidence is underpinned by evidence from mature international biomethane markets as described in section 4.2 below.

4.2 International renewable gas market

> With over 1,400 facilities in the EU and 442 in North America, biomethane is a proven, rapidly expanding industry globally, growing 20% annually. This established track record—particularly the EU's ambitious target to increase production from 152 PJ to 1,330 PJ by 2030—provides a strong blueprint for Australia's biomethane development, reducing implementation risks through demonstrated success in mature markets.

Renewable gases, particularly biomethane, are becoming increasingly critical in global efforts to reduce emissions, and increase circular economy benefits of what were once considered waste streams. In mature markets around the world biomethane has been produced for over 15 years, demonstrating that whilst this is a new initiative in the Australian context it is a proven and an exponentially growing industry in advanced energy markets across the world. Globally, supply and production of biomethane is increasing by about 20 per cent per year.[27] This is where biomethane can be delineated from other renewable fuels in that the technology is existing and proven in many energy markets and shown to enhance the energy transition. This also reduces risks associated with the development of this nascent industry as there are global models that can be followed, and we can adopt the lessons learnt from those models.

The European Union (EU) has set ambitious targets to increase its biomethane production from 152 PJ to 1,330 PJ by 2030.[28] Currently there are over 1400 biomethane facilities operating in the EU and research shows that over 75%[29] of these facilities are connected to either transmission or distribution gas networks, creating a valuable link from the project locations to the traditional natural gas markets. Denmark has the highest biomethane production capacity per capita of any country around the world with ambitions to replace it's natural gas with biomethane entirely by 2030[30].

In the United States and Canada, there are more than 442[31] operational biomethane facilities with a further 170 under construction and 285 planned. The majority of these projects are located in California which has set an ambitious target of 78 PJ by 2030, representing 12.2% [32] of its natural gas throughput. The majority (67%) of North American biomethane projects are from municipal solid waste feedstock sources, including landfill gas sites, with agricultural feedstock growing to 25%, largely over the past five years. Landfill gas projects that were previously producing renewable electricity are also converting to biomethane production as electricity networks

[27] CEDIGAZ 2023, *Global Biomethane Market - 2023 Assessment,* p.4 Available here.
[28] European Biogas Association 2024, *Biogases towards 2040 and beyond, A realistic and resilient path to climate neutrality* p.3 Available here.
[29] GIE_EBA_BIO_2024_A0_FULL_114
[30] European Commission 2021, *Biomethane Fiche – Denmark (2021).* Available here.
[31] RNG+Facility+Map+(NA)+20241205_squarespace2.jpg (2500×1281)
[32] California Public Utilities Commission *Decision implementing senate bill 1440 biomethane procurement program*, p.34 Available here.

decarbonise, and the emissions reduction benefits of renewable electricity generation from landfill gas decrease. Currently 20% of all landfill sites in the United States are producing Renewable Natural Gas (biomethane).[33]

[33] Basic Information about Landfill Gas | US EPA

5. Response to the AER feedback on the inputs and assumptions in the business cases

> Under all sensitivities tested by JGN the economic benefits for both the original base case and the counterfactual use of the biogas resource to generate electricity, are positive (positive NPV and BCR > 1). Demonstrating that the eight renewable gas business cases are robust and the capex is prudent and efficient.

In its draft decision, in *Attachment 5 – Capital Expenditure Part B Renewable Gas Connections*, *Confidential Appendix D*, and via in-person feedback to JGN, the AER has highlighted concerns around the renewable gas business cases and the assumptions used to generate both the costs and benefits. In this section we address the AER's concerns by assessing further scenarios and base cases.

JGN engaged Frontier Economics to review the AER's feedback and assess further scenarios that address specific concerns raised by the AER. Frontier Economics has:

- Tested the counterfactual use of the feedstock to generate renewable electricity and the emissions reduction benefits from this scenario (section 5.1):
  - Using biogas to produce biomethane, rather than generating electricity, delivers greater long-term value. This is because biomethane will continue to reduce emissions throughout its lifecycle, while biogas-generated electricity will increase emissions after 2034 as the grid becomes dominated by cleaner renewable sources.
  - The economic analysis demonstrates that all eight projects show stronger financial returns when compared to electricity generation, validating that biomethane production is the most efficient use of this valuable renewable resource.
- Tested a price sensitivity for the forecast natural gas price at a reduction of 20% to further represent the production value over the 'market price' (section 5.2):
  - JGN's use of $11/GJ as the natural gas price forecast in its business cases represents a conservative approach that likely understates the benefits of the renewable gas connection projects. This price point aligns more closely with producer costs than current market prices, as evidenced by ACCC Gas Inquiry data showing significantly higher market offers for 2025 supply.
  - Even with a sensitivity analysis reducing the price to $8.65/GJ, all business cases maintain positive economic outcomes.

[redacted]

[redacted]

- Reduced the asset life of all eight projects by 6 years to demonstrate they are still viable if feedstock resources are not available post 2047 (section 5.4):
  - The eight biomethane projects demonstrate strong economic viability even with a shortened operational lifespan of 18-20 years (reduced from 24-26 years). All projects maintain positive NPV and BCR above 1.

- Completed a sensitivity analysis of the digestate and biogenic CO_2 prices used in the business cases (+-20%) (section 5.5):
  - Not all biomethane projects will produce marketable byproducts (biogenic CO2 and digestate) due to differences in production processes and feedstock composition. Where byproduct value is included in project assessments, pricing assumptions were conservatively derived from producer-provided ranges, reflecting the emerging nature of these markets in Australia.
  - When digestate and biogenic CO_2 values are reduced by 20% all projects maintain a positive economic outcome.

These changes are detailed by Frontier Economics in the Technical Note found in *JGN - Frontier - RP - Att 4.7M - Revised renewable gas project CBAM – 20241220* (Technical Note).

The key outcomes from this report are highlighted in this section accompanied with details addressing further concerns raised by the AER.

5.1 Considering the counterfactual scenario where feedstock is used for electricity generation

> Analysis by Frontier Economics shows that using biogas to produce biomethane, rather than generating electricity, delivers greater long-term value. This is because biomethane will continue to reduce emissions throughout its lifecycle, while biogas-generated electricity will increase emissions after 2034 as the grid becomes dominated by cleaner renewable sources.
>
> The economic analysis demonstrates that all eight projects show stronger financial returns when compared to electricity generation, validating that biomethane production is the most efficient use of this valuable renewable resource.

In the business cases that were submitted as part of our Initial 2025 Plan, the base case stipulated that the feedstock was not currently utilised for any alternate purpose. In its draft decision, the AER requested that JGN should provide cost benefit analysis to test a counter-factual use of the feedstock to generate renewable electricity, and the emissions reduction benefits associated with this use. The AER noted:[34]

> *The business cases do not consider a counterfactual scenario where the feedstock (i.e. the biogas from decomposing organic material, that can be processed and converted to natural gas) can be used as an input for alternative emissions reductions methods. In particular, the feedstock can, and is, used for electricity generation, which would also contribute to emissions reduction. We consider JGN should provide cost benefit analysis of this counterfactual scenario to determine whether the biomethane production is the most efficient use of the feedstock*

Frontier Economics has prepared updated cost benefit analysis, with a counterfactual use of the feedstock to generate renewable electricity as the new base case for each of the eight business cases. The detailed assumptions and results for these scenarios can be found in *JGN - Frontier - RP - Att 4.7M - Revised renewable gas project CBAM – 20241220* and the summary of the BCR and NPV are shown in Table 5-1.

Table 5–1: Incremental value of project options under original base case vs waste to electricity counterfactual (central case)

Project	Metric	Original base case	Electricity generation counterfactual	Current use of feedstock
Lilli Pilli	**NPV ($2024M)**	[redacted]	[redacted]	

34 AER (2024), Draft decision: Jemena Gas Networks (NSW) Access Arrangement 2025 to 2030, Capital expenditure, Section B.3.

Project	Metric	Original base case	Electricity generation counterfactual	Current use of feedstock
	BCR		[redacted]	[redacted]
Kauri	**NPV ($2024M)**		[redacted]	[redacted]
	BCR		[redacted]	
Blue Gum	**NPV ($2024M)**		[redacted]	[redacted]
	BCR		[redacted]	
Red Gum	**NPV ($2024M)**		[redacted]	
	BCR		[redacted]	
Huon Pine	**NPV ($2024M)**		[redacted]	
	BCR		[redacted]	
Iron Bark	**NPV ($2024M)**		[redacted]	
	BCR		[redacted]	
Coolabah	**NPV ($2024M)**		[redacted]	
	BCR		[redacted]	
Wollemi	**NPV ($2024M)**		[redacted]	
	BCR		[redacted]	

The results in Table 5-1 show that when the base case for the use of the biogas is assumed to be electricity generation, as opposed to the original assumption of 'no current use', the economic outcomes and incremental value for biomethane generation are significantly higher. This suggests there is more value to the community from an alternative use or disposal of waste resources rather than electricity generation. This result may seem surprising, however, understanding the current renewable electricity market and the forecast emissions intensity of the NEM and biogas to renewable electricity generation, and the comparative levelised cost of energy (LCOE) of biogas to electricity vs biogas to biomethane demonstrates why these results were seen.

According to research published by ARENA, producing electricity from biogas is more expensive than producing biomethane. As there is currently only one grid injected biomethane facility in operation in Australia, the costs associated with production are largely estimates gained from international research and local project tendering responses. The most referenced source of biomethane production costs, when compared to other generation costs, comes from The Roadmap. This report highlights that[35]:

- Biomethane production from both landfill and anaerobic digestion are lower in cost than electricity produced from the same source.

The results from this report are summarised in Table 5-2.

Table 5–2: : LCOE $/MWH from Australia's Bioenergy Roadmap

Levelised Cost of Energy	Min ($/MWh)	Max ($/MWh)
Biomethane from landfill gas	**32**	**102**
Solar electricity	42	53
Wind electricity	52	65

35 bioenergy-roadmap-data-charts.xlsx

Levelised Cost of Energy	Min ($/MWh)	Max ($/MWh)
Biomethane from anaerobic digestion	**66**	**144**
Electricity from landfill gas	68	160
Electricity from wastes	70	231
1G Biodiesel	73	170
Electricity from biogas	82	243
Renewable diesel	84	202
2G Biodiesel	135	261
Hydrogen from electrolysis + grid electricity	**143**	**223**
Sustainable Aviation Fuel (SAF)	210	673
Hydrogen from electrolysis + dedicated renewables	**212**	**330**

Electricity generation from biogas provides only a short term benefit in emissions reduction. The graph in Figure 1 below demonstrates the Frontier Economics findings by showing the AEMO forecast emissions of the electricity network in blue and the emissions intensity associated with biogas to electricity generation in grey[36]. As can be seen in the graph, the emissions intensity of the NEM is forecast to be lower than the emissions associated with biogas to electricity generation from 2034 onwards, from which time generating electricity from biogas will be emissions adding not decreasing. This means that whilst the renewable gas projects would reduce emissions in the first few years of operation, they would not have emissions reduction benefits post 2034, as other renewable electricity generation sources with lower associated emissions, such as solar and wind with battery storage, come online in greater volumes.

Figure 1: Emissions intensity of the NEM vs biogas to electricity generation CO2-e/MWh

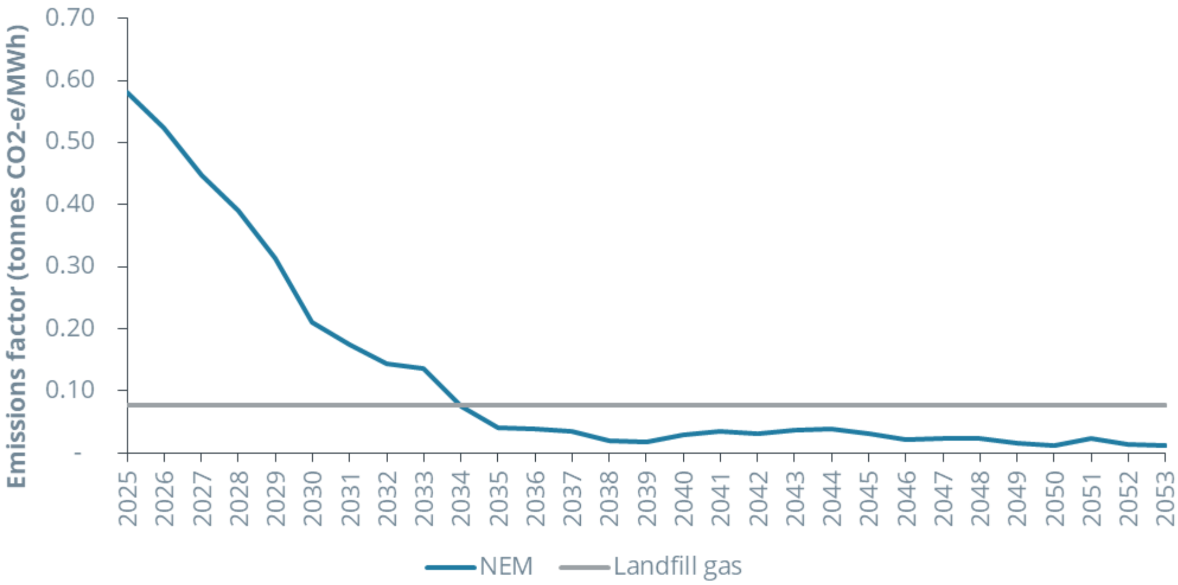
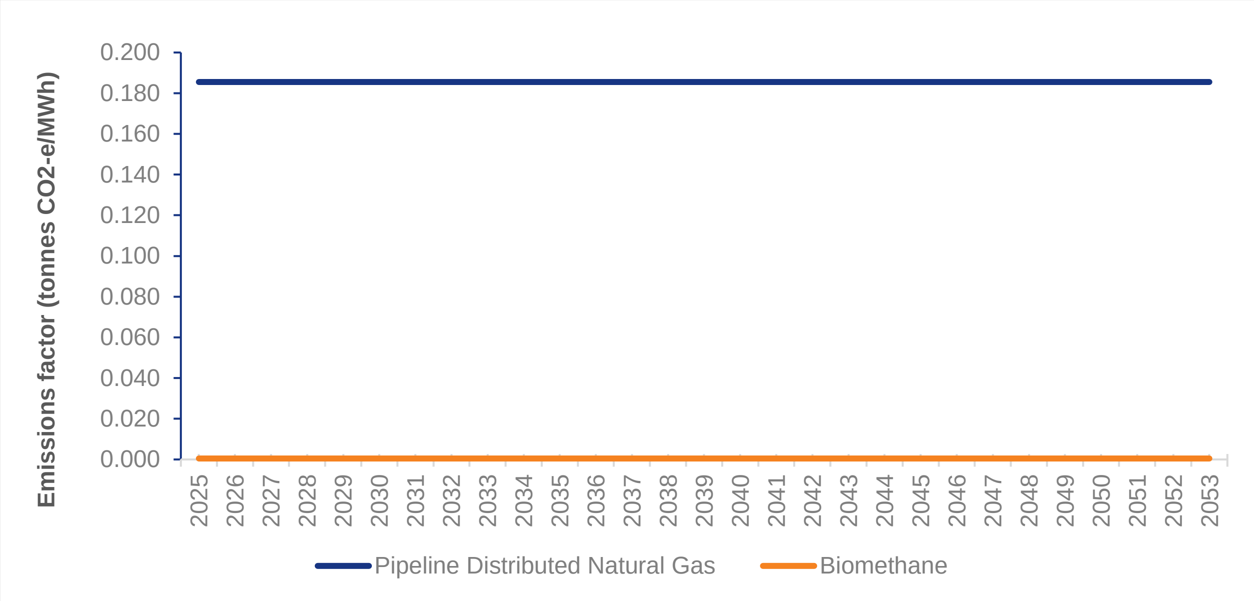


Figure 2 on the other hand, shows the emissions intensity of natural gas delivered through a pipeline vs biomethane emissions intensity factor[37]. Currently as there is no recognised emissions reduction pathway for natural gas delivered through pipelines the emissions intensity of natural gas is not forecast to decline, hence the biomethane emissions intensity factor will remain below the emissions of natural gas for the entire project lifecycle.

36 Australian National Greenhouse Accounts Factors

37 Australian National Greenhouse Accounts Factors

Figure 2: Emissions intensity of pipeline distributed natural gas vs biomethane (CO2-e/MWh)



The above results show that the project options ***are*** "genuinely facilitating a more efficient use of the feedstock for emissions reduction" and ***are not*** "simply transferring emissions reduction from one sector to another" [38]

The biomethane emissions reduction benefits over renewable electricity generation are recognised and reflected in the IASR[39] not including any new single-purpose biogas to renewable electricity generation projects in the 2025 assumptions outlook.

Market evidence points to the counterfactual scenario being unlikely in practice. The information we have received in the market is that there is a reduction in investments in renewable electricity generation from biogas at large scale (non-behind the meter electricity generation). This is driven by the opportunity cost of the baseline generation source that cannot be stored at times of the day when there is an abundance of renewable electricity from solar and wind in the grid. The cost to produce renewable electricity from biogas is above the price offered by the market, meaning the biogas is often flared or offered to the market at a loss. These findings also align with the feedback received from project producers who noted during discussions with the AER and JGN that the individual business cases are not viable when renewable electricity generation is the output. This explains why the eight projects are all focusing on biomethane injected into the network.

This change in the market was also recognised by the Clean Energy Regulator (CER) when it developed the ACCU generation method for biomethane from landfill and wastewater treatments facilities as an alternative use of biogas (where previously only an electricity generation method was available) [40].

Small scale behind the meter biogas to renewable electricity projects are still utilised where there is an onsite baseload demand for the electricity generation, but more importantly for heat and steam, required by the local facility's processes. These facilities are much smaller scale than the eight projects included within our 2025 Plan.

5.2 Revisiting JGN's valuation of the avoided cost of production and transportation of natural gas

In the draft decision the AER commented that:[41]

38 AER, draft decision: JGN access arrangement 2050 to 2030: Attachment 5- Capital expenditure: Confidential Appendix D, November 2024.

39 [AEMO | Draft 2025 Inputs Assumptions and Scenarios Consultation]

40 [Biomethane method package - simple method guide]

41 AER, draft decision: JGN access arrangement 2050 to 2030: Attachment 5 – Capital Expenditure, November 2024, p 29

> *A large proportion of the benefit of the projects is attributed to avoided transportation costs and re-saleable byproducts – we consider there are issues surrounding JGN's valuation of these benefits.*

Frontier Economics has addressed these specific concerns in section 2 of its Technical Note. In this section we give a high level overview of the Frontier Economics report and provide additional comments.

5.2.1 Natural gas producer costs vs market price of natural gas

> JGN's use of $11/GJ as the natural gas price forecast in its business cases represents a conservative approach that likely understates the benefits of the renewable gas connection projects. This price point aligns more closely with producer costs than current market prices, as evidenced by ACCC Gas Inquiry data showing significantly higher market offers for 2025 supply. Even with a sensitivity analysis reducing the price to $8.65/GJ, all business cases maintain positive economic outcomes.

The AER in the draft decision *Confidential Appendix D.1.2* has asked JGN to utilise natural gas producer costs instead of the *"market price at the city gate of $11/GJ"*, that was originally used in the business cases. Frontier Economics has detailed a response to this feedback in its Technical Note 2.1.1.

The assumption used in the business cases for the avoided production and transportation cost of natural gas are based on estimates of delivered gas prices from AEMO's 2023 IASR and 2024 ISP. The prices used are assumed delivered price of gas to industrial customers in NSW. These "bottom-up" commodity cost estimates are not representative of the "market price" (commercial willingness to pay) being paid by JGN customers under natural gas contracts, as was the assumption of the AER. The $11/GJ assumption for delivered gas is actually closer to the producer costs - acting as a proxy for avoidable long run marginal costs- than the market price for natural gas (as per Figure 3 below).

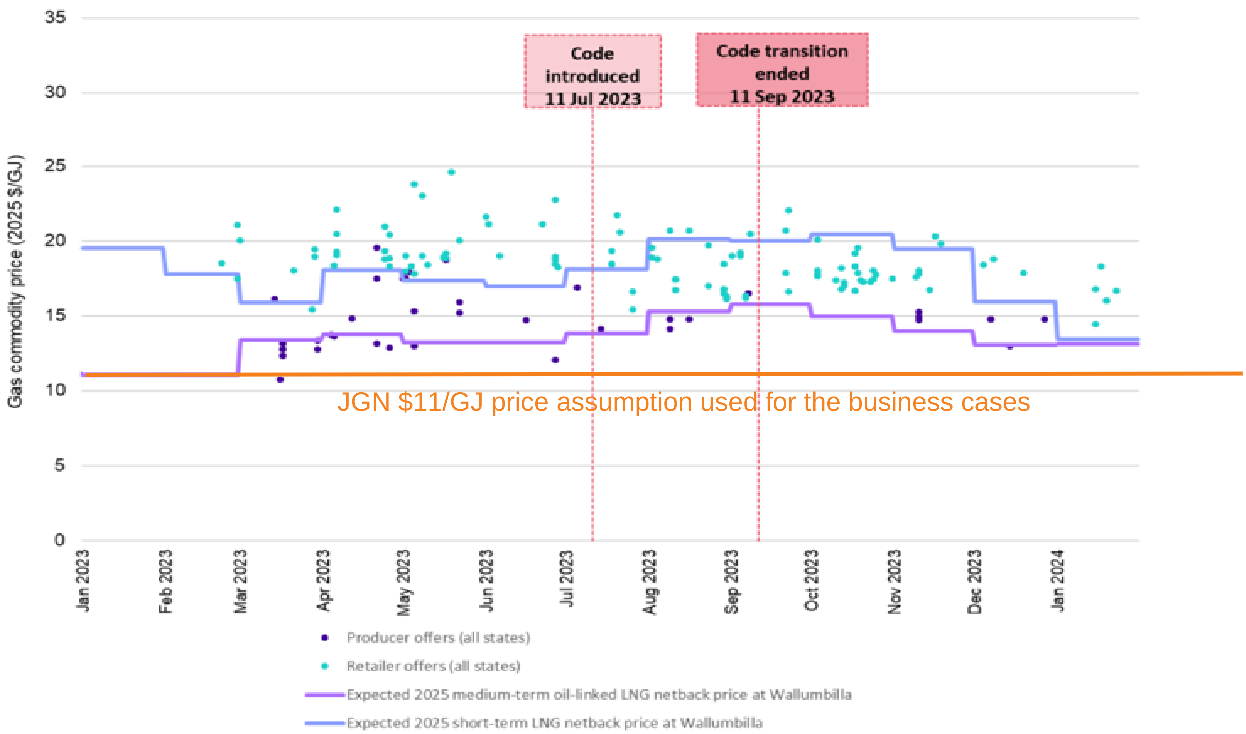
However JGN notes that even if it were an accurate representation of the market natural gas price, this approach would still be in line with standard CBA guidance including NSW Treasury who note that "*generally, CBA should use market prices to value the resources.*"[42]

The conservative nature of the $11/GJ natural gas price is demonstrated by reviewing the gas contracting price offers collated in the ACCC Gas Inquiry reports. Figure 3 shows the gas commodity pricing for 2025 supply offered by both producers and retailers to the east coast gas market compared to the $11/GJ range used by JGN in the business cases[43].

[42] *TPG23-08: NSW Government Guide to Cost-Benefit Analysis, February 2023*

[43] *ACCC Gas Inquiry 2017-2030 – Interim update on east coast gas market June 2024, Chart 3.5 page 56*

Figure 3: Gas commodity pricing (2025$/GJ) offered in the east coast gas market for 2025 supply compared to the LNG netback prices and 2025 ISAR range for 2025 supply



Source: ACCC analysis of bid and offer information provided by suppliers.

Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. All offers are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months. Some offers in the chart may be between the same supplier and buyer and/or represent further offers between parties if a previous offer did not result in the execution of a GSA.

In Figure 3 the blue and purple dots represent the retail and producer offers received by customers in the East Coast gas market for the natural gas commodity (not including transport and retail margins) compared to the orange line showing JGN's business cases assumption for production and transportation cost of $11/GJ. The disparity between the orange line and the blue and purple price offers demonstrate that the assumption used by JGN in the eight renewable gas connection project business cases was closer to the producer cost outlook than the "market price', meaning the benefits of each of the projects is understated.

The ACCC Gas Inquiry interim report for June 2024 (sections 3.3 to 3.5) provides extensive commentary on the observed price variations between actual market offers for forward-year gas supply from producers and retailers against various theoretical price markers (LNG netback) and a backdrop of a commodity price cap of $12/GJ. It's analysis also discusses the role of qualitative features of gas supply arrangements – such as the level of take-or-pay commitment, offtake flexibility (load factor), and overall quantum of gas purchased under individual agreements – has on final (ex-commodity) prices.

For further reference, the standard price paid for natural gas by residential customers in NSW is approximately $25.50-32.80/GJ (not including network charges) which is also significantly higher than the $11/GJ used in the business cases.

As gas supply shortages are forecast in the modelling period[44], and a natural gas import terminal is being built in NSW, it is reasonable to assume that the most expensive natural gas will be displaced by the biomethane projects, and the cost estimate utilised in the business cases is likely lower than the production cost of the gas that will be displaced by a biomethane market, which further demonstrates that the benefits for each business case is understated.

[44] Gas Inquiry 2017–2030 Interim update on east coast supply-demand outlook for quarter 1 of 2025

JGN also tested the sensitivity for each business case to understand the implications of the natural gas price decreasing to $8.65/GJ (22% reduction). In each of the business cases there was still a positive economic outcome (positive NPV and BCR >1) as shown in Table 5-3-1.

Table 5–3-1: Incremental value of project options under 2024 AEMO natural gas price forecast ($11.07/GJ) vs low scenario ($8.65/GJ)

Project	Metric	Original base case, natural gas price forecast of $11.07/GJ	Original base case, natural gas price forecast of $8.65/GJ	Electricity generation counterfactual, natural gas price forecast of $8.65/GJ
Lilli Pilli	**NPV ($2024M)**	[redacted]	[redacted]	[redacted]
	BCR	[redacted]	[redacted]	[redacted]
Kauri	**NPV ($2024M)**	[redacted]	[redacted]	[redacted]
	BCR	[redacted]	[redacted]	[redacted]
Blue Gum	**NPV ($2024M)**	[redacted]	[redacted]	[redacted]
	BCR	[redacted]	[redacted]	[redacted]
Red Gum	**NPV ($2024M)**	[redacted]	[redacted]	[redacted]
	BCR	[redacted]	[redacted]	[redacted]
Huon Pine	**NPV ($2024M)**	[redacted]	[redacted]	[redacted]
	BCR	[redacted]	[redacted]	[redacted]
Iron Bark	**NPV ($2024M)**	[redacted]	[redacted]	[redacted]
	BCR	[redacted]	[redacted]	[redacted]
Coolabah	**NPV ($2024M)**	[redacted]	[redacted]	[redacted]
	BCR	[redacted]	[redacted]	[redacted]
Wollemi	**NPV ($2024M)**	[redacted]	[redacted]	[redacted]
	BCR	[redacted]	[redacted]	[redacted]

5.2.2 Biomethane price vs willingness to pay in the market

> The economic case for JGN's renewable gas connection projects is stronger than basic price comparisons suggest. While the analysis uses reference points of $11/GJ for natural gas and a $3.60/GJ emissions reduction premium, actual customer willingness to pay is significantly higher due to multiple factors: Safeguard Mechanism compliance requiring 4.9% yearly emissions reduction; avoided capital costs of alternative decarbonisation pathways; and limited renewable gas supply against growing demand. This is supported by preliminary market feedback from project producers and reinforced by government commitment through the Future Gas Strategy and NSW Renewable Fuel Strategy. These factors indicate that the projects will deliver greater economic benefits than the conservative initial projections suggest.

The AER has given JGN feedback in the draft decisions *Confidential Appendix D.1.2* that it is unclear how the eight renewable gas connection projects have a net positive outcome when the output gas price required by project producers is higher than the market price of natural gas ($11/GJ), plus the green premium (implied carbon credit price $3.60/GJ).

As demonstrated in section 5.2.1 the $11/GJ is not representative of the market price for natural gas and therefore does not represent the willingness to pay by the end consumers for the natural gas commodity price that biomethane will be replacing. JGN instead estimates this to be significantly higher, as was communicated by the eight renewable gas producers when they met with the AER and discussed their expected offtake prices from their preliminary market interactions.

The willingness to pay for the green premium can also be concluded to not only be $3.60/GJ when traded in the open market. This is because the driving force to decarbonise for our customers is unique and depends on numerous inputs such as the motivation to decarbonise and their alternate decarbonisation pathway and associated costs.

For example, companies mandated under the Safeguard Mechanism need to decarbonise their scope 1 emissions by 4.9% year-on-year. The penalty for not decreasing the mandated company baseline is currently set at $275/T ($14.15/GJ), and offsets such as Australian Carbon Credit Units (ACCUs) can only account for 30% of a company's baseline reduction before they must provide a statement to the CER setting out why more onsite abatement hasn't been undertaken[45]. This is because offsets are not actual emissions reduction, whereas biomethane displacement of natural gas contributes to real emissions reduction and reduces the company's scope 1 emissions as is the intent of the Safeguard Mechanism. Therefore, these companies will most likely have a much higher willingness-to-pay for the green premium than the $3.60/GJ.

Also many industrial, commercial and residential customers are wanting to voluntarily decarbonise their natural gas usage as this can have branding and marketing value over and above the technical and financial value of the emissions reduction. Renewable gases delivered through networks are a way for them to achieve this without expensive investment in replacing onsite infrastructure and appliances such as boilers, hot water systems and furnaces that would be required under an electrification (or other technology) pathway. Therefore, the saved capex of not needing to invest in appliance replacement is a better representation of the willingness to pay than the simple comparison of $3.60/GJ. This value will vary dependant on the end customer and their specific decarbonisation motivation.

The availability of renewable gases will be limited as the market evolves and will most likely not meet demand over the 2025-30 regulatory period. As the supply of renewable gas is unlikely to meet demand, customers' willingness to pay – especially those from hard-to-electrify industries – will rise and increase the economic value of renewable gas.

Further, the Federal and NSW governments have both indicated through the Future Gas Strategy and the Renewable Fuel Strategy Consultation Paper that if there is a market supply price gap for renewable fuels such as biomethane, they will look to close this gap. The NSW Renewable Fuel Strategy Consultation Paper states that "*the Strategy will coordinate the NSW Governments support for diversifying and scaling up a renewable fuel industry in NSW, which can create new economic opportunities and improve fuel security*"[46].

Finally, as the projects begin to operate and efficiencies are realised in their processes, and subsidiary markets are developed, the cost of production and the required offtake price will begin to decrease below customers willingness to pay which will increase the supply of biomethane to meet future demand.

5.2.3 Beneficiaries of avoided production and transportation of natural gas

> Reductions in the costs of supply (or avoided costs) represent a resource 'benefit' and not surplus or transfer between parties. For this reason, they are relevant to the CBA and the assessment of positive 'overall economic value' consistent with Rule 79(2)(a) of the NGR, and calculated in accordance with Rule 79(3).

In its draft decision, the AER noted[47]:

[45] safeguard-mechanism-reforms-factsheet.pdf

[46] Opportunities for a renewable fuel industry in NSW, Consultation summary report

[47] AER, draft decision: JGN access arrangement 2050 to 2030: Attachment 5- Capital expenditure: Confidential Appendix D.1.2

> *it is unclear who benefits from the avoided cost of production and transportation of natural gas, or whether it is a surplus transfer between current natural gas producers, pipeline owners and renewable gas producers. JGN should clearly articulate how these costs represent a net benefit and not simply a surplus transfer.*

To demonstrate a positive net economic value of our renewable gas projects, the cost benefit analysis compared the costs (the production of renewable gas) against the benefits (the displacement of natural gas). The benefits from displacing natural gas include avoiding the cost of producing and transporting natural gas, the costs of a gas supply shortfall and the reduction in greenhouse gas emissions.

Avoiding the costs of producing natural gas is a benefit, not a surplus transfer between natural gas producers, pipeline owners or renewable gas producers.

The approach of calculating the total costs and benefits, is consistent with best practice cost benefit analysis, as well as the Rule 79(3) which is clear that the sum of the economic value accruing to the service provider (JGN), producers, users and end users is to be considered.

The analysis does not identify whether the avoided costs accrue to users or renewable gas producers. However, as Frontier Economics articulate[48] it is likely that these benefits will flow through to consumers. We note that these benefits are likely to flow through to consumers, especially given it will result in additional supply in the currently tight and volatile east coast gas market.[49]

5.3 Foregone cost of generation

> Even with higher biogas costs ($6.21/GJ vs $2.06/GJ), both the Lilli Pilli and Kauri projects remain economically viable. The projects demonstrate positive NPV and Benefit Cost Ratios (BCR) across all scenarios, including when compared against alternative electricity generation options.

In the draft decision confidential appendix D.1.3 the AER asked JGN to change an input assumption using a turbine generator instead of a reciprocating generator for forgone cost of generation at two of the project sites. Frontier Economics addresses these concerns in its Technical Note Section *2.2 Valuing forgone value form use of biogas.* The results of updating the value of biogas from $2.06/GJ to $6.21/GJ for Lilli Pilli and Kauri business cases gives the below results.

Table 5–4: Incremental value of project options under original value of biogas at landfill sites ($2.06/GJ) vs alternative value of biogas ($6.21/GJ)

Project	Metric	Original base case, biogas value of $2.06/GJ	Original base case, biogas value of $6.21/GJ	Electricity generation counterfactual, biogas value of $6.21/GJ
Lilli Pilli	**NPV ($2024M)**	[redacted]		
	BCR			
Kauri	**NPV ($2024M)**			
	BCR			

As can be seen in Table 5-4, the NPV and BCR are still positive with the updated biogas cost under both the original assumptions and the electricity generation counter-factual scenario.

[48] Technical Note section 1.2.1.

[49] ACCC 2024 *Gas inquiry 2017-2030* Interim update on east coast gas market, *December 2024.* p.7 Available here.

5.4 The long-term availability of feedstock

> The 6.7PJ forecast by the eight renewable gas connection project business cases is less than 5% of the total NSW technically available feedstock.
>
> Feedstock availability risk is effectively managed through diversified waste streams, storage facilities, and long-term supply agreements, with feedstock sources having proven sustainability over 30+ years of historical operation.
>
> The eight biomethane projects demonstrate strong economic viability even with a shortened operational lifespan of 18-20 years (reduced from 24-26 years). All projects maintain positive NPV and BCR above 1.1.

In its draft decision the AER noted that it is *"concerned that JGN has not substantiated the long-term availability of feedstock"* [50] that warrants a shorter modelling period scenario. Frontier Economics has addressed the AER's concerns in its Technical Note, Section 2.3: Shorter modelling period to reflect project risk.

The Roadmap identifies that the total feedstock potential in Australia (PJ per annum) is as large as 2,611PJ and in NSW is 553PJ. Whilst not all of this feedstock will be commercialised into renewable energy, a significant volume is available to facilitate the decarbonisation of gas networks. AEMO has also released the Inputs, Assumptions and Scenarios Report (IASR) for 2025 and identified that the technical potential of anaerobic digestion is 506PJ for Australia and 137PJ for NSW[51]. JGN delivered 83.5PJ of natural gas to customers in 2023-24, meaning that the technical potential for biomethane is significantly larger than the total JGN gas demand. The 6.7PJ forecast by the eight renewable gas connection project business cases is less than 5% of the total NSW technically available feedstock identified in the Roadmap. This indicates that feedstock availability should not be of concern and the biomethane industry has the potential to continue to grow and decarbonise gas network customers into the future.

Project producers optimise their project locations primarily on their proximity to target feedstocks and local supporting infrastructure that enables the sourcing of this feedstock (road, rail, power), and subsequent handing of end-products (grid power and gas pipelines). Biomethane project producers are all looking to diversify their feedstocks across different waste streams e.g. animal effluent waste mixed with agricultural waste, also known as co-digestion. This ensures that if there are shortages in one of the feedstock streams others can be utilised. Producers have also designed their projects to include significant feedstock storage on site, and are contracting to secure long-term anchor feedstock supply agreements to mitigate the risk of ongoing feedstock availability. The volume of organic feedstocks available are also expected to increase as the population increases, as the vast majority of organic feedstocks are sourced from human, animal and food wastes.

Further, the feedstocks that all eight of the project producers are looking to utilise are from existing waste streams that have been available in most cases for over 30 years, demonstrating the long-term availability of feedstocks. Also for the greenfield projects that are utilising agricultural waste which converts a waste stream into a resource generating a dollar value, will incentivise farmers to produce more feedstock . [redacted][52].

As to whether potential sources of feedstock will be eligible renewable energy sources under law, GreenPower Renewable Gas Guarantee of Origin (RGGO) Certificates are used by the market to give biomethane and renewable hydrogen its green premium and delineate it from natural gas. In order to create these certificates only certain feedstock sources can be utilised to create these certificates for biomethane generation. Eligible feedstocks are aligned to those able to be used under s17 of the *Renewable Energy Electricity Act* 2000 (Cth) (REE Act) which sets out the categories of eligible renewable energy sources. [53] All feedstock sources to be utilised by the eight project producers fall within the definition of an 'eligible renewable energy source' under s17

50 *AER 2024, Draft decision, Jemena Gas Networks (NSW) access arrangement 2025 to 2030, Attachment 5: Capital Expenditure, p29*

51 ENEA Consulting, 2030 Emission Reduction Opportunities for Gas Networks (Report, Energy Networks Australia, 2022) 36 <https://www.energynetworks.com.au/miscellaneous/2030-emission-reduction-opportunities-for-gas-networks-by-enea-consulting-2022/>.

52 [Landfill_2001_ch2.qxd]

53 [RENEWABLE ENERGY (ELECTRICITY) ACT 2000 - s17]

of the REE Act and therefore can be accredited by GreenPower. This existing legislative basis setting out eligible sources of renewable energy generation, utilised by the eight project developers, provides confidence of the long term availability of feedstock sources which are classified as eligible renewable energy sources.

The original base case assumption for the business cases assumed a 30 year NPV period covering both the construction of the facilities as well as the running life of each project. This is considered at the low end of the range recommended by NSW Treasury for capital projects that suggests "*a period of 30-60 years post construction, for capital infrastructure types*[54]".

In the original business cases, sensitivities were tested for lower biomethane production at the facilities (assuming capital and operating expenditure remains the same but volumes are decreased by 20%) and also feedstock volume decreases (assuming the feedstock volumes decrease and the corresponding impact on operating costs and production volumes by 20%). Both of these sensitivities generate positive NPV and BCR results. Based on the AER feedback, JGN asked Frontier Economics to test a further project sensitivity by shortening the modelling period for each business case from the original period by six years (originally all projects were modelled out until 2053; now they are tested assuming operations out to 2047). Whilst the estimated construction period for the eight projects varies dependant on specific project location and design, sensitivity analysis changes the original assumption from each plant having an operating period of 24-26 years back to 18-20 years (detailed in Table 12 of the Frontier Economics Technical Report).

The results of this sensitivity are shown in Table 5–5 and detail that even with the reduction in operable life, the NPV and BCR for each of the projects is still positive.

Table 5–5: Incremental value of project options under original modelling period (30 years) vs shorter modelling period (24 years)

Project	Metric	Original base case, modelling period of 30 years	Original base case, modelling period of 24 years	Electricity generation counterfactual, modelling period of 24 years
Lilli Pilli	NPV ($2024M)	[redacted]		
	BCR			
Kauri	NPV ($2024M)			
	BCR			
Blue Gum	NPV ($2024M)			
	BCR			
Red Gum	NPV ($2024M)			
	BCR			
Huon Pine	NPV ($2024M)			
	BCR			
Iron Bark	NPV ($2024M)			
	BCR			
Coolabah	NPV ($2024M)			
	BCR			
Wollemi	NPV ($2024M)			
	BCR			

54 https://www.treasury.nsw.gov.au/sites/default/files/2023-04/tpg23-08_nsw-government-guide-to-cost-benefit-analysis_202304.pdf

5.5 The market price of reasonable biogas byproducts

> Not all biomethane projects will produce marketable byproducts (biogenic CO_2 and digestate) due to differences in production processes and feedstock composition. Where byproduct value is included in project assessments, pricing assumptions were conservatively derived from producer-provided ranges, reflecting the emerging nature of these markets in Australia.
>
> All projects under sensitivity analysis for digestate and biogenic CO_2 still provide overall economic value (NPV>0; BCR>1)

The AER in draft decision has noted that[55]:

> *We do not consider JGN has sufficiently justified its assumptions about the market price of resalable biogas byproducts.*

The byproducts referred to are biogenic carbon dioxide (CO_2) and digestate. Not all projects produce both biogenic CO_2 and/or digestate. [redacted] This is because the biogas for these projects is not produced in an anaerobic digester (or don't expect to produce a marketable digestate product), hence no digestate value is attributed to it. Equally if the makeup of the feedstock entering the anaerobic digestion process does not have the correct energy and nutrient contents then there will be no resaleable value of the digestate. This is also why not all projects are estimating the same digestate offtake pricing. For example the [redacted] project has a higher estimated digestate price than other projects. This is because, [redacted] the project producer is both carefully selecting the feedstock entering the anaerobic digestion process as well as the anaerobic digestion technology itself, to ensure it produces a digestate that is of high value to the surrounding agricultural market specific to the projects location.

We sourced the assumptions for the biogenic CO_2 and digestate pricing used in the business cases from each of the individual project producers. Most gave JGN a price range rather than an exact value, because these markets are evolving and the exact price for these commodities is yet to be determined in the Australian context. We took a conservative view of these ranges and applied a universal CO_2 price to all projects, and the digestate price only varied for the [redacted] project due to their more specified approach to digestate.

5.5.1 Digestate price sensitivity

> The business case for digestate production remains strong even with conservative pricing assumptions. When digestate value is reduced by 20% [redacted], all projects maintain positive NPV and BCR. Digestate's value proposition is supported by its ability to replace synthetic fertilizers (currently trading at \$660/tonne), reduce carbon emissions (avoiding 910kg CO2e/tonne of traditional urea production), and provide additional soil benefits. As digestate is present in both biomethane and electricity generation scenarios, its pricing sensitivity does not impact the comparative advantage of biomethane production.

Digestate is the organic matter that is remaining after the anaerobic digestion process. It can be used to complement or displace traditional fossil fuel based fertilisers. It plays a key role in the circular economy process associated with the creation of biomethane, ensuring that feedstocks that were once seen as waste can provide both energy and nutrient value back to the land.

The benefits associated with digestate are immense with the most direct and simple being the value in displacing the use of synthetic/inorganic fertilisers such as urea, to add nutrients to soil (primarily nitrogen, potassium and phosphate). By displacing fossil fertilisers there are significant avoided carbon dioxide emissions and cost savings, for example Urea production emits 910kg CO_2e/T[56] that currently trades at a price of \$660/T[57]. There are also

55 *AER 2024, Draft decision, Jemena Gas Networks (NSW) access arrangement 2025 to 2030, Attachment 5: Capital Expenditure, p29*

56 https://issuu.com/efma2/docs/carbon_footprint_web_v4

57 Market Update June 2024 | Crop Smart | Agricultural Chemicals for Crop Protection

the benefits associated with enabling stabilisation and retention of carbon within the soil, creating carbon sequestration value as well as water retention in the soil[58]. Whilst the organic digestate market is only in its infancy in Australia there are nascent markets developing around the world including the Puro Earth CO_2 Removal Certificate (CORC) Scheme[59].

The digestate benefits and traditional fossil fertiliser market prices formed the commercial analysis and discussions undertaken with project producers in assessing the value of their digestate byproduct. Estimates varied from [redacted] and reflect the varying levels of sophistication in their digestate disposition planning as well as target end-markets (agricultural fertiliser users, private gardener markets)[60]. As mentioned above, some projects will carefully curate their feedstock and digestate refinement process to meet premium pricing points through value-added processes such as drying, concentration and pelleting. Others, due to their feedstock composition (municipal and garden organics) and modest scale can target the private gardener market (where prices are at a considerable premium to nutrient displacement value[49, 61]), or simply sell the digestate in its (lesser value) liquid state.

For the business cases we took a conservative view [redacted] for all projects except [redacted] which was valued at [redacted]. These prices include the digestate commodity price (replacement of traditional fertilisers) and also the green premium which will be attributed to the carbon reduction benefits associated with a developed digestate market.

Frontier Economics in the Technical Note Section 2.4 explore the sensitivity analysis for a lower price of digestate and the impact it has on the business cases. The summary of these results is shown in Table 5-6 where a 20% sensitivity analysis is shown for the digestate producing projects. This brings the digestate price to the bottom of the pricing bracket given to JGN across all projects.

Table 5–6: Incremental value of project options under value of digestate (20% lower)

Project	Metric	Original base case, digestate value of [redacted]	Original base case, digestate value of [redacted]	Electricity generation counterfactual, digestate value of [redacted]
Blue Gum	**NPV ($2024M)**	[redacted]	[redacted]	[redacted]
	BCR	[redacted]	[redacted]	[redacted]
Red Gum	**NPV ($2024M)**	[redacted]	[redacted]	[redacted]
	BCR	[redacted]	[redacted]	[redacted]
Huon Pine	**NPV ($2024M)**	[redacted]	[redacted]	[redacted]
	BCR	[redacted]	[redacted]	[redacted]
Iron Bark	**NPV ($2024M)**	[redacted]	[redacted]	[redacted]
	BCR	[redacted]	[redacted]	[redacted]
Coolabah	**NPV ($2024M)**	[redacted]	[redacted]	[redacted]
	BCR	[redacted]	[redacted]	[redacted]

[redacted]

Note: ** This assumes a 20% lower value for digestate, [redacted]

As can be seen from the results in Table 5-6 there is still a positive economic outcome (NPV and BCR) with the lower digestate benefits. It is also important to point out that the digestate will be present in both the biomethane

58 Environmental Benefits of Anaerobic Digestion (AD) | US EPA

59 https://puro.earth/corc-carbon-removal-indexes

60 https://www.biogas.org/fileadmin/redaktion/dokumente/medien/broschueren/digestate/Digestate_as_Fertilizer.pdf, pp 18 and 26

61 https://anlscape.com.au/landscaping/garden-compost-and-soil-conditioners, dry loose digestate density = 250-350kg/m3

and electricity generation counterfactual business cases so this sensitivity has no bearing on the delta between these scenarios.

5.5.2 Carbon dioxide price sensitivity

> Biogenic CO2, a byproduct of biomethane production, represents a significant market opportunity in Australia where CO2 shortages have led to imports from Asia at costs of $1,000-$2,000/tonne. Recent facility closures, including Incitec Pivot and BP refinery, have further constrained domestic supply. While a formal biogenic CO2 market is yet to be established in Australia, its value is supported by European precedent (where prices have reached A$1,600/tonne) and potential future green premium certification through GreenPower. This byproduct could serve multiple industrial applications while offering a decarbonisation pathway for current fossil-derived CO2 users.

Biogas produced from the anaerobic digestion process contains only about 55-65% methane with the remainder comprising biogenic CO_2 and trace amounts of impurities. When upgraded to biomethane, the CO_2 and other impurities are removed to produce the pipeline specification gas required for the market. The biogenic CO_2 can then either be vented to atmosphere with no carbon addition associated, or otherwise be used to displace fossil derived CO_2 markets. This biogenic CO_2 has significant utility value as feedstock to various established and emerging industrial applications such as in the production of foods and beverages, inputs into greenhouses to stimulate plant growth; as well as for the production of synthetic fuels and chemicals such as renewable methane and methanol. The biogenic CO_2 may also be captured and stored which could lead to negative emissions and therefore also yield carbon sequestration value.

Discussions between JGN and project producers as well as traditional CO_2 market participants have shown that at times the Australian market's CO_2 requirements cannot be met with existing fossil derived CO_2 sources leading to CO_2 being imported into Australia from Asia. Market participants have expressed that the costs associated with this bulk CO_2 import process are between $1,000-$2,000T. The reason for the CO_2 shortages experienced in Australia lead back to the existing sources of CO_2 closing or experiencing long outage periods due to aging assets and unplanned outages. For example in December 2022 Incitec Pivot in Gibson Island closed taking with it the last source of CO_2 production in QLD, after the closure of BP refinery at Bulwer Island in 2015. The QLD market is now supplied largely from a CO_2 production facility at Orica in Kooragang Island in NSW.

Drawing on analysis by the European Biogas Association[62], historically (non-biogenic) European CO_2 commodity prices traded at around €100/T pre-2022 (~A$160/T) but have spiked to as high as €1000/T (A$1600/T) since 2022, and remain significantly elevated above pre-2022 levels due to closures of synthetic fertilizer producers (through steam-methane reforming) on the back of very high gas prices.

Whilst there is no biogenic CO_2 market established in Australia, GreenPower who currently are the accreditation body for both renewable electricity and gas have indicated they will look into a biogenic CO_2 certificate scheme that will give the biogenic CO_2 market a green premium above traditional CO_2 sources. This will give organisations that currently rely on fossil derived CO_2 a decarbonisation pathway in the future. These societal benefits were not accounted for in the eight renewable gas business cases quantitively however they do provide qualitive benefits.

Frontier Economics, in the Technical Note Section 2.4.2, explores the sensitivity analysis for a lower price of biogenic CO_2 and the impact it has on the business cases. The summary of these results is shown in Table 5-7 where a 20% sensitivity analysis is shown for the biogenic CO_2 producing projects.

Table 5–7: Incremental value of project options under value of biogenic CO2 (20% lower).

Project	Metric	Original base case, byproducts values at central case*	Original base case, CO2 valued at 20% lower than central case **	Electricity generation counterfactual, CO2 valued at 20% lower than central case**
Blue Gum	**NPV ($2024M)**	[redacted]	[redacted]	[redacted]

62 https://www.europeanbiogas.eu/wp-content/uploads/2023/02/20230213_Guidehouse_EBA_Report.pdf, page 54

Project	Metric	Original base case, byproducts values at central case*	Original base case, CO2 valued at 20% lower than central case **	Electricity generation counterfactual, CO2 valued at 20% lower than central case**
	BCR		[redacted]	
Red Gum	**NPV ($2024M)**			
	BCR			
Huon Pine	**NPV ($2024M)**			
	BCR			
Iron Bark	**NPV ($2024M)**			
	BCR			
Coolabah	**NPV ($2024M)**			
	BCR			

Note: * [redacted]

Note: ** This assumes a 20% lower value for food/industrial grade CO2 [redacted]

5.6 Mitigating the risk of projects not proceeding

> JGN's 2025 Plan includes only those biomethane projects that have passed a comprehensive risk assessment process, evaluating third parties, feedstock sources, land availability, project scale, and network proximity. While additional projects are under discussion, only the most advanced and viable projects were selected for inclusion, demonstrating JGN's prudent approach to managing customer investment risk.

The AER suggested in the draft decision that[63]:

> *We consider that there is a risk that these projects, which require significant capital and operating expenditure from the renewable gas producer, do not proceed, leaving JGN's customers to fund projects (at least in the short-term) that do not provide gas distribution services*

JGN has undertaken a rigorous risk assessment process to determine which projects were included within our 2025 Plan. This involved assessment of third parties, feedstock sources, land availability, project size and proximity to the JGN. Only those projects assessed as likely to proceed during the 2025-30 period were included within our 2025-30 Plan.

It is important to note that there are many more project producers and locations currently being discussed with JGN however these projects are less progressed and therefore we did not include these within our 2025-30 Plan.

Mitigating the risk of projects not proceeding and this falling on the JGN customers is addressed in section 2 with the fixed principle approach.

63 *AER 2024, Draft decision, Jemena Gas Networks (NSW) access arrangement 2025 to 2030, Attachment 5: Capital Expenditure, p29*

6. Response to stakeholder submissions

In this section we respond to stakeholder feedback received through submissions to our Initial 2025 Plan noted by the AER in the draft decision.

Stakeholder concern[64]	Our consideration
Large renewable projects are inconsistent with our proposal for accelerated depreciation.	Our renewable gas projects complement our proposal to accelerate depreciation. Both initiatives reduce future asset stranding risk by extending the life of the gas network.[65]
The resources needed to produce biogas is limited.	There is more than sufficient resources available in NSW not only for the 6.7 PJs of projects we have proposed but the entirety of our annual demand (83.5 PJS): • Australia's Bioenergy Roadmap identifies that the total feedstock potential in Australia (PJ per annum) is as large as 2,611 PJ and NSW is 553 PJ. • AEMO's Inputs, Assumptions and Scenarios Report (IASR) for 2025 identified that the technical potential of anaerobic digestion is 506 PJ for Australia and 137 PJ for NSW[66].
There are other renewable energy alternatives.	As the Australian Government's Future Gas Strategy notes,[67] many industrial users have few options to switch away from gas. This includes customers which rely on gas as a feedstock, to produce high-heat or for gas powered generation. These customers make up 70% of our industrial gas demand 30.9 PJ, as we outline in section 3.
Biomethane gas is not suitable to serve JGN's gas demand.	Biomethane can be injected directly into the gas network without requiring upgrades of the gas infrastructure or consumer appliances. ACIL Allen - Renewable Gas Target observes that Australia will need access to renewable gas as part of an efficient transition to net zero. It states that "*the most economically efficient pathway to net zero emissions for today's gas users involves a mix of renewable gas and renewable electricity.*"[68]
Biomethane will have a limited effect on emission reduction targets	The 6.7 PJ of biomethane we propose to facilitate will reduce emissions by 0.35 MtCO2e per year[69] decarbonising 8% of the gas we transport by 2030. This reduction will contribute 1% (for NSW) and 0.4% (for Australia) of the reduction in emissions required to achieve the NSW and Australia 2030 emission reduction targets. Further, these initial eight projects pave the way for further projects to support additional significant long term emissions reduction benefits.
We have not demonstrated much demand for biomethane from industrial customers	Confidential discussion with our large customers indicate large interest in biomethane largely, as the Future Gas Strategy recognises,[70] there is no other decarbonisation option for these customers without access to biomethane (or other forms of renewable gas) as discussed in section 3.

[64] AER, Attachment 5: Capital expenditure - Draft decision – Jemena Gas Networks (NSW) 2025–30, page 27

[65] See *JGN - RP - Att 7.2 – Depreciation – 20250115 – Public* for further details.

[66] ENEA Consulting, 2030 Emission Reduction Opportunities for Gas Networks (Report, Energy Networks Australia, 2022) 36 <https://www.energynetworks.com.au/miscellaneous/2030-emission-reduction-opportunities-for-gas-networks-by-enea-consulting-2022/>.

[67] Australian Government 2024, Future Gas Strategy, p.20 Available here

[68] Renewable Gas Target

[69] As per the NGER scheme, the emissions difference between biomethane and natural gas combustion is 51.4 kg CO2e/GJ.

[70] Australian Government 2024, Future Gas Strategy, p.20 Available here.

7. Summary of proposed revisions to Initial Proposal AA

Table 7-1: Explanation of proposed relevant revisions to the Initial Proposal AA

Clause	2020 AA reference	2025 AA reference	Summary of proposed change
Initial Reference Tariffs and Variation Mechanism			
Renewable Gas Connection capital expenditure	N/A	3.14	A new clause 3.14 is proposed which provides that in the event that the AER's Final Decision specifies a capex allowance for renewable gas connections, a fixed principle will apply which requires JGN to propose revenue in the next access arrangement period which is adjusted to true-up for the revenue difference between the actual conforming renewable gas connection capex and the allowance.