Renewable Gas:

Policy Options to Support Australia's Decarbonisation Journey

Final report by KPMG

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1 Executive Summary

1.1 About this report

KPMG has prepared this report for Energy Networks Australia to examine the policy settings needed for renewable gases to contribute to Australia's net zero journey. The report presents KPMG's independent analysis of the potential role of renewable gases in the net zero transition and the policy settings required to ensure that this potential is realised. We pay particular attention to options for deployment incentive schemes, and provide recommendations for how such schemes could be designed in the Australian context.

Our scope is to consider green hydrogen and biomethane only, as the two most prospective renewable gases. Green hydrogen is produced from electrolysis using renewable electricity, and provides a renewable, low-emissions form of energy. Our analysis also includes the range of green hydrogen derivatives, such as green ammonia and synthetic methane. Blue hydrogen, which is produced from fossil fuels with carbon capture and storage, is outside the scope of this analysis. We also consider biomethane, which provides another form of renewable, low-emissions gas that is produced from the anaerobic digestion of biomass. Other forms of bioenergy, such as liquid biofuels, are not within the scope of this report.

1.2 The potential role of renewable gases in the net zero transition

Renewable gases such as green hydrogen and biomethane have the potential to deliver GHG emissions reductions by displacing conventional natural gas and other fossil fuels in the energy system.

The International Energy Agency (IEA) acknowledges that the pathway to net zero requires us to employ renewable gases for dispatchable electricity, long-term energy storage, and to decarbonise hard-to-abate sectors such as heavy industry, transport and agriculture.[1] In the electricity and energy sector, renewable gases can reduce the carbon footprint of gas-fired peaking generation used to complement variable wind and solar, while green hydrogen can be used for long-term renewable energy storage. Meanwhile, there are important applications for renewable gases in the industrial sector (such as chemical production, plastics, steel, cement, glass and food and beverage), either as a source of high-temperature heat or as a chemical feedstock. Other hard-to-abate sectors with renewable gas applications include heavy-duty long-distance transport (such as trucks, ships and planes) and agriculture (ammonia for fertiliser production).

Renewable gases are likely to play a role in the built environment sector, alongside energy efficiency and electrification. In its updated roadmap to net zero,[2] the IEA describes how energy efficiency provides the first pillar of the transition for the buildings sector, while electrification and switching to low-emissions fuels provides the second. Although electricity is expected to supply two thirds of the global energy requirement for buildings in 2050, low-emissions gases such as biomethane and hydrogen play a bigger role in 2050 in regions with high heating needs, dense urban populations and existing natural gas networks.

For Australia's built environment sector, there is a need to clarify the long-term role of renewable gases in distribution networks. Even under a 'rapid electrification' scenario, Net Zero Australia forecasts that gas distribution to homes will have a long tail, and only cease by 2050 in favour of electrified heating and cooling, due to the lengthy average lifespan of gas appliances (20 years). Net Zero Australia calls on policymakers to decide whether existing gas distribution for commercial and household customers should be repurposed to a zero-carbon fuel (such as biomethane), communicate this decision to consumers and explain its implications for their choices.[3]

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[1] IEA Bioenergy. The role of biogas and biomethane in pathway to net zero. December 2022.

[2] IEA. World Energy Outlook 2022. November 2022.

[3] Net Zero Australia. How to make net zero happen: Mobilisation report. July 2023.

1.3 The current state of renewable gas markets

1.3.1 Production volumes

Globally, the green hydrogen market is in its infancy, with less than 1% of global hydrogen produced today produced from renewable energy. Hydrogen makes up around 2.5% of global final energy consumption, with the EU and US considered major markets. Australia is currently not a major global producer or consumer of hydrogen but is host to a significant investment pipeline of green hydrogen projects.

Compared to green hydrogen, the global biomethane market is more mature. Global biomethane production was 7.4 billion cubic metres (bcm) in 2022, with the EU producing 3.6 bcm and the US producing 2 bcm. However, the biomethane market in Australia is not yet established, with Jemena's Malabar Biomethane Demonstration Plant the only current biomethane facility in operation.

1.3.2 Policy settings

Renewable gases are receiving growing policy attention in Australia. Australia's National Hydrogen Strategy sets out the strategic framework for hydrogen and is being updated, and the recently announced Hydrogen Headstart scheme commits $2 billion towards hydrogen projects. There is currently no strategy specifically focused on biomethane but the Australian Renewable Energy Agency (ARENA) commissioned a Bioenergy Roadmap in 2021. Both the Commonwealth and States have supported many renewable gas research and development (R&D) and pilot projects. Meanwhile, in terms of broader climate policy settings, the Safeguard Mechanism and Emissions Reduction Fund provide important indirect incentives for renewable gas uptake.

However, domestic policy settings are less advanced and ambitious than international partners. The Inflation Reduction Act (IRA) in the US includes production tax credits for clean hydrogen and directs US$10 billion in funds and investment tax credits to incentivise the development of biogas facilities. The European Hydrogen Strategy has an objective to produce 10Mt of renewable hydrogen in the EU by 2030, and the REPowerEU Plan commits to increasing Europe's annual production of biomethane to 35 bcm by 2030.

1.4 Priorities for Renewable Gas Policy

We identify three priority areas for policymakers: setting market and regulatory foundations, stimulating production to drive down costs, and managing social license and spill-overs.

1.4.1 Setting market and regulatory foundations

Work is currently underway on green hydrogen certification, but efforts to certify biomethane need to be accelerated. Certification of renewable gases is critical to support market demand as currently end users do not have a mechanism to distinguish biomethane from natural gas or green hydrogen from grey hydrogen. Certificates which guarantee the provenance and emissions attributes of green hydrogen and biomethane, and complementary reforms to emissions reporting frameworks, will allow end users to make emissions reduction claims and support the growth of the market.

Domestic regulatory alignment with international standards is important to provide confidence in product safety and reduce costs. Contrasting biomethane standards within and outside Australia currently adds complexity and cost for prospective project developers, and current gas specifications in Australia are more stringent than in the EU. Regulations should also be harmonised across jurisdictions.

1.4.2 Stimulating production and driving down costs

Deployment incentives will have an important role in supporting Australia's green hydrogen and biomethane industries to move down technology cost curves more quickly and achieve the scale of production needed to contribute to sectoral decarbonisation pathways. Deployment incentive schemes have been widely used in Australia and internationally to support uptake of renewable energy technologies. By providing financial support to bridge the commercial viability gap between production costs and market prices, deployment incentives help to encourage investment in production capacity. This helps industries to achieve economies of scale and learning effects more quickly than would otherwise be the case. For renewable gases, this will translate to faster emissions reductions through more rapid displacement of fossil fuels in priority sectors. Lower costs for renewable gases may also provide additional options for sectors with as-yet uncertain decarbonisation pathways. The Renewable Energy Target (RET) provides a well-known example of a deployment policy which began at a modest scale and helped to drive down the cost of renewable electricity generation.

Deployment policies are also an appropriate response to developments on the international stage. Significant public policy backing for hydrogen in the US and EU means that these economies are likely to be preferred destinations for international capital, and this could lead to first-mover advantages in the international trade of hydrogen. According to some commentators, Australia runs the risk of being 'left behind' in the global hydrogen economy if there is an inadequate response to these industrial policies. For example, it has been estimated that if Australia does not respond to the IRA, exports of hydrogen could be 65% less per year by 2050 than what was expected before the IRA's introduction.[4]

In response to these drivers, the Australian Government has begun developing larger-scale deployment policy for green hydrogen. Namely, Hydrogen Headstart will provide revenue support for a small number of large-scale renewable hydrogen projects. The program will be implemented through competitive hydrogen production credit contracts, with the aim of putting Australia on course for up to a gigawatt of electrolyser capacity by 2030.[5]

Next steps should focus on setting clear aspirational targets for renewable gases, developing suitable deployment incentives for biomethane, and identifying options to build on the Hydrogen Headstart program over the medium term. Deployment measures should be guided by clear aspirational targets for the production of renewable gases by 2030 and 2035. Such targets will set the level of ambition for deployment policy design and provide a clear signal to investors on the role of renewable gases in Australia's decarbonisation journey. Once targets are established, policymakers should evaluate options to build on Hydrogen Headstart and establish similar incentives for biomethane (see Section 1.5 for discussion of options).

1.4.3 Addressing social license and spill over effects

As renewable gas uptake accelerates, it will be important to actively manage the potential for spill-over effects and social license issues. Strategic planning and public awareness initiatives should be prioritised to complement renewable gas deployment policies.

The development of a national bioenergy strategy is recommended, as policy settings for biomethane should be considered in the context of the broader role for bioenergy in Australia's journey to net zero. Other uses of biomass (such as liquid biofuels and electricity generation from biomass) will mean that there is likely to be competition for biomass resources. It will also be necessary to mitigate any risks arising from expanded bioenergy production, including managing land-use competition and impacts. On the other hand, bioenergy holds potential to add value to waste and by-products, providing new sources of regional jobs. The development of a national bioenergy strategy with realistic targets will help to address these potential challenges and opportunities while also providing a clear signal to industry.

Renewable gas policies need to be accompanied with appropriate public communication to build awareness and understanding. Public awareness of renewable gases and their role in the energy transition is limited, and this could lead to social license challenges as deployment policies are progressed.

1.5 Design options for deployment policy

Having identified deployment policy as a priority, we assessed policy options for their suitability to stimulate production over the next five to 10 years. After this initial stage, appropriate policy options would need to be reassessed based on the cost reductions that have been achieved and new information available on the most viable net zero pathways for different sectors and uses.

We shortlisted three options, each of which draw from models that have been widely used in energy markets:

- **A Renewable Gas Certificate (RGC) scheme.** Under an RGC scheme there is an annual renewable gas production target calculated from an estimated proportion of forecast gas consumption. This target could be different for hydrogen and biomethane. Participating producing

[4] Deloitte. deloitte-au-australias-hydrogen-tipping-point-report-updated-280223.pdf. Last updated 28 February 2023.

[5] DCCEEW. Hydrogen Headstart program - DCCEEW. Last updated 6 July 2023.

entities would receive a Renewable Gas Certificate for each 1 TJ of renewable gas supplied to the market. To reach the target, liable entities (large users and gas retailers) are required to purchase a proportion of RGCs in line with their forecasted share of total natural gas consumption.

- **A Contract for Difference (CfD), where the shortfall between the cost to produce renewable gas and the price it can be sold for is covered by the government for an established period of time.** Contracts for difference incentivise renewable gas production by providing price certainty to developers. Some CfD designs include upside risk sharing, where the government will receive the difference between the strike price and market price when the market price is higher.
- **A Feed in Tariff (FiT), where renewable gas producers receive a fixed amount of revenue per unit of renewable gas injected in the network for an established period of time.** FiT's are typically paid as a fixed tariff rate on the volume of renewable gas supplied to the network. The aim of a FiT is to incentivise production by providing a premium above fossil fuel competitors for renewable gases.

The three policy options above are not necessarily mutually exclusive, but rather provide an illustration of the trade-offs between policy design choices. For example, an RGC scheme provides certainty on production quantities but with greater risk on the total policy cost. A CfD provides a cap on the policy cost, but greater uncertainty on the production quantity that will be achieved. In practice, policies can be designed to combine elements across the three instrument types or multiple instruments can be implemented in parallel (e.g. an RGC scheme with CfD contracts for certificates).

For any policy instrument, an important first step is to set ambitious but realistic targets for renewable gas production. While target-setting is an inherent feature of an RGC scheme, CfD and FiT designs should also be calibrated against quantitative production targets that align to the desired policy ambition (which in turn reflects factors such as scale of deployment, availability and cost). The key differences between the three types of instruments are in the mechanisms through which they aim to meet a given production target, and in how they allocate the associated costs and risks.

1.5.1 Qualitative assessment

We qualitatively assessed the three policy instruments against six key criteria, outlined below.

Assessment Criteria	
Capacity to deliver material cost reductions in future	Capacity to cost-effectively reduce greenhouse gas (GHG) emissions and contribute to net-zero pathways
User preferences, social license and avoiding disruptive change	Market co-ordination and managing spill-overs
Allocation of costs	Allocation of risk

Each instrument has their advantages and disadvantages, which may change at different points in time. Importantly they have different allocations of costs and risks that will influence the choice of instrument as circumstances change. As conventionally implemented an RGC scheme will be borne by consumers in the market, via consumer charges. CfDs and FiTs are usually budget-funded, though they can be recovered in other ways. Risks around cost, technology and supply are also allocated differently. An RGC scheme is more administratively complex and would require a longer lead time to implementation than a budget-funded CfD or FiT.

Based on our analysis, an attractive approach at the current juncture would be to combine the strengths of a FiT with elements of a CfD design, as under the proposed Hydrogen Headstart scheme. A conventional CfD design provides flexibility and breadth in terms of eligible sectors and uses, but government bears price risk and uncertainty on the total scheme cost (given that this is dependent on the difference between the strike price and prevailing market price). The proposed Hydrogen Headstart design provides a sensible middle ground. It provides investor certainty in the form of a fixed production credit contract, which also provides certainty to government on fiscal cost. In addition, the government has proposed other risk sharing elements, including that the government can share in upside price risks should they eventuate. It can be developed relatively quickly as it is implemented via contracts rather than legislation, and allows for close attention to potential spill-overs from recipient projects.

An RGC scheme has advantages as a market-based, emitter-pays mechanism, and could be considered in the medium term. An RGC scheme could be a highly effective instrument for stimulating deployment at scale and cost reductions, in a similar fashion to the RET for renewable electricity. Market participants bear some cost and price risk, along with consumers. However, renewable gas technologies and supply chains in Australia are arguably at an earlier stage of development than was the case at the inception of the RET. Both markets are also likely to be considerably less liquid, with fewer suppliers in earlier years due to the importance of scale (with hydrogen) and the need to develop limited biomass/waste supplies (for biomethane). In the short-term, building off the Hydrogen Headstart approach would provide a lower-risk option for managing price risks and unforeseen spill-overs, while also mobilising support more quickly.

Focusing first on CfD-style policy instruments can be considered as a transitionary approach to provide timely industry support and manage risk, while other instruments may be more appropriate in the medium term as the market matures. An RGC scheme can be considered for implementation, based on the information and lessons gathered from Hydrogen Headstart and an equivalent CfD scheme for biomethane. A FiT approach could also be considered for biomethane once more information is available on supply points and prices. We suggest a review point in around five years' time would be the appropriate juncture to consider whether these more structured deployment approaches were warranted, and to consider the scale of aspirational targets for the mid-2030s and beyond.

1.5.2 Possible policy settings and modelling results

Our quantitative analysis of possible deployment policy settings assessed three possible levels of ambition compared to the status quo, with the upper bound aligned to AEMO's 'Diverse Step Change' scenario assumptions for renewable gas blending. For each level of ambition, we defined separate targets for green hydrogen and biomethane given their different characteristics and different potential contribution to decarbonisation pathways. The options were:

- *Status quo*: business as usual to 2030, including Hydrogen Headstart projects, and small amounts of biomethane used by industry.
- *Low ambition:* target 2% of domestic gas consumption for hydrogen by volume, 0.7% by energy by 2030 (equivalent to increasing Hydrogen Headstart by 50%), and 0.5% biomethane by 2030.
- *Medium ambition:* midway option between status quo and AEMO GSOO scenario. 5% of domestic gas consumption hydrogen by volume, 1.7% by energy by 2030, and 1.2% biomethane by 2030 (3% in distribution network, 1% for gas power generation (GPG) and large industrial).
- *High ambition:* 10% of domestic gas consumption hydrogen by volume, 3% by energy by 2030, and 2.7% biomethane by 2030 (7.5% in distribution network, 2% for GPG and large industrial). This ambition aligns with AEMO 2023 GSOO Diverse Step Change (1.8 degrees) scenario for distribution networks.

We then assessed the cost, production volumes and emissions reductions associated with each level of ambition. Based on these targets and the assumed additional cost per GJ to produce biomethane and hydrogen compared to natural gas, the total cost until 2030 in addition to the status quo for the *low ambition* scenario is $370M, $1.87B for the *medium ambition* scenario and $4.0B for the *high ambition* scenario. The *high ambition* scenario generates 197 PJ of renewable gas until 2030 (60 PJ in 2030) and would lead to a cumulative emissions reduction of 10 million tonnes by 2030. This equates to an average abatement cost of $285 and $739 per tonne for biomethane and hydrogen respectively. Comparing this to the RET eight years after its inception[6], abatement costs ranged from $30 to $290 per tonne (in 2011 dollars). The overall cost of the RET was around $300M-$500M per year (or $2.1B-$3.5B over seven years equivalent) and CO2 emissions abated were estimated to be between 4 and 9 million tonnes.

While the more ambitious options involve greater costs now, they may also lead to greater benefits in the 2030s. This is because learning and scale effects would likely be higher, leading to price reductions for renewable gas production, which would in turn trigger greater uptake. As a comparison, when the RET was introduced in 2001, renewables made up 7.7% of electricity

[6] RET How it works and what it costs November 2013.docx (climatechangeauthority.gov.au)

generation in Australia, and 20 years later it was 26.7% of the generation mix,[7] thanks in significant part to the investments stimulated by the RET and the reductions in renewables technology costs that the scheme helped to drive in the Australian context. In the case of renewable gas, the potential extent of future cost reductions remains uncertain and may also be affected by supply constraints as more ambitious production targets place upward pressure on input prices.

We then compared two illustrative policy instruments for achieving these levels of ambition, and assessed the implications for the allocation of costs. We compared Option One: RGC schemes for both biomethane and hydrogen, and Option Two: a CfD-style approach involving an expansion of Hydrogen Headstart and the creation of an equivalent 'Biomethane Booster' for biomethane. These options were chosen for illustrative purposes, to compare contrasting approaches to cost and risk allocation. In practice, policy instruments may be designed with cost and risk sharing arrangements that combine elements of both designs. For Option One (RGC), the cost to fund the scheme would sit with retailers and large gas users. If costs were passed onto households and businesses for the proportion of renewable gas that goes to the distribution network, the cost per household/commercial connection per year in 2030 would be $2 for the low ambition scenario, $33 in the medium and $68 in the high ambition scenario. This is comparable to the early consumer costs of the RET, which have been estimated in the range of $50-$100.[8] If Option Two (CfDs) were taken up, and none of the costs passed to consumers, government would fund the costs to 2030.

The choice of instrument also depends on whether price certainty or volume certainty is preferred, and who (retailers/major gas users or government) should be responsible for bearing cost and market risks. For Option One (RGC), the impact of changes in production cost would be borne by producers, retailers and gas users, and there would be no or limited change to renewable gas volumes. Our analysis shows an increase of 20% on the assumed additional cost to produce renewable gas over natural gas could increase costs to retail consumers and large gas users by $180M - $910M under Option 1, depending on the ambition. For Option Two (CfDs), costs would be borne by government the contract amount would be set, with volumes of renewable gas more uncertain. For Option Two, producers are at risk of losing revenue if the cost to produce renewable gas is higher than assumed under the production credit contract. In contrast, if production costs are more favourable than anticipated, the surplus would be shared between producers and government.

1.6 Our recommended path forward

We assess that a contract-for-difference policy instrument is most suited to the immediate need to accelerate deployment of renewable gases, while an RGC scheme can be established in the medium term as the market matures. A CfD approach will provide an opportunity to share in the several risks around technology cost curves and natural gas pricing, while also allowing the range of positive spill-overs to be explored, and potential risks managed. A CfD approach can be established quickly and help provide the initial steps towards incentivising renewable gas production, before an RGC scheme is considered in the medium term. A FiT could also be considered as a medium-term option for biomethane.

Such a policy approach can occur within the framework of ambitious but achievable targets for each renewable gas. Targets can assist industry planning and guide further policy development. We consider though that this target should be separated from the RGC scheme policy instrument itself given the characteristics of this market, and should be defined separately for green hydrogen and biomethane.

Hydrogen Headstart establishes a CfD-style framework for green hydrogen, and an analogous approach should be developed for biomethane. For Hydrogen Headstart, the focus for potential extensions should be on expanding the range of use cases and supply chain options for bringing this renewable gas to market. A similar 'Biomethane Booster' program, scaled in such a way as to provide

[7] KPMG calculations based on data from Australian electricity generation | energy.gov.au, accessed September 2023

[8] The Centre for International Economics. The Renewable Energy Target: How it works and what it costs Last updated November 2013. On page 14, the report cites consumer cost estimates for 2012/13 from ACIL Tasman ($50, real 2011 dollars), IPART ($102, nominal) and the Climate Change Authority ($68, nominal).

meaningful testing of different feedstock and supply chain options, would address the main gap in the current policy framework.

The below roadmap sets out key recommended actions over the next five years to establish market foundations and drive initial deployment, while gaining more understanding of spill-overs. The initial focus is on setting market foundations and getting production mobilised quickly through CfD contracts, with early actions remaining open to a broad range of use cases and sectors. By the late 2020s, policymakers would turn attention to setting more ambitious 2035 targets and establishing appropriate instruments for this scale up, such as an RGC scheme (or possibly a FiT for biomethane). At that stage, policymakers can also consider the implications of new information on technology costs and sectoral decarbonisation pathways. This could lead to a refinement in the sectoral focus of deployment policies, and/or new focus areas for R&D policy, e.g. to ensure appropriate efforts to develop hydrogen appliances for the most prospective end use cases. A core principle of our proposed roadmap is continuous iteration, with refinements to ambition, sectoral focus and preferred policy instruments over time based on experience, market maturity and new information.

A Five-Year Roadmap for Policymakers

See Appendix 2 for a graphical summary of the Roadmap.

Phase		Priority Actions	Timeline
1	**Next 9 months**	• Accelerate timeline for biomethane inclusion in GOO • Ensure that CCA’s 2023 NGER review considers issues around the recognition by facilities of renewable gas contracting and use, including in the case of blended gas from networks or other shared infrastructure. • Complete review of National Hydrogen Strategy • Develop a high level National Bioenergy Strategy to inform the development of sectoral decarbonisation pathways. • As part of these strategies identify any gaps in technical and market regulation, and user information, on renewable gases and processes to address these going forward	Sep - June 2024
2	**Next year**	• Confirm 2030 aspirational targets for green hydrogen and biomethane • Award contracts for first round of Hydrogen Headstart • Allocate funding for a Biomethane Booster deployment policy in the 2024 budget. Complete program design by end of 2024 • Based on first tender, consider allocating additional funding for a second round of Hydrogen Headstart for the FY25 fiscal year, with the intent of broadening the use cases funded • GOO scheme legislated, covering both green hydrogen (and derivatives) and biomethane • Ensure that existing R&D funding mechanisms (e.g. ARENA) fund a portfolio of both green hydrogen and biomethane demonstration pilots, to inform a wide range of use cases • Ensure any market and technical regulatory issues addressed to ensure sector readiness for wider deployment	June - Dec 2024
3	**Next 2 years**	• GOO scheme is fully operational • Round 1 Hydrogen Headstart projects under development • Round 1 Biomethane Booster projects under development	2025

	Phase	Priority Actions	Timeline
4	**Next 3 years**	• Round 1 Hydrogen Headstart projects begin production by end of 2026 • Round 1 Biomethane Booster projects begin production by end of 2026	2026
5	**Next 5 years**	• Take stock of information learned to date on costs and sectoral abatement pathways, and evolving demand occurring as part of more general policy impulses such as the Safeguard Mechanism and any renewable energy policies. Consider if ambition of 2030 aspirational targets can be increased. • Refresh National Hydrogen Strategy and National Bioenergy Strategy • Set renewable gas strategic targets for 2035 and 2040, consistent with latest national targets for 2035 and 2040 emissions reductions. Based on the lessons learned so far and the evolution of costs, there could be shifts in sectoral focus and overall ambition • Ensure that R&D program complements the focus of these strategic targets. For example, if there is increased emphasis on network blending of green hydrogen, then R&D efforts for hydrogen appliances would need to be prioritised, and potentially deployment incentives • Consider a market based Renewable Gas Certificate scheme for the next phase of deployment, building from momentum of the early CfD programs. A FiT could also be considered for biomethane	2027-2028

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2 About This Report

2.1.1 Purpose

KPMG has prepared this report on behalf of Energy Networks Australia to examine the policy settings needed for renewable gases to contribute to Australia's net zero journey. The report presents KPMG's independent analysis of the potential role of renewable gases in the net zero transition and the policy settings required to ensure that this potential is realised. We pay particular attention to options for deployment incentive schemes, and provide recommendations for how such schemes could be designed in the Australian context.

2.1.2 Scope

Our scope is to consider green hydrogen and biomethane only, as the two most prospective renewable gases. Green hydrogen is produced from electrolysis using renewable electricity, and provides a renewable, low-emissions form of energy. Our analysis also includes the range of green hydrogen derivatives, such as green ammonia and synthetic methane. Blue hydrogen, which is produced from fossil fuels with carbon capture and storage, is outside the scope of this analysis. We also consider biomethane, which provides another form of renewable, low-emissions gas that is produced from the anaerobic digestion of biomass. Other forms of bioenergy, such as liquid biofuels, are not within the scope of this report.

2.1.3 Our approach

In conducting our analysis, we have relied primarily on desktop review of published independent research. In addition, to inform our understanding of the current state of Australian renewable gas markets and the key barriers that are limiting uptake, we completed a series of consultations with industry stakeholders from Energy Networks Australia's membership. However, views and recommendations expressed in this report are solely those of KPMG.

2.1.4 How to read this report

The report is structured as follows:

- Chapter 3: Renewable gases and their role in the net zero transition, including the supply chain for renewable gases and key stakeholders
- Chapter 4: Current state of renewable gas markets and the current policy landscape
- Chapter 5: Priorities for renewable gas policy to establish an enabling environment to overcome key barriers to renewable gas uptake. These include:
  - Setting the market and regulatory foundations
  - Stimulating production and driving down costs
  - Managing social license and spill-overs
- Chapter 6: An overview and qualitative analysis of the potential instruments for deployment of renewable gases. These include:
  - Renewable Gas Certificate (RGC) scheme
  - Contracts for Difference
  - Feed in Tariff
- Chapter 7: Quantitative assessment and analysis of the recommended policy options
- Chapter 8: Report conclusions and next steps, including a proposed five-year roadmap for policymakers.

2.1.5 Disclaimer

The views and recommendations contained in this report are solely those of KPMG.

3 Understanding the Potential Role of Renewable Gases

This section describes the two most important types of renewable gas, green hydrogen and biomethane, and the potential roles they will play during the transition to net zero.

3.1 What is renewable gas?

Renewable gases are gaseous fuels that are derived from renewable sources. Depending on the production pathway, renewable gases can have low or even negative lifecycle greenhouse gas (GHG) emissions associated with their production and combustion.[9] Renewable gases have the potential to deliver GHG emissions reductions by displacing conventional natural gas and other fossil fuels in the energy system.

Our analysis focuses on green hydrogen and biomethane, which are considered the two most prominent and commercially promising types of renewable gases.

3.1.1 Green Hydrogen

Hydrogen is a versatile and widely used energy carrier and feedstock. Hydrogen can be stored as a gas or liquid and has many uses such as fuel for transport or heating, a way to store electricity (or produce electricity via a fuel cell), or a raw material in industrial processes.[10] To produce hydrogen, it must be separated from the other elements in the molecules where it occurs.

Green hydrogen (also known as renewable hydrogen) refers to hydrogen produced from renewable electricity. Green hydrogen is produced via electrolysis, where an electrolyser is used to split water into hydrogen and oxygen. For green hydrogen, the energy used to power the electrolyser comes from a renewable energy source such as solar or wind power.[11]

'Grey' and 'blue' hydrogen

The most common method for producing hydrogen today is steam-methane reformation (SMR), which primarily utilises natural gas in reactions with steam. Approximately 95% of hydrogen produced is via SMR of natural gas and this hydrogen is referred to as **'grey' hydrogen**. Grey hydrogen is highly emissions intensive, producing around 8.5-10kg of carbon dioxide emissions per kg of hydrogen produced.[12]

'Blue' hydrogen is hydrogen that is produced via SMR but the resulting carbon dioxide emissions are captured and stored underground through carbon capture and storage (CCS) technology.[13] While blue hydrogen may hold potential as a low-carbon fuel, it is not considered a renewable gas and so is outside the scope of this analysis.

Hydrogen can also be used to make further derivatives such as synthetic methane, **methanol and ammonia** (which includes **e-methanol** and **green ammonia** which are both made using green hydrogen).[14, 15] Ammonia is an effective hydrogen 'carrier' as it has a much higher density than hydrogen which makes it much easier to store and transport. Ammonia can then be transformed back into hydrogen when required.[16]

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[9] For example, see Defining low-carbon gas and renewable gas in the European Union (theicct.org) for a discussion of renewable gas definitions and estimates of lifecycle GHG emissions of different gases in the EU.

[10] Australian Renewable Energy Agency (ARENA). Hydrogen energy. Last updated 24 August 2023.

[11] Department of Energy, Environment and Climate Action (DEECA). Renewable hydrogen. Last updated 12 October 2022.

[12] Clean Energy Finance Corporation (CEFC). Australian hydrogen market study: Sector analysis summary. 24 May 2021

[13] Howarth R, Jacobson M. How green is blue hydrogen?. Energy Science and Engineering. 12 August 2021

[14] Terega. What is synthetic methane?.

[15] McCurdy M, Podal P. How e-methanol can enable the hydrogen economy while adding value to captured carbon. ICF. 22 February 2023.

[16] The Royal Society. Ammonia: zero-carbon fertiliser, fuel and energy store. 19 February 2020.

Hydrogen can be blended with natural gas at rates of up to 20% before requiring modification of pipeline infrastructure and household appliances.[17] Beyond 20% blending, or for pure hydrogen applications, additional investments are likely to be required to ensure compatibility of appliances and infrastructure. Furthermore, as hydrogen has around a third of the calorific value of natural gas by volume, a blend of 20% hydrogen will displace less than the equivalent volume of natural gas, and deliver a commensurate reduction in carbon emissions of around 6-7%.[18]

3.1.2 Biomethane

Biomethane is a renewable gas with almost identical characteristics to natural gas. It can be fed into the existing gas transportation infrastructure and can rely on proven technologies for its utilisation.[19] However, some additional steps may be required to ensure that biomethane meets regulatory standards for gas grid injection (such as odorization, heating specifications, etc.).[20]

Biomethane is produced by 'upgrading' biogas from organic sources. Biogas is a mixture of methane, carbon dioxide and small quantities of other gases produced by anaerobic digestion – the breakdown of organic matter (such as food waste, animal manure, organic municipal solid waste and crop residue) in an oxygen free environment.[21] Biogas is typically around 60% methane and 40% carbon dioxide, with trace amounts of other gases present. Biomethane is biogas that has been 'upgraded' to remove the carbon dioxide from biogas to leave a near pure source of methane (around 97%).

Bio-synthetic natural gas (bio-SNG) is biomethane that has been produced via thermal gasification of biomass (such as forestry residues or energy crops). Under this process, the biomass is converted into a mixture of gases which are then cleaned to remove any acidic and corrosive components. This leaves bio-SNG, which can be used in the same manner as biomethane.[22] Around 90% of total biomethane produced globally is via upgrading biogas, with the remaining 10% produced via thermal gasification (thus bio-SNG).[23]

For the remainder of this report, biomethane from anaerobic digestion and upgrading and bio-SNG are collectively referred to as 'biomethane'.

3.2 The role of renewable gases in the net zero transition

The International Energy Agency (IEA) acknowledges that the pathway to net zero requires us to employ renewable gases for dispatchable electricity, long-term energy storage, and to decarbonise hard-to-abate sectors such as heavy industry, transport and agriculture.[24] In the electricity and energy sector, renewable gases can reduce the carbon footprint of gas-fired peaking generation used to complement variable wind and solar, while green hydrogen can be used for long-term renewable energy storage. Meanwhile, there are important applications for renewable gases in the industrial sector (such as chemical production, plastics, steel, cement, glass and food and beverage), either as a source of high-temperature heat or as a chemical feedstock. Other hard-to-abate sectors with renewable gas applications include heavy-duty long-distance transport (such as trucks, ships and planes) and agriculture (ammonia for fertiliser production).

Renewable gases are likely to play a role in the built environment sector alongside energy efficiency and electrification. In its updated roadmap to net zero,[25] the IEA describes how energy efficiency provides the first pillar of the transition for the buildings sector, while electrification and switching to low-emissions fuels provides the second. Although electricity is expected to supply two thirds of the global energy requirement for buildings in 2050, low-emissions gases such as

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[17] Melania M, Antonia O, Penev M. Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues. National Renewable Energy Laboratory. March 2013.

[18] Burgess J. UK's gas grid ready for 20% hydrogen blend from 2023: network companies. S&P Global Commodity Insights. 14 January 2022.

[19] IEA Bioenergy. The role of biogas and biomethane in pathway to net zero. December 2022.

[20] U.S. Environmental Protection Agency (EPA). An Overview of Renewable Natural Gas from Biogas. July 2020.

[21] International Energy Agency (IEA). Outlook for biogas and biomethane: Prospects for organic growth. March 2020.

[22] European Technology and Innovation Platform Bioenergy. Bio-SNG (Synthetic Natural Gas) and Gasification Technologies.

[23] IEA. Outlook for biogas and biomethane: Prospects for organic growth. July 2020.

[24] IEA Bioenergy. The role of biogas and biomethane in pathway to net zero. December 2022.

[25] IEA. World Energy Outlook 2022. November 2022.

biomethane and hydrogen play a bigger role in 2050 in regions with high heating needs, dense urban populations and existing natural gas networks.

For Australia's built environment sector, there is a need to clarify the long-term role of renewable gases in distribution networks. Even under a 'rapid electrification' scenario, Net Zero Australia forecasts that gas distribution to homes will have a long tail, and only cease by 2050 in favour of electrified heating and cooling, due to the lengthy average lifespan of gas appliances (20 years). Net Zero Australia calls on policymakers to decide whether existing gas distribution for commercial and household customers should be repurposed to a zero-carbon fuel (such as biomethane), communicate this decision to consumers and explain its implications for their choices.[26]

Table 1: The Potential Role of Renewable Gases in Sectoral Net Zero Pathways

The Australian Government is developing six sectoral decarbonisation plans.[27] Renewable gases have a potential role to play in each, as shown further in the table below.

Major sector	Potential role for renewable gases
Electricity and energy	• Long term storage and export (green hydrogen) • Reducing the emissions intensity of gas-fired peaking plants
Industry	• High temperature heat (steel, cement, glass) • Chemical production
Resources	• Gas generation for remote mining sites • Hydrogen for heavy-duty vehicles such as mining trucks • Low-emissions ammonia and other chemicals for mining and mineral processing applications
The built environment	• Biomethane and hydrogen blending to reduce emissions from gas appliances in existing buildings • May have a more prominent role in southern locations with high heating needs and dense populations
Agriculture and land	• Low-emissions ammonia and fertiliser production • Biomethane as waste-to-energy
Transport	• Hydrogen for heavy-duty transport (trucks and maritime)

3.2.1 Green Hydrogen

According to the IEA, low-carbon hydrogen should first be used to replace existing uses of fossil energy in ways that do not immediately require new transmission and distribution infrastructure. Under the IEA's *Net Zero by 2050 Roadmap for the Global Energy Sector*, priorities to 2030 include hydrogen use in industry, refineries, power plants and the blending of hydrogen into natural gas for distribution to end-users. Under the scenario most consistent with Paris commitments, global hydrogen use expands from less than 90 Mt in 2020 to over 200 Mt in 2030, with the proportion of low-carbon hydrogen rising from 10% in 2020 to 70% in 2030. Around half of low-carbon hydrogen produced globally in 2030 comes from electrolysis (green hydrogen) with the remainder to come from coal and natural gas with CCUS (blue hydrogen).

After 2030, under a 1.5 degree scenario, global low-carbon hydrogen use expands rapidly in all sectors until a projected 530 Mt of hydrogen is produced in 2050.[28] In total, 10% of total global energy consumption in 2050 is to be supplied by low-carbon hydrogen (of which 60% is green hydrogen).

In Australia, hydrogen is expected to enable between 10% to 33% of our required emissions reductions to net zero, while providing opportunities for clean energy exports.[29] The Net Zero Australia study foresees a rapid expansion of hydrogen production out to 2050, with the mix of green

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[26] Net Zero Australia. How to make net zero happen: Mobilisation report. July 2023.

[27] Department of Climate Change, Energy, the Environment and Water (DCEEW). Net Zero. 28 August 2023.

[28] IEA. Net Zero by 2050 - A Roadmap for the Global Energy Sector. October 2021.

[29] DCCEEW. National Hydrogen Strategy Review: Consultation Paper. July 2023.

vs. blue hydrogen varying across scenarios.[30] In its recent National Hydrogen Strategy Review position paper, the Department of Climate Change, Energy, Environment and Water (DCCEEW) noted that Australia is well placed to play a significant role in the global green hydrogen industry, given our renewable energy potential and history as an energy exporter. DCCEEW highlighted several priority use cases for green hydrogen, including:

- **Ammonia production for domestic use and export** – decarbonising existing ammonia production is a relatively straightforward opportunity for carbon abatement as the industry already makes direct use of 425,000 tonnes of hydrogen per year from unabated fossil fuels.
- **Industrial process heat** – Process heat for industrial purposes accounts for around 22% of the nation's end use energy through the combustion of fossil fuels. Hydrogen can replace natural gas for industrial purposes, particularly where heat is required at medium to high temperatures.
- **Electricity grid firming** - Hydrogen can also play a key role in supporting the decarbonisation and transformation of national electricity grids through creating schedulable load, storing energy when generation is in surplus and making it available to help meet peak electricity demand.
- **Transport** – Hydrogen is valuable to displace diesel use for heavy commercial vehicles such as trucks, forklifts, mining vehicles, buses, trains, marine shipping and ferries.

The extent of future hydrogen blending in gas networks is yet to be clarified. While Australia's 2019 Hydrogen Strategy included a substantial focus on hydrogen blending in gas networks, DCCEEW's current Review suggests some caveats. Citing a recent Grattan Institute study,[31] DCCEEW notes that using renewable electricity directly may provide a cheaper and more efficient source of residential space and water heating, given the energy loss involved in producing green hydrogen from renewable electricity. On the other hand, a recent BCG report noted that under certain future pricing assumptions (around $2-3 per kg wholesale or $40-51 per GJ retail), green hydrogen could be total-cost competitive in some existing houses with gas appliances, particularly those where it is expensive to electrify.[32] Meanwhile, DCCEEW also points to the need to prioritise hydrogen for industrial users (which make up a significant share of gas network customers), and the Review is considering how existing gas infrastructure can be repurposed to address these priority industrial use cases.

Consistent with this uncertainty, net zero scenario modelling presents a range of possible futures for hydrogen in gas distribution networks. In its 2023 Gas Statement of Opportunities, the Australian Energy Market Operator (AEMO) has assumed at least 10 percent hydrogen blending (by volume) in distribution networks by 2030 across its scenarios. Under its Green Energy Exports (1.5 degrees) scenario where renewable electricity production and electrification expand most rapidly, hydrogen blending increases to 80% by 2042.[33] The Net Zero Australia report highlights that while reticulating clean hydrogen to household and commercial customers through gas distribution pipes is expected to be technically feasible, it is considered an expensive decarbonisation approach once blending exceeds rates that would require consumers to replace burners and appliances. The use of hydrogen is not an input to any scenario regarding gas distribution to household and commercial customers.[34]

3.2.2 Biomethane

Global biomethane production is set to expand rapidly during the transition to net zero, with a focus on industrial uses and gas network blending. Under the IEA's *Net Zero by 2050 Roadmap for the Global Energy Sector*, biomethane demand grows to 8.5 exajoules (EJ) per year by 2050 (up from 1.4 EJ in 2020) thanks to blending mandates for gas networks. By 2050, average blending rates increase to above 80% in many regions. 50% of total biomethane use is estimated to be used in the industry sector where biomethane replaces natural gas as a source of process heat. The buildings and transport sectors account for a further 20% of biomethane consumption in 2050. In total,

[30] Net Zero Australia. How to make net zero happen: Mobilisation report. July 2023.

[31] Wood T, Reeve A, Suckling E. Getting off gas: why, how, and who should pay?. June 2023.

[32] Boston Consulting Group. The Role of Gas Infrastructure in Australia's Energy Transition. June 2023. BCG notes that the optimal solution for an integrated clean energy system will differ by location and would require extensive regional level planning surrounding climate, network capacity, marginal supply, customer profile and availability of low carbon gases.

[33] Australian Energy Market Operator (AEMO). Gas Statement of Opportunities. March 2023.

[34] Net Zero Australia. How to make net zero happen: Mobilisation report. July 2023.

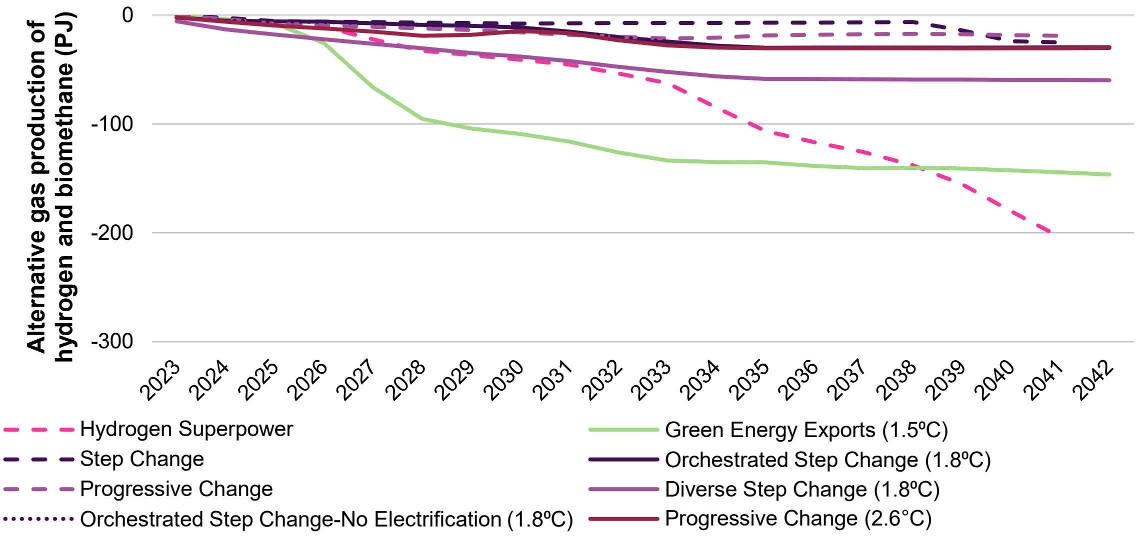
electricity generation using bioenergy reaches 5% of total energy generation by 2050.[35] In the European Union, the REPowerEU Plan has a production target of 35 bcm of biomethane by 2030 (up from 3 bcm produced in 2022).[36]

In Australia, it is likely that there will be a role for biomethane blending in the gas network and to support decarbonisation of hard-to-abate sectors, but with biomass supply being a key factor.[37, 38] In its Bionenergy Roadmap, the Australian Renewable Energy Agency (ARENA) describes how in the long term and with increased support, the share of biomethane injected into the grid could reach 33% by 2050.[39] ARENA's outlook that biomethane is most likely suited to gas grid injection aligns with AEMO modelling, which highlights a variety of biomethane blends in the gas distribution network under a range of emissions outcome scenarios, ranging from a 7.5% to 14% blend by 2030.[40] ARENA's Australian Biomass for Bioenergy Assessment has collated datasets on biomass supply in Australia,[41] but further strategic planning is need (see Chapter 5 for further discussion).

Renewable Gases Will Be Used to Displace Natural Gas, Diesel, and Coal in Hard-to-Abate Sectors

Renewable gases will reduce emissions by replacing consumption of natural gas, diesel and coal. Domestic natural gas consumers provide a key future market for renewable gas, and include: industry (36% of domestic natural gas demand),[42] gas power generators (34% of domestic demand), and residential and commercial buildings (15% of domestic demand). Figure 1 below illustrates a range of scenarios for hydrogen and biomethane to displace natural gas consumption over time. Meanwhile, renewable gases can also support decarbonisation for existing diesel consumers in the heavy transport and resources sectors, and for industrial producers that currently rely on coal (e.g. in ammonia production).

Figure 1: AEMO scenarios for the reduction in natural gas consumption due to hydrogen and biomethane



[35] IEA. Net Zero by 2050 - A Roadmap for the Global Energy Sector. October 2021.

[36] Alberici S, Grimme W, Toop G. Biomethane production potentials in the EU. European Biogas Association. July 2022.

[37] AEMO. Gas Statement of Opportunities. March 2023.

[38] ARENA. Australia's Bioenergy Roadmap. November 2021.

[39] Ibid.

[40] AEMO. Gas Statement of Opportunities. March 2023.

[41] ARENA. Australian Biomass for Bioenergy Assessment - Final Report. April 2021.

[42] Calculated by subtracting LNG exported from total domestic natural gas consumption and multiplying by natural gas carbon intensity (DCCEEW).

Source: AEMO 2023 Gas Statement of Opportunities. Includes green and blue hydrogen consumed due to fuel switching from natural gas. Total hydrogen consumption is higher when considering fuel switching from other sources, such as coal and oil.

3.3 The renewable gas supply chain

Renewable gas supply chains are leveraging existing natural gas infrastructure to a significant degree, but with a few important differences. In particular, co-location of production with points of offtake is currently important for green hydrogen, while biomethane production is more likely to be dispersed and nearby to sources of biomass. The subsection below outlines the key features of Australia's emerging renewable gas supply chain.

3.3.1 Upstream

Upstream production of green hydrogen is likely to be closer to end-use locations compared with conventional natural gas supply chains. Currently, hydrogen transport costs are high, as dedicated pipeline infrastructure is yet to be developed. Production is therefore most likely to be cost-effective when focused in large-scale plants near to major sources of industrial demand, or near to grid injection points for blending with natural gas. Production plants also need to have ready access to large amounts of renewable electricity and water.

In part owing to these constraints, early green hydrogen projects have tended to be vertically integrated within hard-to-abate industries. Project developers in Australia include major industrial and resource companies such as Wesfarmers, Rio Tinto and Fortescue Metals who have an interest in producing green hydrogen on-site for use in their production processes. Firms such as Fortescue Metals and BP have also invested in hydrogen production projects for export.[43] Fortescue Metals has recently developed an Australian electrolyser and has plans to manufacture electrolysers domestically.[44] These examples suggest the potential for a more vertically integrated, co-located, hydrogen supply chain compared to natural gas.

While green hydrogen production is likely to be concentrated in large-scale production facilities, biomethane will be dispersed across a number of smaller-scale producers. Biomethane, on the other hand, is created from the decomposition of biomass via anaerobic digestion. As biomass can be costly to transport, biomethane production must be close to the biomass source, i.e. collocated with farms, landfills and waste water treatment plants. In addition, anaerobic digestion of biomass creates a by-product called digestate, which can be used by the agriculture sector to return nutrients to the soil. It is therefore common to see anaerobic digestors in rural locations in Europe for example, near where the biomass is generated and where the digestate can be used.[45]

The production of both gases relies on renewable energy which has competing uses. Green hydrogen production will be constrained by the availability of low-cost excess renewable electricity, at the same time as the domestic grid is transforming and electricity demand is rising with electrification. Meanwhile, the biomass and bioenergy required to produce biomethane is in some cases already used for onsite electricity and heat generation (e.g. landfill gas) or has other prospective uses such as for sustainable aviation fuels and renewable diesel.

3.3.2 Midstream

There are opportunities to repurpose gas transmission pipelines for hydrogen transport and storage. Australia has an existing network of high-pressure gas transmission pipelines operated by gas infrastructure companies such as APA Group, AGIG and Jemena. These pipelines connect natural gas-producing regions with large industrial customers, LNG export terminals and to 'city gates', where gas is injected to urban distribution networks. Some existing high-pressure gas transmission pipelines can potentially be converted to transport pure or blended hydrogen. In future, new pipelines may also be built to transport hydrogen or derivatives such as ammonia from renewable energy hubs to industrial areas or export terminals. Currently, in the absence of hydrogen

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[43] Toscano N, O'Malley N. Fortescue, BP back Australia's $2b bid to become hydrogen superpower. Sydney Morning Herald. 11 May 2023.

[44] Parkinson G. Fortescue produces its first Australian made hydrogen electrolyser prototype. Renew Economy. 24 April 2023.

[45] Bolzonella D, Bertasini D, Lo Coco R, Menini M, Rizzioli F, Zuliani, Battista F, Frison N, Jelic A, Pesante G. Toward the Transition of Agricultural Anaerobic Digesters into Multiproduct Biorefineries. Department of Biotechnology, University of Verona. 21 December 2022.

transport infrastructure, some projects are using trucks known as ‘tube trailers’ to transport compressed hydrogen to customers.

Pipeline conversion requires further technical investigation and investment in upgrades. There are challenges to the transportation of 100% hydrogen in existing gas transmission pipelines, due to the ability of hydrogen to cause ‘embrittlement’ or the corrosion of existing steel pipelines that were designed to transport natural gas.[46] APA Group, Australia’s largest pipeline operator, recently announced that it expects about 50% of its pipelines to be suitable for hydrogen conversion.[47] Meanwhile, processing for export would also require further technical study and investment, owing to the different physical properties of hydrogen and its derivatives compared with LNG.

Biomethane may be less suitable for injection in high-pressure transmission pipelines. This is due to the dispersion of potential supply points and the cost of compressing low-pressure biomethane.

3.3.3 Downstream

As noted above, for renewable gases it is likely that some of the downstream priority uses will be integrated with upstream production (e.g. on-site hydrogen production and consumption for some large industrial users). However, downstream distribution infrastructure is likely to remain important, as discussed further below.

Downstream, existing gas networks can be used to deliver blended renewable gas to customers in urban areas, including to some industrial customers. In Australia, urban areas are served by networks of lower-pressure gas distribution pipelines. Gas networks are mostly regulated monopolies which earn a regulated return through charging fees to gas retailers for the use of the network over the life of the asset. Although the vast majority of gas network connections are to households, they only consume about half of gas delivered through the networks. In 2020, commercial and industrial customers represented 2.6% and 0.03% of total customer numbers, respectively. However, the 1,415 industrial customers connected to gas distribution networks accounted for 38.5% of total consumption from networks. The share of industrial consumption on networks varies considerably, being highest on the Jemena Gas Network in NSW and lowest in Tasmania.[48]

As noted earlier, hydrogen blending rates in excess of certain thresholds would require pipeline upgrades (and conversion of end-user appliances). These thresholds and the extent of pipeline investment required vary according to the specific pipeline characteristics. While some networks with older steel infrastructure may require more significant upgrades, some Australian distribution networks have already made recent pipeline upgrades that may support higher rates of hydrogen blending.

Finally, petrol retailers have a role in hydrogen distribution for the transport sector. Petrol retailers BP and Ampol have announced investments in hydrogen refuelling facilities to incentivise use of hydrogen in the Australian market.[49, 50]

[46] Clarke C, Michal G, Floyd H, Davis B, Kastelein N, Van Alphen K, Fardi M. Australias First Hydrogen Pipeline Conversion Project.

[47] APA Group. The Parmelia Gas Pipeline conversion project | APA Group. 19 May 2023.

[48] AER - 2021 Gas Network Performance Report - December 2021_0.pdf

[49] BP. Australia’s first hydrogen refueler at service station opens. 18 August 2023.

[50] AMPOL. Green hydrogen plant pilot.

4 Current State of Renewable Gas Markets

The green hydrogen and biomethane industries are in nascent stages of development. This section outlines the current market landscape for renewable gases, including production volumes and relevant domestic policy settings.

4.1 Current production volumes

4.1.1 Green Hydrogen

Hydrogen currently has only a modest role in the global energy system and almost all of it is from non-renewable sources, with green hydrogen making up less than 1 percent of the market. Total global hydrogen demand in 2021 was 94 million tonnes (Mt) which represents about 2.5% of global final energy consumption. The majority of hydrogen consumed was for traditional uses in refining and industry and was primarily produced by fossil fuels, with around 70% of production from natural gas and 30% from coal (grey hydrogen).[51] Low emission hydrogen production was less than 1 Mt in 2021, with practically all of it being produced by plants using fossil fuels but equipped with CCUS facilities (blue hydrogen).[52] Significant hydrogen markets include China (approximately 30% of global hydrogen demand in 2021), the United States and the Middle East (approximately 13% of global demand each), the European Union (10%) and India (9%).[53]

The European Union produces and consumes around 9-10 Mt of hydrogen per year, primarily from fossil fuels. Hydrogen accounts for less than 2% of Europe's energy consumption.[54] It is primarily produced from natural gas (without CCUS), with less than 0.3 Mt of electricity-based hydrogen being produced in the EU. Hydrogen is primarily used for oil refineries, ammonia production and industry.

The United States produces approximately 10 million Mt of hydrogen per year, around 95 percent of which is from fossil fuels. Hydrogen accounts for around 1% of total U.S. energy consumption. Most hydrogen is produced at or close to where it is used, typically large industrial sites. Almost all of the hydrogen produced is used for the refinement of petroleum, treating metals, ammonia production and food processes. The U.S. currently has around 1,600 miles of pipeline for dedicated hydrogen delivery, the majority being located near large petroleum refineries and chemical plants in Illinois, California and the Gulf Coast. [55] [56]

Australia is currently not a major global producer or consumer of hydrogen but is host to a large pipeline of new hydrogen projects. Australia produces around 0.5 Mt of hydrogen per year, which is around 0.4% of Australia's total energy consumption.[57] Virtually all hydrogen production is made via SMR with natural gas and is closely coupled with end-use consumption in industrial processes. Around 80% of hydrogen used to produce ammonia (to produce fertilisers, explosives for mining, and in mineral processing and plastics) and 20% used for crude oil refining.[58] [59] There is a large pipeline of green hydrogen projects under development, and 12 projects are already operational (focusing on transport, industry and pipeline blending applications; see below for details).

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[51] International Energy Agency (IEA). Hydrogen - IEA. Last updated 10 July 2023.

[52] IEA. Global Hydrogen Review 2022 (windows.net). Last updated September 2022.

[53] Ibid.

[54] Energy Conversion and Management Journal. Green hydrogen in Europe – A regional assessment: Substituting existing production with electrolysis powered by renewables - ScienceDirect. Last updated 13 October 2020

[55] Sherman & Sterling. Hydrogen's Present and Future in the US Energy Sector | Shearman & Sterling. Last updated 7 October 2021.

[56] U.S. Department of Energy. Alternative Fuels Data Center: Hydrogen Production and Distribution (energy.gov).

[57] Enerdata.Australia Energy Information | Enerdata. Last updated 2021.

[58] Department of Climate Change, Energy, the Environment and Water (DCCEW). State of Hydrogen 2022 (dcceew.gov.au). Last updated 2022.

[59] Advisian. Australian hydrogen market study (cefc.com.au). Last updated 24 May 2021.

Australia’s green hydrogen industry is set to grow substantially

Australia has an announced pipeline of at least $127 billion of hydrogen and ammonia projects based on the 110 active industry projects in Australia.[60] Of these projects, 80 are in development planning phase, 16 are under construction and 12 are currently operating (see table below).

There are also many additional significant proposed hydrogen projects in Australia which has led to estimates of around $230 billion to $300 billion for the total Australian hydrogen investment pipeline (equivalent to around 40% of all announced global hydrogen projects).[61] However it is important to note that as of December 2022, only one project with a 10 MW capacity or higher has passed final-investment-decision from this pipeline of investment.

Table 2: Operational Green Hydrogen Projects in Australia[62]

Project Title	Location	Main end-use	Estimated cost	Notes
ActewAGL Hydrogen Refuelling Station	ACT	Transport sector	$3 million	Dispenses renewable hydrogen to support ACT Gov in use of 20 Fuel Cell EVs.
ATCO Hydrogen Blending Project	WA	Hydrogen in gas networks	$2.6 million	Renewable hydrogen to be blended into gas network, involving around 2,700 connections.
Clean Energy Innovation Hub	WA	Microgrid applications	$3.5 million	Production, storage and hydrogen use in micro-grids, including blending with natural gas and power use.
Hazer Commercial Demonstration Plant	WA	Demonstration and testing	$23-25 million	Demonstration of Hazer production technology that can convert bio-methane feedstocks into hydrogen and synthetic graphite.
Hydrogen Park South Australia	SA	Hydrogen in gas networks	$14.5 million	Blending of green hydrogen into gas networks to supply 4,000 homes in Adelaide.
Hydrogen Refueller Station	WA	Transport sector	N/A	Hydrogen refuelling facility
Hydrogen Test Facility	ACT	Hydrogen in gas networks	N/A	To enhance understanding of impact of introducing hydrogen into ACT gas network
Port Kembla Hydrogen Refuelling Facility	NSW	Transport sector	$2 million	For use in hydrogen-powered heavy transport vehicles
Renewable Hydrogen Production and Refuelling Project	QLD	Industrial uses, mobility	$5.5 million	To supply green hydrogen to BOC’s existing customer base and supply a refuelling station.
Sir Samuel Griffith Centre	QLD	Microgrid applications	N/A	Designed to operate independently of grid using solar and hydrogen storage.
Toyota Ecopark Hydrogen Demonstration	VIC	Transport sector, power use	$7.4 million	To produce green hydrogen for both transport and stationary applications.
Western Sydney Green Gas Project	NSW	Hydrogen in gas networks, power use	$15 million	Power-to-gas facility to transform renewable electricity into hydrogen gas for blending, storage, power generation and potential mobility/industrial

[60] CSIRO. Industry – active – HyResource (csiro.au)

[61] Department of Climate Change, Energy, the Environment and Water (DCCEW). State of Hydrogen 2022 (dcceew.gov.au). Last updated 2022.

[62] CSIRO. Industry – active – HyResource (csiro.au)

4.1.2 Biomethane

Compared with green hydrogen, the global biomethane market is more mature. Global biomethane production was 7.4 billion cubic metres (bcm) in 2022. This is an increase of 23% on 2021 levels.[63]

The European Union has over 1,000 biomethane facilities in operation and produced 3.6 bcm of biomethane in 2021. 45% of biomethane is produced from crops (including energy crops, crop residues and sequential crops), 33% is produced from animal manure (anaerobic digestors on agricultural sites), 16% is produced from municipal solid waste and 6% is from wastewater.[64] 90% of biomethane produced in the EU is injected into the gas transmission network.[65] The largest biomethane market in the EU is Germany which is home to two-thirds of plant capacity – other significant markets include Denmark, France, Italy and the United Kingdom.[66]

The United States has over 250 operational biomethane facilities and produced 2bcm of biomethane in 2022. The US also has around 220 additional plants being planned or under construction.[67]

In contrast, biomethane production in Australia remains in its infancy, with Jemena's Malabar Biomethane Demonstration Plant the only current biomethane facility in operation. The Malabar plant (located in south-east Sydney) produces biomethane using wastewater and is estimated to initially produce around 95 terajoules of biomethane each year (enough to supply 6,300 households).[68, 69]

Table 3: Renewable Gas Consumption Volumes in Australia, 2022

Gaseous Fuel	Domestic Consumption (PJ)
Green Hydrogen	0.01[70]
Biomethane	0.1[71]
Natural gas	*1,569*

4.2 The current policy landscape

Renewable gases are receiving growing policy attention in Australia, but policy settings are less generous than international partners such as the US and EU. Biomethane has received comparatively little attention in Australia compared with green hydrogen.

This section provides a short summary of key international and domestic policy initiatives.

4.2.1 International context

The US and EU have significant policy support in place for renewable gases:

Green hydrogen

- **The Inflation Reduction Act (IRA) includes production tax credits for clean hydrogen which could reduce the cost of producing green hydrogen by US$3 per kg.** This would make US-produced renewable hydrogen among the cheapest in the world. The US National Clean Hydrogen

[63] CEDIGAZ. GLOBAL BIOMETHANE MARKET 2023 ASSESSMENT - From ambition to action - Cedigaz. Last updated 20 April 2023.

[64] IEA. Outlook_for_biogas_and_biomethane.pdf (windows.net) Last updated 2020.

[65] SiaPartners. European Biomethane Benchmark. Last updated 2022.

[66] IEA. An introduction to biogas and biomethane – Outlook for biogas and biomethane: Prospects for organic growth – Analysis - IEA

[67] Gasworld. Global biomethane production hits record 7bcm in 2022 | Biomethane | gasworld. Last updated 2023.

[68] Jemena. Biomethane Injected into Gas Grid in Australian First - Jemena. Last updated 15 June 2023.

[69] Jemena. Malabar Biomethane Injection Plant - Jemena

[70] ATCO. Hydrogen Blending | ATCO. Last updated 27 August 2021.

[71] Jemena. Malabar Biomethane Injection Plant - Jemena

Strategy also establishes the objective for annual production of 10 Mt of clean hydrogen in the US by 2030.[72]

- **The European Hydrogen Strategy sets out a plan to invest between 320 and 450 billion euros in the decade from 2020 to 2030** as part of an overall objective to produce 10Mt of renewable hydrogen in the EU per year by 2030.[73,74,75] The EU has also established a EUR 3 billion Hydrogen Bank to stimulate and support investment in green hydrogen production.[76] In addition to hydrogen production, the EU also plans to import 10 Mt of renewable hydrogen by 2030.[77]

Biomethane and Biogas

- **The IRA directs approximately US$10 billion in funds and investment tax credits to incentivise the development of biogas facilities.**[78,79] This will be done by expanding the eligibility for tax credits to include biogas systems that produce heat and natural gas.[80] Note that the IRA does not have any specificity towards to upgrading of biogas to biomethane.
- **The REPowerEU Plan commits to increasing Europe's annual production of biomethane to 35 bcm by 2030.** This will require investment of approximately EUR 83 billion to build 5,000 new plants and will be achieved through the EU's Biomethane Industrial Partnership, which is a collaborative initiative between industry and regulators.[81,82]

4.2.2 Australia

Increasing climate ambition has seen growth in policy measures at the Commonwealth and State levels, including in support of renewable gases. Policies differ around whether they directly or indirectly support the supply or demand of renewable gases, the scale of this support, and the extent to which this support is focussed on specific use cases or sectors. Similarly, there are differences between jurisdictions in the maturity of renewable gas policy development. Some jurisdictions, such as New South Wales (NSW), have an established and complementary policy mix, involving targets and enabling policy instruments. Other states are still developing deployment options and canvassing stakeholder views.

Australia's National Hydrogen Strategy sets out the strategic framework for hydrogen. Published in 2019, the Strategy contains 57 actions and principles that outline the initial steps Australia could take to develop a large-scale domestic hydrogen industry.[83] Noting significant developments in the international hydrogen market (such as the Inflation Reduction Act in the US) since its publication, the Energy and Climate Change Ministerial Council (ECMC) agreed to a Review of the Strategy in 2023 and the development of a revised Strategy. The revised Strategy is to be driven by three strategic objectives for hydrogen:

- Australia is on the path to be a global hydrogen leader by 2030
- Enable domestic decarbonisation through the development of the hydrogen industry

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[72]The International Council on Clean Transportation. Can the Inflation Reduction Act unlock a green hydrogen economy? - International Council on Clean Transportation (theicct.org). Last updated 3 January 2023.

[73] European Union Law. EUR-Lex - 52020DC0301 - EN - EUR-Lex (europa.eu). Last updated 8 July 2020.

[74] Ibid.

[75] CSIRO. European Commission – HyResource (csiro.au). Last updated July 2020.

[76] European Commission. Commission outlines European Hydrogen Bank to boost renewable hydrogen (europa.eu).Last updated 16 March 2023.

[77] European Biogas Association. Commission announces groundbreaking biomethane target: 'REPowerEU to cut dependence on Russian gas' | European Biogas Association. Last updated 8 March 2022.

[78]Grist. Biogas set to boom, thanks to IRA incentives | Grist. Last updated 1 Nov 2022.

[79] Fluence. Inflation Reduction Act to Boost Biogas | Fluence (fluencecorp.com). Last updated 3 Nov 2022.

[80] Womble Bond Dickinson. https://www.womblebonddickinson.com/us/insights/alerts/inflation-reduction-act-gives-boost-biogas-sector. Last updated 6 October 2022.

[81] Macquarie. Here and now: Europe backs biomethane | Macquarie Group. Last updated 20 February 2022.

[82] Ibid.

[83] COAG Energy Council. Australia's National Hydrogen Strategy. 22 November 2019.

- Ensure economic benefit for all Australians through the development of the hydrogen industry[84]

There is currently no strategy specifically focused on biomethane. However, ARENA commissioned a Bioenergy Roadmap in 2021, which has four key themes:

- *Enabling market opportunities in hard-to-abate sectors: in renewable industrial heat, sustainable aviation fuel and renewable gas grid injection. These opportunities currently have limited low emissions alternatives.*
- *Enabling market opportunities where bioenergy can complement other low emissions alternatives: in the road transport and electricity markets.*
- *Developing our resources: Australia has a significant bioenergy resource potential. However, there is insufficient clarity and detail over the viability and sustainability of these resources.*
- *Building supportive ecosystems: An enduring and successful bioenergy industry will require concerted efforts beyond those relating to markets and feedstocks. It will be necessary to harness an ecosystem that links the diverse parts of the bioenergy industry to facilitate its growth.*[85]

Although not specifically targeted at renewable gases, the Safeguard Mechanism and Emissions Reduction Fund provide important indirect incentives for renewable gas uptake. The Safeguard Mechanism regulates large industrial facilities to reduce net emissions below a declining baseline. It introduces an effective carbon price for covered emitters, which will improve the cost competitiveness of renewable gases by directly rewarding their lower emissions content. Meanwhile, the Emissions Reduction Fund (ERF) incentivises biomethane production where it is clearly displacing fossil fuel alternatives, by making it possible to generate and sell Australian Carbon Credit Units (ACCUs). There are currently no ERF methods for the use of green hydrogen to displace fossil fuels.

To date, the Commonwealth and States have also supported many renewable gas research and development (R&D) projects and policies. These include demonstration plants in South Australia (Hydrogen Park SA), NSW (Malabar Biomethane Injection Plant) and Victoria (Hydrogen Park Murray Valley), funding for the Future Fuels Cooperative Research Centre (FFCRC), and the Commonwealth and NSW Governments' respective hydrogen hubs programs. These programs will continue to facilitate proof of concept of early-stage projects, while deployment policy will be key to accelerating uptake.

The Hydrogen Headstart program is the first major deployment policy to be announced in Australia. The program will provide funding in the form of direct production credit contracts for two-to-three large-scale green hydrogen plants. Hydrogen Headstart received $2bn in funding in the 2023-24 Federal Budget and is currently under design by ARENA.[86]

The 2023-24 Federal Budget also provided $38.2 million for the creation of a Guarantee of Origin Scheme to certify renewable energy and track and verify emissions from clean energy products. This is considered critical for the international trade of hydrogen and enabling new projects to secure finance and scale up the domestic hydrogen industry.[87] Meanwhile, GreenPower (a renewable energy accreditation program between NSW, VIC, SA, WA and the ACT) recently launched a Renewable Gas Certification Pilot. These schemes and the importance of certification are discussed further in the next section (Priorities for Renewable Gas Policy).

The Commonwealth is also supporting several hydrogen initiatives in the transport sector. The Driving the Nation Fund supports projects to expand both EV charging and hydrogen refuelling infrastructure across Australia.[88] This includes the Hydrogen Highways initiative which will co-invest up to $80 million with State and Territory governments to help decarbonise heavy transport through rolling out hydrogen refuelling networks on key freight routes.[89]

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[84] DCCEEW. National Hydrogen Strategy Review: Consultation Paper. July 2023.

[85] ARENA. Australia's Bioenergy Roadmap. November 2021.

[86] ARENA. Hydrogen Headstart.

[87] DCCEEW. Guarantee of Origin scheme. Last updated 7 June 2023.

[88] DCCEEW. Driving The Nation. Last updated 19 April 2023.

[89] DCCEEW. Budget 2022-23: Reducing emissions and addressing climate change. October 2022.

At the State and Territory level, NSW currently employs the most comprehensive renewable gas policy framework, heavily geared toward green hydrogen. The Renewable Fuel Scheme (which is in development) appears to be a Renewable Gas certificate-based scheme which has a target of the production of 90,000 gigajoules of green hydrogen in 2024 increasing to 8 million gigajoules by 2030.[90] Network charge exemptions and concessions also provide strong production incentives to eligible hydrogen production facilities.[91]

Other states are considering similar policies to the Renewable Fuel Scheme. Victoria is consulting publicly on renewable gas policy options, including a possible Renewable Gas Certificate (RGC) scheme, as part of its update to the Gas Substitution Roadmap. WA is designing a green hydrogen target focused on electricity generation, and has indicated plans to develop a broader renewable hydrogen target scheme across all use cases.[92, 93]

Table 4: Hydrogen and biomethane targets and programs – National and State/Territory

Jurisd-iction	Hydrogen	Biomethane
National	• National Hydrogen Strategy (and 2023 Review) to place Australia on path to become a global hydrogen leader by 2030 and produce 'H2 under $2' – to produce hydrogen at a cost below $2/kg.[94] • $2bn in funding for Hydrogen Headstart, $500m for Regional Hydrogen Hubs Program, $280m for hydrogen R&D projects through ARENA and $300m made available in debt and equity finance to invest in hydrogen projects. • Hydrogen Highways program to deliver up to 16 hydrogen refuelling stations on Australia's busiest freight routes at cost of $80m.[95]	• Australia's Bioenergy Roadmap states that bioenergy has the potential to provide up to 20% of total domestic energy consumption by 2050s. Includes renewable gas grid injection as a focus area. • ARENA $5.9m funding towards Malabar Biomethane Injection Plant • Emissions Reduction Fund (ERF) has had biomethane added as a method
NSW	• NSW Hydrogen Strategy which includes the following stretch targets for 2030: – Produce 110,00t of green hydrogen annually and 700 MW of electrolyser capacity by 2030[96] – 10% hydrogen blending in networks (by volume) – 10,000 hydrogen vehicles and 100 hydrogen refuelling stations, including 20% hydrogen vehicles in NSW Government fleet. – Achieve hydrogen price of $2.80 per kg • $3 billion in incentives and $150m in grants to commercialise hydrogen supply chains. • Planned Renewable Fuel Scheme has further production target of 67,000t of green hydrogen (8 PJ) annually by 2030.[97]	• As of April 2023, the NSW Energy Savings Scheme incentivises fuel switching to biogas.
VIC	• Victoria's Renewable Gas Consultation Paper considers the establishment of a renewable gas scheme, which could include a hydrogen sub-target to incentivise a certain percentage of use amongst an overall renewable gas target.	• Victoria has released its Renewable Gas Consultation Paper, and their scenario analysis found approximately 10 PJ of biomethane could

[90] NSW Climate and Energy Action. Renewable Fuel Scheme | NSW Climate and Energy Action. Last updated 2023.

[91] NSW Department of Planning, Industry and Environment. NSW Hydrogen Strategy. Last updated October 2021.

[92] Victorian State Government. Victorias-Gas-Substitution-Roadmap.pdf (energy.vic.gov.au). Last updated 2023.

[93] Government of Western Australia. EPWA-Renewable Hydrogen Target for Electricity Generation in the SWIS-Consultation Paper_0.pdf (www.wa.gov.au). Last updated October 2022.

[94] ARENA. Australia's pathway to $2 per kg hydrogen. 30 November 2020.

[95] CSIRO. Australian Government - Hydrogen Industry Policy Initiatives. August 2023.

[96] NSW Department of Planning, Industry and Environment. NSW Hydrogen Strategy. Last updated October 2021.

[97] CSIRO. New South Wales – Hydrogen Industry Policy Initiatives. HyResource. August 2023.

Jurisd-iction	Hydrogen	Biomethane
	• Renewable Hydrogen Industry Development Plan to stimulate investment. • Accelerating Victoria's Hydrogen Industry Program to support policy and industry development through grant programs. • $10 million in funding for Victoria Hydrogen Hub to support sustainable manufacturing and clean energy storage [98]	be required annually by 2030 to meet Victoria's 2045 net zero emissions target.[99] • $10 million waste-to-energy support package has aim of halving the volume of organic waste going to landfill by 2030, presenting opportunity for anaerobic digestion. [100]
QLD	• Queensland Hydrogen Industry Strategy 2019-2024 to establish renewable hydrogen production for domestic and export • $25 million in funding for hydrogen projects in QLD including the Queensland Hydrogen Development Fund [101] • $4.5 billion Queensland Renewable Energy and Hydrogen Jobs Fund to deliver more publicly owned renewable energy. Includes $44 million for 3 hydrogen projects in QLD. [102]	• QLD Biofutures 10-Year Roadmap and Action Plan has vision for QLD to be an Asia-Pacific hub in biomanufacturing and biorefining. [103]
WA	• Western Australia Renewable Hydrogen Strategy contains the following 2030 goals: – WA's market share in global hydrogen exports similar to current LNG share – Gas pipelines and networks to contain up to 10% hydrogen blend in pipelines by 2030. [104] – Renewable hydrogen used in mining haulage vehicles and is a large transportation fuel source in regional WA • Renewable Hydrogen Fund to deliver 9 hydrogen initiatives at $22m. [105]	• WA Climate Change Policy has the action step of developing a State Bioeconomy Strategy to facilitate the growth of bioenergy and bio-product industries in WA. [106]
SA	• South Australia's Hydrogen Action Plan to promote domestic and export market opportunities. • $17.5m in grants awarded to hydrogen projects and $70m in funding to the Port Bonython Hydrogen Hub. [107] • $593m to build a green hydrogen power station which includes 250MWe of electrolysers, 200MW of power generation and hydrogen storage capacity, by 2025. [108]	

[98] CSIRO. Victoria – Hydrogen Industry Policy Initiatives. HyResource. May 2023.

[99] Victoria's Renewable Gas Consultation Paper | Engage Victoria

[100] Sustainability Victoria. Government measures and interventions for biogas. November 2021.

[101] CSIRO. Queensland – Hydrogen Industry Strategy. HyResource. August 2023.

[102] Queensland Treasury. Queensland Renewable Energy and Hydrogen Jobs Fund. 16 November 2022.

[103] Department of State Development, Infrastructure, Local Government and Planning. Queensland Biofutures: 10-Year Roadmap and Action Plan. June 2022.

[104] Department of Jobs, Tourism, Science and Innovation (DJSI). Western Australian Renewable Hydrogen Roadmap (www.wa.gov.au). Last updated November 2020.

[105] CSIRO. Western Australia – Hydrogen Industry Policy Initiatives

. HyResource. August 2023.

[106] Department of Water and Environmental Regulation. Western Australian Climate Policy. November 2020.

[107] CSIRO. South Australia – Hydrogen Industry Policy Initiatives. HyResource. August 2023.

[108] Government of South Australia. Hydrogen South Australia | Hydrogen South Australia. Last updated December 2021.

Jurisd-iction	Hydrogen	Biomethane
TAS	• Tasmanian Renewable Hydrogen Action Plan to facilitate production and export of renewable hydrogen by 2030. • $50m Tasmanian Renewable Hydrogen Industry Development Funding Program to support key hydrogen measures. [109]	• The Bioenergy Vision for Tasmania, released in March 2023, sets out the opportunity for bioenergy from a Tasmanian context, with a focus on creating an environment that unlocks investment to deliver against the key drivers of bioenergy adoption. [110] The Vision does not explicitly mention Biomethane.
NT	• Northern Territory Renewable Hydrogen Master Plan includes $5m in funding for expansion of the Territory's hydrogen industry.	
ACT	• ACT is a Founding Partner in the Smart Energy Council's Zero Carbon Certification Scheme for renewable hydrogen, ammonia and metal manufacture. [111] • ACT's Renewable Energy Innovation Fund (REIF) includes funding towards green hydrogen production. [112]	

[109] CSIRO. Tasmania – Hydrogen Industry Policy Initiatives. HyResource. July 2023.

[110] Tasmanian Government. Microsoft Word - Bioenergy Vision FINAL (recfit.tas.gov.au). 27 March 2023.

[111] Chief Minister, Treasury and Economic Development. ACT Government supports new hydrogen certification scheme. 29 April 2021.

[112] ACT Government. The ACT's renewable energy sector has received a funding boost. Climate Choices. 22 May 2023.

5 Priorities for Renewable Gas Policy

Further policy action is needed to realise the potential of renewable gases in Australia's journey to net zero. In previous chapters we have seen how green hydrogen and biomethane are likely to have important roles to play in decarbonising hard-to-abate sectors, but that production of these gases is still at a very early stage. This chapter explores how policymakers can unlock barriers for these nascent industries and set renewable gases on a track to make a meaningful contribution towards Australia's decarbonisation targets.

We have identified three priority areas for policy attention: setting the market and regulatory foundations; stimulating production and driving down costs; and managing social license and spill-overs. Each of these priority areas, and how they address key demand – and supply-side barriers, is elaborated in the remainder of this chapter. Deployment policies provide a particularly powerful tool to stimulate production and drive down costs, and possible design options for these policies are examined in more detail in the next chapter.

5.1 Setting market and regulatory foundations

5.1.1 Accelerate renewable gas certification

Certification of renewable gases is critical to support market demand. Currently end users do not have a mechanism to distinguish biomethane from natural gas or green hydrogen from grey hydrogen. Certificates which guarantee the provenance and emissions attributes of green hydrogen and biomethane will allow end users to make emissions reduction claims. Implementing certification in the Australian market will support a price premium relative to natural gas and make a substantial contribution to market development.

Work is underway on green hydrogen certification. The Commonwealth's voluntary Guarantee of Origin (GO) scheme is expected to be legislated and launched in 2024 and will focus initially on hydrogen and renewable electricity. The GO scheme is being designed to align with the existing National Greenhouse and Energy Reporting (NGER) scheme where possible, which should ensure that Safeguard-covered facilities can use GO certificates to demonstrate the use of low-emissions hydrogen and its derivatives when reporting their Scope 1 emissions. This is also likely to be true of hydrogen blended with natural gas in pipelines, as DCCEEW has indicated that GO certificates could be decoupled from the physical molecules when consumers and producers are on the same gas network.

Efforts to certify biomethane should be accelerated. While the Commonwealth Government has noted the possibility of expanding the GO scheme in future to include biofuels, no timeframe has been set. Biomethane certification should be prioritised for early development, given the availability of existing international biomethane certification frameworks to draw from, the potential benefits this would offer in stimulating investment in domestic grid injection projects, and the potential role envisaged for biomethane in some decarbonisation scenarios. Accelerating GO certification for biomethane would also provide clarity on future directions for participants in the GreenPower Renewable Gas Certification Pilot (see box overleaf).

The GreenPower Renewable Gas Certification Pilot

In August 2023 GreenPower launched a Renewable Gas Certification Pilot scheme. GreenPower is an energy accreditation program administered by the NSW Government, with participation from other Australian states and territories. GreenPower's Pilot is intended as an interim arrangement until a permanent national scheme becomes available for renewable gases.

Under the Pilot, producers can generate Renewable Gas Guarantee of Origin (RGGO) certificates for each kWh equivalent of biomethane, biogas or renewable hydrogen produced to displace natural gas. When a producer injects renewable gas into a gas network, the RGGOs generated can then be purchased, traded and surrendered by or on behalf of gas network customers,[113] providing those customers the right to claim the emissions reduction benefit. Meanwhile, for renewable gas supplied to an off-grid gas customer (e.g. for a behind-the-meter project, or delivery of renewable gas to a customer by road, ship or rail), then the resultant RGGOs are not tradable and the RGGOs can only be retired for that customer. This ensures that emissions reductions claims for off-grid uses are linked to physical trade in the renewable gas, in contrast to a fully 'decoupled' certificate scheme.

Currently, residential gas customers are not eligible to participate in the Pilot. During the consultation process for the Pilot design, respondents preferred to restrict eligibility to commercial and industrial customers only. According to GreenPower's consultation summary, this reflected concern that the Pilot could have unintended consequences for household decisions on electrification.[114]

It is also not clear how RGGOs will interact with the NGER scheme. The Pilot is focused on voluntary rather than compliance reporting. At the time of writing, it is unclear what status RGGOs may have in NGER and Safeguard Mechanism reporting. Clarification of this point would provide a more powerful driver for renewable gas demand.

5.1.2 Finalise regulatory foundations in alignment with international standards

Clear regulatory foundations are important to provide confidence in product safety and to provide legal certainty to de-risk investment. Australian governments are implementing a number of regulatory reforms to ensure that renewable gases are appropriately recognised under the law (see box) and it is important that this agenda continues.

A number of regulatory reforms have been recently completed or are underway

- QLD Hydrogen Industry Bill 2023
- NSW Gas Supply (Safety and Network Management) Regulation 2022
- SA Hydrogen and Renewable Energy Act Bill 2023
- WA Petroleum Acts amendments
- National Gas Framework amendments

As regulatory foundations are established, it is important that these efforts are harmonised across Australian jurisdictions and with international markets. For example, contrasting biomethane standards within and outside Australia currently adds complexity and cost for prospective project developers. Currently gas specifications in Australia are more stringent than in the EU, where most biomethane plant and equipment is sourced. This means that existing biomethane technology cannot readily be utilised in Australia without additional modifications, raising costs.[115]

[113] Under the Pilot, customers can purchase RGGOs from a different gas network. For example, RGGOs could be generated based on a grid injection in the West Coast network and purchased to offset natural gas consumption from the East Coast network. The proposed GO scheme is likely to take a stricter approach and require certificates to be traded within a single network.

[114] GreenPower. Renewable Gas Pilot Public Consultation Findings Summary–GreenPower 2023.pdf. Last updated May 2023.

[115] Bioenergy Australia. https://cdn.revolutionise.com.au/cups/bioenergy/files/bnblexkxxx3o9rpi.pdf. Last updated April 2022.

Table 5: Summary of Priority Issues and Policy Actions for Setting Market and Regulatory Foundations

Market and regulatory foundations			
	Supply-side constraints	**Demand-side constraints**	***Priority policy actions***
Green Hydrogen	• Lack of comprehensive and harmonised regulation across jurisdictions	• Inability to distinguish green hydrogen from other types of hydrogen and claim the emissions reduction benefits in emissions reporting.	• *Accelerate GO Scheme development, including biomethane as a priority product* • *Continue regulatory reforms, including harmonisation with international standards*
Biomethane	• Lack of comprehensive and harmonised regulation across jurisdictions • Contrasting international biomethane standards pose additional costs to adapt technology to Australian standards	• Inability to distinguish biomethane from natural gas and claim the emissions reduction benefits in emissions reporting.	

5.2 Stimulating production and driving down costs

Unsurprisingly given the industry's early stage of development in Australia, renewable gases are currently far from being cost-competitive with fossil fuel alternatives. Table 6 shows the current estimated marginal abatement cost of renewable gas, and domestic consumption. As can be seen, the estimated cost for green hydrogen and biomethane is much higher than natural gas (up to $39 per GJ higher), and the marginal abatement cost (MAC) is upward of $285 per tonne. Our figure assumes emissions from energy used in natural gas production is 52 kilograms of CO2-e per GJ, biomethane upgrade is 1 kilogram of CO2-e per GJ [116] and hydrogen is 0.3 kilograms of CO2-e per GJ[117] Note that a more accurate MAC would also consider the lifecycle emissions from the biomethane supply chain, including the collection and transport of feedstocks to biogas upgrading facilities. It is also important to note that biomethane costs vary considerably according to the feedstock, with biomethane from wastewater being more competitive than other sources. [118]

Table 6: Marginal abatement costs of renewable gas

Option	Estimated cost per GJ	Estimated marginal abatement cost ($/tCO2-e) [119]
Green Hydrogen	$49 [120]	$739
Biomethane	$25 [121]	$285
Natural gas	$10-$15 [122]	-

[116] Australian Government Clean Energy Regulator. Biomethane method package - simple method guide (cleanenergyregulator.gov.au). Last updated January 2022.

[117] Hydrogen Production With A Low Carbon Footprint (forbes.com)

[118] IEA.Outlook for biogas and biomethane: Prospects for organic growth. March 2020.

[119] Assumes combusting natural gas emits one tonne of carbon for every 19.4GJ consumed, from (2023), Australian National Greenhouse Accounts Factors, Australian Government Department of Climate Change, Energy, the Environment and Water, and biomethane and hydrogen generate 1 and 5 kgCO2/GJ made.

[120] Based on $5.82 per kg from Australian hydrogen market study (cefc.com.au).

[121] Upper end of estimates from Culley S.A., Zecchin A.C., Maier H.R., Where are the most viable locations for bioenergy hubs across Australia?. Future Fuels. June 2022.

[122] Based on AEMO as price and demand (AEMO | Australian Energy Market Operator) and quarterly results from Wholesale statistics | Australian Energy Regulator (aer.gov.au)

Technology is a key factor in the high production costs of renewable gas. In the case of hydrogen, the development of industrial electrolysers is necessary to produce hydrogen at a large scale. [123] Yet the high costs of both electrolysers to produce hydrogen and their energy requirements limits the uptake of hydrogen. Electrolyser capital costs sat at $2,700 per kW of capacity in 2022.[124] For biomethane, relatively more mature technology exists but it is largely produced in Europe, creating considerable costs to transfer technology over to Australia and adapt it to domestic conditions.[125]

However, as industries and technologies move to maturity, cost reductions can be achieved through economies of scale and learning effects.[126] For example, a 5% scale effect and a 4% learning effect for both green hydrogen and biomethane could result in a 68% lower unit cost for green hydrogen and a 60% lower unit cost for biomethane by 2035 (all other things held constant).[127] Learning rates could in fact be much higher for green hydrogen (given the technology is relatively less developed compared with biomethane), with one source estimating electrolyser learning rates (for Proton Exchange Membrane or 'PEM' and Alkaline Water Electrolysis or 'ALK') of between 19 and 26 per cent.[128] This does not consider the even less mature Solid Oxide Electrolysis Cells (SOEC) electrolysis pathway, which aims to improve electrolyser efficiency by requiring less electrical energy.[129]

5.2.1 Establish deployment incentives

Deployment incentives will have an important role in supporting Australia's green hydrogen and biomethane industries to move down technology cost curves more quickly and be available to contribute to sectoral net zero emissions pathways. Deployment incentive schemes have been widely used in Australia and internationally to support uptake of renewable energy technologies. By providing financial support to bridge the commercial viability gap between production costs and market prices, deployment incentives help to encourage investment in production capacity. This helps industries to achieve economies of scale and learning effects more quickly than would otherwise be the case. For renewable gases, this will translate to more options for emissions reductions through the displacement of fossil fuels. The Renewable Energy Target (RET) provides a well-known example of a deployment policy which began at a modest scale and helped to drive down the cost of renewable electricity generation (see box).

Deployment policies are also an appropriate response to developments on the international stage. Significant public policy backing for hydrogen in the US and EU means that these economies are likely to be preferred destinations for international capital, and this could lead to first-mover advantages in the international trade of hydrogen. According to some commentators, Australia runs the risk of being 'left behind' in the global hydrogen economy if there is an inadequate response to these industrial policies. For example, it has been estimated that if Australia does not respond to the IRA, exports of hydrogen could be 65% less per year by 2050 than what was expected before the IRA's introduction.[130]

In response to these drivers, the Australian Government has begun developing larger-scale deployment policy for green hydrogen. Namely, the $2 billion Hydrogen Headstart program that is currently under development will provide revenue support for a small number of large-scale renewable hydrogen projects. The program will be implemented through competitive hydrogen

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[123] AFR. What is green hydrogen and can it solve the climate crisis (afr.com). Last updated 12 May 2023.

[124] Hydrogen central. Australia Seeks 'Hydrogen Superpower' Status as Electrolyser and Renewables Costs Fall - Ryze Hydrogen - Hydrogen Central (hydrogen-central.com). Last updated 13 July 2022.

[125] Macquarie. Here and now: Europe backs biomethane | Macquarie Group. Last updated 20 February 2022

[126] Future Fuels. FFCRC_RP2.2-04_Learning_experience_and_cost_curves_final_open-access.pdf (futurefuelscrc.com). Last updated July 2023.

[127] Ibid.

[128] Hydrogen Council. Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf (hydrogencouncil.com) Path to hydrogen competitiveness: A cost perspective. (2020)

[129] Martin Lambert, Gbemi Oluleye, A mountain to climb? Tracking progress in scaling up renewable gas production in Europe - Oxford Institute for Energy Studies (oxfordenergy.org). Oxford Institute for Energy Studies A mountain to climb? Tracking progress in scaling up renewable gas production in Europe, (2019)

[130] Deloitte. deloitte-au-australias-hydrogen-tipping-point-report-updated-280223.pdf. Last updated 28 February 2023.

production credit contracts, with the aim of putting Australia on course for up to a gigawatt of electrolyser capacity by 2030.[131]

Next steps should focus on setting clear aspirational targets for renewable gases, developing suitable deployment incentives for biomethane, and identifying options to build on the Hydrogen Headstart program over the medium term. Deployment measures should be guided by clear aspirational targets for the production of renewable gases by 2030 and 2035. Such targets will set the level of ambition for deployment policy design and provide a clear signal to investors on the role of renewable gases in Australia's decarbonisation journey. Once targets are established, policymakers should evaluate options to build on Hydrogen Headstart and establish similar incentives for biomethane. This subject is explored in detail in the next chapter.

The Renewable Energy Target (RET) Scheme

The RET has been successful in driving industry growth and cost reductions in renewable electricity generation. The RET consists of two schemes, the Large- scale RET and the Small-scale RET:

- **The Large-scale RET incentivises investment in renewable energy power stations such as wind and solar farms and hydro-electric power stations.** These power stations can create large-scale generation certificates (LGCs) for the eligible renewable electricity they produce, and demand is provided by mandating that energy retailers and wholesale users must purchase LGCs according to their share of the market. Projects can also sell LGCs to companies who want to demonstrate renewable energy use for voluntary purposes.[132]
- **The Small-scale RET provides a demand-driven incentive that encourages households and businesses to install small- scale renewable energy systems.** These include rooftop solar panels, solar water heaters and small-scale wind or hydro systems that are grid connected. System owners can create small-scale technology certificates (STCs) when an eligible system is installed. STCs provide an upfront discount on solar power systems up to 100kW.[133]

In September 2019, the Clean Energy Regulator announced that Australia had met the Large-scale RET more than a year ahead of schedule. The scheme continues to require retailers and other liable parties to meet their obligations under the policy until 2030 when it is set to expire.[134]

The RET has contributed significantly to the acceleration of the deployment of renewable energy.[135] Australia currently generates 30 to 35 per cent of its power from renewable sources from both grid and household sources.[136]

The RET has played a role in driving down costs, alongside other factors. At the inception of the RET in the early 2000s, renewable energy was one of the most expensive kinds of energy generation and abatement, though wind and solar have become the cheapest source for electricity generation in Australia, according to CSIRO.[137] This is due to both international and domestic factors, with the RET contributing to significant learning-by-doing benefits for proponents and policy-makers in the Australian context.[138]

The RET carries some key learnings for renewable gas deployment policies. The first RET in the early 2000s set a relatively modest goal of achieving an additional two percent (9,500GWH) of renewable energy in the electricity mix by 2010. This was expanded by 2015 to a goal of 33,000GWH by 2020, which is equal to 23.5% of total electricity generation. This demonstrates a policy approach of setting relatively modest goals at policy inception and increasing over time based on early experience.

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[131] DCCEEW. Hydrogen Headstart program - DCCEEW. Last updated 6 July 2023.

[132] DCEEW. Renewable Energy Target scheme - DCCEEW. Last updated 29 July 2022.

[133] Australian Government Clear Energy Regulator. About the Renewable Energy Target (cleanenergyregulator.gov.au). Last updated 29 June 2022.

[134] Clean Energy Council. Renewable Energy Target Australia | Clean Energy Council. Last updated 2023.

[135] ANU. ECI-renewable-energy-target-review-2014_1.pdf (anu.edu.au). Last updated 2014.

[136] DCCEEW. Renewables confirmed as cheapest source of electricity | energy.gov.au. Last updated 12 July 2022

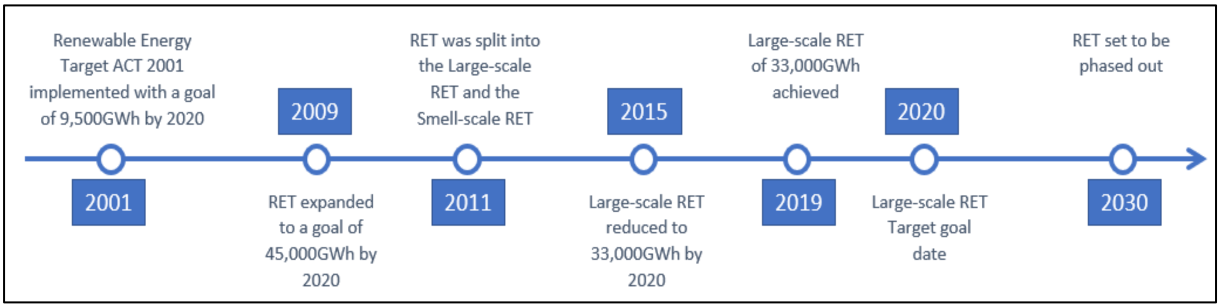
[137]CSIRO. GenCost: annual electricity cost estimates for Australia - CSIRO. Last updated 14 July 2023

[138] Tim Nelson, T, Nolan, J, Gilmore. What's next for the Renewable Energy Target – resolving Australia's integration of energy and climate change policy? Australian Journal of Agricultural and Resource Economics. (2021)

The RET experience also shows the need to target deployment instruments to technologies based on their specific characteristics. The split into large-scale and small-scale schemes was largely driven by policy objectives to encourage both types of deployment. A single scheme would have gravitated to one technology (likely grid scale development) and lost the learning by doing associated with a wider impact. This is relevant to considering the different costs and technological readiness of green hydrogen and biomethane, and the potential to have bifurcated schemes.

A key learning from the RET is the need to consider unanticipated spill-over impacts arising from a powerful deployment instrument. Very rapid deployment of grid scale renewables ran ahead of the capacity of some parts of the grid to manage connections, resulting in curtailment, and produced strong social license concerns. Successor deployment policies – such as the long term energy supply agreement underwriting in NSW, a type of contract for difference, and the development of Renewable Energy Zones – have built in greater control from regulators and policymakers on the types, location and conditions around new renewable developments.

Timeline of Renewable Energy Target



5.2.2 Continue to invest in R&D and demonstration projects

While policymakers' main focus should be on facilitating commercial-scale deployment, there remains a need for continued R&D and demonstration projects. These initiatives perform an important role in facilitating advances in production technologies and providing proofs of concept for their real-world application. The Commonwealth and State Governments should continue to support the significant R&D and pilot project schemes in place for green hydrogen, and consider expanding R&D support for biomethane (and bioenergy more broadly). In this vein, Net Zero Australia has called on policymakers to fund a diverse range of pilots and demonstrations of bioenergy in the 2020s,[139] while ARENA's Bioenergy Roadmap calls for the development of case studies focusing on biomethane production from anaerobic digestion.[140]

Table 7: Summary of Key Issues and Policy Actions for Driving Down Costs

Driving down costs			
	Supply-side constraints	**Demand-side constraints**	**Priority policy actions**
Green Hydrogen	• As an early-stage technology, capital and production costs for electrolysers are currently high • High cost of transporting hydrogen as pipeline infrastructure is yet to be developed • International competition for project capital	• Green hydrogen is currently not cost-competitive compared to available alternatives, such as fossil fuels offset with ACCUs • There is a requirement to upgrade some appliances/equipment to be hydrogen-ready at higher blending rates	• *Set aspirational targets and establish deployment incentive schemes* • *Continue to invest in R&D and demonstration projects for both biomethane and green hydrogen, across a range of use cases*
Biomethane	• Biomethane technology is largely produced in Europe, creating transfer costs • Biogas production requires adequate supplies of affordable feedstock and costs vary depending on the feedstock used • Cost to convert biogas to biomethane relatively high	• Biomethane is currently not cost-competitive compared to available alternatives, such as fossil fuels offset with ACCUs	

[139] Net Zero Australia: How to make net zero happen – Mobilisation report (July 2023)

[140] australia-bioenergy-roadmap-report.pdf (arena.gov.au)

5.3 Addressing social license and spill over effects

As noted above, a key lesson from the RET was on the importance of actively managing the potential for spill-over effects and social license issues associated with development of a new industry. Strategic planning and public awareness initiatives should be prioritised to complement renewable gas deployment policies, as discussed further below.

5.3.1 Develop a national bioenergy strategy

Biomethane policy settings should be considered in the context of the broader role of bioenergy in Australia's journey to net zero. As well as biomethane, biomass provides a feedstock for a range of applications such as sustainable aviation fuels (noting this may be some years away)[141], biodiesel, electricity generation (including providing on site power generation and supplying the grid), bioplastics and biomass energy with carbon capture and storage.[142] As these bioenergy applications will likely need to compete for biomass, it will be necessary to have balanced incentives that do not unduly favour a certain use case over others.

It will also be necessary to manage any potential negative environmental impacts on soil quality or land use change that could arise from bioenergy production. Depending on the feedstock used, the use of biomass to produce biomethane could have flow-on effects on the agricultural sector, by diverting a source of soil nutrients. This can be mitigated by using digestate (the material left over after anaerobic digestion) as fertiliser, which may in turn favour biomethane production that is proximate to the source of the agricultural waste.[143, 144] Meanwhile, the allocation of land to dedicated energy crops (which are grown solely for the purpose of producing bioenergy) can compete with other land uses - such as the provision of food, feed and fibre. To manage these risks, it is important for policymakers to set clear eligibility criteria that restrict policy support to environmentally sustainable sources of biomass.

The development of a national bioenergy strategy with realistic targets will help to address the potential challenges listed above, while also providing a clear signal to industry. A comprehensive strategy should summarise the existing research on bioenergy in Australia including ARENA's *Bioenergy Roadmap* and Future Fuels' '*Where are the most viable locations for bioenergy hubs across Australia?*'. It should also consider the competing destinations of bioenergy (biogas and biomethane, other biofuels, electricity generation and bioplastics) and the associated costs of these uses. This will help determine the volumes that are most appropriate to target across different applications, while balancing economic, social and environmental spill-overs. This is affirmed by Net Zero Australia which calls for policymakers to 'develop a realistic bioenergy strategy that considers competition for land and biomass resources, prospective conversion technologies, and the amount of bioenergy that can be injected into current networks'.[145]

5.3.2 Promote public awareness

Renewable gas policies need to be accompanied with appropriate public communication to build awareness and understanding. Public awareness of renewable gases and their role in the energy transition is limited, and this could lead to social license challenges as deployment policies are progressed. Governments have an important role to play in providing evidence-based information about renewable gases, including: benefits for emissions reduction; safety for air quality, appliances and network distribution; and the standards that the government has in place to protect consumers.

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[141] The Conversation. The future of flight in a net-zero carbon world: 9 scenarios, lots of sustainable aviation fuel. (2020))

[142] ibid

[143] United State Environmental Protection Agency. Basic Information about Anaerobic Digestion. Last updated 17 August 2023.

[144] Paolini V, Petracchini F, Segreto M, Tomassetti L, Naja N, Cecinato A. Environmental impact of biogas: A short review of current knowledge. 13 April 2018.

[145] Net Zero Australia. How to make net zero happen: Mobilisation report. July 2023.

Table 8: Summary of Managing Social License and Spillovers

<table>
<tr><th colspan="4">Managing Social License and Spillovers</th></tr>
<tr><th></th><th>Supply-side constraints</th><th>Demand-side constraints</th><th>Priority policy actions</th></tr>
<tr><td>Green Hydrogen</td><td>• Additionality of renewable electricity – concern that green hydrogen production may put pressure on renewables capacity and delay exit from coal generation.</td><td>• Lack of consumer awareness and potential for safety concerns.</td><td rowspan="2">• Promote public awareness through evidence-based information
• Develop a comprehensive National Bioenergy Strategy</td></tr>
<tr><td>Biomethane</td><td>• Biomethane will need to compete with other potential bioenergy uses such as other biofuels, electricity conversion and bioplastics.
• Potential for negative impacts from LUC to grow energy crops.
• Biomethane production that is proximate to biomass source may be preferable.</td><td>• Consumer perceptions and preference for using biomass for gas use is unknown</td></tr>
</table>

Table 9: Summary of Policy Actions Across the Three Priority Areas

Priority Area	Key issues	Required Policy Actions
Setting market and regulatory foundations	• Challenges for end users of green hydrogen and biomethane to verify the gases' renewable status and claim emissions reduction benefits in emissions reporting • Incomplete regulatory framework, lack of harmonisation with international standards	• Accelerate GO Scheme development, including biomethane as a priority product • Continue regulatory reforms, including harmonisation with international standards
Driving down costs	• Immature renewable gas technologies are not yet commercially competitive • Competition for international investment capital	• Set aspirational targets and establish deployment incentive schemes • Continue to invest in R&D and demonstration projects
Managing social license and spill-overs	• Lack of consumer awareness and perceptions on renewable gases • Managing competing energy demands (renewable electricity for green hydrogen, biomass for other uses such as other biofuels and electricity generation).	• Promote public awareness through evidence-based information • Develop a comprehensive National Bioenergy Strategy

6 Options for Deployment Policy

There are a range of policy instruments that could be used to stimulate production of renewable gases, but these instruments differ in how they allocate costs and risk. This chapter provides an overview of three shortlisted policy instruments – a renewable gas target, contracts for difference, and feed-in-tariffs – and evaluates the three options against a set of assessment criteria.

The policies are assessed for their suitability for initial-stage deployment of renewable gas to stimulate production over the next five to 10 years. After that point, appropriate policy options would need to be reassessed based on the scale of production and cost reductions that have been achieved and new information available on the most viable net zero pathways for different sectors and use cases.

6.1 Short-listed policy instruments

KPMG conducted an evaluation on a long list of policies and narrowed them down to a top three. A notable policy option that was considered but not shortlisted was a tax credit scheme based on production or investment (e.g. as per the US IRA or Canada's Clean Hydrogen Investment Tax Credit).[146] While these instruments can be effective in stimulating deployment, in our view they would not be well-suited to the Australian fiscal regime and would pose significant risks of cost over-runs.

The three shortlisted options are a Renewable Gas Certificate (RGC) scheme, Contract for Difference (CfD) and Feed-in-Tariff (FiT). These options are outlined in Table 10 below, and the next section provides further detail and examples of how these instruments have been used in other jurisdictions. All three options draw from models that have been used successfully in energy markets in the past.

Finally, it is worth noting that the three prioritised policy options are not necessarily mutually exclusive, but rather provide an illustration of the trade-offs between policy design choices. For example, an RGC scheme provides certainty on production quantities but with greater risk on the total policy cost. A CfD provides a cap on the policy cost, but greater uncertainty on the production quantity that will be achieved. In practice, policies can be designed to combine elements across the three instrument types or multiple instruments can be implemented in parallel (e.g. an RGC scheme with CfD contracts for certificates).

Table 10: Overview of Policy Options considered

Instrument	How it works	Why considered
Renewable Gas Certificate scheme	A Renewable Gas Certificate scheme requires gas users to purchase renewable gas certificates equal to a targeted proportion of overall gas consumption.	Inspired by Australia's highly successful Renewable Energy Target scheme for renewable electricity.
Contract for Difference (CfD)	A Contract for Difference (CfD) is where the shortfall between the cost to produce renewable gas and the price it can be sold for is covered by the government for an established period of time.	Commonly used in energy markets and has advantages for limiting the budget risk to government.
Feed in Tariff (FiT)	A Feed in Tariff (FiT) is where renewable gas producers receive a fixed amount of revenue per unit of renewable gas injected in the network for an established period of time.	Has been successfully deployed in Europe to promote the growth of the biomethane industry.

[146] Government of Canada. Consultation on the Investment Tax Credit for Clean Hydrogen. 2 June 2023.

6.2 Renewable Gas Certificate (RGC) Scheme

6.2.1 Policy Summary

A Renewable Gas Certificate (RGC) Scheme is a concept that could operate in a similar fashion to the existing Renewable Energy Target (RET) for the electricity sector. Under an RGC there is an annual renewable gas production target calculated from an estimated proportion of forecast gas consumption. For example, 1 per cent of natural gas consumption would equal 11,000TJ of renewable gas.[147] Participating producing entities would receive a Renewable Gas Certificate (RGC) for each 1 TJ of renewable gas supplied to the market. To reach the target, liable entities (large users and gas retailers) are required to purchase a proportion of RGCs in line with their forecasted share of total natural gas consumption. Liable entities' purchase requirements would evolve over time as the annual percentage target is made more ambitious. This target could be different for hydrogen and biomethane.

RGCs deliver both demand and supply side incentives. Suppliers are incentivised to produce the renewable gas due to the added revenue stream from the certificate sale. On the demand side, liable entities are incentivised to switch from natural gas to renewable gas in order to reduce their certificate compliance obligation.

An RGC scheme focuses on quantity of renewable gas but leaves price uncertain. The cost is borne by wholesale buyers and gas retailers and will therefore pass through to energy bills for consumers.

An RGC scheme could be implemented at a national or state level and could be open to all renewable gases, or specifically target green hydrogen or biomethane. The Renewable Fuel Scheme currently under design in NSW is effectively an RGC scheme for green hydrogen only.[148] This sets a volume (production target of 90,000 GJ in 2024, increasing to 8 million GJ by 2030) rather than proportion target (a percentage of overall gas consumed). The proposed Renewable Hydrogen Target in WA[149] is a somewhat different concept, specifically focussing on the use of green hydrogen for electricity generation (target of 1%).

6.2.2 Examples

RGC schemes have not been widely used internationally and so there is therefore limited evidence of their effectiveness. The RET provides some indication of how successful a scheme of this nature can be.

France has established several targets for biomethane injection into the natural gas grid. The Long Term Energy Schedule (PPE) has set an injection target of 10% of biomethane by 2030, which is equivalent to around 40 TWh of biomethane produced.[150] This is to be achieved through the introduction of Biogas Production Certificates which sets a minimum incorporation rate for all natural gas suppliers.[151]

In the United States, 18 States and Territories have Renewable Portfolio Standards (RPS) that require a specified percentage of the electricity that utility companies sell to come from renewable resources. RPS are therefore akin to a RET (or RGC). It has been estimated that roughly half of the US$64 billion renewable energy market has been driven by state renewable energy requirements since the early 2000s.[152]

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[147] Australian Energy Update, Australian Government Department of Climate Change, Energy, the Environment and Water. Last updated 2022.

[148] NSW Government. Renewable Fuel Scheme | NSW Climate and Energy Action. Last updated 2023.

[149] Government of Western Australia. WA Government takes aim at Renewable Hydrogen Target | Western Australian Government (www.wa.gov.au). Last updated 6 December 2022.

[150] Terega. Biomethane in France in 2023 (terega.fr). Last updated 2023.

[151] Sia Partners.EUROPEAN BIOMETHANE BENCHMARK (sia-partners.com). Last updated May 2022.

[152] National Conference of State Legislatures. State Renewable Portfolio Standards and Goals. Last updated 13 August 2021.

6.3 Contracts for Difference (CfD)

6.3.1 Policy Summary

Contracts for difference (CfDs) incentivise renewable gas production by providing price certainty to developers. Under CfD agreements, the government covers any shortfall between the market price and the agreed reference or 'strike' price. Some designs include upside risk sharing, where the government will receive the difference between the strike price and market price when the market price is higher. An attractive feature of CfD policies is that the fiscal liability is self-eliminating over time, as market prices increase. This avoids risks of lock-in to subsidies that can be challenging to unwind once established.

Australia's Hydrogen Headstart program has some features of a CfD scheme. The initial consultation document released by the Australian Renewable Energy Agency (ARENA) proposes that successful projects will be able to receive a production credit over a 10-year period to cover the commercial gap between the cost of hydrogen produced from renewables and the sales price of that hydrogen or its derivative products.[153] The proposals include some upside risk sharing for Government. However, unlike a conventional CfD scheme, contracts will include a fixed production credit rather than a credit that varies with the market price.

6.3.2 Examples

Germany's H2 Global Foundation

Germany's H2 Global Foundation promotes the production use of green hydrogen and its derivatives through a market-based approach akin to CfDs. H2 Global was established in 2021 as a non-profit organisation by the German Hydrogen and Fuel-Cell Association and sustainable development organisation GIZ. H2 Global has a subsidiary company called Hintco (Hydrogen Intermediary Network Company) which received an initial endowment of 900 million euros from the German government to facilitate competitive tenders and address price differences between volumes purchased and volumes sold.[154]

H2 Global is based on a CfD model whereby Hintco offers 10-year production contracts to the lowest bidders up to a specified total value, and then sells purchased volumes on to the highest bidding offtakers on a short-term basis. This has the effect of minimising the price difference that is to be compensated by Hintco. Short-term sales contracts also mean that H2 Global can benefit from expected increasing market prices for conventional products, reducing the price difference to be compensated (ultimately by the German government).[155]

H2 Global will also support imports of green hydrogen and derivatives to Germany by establishing trade partnerships with countries in which green hydrogen can be produced efficiently (including the EU and Australia).[156] The European Hydrogen Bank is also considered likely to adopt a CfD-style scheme.[157] [158]

UK Hydrogen Production Business Model

The UK's Hydrogen Production Business Model (HPBM) will incentivise investment in low carbon hydrogen production and use by providing revenue support to producers to overcome the operating cost gap between low carbon hydrogen and high carbon fuels. This will be delivered through a contract (the Low Carbon Hydrogen Agreement or LCHA) between a government appointed counterparty and a hydrogen producer. The HPBM will support the UK Government's objective of delivering up to 10 gigawatts (GW) of low carbon hydrogen by 2030.[159]

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[153] ARENA. hydrogen-headstart-consultation-paper.pdf (arena.gov.au). Last updated July 2023.

[154] Guidehouse Insights. Lessons from Germany's H2Global Program (guidehouseinsights.com). Last updated 31 January 2023.

[155] The H2Global Instrument (h2-global.de)

[156] H2Global Stiftung. Hydrogen: the energy resource of the future (embassy.gov.au)

[157] Hydrogen Insight. European Hydrogen Bank will close '100% of the cost gap' between renewable and fossil hydrogen as soon as 2023, but shadow of US tax credit looms | Hydrogen news and intelligence (hydrogeninsight.com). Last updated 26 October 2022.

[158] Guidehouse Insights. Lessons from Germany's H2Global Program (guidehouseinsights.com). Last updated 31 January 2023.

[159] Department of Energy Security and Net Zero. Hydrogen production business model - GOV.UK (www.gov.uk). Last updated 13 December 2022.

The HPBM will support selected producers of low-carbon hydrogen by paying them a premium, calculated as the difference between a Strike Price (reflective of the producer's unit cost of production and negotiated on a project-by-project basis) and a Reference Price (based on the price at which the producer sells their hydrogen, with a floor at the natural gas price). The HPBM also includes a reward mechanism that incentivises producers to achieve higher sales prices, which will reduce the size of the support payment under the LCHA.[160]

6.4 Feed-in-Tariff (FiT)

6.4.1 Policy Summary

Under a FiT, project developers receive a fixed amount for renewable gas production over an established period. FiT's are typically paid on the volume of renewable gas supplied to the network. The aim of a FiT is to incentivise production by providing a premium above fossil fuel competitors for renewable gases. FiT's have been used extensively to establish markets for renewable energy sources including rooftop solar PV, biogas, and biomethane.

6.4.2 Examples

UK Green Gas Support Scheme

The UK's Green Gas Support Scheme (GGSS) is designed to provide tariff-based support for biomethane produced and injected into the gas grid as a direct replacement for natural gas. Following consultation with industry, a 15-year tariff lifetime and a three-tier structure was implemented alongside sustainability criteria.[161] The tariff rates are set based on a model for a reference biomethane anaerobic digestion plant, which is designed to represent the average plant expected to apply for the GGSS. The model indicates what rate of return a set of tariff rates will provide for the reference plant given costs, revenues, and macroeconomic forecast input levels.[162, 163]

The tariff rate may differ dependent on the total volume of renewable gas exported by a single producer. In the United Kingdom, the biomethane feed-in tariff features three tiers, described below. The tiered structure accounts for the economies of scale associated with increased production volumes.

- Tier 1: Up to 60,000 MWh – GBP 5.51/kWh.
- Tier 2: the next 40,000 MWh – GBP 3.53/kWh.
- Tier 3: Above 100,000 MWh – GBP 1.56/kWh

The scheme is funded by the Green Gas Levy (GGL). The GGL places an obligation on all licensed fossil fuel gas suppliers in Great Britain to pay a quarterly levy which will be calculated based on the number of meter points they serve.

German biogas industry

FiTs guaranteed under the German Renewable Energy Act (REA) strongly contributed to the expansion of biogas and biomethane in Germany. The REA was first introduced in 2000 and provided earnings stability to biogas producers through FiTs that were limited for a period of 20 years. FiTs obliged utility companies to remunerate and purchase the biogas produced often at costs higher than conventional electricity generation, which resulted in higher power prices for consumers in Germany (98% of biogas production in Germany is for electricity generation).[164]

FiTs were successful in growing the German biogas industry from around 1,000 biogas plants in 2000 to approximately 9,600 plants in 2020, noting this was predominately biogas to electricity. The German biogas industry is now the largest and most advanced in the world, with

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[160] Shepherd + Wedderburn. UK Hydrogen Production Business Model: an update | Shepherd and Wedderburn (shepwedd.com). Last updated 14 February 2023.

[161] United Kingdom Department for Energy Security & Net Zero, Green Gas Support Scheme Mid-Scheme Review Consultation. Last updated 2023.

[162] United Kingdom Government, Green Gas Support Scheme (GGSS): Annual Tariff Review 2022. Last updated 2022.

[163] Further information on the biomethane tariff-setting methodology can be found here: in Annex B.

[164] Science Direct Understanding stakeholder preferences for future biogas development in Germany - ScienceDirect. Last updated October 2021.

biogas plants providing around 10% of Germany's total electricity.[165] However, as the biogas market has reached maturity the German government no longer offers FiTs to biogas producers, and early biogas producers are beginning to lose their FiTs as their 20-year period comes to an end (1,000 biogas plants lost their FiT in 2021).[166] This has raised some concerns over the long-term viability of the industry, particularly for smaller producers (such as farmers) with estimates that a quarter of the 1,000 plants that lost their FiT may have to close.[167]

6.5 Qualitative Assessment

KPMG has conducted a qualitative assessment of the three policy instruments, applied to both hydrogen and biomethane. We apply the six criteria listed below (see in Table 11) and consider the resulting implications for overall policy design and the choice of instrument. We use this to narrow down the policy instruments to two possible policy packages, which are modelled further in the following chapter.

Table 11: Evaluation criteria

Criterion	Description
Capacity to deliver material cost reductions in future	The extent to which the policy could enable material cost reductions in key technologies that can reduce future abatement costs. This can occur through facilitating technology uptake to achieve scale or learning by doing benefits.
Capacity to cost-effectively reduce greenhouse gas (GHG) emissions and contribute to net-zero pathways	The extent to which the policy could reasonably contribute to cost-effective GHG emission reductions now and in the future. Considers how a policy capitalises on low-risk abatement pathways, or preserves optionality in sectors with less certain decarbonisation pathways.
User preferences, social license and avoiding disruptive change	Assesses the extent to which a policy avoids major disruptions to end-users or mitigates social license issues.
Market coordination and managing spill-overs	Considers how the policy contributions to market coordination (e.g. managing impacts on shared infrastructure) and the potential for positive or negative spill-over effects on the environment, economy or community.
Allocation of costs	Explores how the costs of the policy are distributed across society, informing whether ameliorative and complementary policies are required.
Allocation of risk	Considers how price risks are allocated across stakeholders, including management of fiscal risks.

6.5.1 Summary of results

Each instrument has their advantages and disadvantages, which may change at different points in time. Importantly they have different allocations of costs and risks that will influence the choice of instrument as circumstances change. As conventionally implemented an RGC scheme will be borne by consumers in the market, via consumer charges. CfDs and FiTs are usually budget-funded, though they can be recovered in other ways. For example, the ACT operates a CfD scheme with renewable electricity generators where the electricity distributor, Evoenergy, is required to pay generators and recover costs from electricity consumers through its network tariffs. Risks around cost, technology and supply are also allocated differently. An RGC scheme is more administratively complex and would require a longer lead time to implementation than a budget-funded CfD or FiT.

[165] Mitsui & Co. 2202du_yoshizawa_e.pdf (mitsui.com). Last updated February 2022.

[166] Energy Post. Germany: will the end of feed-in tariffs mean the end of citizens-as-energy-producers - Energy Post. Last updated 3 June 2021.

[167] Clean Energy Wire. Post feed-in tariff futures for pioneer renewable plants: Biogas | Clean Energy Wire. Last updated 1 June 2021.

Our assessment indicates that a FiT could be considered in the medium term for biomethane but should be ruled out for green hydrogen. A FiT design does have several advantages in that it provides a clear investment signal and control to government on cost and risk (given that FiT contracts can be capped at a certain volume, and government retains control over tariff settings). However, in the case of green hydrogen, its main disadvantage is that it ties production to a single use (blending in gas networks). This precludes behind-the-meter production and use by industry, which would result in a substantial distortion. A FiT scheme also typically sets a standard tariff rate across projects, which is less efficient than setting crediting rates based on a market mechanism, particularly in the current context of considerable uncertainty and dynamism in technology costs.

A better approach in the short term – for both hydrogen and biomethane- would be to combine the strengths of a FiT with elements of a CfD design, as under the proposed Hydrogen Headstart scheme. A conventional CfD design provides flexibility and breadth in terms of eligible sectors and uses, but government bears price risk and uncertainty on the total scheme cost (given that this is dependent on the difference between the strike price and prevailing market price). The proposed Hydrogen Headstart design provides a sensible middle ground. It provides investor certainty in the form of a fixed production credit contract, which also provides certainty to government on fiscal cost. The government has also proposed other risk sharing elements, including that the government can share in upside price risks should they eventuate. Unlike a conventional FiT, it uses a market mechanism (a reverse auction) to determine the size of production credits based on the expected viability gap of each project (with more viable projects prioritised for funding first).

An RGC scheme has advantages as a market-based, emitter-pays mechanism, and could be considered in the medium-term. An RGC scheme could be a highly effective instrument for stimulating deployment and cost reductions, in a similar fashion to the RET for renewable electricity. However, renewable gas technologies and supply chains in Australia are arguably at an earlier stage of development than was the case at the inception of the RET. Both markets are also likely to be considerably less liquid, with fewer suppliers in earlier years due to the importance of scale (with hydrogen) and the need to develop limited biomass/waste supplies (for biomethane). There are also risks around interactions with other sectors that require close attention to project location and impacts. In the short term, building off the Hydrogen Headstart approach would allow support to be mobilised quickly and would provide a lower-risk option for managing price risks and unforeseen spill-overs. The more administratively complex RGC mechanism can be considered for implementation in the medium term, based on the information and lessons gathered from the early experience of Hydrogen Headstart and an equivalent CfD scheme for biomethane.

Our assessment against each of the criteria is detailed further in the table below. In the next chapter, we present a quantitative analysis of the RGC scheme and CfD options to illustrate potential costs and contributions to emissions reduction, for different scales of policy intervention.

Table 12: Assessment of Implications for Policy Design and Instrument Choice

Criterion	Implications for Policy Design	Implications for Instrument Choice
Capacity to deliver material cost reductions in future	• Size of incentive per GJ needs to be sufficient to bridge gap between market prices and required rate of return. This will be different for biomethane and hydrogen. • Clear medium-term targets will provide policy certainty and encourage investment. • Targeted production volumes should be sufficient to lead to cost reductions based on reasonable assumptions on scale and learning effects. This will be different for biomethane and hydrogen.	• Instruments that provide greater price certainty for investors will be more likely to stimulate investment. • A CfD or FiT have advantages over an RGC scheme for providing price certainty. • FiTs may appeal to investors since there is upfront certainty on the credit amount. While CfDs provide certainty once contracted, they typically involve a tender and negotiation process where the proponent invests significant time and resources with uncertain outcomes. • In the initial stages of operation for an RGC scheme there would be significant uncertainty over certificate prices. On the other hand, an RGC scheme provides medium-term policy certainty by setting a target and signalling long term commitment. • RGC scheme: Given differences in renewable gases (market readiness, cost to produce) consider separate targets and certificates for the two gases, otherwise certificates could strongly favour one gas over the other.

Criterion	Implications for Policy Design	Implications for Instrument Choice
Capacity to cost-effectively reduce GHG emissions and contribution to net-zero pathways	• Covered projects should align with the sectors and use cases where renewable gases can contribute cost-effectively to abatement in the near term, while aligning with likely sectoral pathways to net zero • This can be largely market-determined since project commercials already factor in current knowledge of future abatement pathways to some extent. Some guard-rails may be needed to favour certain sectors with clear abatement pathways. It is possible that project proponents may put more weight on use cases with the most practical near-term offtake and less weight on long-term pathways than would be socially optimal. • Given uncertainty over sectoral abatement pathways and timelines, at first take a portfolio approach to project investments across use cases, to preserve optionality and avoid 'picking winners'. • There should be regular reviews of the scheme eligibility criteria so that sectoral focus can be adjusted as new information emerges.	• A CfD approach is most advantageous, providing broad applicability across sectors and use cases. • An RGC scheme is also broadly applicable, but unlike a CfD it would be administratively challenging to include the transport sector alongside stationary combustion. • A FiT approach is less favourable since it restricts eligible production to uses with grid injection. This is distortionary since it would exclude the transport sector and on-site/behind the meter production. This a FiT unsuitable for hydrogen, but is only a moderate drawback for biomethane (where blending is likely to be the main use case anyway)
Market coordination and managing spill-overs	• Preserve some central control to manage impacts on network infrastructure • Suggest starting small and increasing size when more is learned on impact and costs. This lowers risk of distorting bioenergy and renewable electricity markets.	• RGC's provides less control over project locations and network impacts than CfD and FiT approaches which are contracted on a case by case basis. Under an RGC scheme these may need to be managed under different policy and regulatory frameworks • All instruments provide control on quantity (can include a volume cap on CfD and FiT contracts) and can be coupled with sustainability criteria • RGC scheme target may need to subject to regular review, and include additional criteria for earning certificates to mitigate known spill-over risks (e.g. sustainability criteria for biomass sources; additionality requirements for renewable electricity)
User preferences, social license, and avoiding disruptive change	• Sectoral scope: consumer choice arguments would favour inclusion of network blending to households in a first phase. This would need to be accompanied with clear consumer information • As above, some central control is important to manage risks of disruption for end users – e.g. if hydrogen blending is heavily concentrated in one network section this could have localised impacts on consumer appliance compatibility	• Hydrogen: case by case CfD contracts offer greater control than an RGC scheme to avoid localised network disruptions from hydrogen blending
Allocation of costs	• In the absence of a broader carbon pricing policy, the preference is for costs to be borne by emitters (and if possible those that eventually benefit). • This may provide additional stimulus for deployment since in an emitter-pays framework there is an incentive to uptake renewable gas to reduce compliance obligation. • An emitter-pays approach introduces costs on households which would need to be carefully managed. If costs are too high, it could accelerate network disconnection. Similarly, impacts on trade-exposed sectors need to be mitigated.	RGC: • has advantage that it is emitter-pays by design. Natural gas users are liable to purchase certificates. • Given the share of energy expenditure declines with income, the impact tends to be regressive across households, though complementary measures can ameliorate this • Similar to the RET, the RGC would have an exemption for trade-exposed entities. • As a market based mechanism, the RGC promotes efficiency through competition in the certificate market. The production incentivised through certificates should be fully additional

Criterion	Implications for Policy Design	Implications for Instrument Choice
	• Some cost-sharing from government would help to limit risks of unintended negative impacts on households and industry, and effectively makes a larger investment incentive feasible. • Efficiency is also important. Cost-sharing from government should only finance additional production, i.e. the instrument should not subsidise production that would occur anyway	CfD/FiT: • Typically taxpayer-funded rather than emitter-pays. Alternatively, a consumer levy or excise could be introduced on gas buyers to finance all or part of the CfD/FiT. • A CfD is more efficient than a FiT. Can use a reverse auction approach that sets credit level or strike price at different levels for each proponent, so credits only subsidise the amount needed for project viability. For a standardised FiT, some producers would receive a credit in excess of what they require
Allocation of risks	• There could be some risk sharing between project proponents and government. Some degree of de-risking on the part of government is appropriate to encourage investment, but it is also appropriate that proponents internalise some risk to incentivise selection of the most prospective projects. • Liable parties should be protected from price risk to some extent to avoid unintended consequences (excessive impact on consumer bills or industry costs). • Fiscal risks should be limited through hard caps on budget allocation. Contracts should have capped volumes to avoid risk of oversubscription.	• Both the proponents and liable parties bear risk on the certificate price for an RGC . Given uncertainties over achievable levels of production in the near term, risk of high certificate prices for liable parties would be significant. This would need to be carefully managed through an opt-out price. Price risk to proponents would be significant at the scheme’s outset. This could to be managed through the addition of CfD contracts, which adds complexity. • For project proponents in the CfD scenario, various risk sharing arrangements are possible. There can be a fixed production credit like Hydrogen Headstart, where the proponent bears all downside risk on the differential between the sales price and break-even price. Or the taxpayer can bear risk if payments are variable based on a strike price. There are various arrangements for upside risk such as 50/50 sharing of upside risk and even re-payments if certain thresholds are met (both are proposed under Hydrogen Headstart) • Under a FiT, tariff rates can be periodically adjusted to reflect price changes. This puts risk-sharing at the discretion of government.

7 Quantitative analysis on prospective policy measures to encourage deployment

This chapter provides a preliminary assessment of possible targets for deployment policy and considers the implications for total cost, emissions reduction and the allocation of costs and risks. We first consider the implications for total costs and emissions reduction from choosing different levels of hydrogen and biomethane production to achieve by 2030, presenting estimates for the status quo and three levels of increasing ambition. We then explore how the allocation of costs and risks differs across an RGC versus a CfD-style approach.

Refer to Appendix 1 for a list of key assumptions used in our analysis.

7.1 Scope

Our quantitative assessment takes a short-medium term view, covering financial years 2024 to 2030. This is to cover the first 'wave' of deployment, with a view that policy settings would be updated in several years' time based on the learnings to-date and new information on costs and risks.

Our scope has an initial focus on domestic gas consumption. We focus on renewable gases displacing domestic consumption of natural gas across all use cases, including residential and commercial, industrial, and gas used for electricity generation.

Assumed domestic gas consumption volumes that the options will influence include[168]:

- Residential and commercial gas consumption (20-21): 166 PJ
- Industrial - Mining, manufacturing and other consumption (20-21): 542 PJ
- Gas used for electricity generation (20-21): 523 PJ.

LNG exports (4,314 GJ) and 'LNG plant other use' (338 PJ)[169] are excluded from the analysis.

The assessment is end use agnostic. Within the scope of the domestic gas market, we recommend the policy instruments be end use agnostic in the short-medium term. When reviewing the instrument performance after the initial implementation, a more targeted approach may be required to ensure that renewable gas uptake according to different end uses remains aligned with the latest information on sectoral decarbonisation pathways. Any assumed volume of renewable gas produced for the three sectors above is for calculation and demonstration purposes only.

For ease of comparison, we have assumed that the transport sector is not initially in scope. As outlined in previous chapters, renewable gases have a potential role in displacing other fossil fuels such as diesel in the transport sector. A CfD-style policy instrument can be designed to include such use cases, whereas there are administrative and equity challenges to designing a single certificate-based RGC across both the natural gas market and transport sector. For example, it would be inequitable if certificates could be generated for renewable gas produced for use in the transport sector, while the liability to purchase certificates is only placed on natural gas users. To simplify the analysis and support comparison between the two types of policy instrument, we have focused on the domestic natural gas market only.

7.2 Setting Ambition

We suggest starting with achievable ambitions for renewable gas volumes, which provide sufficient scale to test technologies while providing a solid base to address unanticipated outcomes and build further ambition in future. Ambitions can grow when markets are established, volumes available are more clearly understood and prices are more certain. The renewable energy target (RET) also started with a small increment, and this demonstrated this can help drive the market forward for a relatively low overall cost (although cost per tonne may be higher). Careful consideration of the degree of ambition and putting in boundaries can be important to prevent unintended consequences and lower risk of actions that are later regretted. The RET was so quickly adopted by

[168] DEECA. Australian Energy Update 2022. Last updated September 2022.

[169] ibid

many different companies that there were side effects such as substantial cost increases and grid preparation issues.

7.2.1 Options for ambition

We have chosen three possible levels of ambition, with the upper bound aligned to AEMO's 2023 'Diverse Step Change' scenario assumptions for renewable gas.[170] Table 13 below presents each of these options. We also include a status quo scenario which consists of the implementation of the Hydrogen Headstart program and some small scale biomethane projects that may be stimulated through the Safeguard Mechanism, Emissions Reduction Fund or ARENA funding.

Table 13: 2030 Ambition for quantitative assessment

Ambition	Green Hydrogen	Biomethane	Notes
Status quo	$2B for Hydrogen Headstart (with $1B spent by 2030)	Assumes Malabar project running at full scale from FY24-FY30 and 0.5PJ per annum uptake from Safeguard Facilities from FY26	Assumes half of Hydrogen Headstart program is expended by 2030
Low	**TARGET: 2% by volume, 0.7% by energy by 2030** For the assessment we assume 0.005% energy for network distribution (based on current volumes in the network), 0.8% for GPG and large industrial	**TARGET: 0.5% by volume, 0.5% by energy by 2030** Assessment assumes 0.5% energy for distribution network blending, GPG and large industrial	Targeting 50% increase to Hydrogen Headstart impact and sets a low target for biomethane. Targets include status quo (what may be achieved by Hydrogen Headstart by 2030 and biomethane projects)
Medium	**TARGET: 6% by volume, 1.7% by energy by 2030** For the assessment we assume 1.7% energy for network distribution, GPG and large industrial	**TARGET: 1% by volume, 1% by energy by 2030** Assessment assumes 3% energy for distribution network blending, 1% of GPG and large industrial	This is the midway option between the status quo and AEMO GSOO target. Targets include status quo (what may be achieved by Hydrogen Headstart by 2030 and biomethane projects)
High	**TARGET: 10% by volume, 3% by energy by 2030** For the assessment we assume 3% energy for network distribution, GPG and large industrial	**TARGET: 2.7% by volume, 2.7% by energy by 2030** Assessment assumes 7.5% energy for distribution network blending, 2% of GPG and large industrial	Aligns with AEMO 2023 GSOO Diverse Step Change (1.8 degrees) scenario blending assumptions for gas distribution networks. Targets include status quo (what may be achieved by Hydrogen Headstart by 2030 and biomethane projects)

Although the percentage targets for biomethane are relatively modest, they are ambitious when considered in the context of the current state of the industry. In relative terms, the *Medium* ambition biomethane target is the equivalent of 66 Jemena Malabar anaerobic digestors operating at full capacity in 2030.[171] Taking another point of comparison, the *Medium* ambition target would equate

[170] AEMO. AEMO | Gas Statement of Opportunities. Last updated 2023.

[171] Jemena. Building a Future Flush with Renewable Gas - Jemena. Last updated 2023.

to a 74% expansion of biogas consumption in Australia,[172] assuming that all biomethane production is additional to existing biogas use (which is already converted to electricity in most cases). Although this is relatively high, there is significant opportunity to increase biogas capture in Australia in addition to that currently captured for electricity generation. The *Medium* scenario would utilise only 4% of biogas potential in Australia, according to one study.[173]

7.2.2 Renewable gas PJs generated and cost

Based on these targets, a summary of renewable gas petajoules created from each level of ambition is included in Table 14. Additional production over FY24-FY30 relative to the status quo ranges from 16 PJ under the *low* targets to 167 PJ under the *high* targets. Depending on the level of ambition, the proportion of renewable gas in Australia's domestic gas consumption ranges from 1.2% to 5.7% by 2030, by energy, and 2.9% to 12.7% by volume depending on the scenario. Note that these percentages are not equivalent to gas blending rates but rather represent the share of renewable gas in total gas consumption, which includes blended gas, behind-the-meter production and use, and (potentially) hydrogen delivered via tube trailers or dedicated pipelines. The maximum overall rate of distribution network blending of hydrogen would be 10% by volume under the *high* target, consistent with 2023 GSOO scenario assumptions.

Based on conservative price assumptions, direct costs would range from $370M to $4.0B over FY24-FY30. As shown in Table 14, the *low* targets are anticipated to cost an additional $370M on top of the status quo to 2030. The high targets are anticipated to cost around $4.0B to reach on top of the status quo costs to 2030. These cost estimates are based on conservative assumptions of the difference in direct production costs of renewable gases relative to the natural gas price and exclude other potential costs (e.g. transport costs for hydrogen tube trailers). As noted above, blending rates are assumed to remain below levels that would incur additional infrastructure or appliance costs. Based on these costs and the CO2 emissions reductions in Table 15, near-term abatement costs are conservatively estimated to be $285 and $739 per tonne for biomethane and hydrogen respectively.

The total cost in the *medium* and *high* scenarios is similar to the estimated historical cost of the RET, although the average cost of abatement is higher. There is limited data available on the costs of the RET in the first years of implementation. However, eight years after the inception of the RET, the overall cost was around $300M-$500M per year (or $2.1B-$3.5B over seven years which is the period we have looked at in our renewable gas assessment). Abatement costs ranged from $30 to $290 per tonne of CO2 (although LRET-only costs were lower, ranging from $37 - $111 per tonne).[174]

There will be ongoing costs after 2030. The costs included in Table 14 are for FY24-30 only. Costs after 2030 depend on factors such as the length of CfD contracts (if this option is adopted), the cost of renewable gas production, and natural gas prices. We discuss benefits after 2030 in section 7.2.3.2.

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[172] Based on current biogas consumption of 18PJ from Australian Energy Update 2022

[173] KPMG calculations from data included in Biogas Opportunities for Australia, March 2019.

[174] The Centre for International Economics. RET How it works and what it costs November 2013.docx (climatechangeauthority.gov.au). Last updated November 2013.

Table 14: Summary of costs and production levels of the three levels of ambition

Note that, in order to be conservative, costings do not include assumptions on scale or learning effects being achieved before 2030. All options would involve costs beyond 2030. For example, CfD-style contracts would typically have a 10-year term.

Ambition	Gas	Share of domestic gas consumption (1,174 PJ) in 2030 (by energy)	Share of domestic gas consumption (1,174 PJ) in 2030 (by volume)[175]	Total PJ produced (FY24-30)	Incremental production relative to status quo FY24-30, PJ)	Total cost ($M) until 2030[176]	Incremental cost relative to status quo ($M)
Status quo (H2 Headstart)	Biomethane	0.1%	0.1%	4		$60	
	Hydrogen	0.5%	1.7%	26		$1,000	
	TOTAL	**0.6%**	**1.7%**	**31**		**$1,060**	
Low	Biomethane	0.5%	0.5%	15	10	$210	$150
	Hydrogen	0.7%	2.4%	32	6	$1,210	$210
	TOTAL	**1.2%**	**2.9%**	**47**	**16**	**$1,430**	**$370**
Medium	Biomethane	1.2%	1.2%	48	44	$700	$640
	Hydrogen	1.7%	5.7%	59	33	$2,230	$1,230
	TOTAL	**2.9%**	**6.9%**	**107**	**77**	**$2,930**	**$1,870**
High	Biomethane	2.7%	2.7%	103	99	$1,490	$1,430
	Hydrogen	3.0%	10.0%	94	68	$3,560	$2,560
	TOTAL	**5.7%**	**12.7%**	**197**	**167**	**$5,050**	**$3,990**

7.2.2.1 Cost sensitivity

The total policy cost is sensitive to the prices of natural gas, biomethane and hydrogen. The above figures are based on conservative assumed costs to produce biomethane and hydrogen of $25 and $49 per GJ respectively. The difference in this cost compared to natural gas (which is assumed to average $11 per GJ over the time period) drives the additional costs to introduce more renewable gas into the system. This price differential is subject to substantial uncertainty, due to movements in natural gas prices and uncertainties over renewable gas technology costs. If the difference between the renewable gas price and natural gas price was 20% less than assumed under the base case from FY24-30, then:

- The *Low* scenario cost would drop by $190M (total cost additional to status quo $190M)
- The *Medium* scenario cost would drop by $490M (total cost additional to status quo $1,390M)
- The *High* scenario cost would drop by $910M (total cost additional to status quo $3.1B).

Similarly if the price difference between renewable gases and natural gas were 20% higher, the anticipated costs for each level of ambition would increase by the same amount.

[175] Assuming 1:1 ratio for biomethane energy to volume and 3:10 for hydrogen based on table 1 in Microsoft Word - 2023 Gas Statement of Opportunities v1.2 (aemo.com.au)

[176] Note that there will be ongoing costs after 2030.

7.2.3 Benefits of increasing renewable gas production and use

Investing in renewable gas deployment will result in some short-term benefits through emissions reductions between now and 2030, but the key benefit will come from increased scale and cost reductions in the 2030s. This section presents estimates of the short term emissions reductions benefits according to different levels of policy ambition, before turning to the potential for more substantial long-term benefits in the 2030s.

7.2.3.1 Short-term emissions reduction (FY24-FY30)

Estimates for short-term emissions reductions are summarised below (Table 15). These estimates assume that each additional GJ of renewable gas displaces 1 GJ of natural gas and therefore results in avoided emissions, which are assumed to equal 51 kg CO2-e per GJ (see Appendix 1 for assumptions). The *low* ambition scenario would achieve approximately 2.4M tonnes of emissions reduction (0.8M tonnes in addition to status quo). The *high* ambition scenario would reduce emissions by 10M tonnes (8.5M tonnes in addition to status quo) by 2030. We also calculated the potential financial benefit from the tonnes of CO2 avoided, based on a social cost of carbon of $136.50 per tonne.[177] The low scenario has a social benefit of $330M, and the high $1.37B.

Table 15: Environmental benefits based on ambition

Ambition	Gas	Total emissions reduction (MtCO2e) FY24-30	Benefits on society from avoided emissions (based on an assumed social cost of carbon)
Status quo (H2 Headstart)	Biomethane	0.2	$30
	Hydrogen	1.4	$190
	TOTAL	**1.6**	**$210**
Low (including status quo)	Biomethane	0.7	$100
	Hydrogen	1.6	$220
	TOTAL	**2.4**	**$330**
Medium (including status quo)	Biomethane	2.4	$330
	Hydrogen	3.0	$410
	TOTAL	**5.5**	**$750**
High (including status quo)	Biomethane	5.2	$710
	Hydrogen	4.8	$660
	TOTAL	**10.0**	**$1,370**

7.2.3.2 Potential longer-term benefits

Investing in policies that drive the production and uptake of renewable gas is likely provide significant benefits beyond 2030 through lower prices, which in turn provide a foundation for faster and more significant emissions reductions. Producers would start to learn more about making renewable gas at scale in the domestic market, and as production increases and more is learnt, prices would likely decrease. Anticipated decreases in price for renewable gas range in the literature. The Future Fuels CRC's central scenario[178] indicates a 5.4% cost reduction on average per year for biomethane and 6.2% for hydrogen, due to learning and scale effects. With these rates applied to the *high* scenario in our model, we would expect prices to reduce to below $15 per GJ for biomethane and $27 per GJ ($3.20 per kg) for hydrogen by 2035. Marginal abatement costs would change from $285 per tonne for biomethane to below $100 per tonne by the mid-2030s, and from $739 per tonne for hydrogen to below $100 per tonne by the late 2030s. These reduced costs would

[177] Based on IEA's estimate of US$75-$100/tonne of CO2 by 2030 (equates to $136.50 AUD/tonne) from 'The importance of real-world policy packages to drive energy transitions – Analysis - IEA'. Applies to all tonnes of CO2 reduced including status quo. Sums may not equate due to rounding.

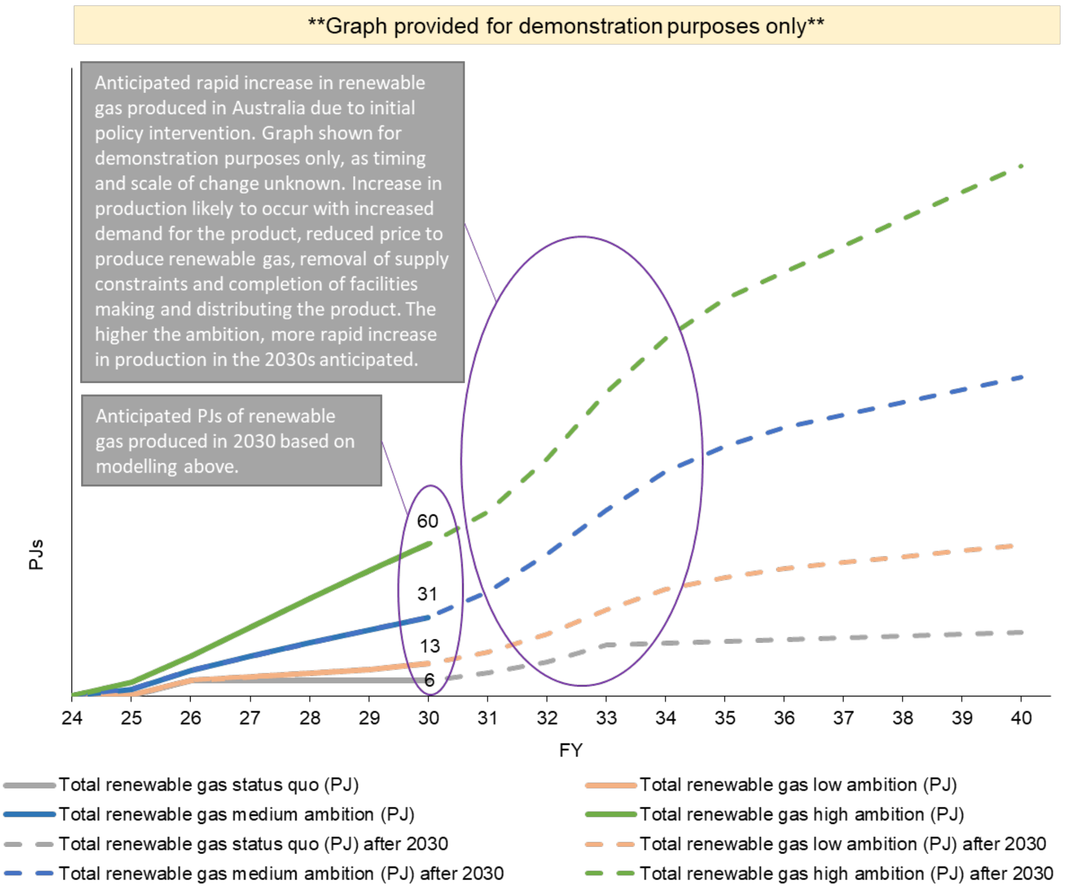
[178] FFCRC_RP2.2-04_Learning_experience_and_cost_curves_final_open-access.pdf (futurefuelscrc.com)

be expected to lead to a more rapid scale-up of renewable gas consumption and therefore emissions reductions.

However, anticipating exactly when these benefits will occur is challenging. As highlighted in Victoria's Renewable Gas Consultation Paper,[179] supply constraints may hold prices up over time in the context of rapid demand expansion and as more ambitious targets lead to more expensive sources of renewable gases being exploited. Long term cost will depend heavily on the interplay of supply and demand, as well as the cost of natural gas.

Figure 2 shows the PJs of renewable gas produced based on the level of policy ambition to 2030, and then illustrates the potential uplift in renewable gas in the 2030s due to these earlier efforts. This is for display purposes only, and is intended to show that the policy intervention now will likely lead to significantly increases in renewable gas production. If policy intervention is left until after 2030, the benefits are delayed. The timing and scale of the uplift is unknown, but will likely occur with increased product demand, lower production costs, removal of supply constraints and when facilities are in operation. To provide a point of comparison for this longer-term growth potential, when the RET was introduced in 2001, renewables made up 7.7% of electricity generation in Australia, and 20 years later it was 26.7% of the generation mix.[180]

Figure 2: Renewable gas energy (PJ) based on each level of Ambition to 2030, and potential increases from 2030-2040 due to earlier policy intervention



[179] Victoria's Renewable Gas Consultation Paper | Engage Victoria

[180] KPMG calculations based on data from Australian electricity generation | energy.gov.au, accessed September 2023

7.3 Cost and Risk Allocation – Comparing RGC and CfD Approaches

In the section above we set targets to assess the potential impact including renewable gas PJs created, cost and emissions reduction benefits. We now compare two policy instruments that could be used to achieve the percentages set in the section above.

Based on the earlier evaluation and design considerations on the three policy instruments, KPMG presents two illustrative policy packages:

Option One: RGC scheme for Hydrogen and Biomethane	Option Two: CfDs via 'Biomethane Booster' and Hydrogen Headstart expansion
Set separate RGC targets for hydrogen and biomethane with certification scheme Hydrogen target expands on existing Hydrogen Headstart Funded by the market	Establish CfD for biomethane Expand the Hydrogen Headstart program Design to establish a range of contracts with agreed price per GJ over 10-year period Funded by government

These two options provide an illustrative comparison of contrasting approaches for cost and risk allocation. The two options differ in who will bear the cost, and if volume certainty is preferred to price certainty**.** Under a conventional RGC scheme (Option 1), costs are recovered from the market. There is relatively high confidence of achieving a targeted production volume, but producer prices (from certificates) are relatively uncertain. By contrast, under a Hydrogen Headstart-style design (Option 2), the scheme costs are funded from the government budget. There is greater certainty over producer prices (via fixed production credit contracts) but less confidence that the credit level will be sufficient to achieve a certain production volume. The following sections present a quantitative illustration of the differences in cost and risk allocation. In practice, policy instruments may be designed with cost and risk sharing arrangements that combine elements of both designs.

7.3.1 Cost allocation

A key difference between Option One (RGC) and Option Two (CfDs) is how the policy is funded. Table 16 and Figure 3 summarise how cost would be covered, with Option Two covered by government and Option One covered by the market (except for the existing Hydrogen Headstart component). If Option One is adopted, with current assumptions the industrial sector would be covering between $200M-$1.4B over FY24-30, depending on the level of ambition. Costs for electricity generators range from $180-$1.8B and are higher as the existing Hydrogen Headstart program is assumed to mainly focus on the industrial sector (and therefore a component of those PJs are covered by the government in all scenarios). Households with gas connections would cover between $50M and $900M over the seven-year period (FY24-30), which ranges from $2 to $68 per household per year in 2030. By comparison, under the early RET the annual cost to consumers was estimated to be between $50 and $102 or 3-4% of the electricity price.[181]

[181] The Centre for International Economics. The Renewable Energy Target: How it works and what it costs Last updated November 2013. On page 14, the report cites consumer cost estimates for 2012/13 from ACIL Tasman ($50, real 2011 dollars), IPART ($102, nominal) and the Climate Change Authority ($68, nominal).

Table 16: potential cost allocation depending on policy instrument, FY24-30

Cost allocation by policy instrument, **Ambition:**	**Status quo**	**Low (incl status quo)**	**Medium (incl status quo)**	**High (incl status quo)**
Option One: RGC for biomethane and H2				
Government ($M, this includes the cost of the existing Hydrogen Headstart program)	$1,000	$1,000	$1,000	$1,000
Industrial ($M, figures do not include Hydrogen Headstart cost)	$60	$200	$430	$1,380
Gas power generators ($M)	$0	$180	$1,070	$1,770
Households and commercial customers ($M)	$0	$50	$430	$900
TOTAL COST FY24-30 ($M) including status quo	*$1,060*	*$1,430*	*$2,930*	*$5,050*
$ per household and commercial customer connected to gas (in 2030)[182]	$0	$2	$33	$68
Option Two: CfDs (Hydrogen Headstart expansion and Biomethane Booster)				
Government ($M)	$1,000	$1,370	$2,870	$4,990
Industry ($M)	$60	$60	$60	$60
TOTAL COST FY24-30 ($M) including status quo	*$1,060*	*$1,430*	*$2,930*	*$5,050*

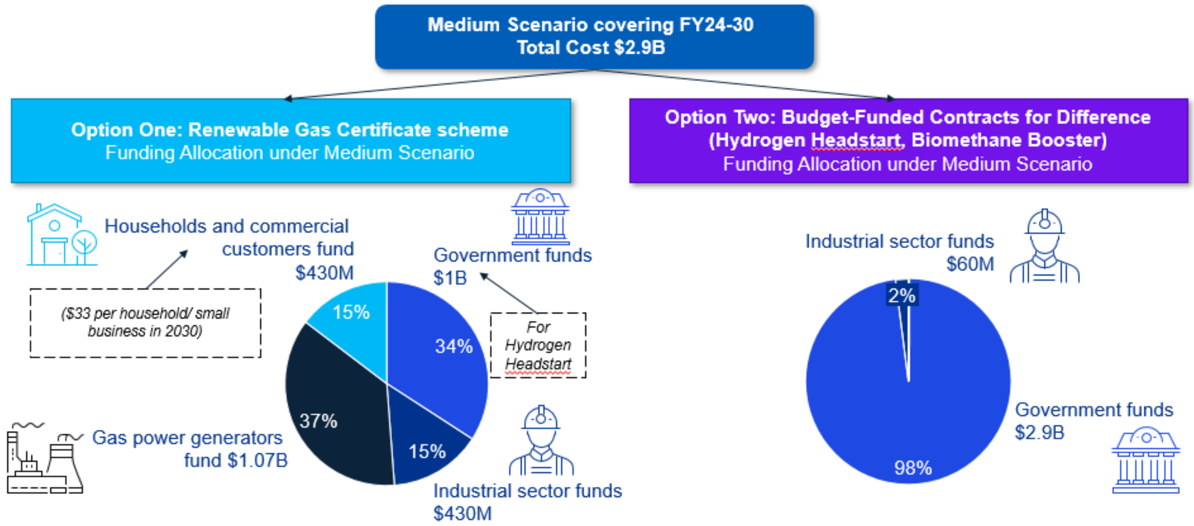
Potential alternative cost distribution

The '$ per household and commercial customer connected to gas (in 2030)' figures in the table above are based on the anticipated cost to households and commercial customers in 2030 distributed across an assumed 4.25 million domestic gas connections.[182] The Victorian Renewable Gas Consultation Paper also considers distributing costs to all gas and electricity users. Assuming all anticipated households in 2030 will be connected to electricity, this means the cost could be distributed over 10.7 million[183] customers rather than 4.2 million. If all domestic gas and electricity users covered the estimated cost for household and commercial customers in 2030 for the medium scenario (anticipated to be $140M in 2030), the cost per household would be $13 in 2030 as opposed to the $33 indicated in the table for gas connected properties only. Note this does not include indirect additional costs that may be extended to electricity customers from increases in the price for gas fired electricity generation.

[182] The number of Australian households and commercial premises connected to gas in 2030 is assumed to be 4.25 million. This is based on an assumption of 5.4 million connections in 2021 with an annual decline in line with AEMO 2023 GSOO core scenario assumptions for reduction in gas consumption plus anticipated changes in WA gas connections from the 2022 WA GSOO. The net result is a 2.7% per annum decline in connections till 2030. This provides a conservative estimate of per capita costs; if the number of household connections were instead held constant, the cost per household in 2030 would be lower.

[183] Based on census data accessed from https://profile.id.com.au/australia/household-size and applying a growth rate based on ABS anticipated household annual growth rate from 2016-2041 (1% per annum)

Figure 3: Graphical representation using the Medium Scenario to show how costs may be allocated for each instrument[184]



7.3.2 Cost sensitivities and risk

Price changes will have different impacts under the two options.

The assessment is based on several assumptions. A key variable driving outcomes of the model is the assumed difference in price per GJ between natural gas and each renewable gas. The base assumption is:

- $14 per GJ additional cost to natural gas for biomethane
- $38 per GJ additional cost to natural gas for hydrogen.

We have not assumed any changes in cost over time.

The medium and long term natural gas price plays a role in the risk of renewable gas production. Significant decreases in the natural gas price make the business case for renewable gas more challenging, while increases in natural gas price make the argument for renewable gas stronger. Victoria's Renewable Gas Consultation Paper argues gas is becoming scarcer and more expensive and if this is the case, renewable gas helps mitigate against potential increases in gas prices.

Another consideration is costs to produce renewable gas. Electrolyser costs influence the cost of hydrogen production and therefore the cost compared to natural gas. Unanticipated costs to produce renewable gas may mean our assumed prices are too low.

Given these risks, we further describe potential changes in the outcomes above based on price fluctuations. The below tables summarise the potential impact of changing the assumed difference in price between renewable gas and natural gas, depending on the policy Option.

[184] This is one example of how costs could be allocated. There are other options for funding for both instruments.

Table 17: Sensitivity to cost changes

Sensitivity	Option One: RGC	Option Two Biomethane Booster and H2 Headstart expansion
If difference between cost of production and offtake prices is **higher** than expected, e.g. due to: - Supply chain bottlenecks in scaling up production quickly, e.g. less biomass or renewable electricity access than expected - Natural gas prices fall significantly - Assumed costs were overly optimistic	Certificate prices will be driven up, liable parties cover the extra cost. Production levels are not affected as targets remain. However, this will only apply up to a point – the scheme would have a sensible penalty/opt-out price to avoid excessive certificate costs.	For Option Two, the production credit is fixed regardless of price, and losses are borne by project proponents. Government costs therefore remain constant, although it is assumed that this will reduce production levels somewhat.
If difference between cost of production and offtake prices is **lower** than expected, e.g. due to: - Assumed costs were overly pessimistic - Scale/learning effects achieved quickly - Natural gas prices remain elevated	Production levels would remain the same (or increase), but costs for liable parties would decrease.	If cost of production of renewable gas is lower than the production credit, 50/50 upside sharing is possible. In this case the proponent earns 50% of the excess returns, and government the rest (which lowers its costs for the program).

Table 18: Model sensitivity to changes of +/-20% between the price of renewable gas and natural gas

Sensitivity	Option One: RGC	Option Two Biomethane Booster and H2 Headstart expansion
If difference between cost of production and offtake prices is 20% **higher** than expected ($17 per GJ for biomethane, $45 per GJ for hydrogen)	Overall costs to liable parties (assuming Hydrogen Headstart cost is unchanged) to increase by: - $190M (low ambition scenario) - $490M (medium) - $910M (high). To achieve the almost the same renewable gas GJs (slight decrease in hydrogen (2 PJ lower) due to Hydrogen Headstart not achieving the same GJs)	A 20% increase in the assumed cost per PJ for both renewable gases compared to natural gas at a fixed overall cost would reduce the total renewable gas production assumed earlier by: - 8 PJ (low ambition scenario) - 18 PJ (medium) - 33 PJ (high).
If difference between cost of production and offtake prices is lower than expected	A 20% decrease in the cost difference per GJ of biomethane and hydrogen compared to natural gas, to what was assumed (assuming Hydrogen Headstart is locked in) would decrease costs converse to the above.	If the additional cost from natural gas to produce hydrogen and biomethane decreased by 20%, this would lead to (assuming PJs remained constant) an additional surplus: - $90M in the low ambition scenario - $240M in medium - $460M in high for proponents, and an equal reduction in costs for government.

8 Conclusion: A Path Forward for Accelerating Renewable Gas Deployment

The above analysis suggests three broad priority areas for policy to focus to ensure renewable gases can play their part in Australia's decarbonisation efforts.

The first is to fully establish the regulatory and market foundations to facilitate more widespread deployment. This involves further development of technical, market certification and information approaches to provide a solid basis for renewable gas markets.

The next priority is to address the cost barriers to renewable gas take up through building on financial incentives already in the market to secure sufficient scale and learning by doing. The nascent nature of these technologies in the Australian circumstances, suggest policy should start with a measured approach to policy ambition, while keeping a range of decarbonisation options on the table.

Ambitious but achievable renewable gas targets should be set to guide market participants, and calibrate policy instrument design. Separate targets are warranted for green hydrogen and biomethane given their different potential contribution to decarbonisation pathways.

Building scale from current very low levels will provide more information to better understand the role different gases have to play in Australia's sectoral decarbonisation journey and to assess the potential to set higher ambition while preserving optionality. This will allow further market policy instruments to be calibrated to deepen more widescale deployment. While the Safeguard Mechanism has potential to provide some incentives for biomethane uptake, international experience suggests specific deployment incentives will be needed to ensure prospective technologies are developed to the right scale and price points so that more general climate policy frameworks can pull deployment through to meet decarbonisation goals.

The final priority is to ensure spill-overs and interactions with other sectors, including unanticipated ones, are well understood and adaptively managed, preserving and enhancing social license.

All these considerations suggest that a contract-for-difference policy instrument is most suited to the immediate need to accelerate deployment of renewable gases. Hydrogen Headstart establishes this framework for green hydrogen, and the focus for potential extensions should be on expanding the range of use cases and supply chain options for bringing this renewable gas to market.

Establishing an analogous approach for biomethane is the main gap in the current policy framework. A 'biomethane booster' program, scaled in such a way as to provide meaningful testing of different feedstock and supply chain options, would be appropriate. A CfD approach will provide an opportunity to share in the several risks around technology cost curves and natural gas pricing, while also allowing the range of positive spill-overs to be explored, and potential risks managed. A CfD approach can act as a starting point to incentivise renewable gas production in the near term but will need to be continually reassessed, helping to inform future policy approaches such as an RGC scheme or FiT, particularly for biomethane.

The below roadmap sets out key recommended actions over the next five years to establish market foundations and drive initial deployment, while gaining more understanding of spill-overs. The initial focus is on setting market foundations and getting production mobilised quickly through CfD contracts, with early actions remaining open to a broad range of use cases and sectors. By the late 2020s, policymakers would turn attention to setting more ambitious 2035 targets and establishing appropriate instruments for this scale up, such as an RGC scheme (or possibly a FiT for biomethane). At that stage, policymakers can also consider the implications of new information on technology costs and sectoral decarbonisation pathways. This could lead to a refinement in the sectoral focus of deployment policies, and/or new focus areas for R&D policy, e.g. to ensure appropriate efforts to develop hydrogen appliances for the most prospective end use cases. A core principle of our proposed roadmap is continuous iteration, with refinements to ambition, sectoral focus and preferred policy instruments over time based on experience, market maturity and new information.

Table 19: A possible roadmap for renewable gas deployment[185]

Phase		Priority Actions	Timeline
1	**Next 9 months**	• Accelerate timeline for biomethane inclusion in GOO • Ensure that CCA's 2023 NGER review considers issues around the recognition by facilities of renewable gas contracting and use, including in the case of blended gas from networks or other shared infrastructure. • Complete review of National Hydrogen Strategy • Develop a high level National Bioenergy Strategy to inform the development of sectoral decarbonisation pathways. • As part of these strategies identify any gaps in technical and market regulation, and user information, on renewable gases and processes to address these going forward	Sep - June 2024
2	**Next year**	• Confirm 2030 aspirational targets for green hydrogen and biomethane • Award contracts for first round of Hydrogen Headstart • Allocate funding for a Biomethane Booster deployment policy in the 2024 budget. Complete program design by end of 2024 • Based on first tender, consider allocating additional funding for a second round of Hydrogen Headstart for the FY25 fiscal year, with the intent of broadening the use cases funded • GOO scheme legislated, covering both green hydrogen (and derivatives) and biomethane • Ensure that existing R&D funding mechanisms (e.g. ARENA) fund a portfolio of both green hydrogen and biomethane demonstration pilots, to inform a wide range of use cases • Ensure any market and technical regulatory issues addressed to ensure sector readiness for wider deployment	June - Dec 2024
3	**Next 2 years**	• GOO scheme is fully operational • Round 1 Hydrogen Headstart projects under development • Round 1 Biomethane Booster projects under development	2025
4	**Next 3 years**	• Round 1 Hydrogen Headstart projects begin production by end of 2026 • Round 1 Biomethane Booster projects begin production by end of 2026	2026
5	**Next 5 years**	• Take stock of information learned to date on costs and sectoral abatement pathways, and evolving demand occurring as part of more general policy impulses such as the Safeguard Mechanism and any renewable energy policies. Consider if ambition of 2030 aspirational targets can be increased. • Refresh National Hydrogen Strategy and National Bioenergy Strategy • Set renewable gas strategic targets for 2035 and 2040, consistent with latest national targets for 2035 and 2040 emissions	2027-2028

[185] A high-level schematic of this table is presented as a roadmap in the Appendices.

Phase		Priority Actions	Timeline
		reductions. Based on the lessons learned so far and the evolution of costs, there could be shifts in sectoral focus and overall ambition • Ensure that R&D program complements the focus of these strategic targets. For example, if there is increased emphasis on network blending of green hydrogen, then R&D efforts for hydrogen appliances would need to be prioritised, and potentially deployment incentives • Consider a market based Renewable Gas Certificate scheme for the next phase of deployment, building from momentum of the early CfD programs. A FIT may alternatively be considered for biomethane	

9 Appendices

9.1 Appendix One: Key assumptions

Key assumptions in quantitative options analysis

Item	Figure	Source/comment
Natural gas cost per GJ	$11	AEMO, see AEMO | Australian Energy Market Operator. Prices state to state across time vary. Selected a price at the lower end to be conservative.
Biomethane cost per GJ until 2030	$25	Upper end of current range estimate from Future Fuels CRC research ($20-$25/GJ), see RP1.2-04-BiomethaneViability_summary.pdf (futurefuelscrc.com)
Hydrogen cost per GJ until 2030	$49	Based on $5.82 per kg cost from Clean Energy Finance Corporation which is the “Base” Green H2 delivered cost in 2020. See Australian hydrogen market study (cefc.com.au) page 11.
Tonnes CO2 saved natural gas displacement (kg CO2/GJ)	52	The NGER (Measurement) Determination emissions factor for natural gas see Biomethane method package - simple method guide (cleanenergyregulator.gov.au)
Additional CO2 from biomethane creation (kg CO2/GJ)	1	The NGER (Measurement) Determination emissions factor for an anaerobic digestion plant at a waste water treatment plant.
Additional CO2 from hydrogen creation (kg CO2/GJ)	0.28	Hydrogen Production With A Low Carbon Footprint (forbes.com), for solar-based alkaline electrolysis.
Year that renewable gas starts to contribute towards target in low, medium and high scenarios: Biomethane	FY25	
Year that renewable gas starts to contribute towards target in low, medium and high scenarios: Biomethane	FY26	
Cost reduction over time per GJ to produce renewable gas	0%	Although it is anticipated there may be some reduced costs for renewable gas production through scale, market demand and learning by doing, we have assumed no change to price by 2030.
Residential and commercial gas consumption (20-21) and growth rate	166 PJ with growth rate of -2.7%	PJ from Australian Energy Update 2022 (Australian Energy Update 2022), growth rate based on AEMO anticipated growth rates from 2023-2030 for central and eastern Australia (Microsoft Word - 2023 Gas Statement of Opportunities v1.2 (aemo.com.au)) and Western Australia (2022-wa-gas-statement-of-opportunities.pdf (aemo.com.au))
Industrial - Mining, manufacturing and other consumption (20-21)	542 PJ with a growth rate of 0.1%	As above
Gas used for electricity generation (20-21)	523 PJ with a growth rate of -3.3%	As above

9.2 Appendix Two: High-level five-year roadmap for policymakers

June 2024

Next 9 months

- Fast-track biomethane inclusion in GOO
- CCA 2023 NGER review
- National H2 Strategy review
- Develop National Bioenergy Strategy, to feed into CCA sectoral pathways

Dec 2024

Next year

- Confirm 2030 aspirational targets
- Award contracts H2Headstart (H2H) and allocate Biomethane Booster (BMB) funding
- Establish second round H2H, broadening use cases
- GOO scheme legislated
- CCA sectoral pathways developed
- Continue R&D funding for wide use cases
- Market and tech reg issues addressed

2025

Next 2 years

- GOO scheme operational
- Rd 1 H2H and BMB under development

2026

Next 3 years

- Rd 1 H2H and BMB begin production (end 2026)

2027 - 2028

Next 4-5 years

- Take stock of learning, consider increasing ambition of 2030 targets
- Refresh Strategies
- Set renewable gas targets for 2035 and 2040
- R&D to complement focus of targets
- Consider market based RGCs for H2 and Biomethane as appropriate