

Renewable Gas Alliance Submission: Guarantee of Origin proposed cost recovery: new production pathways

Bioenergy Australia (BA) is the national industry association committed to accelerating Australia's bio economy. Through targeted advocacy, campaigns, education, industry building and allied sector engagement, we're:

- Enabling decarbonisation of Australia's hard to abate sectors
- Enhancing energy security, supply and supporting the transition of Australia's energy system
- Growing Australia's economy and providing jobs and economic development including for regional Australia
- Enabling the development of Australia's circular economy

This submission is on behalf of the Renewable Gas Alliance (RGA), an alliance founded to accelerate the decarbonisation of Australia's gas network through increased deployment of renewable natural gas (RNG), also known as biomethane, as well as biogas. The RGA has over 100 member organisations, including gas pipeline owners, gas retailers, project developers, technology providers, off takers, research organisations, and state and local government representatives. This submission is a collective response and will be supported by individual member submissions relating to their specific expertise.

RNG represents one of the most immediately deployable pathways to reduce emissions within Australia's existing energy system. Unlike many low-carbon options that focus only on emissions displacement, RNG can achieve net-zero—and in some cases net-negative—emissions by capturing biogenic methane from organic waste that would otherwise enter the atmosphere. In doing so, it delivers both energy and achieves emissions reduction, while supporting waste diversion, regional jobs, and energy system and national energy resilience.

Australia is well positioned to scale this solution. Strong domestic feedstock availability and established technical capability mean there is significant potential to develop a domestic renewable gas industry at scale. A Blunomy and ENA report¹ estimates that approximately **400 PJ** per year of biomethane could be recoverable - equivalent to almost 80 per cent of current domestic east coast gas demand.

The RGA has consistently supported the development of the Guarantee of Origin (GO) Scheme and values the Australian Government's ongoing engagement with industry in developing the scheme. However, we are concerned that the proposed cost recovery approach is either the result of a miscalculation or is grossly disproportionate, and poses a material risk to the viability and scale-up of this important industry unless amended immediately.

¹ Blunomy and Energy Networks Australia (2025) *Biomethane Opportunities to Decarbonise Australian Industry*. Blunomy for Energy Networks Australia.

We submit:

1. The Government's Cost Recovery Policy was not appropriately applied as the approach did not consider the impacts of cost recovery on the nascent biomethane industry, where early-stage projects are highly sensitive to cost structures and require long-term supportive settings to develop.
2. The proposed cost recovery approach for biomethane is disproportionate, with the PGO fee being significantly higher relative to comparable energy products. For biomethane, the proposed PGO fee represents approximately 26% of the underlying gas commodity price (\$2.62/GJ vs \$10.04/GJ).
3. There is a serious miscalculation or methodological error, as the current consultation shows costs significantly higher than the previous consultation, with no explanation for this increase. As a result, the proposed cost level indicates that biomethane participants are being asked to bear nearly the full PGO scheme cost.
4. The proposed approach has not adequately considered how this cost structure will impact biomethane uptake and project development, including risks such as non-participation in the scheme, weakened market and offtake signals, misalignment with broader Government objectives, and overall adverse impacts on the domestic biomethane industry.
5. The proposal that profile and certificate costs will be fully remitted in the first 2 years is insufficient to address these overall structural issues and would likely render participation in the scheme unviable for many biomethane projects.

The RGA calls on the CER to urgently revise the proposed cost recovery approach to ensure it is factually correct, appropriate and can enable the growth of Australia's biomethane sector.

We strongly recommend the following material issues are addressed:

- 1. The CER has failed to consider industry impacts in designing the cost recovery approach, and in doing so has designed a unworkable cost recovery model and failed to appropriately apply the Government's Cost Recovery Policy.**

We submit that the CER failed to appropriately apply the Government's Cost Recovery Policy used to develop the cost recovery approach for biomethane² and as a result, the proposed cost recovery approach is not appropriate and should be reconsidered in light of industry impacts as discussed below. The approach adopted is one designed for mature, established industries rather than emerging markets, and the implications for the viability of the industry, as well as policy goals of the Guarantee of Origin Scheme, were not appropriately considered as required under the Government's Cost Recovery Policy.

In particular, the CER cost recovery process as it applies to biomethane failed to consider "the impact of cost recovery on competition, innovation or the financial viability of those who may need to pay charges" as required under the Cost Recovery Policy. Had it done so, the proposed cost recovery approach would have not been adopted due to the severe impact on the financial viability of

² The Cost Recovery Policy, as described at:
<https://www.finance.gov.au/government/managing-commonwealth-resources/implementing-charging-framework-rmg-302/australian-government-cost-recovery-policy>

biomethane production as demonstrated below. At the very least, we submit that had the impacts of the proposed cost recovery approach in industry been taken into account, the approach would include a ‘phase in’ period, as is explicitly allowed under the Government’s Cost Recovery Policy, to allow the industry to be established before cost recovery fees applied. In addition, it is not clear to RGA that the policy proposal developed and considered by government in its internal cost recovery process included “an analysis of the impact of cost recovery on stakeholders and of any consultation issues” as required by the Cost Recovery Process³, and it seems likely that if it did, it did so in an aggregate way that did not appropriately identify the potential impacts of cost recovery on new industries facing challenging financial circumstances due to a lack of policy that allows investors to fully or even significantly monetise the avoided social cost of carbon through the activity – in this case the production of biomethane. The approach adopted by the CER appears to assume biomethane is currently an established industry operating at scale, where regulatory and administrative costs are not expected to materially influence investment decisions or participation outcomes.

Those assumptions do not reflect the circumstances of biomethane. The Australian biomethane sector remains in early-stage development, with significant barriers to investment, including high capital costs, long development timelines, and reliance on stable long-term policy and offtake certainty. These barriers are exacerbated by the fact the social benefit of the industry through emission reduction is not recognised through specific supportive Government policy such as a production tax credit or a broad based carbon price.

In this context, regulatory and administrative costs cannot be treated as marginal and the below analysis demonstrates the proposed cost recovery approach has a significant and material impact on project economics. In the biomethane sector, even relatively modest cost recovery charges can influence project economics, financing structures, and investment decisions, and therefore whether projects proceed to investment, are delayed or do not occur at all.

Applying a framework designed for mature industries therefore creates a structural mismatch between the assumptions embedded in the cost recovery model and the realities of an emerging industry, such as the biomethane industry. This risks embedding cost settings that are appropriate for established sectors into a market that is still being formed.

As a general principle, this risk is acknowledged in the Government’s Cost Recovery Process and as a result the impacts for industry should be taken into account under that policy both in the policy approval and cost recovery design stages. It appears the CER did not specifically take into account the impacts of cost recovery on the viability of biomethane investment, and as a result failed to appropriately apply the Government’s Cost Recovery Policy.

Accordingly, we strongly recommend that the cost recovery approach for biomethane be revised to properly take into account the impacts on industry, consistent with the Government’s Cost Recovery Policy, and develop a cost recovery approach that is appropriately tailored to the characteristics of an emerging industry. In doing so, the CER should consider the view of the RGA that a “phase in” is appropriate for biomethane GO cost recovery, including to give investors certainty about future costs.

³ Ibid.

2. Proposed cost recovery approach for biomethane, biogas and bio LNG is disproportionate and will unfairly undermine development of these industries

The proposed PGO cost recovery settings are disproportionate and risk undermining the development of the biomethane, biogas and bio-LPG industries in Australia.

For biomethane, the proposed PGO fee represents approximately 26% of the underlying gas commodity price (\$2.62/GJ vs \$10.04/GJ). In contrast, for renewable electricity, the proposed REGO fee represents approximately 0.10% - 0.16% of the underlying energy cost - roughly 120 times less than the proposed biomethane PGO on a like-for-like energy basis, for what is fundamentally the same regulatory activity.

We note that the CER has recently released updated cost estimates for sustainable aviation fuel (SAF) and renewable diesel pathways, resulting in a substantial reduction in the proposed cost burden for those industries. **No corresponding updates have been provided for biomethane, biogas or bio-LPG.** As a result, an already disproportionate cost recovery outcome for these sectors has become even more pronounced. This significant difference in cost treatment demonstrates a clear inequity in the framework and the disproportionate burden being placed on the biomethane, biogas and Bio-LPG sectors.

Table 1: GO cost recovery comparison⁴

Energy	Brown energy cost	Total GO certificate generation costs	GO cost as % of brown energy cost
Renewable Electricity	NEM average electricity price in FY26* \$50.36 - 77.10 / MWh	\$0.09 / MWh \$0.025 / GJ [?]	0.12% – 0.18%
Hydrogen	Natural gas average price April 2026^ \$10.04 / GJ	\$0.0033 - 0.24 / kg \$0.028 – 2.00 / GJ ^{<}	0.27% – 19.9%
SAF	Jet A fuel April 2026[1] \$3.272 / L	\$0.00018 / MJ \$0.006246/ L[2] \$0.18 / GJ	0.19%
Renewable diesel	Average diesel price week end 10 May 2026 [3] Retail price: \$2.472 / L Wholesale price: \$2.237 / L	\$0.00028 / MJ \$0.010052 / L[4] \$0.28 / GJ	0.41 – 0.45%
Biogas	Natural gas average price April 2026^ \$10.04 / GJ	\$2.62 / GJ	26.1%
Biomethane	Natural gas average price April 2026^ \$10.04 / GJ	\$2.62 / GJ	26.1%
Bio LPG	LPG price 11 May 2026~ \$0.62 / L	\$0.57 / MJ \$14.25 / L ^{&} \$570.00 / GJ	2,298%

⁴ Refer to appendix for calculation information input.

Biomethane already faces a structural cost disadvantage relative to fossil natural gas, with production costs approximately \$14/GJ higher. As a result, many projects already sit at or near the boundary of commercial viability under current market conditions. In this context, the addition of \$2.62/GJ in certification costs further reduces investment viability and can directly prevent projects from proceeding to final investment decision.

Although it is proposed that profile and certificate costs will be fully remitted in the first two years, this does not resolve the underlying issue. The long-term cost structure remains unchanged, creating investment uncertainty and undermining the ability of projects to progress or reach financial close.

The effect is direct and predictable: under the current cost recovery approach, demand and offtake for biomethane will be significantly reduced, and a large proportion of biomethane projects will become unviable, effectively stalling industry development in Australia.

As currently designed, the PGO cost recovery framework does not support biomethane market development.

3. Significant increase in biomethane cost recovery compared to previous consultation and unclear volume assumptions underpinning modelling

The previous consultation on cost recovery for the PGO Scheme indicated a cost for biomethane of \$0.036 per certificate (1 kg functional unit). On conversion to a gigajoule basis, this equates to approximately a **2.9× per GJ increase** compared to the previous consultation, with no clear explanation of the methodological change driving this increase.

The difference is not consistent with a simple functional unit adjustment. The consultation paper states that CER assessment costs do not vary with the functional unit and that the functional unit only affects the unit price. This means the observed change cannot be explained by a shift in functional unit alone. On this basis, we submit the calculation is incorrect and the biomethane cost recovery figures must be urgently revised.

A further concern is that there is no clear explanation of the assumed biomethane production volumes used in the modelling. These assumptions are not set out or reconciled in the consultation, nor is it explained how they differ from the previous consultation. We request that the CER provide the assumed volumes and explain the basis for them.

4. Biomethane is expected to bear disproportionate PGO scheme cost under the proposed approach

State governments have already begun legislating frameworks to enable the renewable gas sector, with schemes in place or in development that define the immediate scale exposed to the PGO system:

- New South Wales Renewable Fuel Scheme (RFS): legislated 8 PJ biomethane and green hydrogen target by 2038, with a \$10.50/GJ penalty rate, and scheme expansion commencing in 2028.
- Victorian Industrial Renewable Gas Guarantee (RGT): proposed 4.5 PJ by 2035, with a 1 PJ per year ramp-up in the early years and industry advocacy for a more ambitious 14.5 PJ by 2035 aspirational target.

Against this backdrop, the proposed PGO cost recovery settings place a disproportionate burden on biomethane producers. To illustrate the perceived implication of the published \$2.62/GJ PGO fee, certification costs for the NSW RFS 8 PJ target alone would equate to approximately \$21 million. Not only is the scale of cost difficult to reconcile, but it suggests that biomethane participants are expected to recover the Commonwealth's full administrative costs in the earliest, most fragile years of the industry development - exactly when projects need cost certainty and the lightest possible regulatory burden to reach scale.

5. Misalignment with the Australian Government objectives

Renewable gas and biomethane have been identified as critical pathways across key Commonwealth policy frameworks, including the Future Gas Strategy, the Net Zero Plan, the Electricity and Energy Sector Plan, the Domestic Gas Reservation Scheme - Draft Design Framework, the NDC Investment Blueprint and as part of the Energy and Climate Change Ministerial Council agenda. Collectively, these reflect a clear and sustained policy intent to enable the development and scale-up of the biomethane industry in Australia.

Thus, a cost recovery approach that materially undermines biomethane project viability is directly inconsistent with the Federal Government's stated objectives and broader net zero policy settings.

Additionally, the proposed approach is inconsistent with the *Future Made in Australia (Guarantee of Origin) Act 2024* objectives. Sections 4(b), 4(c), and 4(d) of the Act set out that the Act aims to accelerate the commerciality of low-emission products, support the development of low-emission product markets, and contribute to Australia's emissions reduction targets. The proposed PGO cost recovery settings for biomethane are inconsistent with these objectives as they would reduce participation in the scheme, suppress market uptake, and deter investment in biomethane projects.

We strongly recommend that the proposed settings are immediately revised to ensure alignment with the objectives of the Act and broader Australian Government policy.

6. Risk of non-participation in the GO Scheme due to disproportionate biomethane cost recovery

The proposed PGO cost recovery settings for biomethane are set at a level that makes participation in the GO scheme commercially irrational. As a result, there is a high risk that the biomethane sector will not use the scheme in practice and will instead rely on alternative certification systems.

Foremost, if PGO certificates are sold for their emission reduction qualities, the cost of the PGO certification alone is greater than their Australian Carbon Credit Unit (ACCU) market equivalent:

- **Natural gas:** approximately **\$1.94/GJ**, compared with a GO certificate cost of **\$2.62/GJ** - meaning the GO certificate cost is around 1.4x higher than the ACCU-equivalent carbon cost.

Although ACCUs and PGOs serve different policy purposes, the implication is stark: the proposed administrative cost alone of certifying a renewable gas is higher than the market cost of simply neutralising those same emissions through the government's own carbon offset mechanism.

In addition, GO certification costs are materially higher than those of comparable domestic and international certification schemes, despite providing broadly similar benefits to producers and consumers.

For example, Australia's GreenPower's Renewable Gas Guarantee of Origin scheme performs a similar function for A\$0.12 per gigajoule, 22 times less than the GO scheme proposal.

Similarly, the ISCC system operates with lower per-unit certification fees plus modest annual and audit costs. In comparison to the proposed approach which is significantly higher, producers will likely opt for alternative schemes such as ISCC certification and avoid participation in the domestic GO scheme.

Table 2: Ordinary biomethane plant based on the proposed changes and comparing with ISCC and ACCU.

Cost component	Biomethane 50,000 GJ/year (~900 tonnes)
Functional unit (CRIS V1.1)	1 GJ HHV (Table 6)
GO certificate fee	\$1.78/GJ + \$0.84/GJ = \$2.62/GJ HHV
Total annual GO certification fee	\$131,000
Commodity value at market price ¹	\$502,000 (@ \$10.04/GJ, AEMO GSH Apr 2026)
GO fee as % of commodity value	26.1%
ACCU-equivalent offset cost ²	\$96,384 (@ \$37.65/tCO ₂ e, 51.2 kgCO ₂ e/GJ)
GO fee as multiple of ACCU equivalent	1.36× — GO fee exceeds offset cost³
Equivalent ISCC scheme fees (indicative) ⁴	~AUD \$990 (EUR 0.11/t QDF + EUR 500 cert fee)
GO fee as multiple of ISCC equivalent	~133×

¹ Commodity value uses the AEMO Gas Supply Hub spot price as the gas market reference. The GSH is a thin market; actual contracted prices may differ. The comparison uses commodity value rather than a retail or wholesale delivered price because biomethane producers typically sell into pipeline or behind-the-meter arrangements priced against the wholesale gas reference.

² The ACCU equivalence check uses combustion emission factors from the National Greenhouse Accounts (Scope 1): natural gas 51.2 kgCO₂e/GJ; aviation fuel 70.0 kgCO₂e/GJ. ACCU price of \$37.65/tCO₂e is an indicative secondary market reference (Carbon Pulse reported secondary market trades above \$40 ahead of the March 2026 Safeguard compliance date; EY Carbon Market Outlook 2026 projects a \$30–\$35 floor to 2028). ACCUs and PGO certificates are not equivalent instruments — the comparison is an order-of-magnitude reasonableness check, not a policy equivalence argument.

³ Biomethane is the only product in the GO scheme where the proposed certification fee exceeds the market cost of offsetting the equivalent fossil emissions. For a 50,000 GJ/year facility, the GO fee (\$131,000) is approximately 36% higher than the total ACCU cost of covering the same fossil gas displacement (\$96,384). A producer who purchased ACCUs instead of obtaining GO certification would achieve equivalent emissions accounting at lower cost, with none of the administrative burden. This makes the proposed fee structurally perverse for biomethane specifically: the scheme is more expensive than the instrument it is designed to support.

⁴ ISCC fees exclude audit costs charged separately by accredited certification bodies. Indicative annual audit costs for a single-site facility are USD \$5,000–\$20,000. Even including audit costs, the ISCC total remains a small fraction of the proposed GO fee at equivalent volumes. EUR/AUD conversion at approximately 1.65.

The consequence is that the GO scheme becomes functionally non-operational for biomethane: it exists administratively but will fail to generate meaningful participation from a sector it is intended to support. As a result, there will be little, if any, uptake of the PGO system by biomethane producers.

The result is a structural paradox: While the CER intends the GO scheme to operate on a full cost-recovery basis, that objective cannot be achieved if the pricing design prevents industry participation at scale.

We strongly recommend the CER review the cost recovery settings for biomethane with consideration of comparable schemes to ensure the GO Scheme is capable of supporting meaningful industry participation.

Urgent actions

If not urgently addressed, these issues will materially undermine investor confidence, weaken the domestic project pipeline, and constrain the development of Australia's biomethane industry.

We call on the CER to take the following actions as a matter of urgency

1. Revise the cost recovery approach for biomethane to ensure it is factually correct, fit for purpose, reflects the realities of the industry, and supports a workable cost recovery-based scheme, including through the introduction of a "phase in" period that aligns to a credible expected industry growth path.
2. Revise the cost recovery approach using a credible, ambitious volume forecast for biomethane reflecting state schemes and the project pipeline, with a published unit-charge trajectory. Modelling and production volumes should be published for full transparency.
3. Allocate additional time and resourcing to the cost recovery design process to ensure the scheme is properly structured to support the establishment and scale-up of the biomethane sector.
4. Collaborate closely with industry through industry roundtable to develop a scheme that accounts for the unique characteristics of Australian biomethane production conditions, and ultimately support the long-term growth of Australia's biomethane industry.

Thank you for taking the time to consider our submission. Any questions or request for further assistance are welcome and can be directed to shahana@bioenergyaustralia.org.au.

Sincerely,



Shahana McKenzie
CEO Bioenergy Australia

APPENDIX

^[1] Shellharbour Airport, 2026, 'Aviation fuel pricing: April 2026 Posted airfield price', <https://www.shellharbourairport.com.au/operational-information/aviation-fuel/>

^[2] Ratio of 34.7 MJ/L of jet fuel, CSIRO, 2023, 'Sustainable Aviation Fuel Roadmap', <https://www.csiro.au/-/media/Energy/Sustainable-Aviation-Fuel/Sustainable-Aviation-Fuel-Roadmap-International-Activity.pdf>

^[3] Australian Institute of Petroleum, 2026, 'Weekly Diesel Prices Report: Week Ending 10 May 2026', <https://www.aip.com.au/sites/default/files/download-files/2026-05/Weekly%20Diesel%20Prices%20Report%20-%2010%20May%202026.pdf>

⁴ 1MJ LHV renewable diesel equates to 0.0278 litres and it takes 35.9MJ (LHV) to generate 1 Litre – REN21

<https://www.ren21.net/gsr-2018/pages/units/units/>

Note that diesel competition is high and average annual industry net profit over the last 12 years is around 2 cents per litre of all fuels sold.

<https://www.aip.com.au/sites/default/files/download-files/2017-11/Facts%20About%20Diesel%20Prices.pdf>

*NSW \$77.10, Qld \$63.77, SA \$73.38, Tas \$77.09 and Vic \$50.36 – sourced from AEMO (annual average price)

<https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/data-dashboard-nem>

^Information sourced from AEMO Gas Supply Hub Historical Transactions. Downloaded 15/05/2026. \$7,038,535.00 spent on gas trades across the month of April 2026, and a total of 700,800GJ of natural gas traded.

<https://www.aemo.com.au/energy-systems/gas/gas-supply-hub-gsh/data-gsh/daily-gsh-reports>

Australian Institute of Petroleum, 2026, 'Weekly Diesel Prices Report: Week Ending 10 May 2026',

<https://www.aip.com.au/sites/default/files/download-files/2026-05/Weekly%20Diesel%20Prices%20Report%20-%2010%20May%202026.pdf>

~ Global Petrol Prices, 2026, 'Australian LPG prices, 11 May 2026',

https://www.globalpetrolprices.com/Australia/lpg_prices/

= CSIRO, 2023, 'Sustainable Aviation Fuel Roadmap',

<https://www.csiro.au/-/media/Energy/Sustainable-Aviation-Fuel/Sustainable-Aviation-Fuel-Roadmap-International-Activity.pdf>

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<https://www.aip.com.au/sites/default/files/download-files/2017-11/Facts%20About%20Diesel%20Prices.pdf>

& 1 litre LPG contains approximately 25MJ -

<https://www.elgas.com.au/elgas-knowledge-hub/residential-lpg/lpg-gas-unit-conversions/>

? Standard measure of conversion is 3.6GJ makes 1MWh of electricity

< Energy content of 1kg hydrogen is 141.9 MJ (HHV) or 120.1 (LHV) -

<https://www.nationalacademies.org/read/10922/chapter/21> Calculations of price range are based off \$0.0033 x 120.1LHV, and \$0.24 x 141.9HHV