Policy pathways to advance Australia's biomethane sector: learning policy lessons from international jurisdictions

Final Report

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IMPORTANT DISCLAIMER

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Summary of Report

This project seeks to support the development of a biomethane industry in Australia, which has to date lagged behind many other countries. Policy mechanisms and initiatives employed in a number of international jurisdictions more mature biomethane industries (Denmark, Italy, UK, US and Canada) are examined and compared against the existing policy and regulatory landscape in Australia across the biomethane value chain. Barriers and enablers within Australia are examined, and gaps identified with potential policy mixes discussed that could be applied to the meet the current challenges in the Australian context.

The project completed a comprehensive analysis that included a desktop review complemented by stakeholder interviews, The approach guided by a tailored policy innovation framework worked to:

1) map the current policy and regulatory regime across the biomethane value chain in Australia and identify existing gaps, barriers and opportunities;

2) draw lessons from international case studies to identify suitable policy options and assess whether these could be transferred to the Australian context; and

3) provide recommendations on policy mixes that could support Australia's biogas industry.

This report provides detailed findings of the research completed between July 2024 to February 2025.

Our findings show: Biomethane industry development in Australia has been hampered by a lack of policy support, attitudinal and economic factors. From an economic perspective, various modelled production costs vary between \$9.40 – \$21/GJ depending on feedstock, technology and other variables, as compared to approximately \$12/GJ for east coast wholesale gas contracts in 2024. The cost uncertainty and potential cost gap between biomethane production and natural gas, which biomethane aims to substitute, means that biomethane production typically requires additional value streams associated with green premiums and sale of by-products to de-risk investments and improve its cost competitiveness. Recognition that the value derived through biomethane development extends beyond the energy content and into these other areas is necessary for significant market growth to occur in Australia. A review of other countries where a meaningful biomethane industry has been developed demonstrate the power of enabling policies which recognise the carbon abatement potential of biomethane and value of digestate produced from upgrading biogas to biomethane through anaerobic digestion. Australian interviewees identified widespread challenges on messaging and knowledge of what biomethane is and about the potential of renewable gases to meet decarbonisation challenges in hard to abate sectors. Regulations on the use of waste for the production of biomethane, digestate use and flaring were also identified as issues requiring attention.

Biomethane in Australia: As of 2025, Jemena's Malabar plant in NSW is the only operational biomethane project in Australia. To date Australia has implemented few specific policies for biomethane. Hydrogen has garnered attention from government to meet emissions targets, biomethane has largely been overlooked. Recent policy developments and growing interest from both government and industry point to a recognition of the potential of biomethane to support Australia's decarbonisation of hard to abate sectors. Notable recent developments include: changes to the National Gas Laws to allow various gases, including biomethane, to be injected into natural gas networks; the launch of GreenPower's Renewable Gas Certification scheme to verify and track biomethane, enabling the trading of its 'green value'; the creation of an Australian Carbon Credits Unit methodology for biomethane; and Victoria's recent Renewable Gas Directions Paper, raising the possibility of establishing a state-based biomethane target.

Biomethane policy approaches in other jurisdictions: In terms of policy approaches our study finds there are significant differences to the approaches taken by North America (US and Canada) and European countries (Denmark, Italy, UK) to develop a biomethane industry.

In the European countries we examined, the development of biomethane has largely been driven by policies and investments that incentivise and support production ('technology-push' policies). Within these policies governments guarantee support for project developers through feed-in tariffs or premiums, as well as capital cost support. An example of this support is the European Union's REPowerEU Plan which commits to increasing biomethane production to at least 35 billion cubic metres (1,260 PJ) per year by 2030. €27 billion has been earmarked for investment under this scheme, intended to provide an additional 6.3 bcm (230 PJ) of capacity

each year. In contrast, biomethane markets in Canada and the US have been largely driven by regulatory 'technology-pull' policies, often through mandated quotas that oblige gas utilities or fuel suppliers to blend a proportion of renewable gas into their gas network or fuel supply respectively. This obligation creates long-term demand certainty and has enabled the formation of compliance-based markets supported by biomethane certification and tracking systems that enables biomethane to be traded between producers and suppliers. In the US and Canada, biogas and biomethane have been driven by strong mandated quotas for renewable and low-carbon energies. Coupled with a suite of financial incentives and supports that further drive the supply side, these obligations have created strong demand. The 2020 Inflation Reduction Act (IRA) is one example, committing $US10 billion in incentives and tax credits for biogas and biomethane expansion, and setting strong targets.

These ambitious government policies, targets, and programs have been instrumental in the development of these international biomethane markets and associated industries.

Lessons for Australia from other jurisdictions:

In terms of lessons for Australia, we find that both the demand side approach of North America and the supply side support of Europe are both policy options that could be applied domestically. Our stakeholder consultation and review has revealed that Australian governments have shown little interest in biomethane to date, with a large focus on electrification and hydrogen. However, the gas supply crisis in Victoria and the potential delays of hydrogen technologies reaching commercial readiness have led to some states, particularly NSW and Victoria, showing interest and promising policy developments of recent years also driven by the gas industry and demand from end users. These developments include GreenPower certification of biomethane, a market-based accounting method being developed for reporting of carbon abatement under the National Greenhouse and Energy Reporting Scheme (NGERS) framework, and changes to the Gas Rules that accept biomethane as an eligible gas.

Recommended policy priority areas: The report provides five findings that will enable biomethane technologies to be scaled and deployed within Australia.

1. Recent policy developments mean that Australia's current policy mix could enable viable biomethane projects now, but significant investment and scale up in projects will require additional policy levers. State and federal governments should consider taking a more technology-neutral position by expanding the focus to date from green hydrogen to include all renewable gases, including biomethane.
2. Biomethane in Australia has to date lacked legitimacy as being perceived as an acceptable and feasible solution by governments and policymakers, which in turn has created uncertainty to investors, financiers and project proponents. Our analysis suggests that part of this stems from a lack of knowledge, understanding and capability about biomethane technologies and its potential benefits, resulting in a lack of policy action. Federal and state governments should consider ways to address this knowledge gap such as by upskilling and educating policymakers on emergent technologies, drawing on research and technical experts or employing staff with a greater diversity of subject matter knowledge. As biomethane cuts across energy, agriculture, and waste sectors, governments should also look at cross-sectoral coordination mechanisms. Governments should further consider developing a firm policy direction and explicit targets for biomethane which would increase legitimacy and certainty of the technology for investors and project developers.
3. A robust market structure and financial incentives are needed to make biomethane projects economically viable. This can be achieved through government support incentives for producers on the supply side, regulatory mandates on gas users or sellers to increase demand or a combination of both. Our findings indicate that there is no one-size-fits-all policy necessary for a biomethane industry. Growth of biomethane has been primarily driven by feed-in tariffs for producers in Denmark and United Kingdom, by mandatory targets on gas utilities for grid-delivered gas in Canada, and by mandatory targets for renewable transport fuels for fuel suppliers in the United States and Italy (**Table 14**). What both supply-side and demand-side instruments have in common for success is the guarantee of a long-term predictable returns increasing the viability of projects and increasing cost-competitiveness of biomethane relative to natural gas. Demand-side obligations placed on gas users has the added advantage of ensuring that biomethane will be used to help decarbonise Australian industries and economies.

Other important policy design considerations are discussed. Based on Victoria’s proposal of a Renewable Gas Target, we recommend similar design features used in Canadian provinces of mandated targets for gas retailers with a cost-distribution model between voluntary customers and a small portion spread across the entire gas customer base to be feasible. The government could also expand existing supports and schemes for hydrogen to include renewable gas.

4. An enabling regulatory framework (dimension 4) must underpin Australia’s biomethane market for it to succeed. We identify key gaps that need to be addressed, drawing on international lessons and best practice. For project developers, operators and investors, establishing a sustainable feedstock supply and valorising digestate are key success factors that can be supported through a number of opportunities identified, many which require regulatory reforms.

1. Introduction

1.1 BACKGROUND

Biomethane is a low-carbon and renewable alternative to fossil-based natural gas that has the potential to reduce methane and carbon dioxide emissions in the gas sector and gas-reliant industries. Unlike hydrogen – the other prominent renewable gas – it is a near-pure stream of methane and is almost chemically identical to natural gas.(1) This means it can be injected into the gas network as a substitute to fossil gas without requiring changes to equipment, distribution, and transmission infrastructure. As such, it has great potential to decarbonise gas networks.(1) Another advantage is that biomethane is produced via mature technologies, such as upgrading biogas from anaerobic digesters, which have been implemented at scale around the world. This is particularly the case in Europe and North America, which respectively have 1,500 and 300 biomethane facilities in operation and had at least 950 and 500 facilities in the pipeline as of 2023. For comparison, Jemena's Malabar plant in NSW is the only biomethane project in operation in Australia as of 2025.(2)

Ambitious government targets, policies, and programs have been instrumental in the development of these international biomethane markets and associated industries. For example, the European Union's REPowerEU Plan commits to increasing biomethane production to at least 35 billion cubic metres (1,260 PJ) per year by 2030.(3) To meet this target, €27 billion has being earmarked for investment into biomethane, intended to provide an additional 6.3 bcm (230 PJ) of capacity each year.(4) Around 78% of this investment is flowing to new biomethane projects, with 950 plants planned to enter operation by 2030. A smaller portion is being used for mergers, acquisitions and the conversion of existing biogas facilities, most which are currently being used for cogeneration of heat and electricity.(4) In the US and Canada, biogas and biomethane have been driven by strong mandated quotas for renewable and low-carbon energies. Coupled with a suite of financial incentives and supports that further drive the supply side, these obligations have created strong demand. The *Inflation Reduction Act* (IRA, 2022) is just one example of such a policy package, committing $US10 billion in incentives and tax credits for biogas and biomethane expansion, and setting strong targets.

In contrast, Australia has had few specific policy mechanisms for biomethane to date. While hydrogen has received significant attention from Australian governments to support national and state-based emissions targets, biomethane has been largely overlooked. However, recent promising policy developments and increasing interest from government and industry alike are signalling the potential of a nascent biomethane market. These include: changes to the National Gas Laws that broaden the types of gases (including biomethane) allowed to be injected into natural gas networks; the introduction of GreenPower's Renewable Gas Certification scheme to verify, track biomethane through the gas grid and enable trading; the establishment of an Australian Carbon Credits Unit methodology for biomethane; and Victoria's recent *Renewable Gas Directions Paper*, which seeks feedback on directions for introducing a state-based target for renewable gases that will include biomethane.

1.2 PURPOSE OF THIS STUDY

The purpose of this study was to examine the policy settings and pathways adopted by key international jurisdictions in developing biomethane markets. In doing so, it aims to derive valuable lessons for Australia's own industrial biomethane development. The report has three core objectives to provide:

1. A comprehensive assessment of the current policy and regulatory regime across the biomethane value chain in Australia to identify existing gaps, barriers and opportunities;

2. Actionable lessons from international case studies via the identification of suitable policy options and assessment of whether these could be transferred to the Australian context; and

3. Use of a systems-guided and theoretically-informed approach that draws on both sustainability transitions theory and the transformative innovation policy framework to go beyond single policy mechanisms to develop an understanding of how market, regulatory, social and institutional instruments and arrangements interact to enable or impede new technologies to scale.

The report is structured as follows. The remainder of chapter 1 provides an overview of the biomethane supply chain, highlighting key technologies, inputs, avenues of distribution, Australia's potential biomethane supply, carbon abatement and economic potential. Chapter 2 describes a variety of policy mechanisms available to incentivise biomethane production. Chapter 3 outlines the methods and scope of the report, including the reasons for selecting comparator jurisdictions, methods of data collection and the analytic framework employed throughout the report. Chapter 4 surveys the Australian policy landscape for biomethane at the federal level and each of Australia's states and territories. It then reports on key policy barriers and opportunities as identified by Australian biomethane stakeholders. Chapters 5-10 provide policy examinations of our five selected case studies: the United States, Canada, Denmark, Italy, and the United Kingdom, as well as an overview of the European Union. In the fifth and final section of the report, key lessons concerning the most effective policy mechanisms and mixes are reviewed through a cross-jurisdictional analysis. These are then considered in light of the Australian context, leading to a number of recommendations for policy mechanisms which could help to drive the uptake of biomethane in Australia.

1.3 THE BIOMETHANE SUPPLY CHAIN

Biomethane is a unique commodity in that its value chain spans multiple sectors, including energy, waste management, agriculture and environment. It can be produced using various technologies, constituted from a diverse range of resources, and has a wide array of potential applications and considerable implications for the climate. Broadly, the biomethane supply chain consists of four stages: 1) feedstock supply; 2) production; 3) logistics (transmission, distribution, and transportation); and 4) end use (Figure 1). To develop a sustainable and viable biomethane supply chain, well-targeted and coordinated policies must take each of these steps into account.(5)

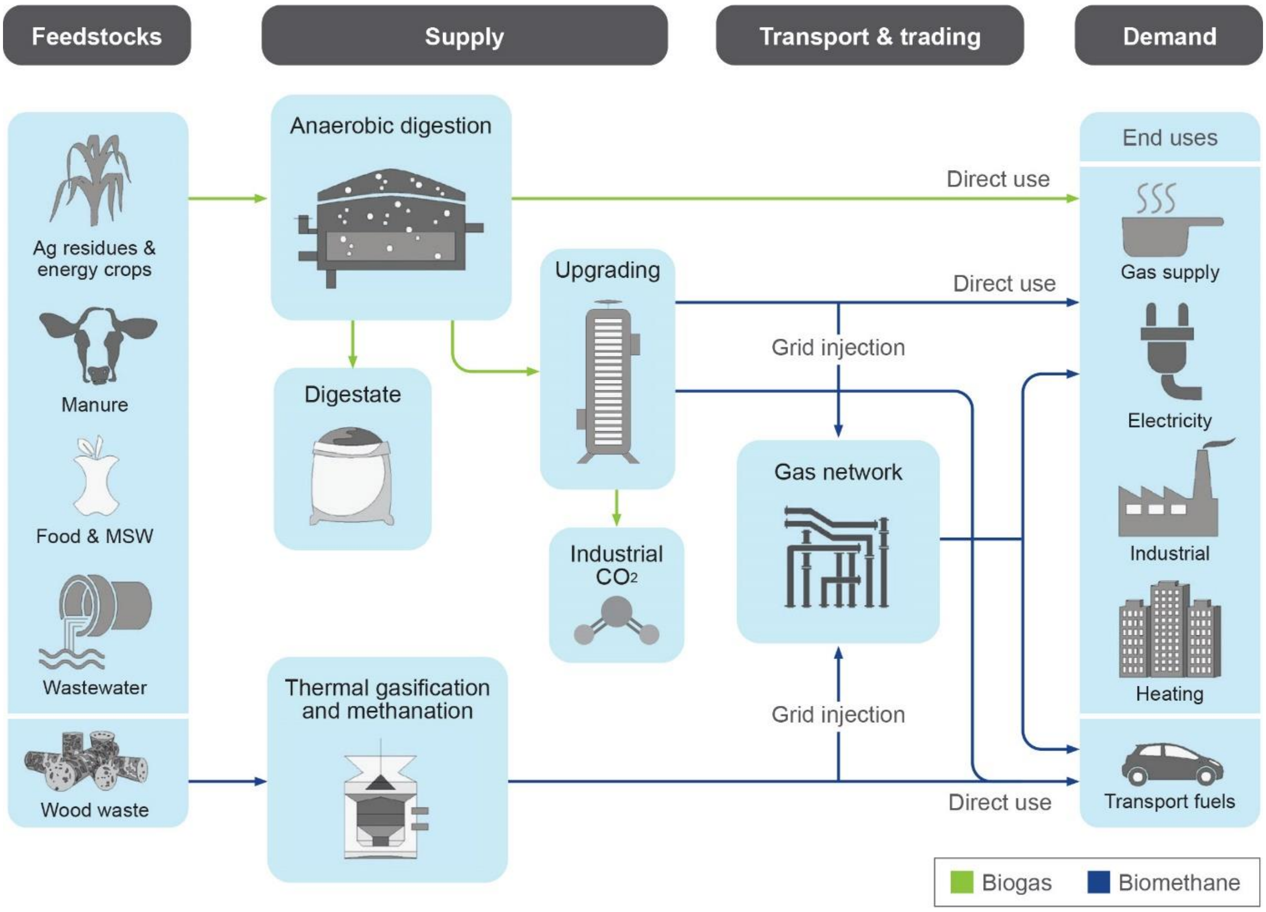

Figure 1. Stages of the biomethane supply chain. Adapted from IEA, 2020.(1)

1.3.1 Feedstocks

Biomethane can be sustainably produced from a variety of feedstocks, including agriculture and forestry residues, solid and liquid wastes, food waste, and energy crops (**Table 1**). Assurance of a consistent and sufficient supply of feedstocks is one of the most critical aspects for the scalability of an Australian biomethane industry. A 2024 techno-economic assessment of biomethane projects by Culley et al. found that among the many variables across the supply chain, factors related to feedstocks had the largest impact on the potential cost of biomethane production, and by extension on the viability of projects and their carbon abatement potential.(6) Naturally, one factor is the quantity of biomass available, but energy density and digestibility of different feedstocks is another as they directly affect biomethane yields and are highly variable (**Table 1**). Temporal availability is another crucial factor, particularly for agricultural residues, which may be abundant during harvest periods but scarce during fallow seasons.

Table 1. Feedstocks suitable for biomethane production in Australia, including estimates of potential biomethane yields per tonne of biomass feedstock.

Feedstock source	Estimated national biogas potential by biogas stream	Feedstock	Potential biomethane yield (m^3 per tonne biomass)
Livestock manure	29.3 PJ (a)	Manure slurry from livestock (8-20% DM^) (7)	15 – 100
Agricultural residues	319.4 PJ (a)	Woody biomass (7)	14 – 320
		Bagasse and sugarcane trash* (8)	330 – 540
		Cereal straw (e.g. wheat, oats, barley) (7)	250 – 650
		Non-cereal straw (e.g. cotton, canola) (7)	250 – 300
		Hay and silage (7)	180 – 500
Food waste	2.2 PJ(a)	Vegetable residues (food waste) (7)	50 – 400
		Fruit residues (food waste) (7)	50 – 510
		Winery waste (grape marc) (7)	160
Crops	700 PJ (b)	Energy crops grown on marginal lands (7)#	160 – 390
		Sorghum (sequential cropping) (7)	295
		Seaweeds (7)	260 – 400
		Weeds, harvested (7)	160 – 400
Waste	19.9 PJ (a)	Municipal solid waste (DM organic fraction) (9)	350
		Wastewater effluent (raw) (10)	287
		Wastewater effluent (treated) (10)	357

* Converted from mL to m3 using a value of 3.7L in 1m3 of methane. ^DM = dry matter. # value for grasses used.
Biogas estimates: (a) Deloitte Access Economics, 2017. Decarbonising Australia's gas distribution networks.
(b) ClimateWorks. 2014. Pathways to Deep Decarbonisation in 2050: Technical Report.

1.3.2 Production pathways

There are two main technology pathways to producing biomethane: 1) upgrading biogas, and 2) thermal gasification of solid biomass.

1.3.2.1 Upgrading biogas

Currently, more than 90% of the world's biomethane is produced by upgrading biogas, which is either generated in purpose-built anaerobic digesters or collected from landfill gas recovery systems.(1) Biogas is a renewable source of energy composed of 45-70% methane, with the remainder being primarily carbon dioxide (CO_2) and small amounts of other chemicals. The produced biogas can either be combusted to generate power and/or heat (co-generation) or upgraded into biomethane for injection into the gas grid or use as vehicular fuel.(1) The process of upgrading biogas removes CO_2 and other contaminants, concentrating the methane component of biogas into a near pure form of biomethane (~100%).

Biogas itself is produced via anaerobic digestion (AD), a biological process in which microorganisms breakdown organic matter in the absence of oxygen. AD can occur naturally, such as inside of landfills during the breakdown of organic waste, and can also be enhanced in man-made digesters for treating farm wastes, wastewater effluents, or sludge. Capturing biogas from these waste treatment processes prevents the release of methane – a potent greenhouse gas with 28 times the warming potential of CO_2(11) – into the atmosphere.

- **Anaerobic digesters** consist of a sealed tank where digestion conditions are controlled to promote specific microbes that metabolise organic material, converting it into biogas and a nutrient-rich digestate. A variety of wet feedstocks can be fed into anaerobic digesters, including agricultural waste, livestock manure, municipal solid waste, industrial and commercial waste, and municipal wastewater. Different feedstocks, such as manure and straw, can be co-digested to enhance biomethane production.(1)
- **Landfill gas capture systems** involve installing a series of pipes and extraction wells to capture the generated biogas and distribute it to a centralised collection point.(12) Capture efficiency rates vary depending on landfill conditions, ranging from as low as 10% in open, operational landfills to as high as 90% in closed, capped systems.(13,14)

Upgrading biogas to biomethane removes CO2 and other contaminants, making the gas suitable for injection into natural gas pipelines. From highest usage to lowest usage, the most common upgrading technologies are as follows:

1. Absorption/scrubbing. This method is based on dissolving the unwanted biogas constituents in a solvent for removal. Specific methods include water scrubbing, chemical absorption, and physical absorption.
2. Pressure swing adsorption. At high pressure, the unwanted biogas constituents adsorb to a material, and the resulting biomethane is removed. The unwanted constituents are released at low pressure.
3. Membrane separation. This utilises permeability properties of materials that allow only certain biogas constituents to pass through.
4. Cryogenics. This utilises the differences in biogas constituent boiling temperatures to separate biomethane as a gas.(15)

1.3.2.2 Thermal gasification of solid biomass

While anaerobic digestion is limited to damp forms of organic feedstocks that can be easily digested and converted to biogas, thermal gasification is an alternative process that can produce biomethane from dry feedstocks, such as woody biomass, plastics, and sawdust.(1) These feedstocks are gasified under high temperature and pressure in a low-oxygen environment to break down organic molecules into syngas, which can then be methanated and purified to produce biomethane.(16)

1.3.2.3 E-methane and other technologies

Other novel technologies, such as hydrothermal gasification of liquid feedstocks and pyrolysis of solid feedstocks, offer further possibilities for feedstock utilisation.(17) Another process is methanation, which converts carbon dioxide into methane through hydrogenation.(18) This process, however, requires significant energy to produce the required hydrogen for the reaction, and while various technology combinations are possible, the methods described in this section have not yet achieved widespread commercial viability.(19)

1.3.3 Distribution and end uses

Nearly all biogas produced globally is currently used to generate electricity or for co-generation of electricity and heat in every region: Australia (>99%), Asia (98%), Europe (90%), North America (85%), and South America (65%).(1) Electricity from biogas can be used both onsite (behind the metre) and/or connected and sold to the electricity grid.(20)

Biogas upgraded to biomethane can be injected into the natural gas network or compressed/liquified for use as a drop-in replacement for natural gas fuels (e.g. CNG and LNG).(20) As of 2020, around 60% of biomethane produced globally was directly injected into the grid, while 20% produced was used as fuel for transport. Notably, biomethane injected into the grid can subsequently be compressed or liquefied for use as vehicular fuel.

Although upgraded biomethane currently comprises a much lower portion of total biogas production as at 2025, biomethane injected into the gas grid is expected to become the largest use of biogases in the future. This is partly due to the falling costs and subsequent increasing share of solar- and wind-generated renewable electricity, which reduces the viability of using biogas for electricity.(1) And secondly, is that biomethane as a substitute for natural gas has greater potential for GHG emissions reduction compared to using biogas directly for electricity generation (408, 409).

Before grid injection, biomethane must meet relevant gas standards and specifications, ensuring that contaminants are within allowable limits to ensure the longevity of gas infrastructure and the suitability of the gas for its eventual use. In Australia, the standard containing specifications for natural gas (AS4564) has stricter limits for certain organic contaminants than some overseas jurisdictions with significant biomethane injection, which adds to the cost and technical complexity of injecting biomethane into the grid.(22,23) This standard is currently under review by an Australian Standards committee.(24)

Once injected, biomethane becomes indistinguishable from natural gas, and can be used for power generation, heating, industrial manufacturing, residential use, or can be compressed or liquified for use as a vehicle fuel.(20) Utilising the gas network also opens other B2B markets in hard-to-decarbonise sectors, such as high-temperature industrial uses and off-site electricity generation at existing gas power stations. Beside grid injection however, in the electricity market, a promising use for biomethane is in gas peakers for firming of renewables capacity as a low-carbon substitute for coal or natural gas; this is more feasible than using hydrogen as it can utilise existing gas network storage infrastructure.(1)

Australia's gas network is comprised of two main types of pipelines. Transmission pipelines are high-pressure, long-distance pipelines which transmit gas from production fields to centres of demand.(25) The gas is then spread to homes and organisations through a reticulated network of high, medium, and low-pressure distribution pipelines.(25) Biomethane may be injected into transmission or distribution pipelines. To enable injection, biomethane producers must first negotiate a connection agreement with pipeline operators and construct an injection facility.(22) These facilities pressurise biomethane to the required levels and typically manage gas quality monitoring, injection flow control, data collection and communication, and odorisation.(22) One challenge with increased injection into distribution pipelines is the potential for excess gas accumulation. Other jurisdictions such as Denmark have addressed this by constructing reverse-flow facilities, which pressurise gas within the distribution network for reinjection into transmission pipelines.(26)

While biomethane is widely used as a transport fuel in other jurisdictions (there are 16 million vehicles operating on CNG,(27) out of a global fleet of more than 1 billion), Australia's limited refuelling network for LNG and CNG has constrained this use case.(27) Additionally, recent trends towards hybrids and battery electric vehicles suggest that this application is unlikely to gain significant traction in Australia. Notably, however, other transport sectors such as cargo shipping have adopted liquefied natural gas (LNG) as a fuel. This may represent a potential future market for biomethane, as may renewable fuel exports.(28)

2.3.4 Co-products

Biogas and biomethane upgrading can produce other potentially valuable co-products that further add to the viability and carbon abatement potential of biomethane and contribute toward a circular economy. These include digestate, a nutrient-rich mixture that remains following anaerobic digestion, which can be separated into solid and liquid fractions, and applied as a crop fertiliser or soil conditioner;(29) and biogenic CO_2 produced from biogas upgrading, which can be further purified and valorised for various industrial applications.(30)

Raw digestate is an output directly from anaerobic digestion which contains a mixture of solid and liquid organic matter with readily available nutrients. Although it can be directly applied to soils, it can be further processed to separate the solid-liquid fractions, and optimize the nutrient composition to make it more suitable for soil amendments and biofertisiers or can be composted or turned into biochar.

1.4 SUPPLY POTENTIAL: HOW MUCH BIOMETHANE COULD AUSTRALIA SUSTAINABLY PRODUCE?

Several studies have modelled Australia's potential for bioenergy production based off available feedstocks. Whilst a detailed analysis of feedstock and biomethane production potential is outside of the scope of this study, we summarise the main estimates reported in the literature below. We note that estimates vary substantially depending on the data and assumptions used. Overall, studies suggest that biomethane could displace between one- to two-thirds of national natural gas demand under the right conditions (

Table 2). An important distinction to note is between the *theoretical* potential which provides an estimate of the energy that could be generated if all possible biomass feedstocks were converted into bioenergy, the *technically realisable* potential which estimates the amount that is useable and practical to collect , and the *economic potential* which assesses what biomass feedstocks are economically feasible, considering factors such as proximity to processing facilities and gas pipelines, cost-effectiveness, demands for other uses, and profit margins sufficient for investment.

In 2021, the Australian Biomass for Bioenergy Assessment (ABBA) project, funded by the Australian Renewable Energy Agency (ARENA), estimated that annually, up to 82 million tonnes of biomass from a variety of waste and residues across the country was theoretically available, equating a theoretical bioenergy potential of 2,600 PJ/year.(34) Agricultural feedstocks represented the largest resource potential at over 1,000 PJ/year (41%), followed by organic wastes (900 PJ/year, 37%), and forestry resources (500 PJ/year, 22%). Based on this upper threshold of 2,600 PJ/year, Australia's Bioenergy Roadmap (2021) estimated a technically realisable potential of 559 PJ/year when accounting for factors such as resource quality, sustainability, practicalities of collection and transport, and resource quality. This compares to a study by Middelhoff et al. (2022) who estimated potential electricity generation from bioenergy of 1,676 PJ/year,(35) and another by Net Zero Australia which projected 1,100 PJ/year of available bioresources in 2040.(36) An earlier study specifically for the production of biogases, by Deloitte in 2017 estimated feedstock potential of 371 PJ – enough to replace Australia's entire natural gas consumption from the distribution network. The majority of feedstocks were agricultural residues (86%) followed by livestock waste (8%), highlighting the critical role of the agricultural sector in the development of a biomethane industry. ACIL Allen's biomethane projections used for AEMO's Gas Statement of Opportunities 2025 provided a detailed breakdown of biomethane production by state and territory and feedstock under three scenarios of technology development (slow, consistent with current policies, or rapid) (**Table 3**)(58). Based on consistent projections, they estimated around 258 PJ of biomethane could be produced in Australia by 2030, an amount that could displace around 44% of Australia's natural gas use for industry and buildings.

Gas network operators have also commissioned studies to estimate biomethane production potential within their gas network catchments. A study commissioned for Jemena identified 34 PJ of feedstock available near their gas networks – enough to satisfy their residential gas demand of New South Wales or about half the energy needs of its industrial gas customers. (31, 32). A 2024 study by Blunomy commissioned by Australian Gas Infrastructure Group (AGIG) looked at biomethane potential within AGIG's catchments in Victoria, Queensland and South Australia modelling two scenarios: a business-as-usual (BAU) and a policy-enabled scenario where regulatory changes were made to improve feedstock capture, e.g., stubble burning ban, no organics in landfill. The models estimated that a theoretical biomethane potential in the three states is 323.5 PJ, with 84.6 PJ recoverable under the BAU scenario and 204.7 PJ recoverable under the PE scenario of biomethane within a 50 km perimeter of AGIG's catchments under each of these scenarios respectively.

In terms of the most suitable sites based on feedstock availability and lowest LCOE, a Future Fuels CRC study by Culley and co-workers identified 15 locations in five states that could deliver at least 50 PJ/year with average levelised cost of energy (LCOEs) ranging between $11.6–23/GJ.(37)

Additional novel feedstocks not included in these studies could potentially increase bioenergy supply. For example, a study commissioned by the European Biogas Association looked at sustainable opportunities to increase feedstocks, including the use of marginal or contaminated lands to grow energy crops, sequential cropping on farms during fallow seasons, and cultivating novel crops such as seaweeds. The study estimated that up to 10 million hectares of marginal or contaminated land in Europe could be used to grow lignocellulosic crops for the purpose of producing biomethane.(17)

Table 2. Actual natural gas consumption used in buildings and manufacturing and biogas production vs potential production of bioenergy and biogases based on estimates of Australia's biomass feedstocks and as a percentage of supply of natural gas consumption.

Energy type	Description (38,39)	PJ	% gas consumption	Source
Actuals				
Natural gas consumption	Total gas use (buildings & manufacturing* (2021-22)	591	100%	Future Gas Strategy Analytical report 2024, p37
	Buildings – household and commercial natural gas consumption (2021-22)	211	36%	
	Manufacturing, industry & transport (2020-21)	380	64%	
Biogas	Total production (2021-22).	18	3%	Future Gas Strategy, 2024 p34
Potentials based on feedstock estimates				
All types of bioenergy	All types of bioenergy - theoretical potential based on biomass feedstocks	2,610	442%	ABBA, Bioenergy Roadmap, Resource Availability Appendix
	All types of bioenergy – realisable potential (assumes a 45% cap)	1,170	198%	Bioenergy Roadmap
Biogases including biomethane	Targeted deployment scenario for hard-to-abate sectors including 23% of gas supply and one third of industrial heat (from biogas and solid biomass)	349	59%	Bioenergy Roadmap
	Biogases – realisable potential	371	63%	Deloitte, 2017
Biomethane	Current policies – realisable potential	258	44%	ACIL Allen, 2025. Table B.6
	Green exports – realisable potential	316	53%	

* Excludes gas use for the mining sector and for electricity generation.

Table 3. Natural gas use by state (57) and estimated biomethane production potential based on available feedstocks (58) including potential for natural gas displacement (%)

Jurisdiction	Natural Gas Consumption* (2021-22, PJ)	Estimated biomethane production (PJ/yr)				natural gas displacement (%)
		Landfill gas	AD – wastes	AD – crop residues	Total biomethane (PJ/yr)	
New South Wales	114	5.4	17.1	45.1	67.6	59%
Victoria	181	6.7	15.9	24.1	46.7	26%
Queensland	81	3.3	11.4	14	28.7	35%
Western Australia	178	1.7	16.3	56.7	74.7	42%
South Australia	32	1.1	10.1	24.9	36.1	113%
Tasmania	5	0.4	3.8	0	4.2	84%
Australia	**591**	**19**	**75**	**165**	**258**	**44%**

* Includes gas use for industry and buildings. Excludes gas use for mining and electricity generation. Sources: Future Gas Strategy Analytical Report, p37 (57) and ACIL Allen, 2025, Table B.6 (Step Change Scenario) (58).

1.5 CARBON ABATEMENT POTENTIAL OF BIOMETHANE

Beside energy supply, the main benefit of biomethane is its carbon abatement potential. A reduction in carbon emissions from biomethane comes from two areas:

1. The *avoidance* of methane and CO_2 emissions generated from the breakdown of organic waste sources that would otherwise be released to the atmosphere, but are instead captured via AD or landfill gas capture systems.
2. The *displacement* of fossil gas use and its associated emissions across the supply chain (e.g. energy used in the processing, refining, and transport of natural gas, alongside the CO_2 released upon combustion).

Indirectly, further carbon abatement can be achieved by using digestate as a biofertiliser, which can displace the need for chemical fertilisers (a major source of GHG emissions). There is also evidence that the use of organic fertilisers (including digestate) can increase soil organic carbon, providing further carbon abatement through sequestration. Finally, the use of biogenic CO_2 from upgraded biogas for industrial applications has the potential to displace the need to industrially manufacture CO_2.

The type of feedstock used to produce biomethane has a large bearing on the carbon abatement potential and the associated green value of certificates. In the US, carbon intensity (CI) values under California's Low Carbon Fuels Scheme (LCFS) shows that fossil-based CNG for the transport sector has a carbon intensity of 78.36 g $CO2_e$ / MJ. In comparison, the average CI from landfill and wastewater is around 47 and 32 g CO_2e / MJ respectively, while biomethane from food and garden organics and animal manure have negative CI values of -15 g CO_2e / MJ and a massive -310 g CO_2e / MJ respectively.

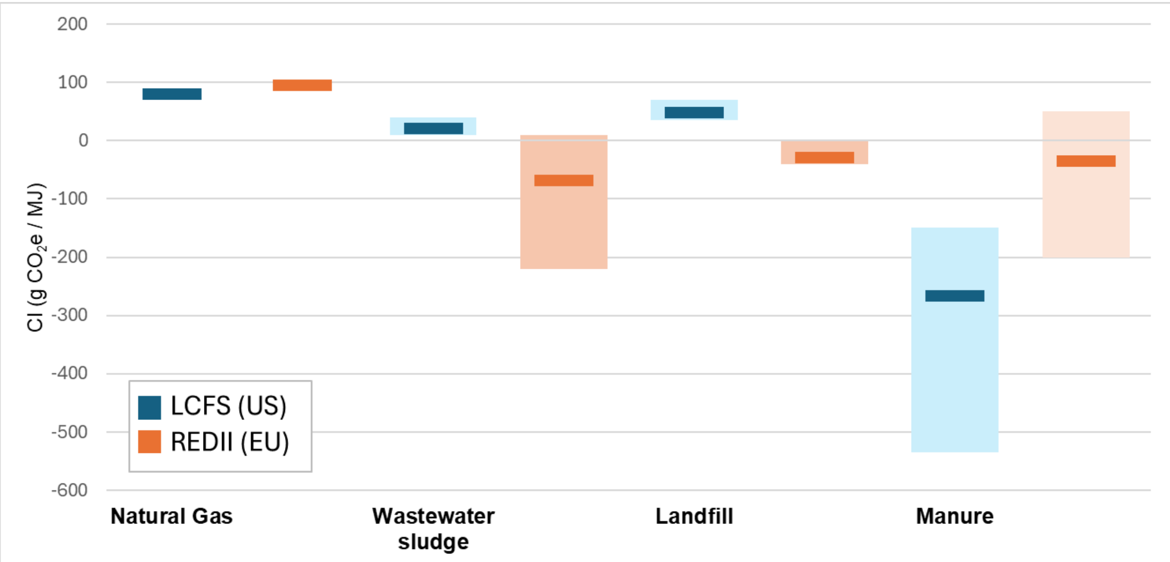

Figure 2. Comparison of carbon intensity (CI) values for biomethane production pathways under the California Low Carbon Fuel Standard (LCFS)(40) and the EU's Renewable Energy Directive II (REDII).(41)

1.6 ECONOMIC POTENTIAL OF BIOMETHANE

1.6.1 Value of biomethane

The value of biomethane comes from three distinct revenue streams: the value of the physical gas as an energy source, the 'green value' associated with the gas, and the value of any co-products or services valorised (digestate, biogenic CO_2, gate fees for waste receival). Australian wholesale gas prices have varied greatly over the last decade from a low of under $5/GJ in 2014/15 to a high of over $20/GJ in 2021/22 SEQ. Since 2022, Australia's east coast wholesale gas contract price has been capped at $12/GJ (first as a temporary measure and now under the Gas Market Code), although the market price may be lower than this amount.(46)

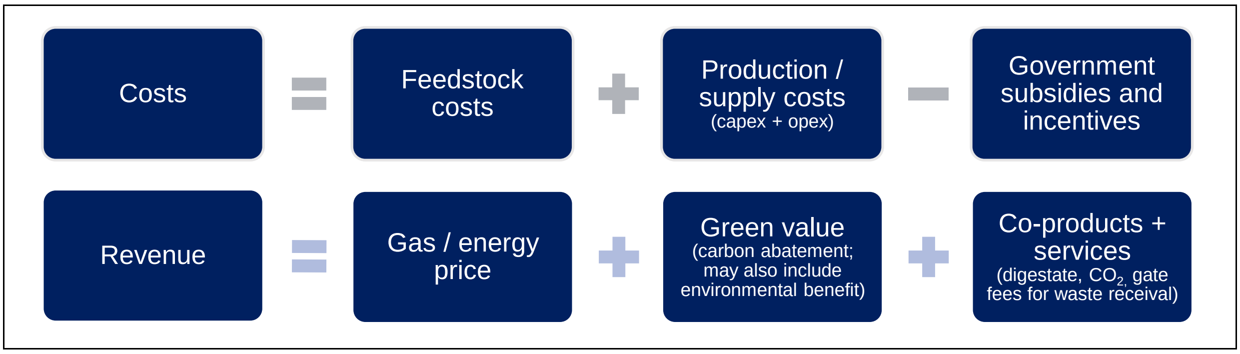

Figure 3: Components of biomethane costs and revenue.

Biomethane's green value is mostly derived from its carbon abatement (but also potentially other environmental benefits), thus it is dependent on the specific legal instruments or schemes that incentivise carbon reductions such as carbon taxes, emissions trading schemes and regulatory mandates for emissions reductions or renewable fuel supply. Because of this variability, and because of international differences in the price of natural gas, the economics of biomethane can look very different in different countries.

Marginal carbon abatement cost curves show that in Europe, biomethane offers one of the lowest costs for achieving net-zero steel production, ranging between $17 and $84 per tonne of CO_2e.(17) This cost advantage primarily stems from the potential for negative emissions. Additionally, biomethane is a lower-cost option for peaking capacity than hydrogen.(17) Gas peaker plants, which operate during short periods of high market demand, could support relatively high biomethane production costs due to the price premium in these high-demand periods.

This green value may be disassociated from the gas itself (as is the case in many emission trading and offset schemes, where producers of biomethane are granted certificates that may be sold to any interested party) or may be attached to the gas (as is the case in obligation schemes which employ a mass balance approach, where biomethane must be injected into the gas grid while an equal quantity of gas is simultaneously withdrawn).

While there is no across-the-board carbon price in Australia, the Safeguard Mechanism implements carbon limits for Australia's largest emitters, resulting in additional value for carbon-neutral energy sources. The Safeguard Mechanism allows Safeguard Facility to purchase Australian Carbon Credit Units (ACCUs) from the government to offset their emissions at a price of $75 per tonne for excess emissions that are not otherwise offset, plus CPI and an annual increment.(49) The demand for ACCUs has been increasing across the board, reflected in a rise in market prices from $31.96 on 15 April 2024(50) to $42.50 on 19 November 2024.(51) These mechanisms are discussed in greater depth in the Australian Policy Framework section of this report.

Current reforms to the National Greenhouse and Energy Reporting (NGER) Scheme will soon allow certified renewable gas to reduce a facility's Scope 1 emissions. It is expected that stakeholders may value this option more highly than ACCUs as it is seen more favourably than reporting higher emissions and buying carbon offsets, although a precise valuation of what price premium buyers are willing to pay is uncertain.

The final component of the potential revenue stream from biomethane production relates to the value of co-products and services. A 2024 report from the Future Fuels CRC (FFCRC) by Maier et al. noted that in Australia "the profit available from digestate is highly uncertain due to several factors (e.g. limitations of use of digestate, market competition, and potentially having to dispose of the digestate at cost)."(6) In a 2022 FFCRC report, Culley, Zecchin and Maier assumed a $50 profit per tonne of digestate sold,(37) though this should be taken as an estimate for the purpose of modelling. The value of food grade biogenic CO_2 is also uncertain, with the 2024 report's sensitivity analysis modelling profit margins at between $0 and $200 per tonne sold.(6) Additionally, the collection and/or receival of wastes can be cost negative, as waste generators may be willing to pay a fee to collectors to avoid landfill disposal costs. In Australia, all states have landfill levies in place, ranging from $45 per tonne in Tasmania up to $170 per tonne in metro areas of NSW as of 2024/25.(52) Stakeholders noted that the willingness of feedstock suppliers to pay for waste removal, or to have it removed without charge, could lessen if demand for organic wastes from bioenergy producers starts to exceed supply.

1.6.2 Production costs

Biomethane production costs vary significantly by location, feedstock type and processing. In terms of processing, landfills offer cheaper production of biogas than anaerobic digesters because anaerobic digestion occurs naturally in landfills, hence they only require a gas recovery systems (and biomethane upgrading). Upgrading biogas to biomethane is estimated to add around 25% to production costs.(1) In terms of feedstocks, municipal organic wastes are cheaper to recover than agricultural residues.

The most recent estimated of the levelized cost of energy (LCOE) for biomethane include those of ACIL Allen (2025)(58) and Culley et al. (2025) (410). ACIL Allen estimated costs of biomethane production under a 'medium rate' of technology and policy development of $10-13/GJ for landfills; $15-25/GJ for anaerobic digestion of waste, and $28-36/GJ for anaerobic digestion of crop residues. Culley et al. (2025) modelled biomethane produced from either agricultural waste or source separated municipal organic waste only (landfills and wastewater projects were excluded). Without additional supports or revenues from co-products and services, they showed a significant area of Australia could produce biomethane at an LCOE between $20-25/GJ. However, scenarios that added either revenues from co-products and services (gate fees of $60/t and sale of digestate and CO2 of $100/t feedstock each) and a scenario with an $11/GJ renewable gas incentive could achieve substantial areas across multiple states of Australia with a LCOE of <$12 and vast swathes of land that could produce biomethane at a LCOE between $12-20/GJ.

An FFCRC study estimated a LCOE for biomethane at $21/GJ in Australia, before factoring in policy supports or additional revenues.(6) Comparatively, reported estimates in Australia's Bioenergy Roadmap estimates were significantly lower, at $12.20/GJ for 2021 and $9.80/GJ for 2030,(34) as was AGIG's estimates ranging between $9.40-10.20/GJ.(32) The latter estimates are comparable with new domestic wholesale gas contracts on Australia's east coast, which have a price cap of $12/GJ under the Gas Market Code as at 2024/25. A Deloitte survey commissioned by Bioenergy Australia estimated that there is a current potential to inject 26 PJ of biogas into Australia's gas network by 2030, with production cost estimates averaging $18/GJ.(54) A 2023 analysis by Blunomy (formerly ENEA) for AGIG suggested that the costs of renewable gases are expected to fall with economies of scale.(32)

1.6.3 Projected biomethane demand

Whilst biomethane offers the potential to avoid stranded gas network assets in the event of fossil gas being phased out due to climate targets,(55) it is important to consider the potential biomethane supply chain within the context of current and projected demand for gas. An EY/AER report states that gas demand from hard-to-abate industrial processes is expected to remain stable until 2050. The report also reviewed approximately 350 global net zero pathways from a variety of sources (including IPCC, IEA, World Bank, and BP). It found that although there was a wide range of projections for future global gas demand, all had some level of gas in their 2050 projection.(56)

Analysis provided for Australia's Future Gas Strategy concluded that 'under all credible net zero scenarios, natural gas is needed through to 2050 and beyond.'(57) This is due to the necessity of gas for high-temperature industrial projects, for use as a chemical feedstock (59) and because existing investments in gas networks make the prospect of stranded assets an unappealing option.(55) Many large manufacturers and refineries are likely to demand significantly more natural gas as coal and diesel are phased out. For example, "BlueScope has stated that using gas-based DRI would reduce their steelmaking emissions by approximately 3.7Mt CO_2e per annum but require an additional 40PJ of gas per annum".(59) This figure is based on using natural gas, therefore using biomethane would amount to even greater emissions reductions. Thus, the development of biomethane is an effective vector for decarbonisation.

ACIL Allen (2024) modelled the least-cost pathway to decarbonise gas in Australia, considering the industrial, commercial and residential sectors. The analysis concluded that "failing to develop renewable gases significantly risks the energy transition".(58) It found that renewable gases (both biomethane and green hydrogen) have a long-term role to play in the lowest-cost pathway, in addition to electrification and energy efficiency improvements that will reduce the overall energy demand of gas that is required today. The study highlighted the long-term need for a reliable and renewable gas option, showing that hard-to-electrify sectors will require renewable gas options to achieve our net zero pathway and that this will continue beyond 2050.(58)

1.7 SUMMARY OF AUSTRALIA'S BIOMETHANE POTENTIAL

Projections of continued future gas use in Australia, and the ongoing need for gas in industrial processes, indicate that the risk of a lack of future demand for gas is unlikely to pose a problem for an Australian biomethane industry. Rather, the focus areas to achieving a viable Australian biomethane industry are to ensure a realisable feedstock supply and to address production cost gap between biomethane and natural gas.

The range of economic analyses reviewed in this report suggests that it is possible to produce biomethane in Australia now under specific conditions at production costs comparable with recent natural east coast gas wholesale market prices of $12/GJ, even without the addition of new policies or subsidies. However, there is significant potential to scale biomethane production by providing policy supports and subsidies that will enable a range of project types to come online– particularly agricultural and source separated organics facilities to ensure that net production costs can compete with future projects of natural gas prices ranging between $7–15/GJ through to 2050.(60)

2 Policy settings to support biomethane

Encouraging the investment needed to create a sustainable and viable biomethane market and associated industry in Australia will require government support. Governments should firstly set an overall direction and ambition for the technology through strategies and targets. Secondly, they should design and implement specific mechanisms at different parts of the supply chain that help to overcome the economic, technical and social barriers that can prevent emerging technologies from being adopted and deployed at scale (Figure 4).

2.1 POLICY INSTRUMENTS

The policymaker's toolbox includes a range of instruments to help meet policy goals. Essentially, policy instruments are designed to influence stakeholders at different parts the value chain to take action (Figure 4). As such, instruments are typically divided into three categories based on *how* they *influence* stakeholders:

1. Market-based and financial instruments *incentivise* (or *disincentive*) stakeholders through economic means, some that influence supply and others that create demand
2. Regulation-based instruments are command-and-control tools; they set rules and standards that stakeholders are *obliged* to adhere to; and
3. Information-based instruments are those that educate, build awareness and knowledge, skills and capabilities or advocate for an innovation; these instruments are designed to *persuade* stakeholders to voluntarily take action.

Beside the types of instruments employed, their *design features* are equally as important, for example, the duration of a policy program, and the level of stringency or support.

2.2 POLICY MIXES

Single policy instruments alone, however, are rarely effective to scale a new and disruptive technologies. This is particularly so for renewable energies, like biomethane, that seek to displace or at least compete with well-established systems based on fossil fuel use. Enabling such a transition to occur requires a more holistic and transformative policy approach consisting of so-called *policy mixes* that are able to overcome market and other system failures in order to achieve a desired policy objective.(61)

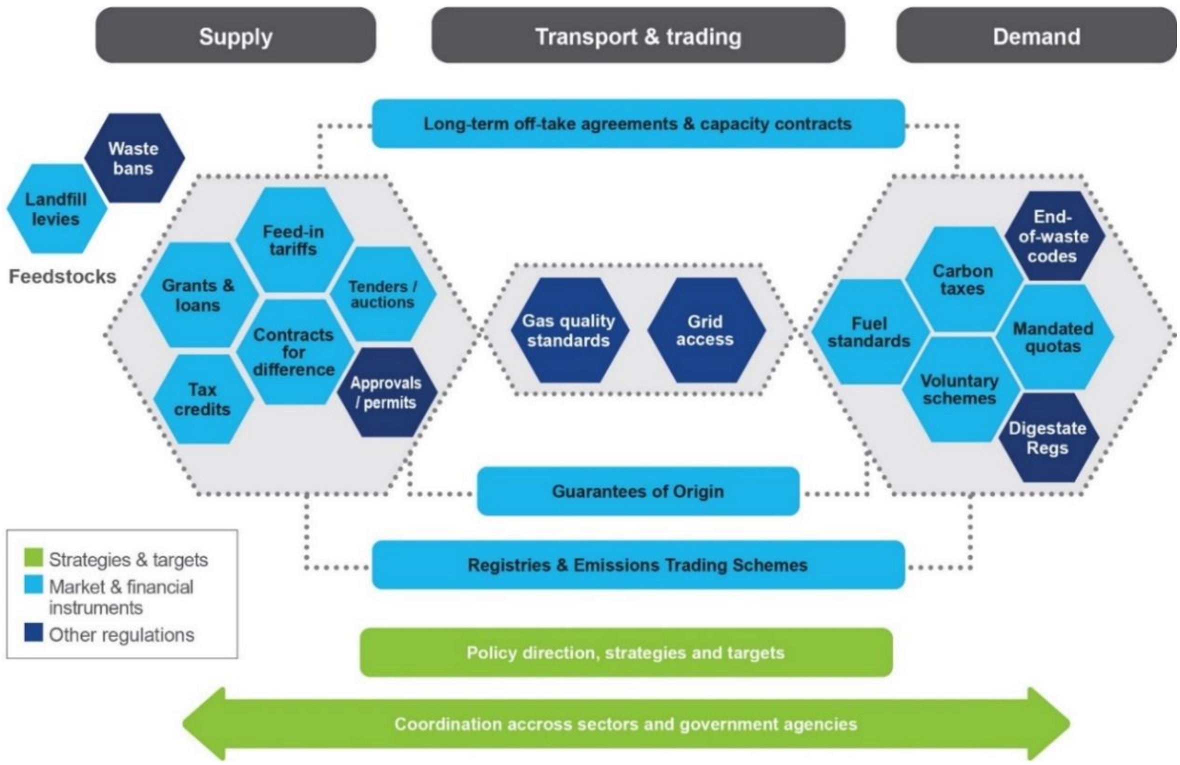

Figure 4. Policy instruments to influence different parts of the biomethane value chain.

Policy innovation studies have identified key dimensions that determine a technology's level of success or failure. These are: 1) financial viability, 2) market structure, 3) regulatory settings, 4) legitimacy, or social acceptance of a technology, and 5) knowledge and skills.(62) (**Table 4**). These dimensions, along with the barriers that occur if they are not addressed, and the types of instruments that can employed to address them are summarised below. Additionally, for policy mixes to address these dimensions, due consideration should be given to the *integration and alignment* of policies, as well as the *timing or sequencing* of policies over the different phases of a technology's deployment. (62–64). In relation to the former, not only are supports for new technologies important, but effective policy frameworks should reduce or remove supports for unsustainable technologies, a key example being the removal of subsidies and tax credits for fossil fuel production or use. In relation to the *policy sequencing*, the early *initiation* phase of biomethane development should consider higher supports for research and development, demonstration pilots and grants and loans for project development for example, while the *expansion* phase requires a market and economic focus to scale up solutions, drive down costs and increase technology adoption. As the technology matures, the *consolidation* phase should address any legacy issues to ensure the industry continues to grow, adapt and prosper.(65)

2.3 SUPPLY SIDE INSTRUMENTS

Supply-side instruments encourage investment in project development. Market-based incentives drive the production of biomethane through subsidies typically paid for by governments, to make the production of biomethane financially viable, while regulatory settings are important to remove unnecessary barriers.

Feed-In Tariffs

Feed-in tariffs (FiTs) are fixed payments for the injection of a quantity of biomethane into the gas grid. FiTs are generally set above market price, as the tariff is intended to cover CAPEX, OPEX, feedstocks, and grid-connection costs.(66) FiTs typically also guarantee grid access, and usually run for a long time (often 10–20 years), providing investors with a degree of stability and certainty. FiTs that cover the entire cost of biomethane (plus a profit margin) involve the government (or an energy company) taking and distributing the gas and its green value, meaning that the producer does not need to find an off-taker for these products.(66)

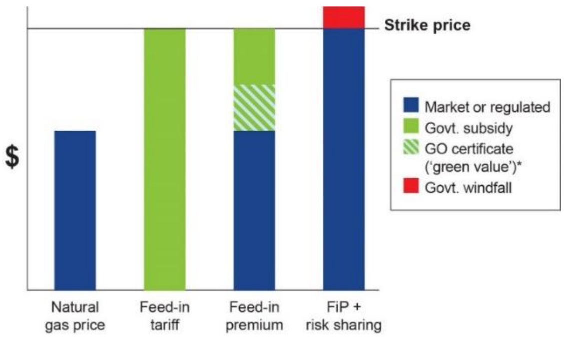

Figure 5. Schematic of government production subsidies (feed-in tariffs and feed-in premiums).

Feed-In Premiums (Contracts for Difference)

Feed-in premiums (FiPs), also called contracts for difference, are a more flexible support mechanism than FiTs that can reduce government expenditure. FiPs are variable top-up payments paid above a pre-specified benchmark price. They typically cover the difference between the market price of natural gas and the estimated production cost of biomethane plus profit margin. FiPs can be set at a fixed price based on pre-determined estimates of gas prices, or set at a sliding price that varies according to a strike price and the market value of natural gas and other factors (e.g. certificate values). They can be adjusted to account for the biomethane's carbon footprint, and adjusted annually to allow for budgetary flexibility. FiPs can also be designed to share risk, for instance, governments may set the contract's terms to receive a windfall if the price exceeds the strike price.

Tenders/Reverse Auctions

A tender involves a buyer (usually government) putting out a call for a specified quantity of biomethane and other criteria, followed by a competitive application process by suppliers able to fulfil the buyer's needs. Contracts are typically awarded based on the lowest bidder able to fulfill the requirements of the tender. Tenders can also be used to establish a suitable strike price for FiTs and FiPs.(66) Reverse auctions are similar to tenders, but the bid price suppliers are willing to pay can be bid for by multiple sellers and multiple bids in real time.

Capital Supports

Capital supports such as grants, investment tax credits, low-interest loans or repayable loans can reduce the barrier of market entry associated with the substantial up-front capital investment requirement to develop a biomethane project. The funding is typically independent of the quantity of biomethane produced.

Table 4. Five dimensions for emerging technology, including the barriers that can prevent success and the policy enablers needed to overcome them. Adapated from (401).

Instrument domain	Dimensions	Example of barriers if dimension not addressed	Policy enablers that help to address and overcome barriers
Policy goals, strategies & targets	**Legitimacy**	• Lack of policy support creates uncertainty and risk for investors. • A lack of understanding about a technology, its benefits and risks, by governments, industry and/or the public leads to view that technology is not an appropriate solution.	• Government ambition and narratives / discourse about a technology • Strategies and roadmaps underpinned by quantitative targets. • Demonstration projects. • Information, education, advocacy • Increasing government capabilities and knowledge for a technology. • Industry-government networks and collaboration.
Market-based and financial instruments	**Financial viability & feasibility**	• High capital and/or production costs makes projects unviable or an investment risk.	• Production incentives such as feed in tariffs and premiums, Capital incentives such as grants, subsidies, rebates, low-interest and/or repayable loans, tax credits
	Market structure	• Lack of a pre-defined market and industry structures, including processes for supplier-consumer trading, and business models.	• Mandates for quotas on demand side and public procurement policies to create market demand • Robust certification and trading schemes, including book and claim or other registries and emissions reporting frameworks that recognise the 'green value'
Regulatory instruments	**Legal & regulatory framework**	• Lack of definitions or standards for new technologies • Regulations not fit-for-purpose for new technology. • Lengthy and/or complex approvals processes.	• Mandates for technology use, prohibitions / restrictions on others. • Emissions & pollutions caps • Streamlining approvals & permits • Updating regulations so that they are fit-for purpose.
Informational instruments *(not covered in scope of this study)*	**Knowledge & capability**	• Lack of coordination between governments and agencies • Lack of knowledge and skills needed for a new industry • Lack of qualified workforce • Supply chain gaps or discoordination.	• Cross-coordination of government agencies, taskforce, committees or dedicated agencies • Training & education programs. • Investment in apprenticeships. • Support for third party services and providers addressing supply chain gaps (e.g. feedstock aggregators). • Fact sheets & guidance material

Supply-side Tax Credits
Investment tax credits provide investors with a discount on the tax they owe proportional to their investment in eligible technologies, while production tax credits reward operational expenditure based on the quantity of biomethane supplied or quantity of carbon abated.

Permitting and Approvals Processes
Constructing a biomethane plant may require a multitude of approvals and permits, potentially including land use permits, development approvals, environmental permits, and approvals for the management and transport of waste or hazardous materials. The time taken for these processes can be a crucial factor for biomethane projects with lengthy processes and delays leading to additional costs for project developers.

Gas Specifications
Gas specifications can influence the viability of biomethane projects, with more stringent purity requirements resulting in greater processing costs for producers.

Policies driving feedstock availability
Regulations that encourage greater feedstock availability can enhance the biomethane sector. These include banning waste from going to landfill, bans on stubble burning and bans on flaring biogas at landfill sites. Such bans lead to finding alternatives including the production of biomethane.

2.4 DEMAND-SIDE INSTRUMENTS

Mandatory and voluntary targets or quotas
Mandatory targets and quotas are an effective market-based regulatory mechanism that guarantees demand for biomethane by obligating a group of market participants, usually gas or fuel suppliers, to provide a specified portion of renewable gas or a carbon reduction in their final product. This enables obligated parties to offer producers offtake agreements or to develop or partner in biomethane projects themselves. The additional costs of sourcing renewable energy are typically borne by gas utilities or fuel suppliers, who may pass these costs on to end users in the absence of pricing regulations.

Carbon Pricing
Carbon taxes are a way to account for the 'true price' of producing products and services by pricing in the costs of negative environmental impacts from carbon emissions for which the producer or consumer must pay. Carbon pricing is based on a determined rate per tonne of equivalent CO_2 emitted. Carbon taxes can be applied to the price of goods directly, such as transport fuels, where the costs may be incurred by consumers, or charged to companies based on their carbon emissions, often for emissions that exceed a specified threshold limit. Cap and trade schemes enable companies to trade emissions via those who exceed their emissions cap by purchasing emissions credits from companies who fall below their cap or produce carbon offsets. In this way, carbon pricing on products incentives the use of biomethane by increasing the cost of fossil fuels like natural gas, which helps to reduce the cost gap between biomethane and natural gas and thus increase its cost competitiveness, while carbon pricing on a company's emissions encourages them to source low-carbon alternatives.

Green Certificates & Registries
There are a number of other legal instruments that countries have used to value and financialise the carbon emissions reduction generated by biomethane and biogas. Guarantees of origin have emerged as the predominant instrument for this purpose. Guarantee of origin schemes can be voluntary (in the sense that purchasers' only incentive to acquire guarantees of origin is for voluntarily making claims to end users about greenhouse emissions), or they can form part of a broader suite of mechanisms, usually as legally certified proof of emissions reductions for emissions trading schemes.

Supportive regulatory frameworks for co-products
Regulations relating to the storage, transport, and use of digestate may influence the value and the ability to sell digestate as a product, and consequently affect the economics of biomethane plants. Similarly, regulatory frameworks surrounding the sale of biogenic carbon dioxide may influence the value of this co-product.

3. Methodology

3.1 POLICY ANALYSIS FRAMEWORK

In consideration of all the above, we use the following analysis framework (Table 5. Policy analysis framework for biomethane market development.) to evaluate the policy settings that have been employed to establish biogas and biomethane markets. We compare this with the Australian context and identify policy options that could be applied to advance a domestic biomethane industry. The framework is adapted from policy studies on transformative policy innovation (67–69) and informed by the 'Manual for National Biomethane Strategies',(70) and the Biomethane Industrial Partnership's report on 'Biomethane Incentives and their Effectiveness',(66) and the various policy and implementation reports released by the European Biogas Association.(71–73)

Table 5. Policy analysis framework for biomethane market development.

Element	Description
Strategies & targets	• Is the policy direction clear and well-defined? • Are long-term and interim targets identified, quantified, and ambitious enough? • Are there strategic and actionable implementation plans in place?
Policy instruments	**Instrument type:** • Market & financial instruments: what are the supply side incentives to 'push' the technology, what are the demand side 'pulls'? • Regulatory instruments: do regulations around feedstock use, planning and permits, distribution, use of digestate enable or create barriers for the technology?
	Instrument design features: • What is the legal form, target actors, duration, stringency, level of support, flexibility, differentiation and depth for instruments? **Integration**: • Policy mixes and alignment: is there synergy and complementarity of policy instruments and strategies? Are specific biomethane goals integrated into other climate, renewable energy and circular economy policy and regulatory frameworks? • Timing: what is the temporal sequencing of policies over phases of technology development, are support measures strong enough in the initiation phase to stimulate market development then reduced over time as the market matures? • Implementation: what are the arrangements by authorities and other actors for putting policy instruments into action.

3.2 APPROACH AND SCOPE

We conducted a comparative case study analysis of international jurisdictions to explore the policy mixes that have successfully supported the development of biomethane markets. Based on these findings, we provide recommendations on policy options to advance the Australian biomethane industry. A systematic desktop review was undertaken to map policy and regulatory settings related to biomethane in both Australia and international case studies. The review was supplemented by 22 interviews with key stakeholders. The scope of the analysis encompassed policies and regulations across the entire biomethane value chain. These included policies impacting feedstocks, biogas and biomethane production, injection into gas distribution networks, direct supply to industry, use as renewable transportation fuels, and policies designed to incentivise biomethane production. Additionally, we examined regulations and policies related to the use of co-products, such as digestate and biogenic CO_2, the sale of which can support the economic viability and environmental sustainability of biomethane projects. The review's primary focus concerns scaling biomethane for end uses that displace natural gas, particularly through gas supply networks, industrial use, heating, or LNG or CNG transport fuels. While biomethane can be used to generate electricity, this was not the primary focus, as other significant renewable and low-carbon alternatives exist for the power sector, whereas there is a critical need to develop low-carbon liquid and gaseous fuels.

3.3 DESKTOP REVIEW

A comprehensive desktop review of Australia and the selected international case studies was undertaken using the most recent available information, given the rapid policy, market and technology developments. Data was sourced online through key searches and a snowball approach, with key information being cross-referenced with related documents. The literature reviewed included policies, regulations, guidelines and programs directly and indirectly related to the biomethane supply chain, key industry reports (e.g. FFCRC, Bioenergy Australia, biogas associations), intergovernmental organisations (e.g. IEA, UN), academic literature, and select news sources. International case studies began with the IEA's 2023 Energy Policy Reviews, which used a similar snowball method to find relevant literature, and helped identify key policies. A database was created to capture each document, its jurisdiction, publisher, year published, summary, key points, document type. Documentation and literature reviewed are summarised in the bibliography.

3.4 STAKEHOLDER CONSULTATION

Expert and stakeholder interviews serve as an invaluable source of data alongside published materials, helping identify the informal institutional structures and 'soft factors' that play a critical role in developing a new technology, industry, or market.(74)

To ensure a comprehensive perspective, we engaged a wide spectrum of stakeholders involved in the biomethane industry. These included feedstock suppliers and biomethane producers (typically the same organisation, such as landfill or wastewater treatment operators and farmers); gas network operators; industry and academic experts; relevant industry associations and peak bodies; policymakers from relevant sectors (energy, agriculture, climate, environment, agriculture, waste, transport and finance), as well as regulators, market operators and authorities (AEMO, AER, ARENA). Additional stakeholders were identified through snowball sampling.

One on one semi-structured interviews were conducted online in parallel to the desktop review. In all twenty-two interviewees were included in the study from Australia, United States, Canada, Denmark and Italy. This served to complement the desktop findings, providing new avenues for documentary research and addressing identified knowledge gaps. Interview questions were tailored to different stakeholder groups and guided by findings from the desktop review and the policy analysis framework. Broadly, questions sought to identify stakeholder's perspectives in relation to the barriers, enablers, opportunities, and challenges associated with increasing biomethane supply and demand. Technological, economic, social, issues were discussed, as was how these issues might be addressed by policy and regulatory frameworks.

3.5 INTERNATIONAL CASE STUDY SELECTION

Comparative case studies allow an in-depth examination and comparison of incentive strategies, allowing us to assess what has (and hasn't) worked in practice. We selected five countries to serve as case studies using the following criteria: political and legal systems sufficiently similar to Australia to ensure the transferability of lessons; variation in biomethane production levels to analyse different market dynamics; and differences in market maturity to examine early versus later-stage policy levers. Additionally, we focused on countries that have successfully developed biomethane markets, as evidenced by recent growth trends. We chose three countries with well-established biogas and biomethane markets (the US, the UK and Denmark) and two emerging markets with significant growth (Canada and Italy). These cases were also chosen due to the availability of rich data. Following a review of Australia's policy and regulatory landscape, international case studies were chosen based on their suitability to the Australian context.

The United States (US): The US was selected for its similarities with Australia, and for the scope of its biomethane production. As of 2025, it is the largest producer of biomethane and the third largest producer of biogas globally, though its per capita production remains lower than in many other countries. Like Australia, the US is a geographically large and diverse country with an uneven distribution of biogas and biomethane production. The US's strong federalism has led to highly variable biomethane incentives between states, allowing both interstate and international comparisons to be drawn.

Canada: Canada was selected as an international case study due to key similarities with Australia. These include its large geographical size, its low population density concentrated along its southern border (comparable to Australia's coastal population distribution), and its significant fossil fuel resources and associated industries, particularly for natural gas. As a federal system, Canada's provincial policies play a crucial role. For example, mandates for distributors to supply minimum blends of biomethane across their gas grids in British Columbia and Québec have driven increased procurement from Canadian gas utilities. National biomethane capacity is expected to double between 2022 to 2026, from approximately 9 PJ to 18.1 PJ per year.(75)

Denmark: Denmark leads the world in replacing natural gas with biomethane. By the end of 2024, biomethane accounted for nearly 40% of the country's natural gas supply (26.7PJ) and measures in place by the Danish Government are expected to achieve 100% supply before 2030.(71)

Italy: Over the past two years, Italy's biomethane production has grown tremendously (albeit from a small base) to become one of the top four countries in Europe for installed biomethane production capacity (currently there are 133 biomethane plants of 2,000 biogas plants).(4) The National Recovery and Resilience Plan (NRPR) commits investments of 1.9 billion € for the development of biomethane in Italy, regulated by applicable regulations and legislative decrees to increase production by 2.3-2.5 billion cubic metres per year by 2030.(76) In August 2022, the European Commission approved a 4.5 billion € scheme to support biomethane production in Italy, aiming for 4 billion cubic metres per year by 2026. Additionally, on 15 September 2022, the Ministry for the Ecological Transition issued a decree to support the production of bio-methane from 2022 until 2026, with implementation rules coming into effect in January 2023.(76)

The United Kingdom (UK): The United Kingdom was selected as a case study of a more mature market for several reasons: since 2011, the government has provided a feed-in-tariff for biomethane injected into the gas grid;(77) its regulation and digestate reuse is considered as an exemplar of best practice; and for its ongoing focus on growing biomethane capacity, as evidenced by its Future Policy Framework for Biomethane Production, which is currently under development.

4. Australia

4.1 EXECUTIVE SUMMARY

As of 2025, Australia's biogas industry is relatively small, and biomethane production is limited to just one demonstration plant in New South Wales (NSW) and a few others are in development. However, recent policy reforms to incentivise biomethane production highlight a growing interest by government and industry in developing the sector.

The **Australian Carbon Credit Units** (ACCU) scheme and its **biomethane package** has several methods through which biomethane producers can generate ACCUs, which can then be sold to buyers, including facilities regulated by the **Safeguard Mechanism**. However, these methods are limited to specific types of projects and activities, limiting their applicability across the broader industry. Australia also has a voluntary certification scheme for biomethane - the **GreenPower Renewable Gas Certification**. While this scheme currently exists to support a voluntary market in renewable gas, amendments to the NGER scheme are expected to allow purchasers of certified gas to reduce their accounted scope 1 emissions, helping Safeguard Facilities meet their emissions reduction obligations. At the state level, NSW and Victoria have been pivotal in driving the development of biomethane incentives. As at 2025, NSW hosts Australia's only operating biomethane plant and is currently in the process of developing a **Renewable Fuel Strategy** and a **Gas Roadmap**. The NSW government is also considering adding biomethane as an eligible fuel for its **Renewable Fuel Scheme**. Victoria's **Gas Substitution Roadmap** sets out a path for transitioning away from fossil gas use. The state is also exploring policy options to incentivise biomethane and has recently proposed a renewable gas obligation in its **Renewable Gas Directions Paper**.

4.2 BIOMETHANE AND ENERGY SNAPSHOT

In 2022-2023, Australia consumed 18 PJ of biogas for energy, the majority of which was sourced from landfill (13.5 PJ).(78) Biogas accounts for less than 10% of Australia's total bioenergy supply (216 PJ in 2017-2018); the major sources of bioenergy being bagasse (almost 50%), and wood and wood waste (~37%), with smaller amounts of municipal and industrial waste (<3%), and bioethanol (<3%). Overall, organic wastes and residues used for bioenergy are marginal compared to the overall quantity of waste.(38)

Data on the number of biogas facilities is limited, with the latest report from 2017 estimating there were 242 biogas plants in Australia.(20) Half of these facilities were landfills, and the remainder from wastewater treatment plants, sludge biogas (mostly manure), bagasse, and wood waste.(79) Biogas accounts for 0.5% of Australia's total energy consumption of 3,900.4 PJ; 3.2% of its natural gas consumption of 561 PJ, 1.2% of its domestic natural gas supply of 1,518 PJ, and 0.4% of its exports (4,541 PJ).(80) Australia has only one biomethane facility in operation, Jemena's Malabar Biomethane Injection Plant. The plant has an initial capacity of 0.095 PJ of biomethane per annum. This demonstration project uses wastewater feedstock from the Malabar Water Resource Recovery Facility. The plant was previously a biogas plant.(81)

4.2.1 Australian Gas Market Structure

The gas markets in Australia are divided into three regions: eastern, western and northern. The interconnected eastern gas market covers Victoria, South Australia, Queensland, NSW and Tasmania. This market has three different wholesale gas market trading designs, all operated by the **Australian Energy Market Operator** (AEMO). The short-term trading market (STTM) has hubs in Adelaide, Brisbane, and Sydney; the declared wholesale gas market (DWGM) is located in Victoria; and the gas supply hubs (GSHs) are situated in Wallumbilla, Queensland and Moomba, South Australia.(82)

The gas basins that supply the eastern market contain around one third of Australia's gas reserves. Originally focused on domestic sales, this market has undergone significant structural changes alongside the development of the Queensland gas export industry. In contrast, the gas basins of the western gas market make up more than half of Australia's gas reserves. The western market is primarily focused on exports, though they also supply WA's domestic needs. The northern gas market is relatively small, with its basins also providing gas primarily for export, alongside meeting some of NT's domestic consumption requirements.(83)

4.3 STRATEGIES, TARGETS, AND PROPOSALS

At present, there are no national strategies or targets specifically addressing biogas or biomethane. The development of a biomethane industry and market is mostly being led at the state level, particularly by NSW and Victoria.

However, the **Future Gas Strategy**, released in May 2024, does provide some indicators of the government's direction regarding gas policy.(60) The policy's goals are threefold: to address projected shortfalls in natural gas supply, to mitigate cost of living pressures, and to encourage decarbonisation. Despite increased climate ambitions through legislated emissions targets, the Future Gas Strategy has affirmed the role of fossil-based natural gas use through 2050 and beyond. Moreover, the strategy explicitly encourages the expansion of domestic fossil gas production in the near term. While the strategy pays lip service to the role of renewable gases including biomethane, it does not set targets for biomethane production nor proposes policies to foster such a sector. Rather, the strategy's framing suggests that biogas technologies may emerge without government support:

> "Low-emission gases such as hydrogen and biomethane may become important elements of Australia's energy landscape, as well as adding to our exports. These low-emissions gases are not yet produced at a scale or price able to compete with natural gas. However, they are expected to become more competitive as technology costs reduce and these gases are produced on a commercial scale."

The Australian Renewable Energy Agency's (ARENA) **Bioenergy Roadmap**, prepared by ENEA Australia and Deloitte in 2021, though not an official government policy, offers a more structured framework for the development of a bioenergy industry from 2021 to 2030.(34) The roadmap is supported by $33.5 million in funding for ARENA bioenergy projects, and identifies biomethane grid injection and hydrogen as the pragmatic solutions for hard-to-abate sectors of gas consumption, forecasting that commercial-scale digestion and injection facilities could be operational by 2030 if the industry advances quickly. Renewable gas grid injection is a key component of the roadmap's first section, 'Enabling market opportunities in hard-to-abate sectors'. Specific recommendations include developing a certification of origin scheme, establishing ACCU methodologies recognising biomethane injection into gas networks, implementing a uniform regulatory system for digestate specification and use, and assessing the suitability of natural gas specifications for biomethane grid injection. Longer term, it recommends exploring ways to reduce the economic viability gap, including "lowering production costs for biomethane production from anaerobic digestion".(34) The Bioenergy Roadmap's third section, 'Developing resources', focuses on the regulation and utilisation of feedstocks. It recommends encouraging the separation of organics at source, developing a sustainability framework for feedstock production, and harmonising waste policies and levies across the country.(34)

In September 2024, the Climate Change Authority released its **Sector Pathway Review**.(84) Commissioned by the Australian Parliament, this review analyses pathways towards decarbonisation in six sectors: electricity and energy; transport; industry; agriculture and land; resources; and the built environment. It identifies six strategies for decarbonisation which, although not applied to biomethane, are highly relevant:

1) "Overcome the 'green premium' [of low-carbon technologies] through fit-for-purpose policy interventions, including regulation, market-based mechanisms and government finance to leverage private investment."
2) "Accelerate the deployment of net zero infrastructure by reforming planning and approvals processes, coordinating business engagement within and across jurisdictions, and identifying and fast-tracking the development of renewable energy zones and clean industrial hubs."
3) "Strengthen the foundations for social licence and a just transition to net zero through enhancing climate literacy, building capacity in business and communities to negotiate benefit and burden-sharing arrangements, and working with communities to support the net zero transition."
4) "Think global, act local for Australia to prosper in a net zero world."
5) "Rapidly address workforce shortages by diversifying and deploying a rapid skills program and enhancing workforce mobility."
6) "Address information and data gaps by expanding, simplifying and automating data collection and dissemination."(84)

These overarching strategies all intersect with biomethane production in various ways, with strategies 1–3 being particularly relevant, however there are only a few specific plans and supports for biomethane in the report. The "Industry and Waste" section discusses the potential of anaerobic digestion to reduce emissions from organic waste, and outlines policy enablers including certification schemes, shared infrastructure through low emissions industrial precincts, and separate collection of organic waste in households and commercial sources.(84)

The "Built Environment" chapter is less positive about the future of biomethane, stating that "some stakeholders suggested that both gas and electrical systems could be maintained with renewable gases (e.g. hydrogen or biomethane), that broad electrification is cost-prohibitive and faces significant workforce challenges […] The authority is of the view, however, that in the long-term complete electrification of buildings is the optimal decarbonisation approach and governments should develop strategies to efficiently and equitably realise this," later stating that "biomethane is not projected to form part of the energy mix for residential or commercial buildings, as electrification is a cheaper way to decarbonise."(84) The "Electricity and Energy" chapter does not mention biomethane at all.

Looking outside of biomethane, the Federal Government's heightened climate ambitions in 2022 in seeking to align its Nationally Determined Contribution (NDC) with the Paris Agreement provides encouragement for the development of renewable energy. The Federal Government has enshrined emissions reduction targets of 43% below 2005 levels and net zero by 2050 under the *Climate Change Act 2022* through its **Net Zero Plan** (cf. 26-28% by the former LNP Government). It is also seeking advice to determine a 2035 target.(85) However, Australian strategies for achieving emissions reductions are focused largely on electrification, with an ambition for renewables to reach an 82% share of electricity nationally by 2030 through the **Powering Australia Plan**.

Alongside electrification, Australian energy strategy to date has foregrounded hydrogen. The 2019 **National Hydrogen Strategy** includes a $4 billion investment to develop the industry through its **Hydrogen Headstart** scheme, with a focus on domestic uses and exports. The Australian Government claims that "Australia's pipeline [of up to $300 billion of potential hydrogen investments] is the largest in the world."(86) While governmental focus has largely been on the development of renewable hydrogen, technical challenges in scaling up the technology have led to a growing interest in biomethane from policymakers.

Besides decarbonising domestic electricity, there has been a strong government focus on developing markets and industries for renewable fuels with export potential. The government's strategy is to position Australia as a 'green energy superpower' through the production and export of green hydrogen for liquid fuels in sustainable aviation fuels (SAFs) and marine biofuels.(87) Policies directed at hydrogen and liquid biofuels can be both competitive and complementary to the development of a biomethane industry.

In the transport sector, the **Future Fuels and Vehicles Strategy** and its $250m **Future Fuels Fund** has been limited to supporting EV fast charging infrastructure and hydrogen refuelling stations (although it also mentions including new technologies for long-distance and heavy vehicles).(88)

4.4 MARKET-BASED INSTRUMENTS & FINANCIAL INCENTIVES

Currently, the main instruments to support a viable market for biomethane are the **Biomethane Method Package** introduced into the ACCU Scheme, which provides financial incentives for producers(89) and the **GreenPower Renewable Gas Certification**, which facilitates a voluntary market for the purchase of renewable gas.(90) Anticipated changes to the **National Greenhouse and Energy Reporting (NGER) Scheme** may drive additional demand from facilities regulated by the **Safeguard Mechanism**, which are obligated to reduce their emissions by 4.9% each year from a benchmark.(49) The proposed NGER scheme changes would allow these facilities to lower their reported scope 1 emissions through the purchase of certified biomethane.(91)

Biomethane Package and the ACCU Scheme

Australian Carbon Credit Units (ACCUs) are granted by the Australian Government for "carbon abatement activities".(92) ACCUs are granted to organisations who carry out approved methods for reducing carbon emissions.(93) Prior to 2022, three approved methods involved the capture and use of biogas. The *landfill gas (electricity generation)* method covered the collection and combustion of landfill gas to generate electricity; the *wastewater treatment* method covered the installation of anerobic digestors to replace open anaerobic lagoons for treating wastewater; and the *animal effluent* method covered emission reductions from destroying or avoiding methane emissions from animal manure.(94)

In 2022, the Clean Energy Regulator released the biomethane package, which changes the three existing methods “to allow projects under these methods to produce biomethane from waste methane, generating eligible carbon abatement.”(94) These variations are intended to incentivise both types of emissions reductions achieved by injecting biomethane:

1. Generation of biogas through the capture and conversion of methane to CO_2 from waste facilities; and
2. Displacement of natural gas through substitution with biomethane.

The addition of the biomethane component essentially enables projects to produce a greater number of ACCUs through both conversion abatement (the conversion of methane into carbon dioxide, which is a much less potent greenhouse gas) and displacement abatement (the displacement of natural gas caused by substituting biomethane). This also helps to place biomethane on an equal footing with biogas, as the latter is eligible for Large-Scale Generation Certificates when used to generate electricity.

Safeguard Mechanism

The **Safeguard Mechanism** regulates facilities that emit more than 100,000 tonnes of carbon dioxide equivalent in scope 1 emissions each year. These major emitters (~219 facilities in 2024) contribute around 30% of Australia’s greenhouse emissions. Safeguard facilities are required to reduce their emissions by 4.9% each year from their determined baseline.(98) Facilities which do not exceed the allowable emissions limits can earn Safeguard Mechanism Credits (SMCs),(99) while those that exceed the limits must surrender SMCs or ACCUs or apply for one of the alternative legislative options for managing excess emissions.(100) The current design of this system does not facilitate the sale of biomethane’s green value. The situation was summarised in a submission to the federal government by Bioenergy Australia in June 2023:

> “In 2022, a NGER Measurement Determination was made to account for the scope 1 emission benefits of grid-injected biomethane. However, the determination spreads the emission benefits of biomethane to all gas users, rather than those who purchase the product. As a result, Safeguard Facilities are not commercially incentivized to purchase biomethane, as they cannot report an emission reduction and instead must purchase offsets to account for emissions from purchasing biomethane through the gas grid. This presents a market barrier for all renewable gases, including biomethane and hydrogen, and impedes further deployment of renewable gas technology in the Australian gas grid. The barrier could be overcome if Product GOs were recognised under the NGER Measurement Determination, similar to Renewable Electricity Certificates (LGCs and STCs) that can be surrendered under NGER. This is essential in supporting decarbonisation.”(54)

Allowing RGGOs or Product GOs to be surrendered to reduce a Safeguard Facility’s emissions would increase the value of these certificates.

GreenPower Renewable Gas Certification (Renewable Gas Guarantees of Origin)

GreenPower Renewable Gas Certification is a national certification program run by the NSW Government, with guidance from a national steering group. It provides independent accreditation for renewable energy products, including a Renewable Gas Certification. This operates similarly to a European Union Guarantee of Origin, allowing commercial and industrial customers to purchase the green value of biomethane. This is a voluntary market, and currently the main commercial reason to purchase a Renewable Gas Certification is to substantiate claims of carbon neutrality (which is increasingly required under Australian consumer law). Because renewable gas is fungible and unidentifiable once injected into the gas network, Renewable Gas Certifications are traded independently of the gas itself, unless the gas is used behind the meter or delivered directly to a local customer.

One certificate, called a **Renewable Gas Guarantee of Origin** (RGGO), is issued per gigajoule of renewable gas produced in Australia and injected into a gas network, used directly in a behind the meter project, or directly delivered to a consumer.(90) RGGOs are represented by electronic records with a unique serial number which are stored in a centralised Registry.(90) The certificates are called Renewable Gas Guarantee of Origin (RGGO). RGGOs can only be purchased by commercial and industrial gas users.(95)

There is currently one GreenPower Certified Renewable Gas facility - Jemena’s Malabar Facility became the first in Australia in March 2024. The GreenPower certificates generated by the Malabar Facility are purchased by Origin, for subsequent sale to end users.(96,97)

Projects that generate both displacement ACCUs and GreenPower certificates will have to surrender them at the same time. The scheme providers are currently looking at how these certificates will interact to ensure there is no double counting (stakeholder pers. comm.).

RGGOs enable commercial and industrial customers to substitute their fossil natural gas use with low-emission renewable gas. Presently, the primary value lies in their ability to substantiate customers' emissions claims. However, changes to the NGER Scheme may allow certified renewable gas to directly reduce a company's accounted emissions. This would lower liabilities under the Safeguard Mechanism, which stakeholders have indicated could lead to a significant increase in the value of certified renewable gas.

National Greenhouse and Energy Reporting (NGER) Scheme

The **National Greenhouse and Energy Reporting (NGER) scheme** is Australia's national framework for reporting and publishing company information concerning greenhouse gas emissions, energy consumption and energy production. The NGER scheme requires companies and facilities with emissions over a set thresholds (50,000 tonnes CO_2e per year) to report their energy consumption emissions. However as the ACCU Biomethane Method Package guide notes, "there is no emissions factor for the combustion of biomethane sent by pipeline that is used by a facility."(89) This means that facilities that wish to buy biomethane cannot report emissions reductions from replacing natural gas with biomethane. To address this barrier, stakeholders we interviewed noted that a working group has been established with monthly discussions between DCCEEW, industry associations, and industry participants to design an NGER Scheme reporting method. The NGER method is anticipated to be released on 1 July 2025. (stakeholder pers. comm.)

Guarantee of Origin (GO) Scheme

The Clean Energy Regulator is currently in the process of developing a "Guarantee of Origin" certification scheme. There are two types of proposed GO schemes in the pipeline: a **Renewable Energy Guarantee of Origin** (REGO), and a **Product Guarantee of Origin** (Product GO).(101)

The proposed REGO certificate mechanism would build on the Large-scale Generation Certificate (LGC) framework under the Renewable Energy Target (RET) scheme. REGOs would initially exist alongside LGCs but are planned to continue beyond 2030 when the RET ends. Implementation of a REGO mechanism would not involve any changes to liability under the RET scheme. Similar to LGCs, REGOs would be available to projects producing electricity from renewable biogas.(101)

The proposed Product GO scheme employs a mass-balance chain of custody approach to the sale of fungible products with a digital certificate hosted on a publicly available register.(102) This certificate will contain information about where the product was made, what it was made from, and how it was transported.(101) Certificates will be issued post-production and can be surrendered to reduce an organisation's accounted emissions, similar to LGCs and ACCUs. This process means that there must be a "reasonable physical link" between the production and consumption of the product, ensuring a balance between the amount of product consumed (e.g. biomethane) and produced.(102) If electricity is used in the production of renewable fuel, as is the case in the production of biomethane, REGOs and/or LGCs (but not ACCUs or SMCs) may be surrendered to claim renewable energy use in biomethane production, reducing emissions in the Product GO certification.(102)

While the Product GO Scheme does not include biomethane at present, a number of industry proponents are advocating for extending the Product Go Scheme certificates to biomethane and biofuels to provide a driver for financing low-carbon fuels. The department has proposed releasing an annual product prioritisation list of products intended to be added to the scheme.(102)

Climate Active Carbon Neutral Certification

Climate Active Carbon Neutral is an Australian Federal Government program that provides certifications of carbon neutrality for Australian organisations, products, services, events, buildings, and precincts. Receiving this certification involves self-measurement and calculation of emissions, purchasing of carbon offsets, audit supervision on emission data, and publication of emissions data. Becoming certified authorises an organisation to use the Climate Active Carbon Neutral certification trade mark.

Climate Active publishes a "voluntary standard", the *Climate Active Carbon Neutral Standard for Organisations*, which provides "best practice guidance on how to measure, reduce, offset, validate and report emissions that occur as a result of the operations of an organisation".(103) If an organisation complies with this standard, they are able to market themselves as "climate neutral", although it does not allow them to use the Climate Active Carbon Neutral certification trade mark.(103) Because Climate Active is technology-neutral, producers of biomethane can apply for and use the Climate Active Carbon Neutral certification trade mark to certify the carbon neutrality of a biomethane product, or of the company itself, in much the same way as a GreenPower certification.

Supports for renewable electricity

The mentioned supports for decarbonising gas are relatively trivial in comparison to the decarbonisation policies directed toward electricity. Key instruments for electricity include a $20B investment committed in 2022 for transmission and distribution infrastructure, distributed energy and battery storage through **Rewiring the Nation Fund** as part of the **Powering Australia** plan; and establishing a supportive regulatory framework to develop an offshore wind industry and supply chain through the ***Offshore Electricity Infrastructure Act 2021*** *(OEI Act)*. The **Capacity Investment Scheme** (CIS) provides a national framework to encourage new investment in renewable capacity, such as wind and solar, as well as clean dispatchable capacity, such as battery storage, to deliver an additional 32 GW of renewable capacity by 2030.

The long-running **Large-scale Renewable Energy Target (LRET)** certificate trading scheme since 2011 involves tradable **large-scale generation certificates** (LGCs) which represent quantities of renewable electricity generated by large-scale renewable energy power stations.(104) Specifically, each LGC represents 1 MWh of renewable energy generated or displaced by a facility. "Liable entities" (large purchasers of electricity) can surrender LGCs to meet the annual renewable energy target set by the Large-Scale Renewable Energy Target.(105) 'Eligible renewable energy sources' under the *Renewable Energy (Electricity) Act 2000* (Cth) include agricultural waste, food waste, bagasse, landfill gas, and sewerage gas (among others). As such, the use of biogas to produce electricity can generate LGCs. Because LGCs are granted for the generation of electricity, they are not available for the creation of biomethane. For their Malabar Biomethane Injection Plant, Jemena "procures Large-Scale Generation Certificates (LGCs) to offset the electricity that is consumed on site in the production of the biomethane."(81)

4.5 REGULATIONS AND STANDARDS

Gas specifications

The ***National Gas Rules***, made by the Australian Energy Market Commission under the *National Gas Law* (a harmonised set of state legislation), sets out regulations relating to gas pipelines and other infrastructure. Prior to 2024, these rules referred to "natural gas" only, which created legal uncertainties for the injection of biomethane, hydrogen, and other blends into the gas network. The regulation has since been amended to instead apply to "covered gases", which includes natural gas, hydrogen, biomethane, synthetic methane, and blends of these primary gases.

The *National Gas Rules* also specify the relevant technical standards for gas injection in Australia. In the words of the Victorian Department of Energy, Environment and Climate Action, the gas specification standard (Australian Standard 4563) "does not currently reflect the specific characteristics of biomethane. This is a current barrier to direct substitution and is currently under review by an Australian Standards committee."(24) Other jurisdictions have more permissive standards for gas injection, and research conducted by the Future Fuels CRC has recommended that allowable oxygen levels in pipeline levels could be raised in the Australian context (to allow the injection of biomethane without prohibitive purification costs) following appropriate validation of downstream assets.(106)

Ownership of the supply of natural gas is concentrated with a few large producers. Producers sell gas to energy retailers, and sometimes to major industrial, mining, and power generation customers, through wholesale gas markets. This is typically done through long term supply contracts, often lasting up to 20 years.(25)

Gas transmission pipelines are high-pressure pipelines used to transport natural gas from production fields to demand centres. Gas distribution networks then distribute gas to homes and organisations through a reticulated network of high, medium, and low-pressure distribution pipelines.(25) Because of the natural monopolies which arise in gas transmission and distribution, pipeline prices are economically regulated.(25) Pipelines are classified as either scheme or non-scheme pipelines under the National Gas Rules, with scheme pipelines subject to heavier regulatory requirements. Scheme pipelines are further subdivided into fully or lightly regulated pipelines.(107) Importantly, full regulation covers the access arrangements that determine how third parties can gain access to the pipeline.(107) Finally, retailers act as contractual intermediaries between gas distributors and customers, such as households and small businesses.(25)

Grid access

Unlike in other countries such as France and Denmark, Australia's National Gas Rules does not provide suppliers of biomethane with a right to inject. Further, Australia lacks a complaints process for addressing unfair constraints or conditions imposed by pipeline operators, shippers, and retailers.(108) Instead, as Shi and Grafton observe, "users need to purchase primary pipeline capacity rights from pipeline owners through long-term contracts. This individual, bilateral negotiation of pipeline capacity raises the barrier for new producers or gas users to enter the pipeline capacity market, as they may not have the resources to negotiate on an equal basis with incumbents."(82) In interviews, stakeholders expressed that the need to contract with pipelines has prevented biomethane projects from proceeding.

Landfill Gas and Source Separation

In Australia, it is estimated that the largest landfills use around 20% to 30% of their potential waste methane for electricity generation, with the remaining biogas either being flared or escaping to the atmosphere.(21) Source-separation of waste can greatly increase biogas recovery as it allows all organic material to be diverted from landfill to purpose-built facilities (i.e. anerobic digesters).(109) Australia lags behind international counterparts, particularly Europe, in terms of waste source separation. However, various state-based waste strategies and local council initiatives are starting to improve waste separation and better utilise waste resources, through methods such as the provision of food organics and green organics (FOGO) bins to households.

Information-based mechanisms

Australia's most prominent industry body for biomethane is Bioenergy Australia's Renewable Gas Alliance.(110) Its members include 69 industry, government, and research organisations whose remit is to 'assist in driving a higher level of understanding, uptake and engagement relating to the renewable gas opportunities in Australia' and to advise Bioenergy Australia on issues relating to the biogas sector.(110) Bioenergy Australia's Bioenergy Government Network seeks to build capability and knowledge between the states by connecting policymakers engaged in bioenergy-related areas across government jurisdictions to share information and explore opportunities across jurisdictions to include bioenergy in Australia's energy mix.

4.6 STATE POLICY FRAMEWORKS

In this section, we outline the State- and Territory-level strategies, targets, funding schemes, and regulations with the potential to influence the development of a biomethane industry in Australia. All States and Territories have environmental and planning legislation which will need to be complied with to establish biomethane infrastructure. Because of the complexity of this area of law, and the wide variation in which laws and regulations will be applicable to a given project, we have only addressed the environmental and planning initiatives that are directly targeted towards biogas or biomethane. While the National Gas Law is legislated separately in each State and Territory, these laws are nationally consistent and have therefore been addressed in the review of the Australian policy framework.

4.6.1 Australian Capital Territory

The ACT uses approximately 6.5 PJ of gas annually, ~20% of the ACT's total energy demand, which accounts for 21% of the ACT's total emissions.(111) The potential of biogas production in the ACT is estimated to be 0.74 PJ/year, or up to 1.98 PJ/year if all currently composted garden waste is also used as feedstock.(112)

Strategies and Targets

The Australian Capital Territory reached its target for 100% net renewable energy in 2020, and has set a target of net zero emissions by 2045.(111) The ACT's **Integrated Energy Plan** lays out a pathway for transitioning away from gas, with a primary focus on decarbonisation through electrification. The plan envisions the eventual decommissioning of the gas network "over the next few decades".(111) The plan envisions an ongoing role for biogas and biomethane in powering industrial applications where electrification is not possible. Biomethane grid injection is described as "well understood and mature",(111) and lower cost than bottled green gas and renewable hydrogen. The Integrated Energy Plan describes the following potential pathway: "the gas network (or parts of it) remain, supplying biomethane to those consumers who require green gas where electrification is not possible."(111)

A report commissioned and published by the ACT Environment, Planning and Sustainable Development Directorate has indicated that the ACT is exploring a number of options to incentivise the uptake of biomethane and biogas. These include green gas certification, feed-in tariffs, market obligation methods, grants for the construction of facilities, grid injection priority, tax or regulatory exemptions for the construction of facilities, gas injection priority, and carbon pricing.(112)

The ACT **Waste Management Strategy 2011-2025** suggests that a Material Recovery Facility for residual waste from households could recover upwards of 50,000 tonnes of wet-mixed waste, which could be used as an additional feedstock stream.(113) The strategy promotes biogas and bioenergy as important technologies for creating energy from waste, and proposed expanding bioenergy generation. In particular, it promotes the use of sewerage biosolids as a feedstock. Strategy 2.3 suggests that the development of markets for organic and residual waste "adhere to the principle that waste should be directed to the highest-value use".(113) Further, Strategy 4.1 promotes additional methane capture from landfills, and Strategy 4.3 proposes expanding bioenergy generation, highlighting anaerobic digestion, landfill gas generation, pyrolysis, thermal gasification, and direct combustion as avenues for further exploration.(113)

Instruments

To support the ACT's transition away from gas under the Integrated Energy Plan, new connections to the gas network have been banned, and a number of grants, rebates, and low- or zero-interest loans exist to help households and businesses replace gas use through electrification.(111)

4.6.2 New South Wales

In 2022-2023, New South Wales had a total energy consumption of 1,439.2 PJ, with a total gas consumption of 134.3 PJ.(114) In the same period, it produced 9.3 PJ of liquid and gas biofuels, the largest production of any state.(115) Biogas was used to generate 1.5 PJ of electricity.(116) New South Wales contains Australia's only existing biomethane plant, Jemena's Malabar Biomethane Injection Plant.(81)

Strategies and Targets

While New South Wales has no strategies or targets specifically for biomethane at present, in August 2024 the NSW Government issued a discussion paper on the 'Opportunities for a Renewable Fuel industry in NSW'. The paper requested feedback to inform a Renewable Fuel Strategy, which is expected to be released in mid-2025.(117) The discussion paper recognises the role that renewable fuels, including biomethane, play in the state's energy transition – particularly in helping hard-to-abate sectors decarbonise. Biomethane is identified as "an attractive option for short-term decarbonisation", as it can be used with existing gas infrastructure with minimal or no modification.(117) The paper also notes the potential of renewable fuels to drive regional economic development and to improve fuel security in NSW.

While the current **Renewable Fuel Scheme** (RFS) only considers hydrogen, the NSW Department of Climate Change, Energy, the Environment and Water is currently examining the impacts of including new fuels, including biomethane.(117) The department is specifically exploring the effect that the inclusion of biomethane might have on hydrogen and sustainable aviation fuels, expressing concern that inclusion might lead to biomethane outcompeting these fuels.(117)

More broadly, the New South Wales Government has committed to emissions reduction targets of 50% from 2005 levels by 2030, 70% by 2035, and net zero by 2050. This includes a specific sub-target of net zero emissions from organic waste by 2030.(118) To achieve this, the NSW Government has promised to "support local councils to provide communities with best-practice food and garden waste management infrastructure" and to "facilitate the development of 'waste to energy' facilities in locations that have strong community support, provided those facilities meet strict environmental standards".(118)

NSW Climate and Energy Action has committed to publishing a NSW gas decarbonisation roadmap by late 2026. As of December 2024, public consultation is expected to begin in 2025. Preliminary remarks on this roadmap note that "gas will likely remain an important fuel source for some sectors."(119)

The NSW Department of Climate Change, Energy, the Environment and Water is considering a number of policies that could incentivise biomethane production, including helping to aggregate feedstocks, repurposing under-utilised or mothballed facilities for renewable fuel production, expanding the Renewable Fuel Scheme to include biomethane, contracts for difference, long-term energy service agreements, and setting separate or combined renewable gas targets (for hydrogen, biomethane, and biodiesel).(117)

Instruments

Like Victoria, the New South Wales Government has focused its support on hydrogen, with the NSW Hydrogen Strategy providing up to $3 billion of incentives supporting the hydrogen industry through 60 industry development actions.(120) The NSW Government's **Net Zero Industry and Innovation Investment Plan** provides $305 million to help high-emitting manufacturing and mining facilities decarbonise,(121) although it is uncertain as to whether any of this funding will go towards biogenic gas projects. The NSW Renewable Fuel Scheme, which provides tradable certificates for renewable fuel production, does not currently apply to biomethane, with its potential to outcompete hydrogen cited as a concern for expanding the scheme. However, the possible expansion of the scheme to include biomethane was one of the questions directed at stakeholders during an August 2024 discussion paper and consultation about the scheme, indicating that this may occur in the future.(117)

Biofuel and biogas are listed as eligible fuels under the New South Wales Energy Savings Scheme. In effect, this means that suppliers can generate tradable energy saving certificates by installing energy saving upgrades for households and businesses. These certificates can then be purchased by energy market participants who are required to meet energy saving targets.(122)

The NSW Department of Primary Industries and Regional Development has developed an interactive spatial tool called BioSmart, which shows the location and availability of biomass residues across NSW and potential locations for new biomass sources.(123) It also provides predictions of the amounts of biomass required to run various renewable technologies, fuel costs and emissions associated with biomass transportation, and distances to existing transmission lines and substations.(123)

4.6.3 The Northern Territory

In 2022-2023, the Northern Territory had a total energy consumption of 129.6 PJ, with a total gas consumption of 91.3 PJ.(114) In the same period, it produced 0.1 PJ of liquid and gas biofuels.(115)

Strategies and Targets

The Northern Territory's 2017 "Roadmap to Renewable" set out policy directions for reaching its target of 50% renewable energy by 2030. The Roadmap does not place significant emphasis on biogas or biomethane, stating only that "the key challenge facing bio-gasification is the lack of available data to support the assessment of the biomass resource". In its assessment of liquid biofuels, the Roadmap states that "the key challenge will be the development of sufficient feedstock, and it is considered unlikely that this will be achievable in the medium term".(124)

Instruments

A 2018 report commissioned by Bioenergy Australia found that "Northern Territory policies and regulatory frameworks do not appear to have supported the growth of the bioenergy sector" and found "no evidence of sustainability guidance in place".(125)

4.6.4 Queensland

In 2022-2023, Queensland had a total energy consumption of 1,442 PJ, with a total gas consumption of 291 PJ.(114) In the same period, it produced 5.1 PJ of liquid and gas biofuels,(115) and consumed 0.9 PJ of biogas for electricity generation. Biogas was used to generate 0.9 PJ of electricity.(116)

Strategies and Targets

The Queensland Government has set non-binding renewable energy targets of 50% by 2030, 70% by 2032, and 80% by 2035. Government policy and investment to date has focused on pumped hydro, solar and wind farms, batteries, and hydrogen, and the **Queensland Energy and Jobs Plan** does not mention biogas or biomethane.(126)

The Queensland Energy and Jobs Plan recommends 23 actions across 3 key focus areas. Actions potentially relevant to biomethane include Action 1.5, "ensure reliability with low-to-no-emissions gas" (though the focus here is on hydrogen) and Action 1.9, "advance Queensland's bioenergy future". Details on the implementation of these actions is limited; steps listed to advance Queensland's bioenergy future are "a) Register of interest for feasibility and technical studies" and "b) Finalise feasibility and technical studies to identify options and pathways to expand bioenergy generation and support technology innovation in the bioenergy sector".(126)

Instruments

The Queensland Bioenergy fund is providing $4 million to support bioenergy generation from underutilised biomass waste streams.(127)

Queensland recently introduced an End of Waste Code for digestate, which sets out the criteria for digestate to be reclassified as a 'resource' rather than a 'waste'.(128) This allows digestate to be used as a soil amendment, rather than requiring that it be disposed of as a waste.(129) To be classified as a resource in Queensland, digestate must result from only the following feedstocks: paunch, organic material from agriculture (including livestock production), liquid digestate, green waste from municipal kerbside collection, food and food processing waste (including pet food and beverages), and cardboard and paper waste. The digestate must also be pasteurised, and must fall below the maximum allowable concentrations of listed chemicals and materials.(129) One stakeholder argued that these requirements are unreasonably strict, stating that the limit for PFAS contamination (not detected at a limit of detection of 0.002µg/L) would not be met by the general environment.

4.6.5 South Australia

In 2022-2023, South Australia had a total energy consumption of 300.0 PJ, with a total gas consumption of 74.8 PJ.(114) In the same period, it produced 1.8 PJ of liquid and gas biofuels.(115) During this period, biogas was used to generate 0.3 PJ of electricity.(116)

Strategies and Targets

South Australia has primarily focussed on supporting the development of a hydrogen industry, through initiatives such as its Hydrogen Jobs Plan, the establishment of a Hydrogen Hub, and support of several major hydrogen infrastructure projects.

In 2015, the Government of South Australia's Department for Energy and Mining published a report commissioned by RenewableSA, titled "Bio-energy Roadmap for South Australia", which notes the possibility of upgrading biogas to biomethane for injection into the gas grid.(130) It also identifies a number of barriers to the uptake of small-scale bioenergy projects in South Australia: the absence of an adequate carbon signal, the low price of renewable energy certificates, regulatory gaps affecting eligibility and accreditation, the high cost of connecting to existing distribution networks, and the coordination difficulties faced by smaller operators. The report also noted a lack of government support for bioenergy projects in South Australia.(130)

Instruments

A 2018 report commissioned by Bioenergy Australia notes that South Australia "actives advocate[d] for and provide[d] information on the bioenergy sector", including information on obtaining development approvals.(125) The report also noted the 2018 South Australian Energy Plan's support for the Renewable Technology Fund, which provided investment for developing bioenergy technologies, and the Regional Growth Fund, which included funding for waste-to-energy plants.(125)

4.6.6 Tasmania

In 2022-2023, Tasmania had a total energy consumption of 105.5 PJ, with a total gas consumption of 7.2 PJ.(114) In the same period, it produced 0.4 PJ of liquid and gas biofuels.(115) Biogas was used to generate 0.1 PJ of electricity during this period.(116)

There are currently 13 industrial scale anaerobic digesters in Tasmania, though these produce biogas rather than biomethane. LMS Energy, which works with waste authorities to capture landfill biogas, has estimated its total Tasmanian biogas reserve at 12 PJ for 2022-2040.(131)

Strategies and Targets

A 2022 report commissioned by the Department of Natural Resources and Environment Tasmania on organic waste in Tasmania found that Tasmanian industries generated 811.9 kilo-tonnes of organic waste in 2020, 169.9 kilo-tonnes of which went to landfill.(132) The report noted the benefits of biogas and biomethane as forms of circular waste disposal, but stated that "Australia doesn't currently have the incentives for this technology to be viable."(132)

The Tasmanian Department of State Growth published its “Bioenergy Vision for Tasmania” report in March 2023.(131) This report indicates that the Tasmanian Government is focused on using waste and residue streams as biogas feedstocks. It argues that there is significant potential to increase bioenergy production in Tasmania, with up to 1.36 million tonnes of solid waste and 7.80 million tonnes of liquid waste available per year (from 2016 data).(131)

Instruments

In 2023, the Tasmanian Government committed $10.1 million over four years to replace fossil fuels used in government-owned boilers with renewables, primarily bioenergy.(131)

4.6.7 Victoria

In 2022-2023, Victoria had a total energy consumption of 1.172.6 PJ, with a total gas consumption of 215.2 PJ.(114) In the same period, it produced 6.1 PJ of liquid and gas biofuels.(115) Biogas was used to generate 1.5 PJ of electricity,(116) representing 0.7% of the state’s gas consumption.

A 2022 assessment of Victoria’s biogas potential estimated the state’s theoretical feedstock potential at 80.6PJ per year (37% of total gas consumption), and its more achievable or recoverable biogas potential at between 10.5 and 24.9 PJ/year.(133)

Victoria has the highest natural gas use of any state in the residential sector, with 88% of households reporting use of gas appliances for cooking, hot water systems, and heating in 2023.(134) However, AEMO projects that from 2028, the east coast’s gas demand will outpace supply due to falling gas production in the Bass Straight.(135) This has coincided with “tighter links between domestic prices and global gas markets, as private companies continue exporting Australian gas overseas”,(136) leading to projections of increasing gas prices in Victoria.

Strategies and Targets

Victoria’s Gas Substitution Roadmap was released in July 2022,(137) and updated in December 2023.(136) The roadmap provides the most ambitious path of any Australian state to transition away from fossil gas. While there is recognition of the need for renewable gases such as biomethane and hydrogen for industrial uses that can’t “readily electrify”, the key focus of the Roadmap is a shift from gas to electrification, particularly for residential and commercial use. This involves a move away from gas usage by removing the requirement in the Victoria Planning Provisions 2022 that new housing developments be connected to gas. To push the substitution of gas, the government has banned gas connections in new homes requiring a planning permit from 2024, limited fees for disconnecting from the gas network, and removed Victorian Energy Upgrades (VEU) incentives for fossil gas residential appliances.(136)

The Gas Substitution Roadmap concludes that renewable hydrogen and biomethane should not be used for residential applications, due to the “uncompetitive cost of renewable gases to power homes, and the added supply chain strain from developing the necessary infrastructure to pipe renewable gases into domestic settings”. Instead, biomethane and renewable hydrogen are envisioned as necessary for decarbonising hard-to-abate industrial processes.(137)

Future support measures for biomethane flagged in the Gas Substitution Roadmap include developing a nationally consistent approach to regulating renewable gases in the Declared Wholesale Gas Market, consideration of a renewable gas scheme and renewable gas targets to drive investment, and analysis of a renewable gas certification scheme.(137)

In connection with the Victorian Gas Substitution Roadmap, a Renewable Gas Consultation Paper was published in 2023.(138) It aims to introduce and elicit feedback on policy mechanisms for scaling up the production and consumption of renewable gas in Victoria. The consultation paper notes that “renewable gas does not necessarily need to be supplied through the existing gas distribution network,” and that “The future of the reticulated gas distribution network is uncertain, as there could be a rapid change in its utilisation this decade. Policy must carefully balance the risks of over-investment and asset stranding. Change to the reach or composition of the existing reticulated gas network must be managed in an orderly way to avoid remaining users being burdened with a rising share of network costs.”(138) For this reason, along with significant costs of residential renewable gas and infrastructural development and maintenance, the Consultation Paper suggests that renewable gas will be primarily used in industrial settings and for gas-fired power electricity generation (particularly at peak load periods).(138)

The Consultation Paper explores both government-funded and market-based approaches to developing a renewable gases industry in Victoria. Specific policy instruments considered include feed-in tariffs, reverse auctions or competitive grants, certification schemes, and direct regulatory obligations. A renewable gas target, paired with a certificate scheme (as in the federal Renewable Energy Target scheme), is also discussed in some depth. The Consultation Paper expresses a preliminary view that three categories of projects be eligible for any renewable gas policy or scheme enacted in Victoria:

1. existing biogas facilities that convert to biomethane production or convert to the burning of biogas for heat that displaces fossil gas;
2. renewable hydrogen production;
3. [behind-the-meter] facilities that displace reticulated (i.e. network-delivered) fossil gas to non-substitutable uses (e.g. high heat industrial processes).(138)

This appears to indicate the absence of government support for establishing new biomethane facilities, in favour of supporting existing biogas facilities to switch to biomethane production.

The Renewable Gas Consultation Paper also outlines a number of barriers to biomethane uptake in Victoria. Regulatory barriers listed include "the current gas specification standard (Australian Standard 4564) needs to be updated to reflect the components of biomethane"; "regulatory barriers for end use by-products for biomethane (i.e. digestate and lack of specifications for feedstock quality)"; the "lack of current cost incentive to switch to renewable gases"; and the "lack of a market mechanism to support and encourage renewable gases to be used in the grid and behind the meter including recognition of renewable gas (e.g. through the Guarantee of Origin scheme)." Non-regulatory barriers to biomethane uptake identified in the Consultation Paper relate to capital and operating expenditure, training and education, and social licence and community support.(138)

A report conducted by ENEA Consulting on behalf of the Victorian Government, "Sustainability Victoria – Government Measures and Interventions for Biogas", assesses various policy measures and governmental intervention strategies employed across five international jurisdictions to encourage the development of anaerobic digestion infrastructure.(139) It concludes that the biogas sector in all five jurisdictions was predominantly driven by high electricity feed in tariffs; that four of the five jurisdictions targeted biomethane (as opposed to energy from biogas); that as the biogas industry in the five jurisdictions matured, government support switched from feed in tariffs to other mechanisms including grants, mandates, certificates, and auctions; that all five jurisdictions targeted agricultural waste with additional incentives; and that feed in tariffs were more expensive than grants.(139)

From this comparative analysis, the report made a number of Victoria-specific recommendations:

- Target Victoria's agricultural waste as a feedstock;
- Implement clear regulations for the use of digestate;
- Consider implementing a biomethane feed in tariff;
- Consider introducing a biomethane certificate linked to a mandated target for biomethane consumption;
- Use grants in conjunction with feed-in tariffs to drive the biomethane sector's growth, with a view towards replacing the feed-in tariff with grants in the longer term; and
- Move towards market-exposed mechanisms in the long term.(139)

Instruments

In December 2024, the Victorian Department of Energy, Environment and Climate Action released a Renewable Gas Directions Paper on a proposed Industrial Renewable Gas Guarantee for public comment.(24) This followed from the earlier Renewable Gas Consultation Paper.(138) The proposed instrument is a market-funded, certificate-based renewable gas mandate with a target of 4.5 PJ of renewable gas by 2035. While this instrument will cover both biomethane and hydrogen, "biomethane projects are expected to be deployed before renewable hydrogen projects until the production cost of renewable hydrogen reduces to meet, or fall below, the production cost of biomethane".(24)

The Gas Substitution Roadmap notes the potential of biomethane several times and projects its growth throughout the next several decades.(137) However, to date there have been relatively few policy instruments or grants supporting its uptake in Victoria, and none which specifically target biogas or biomethane. In 2023, the Victorian Waste to Energy Fund awarded $9.08 million in grants for projects to expand renewable bioenergy generation in Victoria, several of which involve the generation of biogas or biomethane or the improvement of feedstock management.(140) Round 2 of the Energy Innovation Fund involved a distribution of ~$20 million for two bioenergy projects.(141) The Bioenergy Infrastructure Fund Grants provided $737,000 towards four projects on recovering and reprocessing organic waste.(142) The Agriculture Energy Investment Plan provided an undisclosed portion of $60 million towards bioenergy projects.(143) All of these grant schemes have now closed. The ongoing Victorian Energy Upgrades (project-based activities) will provide "up to $5m in Victorian Energy Efficiency Certificate (VEEC) value for businesses to undertake bioenergy upgrades that have a net emissions reduction."(24)

Aside from these funds, which support bioenergy generally, Victorian funding to date has been concentrated on hydrogen. Support measures include $12.3 million toward the Hydrogen Park Murray Valley project, $10 million for a renewable hydrogen highway transport backbone, $6.2 million for renewable hydrogen pilots, trials and demonstrations, $7.2 million for grants handed out by the Renewable Hydrogen Commercialisation Pathways Fund and the Renewable Hydrogen Business Ready Fund, $11.9 million for the Yarra Valley Water electrolyser pilot, $8 million to establish a Renewable Hydrogen Worker Training Centre, and $500,000 for a feasibility study to produce green methanol from renewable hydrogen.(24,136)

Victoria's circular economy policy, "Recycling Victoria: a new economy", involves the standardised separation of waste into four streams, one of which is food organics and garden organics (FOGO), allowing the more efficient conversion of organic waste into biogas.(144)

For new biomethane developments, planning permits must be obtained from Victoria's Environmental Protection Agency.(145) To help navigate complex environmental planning regulations, applicants may contact the EPA early for development pathway advice on which regulations will apply and what is required from the applicant.(146)

In December 2023, Victoria introduced a streamlined regulatory pathway for use of low-risk digestate.(147) Prior to the introduction of these changes, digestate from waste to energy was classified as a reportable priority waste, with the waste code N205: "Residues from industrial waste treatment and disposal operations, including digestate, bottom ash and char".(148) This meant that digestate fell within the same regulatory framework as incinerator ash, and had to follow the same waste management protocols. The new pathway applies to digestates which fall within specified contaminant ranges, which have been either pasteurised or composted, and which do not use any biosolids as feedstocks.(147) Digestates which meet these conditions are no longer classified as "reportable priority waste", meaning that permissions are not required for the supply and transport of digestate. However, it remains classified as "industrial waste" and "priority waste".(148) Nonetheless, this change allows the use of digestate as a fertiliser without requiring permissions, a move towards recognition of digestate as a resource rather than a waste residue.

4.6.8 Western Australia

In 2022-2023, Western Australia had a total energy consumption of 129.6 PJ, with a total gas consumption of 91.3 PJ.(114) In the same period, it produced 1.5 PJ of liquid and gas biofuels.(115) Biogas was used to generate 0.4 PJ of electricity during this period.(116)

Strategies and Targets

Western Australia is currently considering a proposed hydrogen target, but this scheme makes no mention of biogas or biomethane.(149)

Instruments

A 2018 report commissioned by Bioenergy Australia did not identify any state government grants or incentives supporting biomethane and found no evidence of sustainability guidance being in place.(125)

4.7 POLICY BARRIERS IN AUSTRALIA

4.7.1 Cost Gap with Natural Gas

A major barrier to the uptake of biomethane is its higher cost compared to natural gas. Stakeholders were divided on whether companies and users would be willing to pay a premium for renewable gas, but there is broad agreement that cost is a central concern.

It is important to note that the relative cost of a technology (after government supports) is not the only factor influencing a technology or sector's appeal to investors. Investors ultimately pursue profitability, which is not determined solely by cost. Falling costs do not necessarily lead to increasing revenues (as a result of price competition), and therefore in a vertically disintegrated energy market, producers may lack an incentive to switch to cheap power alternatives. Investment decisions in the energy space are also influenced by industry structure, the revenue potential of the energy produced, and the relationship between energy cost and revenue.

Nonetheless, the price gap between natural gas and biomethane emerged as a key factor in the financial viability of biomethane projects. While some companies might be willing to pay a premium for renewable gas, stakeholders were unified in suggesting that some form of government intervention would be required to narrow this cost gap. There are two ways to close the cost gap: the price of biomethane could be lowered through government support, and the price of natural gas could be raised through carbon pricing.

4.7.2 Political will and understanding

Our desktop review and stakeholder interviews indicate that government support for biomethane has been overshadowed by a national and state-level focus on hydrogen and electrification. Examples of this include the exclusion of biomethane from the national Capacity Investment Scheme, exclusion from the NSW Renewable Fuels Scheme, and a notable lack of tailored supports for biomethane and biogas compared to electrification and hydrogen. This creates barriers in the dimensions of financial investment and market structure.

While hydrogen and electrification are important avenues for decarbonisation, their development should not come at the expense of supporting a biomethane industry in Australia, with multiple studies concluding that biomethane is a mature and cost-effective decarbonisation solution compared to hydrogen and electrification.

Stakeholders emphasised that biomethane should be considered as an effective and immediately available option for decarbonisation, with a continuing role to play in the decarbonisation of hard-to-abate sectors. Because of its decarbonisation effectiveness in the short to medium term, it should be viewed as complementary to, rather than competitive with, longer-term solutions of hydrogen and electrification.

Stakeholders also cited barriers stemming from the lack of knowledge and capacity of policymakers to effectively promote the development of a biomethane industry. Our desktop review noted that biomethane was not discussed at all in ostensibly relevant reports, such as the CCA's "Electricity and Energy" sector pathways review, the Queensland Energy and Jobs Plan, and the Northern Territory's 'Roadmap to Renewables' report. Some stakeholders felt that policymakers had inconsistent focuses and goals (safety, technical efficacy, social, environmental), and that this had led to a lack of harmonisation between regulators and departments.

A sub-theme of political will pertained to the question of which government sector should take ownership of policy development. This arises from both the siloed nature of different government portfolios and the cross-sectoral nature of biomethane, which intersects the areas of agriculture, waste management, and energy. As such, some stakeholders stated that due to this atypical supply chain, specific agencies didn't see biomethane as being part of their remit. To overcome these barriers, BIP Europe emphasises the need for "cross-sectoral synchronisation of [policy] measures to optimise the benefits and internalise the positive externalities."

4.7.3 Legitimacy, government framing and regulatory certainty

Many stakeholders noted that investor confidence requires consistent government messaging about ongoing support for biomethane in Australia. The desktop review found inconsistent messaging between different governments, different departments, and different jurisdictions. Some reports and policies declare long-term ambitions for biomethane in Australia, while others such as Victoria envisage the decommissioning of the gas network in favour of widespread electrification. This presents a legitimacy barrier to the broader uptake of biomethane. Stakeholders we interviewed called for a disassociation of fossil gas from renewable gas in government messaging. Government policy frequently refers to "gas" without differentiating between renewable and natural gas, often in the context of promoting an eventual phase-out of gas.

> "…I would say [that] the majority of investors would not touch Victoria in its current state given it doesn't disassociate fossil gas from renewable gas. The consistent messaging around gas is very poor. [A lot of] renewable gas producers – a lot of their projects aren't actually based in Victoria when it probably has one of the biggest potentials." – stakeholder interviewee.

> "In the US people talk about banning natural gas, but they don't talk about banning RNG [biomethane] and it's similar in Europe – biomethane is celebrated, but they like to say 'banning natural gas or reducing natural gas or fossil gas'. They're very, very clear messaging, though, and they separate that within the media." – stakeholder interviewee .

Finally, some stakeholders suggested that clear and consistent messaging around future government support for renewable gas would be useful for promoting investor certainty and spurring investment in biomethane.

> 'There's no actual targets, there's no roadmap to have any goals for renewable gas. Why would you invest?' – stakeholder interviewee.

> 'Stable policy and clear direction that can be defined through, say, renewable gas targets. It's vision as well. So, if you go and talk to investors, what do they want to see with the government? I see roadmaps, I see targets. They see all these things as a derisking of their investment. It's critical." – stakeholder interviewee.

At least two stakeholders we interviewed noted that critics of biomethane argued that developing a market for it would extend the use of gas infrastructure, and by extension, could extend the use of natural gas, advocating instead for complete electrification. However, they counter-argued that biomethane is one of the many renewable gases that will form part of a complete decarbonised gas network, include e-methane and green hydrogen.

4.7.4 Supply and Demand Supports

Many stakeholders expressed that there is a need for government intervention targeting both supply-side (such as capital assistance for establishing biomethane infrastructure) and demand-side (such as allowing manufacturers to claim scope 1 emission reductions from biomethane). These supports are seen as necessary to address barriers in the dimensions of financial investment and market structure.

Pre-commercial support

Concessional loans, such as access to low-interest rates can be highly effective, particularly at the earlier stages of project development. One stakeholder lamented that while finance options are available for commercial ready-to-go projects, the biggest risk and bottleneck is the financing of the pre-commercial phase.

> 'I think some of the projects in ARENA, for example, could have a lower financial threshold to bring in … most technology starts at a smaller scale and grows so [that] people aren't making taking big risks.'

A 2024 report by the Centre for Policy Development (2024) also found that "government funding is generally skewed towards the later stages of industry development which are already comparatively well-financed by private capital markets."(150) It suggests "shifting more funding towards the early stages of industry development, including high-risk high-reward projects that might otherwise struggle to gain private finance, and could one day become major players in the Australian economy."(150)

4.7.5 Gas Network Access

Currently, access to gas networks must be negotiated between biomethane injection plants and owners of pipeline infrastructure. There are no legal requirements to grant access, or for infrastructure owners to negotiate in good faith. As gas must often pass through pipes owned by multiple parties, and each must be negotiated with, this provides many opportunities to "block" potential projects from proceeding.(82) Stakeholders identified this as an issue, citing instances where potential biomethane projects had been abandoned as a result of inability to obtain pipeline permission.

4.7.6 Commercial Use of By-products

The production of biomethane can also generate valuable byproducts, including digestate, biochar, and biogenic CO_2. However, the commercial use of biomethane bioproducts in Australia is impeded by unsupportive regulatory policy.(29) Across most states, there is a lack of clarity and consistency surrounding the use, transport, and sale of byproducts. Victoria and Queensland are currently the only states in Australia to have implemented digestate-specific regulations. In other states, digestate falls within regulations covering waste, compost, or both. Biochar, the product of pyrolysis or thermal gasification, is in the same position, with no specific regulatory pathways in any states or territories. Where there are regulations in place, these are not harmonised between states. In addition, stakeholders raised the issue that these regulations are prohibitively and unnecessarily strict. For example, one stakeholder argued that the limit of PFAS allowed in digestate under Queensland's End of Waste Code was less than that found in the general environment. In addition to these regulatory obstacles, a report by Bioenergy Australia identified a number of other barriers. Legitimacy barriers exist in the form of farmers' perspectives on the safety and efficacy of digestate, while market structure and financial investment barriers are raised by competition from an incumbent mineral fertiliser industry.(29)

4.7.7 Regulation of Anaerobic Digestion

Some stakeholders argued that regulatory requirements for anaerobic digestion were unduly demanding compared to similar technologies. One example provided was the requirement in Victoria that anaerobic digestors to have a secondary odour control system in place, which is not required for composting despite the fact that composting occurs in open air while anaerobic digestion happens within a closed system.

4.7.8 Emissions Accounting

Noting that NGER Scheme emission accounting laws are anticipated to be changed in 2025, a significant barrier up until now has been that there is no way to transfer scope 1 emissions reductions resulting from the purchase of biomethane. This means that a manufacturer or energy producer who switches from natural gas to biomethane is unable to record this as an emissions reduction. The biomethane producer can generate ACCUs for its production and injection, but stakeholders argued that manufacturers generally prefer accounting for scope 1 emissions reductions rather than offsetting. This is because this allows the company to claim actual emissions reductions, rather than offsetting (which is socially controversial, and leaves the company exposed to the price of ACCUs). ACCUs for biomethane production are also limited to certain feedstocks, digestion processes, and accounting methods.(29) The forthcoming NGER Scheme reforms should provide a boost to biomethane viability, as the current low price of ACCUs (due at least in part to the ease for which they are granted) is insufficient to close the price gap between natural gas and biomethane.

4.7.9 Gas Standards

Gas standards regulate the allowable percentage of contaminants in biomethane, including oxygen, nitrogen, and siloxane. There was suggestion by stakeholders that Australian standards for gas injection for certain contaminants are stricter than required, and that this unnecessarily raises the cost of upgrading to biomethane. The Future Fuels CRC conducted research into the possibility of raising the allowed limits of oxygen, with findings indicating that infrastructure and appliances can safely operate with oxygen levels up to 1%, subject to validation of downstream assets.(106) IN 2023, Standards Australia began a consultation on amendments to the AS/NZS 4564:2020 standard for general-purpose natural gas to consider reforms to the standard to enable the safe and reliable introduction of renewable gases while removing barriers (e.g. hydrogen blending and the injection of biomethane) .

5. The United States

5.1 EXECUTIVE SUMMARY

The development of biomethane in the United States has primarily been driven by policies aimed at reducing greenhouse gas emissions from the transport sector, which is the country's largest source of emissions. The secondary driver has been energy security, which has led to policies promoting domestic production of cleaner renewable fuels in order to reduce US reliance on imported oil.(151)

The ability to stack certificates from various schemes for the same quantity of biomethane has led to a surge in investment in biomethane projects, particularly in the dairy sector. The main instruments employed to date have been federal and state-based fuel schemes, namely the Renewable Fuels Scheme (RFS) and California's Low Carbon Fuel Standard (LCFS). These schemes have mandated strong and incrementally increasing quotas of low carbon and renewable fuels that have created compliance-based markets and seen significant growth in demand for biomethane that has spurred high investment in biomethane projects. This is evidenced by a five-fold increase in production over the past decade following their introduction.(152) Though most biomethane is grid injected, transport fuels account for 75% of the final end use of biomethane.(153)

Since the roll out of the *Inflation Reduction Act* in 2022, investment and production tax credits have served as a more recent supply-side incentive mechanism for biomethane suppliers. The importance of these credits is expected to increase as, from 1 January 2025, Clean Fuel Production Credits are available for the production and sale of low emission transport fuels including biomethane, with a value ranging between US$0.20 to $1.00 per gallon (US$1.39 to $6.94 / GJ). The value of credits is equal to the applicable credit amount per gallon multiplied by the fuel's emissions reduction factor, incentivising low-carbon fuels. (154,155)

Looking forward, it is expected that the use of grid-injected biomethane for industrial and heating purposes will overtake its use for transport fuel over the coming years,(156) with several states and utilities companies having set targets for thermal biomethane supply amounting to nearly 70 TWh (252 PJ) between 2030 and 2035.(156)

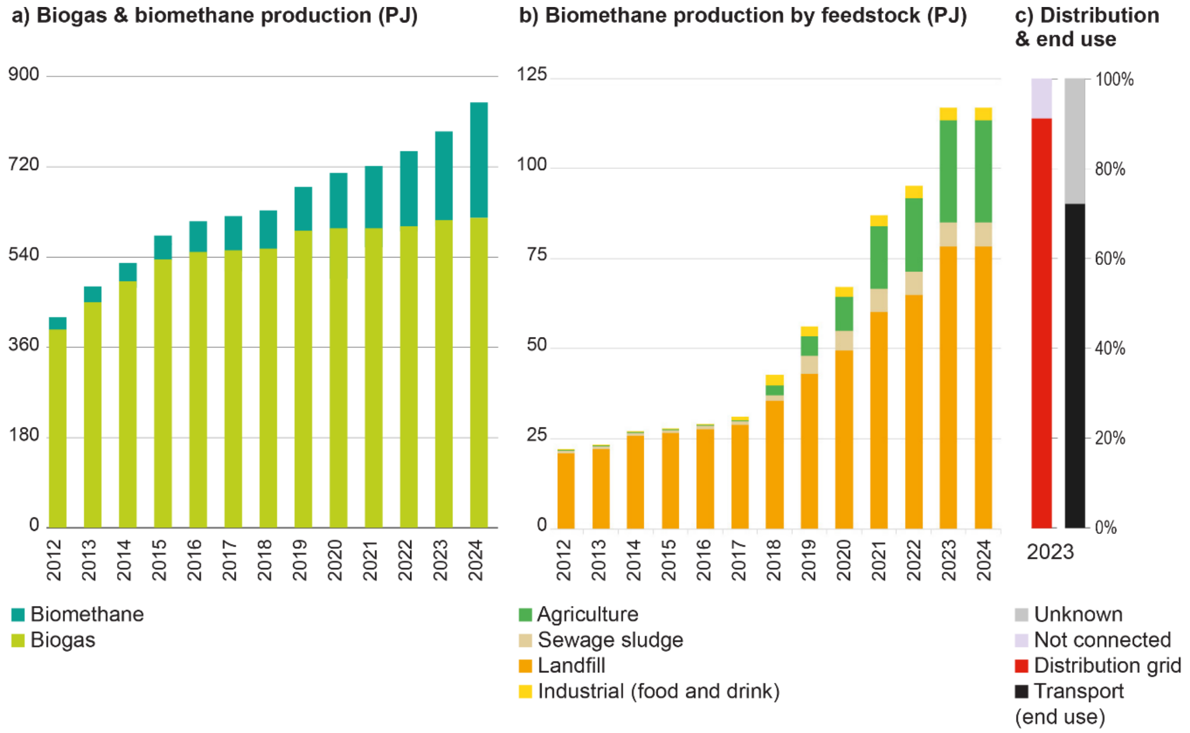

Figure 6. Annual production of biogas and biomethane production, biomethane by feedstock type, and distribution and end use of biomethane in the United States.(71)

5.2 BIOGAS, BIOMETHANE AND ENERGY SNAPSHOT

Over the past decade, the US has seen high growth in biomethane production alongside sustained growth in biogas projects over the past decade (Figure 7). As of October 2024, there were 2,327 biogas systems in operation nationwide, with around 20% (456) of plants producing biomethane and 80% (1,409 plants) generating electricity.(157) According to the Argonne National Laboratory, there were 111 biomethane projects in the planning phase at the end of 2023.(153)

Over the five years from 2024 to 2028, the IEA (2023) forecasts that supply of biogas and biomethane in the US is expected to more than double, based on mandatory targets that have been set and projects in the pipeline.(158) While this represents a robust and growing market, the American Biogas Council (ABC) estimates that there is still feedstock potential for a ten-fold increase in the number of biogas and biomethane projects.(159)

In the transport sector, biomethane has been highly successful in displacing natural gas, accounting for 79% of fuel used in natural gas vehicles across the US in 2023.(160) Almost all biomethane is distributed through grid injection (92%); much of this is dispensed by fossil fuel suppliers to produce transport fuels, while a small portion (8%) is supplied locally for use as transport fuels without being grid injected.(153)

In terms of the overall energy system of the US, however, biogas and biomethane represent a small fraction of energy consumption and production. In 2023, the US consumed 98,743 PJ of energy and produced 108,491 PJ.(161) Natural gas accounted for around a third of this consumption (35,450 PJ) and 38% of production (41,411 PJ), making the United States the world's largest producer of natural gas.(161) Total biogas output (including that upgraded to biomethane) amounted to 697 PJ, equating to almost 2% of gas consumption, while installed biomethane capacity was estimated at 114.4 PJ, (around 18% of biogas output),(162) equating to a per capita biomethane production potential of 0.34 GJ. Based on biomass feedstock available, studies have estimated that biomethane could displace around 10–16% of the US' natural gas consumption.(163,164)

In recent years, there has been a significant shift away from biogas in favour of biomethane, with 91% of the 96 new projects commissioned in 2023 producing biomethane, representing nearly US$1.5 billion of biomethane investment compared to around $100 million for biogas projects.(159) This reflects a trend that has seen the proportion of biogas facilities upgrading to biomethane rise from around 5% in 2017 to 20% in 2023, likely owing to a steep increase in investment amounting to $1.8 billion in 2023.(159)

There has also been a notable change in the types of biomethane projects from 2017 to 2024, from a majority of landfill projects to a majority of agricultural projects. (Figure 7). In 2023, biogases from agricultural sources grew by experienced the largest growth (13.4%), compared to 4-5% growth for landfill gas.(159) This is attributed to the higher price available for agricultural biomethane because of its extremely low carbon intensity values compared to landfill or wastewater, resulting in a higher 'green value' of certificates. To improve economies of scale, most of the new on-farm facilities are operated as 'cluster projects', where feedstocks are supplied from a co-op of local farms to at least one shared biogas and biomethane upgrading facility.(159)

Table 6. Total biogas facilities at 2024 and estimated biomethane facilities and production capacity based on those operational and under construction as at 31 December 2023, by project type.(153,157)

Project type / feedstock	Total biogas & biomethane facilities at 2024*		Biomethane facilities at 2024*		Installed biomethane capacity at 2024*	
	No. projects	% total	No. projects	% total	PJ / year	% total
On-farm	526	23%	247	57%	39.6	26%
Landfill	579	25%	126	29%	99.4	65%
WWT	1112	48%	34	8%	5.2	3%
Food waste	110	5%	23	5%	7.7	5%
Total (2024)*	**2,327**	**100%**	**430**	**100%**	**152**	**100%**

*Total biogas and biomethane facilities are based off American Biogas Association (Serfass, 2024) report. Biomethane facilities and installed capacity are based on projects operational and under construction as at 31 December 2023.(153)

5.2.1 Gas market structure

Domestic gas markets in the United States are characterised by a complex network of nearly three million miles (4.83 million km) of pipeline that connects domestic gas production sites and storage facilities with end users. Domestic gas markets are predominantly structured at the state level, with additional oversight from the Federal Energy Regulatory Commission, which reviews proposals to build interstate gas pipelines and LNG terminals, reviews electricity mergers and acquisitions, and regulates the interstate transmission and sale of electricity and gas, among other functions.(165) Key actors in the United States gas market include producers, transmission pipeline operators, local distribution companies, and gas marketers/retailers. Customers can purchase natural gas directly from local distribution companies, or from gas marketers/retailers.(166) While gas prices haven't been directly regulated since 1993, they continue to be influenced by government policy and taxation. Typically, gas marketers negotiate to purchase gas from different suppliers to sell on to customers, arranging delivery through the customer's gas utility with associated charges paid to the utility.(167) While state utility and public service commissions do not allow local distribution companies to earn a profit on the delivered natural gas, gas marketers remain unregulated and are not subject to such restrictions.(168)

5.3 POLICY SETTINGS

5.3.1 Strategies and Targets

After re-joining the Paris Climate Agreement in 2021, the federal government set a more ambitious national target to reduce greenhouse gas emissions by 50–52% of 2005 levels by 2030.(169) In the same year at COP26, the US and the European Commission also launched the Global Methane Pledge, which aims to reduce global methane emissions by 30% of 2020 levels by 2030. The Methane Emissions Reduction Action Plan 2021 is the US's response to the Global Methane Pledge; it includes a number of relevant actions to encourage biomethane development. These include boosting the capture of methane emissions from landfill to an average rate of 70% nationally, providing technical support for landfills to collect and sell renewable gas, expanding on-farm biogas generation, requiring pipeline operators to cut methane leaks and excursions, and requiring oil and gas operators to pay royalties for the venting or flaring of gas on public lands and waters.(170) In January 2025, the United States withdrew from the Paris Agreement. At the time of writing, it is unclear what effects this may have on the biomethane industry.(169)

5.3.2 Market-based Instruments and Financial Incentives

A range of market-based schemes and financial incentives have been implemented across the US to encourage biogas and biomethane production and use. With the notable exception of the Renewable Fuel Scheme, most instruments have mostly been enacted at the state level in multiple states.(171)

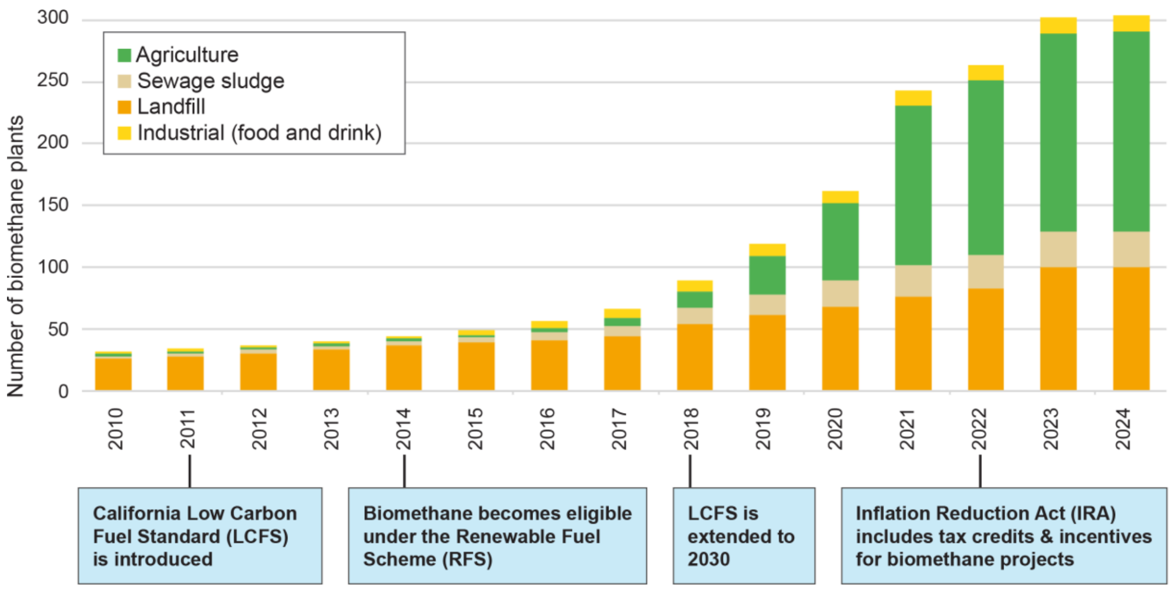

Figure 7. Development in the number of biomethane projects by facility type in the US following key policy milestones.

Biogas development under state-based electricity schemes

Biogas has been in the US since the 1970s and '80s. Many systems were installed at large municipal solid landfill sites due to regulations under the *Clean Air Act* that required landfills to include a gas collection and control system for safety and to reduce emissions and odours. Much of the biogas was initially flared to reduce methane to CO_2 or used onsite for co-generation of heat and electricity.

From the early 1980s, biogas began to be used to produce electricity following the introduction of state-based Renewable Portfolio Standards and Clean Energy Standards, which aimed to increase the share of electricity generation from renewable and low carbon sources respectively. Schemes vary by state, and many qualify biogas and/or biomethane as renewable or low carbon sources.(172,173) These market-based compliance schemes mandate electricity providers to supply a minimum percentage of power from a combination of renewable or low carbon sources by a certain date.(174,175) Typically, both schemes involve the issuance of renewable electricity certificates for each megawatt-hour (MWh) of electricity generated and delivered to the electricity grid from a renewable energy resource.

Because biogas can be used to produce electricity without upgrading, electricity schemes typically incentivised biogas rather than the production of biomethane.

Biomethane upgrading for transport fuel schemes.

Biomethane upgraded from biogas really started to take off following the introduction of California's Low Carbon Fuel Scheme (LCFS) in 2011 and in 2014 when biomethane became eligible as a fuel under the Renewable Fuel Scheme (RFS).

Strong mandatory targets for low carbon or renewable fuels set by both the federal government's RFS and California's LCFS have created vibrant compliance markets for biomethane fuel credits, rendering many biomethane projects 'highly lucrative' according to stakeholders (stakeholder comm.).(187) As a result, almost all biomethane produced in the United States is utilised for transport (~87% in 2019).(188) Under both programs, biomethane is predominately injected into the gas grid and subsequently dispensed to produce compressed natural gas (CNG) for vehicles (stakeholder comm.). Importantly, credits can be generated under both schemes and 'stacked' for the same amount of biomethane, providing that grid-injected biomethane is sold to a company that supplies transport fuels via a dispensing facility or to a vehicle fleet in California.(154,189)

The fundamental difference between the federal RFS and California's LCFS are that RFS quotas are based on the volume of renewable fuels supplied as a percentage of total fuel, while the LCFS mandates a reduction in the carbon intensity of fuels, as a percentage of GHGs released per volume of fuel. Thus one LCFS credit is equivalent to one metric tonne of avoided CO_2 equivalent emissions as compared to baseline fuel (gasoline or diesel) (156), while one Renewable Identification Number (RIN) certificate issued under the RFS is issued for each ethanol-equivalent gallon of renewable fuel.

Biomethane development under the Renewable Fuels Scheme (RFS)

Under the RFS scheme, national volumetric targets for renewable fuels are set annually as a percentage of projected of gasoline and diesel production. Initially authorized under the *Energy Policy Act 2005*, legislated targets for the total volume of renewable fuels supplied through the RFS were expanded under the *Energy Independence and Security Act 2007,* increasing from 4.7 billion US gallons mandated in 2007 to 36 billion gallons by 2022. This long-term and escalating target guaranteed a market for biofuels, and provided increased certainty to investors.(172) Since 2020, annual volume targets of renewable fuels have been set by the Environmental Protection Agency (EPA) determined by a variety of statutory factors, including costs, air quality, climate change, implementation of the program to date, energy security, infrastructure issues, commodity prices, water quality, and supply.

The RFS operates through the creation of Renewable Identification Numbers (RINs) certificates. Producers of renewable fuels are issued one RIN certificate to each ethanol-equivalent gallon of renewable fuel.(176) There are four categories of renewable fuels: cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel. Percentage and volumetric requirements for each category of renewable fuel are set separately (**Table 7**). Fuels that meet more stringent criteria (such as cellulosic biofuels) can also qualify for advanced biofuels and renewable biofuels. Cellulosic biofuels are the most difficult to produce, and correspondingly the most valuable RIN certificates under the RFS.(172) Biomethane qualifies as a renewable fuel and an advanced biofuel and may also qualify as cellulosic biofuel depending on the feedstock and process utilised.(178) Biomethane produced agricultural biodigesters can be classified as eligible to generate either "D5 RINs" (covering advanced biofuels) or "D3 RINs" (a subset covering cellulosic biofuels). (179, 180, 181).

Obligated parties (suppliers of fossil fuels, including refiners, importers, blenders and exporters) use the percentage standards to calculate their individual required volume obligations (RVOs) and must demonstrate compliance annually to the EPA. They can meet their obligations by supplying the required volumes of renewable fuel in their fuel supply or by purchasing RINs from renewable fuel producers or other businesses that exceed their requirements through a book and claim system.(176) Many of these obligated parties are the so-called 'super-majors' of the fossil fuel industry, such as Exxon Mobil, Chevron, and Shell.(176) Compliance standards for certification and tracking of RINs are set and monitored by the Environmental Protection Agency (EPA), while a third party assessor is required for auditing. Compliance auditing was boosted after cases of fraudulent RINs, although one report noted that, "compliance with the biofuel volume requirements continues to be low and lacking in enforcement."(172)

Table 7. Biofuel volume targets (billion RINs)a under the final Renewable Fuels Standards Rule for 2023, 2024, and 2025.(177) The cellulosic biofuel category primarily applies to biomethane.

Renewable fuel type	2023		2024		2025	
	Vol [a]	%	Vol [a]	%	Vol [a]	%
Cellulosic biofuel (D3)^	**0.84**	**0.48**	**1.09**	**0.63**	**1.38**	**0.81**
Biomass-based diesel b	2.82	2.58	3.04	2.82	3.35	3.15
Advanced biofuel (D5)^	**5.94**	**3.39**	**6.54**	**3.79**	**7.33**	**4.31**
Renewable fuel	20.94	11.96	21.54	12.5	22.33	13.13
Supplemental standard	0.25	0.14	n/a	n/a	n/a	n/a

[a] *Volume is based on billions of gallons of ethanol equivalent. Table I.A.2-1-Percentage Standards. ^Biomethane qualifies as a cellulosic or advanced biofuel depending on how it is produced.*

In 2023, the EPA's renewable fuel volume targets were updated, aiming to double biomethane supplies from 2023 levels by 2026.(158) However, in many prior years, statutory quotas for cellulosic biofuels have not been met, and the EPA has the ability to reduce the volume of cellulosic biofuel during a given calendar year, by issuing cellulosic waiver credits which may be purchased by obligated parties. It has used this cellulosic waiver authority frequently, exercising it in 2020, 2021, and 2022.(180)

The additional cost of biomethane and other renewable fuels under the scheme is paid by the obligated fuel suppliers who must comply under these programs. Producers of biomethane generate RINs through the EPA and negotiate to sell their RIN certificates with the obligated suppliers. Ultimately, the cost is passed onto fuel consumers (stakeholder comm.), with the market determining the price of RIN certificates. One stakeholder commented that although the price of biomethane can be 'highly volatile' it has also often proved to be 'very lucrative'. Here, they noted that the while price of natural gas was around US$2 per dekatherm and the production cost of biomethane is around $8-12 per dekatherm, RINs for biomethane could receive prices between $50 to $70 a dekatherm for biomethane fuels produced from dairy projects. This stakeholder further noted that diary-based biomethane projects were attracting many project developers who were consolidating as well as large financial institutions such as Blackrock and Citibank who were starting to finance projects.

California's Low Carbon Fuel Standard (LCFS)

At the state level, **California's Low Carbon Fuel Standard (LCFS)** has been the other key market mechanism for biomethane, not only within California but across other US states and Canada.(172) As long as biomethane is injected into the North American natural gas pipeline system, it can nominally be "sold" in California as a low carbon fuel through a book and claim accounting system.(182) As a result, more than 80% of LCFS credits granted for biomethane are generated outside of California.(156)

The goals of the federal RFS and California's LCFS differ significantly in how they incentivise renewable fuels. While the RFS categorises renewable fuels into a limited number of groups, incentivising each category at a set level, the LCFS incentivises renewable fuels in direct proportion to their reduction in carbon intensity. This means that under the LCFS the specific conditions of fuel's production can be taken into consideration, including the process and feedstocks used in its production.(190) This allows each fuel's emissions abatement potential to be more appropriately incentivised. However, it also places additional reporting obligations on fuel producers and importers, and has led to instances of misreporting and fraud (191–193). Unlike the federal RFS, the California LCFS only allows market participation from regulated parties, meaning that non-regulated parties cannot speculate on the price of LCFS credits.(194)

One stakeholder noted that the LCFS has been 'extremely successful' because it is a 'technology-neutral, performance-based program', meaning that it does not prescribe what technologies can and can't be used but rather assigns a value based on a fuel's carbon footprint. Nonetheless, the design of the LCFS's accounting methodology can favour certain fuels over others.(190,194) Stakeholders and commentators have noted that the substantial credits received by dairy-based biomethane under the LCFCs are granted because methane emissions from agriculture in California are unregulated, unlike other those from landfills. This regulatory gap allows dairy manure, which would otherwise emit methane, to claim significant carbon intensity reductions when anaerobically digested.(195) However, while regulated reductions in emissions cannot be counted in the CI values, because they would have occurred anyway, unregulated values can be, resulting highly negative CI values for dairy-based biomethane.

According to a recent report by CI Consulting and S&P, the LCFS has been a significant contributing factor for the growth of the United States' biomethane production capacity. It notes that "more than 200 new landfill and manure biomethane facilities have come into operation or are under construction since 2015 across the US. The recent increase in LCFS credit price has sent a strong market signal to biomethane producers, driving an increase in biomethane production in recent years".(156) This market may be close to saturation, however, with biomethane accounting for 97% of natural gas use as transport fuel in California in 2023.(186)

In November 2024, the California Air Resources Board (CARB) approved major amendments to the LCFS that are expected to influence further investment in biomethane projects.(196) Among other changes, fuel producers will be required to track feedstocks to their point of origin through independent feedstock certification, with the aim of increasing the stringency of the scheme's carbon reductions. The amendments will also place new "deliverability" requirements for the book-and-claim system. Currently, biomethane injected into the North American natural gas grid can receive LCFS credits regardless of its final destination; under the new rules, credits will only be awarded if the biomethane is transported via pipelines that either flow within California or are destined for end use in California, with at least 50% of the pipeline flow directed toward the state.(182) Although the precise measurement criteria is not yet clear, it is likely that this would preclude many producers from participation in the scheme.(194) CARB anticipates these deliverability requirements to be implemented "as soon as 2037".(196)

Additional amendments stipulate that, from 2030, hydrogen used as a vehicle fuel must be 80% renewable to qualify for LCFS credits. From 2035, any natural gas use will preclude hydrogen from LCFS credits unless biomethane is used instead (that is, matched via book and claim accounting).(197) Furthermore, LCFS crediting for avoided methane emissions is scheduled to be phased out after 2040, which means that biomethane would produce a deficit instead of a credit under the LCFS.(182) The specific period for which avoided methane crediting will be guaranteed will depend on the project's start date.(196) This has been described as "an attempt to phaseout its usage as a transportation fuel by 2040 in favor of other transportation fuels such as renewable hydrogen."(182)

Similar schemes have also been implemented in other states. For example, Oregon implemented the **Oregon Clean Fuels Program** in 2016,(198) and Washington State introduced a **Clean Fuel Standard** in 2023.(199) While these schemes closely mirror the LCFS model, Washington's Clean Fuel Standard requires the reporting party to retire either Renewable Thermal Certificates or Renewable Energy Certificates, meaning that no other environmental attributes can be separately monetised.(194)

Certification and tracking

Both the federal Renewable Fuel Standard (RFS) and the state Low Carbon Fuel Standards (LCFS) rely on certification models to ensure that retailers meet their renewable or low carbon fuel targets. Renewable Identification Numbers, under the RFS model, are issued by renewable fuel producers, with obligated parties expected to conduct due diligence on the validity of any RINs they purchase. This 'buyer beware' approach has raised some concerns as to the reliability of the RINs, and thus to the actual effectiveness of the scheme at reducing emissions.(156) To address these issues, "independent third-parties may audit and verify that RINs have been properly generated and are valid for compliance purposes."(200) These EPA-approved quality assurance plans verify that RINs have been correctly generates and remain valid for compliance purposes, providing obligated parties with a degree of legal protection should and RINs later be deemed invalid.(201)

Renewable Thermal Credits (RTCs) offer another policy mechanism for tracing green value. RTCs provide "a distinctive representation of the environmental attributes entwined with the generation and utilization of one dekatherm (Dth) of renewable thermal energy", further enhancing the tracking of green value within the system.(202)

In addition to being a key economic incentive for biomethane development in the US, the issuance and tracking of certificates provides the government of a synoptic record of progress towards climate targets.(172)

Renewable gas procurement targets will drive grid-injected biomethane for the residential and commercial sector

Several states are now pursuing renewable gas procurement targets in an effort to displace natural gas in their gas networks. One example is the Californian Senate Bill 1440 which establishes a mandatory biomethane procurement target for gas utilities. Since February 2022, Californian gas utilities have been required to supply an increasing percentage of biomethane to gas network customers, with a 2025 target of 17.6 billion cubic feet of biomethane (~19 PJ) increasing to a 2030 target of 72.8 billion cubic feet (~77 PJ). These targets represent around 12% of 2020 residential and small business gas usage.(203) It is important to note that dairy manure cannot serve as a feedstock for meeting these targets until a utility has fulfilled its portion of an 8-million-tonne waste feedstock requirement.(203) Similar to the Canadian case study, the costs of biomethane will be recovered from the utilities' rate base of customers. Interestingly, Californian gas utilities companies have played a pivotal role in driving this policy initiative.(204)

In Oregon, Senate Bill 98 (2019) requires that the Public Utility Commission develop biomethane procurement programs for both large and small natural gas utilities. Under this legislation, the state has set a series of progressively increasing targets: 10% renewable natural gas by 2025, 15% by 2030, 20% by 2035, 25% by 2040, and 30% by 2045.(205)

Carbon pricing

The United States does not have a federal price on carbon. Instead, the multi-state Regional Greenhouse Gas Initiative (RGGI), a cooperative effort between the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont, has been operating a cap-and-trade system regulating the power sector since 2009. The Initiative sets a regional cap for emissions within the participating states and issues a corresponding number of tradable CO_2 allowances (each authorising 907.185 kg of CO_2 emissions) to power plants. The majority of allowances are distributed via quarterly auctions. Academic analyses have found that the RGGI was effective in reducing greenhouse gas emissions overall, even though it may have also incentivised power plants to move to nearby unregulated states.(206)

At the state level, both California and Washington have implemented their own cap and trade carbon pricing systems.(207) Oregon is currently in the process of reinstating its cap-and-trade program after it was invalidated by the Oregon Court of Appeals for non-compliance with disclosure obligations.(208) However, other U.S. states have yet to adopt any form of carbon pricing. While these cap-and-trade systems currently only apply to power plants, and as such do not directly influence or interact with the production of biomethane, they can indirectly influence the market by raising the cost of competing energy sources. Notably, they do not increase the cost of producing and distributing natural gas, the closest substitutable product for biomethane.

Tax credits under the Inflation Reduction Act as supply side incentives

The **United States Inflation Reduction Act (IRA) of 2022** has further enhanced biomethane project viability by establishing both **Investment Tax Credits** for investment in (among other things) biogas and biomethane projects, and **Production Tax Credits** for facilities producing renewable energy from biogas and biomethane.(172) Notably, these tax credits are only available for biogas projects whose construction began before 2025.(172) Tax credits directly lower the tax liability of a business, effectively functioning as a subsidy. Investment tax credits of up to 50% are available for biogas and biomethane projects,(209) and tax-exempt entities are eligible to receive cash payments instead of a tax credit.(210)

Investment Tax Credits, also known as Section 48 Energy Credits, were tax credits granted in proportion to investments in various "energy property" types. Section 48 Investment Tax Credits were available for "qualified biogas property", which included systems for converting biomass into gas of at least 52% methane by volume, as well as "any property which is part of such system which cleans or conditions such gas".(211) As a result, Section 48 Investment Tax Credits were available for biomethane as well as biogas. Energy credits were set at 6% for qualified biogas property.(211) By contrast, **Production Tax Credits** (Section 45) are paid per kilowatt-hour of energy generated. From 2022, production tax credits of up to 1.5 cents/kWh (US$4.17/GJ) were available.(212) To receive the full amount, additional labour-related requirements must have been met, including that workers were paid at prevailing rates or above, and that a certain percentage of the labour hours were performed by qualified apprentices (10-15%, depending on the date on which construction began) (213). As a financial incentive paid per unit of energy produced, these credits are similar to a feed-in tariff or feed-in premium, but are delivered as a tax break rather than a direct payment. Credits were available for 10 years after the equipment came into service.(212)

From 2025, these credits have been replaced by technology-neutral **45Y clean energy production credits** and **48E clean electricity investment credits**. These will run until at least 2032, and are limited to electricity generation.(214) As a result, only projects which use biogas for electricity generation will be eligible, while those that generate biomethane for use in transportation or non-electricity use will be precluded.(215) A number of other tax incentives cover or are anticipated to cover biogas and biomethane, including $0.50 alternative fuel tax credits, Section 45Q carbon oxide sequestration credits, and clean hydrogen tax credits (which allow biomethane as a qualifying feedstock for hydrogen production).(154)

State-level tax credits and incentives have also been implemented. Washington provides tax incentives for anaerobic digesters, and exempts biomethane from public utility taxes when it is used as a transportation fuel.(180) Colorado has implemented a sales tax exemption for anaerobic digesters.(180)

Grants and funding

In addition to tax credits, the Inflation Reduction Act allocated roughly $20 billion to the federal Natural Resource Conservation Service, which has historically provided assistance for the installation of livestock anaerobic digestors.(180) This substantial funding is channelled through programs such as the **Environmental Quality Incentives Program** (EQIP), **Conservation Innovation Grant** (CIG), the **Conservation Stewardship Program** (CSP), and **Regional Conservation Partnership Program** (RCPP).(180) However, Donald Trump has pledged to "terminate the Green New Deal", and to rescind all unspent funds under the Inflation Reduction Act,(216) so the future of this funding remains uncertain.

Korkut et al. identify a number of other possible USDA programs that provide loans or grants for installing anaerobic digesters: "the Business and Industry (B&I) Loan Guarantee program; Rural Development Value-Added Producer Grant Program; USDA's Advanced Biofuel Payment Program; Biorefinery, Renewable Chemical, and Biobased Product Manufacturing Assistance Program (Section 9003); and the Farm Service Agency (FSA) Conservation Loan (CL) Program."(180)

The Rural Energy for America Program, under the Agricultural Improvement Act of 2018's Title IX, includes a suite of bioenergy programs designed to incentivise the use of agriculture-based feedstock for the production of renewable energy.(217) These initiatives include: **Biobanks Markets** (a certification mark program for biobased products); the **Bioenergy Program for Advanced Biofuels** (funding the production of advanced biofuels); **Biomass Research and Development** (competitive funding for R&D relating to biofuel and biobased products); the **Biomass Crop Assistance Program** (financial assistance to agricultural and forest landowners to establish, produce, and deliver biomass feedstock); and various other funding and loan assistance programs.

At the state level, targeted efforts such as California's Dairy Digester Research & Development Program have provided substantial funding for constructing biogas and biomethane facilities in the state's dairy sector.(154)

5.3.3 Other Regulations

Feedstock supply

Like many other jurisdictions, securing a consistent, stable supply of feedstock is one of the key challenges for the biomethane industry in the United States.(209) Regulations governing land use, water use, and waste management can influence both the availability and the costs associated with processing, storing, and transporting feedstock.(209)

There are various state-level initiatives intended to increase organics recycling and drive feedstock supply. California's SB 1383 requires jurisdictions to introduce separate organics collection programs in an effort to cut down on landfill emissions,(218) which could create a new stream of feedstock for anaerobic digestion. California State AB 1826 requires commercial businesses and multi-family dwellings with landscaping services to recycle their organic waste if they generate more than 8 cubic yards of organic waste per week, with this limit set to reduce over time.(219) New York State requires businesses and institutions that generate an annual average of at least two tons of wasted food per week must donate excess edible food, and recycle all remaining food scraps if they are within 25 miles of an organics recycler (which includes AD facilities).(220) New Jersey requires regulated large-scale generators of organic waste to recycle this if they are within 25 miles of an authorised recycling facility.(221) Massachusetts bans the landfill disposal of Commercial Organic Material, which is "food material and vegetative material from any entity that generates more than one ton of those materials for solid waste disposal per week", but excluding material from a residence.(222) Vermont bans the landfill disposal of certain organic materials including food waste, clean wood waste, and leaf and yard debris, and mandates 'parallel collection' (requiring that trash collection sites also collect organic materials).(223) In Rhode Island, entities which generate more than 104 tons of organic waste per year must recycle that organic waste (including via AD) if there is a recycling centre within 15 miles. Connecticut requires producers of more than 26 tons of organic waste to recycle this if there is a facility within 20 miles.(219)

Gas Specification

In the US, as in Canada, the federal government does not set quality specifications for renewable gases. Rather, quality specifications for biomethane and other gases are set by individual utilities, often on a project-by-project basis. This decentralised approach can lead to increased project costs, as developers must navigate and comply with a patchwork of strict and differing regulations.(224) Such variability is widely recognised as a barrier to the widespread grid injection of renewable gases.(188) Subsequently, industry groups and associations are working to standardise renewable gas quality specifications.(224) For instance, the American Biogas Association has developed a renewable gas purity recommendation for pipeline injection, aiming to assist utilities, producers, and commissioners in adopting a more uniform gas quality specification across the country (**Table 8**).

Grid Injection

The question of who pays and how for biomethane to gas grid connection costs varies between states and utilities companies. For example, in Oregon, NW Natural charges all connection costs to the biomethane producer upfront,(226) and similarly in Vermont, Vermont Gas Systems requires connection costs to be paid by the producer either up-front or over time.(227) Meanwhile, California has adopted a biomethane interconnector monetary incentive program, which covers 50% of biomethane interconnection costs, up to a total of $3 million. This incentive, funded by California utility customers and administered by the Southern California Gas Company, helps lower barriers for producers seeking to inject into the grid.(172)

Digestate use

Digestate use in the United States is regulated at local, state, and federal levels.(228) In general, digestate from farm-based anaerobic digestors is much less regulated than industrial or waste treatment plants.(229) However, most states do require a nutrient and soil management plan to ensure that land application is appropriately carried out.(229) To facilitate regulatory approval and improve communication with users and regulators, the American Biogas Council has established the Digestate Standard Testing and Certification Program. The industry-led program exists to measure and certify the physical and chemical qualities of digestate, providing producers with a reliable standard for demonstrating quality and safety.(230)

Table 8. Renewable gas purity recommendation by the US peak industry body, American Biogas Association.(225) Commercially free is defined as equal or less than the levels present in conventional natural gas

Physical Property	Units	Lower Limit	Upper Limit
Heating Value	BTU/ft3	960	1100
Carbon Dioxide	mol %		2
Oxygen	mol %		0.4
Total Inerts	mol %		5
Hydrogen Sulfide	gr./100 ft3		1/4
Total Sulfur	gr./100 ft3		1
Water	lbs/mmSft3		7
Siloxanes	ppm(v)		1
Hydrocarbon Dew Point	Fahrenheit		-40
Temperature	Fahrenheit	50	120
Dust, Particulate			commercially free
Biologicals			commercially free
Heavy Metals			commercially free

6. Canada

6.1 EXECUTIVE SUMMARY

Like the US, Canada has focussed heavily on demand-side incentive mechanisms to develop a biomethane market. In particular, the industry has largely been driven by renewable gas mandates on gas utilities introduced in Quebec and BC. Additionally, a two-part carbon pricing system on fossil fuels and industrial emissions outputs,(250) as well as draft regulations for an emissions cap-and-trade system on Canada's oil and gas producers by 2030and a phasing out of inefficient fossil fuel subsidies are helping to reduce the cost differential and encourage investment in cleaner production processes such as biomethane (251, 252).

Canada's biomethane industry has been driven primarily by provincial gas utilities such as FortisBC in British Columbia and Energir in Quebec. These utilities are both network operator and retailer and have a monopoly within the state. Gas utilities have been proactive in decarbonising their gas networks by introducing voluntary renewable gas programs for customers and by working with provincial governments to introduce mandated gas targets. Unlike jurisdictions that have relied primarily on supply-side financial incentives paid for by governments, Canada's key policy drivers have focused on creating demand through regulatory mandates on gas utilities to supply incrementally increasing targets of renewable gas into their network, as well as a national two-tiered carbon pricing system on fuels and companies since 2019. These regulatory measures, supported by policies and financial incentives designed to reduce and revalorise waste, have created a robust market and spurred both the development of Canada's biomethane industry and the adoption of Renewable Natural Gas (RNG) programs by public utilities.

6.2 BIOGAS, BIOMETHANE AND ENERGY SNAPSHOT

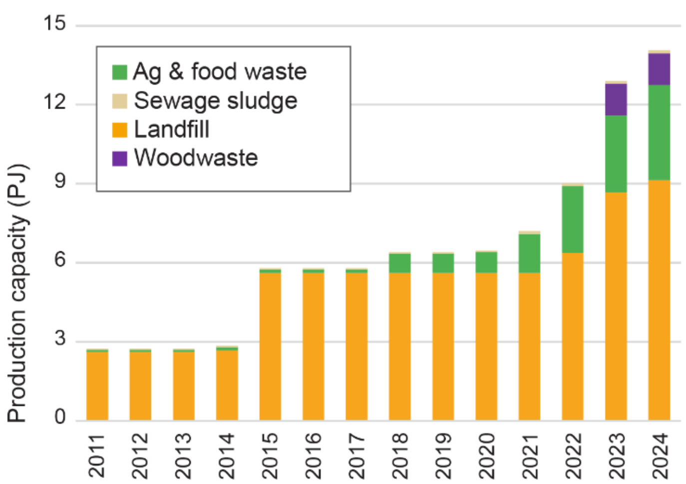

Figure 8. Development of biomethane installed production capacity.

Canada has 300 operating biogas plants, producing around 22PJ of energy (402). Around 10% of these are biomethane facilities (32) producing 14 PJ,(231) an increase of 55% over the 9 PJ produced in 2022 (**Table 9.** Provincial estimates of number of operational biomethane facilities (and total inc. planned or under construction in brackets), and biomethane production in 2023 relative to natural gas use, and comparison.).(231) More than half of this biomethane is produced in Quebec, where biomethane supplies are equivalent to 3.5% of the province's natural gas use. Nationally, biomethane accounts for 0.32% of total natural gas demand (4,422 PJ). Over half of Canada's biomethane is derived from agricultural feedstocks (18), while roughly one third comes from landfills (11) (**Figure 8**). Nearly all biomethane production facilities are owned by the major gas utilities, including Enbridge Gas Inc. (Ontario), Energir and Local Gas Network (Quebec), FortisBC (British Columbia), and ATCO (Alberta).(75)

Canada is a major consumer and producer of both natural gas and oil. In 2023 it was the world's fifth-largest producer of natural gas, accounting for around 4% of the global supply.(232) Approximately 98% of natural gas comes from the provinces of Alberta and British Columbia. In 2020, natural gas accounted for 38% of total end-use demand, followed by petroleum products (37%), electricity (18%) and biofuels (6%). Around 82% of Canada's electricity is generated from renewable sources, primarily from hydroelectricity (60%). Across Canada's broader energy landscape, 2023 saw the production of 23,759 PJ of energy, with a total energy supply of 12,549 PJ. Total energy consumption stood at 8,274 PJ in 2022. In terms of natural gas, Canada's total production in 2023 was 7,346 PJ, with a natural gas supply of 5,078 PJ compared to 2,195 PJ consumed in 2022.

The price difference between biomethane, natural gas, and electricity varies significantly between the provinces, owing to differences in provincial energy mixes. For instance, in Ontario, biomethane is $25.00/GJ ($0.09/kWh), making it cheaper than electricity ($35.56/GJ, $0.128/kWh) but more than double the price of natural gas ($11.11/GJ, $0.04/kWh). In Quebec, biomethane is a similar price to Ontario at $22.65/GJ ($0.08/kWh). This makes it slightly dearer than Quebec's electricity ($19.44/GJ, $0.07/kW), which is the cheapest in Canada owing to Quebec's significant generation of hydroelectricity. However, it is eight-fold the price of natural gas in Quebec, which is extremely low at $2.77/GJ ($0.01/kWh).(233) In Alberta, where most natural gas is produced, natural gas is less than one cent per kilowatt hour ($1.94/GJ, $0.007/kWh), making it more than 20 times cheaper than electricity at (~41.5GJ, $0.15/kWh). In BC, natural gas prices in many parts of the province are the highest in Canada despite its own production in the north-east, at $6.53/GJ ($0.02/kWh) in 2024.

Studies vary in how much biomethane could be produced in Canada based on feedstock available. A 2010 study estimated biomethane production potential at 1,441 PJ per year – about a third of Canada's gas demand.(234). However, a 2020 study commissioned by Natural Resources Canada estimated about half the amount, giving a theoretical potential of 809 PJ (16.5% of gas demand), with a realisable potential estimated at 155 PJ (3.3% gas demand) when competing feedstock demands, logistics, and economic viability were factored. The feedstocks mapped included livestock manure, biosolids (sewage), wastewater, urban organics, corn silage, crop residues, pulp mill sludge, landfills, and unallocated forest resources. Crop residues and landfill gas had the most potential for biomethane production. The study found that biomethane supply potential and demand varies widely between the provinces. The mountainous provinces of Alberta and British Columbia likely becoming large importers of biomethane if volumetric targets of 5% were required in each province while Ontario and Quebec have the highest biomethane production potential, though estimates were dependent upon corn and grain silage, which might run into issues around food competition and sustainability.(235)

Table 9. Provincial estimates of number of operational biomethane facilities (and total inc. planned or under construction in brackets), and biomethane production in 2023 relative to natural gas use, and comparison.

Province	No. facilities	Production (PJ / yr)	Natural gas use (PJ / yr)	% RNG of gas supply	Price of biomethane	Price of natural gas	Price of electricity ($/kWH) (236)
Alberta (AB)	3 (10)	1.04	2,566	0.04%	No data	$1.94/GJ $0.007	$0.258
British Columbia (BC)	11 (15)	2.18	223	0.3%	$0.0721 (237)	$0.0472	$0.114
Ontario (ON)	8 (34)	3.06	1,041	1.0%	0.09	$0.128	$0.141
Quebec (QB)	13 (28)	7.79	219	3.5%	$22.65 (GJ)(233)	$2.52 (GJ)	$0.078
All others (2)		-	372	-	-	-	$0.102-0.41
Canada	**32**	**14.07**	**4,422**	**0.32%**			**$0.192**

6.2.1 Gas Market Structure

Gas markets in Canada are regulated at both the federal and the provincial level. Natural gas imports and exports from Canada are regulated by the Canadian Energy Regulator (CER), with exports only permitted once domestic gas needs have been met.(232) Pipelines are primarily regulated at the provincial level, with the CER regulating less than 10% of Canada's pipelines by length.(238) Canada's major gas utilities including FortisBC, Energir, and Enbridge are vertically integrated, meaning that they own or operate multiple parts of the supply chain, including the transmission and distribution pipelines and deliver gas and gas services to customers. Many landfill-based biomethane facilities in BC are also FortisBC investments, with one stakeholder noting that the cost of capital is lower for utilities than private investors. Investment in landfill is low-risk as feedstock supply is guaranteed but farm-based biomethane sites can be more risky in terms of feedstock constraints. These entities are regulated by provincial energy regulators, that oversee and approve rates for gas distribution services, however the commodity price of the gas itself is unregulated and fluctuates based on market forces.(239) In recent years, provinces have relaxed gas market regulation, enabling other competitive retailers to enter the market.

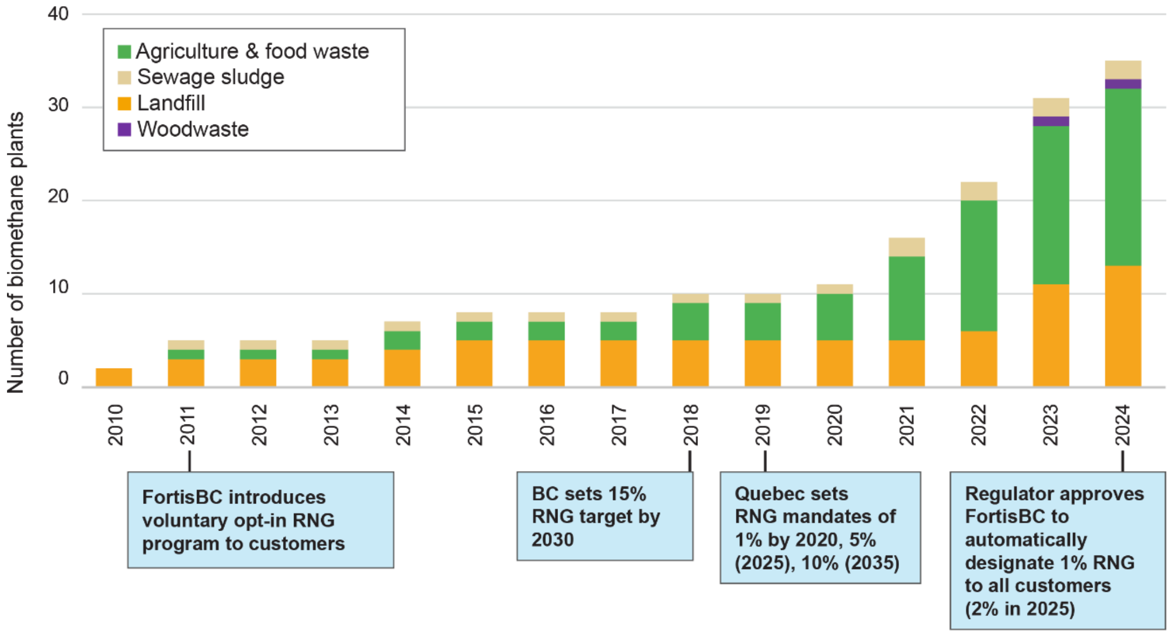

Figure 9. Policy milestones and the development of biomethane projects by type in Canada.

6.3 POLICY SETTINGS

Canada's biomethane sector has been mostly driven by provincial policies and programs from the more climate progressive provinces of Quebec, British Columbia, and Ontario. Nationally, Canada has consistently been an early adopter and leader on climate action, and its ambitious emissions reductions policies have underpinned biomethane development by encouraging the capture and reuse of methane.

6.3.1 Strategies and Targets

A number of provincial policies explicitly recognise and endorse biomethane as a legitimate technology in their energy transition plans and define ambitious targets for its development. These policy ambitions are crucial to driving investment certainty in biomethane projects and confidence for long-term demand. In Quebec, the **Green Hydrogen and Bioenergy Strategy** (2023) commits to 10% renewable source gas content in its gas network by 2030, as well as an increase in overall bioenergy production by 50% through consumption of bioenergy produced in the province.(245) The **Plan for a Green Economy 2030** and its **2024–2029 Implementation Plan** sets a target to reduce 26% of industry emissions by 2030 through three pathways, one of which is "regulation governing the increase in the share of renewable natural gas in Québec natural gas supplies."(245) In British Columbia, the **CleanBC Plan** (2020) goes even further, setting an biomethane target of 15% by 2030. In Ontario, an aspirational 5% biomethane target by 2020 was included its **2030 Energy Policy Action Plan** released in 2017. Although current production data suggests that Ontario is well short of this target (~1% biomethane supply at 2024, Table 9), this ambition has likely contributed to Ontario's development of biomethane nonetheless.(246) In addition to provincial targets, the peak gas bodies, Canadian Biogas Association and Canadian Gas Association, endorse nationwide biomethane targets of natural gas supplies of 5% by 2025 and 10% by 2030 in Canada and BC's major gas utility FortisBC has announced that by 2050, 75% of its gas supplies will be renewable.(246) New Brunswick's **Climate Change Action Plan 2022-2027** seeks to set an biomethane target by 2025, and both this plan and its Powering our Economy and the World with Clean Energy plan released in 2023 frequently mention biomethane as a key technology to enable its energy transition.(231)

Provincial policies are underpinned by Canada's strong climate commitments. The **2030 Emissions Reduction Plan** commits to a 40-45% reduction in emissions below 2005 levels, a target that is enshrined under the ***Net-Zero Emissions Accountability Act***.(240) In 2022, the Canadian Government also updated the methane strategy, *Faster and Further*, increasing 2030 methane reduction targets to 35% overall, with sector-specific goals of 75% for oil and gas and 50% for waste. The strategy also targets agricultural methane emissions but does not set targets specifically.(241) These initiatives build on the earlier 2016 **Pan-Canadian Framework on Clean Growth and Climate Change**, which took a whole-of-government approach to reducing emissions, fostering renewable technology development, and ensuring that Canadian businesses remained competitive in the global transition to a low-carbon economy. At the provincial level, most provinces have set similar 2030 emissions reductions targets to the national one, including 37.5% for Quebec,(242) 40% for British Columbia,(243) and 37% for Ontario.(244)

6.3.3 Market-based instruments

Renewable gas mandates and associated gas pricing regulations

The provincial gas utilities, Energir in Quebec and FortisBC in BC, have been proactive and worked closely with their respective provincial governments and energy market regulators to introduce biomethane mandates into their respective provinces that oblige gas utilities to blend a portion of renewable gas into the total gas supply and offer it to customers. According to stakeholders, utilities companies have been driven by recognising the need to decarbonise their gas networks early and become 'part of the solution' following the introduction of Canada's ambitious climate policies (253).

To make biomethane more cost-effective, gas utilities have pushed for other features to help create a more sustainable cost model. First, they have introduced voluntary 'opt-in' programs where customers can purchase gas and nominate the amount of blended biomethane to include at a price premium.(231) The second feature has been to include a provision within the biomethane mandate regulations that enables gas utilities purchasing or supplying biomethane to pass some of the additional cost across the customer base.(254) The result is that most of the additional cost of biomethane is covered by voluntary end users who are willing to pay a premium for natural gas to reduce their carbon emissions; while any residual costs are spread across the utility's entire rate base (e.g. all customers).

Under British Columbia's **Greenhouse Gas Reduction (Clean Energy) Regulation** (GGRR), the energy utilities regulator, British Columbia Utilities Commission (BCUC) must assess and decide whether to approve a proposal by the utilities to offer biomethane to its customers. Key parts of the proposal that the BCUC must approve include a price cap that utilities are allowed to procure biomethane for in order to limit the cost of renewable natural gas to purchases (255) and the allowable limit of biomethane that can be supplied. Initially the allowable limit for biomethane was set of 1% of FortisBC's total gas supply and has incrementally increased over time. The price cap to procure biomethane was $31 per gigajoule (GJ) of biomethane in the 2021/22 fiscal year, while the approved charge (cost of renewable gas) to customers wanting to purchase biomethane was set at $13.22 / GJ. A further key design feature of the regulation allows the utilities to recover the remaining price difference between the rate charged to opt-in customers ($13.22/GJ) and the price procured ($31/GJ) by distributing the remaining cost across its entire rate base of customers.

In addition to the voluntary opt-in program for customers wishing to purchase biomethane, in 2024, BCUC approved FortisBC Energy Inc. (FortisBC) to automatically designate 1% of gas as biomethane to its customers commencing 1 July 2024, making it the first energy utility in North America to do so.(254) Much of the biomethane supplied is purchased voluntarily through opt-in programs offered by utilities, while the regulator has allowed FortisBC to recover the remaining cost by spreading it across the rate base of all customers (about 1%). As biomethane makes up only a small percent of total gas supply, one stakeholder we interviewed indicated that the cost to each customer when distributed across all consumers was 'extremely low'. FortisBC's voluntary program allows customers to voluntary select a portion of biomethane between 5 to 100%.(237)

In 2019, Quebec became the first province to introduce an biomethane mandate, requiring gas distributors to blend a minimum of 1% biomethane by 2020, increasing to a minimum of 5% by 2025 and at least 10% of all renewable gases by 2030. Quebec's energy regulator, the Régie de l'énergie, not only sets the mandate but also places a price cap that the utility can purchase biomethane through the **Provincial Biomethane Regulation**. Unlike biomethane, the price of natural gas is determined by an open market and is subject to price fluctuations. Since January 2023, renewable gases have been defined to include synthetic renewable gas, biomethane and green hydrogen. The price charge to customers for biomethane in Quebec was CAN$22.65/GJ in 2024. The annual supply target is set annually as part of the Rate Case filed each year with Régie de l'énergie. In 2024, this was set at 2%. The purchase price of biomethane distributed by Énergir varies by supplier and is governed by contract. The annual price for biomethane sold to customers is based on the average of these contract amounts.

The price is set annually as part of the Rate Case. Biomethane purchased is exempt of Quebec's Cap and Trade System (CATS) of carbon pricing that applies to natural gas as well as exmpt from socialisation fees that are charged to customers who do not purchase the regulatory injection target of at least 2% biomethane. Like BC, the cost of biomethane is recovered first by customers who opt-in to purchase and pay a premium for various levels of biomethane and the rest is distributed across its customer base. The Canadian Biogas Association praised Quebec's approach, stating that its "clear and predictable schedule for increasing minimum content requirements both optimizes the environmental benefits and the economic benefits of the regulation."(256)

Carbon pricing

Supporting market demand for biomethane is a national carbon pricing mechanism on fossil fuels and large industrial emitters implemented through the *Greenhouse Gas Pollution Pricing Act (GHGPP Act, 2018)*. Prior to 2016, carbon pricing was only implemented by some provinces. In 2016, the federal government announced that all provinces and territories would be required to have a carbon price in place by January 2018 (either a carbon tax or a cap-and-trade system).(266) Under the GHGPP Act, each province and territory are permitted to design their own carbon pricing system so long as it meets the minimum federal price on carbon, or to adopt the federal system.

The exception is Quebec, who was able to negotiate with the federal government to have a carbon price lower than the benchmark (in 2023, this was CAD $48.15 per tonne compared to $65 per tonne benchmark). As a further incentive for biomethane suppliers, Québec's cap-and-trade carbon system allows landfill- and manure-based biogas and biomethane projects to generate carbon offset certificates that can further be used to generate revenue from the green value of biomethane. While carbon pricing should improve the price competitiveness of biomethane in relation to natural gas, Quebec's cap-and-trade scheme has drawbacks including that it offers a free allocation of carbon emissions to businesses where a portion of their emissions are not charged and second, the price of carbon is market driven rather than regulated – the combination of these effects have resulted in a carbon price that is often lower than the national benchmark price of carbon, reducing the cost competitiveness of biomethane.

The national carbon pricing system applies to business and consumers alike as it is based on two parts: a regulated fuel charge on fossil fuels including gasoline and natural gas, and a performance-based emissions trading system for heavy-emitting industries where facilities have an annual emissions exceeding 50,000 tCO_2e (and smaller facilities on application), known as the Output-Based Pricing System (OBPS).(267) A key design feature has been the incremental increase in carbon pricing. Initially set at $20 per tonne in 2019, it increased by $10/tonne annually to 2022, then by $15 tonne annually from 2023 until 2030, at which point it will reach $170/tonne.(268)

The OPBS sets an output-based standard based on production-weighted average emissions for a given activity in covered sectors. Similar to the Safeguard Mechanism, facilities which exceed this benchmark must pay compensation, while facilities which perform better than the standard are issued with tradeable credits.(269) Under the system, the price of carbon is scheduled to rise incrementally until 2030.(267) Provincial government-regulated carbon offset systems are in place in Alberta and Québec.(260)

The impact of a carbon tax on reducing the price parity between biomethane and natural gas is debated. One stakeholder we interviewed commented that when 'the carbon market goes up, it is actually beneficial.' However, another stakeholder from Quebec noted that many large gas consumers in the province were exempted from a carbon tax, and so it did not have much impact on biomethane (stakeholder pers. comm.) Although Canada's carbon price has been heralded as one of the most progressive in the world and has been effective at driving down emissions, its long-term outlook is uncertain. Stakeholders that we interviewed noted that there was a political campaign by the opposition party to 'axe the tax' leading up to Canada's federal election in October 2025 that was allegedly receiving 'widespread support' from voters (stakeholder pers. comm.).

Clean Fuels Regulations and standards

Canada's Clean Fuel Regulations (CFR) of 2022 came into effect on 1 July 2023, replacing the Renewable Fuel Regulations, introduced in 2011. It provides a set of rules and requirements that obliges transport fuel suppliers, producers, importers and distributors to reduce the carbon intensity of transport fuels by 15% by 2030 compared to 2016 levels. (262). The regulation creates a market-based mechanism for fuel producers and distributors to create carbon credits through innovation, where each credit represents an emissions reduction of one tonne of

CO_2-equivalent.(262) biomethane is eligible to obtain credits when produced as a transport fuel or supplied for gas vehicles. In 2023, nearly 26.5 million cubic metres of biomethane production (~1PJ)[1] generated 24,540 credits under the Clean Fuel Regulations.(263), representing 7% of Canada's total biomethane capacity. The scheme also awarded 51,666 credits for the *supply* of 78.66MT of compressed natural gas (CNG), though contributions from biomethane were not delineated.(263) Both British Columbia and Quebec have introduced their own Low Carbon Fuel Standards. In British Columbia, regulations under the Low Carbon Fuels Act, effective 1 January 2024, are replacing the Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act,(264) with CNG and LNG as eligible fuels.(265) Quebec introduced a regulation on January 1 2023 that mandates the integration of low intensity fuels – 10% content for gasoline and 3% content of diesel fuel, increasing gradually to 15% and 10% respectively by 2030). As biomethane is not suitable for blending with gasoline or diesel, it is not covered by this scheme.

Grants and supply side support

On the supply side, a range of funding and incentive programs are available for biomethane projects from different sectors and for different end uses.

At the provincial level, Quebec has significantly invested in biomethane projects to convert agricultural and municipal waste into biomethane. Under its **Renewable Natural Gas Production Support Program**, agricultural producers, businesses and local councils can apply for grants of up to $12 million for biomethane projects injecting into the gas network using a range of technologies, and financial support up to 75% or $300,000 for project feasibility studies. In August 2024, the provincial and federal governments jointly announced more than CAN $26 million to develop an organic waste recovery centre using biomethanisation and composting, that will convert 35,000 tonnes of organic matter each year into 1.2 mcm of biomethane into Energir's network (257). Ontario has also provided significant investments into biomethane development, for example, including $100 million under its 2017 **Energy Policy Action Plan**.(259) The province's biomethane development has involved collaboration with municipalities and industries to increase biomethane production from agricultural and food waste, wastewater, and landfills. Utilities like Enbridge Gas have actively expanded biomethane programs, incorporating biomethane in natural gas networks and developing supply partnerships to support Ontario's emissions reduction goals. In 2021, upon receiving approval from the Ontario Energy Board to adjust its rates to allow for biomethane, Ontario's gas utility Enbridge Gas Ontario launched its first voluntary biomethane program, following two unsuccessful attempts.(258) In Alberta, biomethane has been encouraged through carbon credits and emissions trading. Alberta's carbon offset protocols supports biomethane project development by allowing credits to be generated by biogas and biomethane projects, including landfill gas, organic waste, manure, and wastewater residue.(260) On the demand side, the **Technology Innovation and Emissions Reduction** (TIE) Regulation requires facilities that emit more than 100,000 tonnes of CO_2e per annum to reduce greenhouse gas emissions, setting high-performance benchmarks and allowing company directors to set facility-specific product benchmarks. To meet the TIE regulatory requirement, facilities can purchase credits, reduce their emissions, or pay into the regulated fund.(261)

At the federal level, for transport, the $1.5 billion **Clean Fuels Fund** (2021–2026) provides capital support for clean fuel production facilities. (247) Funds can also be used to support front end and feasibility studies, and to improve biomass supply chain logistics (e.g. collection, supply, and distribution of biomass materials such as forest residues, municipal solid waste, and agriculture crop residues). It also provides resources to address gaps and misalignment in codes, standards and regulations related to the production, distribution and end-use of clean fuels.(247) For farm-based projects, the **Agricultural Clean Technology Program** provides $3 billion over 5 years for clean technology in agriculture with biomethane listed as an eligible technology,(154). For industry, the **Output-Based Pricing System Proceeds Fund** supports industrial initiatives to reduce greenhouse gas emissions, for regions and communities the $2.4 billion **Green Municipal Fund** supports local biogas projects, and the **Smart Renewables and Electrification Pathways Program**.(249) Québec has in place a **Renewable Natural Gas Production Support Program** that helps to fund biomethane feasibility studies and support biomethane production and injection projects. For R&D and demonstration, it also has the **Technoclimate**

[1] Calculated using an energy density of 36 MJ/m^3.

Program to help fund new technologies, particularly for the production of biomethane.(249) In addition to these direct funding initiatives, federal tax incentives are available to certain businesses for an accelerated capital cost allowance of up to 50% on eligible types of equipment to encourage investment in low-carbon energy projects, including biomethane.(249) British Columbia has an Innovative **Clean Energy (ICE) Fund** to support pre-commercial clean energy technology projects, and research and development.

Certification

biomethane produced in Canada can be certificated through the Renewable Gas Guarantee of Origin (RGGO). RGGOs allow pruchasers of biomethane to claim that their gas use matches renewable gas that's been added to the gas network. This also allows biomethane to be distributed and sold to US markets, including renewable fuel under the federal US Renewable Fuel Standard and the Californian Low Carbon Fuel Standard.(270)

6.4 REGULATIONS

Feedstock supply

Provincial landfill gas controls, organic diversion targets, and environmental regulations have been important in incentivising the use of waste feedstocks for biomethane production.(260) Lists of feedstocks suitable and not suitable for anaerobic digestion may be included in provincial regulations or defined in operating permits issued to biogas facilities. In Ontario, the regulation of on-farm biogas plants includes a list of materials not permitted as feedstocks.

For landfill-based biomethane, Quebec's Residual Materials Management Policy which implements a ban of organic waste to landfill or incineration from 2022 onwards. However, one stakeholder argued that this could detract from biomethane production, as landfills are a concentrated source of biomethane. They argued that utilising landfill resources by introducing a ban on landfill gas flaring would be a key opportunity to increasing biomethane supply.

Gas specification

Only Quebec imposes provincial-level quality standards for injection of biomethane into the natural gas network through standard BNQ 3672-100 / 2012. All other biomethane quality standards for gas injection are set by major Canadian gas suppliers but are generally similar between the major utilities (242).

Grid Injection

Cost-sharing arrangements for grid connection costs vary by province and utility.(271) In Quebec, Energir invoices all grid connection costs back to the biomethane producer for a 20-year period, while Gazifère pays all interconnection costs and then reclaims them through tariffs to end-users, first through voluntary agreements and then, if necessary, on a non-voluntary basis when costs are not fully covered by voluntary biomethane purchases.(227)

Digestate Use

In 2020, biogas and biomethane plants produced 1.2 million tonnes of digestate. The quality and safety requirements of digestate is regulated at the provincial level through environmental legislation and quality standards.(274) In many provinces, biogas plants co-located with farm operations are treated as part of the farm operation. These typically have more permissive regulatory frameworks in place for digestate, allowing its application to the owner's farm and nearby farms. By contrast, other biogas plants are regulated as waste treatment facilities. It is possible for biogas operators to register and certify digestate as a fertilizer through the Canadian Food Inspection Agency under the federal *Fertilizers Act and Regulations*. In some jurisdictions, digestate registered as a fertilizer product can be sold and used similar to other commercially available fertilizer and soil amendment products. However, to be registered as a fertilizer it is subject to nutrient management regulations and must meet strict safety standards for contaminants and provide clear labelling, including precautionary statements where necessary to protect human, animal, and environmental health.(273). Depending on local market opportunities, some biogas operators further treat digestate to produce other products (e.g. aerobic composting to produce compost products).(274)

CASE STUDY: BRITISH COLUMBIA, CANADA

In 2007, British Columbia introduced the *BC Clean Energy Act*, which included ambitious targets to reduce carbon emissions by 33% by 2020 and was one of the first jurisdictions in North America to introduce a carbon tax. Subsequently, the province's largest (and provincially regulated) gas utility, FortisBC, began exploring low-carbon products to offer its customers, including renewable natural gas (pers. communication).

In 2010 FortisBC became the first utility in North America to introduce a voluntary biomethane program to its customers.(275) Under this initiative, residential and industrial gas customers could opt to have up to 10% of their natural gas replaced with biomethane at a price premium. They were charged $13-15 per GJ under the Biomethane Energy Recovery Charge, compared to $4/GJ for natural gas. To ensure accurate tracking, the utility provided its own metering to biomethane grid connections to monitor the amount of biomethane that was being fed into the gas network. It also introduced its own book-and-claim system to account for what was being supplied and purchased. By 2019, the program had 8,300 residential and commercial customers, with demand exceeding supply (to put these figures into perspective, FortisBC electric and gas companies service approximately 1.3 million customers).

As commodity costs for biomethane increased, voluntary demand for biomethane began to decline. In response, FortisBC sought to adjust the rate design. In 2015, FortisBC applied to the British Columbia Utilities Commission (BCUC) for a new rate design called the "Approval of Biomethane Energy Recovery Charge Rate Methodology" which was approved in 2016 (BCUC, 2019). The design of the recovery charge involved distributing the cost difference of biomethane between customers opting in to purchase biomethane at a rate deemed acceptable, while the remaining cost would be spread across its entire customer base. FortisBC argued that it was better to have a system where voluntary customers could choose to purchase biomethane at a reasonable price, and that the remaining costs would be distributed across all of its customer base, which in effect would be quite small. This would ensure that not all of the additional cost of biomethane was 'front-loaded' onto the first few voluntary biomethane customers, which would be too high and effectively 'kill the program right away'.

Initially BCUC rejected the proposal on the basis that its main remit was to ensure affordable energy for BC consumers. FortisBC then approached the provincial government, which enacted an article within the *Clean Energy Act,* that effectively enabled the utility to purchase up to 1% of total gas supply as biomethane at a cap of $30 per GJ on the basis that the Act's remit was to lower greenhouse gas emissions. The approval of the Biomethane Energy Recovery Charge Rate Methodology essentially kick-started BC's biomethane market by enabling a cost structure that didn't place too much burden on any given stakeholder. As one stakeholder explained, 'even though it was a very simple regulation, it allowed for all the other things to happen.'

Under BC's Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR), the BCUC now caps the amount that gas utilities can pay for biomethane and permits some of this cost to be passed on to its customer base. A market analysis by FortisBC determined that customers were willing to pay a $7/GJ premium biomethane and included this in their 2015 application (Khan 2020). Moreover, the utility requested that the cost of acquiring biomethane from suppliers be recovered over the entire customer base instead of just biomethane customers to reduce volatility for biomethane customers (BCUC, 2016). This charge was embedded in the total delivery charges of every customer's bill at a very small rate of $0.019/GJ. In effect, conventional natural gas consumers helped to subsidise the premium for biomethane consumers. Since this rate design came into effect, demand increased such that all available biomethane was sold out between 2017 to 2019.

In 2019, customers paid $11 per GJ for biomethane which was around a $9/GJ premium on conventional natural gas of $2/GJ (the latter includes the carbon tax on the amount of conventional natural gas in the energy mix, and the total amount of conventional natural gas consumed). As mentioned above, costs are spread out over customers, and all utility customers are charged a fixed rate of $0.019 on their invoices. biomethane customers who would like to purchase additional biomethane are able to choose how much biomethane they want to blend with their conventional natural gas. Customers can choose between a 5%, 10%, 25%, 50%, or 100% biomethane blend amount. If customers choose 5%, the cost is about $2.53 extra per month on their total natural gas bill. At 50%, the cost is $25.32 extra. At 100% biomethane, it would cost customers about $50.64 per month extra on top of their regular utility bill, based on an average of 90 GJ of consumption annually (FortisBC, 2019).

In 2018, the provincial government ramped up its climate targets through the *Clean BC Act* and its associated Clean BC Plan, which includes a renewable gas target of 15% of gas supply by 2030. Subsequently, FortisBC applied once again to the BCUC, this time to introduce a mandate that all customers must have a portion of biomethane automatically designated which would thereby increase demand to work toward the 15% target. In 2023, the BCUC approved FortisBC to automatically designate 1% biomethane to all of its residential and commercial customers as of July 1, 2024, making it the first energy utility in North America to do so.(254).

7. European Union (EU)

7.1 EXECUTIVE SUMMARY

The European Union's overarching policies provide an important backdrop for our case studies of Denmark, Italy, and the United Kingdom. In the EU, and in Europe more broadly, biomethane development is an area of policy focus. The European Commission envisions it as a key tool for meeting the region's clean energy goals, and for achieving independence from gas imports, reducing the volatility of gas prices.(3)

The EU is a leader in climate action and energy transitions, evident in its ambitious suite of decarbonisation goals and policies for its member states. With harmonisation between climate, energy, circular economy, and sustainable agriculture policies and implementation plans, the EU is an exemplar of strategic policy that is integrated and aligned. As a result, many EU member countries are leaders in biomethane production and use.

The geopolitical fallout of the Ukraine war in 2022 has added another urgent driver to reduce the EU's reliance on Russian oil and gas imports. Through major initiatives including the **REPowerEU Plan** and the **Fit for 55 Package** under the **European Green Deal**, already the EU has reduced gas supplied by Russia from 45% in 2021 to just 15% in 2023 thanks to acceleration and diversification of renewables.(277,278,279) This rapid transition has been bolstered by a €45 billion commitment from the European Investment Bank to finance renewable energy infrastructure and net-zero technologies.(280)

7.2 BIOMETHANE, BIOGAS AND ENERGY SNAPSHOT

Between 2011 and 2024 biogas production in Europe tripled, increasing from 263 PJ to 849 PJ. Since 2019, while growth in biogas has plateaued, biomethane production on the other hand, has increased nearly tripled, to 230 PJ in 2024 (Figure 10), more than 80% being produced from EU member states. Despite this impressive growth, a 2024 study found that a realistic estimate, utilising available technologies and sustainable and novel feedstocks, across all 27 EU countries plus the UK, Sweden and Switzerland could amount to 1,584 PJ (44 bcm/yr) by 2030 and 111bcm/yr (3,996 PJ) by 2040.(17)

7.3 POLICY SETTINGS

7.3.1 Strategies and Targets

REPowerEU Plan

The **REPowerEU Plan** was launched in May 2022 in response to Russia's invasion of Ukraine.(277) Designed to increase energy independence, the plan sets an ambitious target to produce 35 bcm (1,260) of biomethane by 2030, equivalent to 20% of Russian gas imports in 2022. In 2024, the EU's installed capacity was 5.2 bcm (805 PJ).(71) This means that EU states combined will need to increase biomethane production by a similar amount to current levels (5 bcm) *each year* until 2030 to achieve the target.(281)

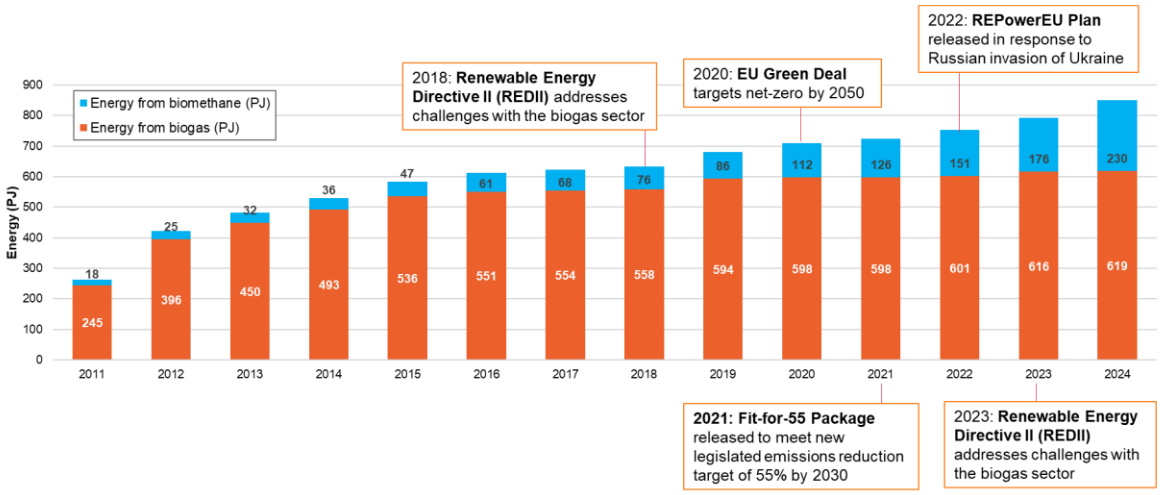

Figure 10. Combined biogas and biomethane production in Europe (in petajoules).(71)

To support the REnewEU's high ambition, a number of recommended actions were proposed by the European Council in a paper accompanying the REPowerEU Plan.(282) These include:

- Increasing the use of waste resources, rather than using food- or feed-based resources
- Accelerating permitting and approvals of new projects and facilitating renewable gas injection.(283)
- Reducing production costs through incentives for upgrading biogas into biomethane and addressing infrastructure challenges and 'bottlenecks' preventing the achievement of cost-efficient biomethane deployment
- For national authorities to assess potential investment challenges to increasing the uptake of biomethane and connecting decentralised production sites with consumers over large distances.'
- Continued support of innovative technologies for the sustainable upgrade of biogas to biomethane and its integration into the gas network. This will include ***streamlining existing funds and funding mechanisms*** at EU and national levels.

To help address these recommendations, in September 2022, the EC launched the **Biomethane Industrial Partnership (BIP)**.(284) The BIP's goal is to promote the sustainable production and use of biomethane through active engagement between the Commission, EU member states, industry representatives, feedstock producers, academics and NGOs to build knowledge, skills and capability for the production of biomethane and to increase legitimacy of the technology.(284)

Fit for 55 and the European Green Deal

The **2020 European Green Deal** sets the EU on a path to climate neutrality by 2050, with an interim goal of reducing emissions by 55% compared to 1990 levels by 2030. Building on these targets, the **Fit for 55 Package**, adopted in October 2023, brings together a suite of legislative proposals and measures aimed at achieving the climate goals of the Green Deal.(278) For the gas sector, Fit for 55 has two key objectives – to progressively replace fossil gas with renewable and low-carbon gases, and to reduce overall gas consumption.(285) To achieve the latter, the **hydrogen and decarbonised gas market package,** adopted in May 2024, seeks to reduce total gas consumption by 30% by 2030. The package intends to modernise the EU's gas market design by introducing new rules and revising existing ones, such as the **Gas Directive 2009/73/EC** and the **Gas Regulation 715/2009**, and the **Security of Gas Supply Regulation 2017/1938**. These measures also aim to facilitate gas grid access, remove cross-border tariffs, support a common certification system, and develop standards for monitoring gas quality.(285)

As part of the Fit for 55 Package, the revised **Renewable Energy Directive III (RED III)** came into force in November 2023. RED III not only raises 2030 renewables energy targets to 42–45% of the total energy mix and 29% of transport fuels but also mandates a minimum general blending obligation of 6.8% low emissions fuels in the transport sector. Notably, the directive broadens the scope of the fuel supply obligation to cover *all uses* of biomethane,(3) streamlines permitting and approvals for renewables projects, and facilitates cross-border trading through an extension of guarantees of origin to renewable gases and a mass balancing system adapted for grid-injected biomethane.(286) Other key elements of the Fit for 55 Package that will directly or indirectly encourage the use of renewable gases include:

1. The **Carbon Border Adjustment Mechanism (CBAM).** The CBAM places a tariff on imported goods with a high-carbon footprint to ensure that its member states are not at a competitive disadvantage by implementing emission reductions measures. This may indirectly increase the use of low carbon gases both within and outside of the EU for industrial production of gas-reliant and carbon-intensive products such as steel, cement and fertilisers.
2. Amendments to the **Energy Taxation Directive (ETD)**. The ETD provides a harmonised framework for energy taxation across the EU by defining minimum duty rates and structural rules for taxing electricity, motor, and heating fuels. Introduced in 2003, the ETD was amended as part of the Fit-for-55 package, introducing a new structure of tax rates responsive to the energy content and environmental performance of fuels and electricity, rather than simply their volume.(154)

7.3.2 Market-based instruments

Carbon Pricing in the European Union

The EU prices carbon through its **Emissions Trading System (ETS)**. This is a cap and trade scheme, where a declining limit is set on the total emissions allowed by installations and operators covered under the scheme.(287) Emissions allowances are predominantly sold in auctions, but some are also distributed for free to prevent capital flight or investment offshore which can create carbon leakage.(288) Each allowance gives its holder the right to emit one tonne of CO_2e.(287) The scheme covers carbon emissions from electricity and heat generation, energy-intensive industry sectors, aviation within the European Economic Area, and maritime transport (50% when starting or ending outside of the EU). It also covers other GHGs such as perfluorocarbons from the production of aluminium, and nitrous oxide from the production of certain industrial chemicals. In some sectors, only larger operators are included in the scheme.(289)

The EU ETS is an important factor in biomethane economics because it covers several sectors in which biomethane may be used as a fuel or input, particularly heat and power generation and industrial manufacturing. Certified biomethane can be used to bring down an operator's overall emissions,(156) resulting in this being more valuable to these operators than natural gas.(290) From 2024, municipal waste incinerators above a threshold are required to monitor and report their emissions.(289) From 2027, the EU's ETS2 will also address emissions from fuel combustion in buildings and road transport.(291) Under this scheme, fuels from advanced biomass receive the lowest possible tax rate, while fuels from sustainable biomass are taxed at a reduced rate.(154) These are both promising developments for the outlook of biomethane under the ETS.

Certification and cross-border trading via the REGATRACE systems in the European Union

The European Union's Renewable Energy Directive requires two distinct types of renewable gas tracking and certification systems. The first of these are Guarantees of Origin, which exist to track ownership of renewable gas once it is injected into a network as a fungible gas. A GO is defined under Directive 2018/2001 as an "electronic document which has the sole function of providing evidence to a final customer that a given share or quantity of energy was produced from renewable sources."(292) These are sold using a book-and-claim system, meaning that biomethane's GOs (sometimes also referred to as the gas's "green value") can be bought and sold independently of the gas itself.(156) The primary purpose of GOs is consumer disclosure and evidence, so that customers can voluntarily purchase a given quantity of renewable gas.

One report found that across Europe, the sale of GO certificates can cover 36-58% of typical biomethane production costs.(156) One important use of GOs is to certify LNG or CNG created from the gas grid as bio-LNG or bio-CNG.(154) Despite EU-level standardisation, pan-European trade in GOs is not currently occurring.(293) This is due to the absence of a single cross-border transfer scheme, a lack of harmonisation between national biomethane GO systems, and the presence of two overlapping but non-identical multilateral schemes for exchanging GOs (ERGaR and AIB).(293) A revised EU standard on GOs is currently under development.(294)

The second tracking system employed in the EU is termed Proof of Sustainability (PoS). Unlike the book-and-claim method used for GOs, these certificates are traded through a mass balancing system. This means that PoS must be traded alongside its associated renewable gas. As tracing the actual molecules of biomethane through the gas network is impossible, tracing is carried out through a process of mass-balancing, where each injection of biomethane must be matched by a corresponding withdrawal, and a corresponding PoS. Unlike GOs, which are issued by an official issuing body, PoS is issued by certified producers of biomethane. PoS includes a record of the lifecycle emissions created across the entire biomethane value chain (Scope 1, 2, and 3 emissions), and may be used to fulfil other carbon accounting requirements. In particular, PoS can be used as proof of emissions reductions under the EU ETS.(156)

Since 2020, efforts have been made to enable the trade of biomethane between EU member states through a consistent platform. The EU-funded REGATRACE (REnewable GAs TRAde Centre in Europe) is an initiative to create a harmonised system of tradable renewable gases certificates between countries (GOs and PoS). It involves a network of national issuing bodies in European countries, facilitating the sale of GO beyond national borders.

7.4 REGULATIONS

Gas Injection Standards in the European Union

The European Union gas quality standard, EN 16726, is presently under review, with a revision due to be published in mid-2025.(295) Parameters to be standardised include the Wobbe index, hydrogen content, oxygen limit, sulphur limit, and methane number.(293) The oxygen limit is one of the most important discussion points, as this currently varies significantly across EU countries, grid operators, and infrastructure points.(293)

Feedstock Availability

The **Waste Framework Directive (2008/98/EC)** is an important European Directive for feedstock availability, having been amended to stipulate that all EU members will have to collect organic waste separately by 2024.(296) This provides "an opportunity to scale-up the production of sustainable biomethane and create income opportunities for farmers and foresters."(3)

Digestate Use

Directive No 2008/98/EC of 19 November 2008 sets out the EU's regulatory framework for waste management. This includes requirements which must be met for a substance to be considered a by-product rather than a waste. These are laid out in Article 5:

> "A substance or object, resulting from a production process, the primary aim of which is not the production of that item, may be regarded as not being waste referred to in point (1) of Article 3 but as being a by-product only if the following conditions are met:
>
> (a) further use of the substance or object is certain;
>
> (b) the substance or object can be used directly without any further processing other than normal industrial practice;
>
> (c) the substance or object is produced as an integral part of a production process; and
>
> (d) further use is lawful, i.e. the substance or object fulfils all relevant product, environmental and health protection requirements for the specific use and will not lead to overall adverse environmental or human health impact."

Known as the Nitrates Directive, EU Directive 91/676/EC sets nitrate standards to protect water quality. This Directive regulates digestate as equivalent to livestock manure.(297)

Information-based instruments

GreenMeUp, a project funded under the EU's Horizon Europe Research and Innovation Programme aims to increase education and awareness to facilitate the wider market uptake of Biomethane in the EU.

Streamling approvals and permits

The **Net-Zero Industry Act** stemming from the Green Deal Industrial Plan, came into effect on 29 June 2024. Its aim is to foster and scale up home-grown technology and manufacturing to deliver 40% of the EU's net zero technology deployment needs by 2030, including sustainable biogas and biomethane. A key objectives is to simplify the regulatory framework for the manufacturing of these technologies which will help to increase the competitiveness of the net-zero technology industry in Europe and also accelerate the capacity to store CO_2emissions

8. Denmark

8.1 EXECUTIVE SUMMARY

Denmark's sequencing and mix of policies provides an outstanding example for building a sustainable biomethane market. This strategy has centred around providing strong and stable support for biomethane with subsidy schemes until it reaches maturity as a viable industry based on market demand for the green value of renewable gas.

Denmark was an early adopter of biogas, owing to its large pork and dairy industry and the need to treat manure waste, with subsidies for biogas for combined heat and power generation. Since 2012, upgrading of biogas to biomethane and its injection into the gas grid has been stimulated by substantial feed-in tariffs introduced under the **2012 Energy Agreement**, the primary driver of biomethane growth between 2012 and 2018. As the market has substantively matured, the Danish Government is looking to replace feed-in tariffs with a tendering system of feed-in premiums and shorter contracts (10 years). Another part of Denmark's biomethane success is its large market for digestate, which commands a premium as a biofertilizer necessary for organic farming.

Despite its successes, there have been some barriers to parts of the market. These include grid-injected biomethane being subjected to a carbon tax, unlike in other EU countries such as Germany and Sweden where it is exempt. Whilst this has enabled high export demand to these countries, it has not helped Denmark in achieving its own emissions reduction goals. The second is the proposal of subsidies going forward. Here, players in the Danish biogas industry have expressed concern at the lack of stability in the regulation of biomethane, noting that this constitutes an obstacle to long-term agreements for biomethane.

In the transport sector, Denmark has had a mandatory renewable fuel target in place since 2009 (7.6% in 2020),(298) and in January 2022 the Danish government introduced a carbon reduction obligation for transportation fuels where only unsubsidised biofuels like biomethane can fulfil the obligation.(299)

Beside market-based instruments, regulatory enablers have been essential to biomethane development, including those for digestate use, guaranteed access to the gas grid,(77) a relaxed standard for impurities in injected gas, the Guarantee of Origin (GO) certification scheme, carbon pricing through an emissions trading scheme and carbon tax, and streamlined development approvals.

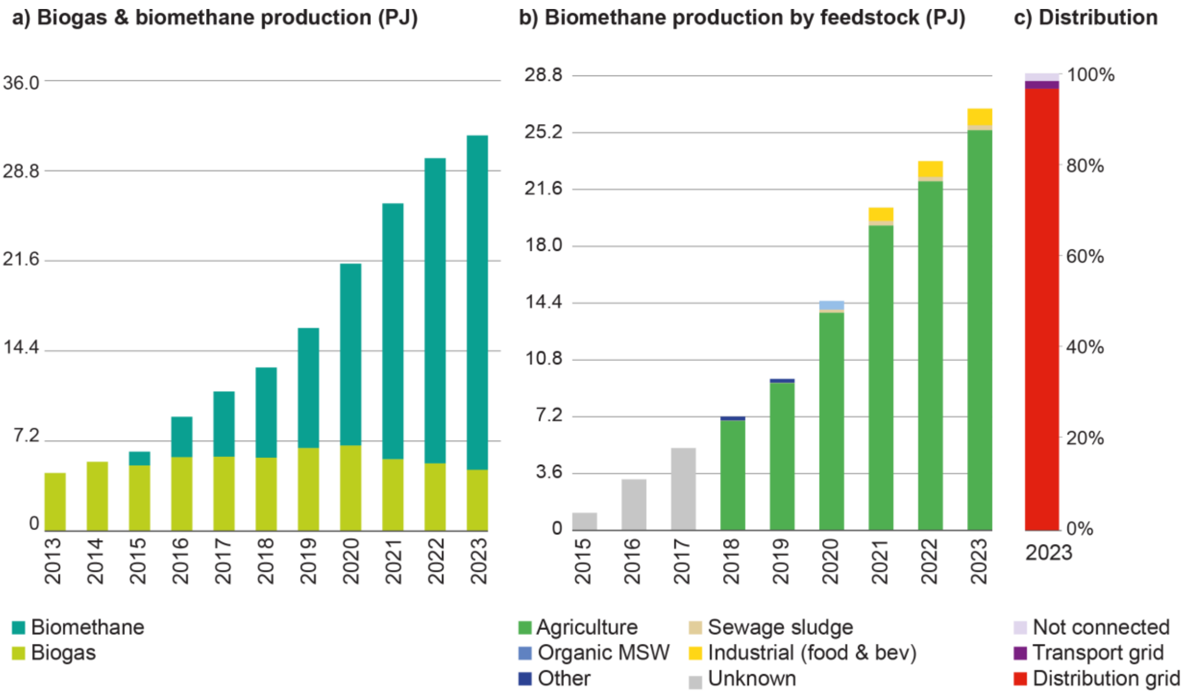

Figure 11. Development and distribution of biogas and biomethane production in Denmark.

8.2 BIOGAS, BIOMETHANE AND ENERGY SNAPSHOT

In 2023, Denmark had 122 biogas plants and 59 biomethane facilities.(71) A 2022 survey by the Danish Biogas Association found that there were another 40 biomethane projects under development, and 30 biomethane plants planning to increase production.(71) Since 2018, production of biomethane has vastly overtaken biogas, accounting for an 85% share (27 PJ) of the 32PJ of biogases, compared to just 15% for biogas (~5 PJ), despite a greater number of biogas plants. Denmark's annual per capita biomethane production is 4.5 GJ.(71) Based on current policy support schemes, the Danish Energy Agency forecasts biomethane production will continue to grow at a rapid pace, with a projected production of 52 PJ production by 2030.(299, 303) Other assessments have estimated potential biomethane production from feedstocks ranging from 65–94 PJ per annum.(17,299)

Farm-scale anaerobic digester biogas plants have been in operation in Denmark since the mid-1970s, and the first centralised biogas plant was constructed in 1984. Further capacity was developed in 1980s and 1990s assisted by capital grants for anaerobic digestion plants and subsidies for both biogas and combined heat and power production in the 1990s. While the number of biogas plants has declined from 196 facilities in 2011 to 122 facilities, since 2015, the number of biomethane plants has increased sharply from 1 facility to 59 facilities. The decline in biogas plants is partly due to facilities that previously generated electricity converting to producing upgraded biomethane, while some smaller on-farm plants have ceased operation. In addition, many smaller biogas facilities coupled to wastewater treatment plants have been closed, with the sludge being transferred to larger processing plants.

Compared to the rest of Europe, Danish biomethane plants tend to be bigger, having the largest average plant size in Europe. They are typically more centralised and industrialised, with annual capacities to process up to 1 million tonnes of feedstock. Many of these biogas plants are farmer-cooperative owned.(300) Virtually all biomethane (95%) and three quarters of biogas (76%) is produced by agricultural feedstocks, with a substantial portion from livestock manure which is typically co-digested with smaller amounts of agricultural residues or industrial wastes.(71) Denmark has a large dairy industry like Australia, but operates through high-density shedding as it has among the highest livestock density in the world. These attributes make the collection of manure feedstocks much more efficient and cost effective than open field dairy.

8.2.1 Gas Market Structure

Energinet owns and operates the gas and electricity transmission networks in Denmark. It is an independent public utility owned by the Danish Ministry of Climate, Energy and Utilities.(156)

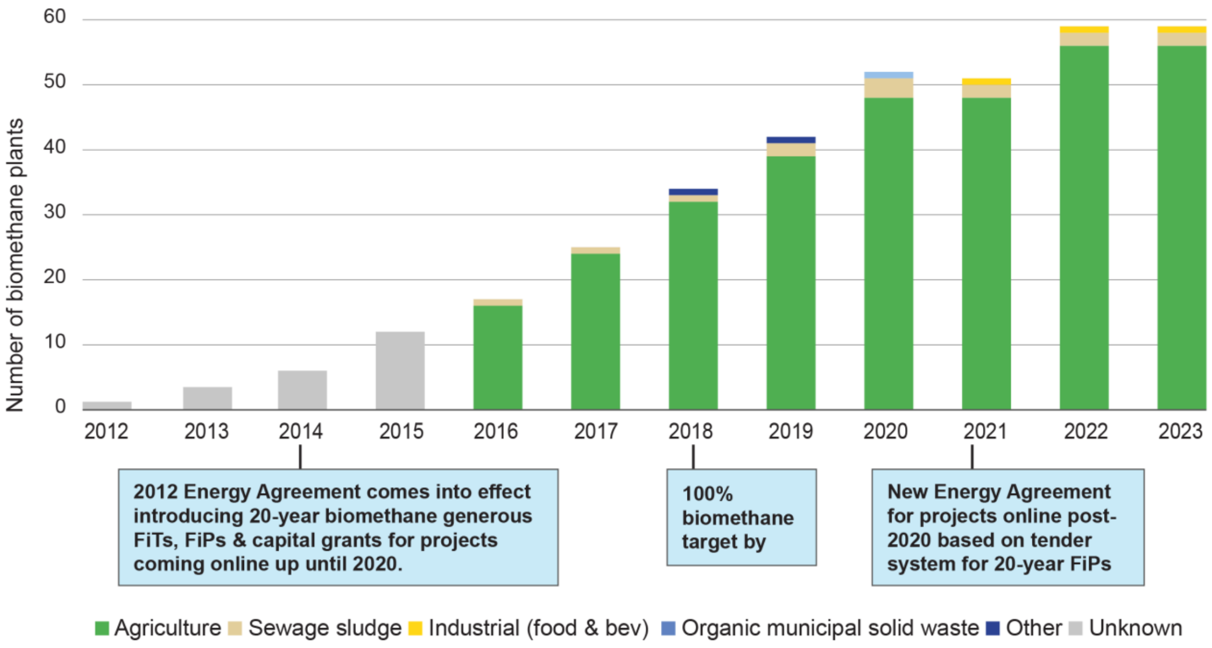

Figure 12. Policy milestones in the development of biomethane projects by type in Denmark.

8.3 POLICY SETTINGS

8.3.1 Strategies and targets

Denmark has been pursuing an energy transition away from fossil fuels for more than 50 years. In June 2018 the Danish Parliament adopted the new **2018 Energy Agreement** which was supported by all political parties. In it included a target to reach zero net emissions in 2050 and 55% renewable energy in 2030. The Danish parliament has the most ambitious renewable gas goal of any country, with political ambitions to have 100% of renewable gases supplying its gas grid by 2030 under its **2019 National Energy and Climate Plan (2021-2030)** and outlined in its **Biomethane Fiche 2021**.(302) The 100% biomethane target both supports and is supported by other national and EU targets, including:

- National 2030 emissions reduction target of 70% compared to 1990 levels under its 2020 Climate Act;
- National waste targets to achieve at least 50% recycling of household of solid waste by 2023;(304)
- REPowerEU's non-binding target to produce 35 bcm of biomethane annually by 2030; and
- EU Waste Framework Directive 2008/98/EC target to recycle 55% of municipal waste by 2025.

8.3.2 Market-Based Instruments and Financial Incentives

Denmark's two-pronged approach to phase out fossil gas use in the gas grid is to scale up biomethane while simultaneously reducing total gas consumption via electrification and energy efficiency measures (Error! Reference source not found.).

Historically, growth of Denmark's biogas has been supported with subsidies and incentives for a range of uses, including upgraded biogas (biomethane), combined heat and power, and transport and industry.(77) Investment subsidies played an important role in the initial establishment of Denmark's biogas industry, with early subsidies reaching up to 40% of a biogas plant's capital costs. These subsidies were reduced over time, until being phased out completely in 1997. In 2009, they were subsequently revived, with a 20% cap that was then raised to 30% in 2012 under the 2012 Energy Agreement.(77) Denmark's first AD biomethane facility to inject gas into the network was established in 2013.

Between 2000 and 2012 biogas was primarily used for district heating after it was added as an eligible technology under the *Heat Supply Act* amendment of 2000.(305) In the Energy Strategy update in 2021 it was suggested that the future of district heating would consist of renewable heat from biomass, effectively decarbonising the heating networks (306). However, from June 2022, "the Danish Parliament agreed to stop the use of natural gas for space heating in 2030 and to introduce a full stop for the use of other kinds of gas, typically biogas, for space heating in 2035. The agreement in the Danish Parliament required Danish municipalities, in cooperation with district heating companies and gas distribution companies, to make a plan for phasing out natural gas as soon as possible, and to communicate the plan to all citizens whose homes are warmed with a gas boiler."(307) The **Climate Agreement on Green Power and Heat**, made in June 2022, states the ambition of phasing out fossil fuel based heating services in all buildings by 2035 at the latest (308).

Feed-In Tariffs and Feed-in Premiums

Upgrading biomethane for grid injection really took off from 2012, after changes to the Energy Agreement's incentive scheme were made to allow biogas upgraded to biomethane and the use of biogas for industrial, transport- and heating purposes eligible for support. Supports included generous feed-in tariffs and premiums and economic support instruments for biomethane injection into gas networks were introduced as part of the **Energy Agreement 2012–2020**. The ambitious framework was designed to reduce Denmark's greenhouse gas emissions and increase the supply of renewable and clean energy (309,310). The Energy Agreement received EU state aid approval in 2013 and was ratified by the EU in 2014. Under the agreement, applications for new projects were accepted until 2020. Key aspects of the 2012 Energy Agreement that helped to stimulate biomethane projects included:

- A target to divert 50 percent manure into biogas by 2020;
- An increase in investment grants from 20% to 30% of capital costs;
- Feed-In-Tariffs (FITs) of the following amounts:
    - Upgraded biomethane into the gas grid: 115 DKK/GJ ($18.10 per GJ)
    - Biomethane and biogases directly used for transport and industry: 75 DKK/GJ ($11.8/GJ)

- A price premium consisting of 0.26 DKK/kWh pegged to the market price of natural gas but with a floor price included. This meant if the market price of natural gas dropped below the floor price, the premium increased to compensate for it. (Denmark Biomethane Fiche, 2021)
- Funding for a dedicated Biogas Task Force.(310)

A key feature of the 2012 Energy Agreement was that supports for upgrading and injecting biomethane were set more than 50% higher than the supports received for direct use of the biogas for heat and power production, so as to incentivise grid injection.(311) Biogas was also supported when used as a transport fuel for industrial processes or for the production of electricity.(300) In addition to the basic subsidy amount, subsidies have at times included an additional 'early bird' subsidy to incentivise rapid uptake.(312) Subsidies consisted of a combined feed-in tariff and feed-in premium, with a fixed and a variable component,(154) the variable component allowing adjustment to be made based on the price of natural gas.(154) Subsidies were granted for a 20-year period.(302)

Prior to the Energy Agreement, biomethane was primarily used to fuel district heating, and was accordingly regulated under the Heat Supply Act. This law regulated consumer prices so that district heating companies could only charge the "necessary and actual costs" of heat, including its production, distribution, and asset depreciation costs.(313) This has been referred to as the "non-profit principle".(314) The 2012 Energy Agreement added a new avenue for revenue generation from biomethane, this time without price controls in place. As such, it effectively removed the barrier to investment profitability posed by price controls on district heating. One interviewee noted that this led to an influx of international investment, and a consequential shift away from local farmer-owned biomethane plants towards a more centralised model of larger facilities (interviewee, pers. comm).

In 2018, a new Energy Agreement entered into force.(315) Under the **2018 Energy Agreement,** more ambitious climate goals were set, including a national renewable energy target of 55% by 2030, fossil fuel independence by 2050, and net zero carbon dioxide emissions by 2050. However, it also announced the removal of the existing system of feed-in tariffs and supports for new projects coming online after 2020. Instead, a new €1.7 billion euro EU State Aid was approved in 2024 to support biomethane and e-methane production for injection into the grid.(403) The scheme includes supports for the construction of new plants and extension or upgrading of old plants and a tender system for 20-year feed-in premiums to successful project bidders. Approved tenderers receive 20-year feed-in premiums,(154) paid on top of the market gas price of natural gas until a cap at 120 kr./GJ, above which supports are to be reduced proportionately.(316) Under the tender system, tenderers must propose a price premium required per GJ of production, and the amount of biomethane production they intend to bid for.(316) Plants must be connected to the grid within three years of receiving aid. The Danish government's stated intention is to hold five rounds of tendering between 2024 and 2030, with a separate budget for each bidding process. Tenders have not yet begun as the scheme has yet to be approved by the European Commission, despite plans for the scheme to commence in 2024.(71) As a result, detailed information about how these tenders will operate is currently not publicly available.

Grants and funding

As noted above, the 2012 Energy Agreement provided investment grants for biomethane facilities covering up to 30% of capital costs.

8.3.4 Demand-Side Instruments and Incentives

Fuel Obligations

Denmark has a statutory requirement that a minimum of 5.75% of the energy content of fuel sold for land transportation comes from biofuels, with biofuels based on waste and residue counting double for meeting this requirement.(77)

Carbon Pricing

In addition to the EU Emissions Trading Scheme,(300) Denmark has an explicit carbon tax, implemented in 1992.(317) As of 2023, this tax applied to around 40% of Denmark's greenhouse emissions.(318) From 2025, the existing carbon tax on fuels will be increased by 400%, and a new tax on CO_2 equivalents will be added for companies covered by the EU ETS.(319) One drawback of Danish policy is that biomethane cannot be used to claim carbon tax refunds in Denmark, unlike other countries such as Germany and Sweden.(299) Subsequently, a very significant portion (~80%) of Danish biogas is exported to other European countries, primarily Germany and Sweden.(299) This export market is facilitated by partially harmonised national Guarantee of Origin systems, which allow Danish biomethane producers to sell the green value of biomethane wherever will net the greatest return.This export market is facilitated by partially harmonised national Guarantee of Origin systems, which allow Danish biomethane producers to sell the green value of biomethane wherever will net the greatest return. Because biomethane can be sold across national borders, the carbon prices of other European Union countries have also been a key driver of Danish biomethane production. Sweden and Germany in particular both have high carbon prices, which can be refunded in full if unsubsidised biomethane is purchased.(299) While biomethane cannot currently be used to reduce the carbon tax burden of purchasers, although the possibility of allowing unsubsidised biomethane to generate a tax refund is under consideration by the Danish Parliament.(299)

Certification

Denmark has a Guarantee of Origin certification scheme, which are issued for every 1MWh of biomethane injected into the gas network.(299) This was initially an industry-led voluntary certification scheme,(154) but GOs are now issued, transferred, and retired by Energinet, the Danish energy regulator and transmission network operator. GO certificates are primarily purchased by businesses to offset their emissions under the EU emissions trading scheme, or as part of meeting their corporate social responsibility obligations. To a lesser extent, they are also purchased by private households voluntarily choosing to reduce their carbon footprint, and by municipalities.(300) In Denmark, Guarantees of Origin are recognised for CO_2 quota purposes (for mandatory quotas of green energy), but cannot be used to generate tax refunds. They can, however, generate tax refunds in Germany and Sweden, which has led to most of Denmark's biomethane being exported to take advantage of this policy.(299)

Guarantees of Origin are also used to meet the required percentage of renewable fuel in transport fuel. Since the feed-in subsidy scheme was discontinued for new projects beyond 2018, to facilitate the competitiveness of new biomethane plants a Guarantee of Origin certificate is now issued for unsubsidised biomethane. Guarantees of Origin also record the subsidisation status of biomethane,(299) with unsubsidised biomethane receiving a higher price than subsidised biomethane, particularly in the transport sector.(312) This is because Danish GOs were valued at €22/MWh in March 2024.(320)

Sustainability certificates are another form of accreditation of biomethane in Denmark. Unlike Guarantees of Origin, which serve to document the origin of biomethane and ensure that it is only sold once, sustainability certificates document that the EU Renewable Energy Directive's sustainability criteria have been met by the biomethane feedstock. Issued by EU-accredited certification organisation, these are traded alongside a Guarantee of Origin and impact on its value.

8.4 Regulations

Feedstock

Denmark has a number of policies that encourage utilisation of the country's bioresources for biogases, and an increasing focus on environmentally sustainable feedstocks. The 2012 Energy Agreement set a political target that 50% of Denmark's biomass should be used as a feedstock for biogas by 2020.(312) The maximum feedstock from energy crops is capped at 4%, to reduce land use competition with food crops. This limit is regularly tightened. The use of corn as an energy crop is also prohibited.(302) Since 1998, Denmark has implemented a ban on sending organic waste to landfill, which has helped to increase feedstock availability.(300) Most Danish municipalities source separate household organic waste, which depends upon mandatory separation of waste by households and businesses. Sustainability criteria and schemes exist throughout the European Union, with the goal of ensuring that "sourcing feedstock does not negatively impact the environment and biodiversity, that biogas and biomethane and biomethane are used in an efficient fashion and that substantial greenhouse gas emissions are saved compared to when fossil fuels are used."(73) From 2030, Denmark plans to introduce the world's first carbon emission tax on livestock emissions, emissions from spreading manure and agricultural lime on fields, and emissions from carbon-rich agricultural land.(321) This has the potential to influence feedstock availability by incentivising the use of anaerobic digestion instead of spreading raw manure.

Grid Injection

Denmark has a "right to inject" policy, meaning that biomethane producers have a legally enforceable right to connect to and inject into the gas grid. However, biomethane does not receive preferential treatment to natural gas.(77) Denmark has also created a framework for contractual relations between biomethane producers and grid operators.(154)

While compression costs were originally paid for by biomethane producers, this responsibility was eventually shifted to the state-owned Danish gas distribution company. As a stakeholder explained, "Originally, the interpretation was that the compression also was a part of the direct costs, but this led to the awkward situation where there was enough downstream consumption of biogas for the connection of the first biogas plant, but when the biogas plant number 2 was connected, then he has to pay for the compressor to push backwards the gas. […] So back in 2016 or 2017 there was a new interpretation and legal agreement saying that the cost of the compression, the reverse flow investments, and even if it was smarter to make a new ring pipeline from one local grid to another, then it was a cost to be paid by the gas grid, and of course at the end of the day, by the gas consumers."

While biomethane plants must pay the direct costs of grid connection, transmission and distribution grid operators finance necessary investments in grid infrastructure, such as grid expansion and gas compression.(77) To maintain gas distribution system balance (due to greater supply than demand caused by concentrated biomethane injection in the distribution grid), Energinet operates four reverse flow facilities, which compress the biomethane from the 20-40 bars of the distribution grid to the 80 bars of the transmission grid. These facilities address physical barriers to injecting into the gas distribution grid, by pressuring excess gas to the pressure required by the transmission grid.

Gas Specification

Denmark's gas quality standards allow a relatively high tolerance for O_2 content, at 0.5% mol/mol at entry points and during transit and 0.1% at storage points.(322)

Digestate

Denmark has a simple and efficient digestate management system where farmers deliver manure to biogas processors, and in return collect digestate to use as a fertiliser. This simultaneously facilitates cost-effective transport of feedstock and efficient removal of digestate, with biogas plants paying for the cost of transporting the feedstock and digestate.(323) Digestate use is primarily regulated by Order No. 1060 of 26/07/2023 on the use of fertilisers in agriculture. It mandates biogas plants to measure and report on the nutrient content of digestate to farmers, who use this information to develop fertilisation plans. Regulations specify that nutrients in manure and slurry must be either used as fertiliser on crop land or incinerated. The co-digestion of manure and waste is regulated by Order No. 1001 of 27/06/2018 on the use of waste for agricultural purposes. If livestock manure makes up more than 75% of the feedstock, digestate can be applied in accordance with the Danish "Executive Order on commercial animal husbandry, livestock manure, silage, etc." This means it is not considered a waste, and is allowed to be spread on farm as fertiliser without needing to apply for a permit or licence.(326) (324,325) Denmark has also implemented policies restricting the application of nitrogen and phosphorous per hectare of agricultural land. These regulations have incentivised farmers to remove surplus livestock manure, with anaerobic digestion providing an avenue for said manure. Livestock manure can be applied to agricultural land untreated, or in the form of digestate following anaerobic digestion but may only be applied during the growing season (300) under approved application methods to prevent excessive nitrogen loss to the atmosphere during application.(300)

Fugitive Methane Regulations

In 2023, Denmark introduced regulation requiring agricultural, sewerage, and industrial biogas plants to implement a self-monitoring program to reduce methane loss, accompanied by annual inspections by an independent and accredited third party. Along with reducing fugitive methane emissions, which are capped at 1%, this program aims to ensure that biogas production is genuinely sustainable (through the use of renewable feedstocks and materials, for example).

9. United Kingdom

9.1 EXECUTIVE SUMMARY

The development of biomethane in the United Kingdom has predominantly been driven by a three-tier system of 20-year feed-in tariffs for biomethane injection into the grid (BtG), first under the **Renewable Heat Incentive** for projects coming online between 2014 to 2020, then 15-year feed-in tariffs under its successor, the **Green Gas Support Scheme** for projects coming online between 2021 until early 2028. Around 90% of biomethane supplied receives support under these schemes and a further 10% by the **Renewable Transport Fuel Obligation.** Its digestate certification system as a biofertilizer has also played a role in improving the business case of biomethane projects. The United Kingdom allows digestate to be sold and spread without requiring specific permitting approvals, as long as quality standards are met. These instruments have been supplemented by funding for innovation in biomass feedstocks, an industry-led voluntary biomethane certification scheme, and emissions trading incentives for the combustion of biogas and biomethane (though not currently for gas grid injection). The UK government has not set specific production targets for biomethane, however expected deployment for biomethane under current schemes is expected to produce around 29 PJ (8TWh) by 2030. Moreover, in both the 2023 **Powering Up Britain: Energy Security Plan** and the **2023 Biomass Strategy**, biomethane is emphasised as a viable technology for achieving net zero in the UK by 2050, increasing domestic energy security and gas supply, and decreasing reliance on natural gas.

9.2 BIOGAS, BIOMETHANE, AND ENERGY SNAPSHOT

At the end of 2023, there were 1,233 biogas and 120 biomethane plants in operation in the UK, producing 75.6 and 27 PJ of biogas and biomethane respectively.(71) (Figure 7) This equates to a per capita biomethane production of 0.40 GJ/person. Biogas and biomethane combined made up 4.5% of the United Kingdom's total natural gas consumption (2,286 PJ). In 2024 there were a further 29 biomethane facilities currently in the process of connecting to the grid.(327) In 2023, ~50% of the United Kingdom's biomethane was used for heating, around 12% was used for industrial purposes, and the remainder went towards power generation. Agricultural waste is the largest source of feedstock for biomethane production in the UK, accounting for 82% of all biomethane produced in 2021(154). As of March 2024, around half of the UK's biogas plants are anaerobic digesters using agricultural and food waste feedstocks,(328) of which 120 are producing biomethane and connected to the gas grid (known as biomethane to grid, BtG).(327) Studies assessing biomass feedstock availability estimate a theoretical biomethane potential of 600 to 3,200 PJ could be produced in the UK annually.(332)

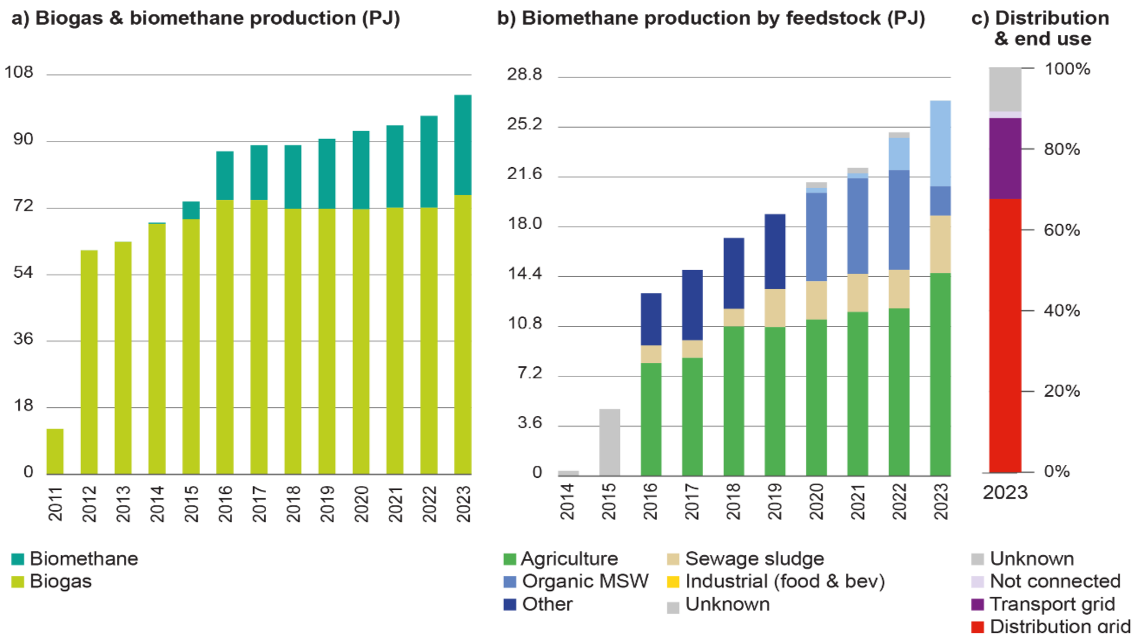

Figure 13. Distribution and production of biomethane in the UK.(71)

Realisable assessments suggest biomethane could displace between 13-16% of the UK's gas consumption. These include UK's Biomass Strategy 2023 which estimated biomethane production of 370 PJ in 2025 based on available feedstocks and an assessment by ABDA that estimated 288 PJ (8 bcm) of biomethane could be produced in the UK each year by 2030 – enough heat to power 6.5 million homes. England's target to eliminate food waste sent to landfill by 2030 may provide additional feedstock for anerobic digestion.(336)

9.2.1 Gas Market Structure

As of 2017, Great Britain had a number of options for importing (and exporting) natural gas: two pipelines connected to mainland Europe, five pipelines connected to Norwegian offshore gas fields, and three LNG terminals accessing the global LNG market. The country also has domestic gas reserves (mostly offshore) and eight gas storage sites.(333) Once gas has been produced or imported, it is traded between shippers and suppliers on the wholesale gas market.(333) Shippers transfer the gas through transmission and distribution pipelines, which are operated by private pipeline operators. The gas is then sold to retailers, or directly to end users.(333) The UK's energy regulator, Ofgem, plays a key role in monitoring and regulating retail gas markets, including through price controls and enforcement.(334)

9.3 POLICY SETTINGS

9.3.1 Strategies and Targets

The United Kingdom has committed to lowering emissions by 68% from 1990 levels by 2030, (335) and set a target to achieve net zero greenhouse gas emissions by 2050.(327) In 2023, the UK released its **Biomass Strategy,** to "set out the role biomass can play in reaching net zero, what government is doing to enable that objective and where further action is needed."(336) Biomethane forms a key part of the strategy, with anaerobic digestion for biomethane production presented as the "preferred destination for unavoidable food waste that cannot be redistributed, used as animal feed or processed into biomaterials".(336) The Biomass Strategy also suggests that 30-40 TWh of biomethane production could be critical in enabling the United Kingdom to cost-effectively achieve net zero by 2050. The **Net Zero Strategy: Build Back Greener**, published in 2021, states that the government "will explore the development of commercial-scale gasification and the replacement of the GGSS with a long-term biomethane support scheme."(337) The strategy predicts that biomethane could provide up to 72 PJ (20 TWh) of energy per year by 2050.

In the 2023 **Powering up Britain – Energy Security Plan** the UK government committed to consulting on introducing a policy framework for biomethane to follow the Green Gas Support Scheme. It projects that gas will play "a declining but still significant role in our energy system for decades to come", and that biomethane production will be increased to provide energy security and emissions reductions.(338)

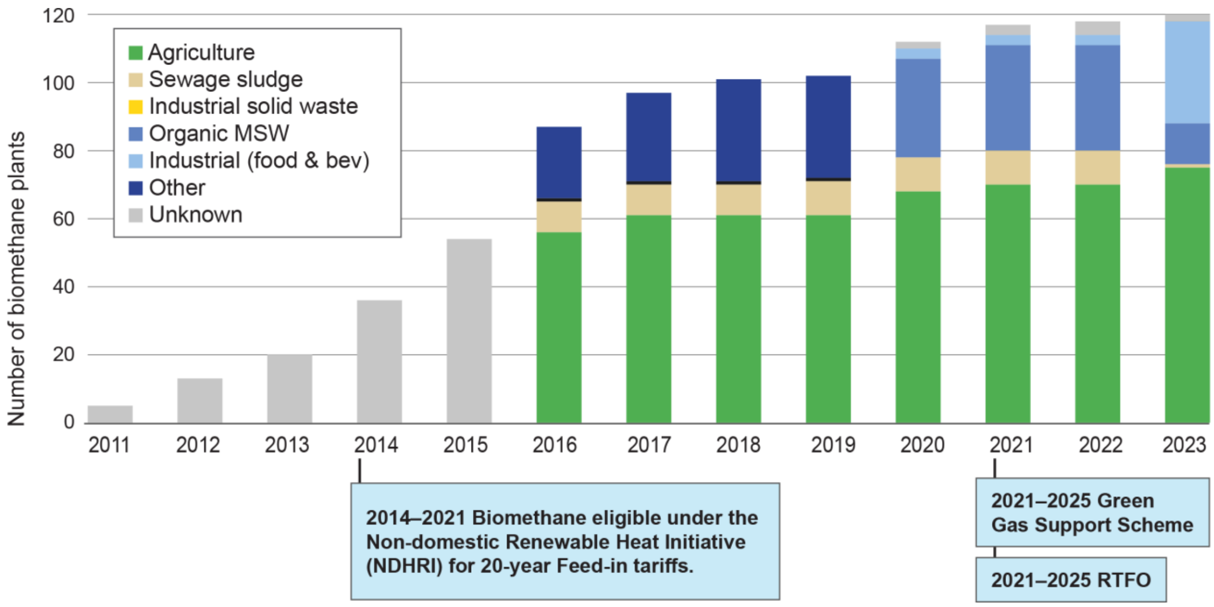

Figure 14. Policy milestones in the development of biomethane projects by type in the UK.

From February until April 2024, the United Kingdom accepted submissions on its **Future Policy Framework for Biomethane Production**. The Call for Evidence for this framework lists a number of barriers already identified by stakeholders, including unclear government strategy or messaging, uncertainties over the demand for biomethane and the future of the gas grid, concerns over the environmental sustainability of some feedstocks and digestates, an underdeveloped supply chain, lack of utilisation of potential revenue streams, grid capacity limitations, and the requirement of propanation to inject biomethane into the gas grid.(327) It forecasts that "any future incentive mechanism that forms part of the framework will move away from tariffs and instead use a market-based mechanism that better prepares the industry to bear responsibility for its long-term growth."(327) The Call for Evidence also sets out how biomethane use in the United Kingdom is projected to evolve over time. Its modelling suggests that until 2035, biomethane will primarily be used to decarbonise the gas grid, which is mainly used for heating, industrial processes, and power. From 2035 to 2050, biomethane's role in decarbonising building heating is projected to decrease due to the uptake of other renewable heating technologies, while its role in delivering peaking power and carbon capture may increase.(327)

9.3.2 Market-Based Instruments and Financial Incentives

Biomethane development has been primarily supported by the Renewable Heat Initiative, and its successor policy, the Green Gas Support Scheme (GGSS). The Renewable Transport Fuel Obligation (RTFO) has also played a role. Although there are many biogas facilities that could convert or expand to producing biomethane, the current GGSS is only eligible for new anaerobic digester systems, despite calls to include converted plants. However, it is anticipated that as support schemes for biogas systems diminish, such systems may upgrade to produce biomethane for transport fuels under the RTFO.

Renewable Heat Incentive (RHI) and the Non-Domestic Renewable Heat Initiative (NDRHI)

The most influential policy for biomethane development has been the **Renewable Heat Incentive.** Introduced in 2011, the RHI aimed to encourage the installation of renewable technologies in place of fossil fuels to heat buildings through the provision of feed-in tariffs for every kWh generated.(339) There were two types of RHI: a domestic RHI for households and landlords, and a Non-Domestic HRI (NDRHI) for industry, businesses and the public sector. Eligible technologies under the NDRHI included biogas combustion from 2011, and from 2014, biomethane injection into the gas grid (BtG). While the NDRHI closed to new applicants in March 2021, existing 20-year FiT contracts will remain in place until 2041. The NDRHI saw a large increase in anerobic digester systems across the UK between 2011and 2017, many which were upgraded to include BtG capability (Figure 7a). Despite the scheme's name, biomethane does not need to be used specifically for heat to qualify, as there is no way to determine the end use after injection.(340)

The NDRHI guarantees a fixed feed in tariff per kWh to producers for a period of 20 years. Feed in tariff rates are tiered depending on the size of the system for biogas projects or the quantity injected into the grid for biomethane projects, as well as the date the project enters the market. Producers of BtG and biogas receive a feed-in tariff paid per kWh. Higher feed in tariffs rates for biomethane were offered in earlier years of the scheme, including for large-capacity injecting plants, which is responsible for the steep increase in biomethane production seen from 2014 onward, which showed fewer projects but with larger capacity (**Figure 7**). Prior to 1 Jan 2015, the biomethane feed-in tariff was set at a fixed amount of 11.9 pence per KWh for BtG,(341) but was amended in 2015 to a three-tiered system of degression, where a tier 1 tariff is given for the first 40,000 MWh (0.144 PJ) injected, a tier 2 tariff for the second 40,000 MWh injected, and a tier 3 tariff for any additional injections.(342) The rates for Tier 1 tariffs are more than double those of tier 3 tariffs, thus providing incentives for both small- and large-scale producers (**Figure 9**). Tariff rates are fixed (index-linked) from the date of commission with tariff rates declining over the life of the scheme to encourage early participation in the scheme.(343) Due to concerns of fewer biomethane and biogas projects coming online as feed in tariffs reduced, and to encourage continuing growth, in 2018 a reinstatement of tariffs at 2016 levels was applied for new projects until 2021 (**Figure 9**).

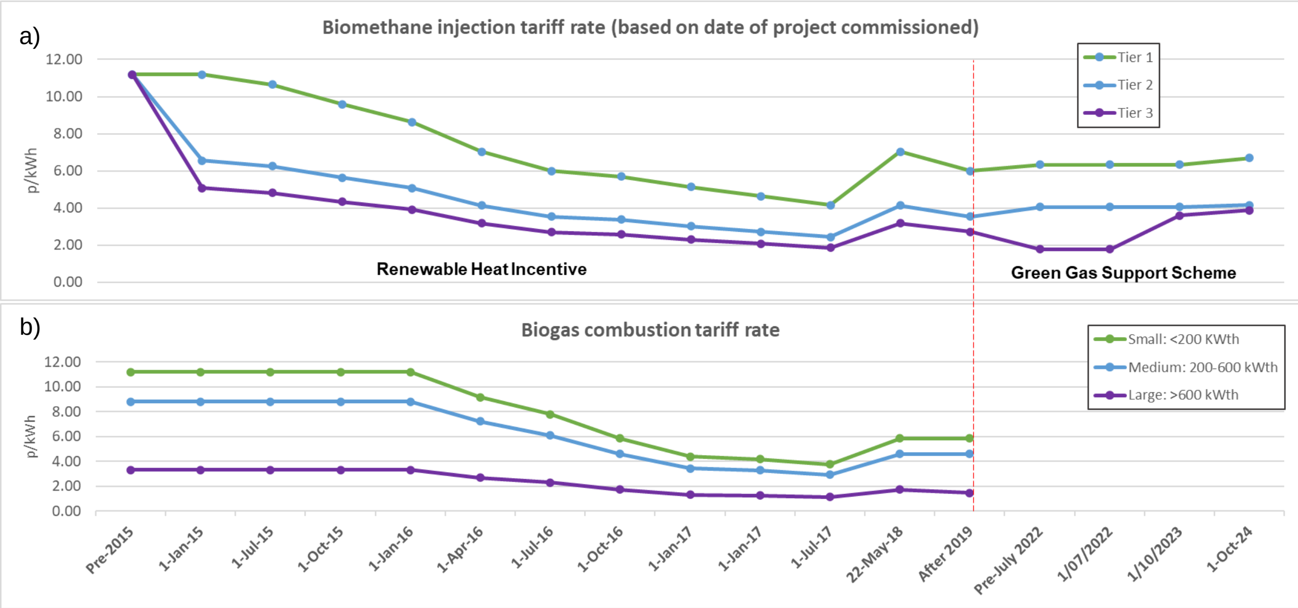

Figure 15. Biomethane injection tariff rates. A) Three-tiered feed-in tariff for A) BtG under the RHI scheme from 2016 to 2019 and then the GGSS from 2019 to 2024; and B) biogas under the RHI scheme. (343–345)

Tiers for biomethane under the RHI and GGSS respectively differ. For Tier 1 = first 40,000MWh (RHI) / first 60,000MWh (GGSS); Tier 2 = next 40,000-80,000MWh (RHI)/ 60,000-100,000 MWh (GGSS); Tier 3 = >80,000MWh (RHI)/ 100,000-250,000MWh (GGSS)

Project eligibility for the NDRHI has been conditional on meeting a number of initial and ongoing obligations. Importantly, projects have had to demonstrate lifecycle greenhouse gas emissions less than 34.8g CO_2 per MJ of biomethane injected (a 60% GHG saving relative to the EU fossil fuel average), and were required to self-report against a set of feedstock sustainability criteria.(346) In 2015 it became a requirement that producers only use sustainable solid biomass, requiring that non-waste feedstocks are purchased from an approved provider or that the producer register themselves as a “self-supplier” of sustainable biomass. The NDHRI was broadly successful in incentivising the grid injection of biomethane. The Incentive’s 2024 Annual Report estimated that 2.5 bcm of biomethane was injected into the gas grid since the scheme’s launch, with payments from the incentive made for 389.9 m^3 of injected biomethane in the 12 months from April 2023 to March 2024.(340)

Green Gas Support Scheme (GGSS)

The closure of the NDRHI to new applications in 2021 to November 2025 was followed by the **Green Gas Support Scheme**. A favourable mid-scheme review in 2023/24 extended the period in which project proponents can enter the scheme to March 2028. Like its predecessor, the GGSS operates as a three-tiered feed-in tariff based on the amount injection with lower rates over higher production thresholds. Unlike the NDHRI, the rates remain relatively unchanged over time, therefore they do not penalise later entrants. Th tariff rates are reviewed annually to ensure both that billpayers receive value for money (i.e. gas bills do not become too high) and that tariffs are sufficient enough to encourage new entrants. Key differences between the GGSS and the NDHRI are that FiT contracts were reduced from 20 to 15 years, but that tiered bands were adjusted to encourage greater biomethane production. This has been achieved by expanding Tier 1 production from 40,000 to 60,000 MWh of BtG, increasing tier 2 to the next 40,000 MWh injected, and tier 3 up to the next 150,000 MWh injected, with the FiT rate doubling for Tier 3 from 2023. Like its predecessor, the GGSS also requires that at least 50% of the biogas produced must be derived from wastes and residues (as opposed to energy crops).(154)

Biomethane certification

The United Kingdom currently has one industry-led green gas certification scheme in operation, the **Green Gas Certification Scheme**. Run by Renewable Energy Assurance Limited, this scheme uses sustainability criteria from the Renewable Heat Incentive to certify grid-injected biomethane. Certificates are purchased voluntarily, for the purpose of advertising emissions reductions or offering consumers certified green gas (327).

The UK's Emissions Trading Scheme, a cap-and-trade system for financialising emissions, also plays a role in incentivising biogas and biomethane. The combustion of solid or gaseous biomass (including biogas and biomethane), or bioliquids for purposes other than energy generation, has an emission factor of zero for the purpose of calculating emissions under the ETS. However, grid-injected biomethane currently receives no incentive under the UK Emissions Trading Scheme, and the green value of this gas can only be traded through voluntary certification schemes.(327)

The United Kingdom also has in place a Contracts for Difference scheme for low carbon electricity, which operates through private law contracts between a government-owned company and a low carbon electricity generator. For the 15-year period of each contract, the generator is paid the difference between the strike price (a benchmark price intended to reflect the cost of investing in low carbon electricity) and the market price.(347) Anaerobic digestion is covered as an eligible technology under this scheme, but to date no AD projects have established contracts for difference.(348)

Biogas production under the Renewables Obligation & Feed-in Tariffs

Biogas production for electricity from landfills and anaerobic digesters with Combined Heat and Power (CHP) units received a significant boost from two support schemes: the **Renewables Obligation** (RO) for new projects generating 50kW and above from 2002 to 2017, and a feed-in tariff scheme for new projects between 2010 to 2019, designed to encourage households and businesses to generate and export renewable power to the grid. Under both schemes, a range of technologies were eligible, including ADs and CHPs. Projects accrued payments over a 20-year duration for both schemes, meaning that although the schemes are closed to new applicants, many projects will remain supported until as late as 2039. Under the RO, a set number of Renewables Obligation Certificates (ROCs) are provided for each MWh generated depending on the technology used. For instance, AD-CHP facilities received 2 ROCs per MWh until April 2015, 1.9 the following year and 1.8 until April 2017. The value of each ROC is subject to an open market and varied between £45–50 per MWh in 2022.(343) For the FIT Scheme, three tariffs were included for ADs based on size (Figure 15b).

Renewable Transport Fuel Obligation (RTFO)

Since 2010, biomethane has been an eligible renewable transport fuel for use in natural gas vehicles under the **Renewable Transport Fuel Obligation (RTFO)**, which came into force in April 2008 under the *Energy Act 2004* and remains currently active. The RTFO mandates that suppliers of transport fuels who supply over a 450,000 litres per year include a specified volume of renewable fuel as a percentage of fuel supplied, as well as a small volume of development fuels. This proportion has steadily increased since its inception, from 2.56% in 2008 to 11.8% by 2023 (plus 1.142% for development fuels), and is expected to increase to 19.47% by 2032.(352)

Obligated suppliers that fall short of the required renewable fuel share are able to purchase Renewable Transport Fuel Certificates (RTFC) on an open market from renewable fuel suppliers or fuel suppliers who are certified as having sold more renewables than their obligation.(352) If obligated suppliers do not meet the target or secure the necessary certificates, they must pay a buy-out price (which was 50 pence per normal RTFC and 80 pence per development RTFC as of 2024). RTFCs are awarded for each litre of sustainable renewable fuel produced (or each kilogram of sustainable gaseous fuel produced).(154) Biofuels made from waste feedstocks receive double certificates under this scheme.(154) In 2023, biomethane producers received 1.9 RTFC per kilogram, or 3.8 RTFC / kg for biomethane made from waste feedstocks.(154) Non-crop RTFCs have traded at around 20 pence per certificate since 2023.(353) To qualify under the RTFO, renewable fuels must demonstrate certain sustainability criteria and a carbon intensity (CI) at least 55-65% lower than fossil fuels, verified by a recognised sustainability standard scheme. In 2018, following reports of a number of negative environmental impacts associated with biofuel feedstocks from food crops, the RFTO standards were tightened to mandate that half of all biofuels under the scheme are made from waste feedstocks, limiting sourcing from food crops to just 4% in 2018, 3% in 2026, and 2% in 2032.(354) This amendment has correlated with an increase in biomethane production under the scheme (**Figure 16a**).

Despite recent growth, biomethane still makes up only a small fraction of the United Kingdom's total renewable transport fuel (3% or ~111 million litres eq.).(355) The total amount of energy produced by biomethane used as a transport fuel in 2023 was 3.30 PJ (comprised of 2.28 PJ of compressed biomethane and 1.02 PJ of liquified biomethane),(356) constituting roughly 10% of the country's overall biomethane energy supply (**Figure 7c**). Importantly, producers cannot claim both Renewable Transport Fuel Certificates and credits or subsidies under the NDRHI or GGSS schemes.(327)

Table 10. A comparison of the design features of the two main support schemes for biomethane in the UK, the NDRHI and the GGSS

Features	Non-domestic Renewable Heat Incentive (NDRHI) (2014-2020)	Green Gas Support Scheme (GGSS) (2021 – 2025)
Open and closing date for new biomethane projects	2011 to 31 March 2021 (extended for some applicants to 31 March 2023 due to Covid delays). Biomethane injection introduced in 2014.	November 2021 – March 2028
Policy goal	To encourage the installation of renewable heat technologies to help reduce carbon emissions from the heating (and energy) sector and to support the UK's renewable energy targets.	To increase the proportion of green gas in the gas grid.
Eligible technologies	A range of heating technologies are permitted including biogas combustion (200Wth and above) and CHPs from anaerobic digesters. Biomethane injection was included from 2014 but can be used for purposes other than heating.	New anaerobic digestion biomethane plants only.
Financial incentive	Three-tier system of feed-in tariffs guaranteed for 20 years. Payments are made quarterly based on the amount of BtG injected. Tiers are based on quantity of BtG generated.	Three-tier system of fixed feed-in tarrifs guaranteed for 15 years (adjusted for CPI). Payments are made quarterly based on the amount of BtG injection. Tiers are based on quantity of BtG injected.
Who pays?	The UK's non-domestic Renewable Heat Incentive (RHI) is funded by the Government, which sets the tariff levels. A total of £4.99 billion was paid to scheme participants for the 89 TWh of heat generated since the scheme began.(350)	The Green Gas Levy places obligations on licensed gas suppliers, including a requirement to make quarterly levy payments, in order to fund the GGSS.(351) Two separate budget caps are used, one to set the Green Gas Levy and an overall cap to limit approved projects within budget.
Key agencies	Department for Energy Security and Net Zero reviews policy and sets the rules. Ofgem administers the scheme.	Department for Energy Security and Net Zero reviews policy and sets the rules. Ofgem administers the scheme.
Administrator	Ofgem	Ofgem
Eligibility criteria	Minimum waste thresholds of 50%, to promote the use of wastes and residues as a feedstock instead of energy crops.(362)	GHG lifecycle emissions less than or equal to 24g CO_2e / MJ of biomethane injected; minimum waste threshold of 50% and land criteria around environmental protections from which the biomass is sourced and compliance with sustainable forestry management practices.

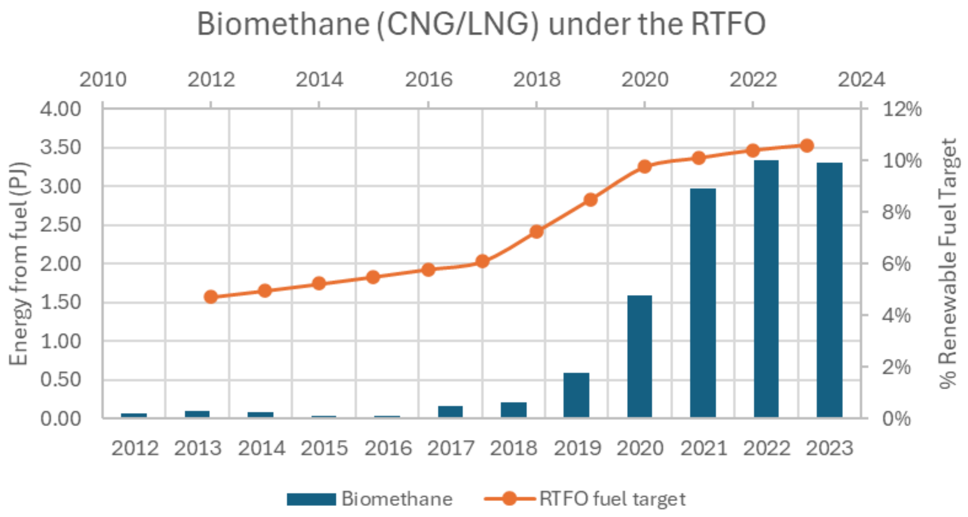

Figure 16. Biomethane-based renewable fuel volumes under the RTFO. Source: UK.gov

Carbon Pricing

The United Kingdom has a cap-and-trade emissions trading scheme, established while the country was part of the EU and continued after its departure. The scheme applies to "energy intensive industries, the power generation sector and aviation".(357) In June 2023, the UK ETS Authority announced that "emissions from Energy from Waste (EfW) or waste incineration" will be included in the scope of the UK ETS from 2028.(358) This is intended to further incentivise anaerobic digestion and biomethane production, creating additional demand by rewarding the carbon savings of AD compared to other waste removal options. Regarding certification schemes to exempt biomethane emissions from the ETS, the Authority has pledged to "explore the interactions between biomethane and the UK ETS and expect to set out further details in due course."(358)

The UK also has a fuel duty in place. This tax extends to biofuels if they are used as motor fuel or as an additive, but not when they are used for any non-motor fuel use.(359)

The UK plans to implement an import carbon pricing mechanism, placing a tax on the import of carbon-intensive products. This is intended to be operational by 2027.(360)

Renewable Gas Certification

Renewable Gas Guarantees of Origin (RGGOs) in the United Kingdom are issued, transferred, and retired by the Green Gas Certification Scheme (GGSC). As with EU GOs, these may be freely traded through a book-and-claim system, independently of the gas that produced them. The main purpose of this is to facilitate the voluntary purchase of certified renewable gas. RGGOs are not official GOs in accordance with the requirements of the EU Renewable Energy Directive, but can be traded with countries such as Germany under reciprocal arrangements.

9.4 REGULATIONS

Feedstock Supply

The Biomass Feedstocks Innovation Programme provided £30 million in funding for innovative ideas that address barriers to the production of sustainable UK biomass feedstocks through breeding, planting, cultivating, and harvesting.(361) A 2020 stakeholder analysis reported that feedstock availability was one of the three key concerns of biomethane stakeholders in the UK (alongside a lack of parity with natural gas and a lack of supportive policy, prior to the Green Gas support Scheme). The analysis suggested several possible policy mechanisms to address this, including for England to implement food waste segregation mandates and banning incineration of food and non-segregated wastes; relaxing the 50% energy crop limit for feedstocks, or providing dispensation for 'break' crops grown on marginal land; and implementing an independently co-ordinated national feedstock assessment program.(349)

Grid Injection

In the UK, the costs of connecting biomethane plants to the gas grid are borne by biomethane producers.(77) Biomethane installations must pay for the full cost of connecting to the natural gas network, which is determined on a site by site basis and varies considerably between different grid operators, though the industry is pushing for this process to be standardised and for costs to be reduced. Gas grid capacity limitations remain a barrier to the injection of biomethane into the grid and the development of new AD plants. As Future Biogas noted in a submission to parliament: “The location of biomethane plants is constrained by a number of factors. Each must be situated near to a gas grid to enable export of the gas, and to farmland to a secure supply of feedstock and for digestate spreading. Consequently, most plants are situated in rural areas, treating agricultural feedstocks and spreading its nutrients back to soil. In many cases, however, it is the suitability of nearby gas infrastructure that will ultimately determine the viability of biomethane production. To connect to the gas grid, a biomethane plant developer will typically submit an application to the local gas distribution networks (GDN)… to evaluate the pipeline’s capacity for biomethane injection, assessing its seasonal flow rates and downstream demand throughout the year. In many instances, particularly on lower pressure pipelines, the DAS suggests that biomethane injection may not be possible for large portions of the year, citing a lack of capacity within the pipeline. Such a response can present an existential risk to project development.”(363) Future Biogas goes on to say that the DAS often reports two reasons for lack of capacity: ill-equipped gas infrastructure; and risk-averse modelling around the consistency of supply. Though the former could be addressed with established reverse compression technologies, Future Biogas claims that some gas distribution networks are reluctant to allow potential biomethane suppliers to install such facilities and relinquish control over gas flow. The organisation recommends mandating the development of industry standards that would enable developers to fund and construct reverse compressors, noting the possibility that these could then be operated by the gas distribution network operators.(363)

Gas Specification

The United Kingdom has a variable grid injection oxygen limit of either 0.2% mol/mol or 0.001% mol/mol, depending on the sensitivity of the final consumers.(322)

Digestate Use

Digestate that reaches the **British Standard Institution’s Publicly Available Specification 110** and **Quality Protocol** standards does not need a permit to be spread. If PAS 110 standards are not reached, a permit is required unless an exemption applies (spreading under 50 tonnes/hectare from pre-defined feedstock, with a storage limit of 200 tonnes). Australian stakeholders highlighted the United Kingdom’s system of digestate regulation as a particularly desirable model – allowing digestate to be spread without a permit (provided quality standards are met) greatly enhances the ability of biomethane producers to use this resource commercially, and its value as a product of anaerobic digestion.

In the United Kingdom, anaerobic digestors are regulated through a three-tier permitting system. The first level is a regulatory exemption, meaning that no permit is required (although the project must still be registered with the Environmental Agency). This is available for on-farm anaerobic digestion producing digestate for use as a fertiliser, for biogas burned for energy, and for the anaerobic digestion of biodegradable waste to produce fertiliser.(364) The second level of regulation is standard permitting, where projects fit within pre-defined specifications. Standard permitting “enables anaerobic digester operators (processing no more than 100 tonnes per day) to carry out anaerobic digestion of wastes and also combustion of the resultant biogas in gas engines. The rules also allow use of gas turbines, boilers, fuel cells and treatment and/or upgrading the biogas to biomethane. Permitted wastes include those controlled by the Animal-By-Products Regulations but do not include hazardous wastes.”(365) Finally, bespoke permitting is available for projects that do not fall within an exception or the standard permitting specifications.(366)

“In the United Kingdom, digestate is generally classified in two categories: digestate with waste status and digestate with a product status. Total digestate production was 705,771 tonnes DM in 2021. The production of whole digestate amounted to 331,158 tonnes DM. Plants with separation units produced a total of 256,290 tonnes DM of liquid fraction digestate and another 118,323 tonnes DM of solid fraction digestate. The production of compost from digestate is not yet being quantified. A small number of the UK’s facilities aerobically mature separated digestate and a small portion of plants co-compost their digestate at a composting facility, where it is combined with other biodegradable streams. Relatively little digestate in the UK is upgraded.”(324)

10. Italy

10.1 EXECUTIVE SUMMARY

Italy was selected as a case study of a less mature market based on its rapid growth in recent years and its proactive approach towards incentivising biomethane production for multiple end-uses. (311, 4) In 2018, Italy had one biomethane plant; today, it boasts 133 biomethane plants alongside more than 1,800 operational biogas plants.(71,72) Between 2022 and 2023, Italy's biomethane capacity increased by 238% - by far the largest percentage growth in the European Union.(4) This growth is projected to continue, spurred by substantial state investments (71) of €1.9 billion committed under the National Recovery and Resilience Plan, and additional EU funding of €4.5 billion approved in August 2022.Italian biomethane is primarily used as a transport fuel; production has been driven by feed-in tariffs and feed-in premiums, rather than by certificate-based obligations like fuel schemes in the United States. Tariffs were supplemented by substantial capital grants, Guarantees of Origin, the EU emissions trading scheme, permissive oxygen standards for grid injection, and regulations streamlining the use of digestate as a fertiliser.

10.2 BIOGAS, BIOMETHANE, AND ENERGY SNAPSHOT

As of 2023, Italy has 1,803 active biogas plants,(71) and 133 biomethane plants,(72) producing 28 PJ of biomethane and around 90 PJ of biogas. (Figure 17) (71) Combined, biogas and biomethane account for 5.6% of Italy's natural gas consumption (2,110 PJ).(71) On a per capita basis, this equates to approximately 0.45 GJ of biomethane per person. Looking ahead, Italy's rapid biomethane growth is projected to continue. In the first three of four tenders held in 2024, a total of 243 biomethane plants were approved, with a combined annual productive capacity of 38 PJ and a further 30 new bio-LNG plants were under development.(71) Agriculture provides more than half of feedstocks for Italy's biogas and biomethane (~57%) with additional inputs from landfills, sewage sludge, organic municipal solid waste, and industrial waste.(71) As of 2023, biomethane in Italy was used exclusively as a transport fuel.(71) Its distribution network includes five bio-CNG stations, three bio-LNG stations, 1,672 CNG stations, and 166 LNG stations (the latter two through fuel blending).(71)

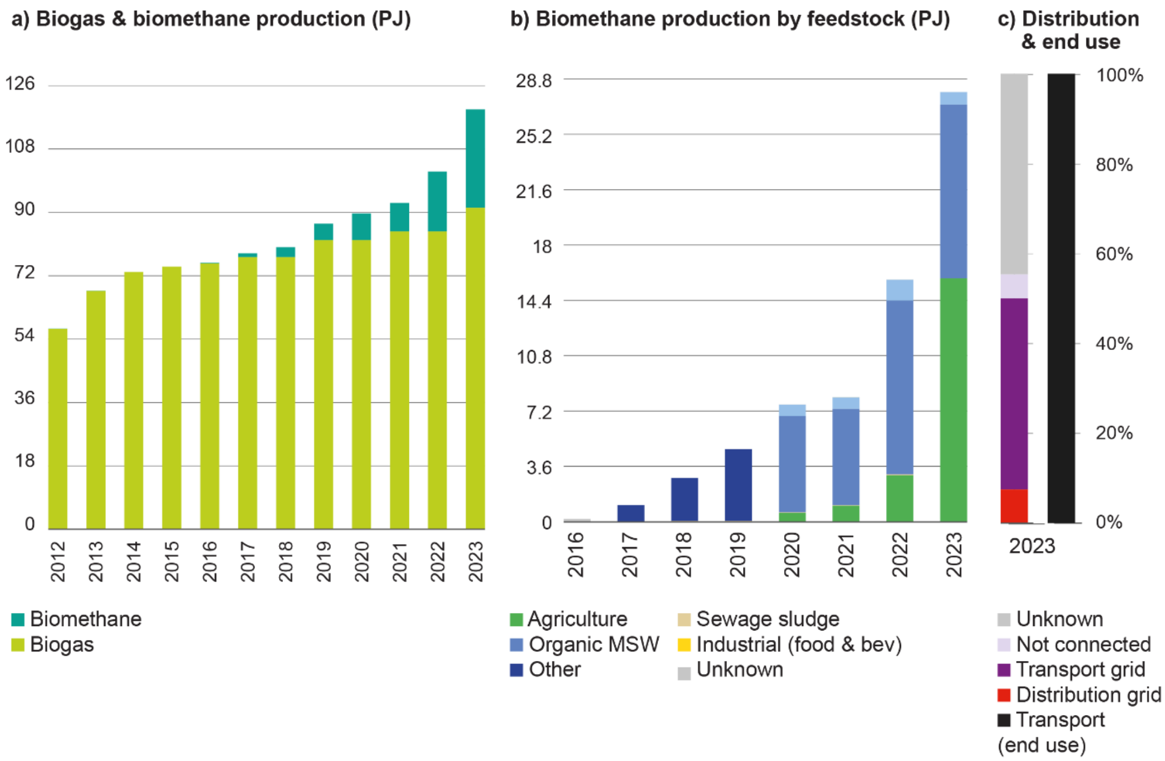

Figure 17. Development of biogas and biomethane, end use and distribution pathways in Italy.

Gas Market Structure

In Italy, gas distribution and transmission is primarily operated by Snam – a private, partially government-owned company that holds a monopoly on gas distribution, operating a vast nationwide pipeline network covering (~32,000 km) and supplying roughly 95% of the Italian gas market. Snam operates under heavy regulation, with close ties between the company and the government., The primary distribution company is Italgas, with other significant distributors including 2i Rete Gas and A2A, all operating under local government concessions.

10.3 POLICY SETTINGS

10.3.1 Strategies and targets

Italy released its **National Recovery and Resilience Plan (NRRP)** to the European Commission in 2021 which was approved to become the largest national plan utilising funds from the Next Generation EU policy at a total of €235 billion euro. The NRRP is broad in scope, addressing post-Covid economic and social recovery through six streams, one of which is for green transitions. Within this stream, the NRRP committed investments of €1.9 billion for the production of biomethane, regulated by applicable regulations and legislative decrees to increase production by 2.3-2.5 billion cubic metres (404). This ambition was increased in August 2022, where European Commission approved € 4.5 billion scheme to support biomethane production in Italy for 4 bcm of biomethane per year to be produced by 2026 with the allocated funds.(368)

10.3.2 Supply-Side Instruments and Incentives

Ter Biomethane Decree

To support these production targets under the NRRP, the Ministry for the Ecological Transition issued a decree in September 2022, known as **Ter Biomethane Decree**, which came into effect in January 2023 (Figure 18). The decree extends the scope of the previous biomethane instruments beyond transport to other uses including heating, industrial, residential, tertiary and agricultural sector. Its primary function is to regulate the modes of allocation of incentives for grid-injection biomethane which include both feed-in tariff and a premium tariff assigned through competitive process. The decree earmarked €1.73 billion in grants through competitive procedures. 1.6 billion euros are being distributed as capital incentives, for either the construction of new biomethane plants powered by agricultural feedstocks or organic waste, or for the conversion of existing electricity-producing agricultural biogas plants into biomethane plants injecting into the gas network. The remaining $130 million is allocated to projects aimed at enhancing the management of digestate, specifically as part of a broader strategy to produce biomethane.

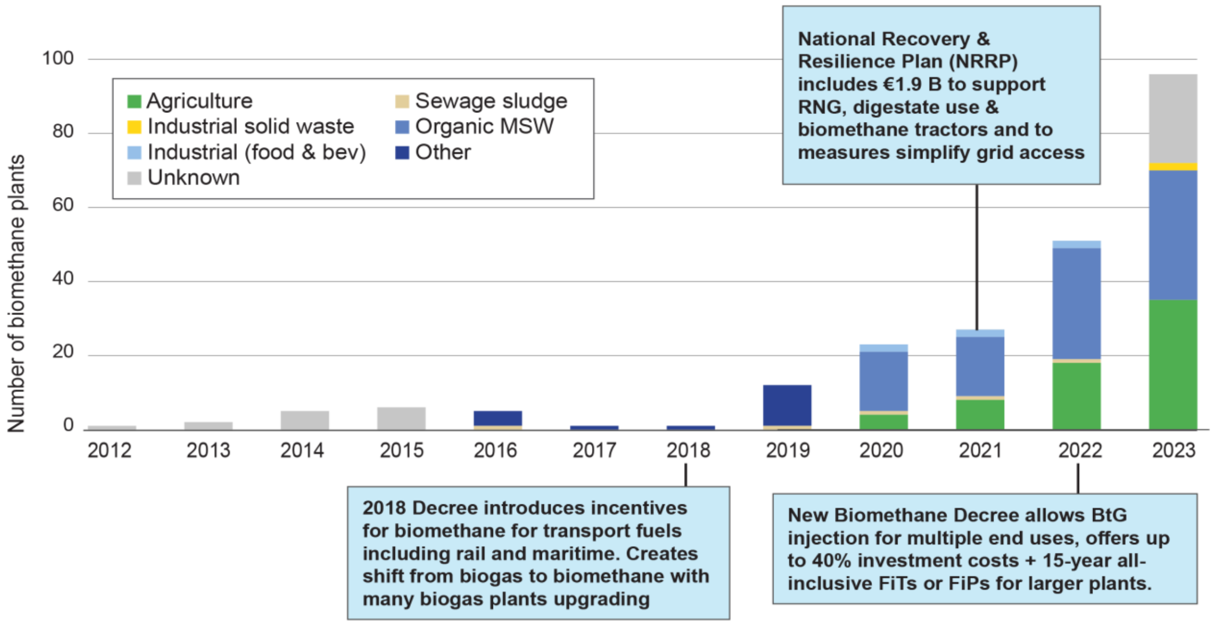

Figure 18. Development in the number of biomethane projects by facility type in Denmark following key policy milestones.

In particular, the Ter Biomethane Decree, in order to support and promote the biomethane production provided for in the NRRP, regulates the allocation of incentives to biomethane injected into the natural gas network and produced, in accordance with the criteria laid down in the RED II Directive, from newly built plants or biogas plants undergoing reconversion.(405). The most relevant measures introduced under the Ter Biomethane Decree for plants respecting the requirements set forth therein are:

a) a capital contribution equal to the 40% on the eligible costs of the investment incurred; and

b) an incentive tariff scheme consisting of feed-in tariffs and feed-in premiums, applied to the net production of biomethane, disbursed from the date of commissioning of the plant and for a duration of 15 years (to be calculated as indicated under the decree).(372)

Incentives are awarded based on a competitive tender procedure based on annual quotas. This new Decree coexisted with the prior 2018 scheme until it concluded at the end of 2023, with biomethane plants having the option of selecting either scheme.(370) As of August 2024, three tenders had been held, collectively covering a production capacity of 1 bcm of biomethane, or 38 PJ per year, of which 243 biomethane tenders were accepted.(71) The Decree is planned to run until the end of June 2026.(370) Smaller grid-injecting biomethane plants (those with a production capacity of 250 Smc/h or less) have the option of an all-inclusive tariff, where the government arranges the offtake of both the biomethane itself and its associated Guarantees of Origin.(372) Larger biomethane plants receive a feed-in premium tariff equal to the difference between the all-inclusive tariff and the average monthly price of gas plus Guarantees of Origin.(373) Under this arrangement, larger biomethane plants are responsible for finding purchasers for their gas and Guarantees of Origin (while smaller plants have the option of an all-inclusive tariff or a feed-in premium). To access incentives, producers are required to obtain appropriate permits, possess an accepted network connection quote where needed, ensure biogas recovery tanks are covered for at least 30 days or have a composting plant available, and comply with sustainability criteria according to the intended use of biomethane.

Table 11. Capital and production incentives under the Ter Biomethane Decree (407).

Facility type	Plant size	Capital incentives			FiT rates
	(m^3 /h)	(new) €/m^3/h	(reconversion) €/m^3/h	% capital limit	(€/MW h)
Ag facilities	<100	33,000	12,600	40	115
	100-500	29,000	12,600	40	110
	> 500	13,000	11,600	40	110
Organic waste	Any	50,000	-	40	62

Incentives for biogas

Italy's biogas sector has been in development since the early 1990s, with a green certificate system introduced in 1999.(71) Italy's major biogas market growth was predominantly driven by a fixed feed-in tariff for the production of renewable electricity, which was introduced in 2008.(71,311) This feed-in tariff was available for plants with a capacity of up to one megawatt, and was open to applicants from 2008 until 2012.(71) This was followed by a combined feed-in tariff and feed-in premium model from 2013 until 2016, with FiTs offered for plants with a capacity below one megawatt and a FiP for plants with a capacity greater than one megawatt. These tariffs were then replaced by a similar model, but with a new cutoff point for feed-in tariffs set at 500kW over which no tariff would be paid.(369) Amendments continued in 2018, 2021, and 2022, with the cut off limit for set at 300kW in 2022.(370) Tariffs were guaranteed for a period of 15 or 20 years.(370) These support schemes were reduced compared to those available from 2008-2012, resulting in a reduced (but still steady) rate of growth in biogas.(71) As of March 2023, this tariff was set at 280 €/MW.(370) As this feed-in tariff is for the generation of renewable electricity, it does not subsidise biomethane grid injection.

2018 Biomethane Decree

Prior to the Ter Biomethane Decree, the Italian Government's **Decree 02 March 2018** kick-started incentivises for biomethane production for use as a transport fuel. This was fed into a larger renewable transport fuel scheme introduced in 2014, that obligated a percentage of biofuels of total supply, increasing each year. In 2022, 9% biofuels and 1.85% advanced biofuels were required, of which biomethane was classified as an advanced biofuel.(77) The use of biomethane as a transport fuel was enabled by existing infrastructure,(77) and by Italy having one of the largest methane vehicle fleets in the world.(172) The Decree set a target of 1.1 bcm of biomethane for use in the transport sector by 2022.(154) This system was based on the issuance of "certificates of release for consumption" (CICs) for each 10 GCal of biomethane produced, which could then be sold to transport fuel suppliers to meet legislated obligations.(370) Twice the number of certificates were issued for 'advanced biomethane,' which was produced using at least 70% municipal solid waste, manure, or agricultural feedstocks.(370) This was accompanied by what was effectively a feed-in tariff for advanced biomethane – a 10-year scheme where the government-appointed agency GSE would purchase the advanced biomethane certificates for a fixed value.(154) This support scheme was limited to biomethane plants that were operational before December 2022.(406)

The effectiveness of the 2018 Decree was hampered by a number of design and implementation flaws. Deadlines to apply for access to the scheme did not provide adequate time for interested parties to obtain the necessary permits and approvals.(406) This problem was exacerbated by the complexity of permits and the lengthy timeframes required for approval. Secondly, biomethane was incentivised exclusively for the transport sector, limiting its impact.(406) Further, relative to electricity feed-in tariffs for biogas facilities, incentives for biomethane were not large enough to incentivise upgrading biogas to biomethane. Finally, the incentives did not sufficiently incentivise biomethane produced from agricultural feedstocks, particularly in light of the restrictive sustainability requirements imposed on agricultural feedstocks by the EU Renewable Energy Directive II. As a result of these issues, the target of 1.1 billion cubic meters of biomethane production was significantly undershot, with an actual biomethane production of 0.3 billion cubic meters of biomethane production in 2022. (406)

10.3.3 Demand-Side Instruments and Incentives

Carbon Pricing

Italy places a price on the consumption of fossil fuels through its participation in the EU Emissions Trading Scheme and through fuel excise duties.(374) While Italy does not have an explicit carbon tax, it is currently under consideration.(375)

10.4 REGULATIONS

Feedstock Supply

The **Italian Waste Framework Legislation** sets a target of 65% separate municipal solid waste collection, requiring municipalities to implement source separation of food waste. In 2015, this resulted in the separated collection of 100 kg of food waste per person.(376) The 2022 biomethane decree has differing feed-in tariffs depending on the type of feedstock used. Biomethane produced from agricultural residues and by-products receive a higher tariff, to compensate for the greater costs of these feedstocks compared to municipal solid waste.(154)

Grid Injection

Legislative Decree 199/2021 extended "simplification measures related to the infrastructures for connecting biomethane to the grid".(370) While the costs of connecting biomethane plants to the gas grid are paid by biomethane producers, the network operator is responsible for odorising the gas if necessary.(77)

Gas Specification

Italy has a permissive oxygen limit of 0.6% mol/mol for injection into the gas grid.(322)

Certification

Italy has issued and auctioned Guarantees of Origin domestically since 2013. These are issued by Gestore dei Servizi Enrgetici (GSE).(377) In March 2024, 375.5GWh of non-exportable biomethane GOs were auctioned from fourth-quarter 2023 production, with an average weighted price of €1.20/MWh.(320)

Digestate

Italy's **Interministerial Decree 5046** of 25 February 2016 sets out regulations for using digestate as a by-product (for use as a fertiliser). The digestate must result from permissible inputs, which include agricultural residues, manure and effluent, wastewater, and food wastes. The digestate producer must demonstrate that the digestate will be used for agronomic purposes, and that it meets specified quality standards. Digestate that results from biowaste or sewage sludge is classified as a waste under the **Legislative Decree 152** of 3 April 2006. The solid fraction of this waste can be further treated by an aerobic process to become classified as compost by meeting the quality standards of the Legislative Decree of 29 April 2010, while the liquid fraction may receive authorisation for direct agricultural use. Of the total €1.7 billion invested into biomethane in the 2022 Decree, €130 million is earmarked for projects aimed at enhancing the management of digestate, specifically as part of a broader strategy to produce biomethane. In Italy digestate is classified as either "agrozootechnical" or "agri-industry" on the basis of the feedstocks used.(324) Digestate may be used in organic farming in Italy with the Italian Biogas Association having published guidelines for its use. Timelines for spreading digestate in Italy are regulated by the Interministerial Decree no. 5046 of 25 February 2016, which prohibits digestate application during a 90-day period (spanning November to February).

Permitting and approvals

Stakeholders we interviewed from Italy noted that the key barriers to progressing biomethane even further in Italy is the long and complex permitting and approvals times and insufficient time for incentive schemes. For example, the Decree for new projects was only open between 2022 and 2026, but the bureaucracy of permitting often takes many years longer than this. Another barrier of note was that many facilities already receive green credits for renewable electricity from biogas, meaning that, along with costs to upgrade, upgrading to biomethane does not provide sufficient incentives. (interviewee, pers. comm.)

11. Key lessons and policy options for Australia

This report has surveyed the policy mechanisms employed to incentivise biomethane production in five countries: Canada, Denmark, Italy, the United Kingdom, and the United States as well as provided an overview of the European Union's key schemes. Each country's installed biomethane and biogas production capacity are summarised in **Table 12**.

Diverse stakeholders from our case countries and Australia across industry and government were interviewed as part of this research to understand their experience with and views of overcoming barriers to further development of biomethane in Australia. Overall, several key themes emerged from the interviews relating to policy priorities and how they shape both the supply and demand for renewable gas. These themes have been integrated into the analysis presented below. Drawing from our policy dimensions and enablers framework (Table 5, Chapter 2), the following key lessons and policy options is structured into five findings that address the dimensions needed to enable new innovations such as biomethane technologies to be scaled and deployed (*legitimacy, market structure, financial incentives, supportive regulation, and knowledge and skills*).

1. Recent policy developments in Australia can enable viable biomethane projects to be developed now, but significant investment and scale up in projects will require additional policy levers. State and federal governments should consider taking a more technology-neutral position by expanding the focus to date from green hydrogen to include all renewable gases, including biomethane.
2. Biomethane in Australia lacks legitimacy as being perceived as an acceptable and feasible solution by governments, policymakers, as well as investors, financiers and project proponents. Our analysis found that part of this stems from a lack of knowledge, understanding and capability about biomethane technologies and its potential benefits, which in turn has led to a lack of policy action. Federal and state governments should consider developing a firm policy direction and explicit targets for biomethane to improve confidence for investors and project developers as well as increasing capability and coordination for bioenergy in key government agencies.
3. A robust market structure and financial incentives are needed to improve the financial viability and assurity of biomethane projects. Financial instruments could include government support incentives on the supply side, regulatory targets for biomethane quotas on the demand side or a combination of both. Our findings indicate that there is no one-size-fits-all policy necessary for a biomethane industry. Growth of biomethane has been primarily driven by feed-in tariffs in Denmark and United Kingdom, by mandatory targets for grid-delivered gas in Canada, and by mandatory targets for renewable transport fuels in the United States and Italy (**Table 14**). What both supply-side and demand-side instruments have in common for success is the guarantee of a long duration of predictable returns to assure the viability of projects and improve the cost-competitiveness of biomethane relative to natural gas. Other important policy design considerations are discussed. Based on Victoria's proposal of a Renewable Gas Target, we would recommend similar design features of policies employed by Canadian provinces that have introduced mandated targets for gas retailers – specifically a cost-distribution model between voluntary customers and a small portion spread across the entire gas customer base to be feasible. The Australian government should also consider a more technology-agnostic approach by expanding existing support schemes for hydrogen to include biomethane and other renewable gases.
4. An enabling regulatory framework (dimension 4) must underpin Australia's biomethane market for it to succeed. We identify key gaps that need to be addressed, drawing on international lessons and best practice. For project developers, operators and investors, establishing a sustainable feedstock supply and valorising digestate are key success factors that can be supported through a number of opportunities identified, many which require regulatory reforms.

Table 12. Summary of biomethane and biogas production of case countries in 2023.

Country (sources)	Biomethane capacity (PJ)	Per capita biomethane capacity (GJ)	Number of biomethane facilities	Biogas capacity in 2023 (PJ)	Number of biogas facilities
Canada (402)	~17	0.42	32	22	300
Denmark (71, 72)	27	4.51	58	5	122
Italy (71, 72)	28	0.45	133	~90	1,803
United Kingdom (71, 72)	27	0.40	119	76	1,233
United States (157, 162)	114	0.34	305	697*	2,327

**Includes all biogases (biogas and biomethane). 697 PJ calculated from American Biogas Council report of total annual biogas output of 1.3 million standard cubic feet per minute. Serfass, September 2024. Population data for 2023 from the World Bank was used to calculate per capita amounts.(378)*

Table 13. Key and supporting policy mechanisms in case study countries.

Country	Key Policy Mechanisms	Supporting Mechanisms
United States	Renewable transport fuel obligations	Capital grants, tax credits, emissions trading scheme
Canada	Renewable gas obligations for grid injection	Renewable transport fuel obligation, emissions trading scheme, carbon tax, capital grants
Denmark	Feed-in tariffs and feed-in premiums for grid injection	Capital grants, renewable transport fuel obligation, emissions trading scheme,
Italy	Capital grants, feed-in tariffs and feed-in premiums	Renewable transport fuel obligation, emissions trading scheme
United Kingdom	Feed-in tariffs for grid injection	Capital grants, emissions trading scheme

Point 1: Australia's current policy mix can enable viable biomethane projects to be developed now, but significant investment in biomethane projects and scale up will require additional policy levers.

As of early 2025, Australia has in place many of the policy instruments needed for a nascent biomethane market:

1. Certification: biomethane can now be certified under GreenPower, enabling certificates to be traded between producers and buyers, enabling purchasers to directly reduce their Scope 1 emissions.
2. Regulatory demand: reforms to the Safeguard Mechanism create regulatory demand for ACCUs and GreenPower certificates from Safeguard Facilities who are mandated to reduce their emissions by 4.9% per annum from their determined baseline, and
3. Supply incentives: biomethane projects can register under the ACCU Scheme's biomethane package to generate and sell carbon credits ACCU credits to both compliance and voluntary buyers
4. Altered National Gas Rules: definition of 'natural gas' under the National Gas Rules broadened to include biomethane, green hydrogen and other renewable gases enabling biomethane to be injected and distributed into the gas networks providing it meets gas quality standards.

Two missing elements needed that are expected to be available in mid or late 2025:

1. New accounting rules under the National Greenhouse and Energy Reporting Scheme (NGERS) that will enable Safeguard Facilities and other NGERS reporting entities to claim emissions reductions from purchasing biomethane certificates. Interviewees noted that a working group is actively developing these methods which are expected to be released in mid-2025 (stakeholder, pers. comm.).
2. Gas quality standards: Australia's gas quality standard, AS4564 is undergoing revision to incorporate relevant aspects of biomethane.

This progress has been applauded by many Australian interviewees we spoke to who listed these as priority pre-conditions needed for a market. One interviewee questioned, however, whether the price of GreenPower certificates under Australia's current carbon prices would make biomethane competitive enough to incentivise project development (stakeholder, pers. comm). We examine this issue by estimating potential revenues and production costs based on the current policy settings (Figure 19). The value of biomethane is a combination of its revenue streams which include the value of the energy commodity itself (gas value), the value of carbon abatement (including methane abatement) (green value), and the value of government supports. The energy value of biomethane is identical to fossil-based natural gas, and thus any additional value comes from its carbon abatement potential or green value as there are currently no direct government supports. Estimates presented below use the price cap on natural gas, as at October 2024 of AU$12 / GJ; and a "green value" calculated from the average ACCU spot price of 2024 of AU$33.75 multiplied by the average carbon intensity (CI) values of three different biomethane production pathways used in the EU's REDII and California's LCFS schemes (see **Figure 2**). Production costs are based on the levelised cost of energy (LCOE) values modelled and reported in Blunomy's 2024 report commissioned by AGIG.

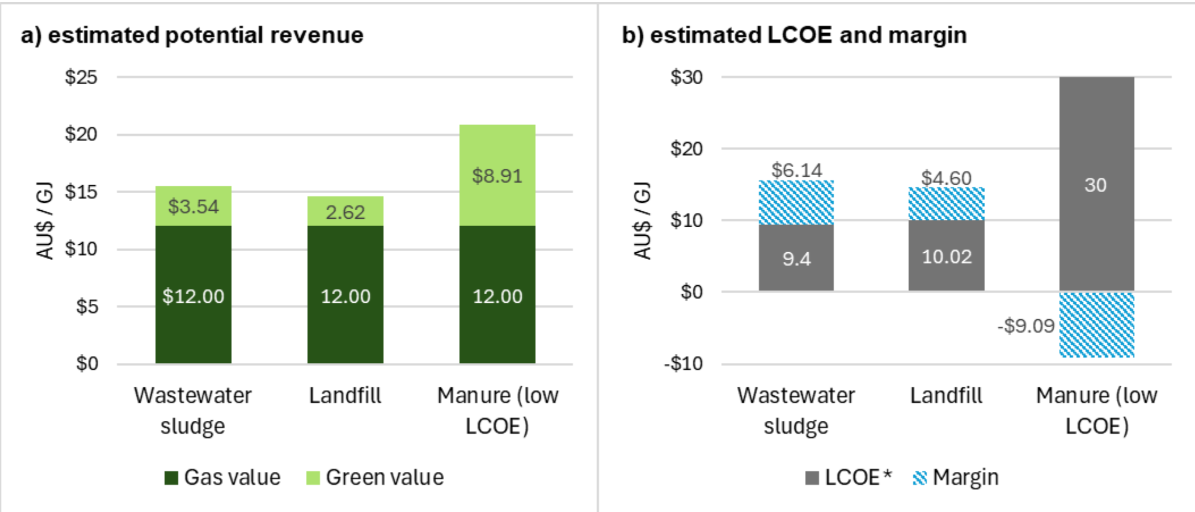

Figure 19. Revenue and production cost estimates of biomethane in Australia under current policy settings. *See text for data and assumptions used in estimates.

Based only on the price of gas and the green value of certificates or credits, estimates suggest that biomethane projects from wastewater and landfill can be profitable under existing policy settings without any direct government supports. The higher cost of farm-based projects, here using manure feedstocks, would likely require further supports, despite the higher 'green value' that comes from higher carbon abatement.

While recent policy developments and revenue-cost estimates are encouraging, the uncertain viability of biomethane projects, their high upfront costs and remaining challenges highlighted by interviewees and other studies is unlikely to attract the investment required to scale up biomethane to a meaningful extent. Unless the price of natural gas is expected to remain at a price that makes biomethane production competitive in the long term or major technology breakthroughs are achieved that lower production costs, further policy levers will be essential to strengthen the business case and long-term certainty for investors and project developers.

Additionally, opportunities for other revenue streams can substantially contribute to the viability of biomethane projects under the right regulatory and local conditions. These include the sale of anerobic digestate and concentrated CO_2, and gate fees for producers to receive waste feedstocks diverted from landfill that would have otherwise been subject to landfill levies. There are also potential future opportunities associated with the sustainability and circularity benefits of biomethane that could be monetised through the development of new environmental credits and markets in the future, such as nutrient or nitrogen abatement, and additional carbon credits through the displacement of chemical fertilisers with digestate.

Recommendation 1: Australia has made significant headway in policy settings to enable a biomethane market, but additional levers are required to attract the investment needed to scale. State and federal governments could consider investigating new policy instruments and schemes or make biomethane an eligible technology for existing schemes, to encourage investment into projects, underpinned by government direction and a supportive regulatory environment.

Point 2: Biomethane must be accepted as a legitimate solution by governments and industries. To do this requires increased awareness and understanding of biomethane and its benefits through advocacy and education and increasing government capability and coordination.

Many Australian interviewees highlighted that disinterest and a lack of awareness and understanding about biomethane and its potential benefits by many stakeholders across government, agriculture, industry and the broader public had been a key challenge to date. However, some noted that from 2024 there had been 'a significant shift' in sentiment, and growing interest, in particular from New South Wales and Victorian governments.

Australia's national net zero policy to date has heavily focussed on decarbonising the electricity sector, electrification of transport and buildings, as well as investment for a longer-term hydrogen export industry. On the other hand, the national Future Gas Strategy see that natural gas, which makes up around a quarter of Australia's primary energy use, will continue to remain a substantial part of Australia's energy mix. Australia has a significant piece of infrastructure in its gas network with many gas-reliant industrial and commercial customers. Several interviewees pointed out that policies for biomethane should encourage the renewable gas to go where it is most needed – hard-to-abate industries with processes that can't be electrified.

The main arguments that interviewees cited for why governments should support biomethane were that it:

1. enables hard-to-abate industrial and commercial gas users to demonstrate and directly reduce their scope 1 gas emissions through certification, tracking and trading of biomethane to match their gas use with renewable gas certificates (not just arbitrarily offsetting emissions by purchasing carbon credits).
2. is a drop-in replacement for natural gas and supports gas network decarbonisation by providing both a near-term solution until green hydrogen becomes commercially ready to scale, and a long-term solution through a consistent supply of and need to treat organic residues and resources.
3. is a dispatchable low-carbon energy that can firm increasing amounts of variable renewables like solar and wind entering the power grid.
4. supports government sustainability goals and targets, including to reduce carbon emissions by 43% by 2030, to reduce methane by 30% by 2030 under the Global Methane Pledge, and to support waste diversion targets and circular economy goals.
5. increases domestic gas supply and security, particularly in the states of Victoria (which is running out of gas) and in New South Wales (which does not produce its own gas).
6. avoids the risk of Australia's gas network becoming a stranded asset or the mass removal of customers off the network, leaving remaining customers with higher costs.
7. supports regional development, diversification and employment. For example, AGIG's modelling suggests that biomethane projects developed for its network could support 10,100 new jobs in Victoria, Queensland and South Australia.
8. can provide additional sources of revenue for farmers, and operators of landfills and wasterwater treatment facilities.

Interviewees stated that government messaging was ‘a huge factor’ for influencing the legitimacy of biomethane (as well as digestate) as being an acceptable solution that should be scaled. A key priority expressed by several Australian interviewees was the need to *build knowledge and awareness* of biomethane and renewable gases, as one interview viewed that, ‘… part of the problem is that I think generally government doesn't understand it.’ Interviewees in both Australia and North America noted that some governments and advocacy groups had developed an ‘anti-gas’ position where, as one interviewee put it, they ‘equate [all] gas to fossil fuel’ and advocated to ‘electrify everything and [sic] get rid of the gas network.’ An Australian interviewee stated that those who held that position felt it was hard to change tack ‘…it's very hard for them to come out and go, well, actually there are some new gases – there are renewable gases which are quite good.’

Several interviews emphasised that knowledge development needs to occur across the board, with particular mention being made of the need for both state and federal governments to broaden their views around *all* renewable gases and to drive education and build confidence on the benefits of a biomethane sector,

> “There's no team within government that actually looks after bioenergy, so it kind of gets left by the wayside. So, I think it's not just policy, it's actually the institutional and governance arrangements that you need to have to enable the right policy … I mean, there's individuals here and there who are kind of deeply passionate about it and understand it. But being like a cohesive network of people or a team that's kind of championing it across government just doesn't exist.”

One interviewee also believed that the lack of policy direction and government ambition towards biomethane had a flow on effect to investors, claiming that “biomethane generally isn't really on the radar for a lot of project developers”.

In this regard, interviewees stated that policies needed to be technology agnostic rather than ‘picking winners’ as one commented,

> “…getting policymakers off the hydrogen-only bandwagon and getting them back to, why did you like hydrogen? It was because it was a renewable gas in the system. What you need is a renewable gas. What's the low-hanging fruit, bankable solution? Biomethane – not at the exclusion of hydrogen – but it's the near term. It's now, it's bankable and it's lower cost.’

Many government support schemes, including those considered in this study, have been limited in scope, either in terms of eligibility of technologies used (e.g. the production process), or the end use. However, many stakeholders we spoke to, both in Australia and internationally, argued that policy design should be more outcome-driven rather than prescriptive. This is essentially relevant for production processes, where if the intent of a policy is to drive carbon abatement, than the final emissions reduction should be prioritised over the process.

In terms of policies designed for particular end uses (e.g. heating, transport fuels, gas injection), our case studies indicate that schemes allowing multiple end uses resulted in a surge in projects. For example, in the UK, the number of biomethane projects increased sharply when it was included as an eligible technology for gas injection under the Non-Domestic Renewable Heat Initiative, despite no way of discerning what the gas is used for once it enters the gas network. Italy has also expanded the types of end uses for biomethane from transport fuels to grid injection for industry and residential, under its New Biomethane Decree. However, some stakeholders argued that biomethane should be put to its ‘highest order use’, in particular, for hard-to-abate industrial processes or for gas peakers that provide dispatchable power to balance renewable power from solar and wind in renewable electricity systems.

Integrity is another vital aspect of building and maintaining support for biomethane, particularly around sustainability claims. Just as a technology like biomethane can gain legitimacy, so too can it lose it. In Germany, for example, Markard et al. (2016) highlighted that biogas initially gained public acceptance because it was viewed as a sustainable way for farmers to treat waste while producing a renewable source of energy and income and was supported by formal endorsement of regulatory agencies. However, as biogas developed from small-scale farms to larger industrial entities that relied heavily on the use of energy crops, it came to be viewed negatively as a “competitor and threat to conventional farming,” resulting in a loss of both public and political support (74). To maintain social licence, biomethane certificate schemes, such as GreenPower and Renewable Gas Guarantees of Origin (RGGOs) should be underpinned by effective accounting methodologies that avoid double counting, along with robust tracking systems, verification, and oversight. Failing to do so may result in similar criticisms to those of Australia's carbon market, the ACCU Scheme, for rewarding projects that did not meaningfully contribute to emission reductions that they claimed to. This is not only a risk for maintaining social licence but can reduce the market value of biomethane certificates and thus risks the viability of projects and future investments.

Other risks around biomethane's sustainability claims that need to be managed include the use of unsustainable feedstocks such as food and energy crops, and associated land use changes and resource use (e.g. water, nutrients, energy) that come from increased energy cropping.(382,383) (172). Sustainability criteria should be designed into eligible biomethane schemes and regulations as has been done elsewhere. The UK's GGSS for example, has increased its sustainability criteria for producers to receive government supports, including that the carbon intensity of biomethane produced must be at less than or equal to 24g CO_2e (60% lower than natural gas) and impacts to land. This has resulted in a marked reduction in the use of food crops. Another risk to be addressed is methane leakage from anaerobic digesters and landfills and more broadly leaks in gas pipelines. According to one industry stakeholder, the GreenPower RGGO scheme has a documented auditing process to ensure these emissions are within requirements and pipeline losses are accounted for by the pipeline distribution service operators (DSOs) and transmission service operators (TSOs). (411).

Key finding: International cases demonstrate that biomethane presents a mature, proven technology that could help to decarbonise Australia's gas networks now, but this will not occur through actions by the private sector alone. Our review shows that for biomethane production to occur at scale in Australia, it must be driven by government ambition and policy direction, underpinned by quantifiable targets set at federal levels, a national strategy, and an effective mix of policy instruments at state and federal levels.

Recommendations:

Governments could consider adopting a more technology-agnostic position by advocating and providing policy direction for all types of renewable gases, including biomethane and e-methane, alongside green hydrogen.

The Australian Government could also consider a review of the National Hydrogen Strategy to include other renewable gases or establish dedicated national targets and a strategy for biomethane.

Government could consider assigning an agency to lead bioenergy development, and establish cross-sector committees or groups to increase coordination between key sectors such as energy, agriculture, environment, and waste.

Point 3: Getting the economics right and creating a robust biomethane market can be achieved via different pathways but requires careful design considerations of policy instruments.

For a biomethane industry to be developed by the private sector, it must be profitable for investors. That means that the sum of the gas and other commodities like digestate, its green value, and any financial incentives received, must exceed the total costs of production and distribution. In all case studies examined, targeted government schemes were put in place to make biomethane projects viable. Based on our case study analysis, we consider broadly two policy options on the table for Australia to develop a biomethane market:

1. the *technology push* option, as seen in our European case studies, which involve government supports to subsidise the cost of biomethane through direct payments to producers to incentives biomethane supply, or
2. the *technology pull* option as seen in our North American case studies, which is to create demand through compliance-based markets that, in turn, incentivises producers to enter the market. Demand can also be achieved through voluntary markets, albeit these are typically not as strong as compliance markets and create less demand certainty than mandated quotas.

Naturally, a combination of technology push and technology pull levers is a third and potentially even more feasible option with many interviewees and analysts indicating that a combination of some level of supply-side incentives, demand-side obligations, and enabling regulations would be most effective.

Based on values presented in a number of industry reports and government data, a comparison between case countries of revenues based on the market price of gas (*gas value*), certificates (*green value*) and *government supports* versus reported production costs under the major policy schemes is estimated (**Figure 20**)**.** Note that US figures are much higher than other countries as all prices are normalised to the US dollar which is high against most currencies as of February 2025. Important to note is that production costs vary significantly depending on how and where biomethane is produced, and gas prices and certificates are subject to market fluctuations. We emphasise that these estimates are rudimentary and are based on average reported values from each jurisdiction for data in 2024. Nonetheless, the purpose of Figure 35 is, firstly, to illustrate the variety of options that arise between the different mechanisms employed by each jurisdiction that can add to the value of biomethane. And secondly that these estimates suggest that a substantial margin is needed over the cost of production, has likely attributed to the success of biomethane development in these jurisdictions.

The *technology push* approach of our European cases (Italy, Denmark, UK) has mostly been achieved through government supports. In the early initiation phase of each country's biomethane development, these involved early, generous and long-term (15-20 years) feed-in tariffs as well as capital supports. The introduction of the main support schemes highlighted in our EU case studies, namely the UK's NDRHI and GGSS for biomethane injected into the grid, Denmark's 2012 Energy Agreement with higher supports for injected biomethane than for biogas, and Italy's all-inclusive tariff under the 2022 Ter Biomethane Decree, all correlate with rapid growth in the number of biomethane projects that came online soon after (Figure 35). However, demand-side incentives, notably the EU ETS and Italy's renewable transport fuel obligation, have also played important roles, but generous feed-in tariffs and grants have provided the bulk of the additional capital and revenue required to attract larger-scale investment.

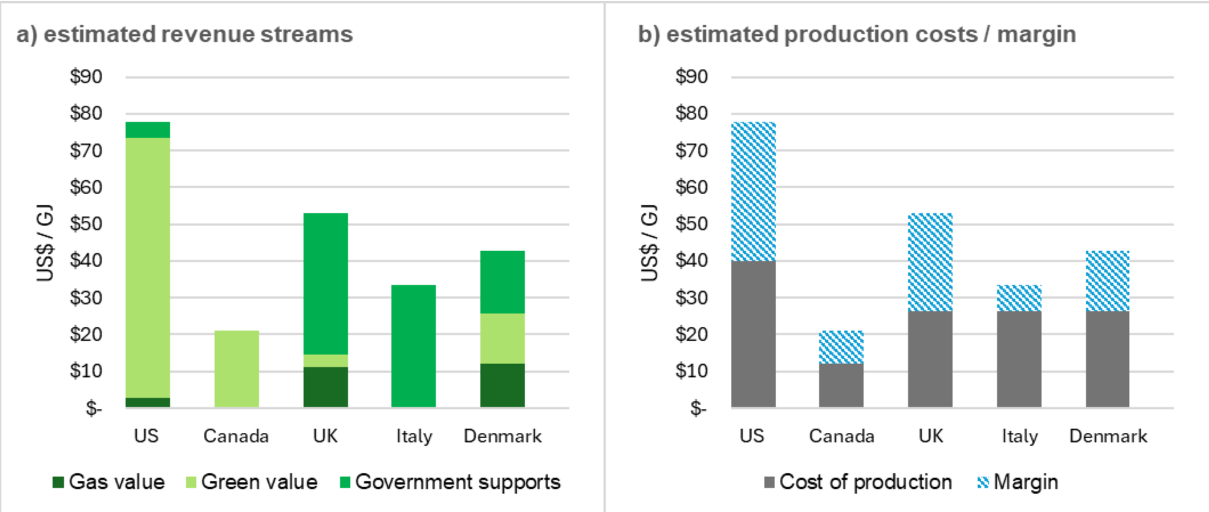

Figure 20. Comparison of estimated revenue streams (a) and average production costs and margins (b) for biomethane projects in the five country case studies assessed in this study based on their major policy scheme.

Revenues are estimated on the following: for the US: credit stacking of RIN and LCFC certificates (green value) and production tax credits under the IRA (govt supports), in addition to the sale of gas on the gas market which is traded separately; Canada: a regulated price cap paid by gas utilities to producers in off-take agreements of CAN$30 /GJ; UK: government supports of feed-in tariffs under the GGSS for a 100,000 kWH capacity biomethane plant, the green value of RGGO certificates that can be traded separately, and the average price of natural gas in the UK in 2024. Italy: an all-inclusive tariff of 115 EUR / MWh (the government receives revenue from gas sale); Denmark: a feed-in-premium, which is the difference between sum of GO certificate sales and gas revenue and a price cap to a ceiling price of 120kr / GJ. Production prices are averages taken from: US: S&P Global Insights (156); Canada: stakeholder estimate of CAN$10-25/GJ; UK; Italy and Denmark: European Biogas Association (72).

By contrast, North America has favoured a *technology pull* approach via ambitious targets and associated mandated quotas placed on fossil fuel suppliers that obliges them to either reduce the carbon intensity of their fuel or gas by blending lower carbon sources, or to blend a given percentage of renewable energy such as biomethane in their final product. Additional costs imposed on gas or fuel distributors are typically passed on to end users. The United States has primarily driven the development of its biomethane industry through federal and state level renewable transport fuel obligations, while Canada's renewable gas obligation has operated alongside a carbon tax, and an emissions trading scheme. The US does also provide a number of supply side incentives, most notably through tax credits since 2022 under the IRA, whereas Canada's biomethane producers have received less government supports. According to one stakeholder,

> "… the renewable natural gas industry in Canada really isn't being subsidised almost in any way by federal or provincial governments. It's very much just driven by the project economics on their own, somewhat to those policies in a couple of the provinces [British Columbia and Quebec]. … the biomethane industry in Canada is growing right now without government help." (stakeholder pers. comm.)

We next highlight some of the key policy instruments used and important design features to their effectiveness.

Long-term guarantees

Although our cost-revenue comparison of case countries is not, nor intended to be, a comprehensive analysis, it is interesting to observe that schemes in Italy and Canada seem to require lower margins. An important design feature in both cases is **long-term guarantees** for producers – in Italy through government supports of an all-inclusive 15-year tariff, and in Canada under long-term off-take agreements (~20 years) from utilities companies guaranteed at $30 / GJ in British Columbia, Canada. In the latter case, Canadian stakeholders observed that although Guarantees of Origin allow Canadian producers to export to the US and obtain higher prices through the open market, the risks involved meant that many producers opted for the security of long-term offtake agreements provided by Canadian utilities instead. As one stakeholder commented,

> "the US markets can be very hot – but it's very volatile because of political change in government, and all of a sudden that market could just die. So, they're short term [windfalls], they're living year to year, and mostly it's been good. We offer twenty-year contracts – so we'll give you this price for 20 years because we're not going anywhere, we're in it for the long term. We might not be as high as the other ones, but we're safer, and that is a big advantage as well…"

Design considerations for demand-side mandates and compliance-based schemes

In the context of biomethane, targets and mandates are mechanisms for increasing the demand for biomethane by requiring one group of market participants, usually gas or fuel distributors, to include a given percentage of biomethane or renewable fuels in their products. In some cases targets operate through certificate mechanisms, where producers who exceed the required amount of renewable fuels receive certificates that may be sold to producers who fail to meet the target. The additional costs of sourcing renewable energy are borne by distributors, who may be expected to pass these costs on to end users in the absence of regulations preventing this. Mandatory targets are a demand-side command mechanism that are intended to create a sustainable market price for renewable fuels without the need for ongoing subsidies.

Biomethane production in the United States and Canada has been primarily driven by compulsory targets and mandates. In the United States, a number of state-level renewable portfolio standards required that set percentages of a state's energy production came from renewable sources.(174) These were followed by a federal Renewable Fuel Standard, which created mandatory targets for a variety of renewable fuel categories, to be met through a certificate scheme.(176) Several states have implemented their own renewable fuel schemes, with California's Low Carbon Fuel Standard identified as a particularly important model.

Whereas the United States targets have focused on renewable fuel obligations, Canada's biomethane industry has been facilitated by mandatory renewable gas targets in Quebec and British Columbia, and by federal- and state-level carbon pricing. Renewable fuel obligations have also been enacted in the United Kingdom, although these have been secondary to feed-in tariffs in incentivising biomethane production as they have mainly been met with biodiesel, bioethanol, and hydrotreated vegetable oil. France has also implemented renewable gas targets of 10% renewable gas consumption by 2030 and 50-79 PJ of biomethane injection by 2028 (from 32.4 PJ of biomethane injection capacity in 2022).(390) A substantial number of industry associations have argued for the introduction of a binding biomethane target across the entire EU, with specific mechanisms to be set by individual Member States.(391)

Provided that sufficient penalties are in place, a renewable gas mandate provides policymakers with a great deal of control over the scale-up of biomethane. A biomethane mandate would place pressure on suppliers to secure the required biomethane, helping to provide urgency and drive investment. Mandates provide long-term viability for the industry without requiring ongoing financial support from government, and provide a predictable and consistent investment environment due to a known demand. They are tailorable and can be increased over time to scale with climate targets.(66)

Biomethane mandates also have a number of downsides compared to other incentive mechanisms. They impose additional obligations and costs on suppliers, and these are likely to be passed onto gas consumers. Based on case studies, mandates have historically created lower rates of growth than more direct incentives such as feed-in tariffs, due to the government assuming less of the business risk. A mandatory biomethane target may also be less granular than other incentive mechanisms; tracing the specific feedstock or origin of biomethane, for instance, would require sub-categories of biomethane (as the United States has implemented via its Renewable Fuel Standard).(66)

A renewable gas mandate has the advantage of not requiring direct government funding. A mandatory biomethane target would result in an increase in the cost of gas, but spread across the entire rates base this increase would be relatively small for each individual customer. Raising the price of gas may also disincentive gas use, contributing to broader decarbonisation objectives.(5) Canada's implementation demonstrates that, when appropriately designed, a mandatory renewable gas target can increase demand sufficiently to allow a biomethane market to develop, even in the absence of strong supply-side supports.

One Australian analysis found that "adopting an Optimal RGT rather than an electrification-focused approach to decarbonisation of the gas sector will save Australia in the order of $30 billion (in present value terms) over the transition".(58) The report suggests that a certificate model analogous to the RET is the optimal mechanism for such a target.(58) Bioenergy Australia has argued for "implementing obligations on gas network operators to procure renewable gas as part of their unaccounted-for gas (UAFG), thereby creating a premium market solution."(108) Energy Networks Australia has also advocated for the implementation of a Renewable Gas Target.(392) Many of the Australian interviewees in this research also mentioned their support for a renewable gas target.

A 2022 study commissioned by the Canadian Biogas Association modelled the impact of a number of potential policy levers in achieving Canada's carbon emissions targets. It found that an 'optimal policy mix', consisting of a *nationwide* biomethane mandate of 15% by 2030 and rising to 30% in 2040, coupled with a carbon offsets system that allowed credits for methane destruction and utilisation in landfills and agriculture, could deliver an estimated 544 PJ of biogas and biomethane in 2050, compared with 50 PJ under current policies.(260) To complement the study, the **Clean Gas Coalition** developed a proposal for implementing the nationwide biomethane mandate through a Clean Gas Standard (analogous to the Clean Fuel Standard), which would require gas distributors to reduce the carbon intensity of the gaseous fuel stream by introducing clean gas into the domestic market.(393)

There are a range of factors that need to be considered in the design of a renewable gas mandate. Key considerations include the amount of biomethane targeted; whether a biomethane target should also include hydrogen; whether certificates should be traded bilaterally or via a pooled mechanism; whether offsetting is allowed; whether shortfall or surplus can be carried forward to future years; whether biomethane projects should be subcategorised and differentially incentivised based on their emissions reductions; and how to address issues around 'double counting'.(5) We address each of these in turn.

The quantity of biomethane targeted each year is critically important to the success of renewable gas mandates. If the target is set too low, it will not incentivise additional biomethane production. This is the case for the proposed Victorian renewable gas target. If the target is set too high, there is a risk that costs will become disproportionate due to a lack of available biomethane supply. These costs may then be passed on to gas users. If allowed under the scheme, overly optimistic targets may also result in mid-year changes to said targets, which undermines the scheme's certainty and ability to serve as an investment signal. This has occurred in the United States Renewable Fuel Scheme.

While most proposed and existing biomethane mandates focus exclusively on biomethane, some analysts have explored the possibility of renewable gas targets that includes both biomethane and hydrogen.(5) Successful international examples suggest that focusing on each of these separately is preferable, allowing more finely tuned supports for each. This is particularly relevant in the Australian regulatory context, where extensive government supports for hydrogen already exist.

Some certificate and credit schemes allow shortfalls and/or surpluses to be carried over to subsequent years. The Safeguard Mechanism, for instance, allows participants to apply to "borrow" baselines from the following year.

The granularity of biomethane categories is another important policy setting for a renewable gas mandate. A renewable gas mandate could treat all biomethane equivalently, or it could subdivide biomethane by carbon intensity, feedstock type, or other criteria.

Setting appropriate goals and thresholds for targets and quotas

Mandated quotas placed on obligated parties (mostly suppliers of gases and fuels) are usually fulfilled by purchasing certificates through compliance-based markets or through long-term offtake agreements with producers. Interviewees indicated that the market price for biomethane acquisition was determined by the following three factors: 1) supply-demand forces, 2) penalty rates and additional values of avoiding non-compliance for the obligated party, and 3) the price of carbon.

Relating to supply-demand forces, an important design consideration for policymakers is to ensure that targets and quotas are set high enough and for long enough to sustain sufficient long-term demand to de-risk projects. Targets should not be set too high, however, that liable parties are unable to meet their obligations or that market prices are driven to unreasonably high prices leading to push back from industry or consumers, as has been seen in California with higher fuel prices leading to criticisms of its LCFS. This means that targets should be reviewed periodically and incrementally increased as more capability and production capacity comes online to promote sustainable growth.

Relating to penalty rates and compliance, some interviewees from North America remarked that compliance buyers were willing to pay higher prices than the penalty rates set for failing to meet mandated quotas in order to avoid non-compliance, as they were 'theoretically …. breaking the law'. As one stakeholder noted,

> "Liquid fuel producers will actually pay more to avoid breaking the law for the carbon credits … I think the compliance [penalty] was like $200 a tonne [of carbon], but the market was at $275 and you'd ask yourself well, why if you could just pay the penalty, why would you pay more? … Because then I have to go to my CEO and say, 'actually, I broke the law and I'm paying a fine.'" – stakeholder, pers. comm.

Relating to the price of carbon (3), most of the value of biomethane certificates derives from this so-called 'green value', as reducing carbon emissions in line with climate policy goals was cited as the primary driver to governments seeking to develop a biomethane market (noting that another driver cited by stakeholders from all case countries was to increase domestic energy security and supply).

An important design aspect of mandated quotas is what the target is based on. The goal of California's Low Carbon Fuel Scheme is to reduce the overall carbon intensity of transport fuels and thus mandates blending low carbon fuels to achieve a percentage reduction in CI whereas the federal Renewable Fuel Standard's goal is to increase the share of renewable fuel supplied and thus provides volumetric targets. The latter as well as the UK's Renewable Transport Fuel Obligation, and Italy's Decree 02 March 2018, do consider carbon intensity indirectly, by having categories of biofuels depending on factors such as the feedstock used, providing further incentivisation for feedstocks which produce greater carbon abatements.

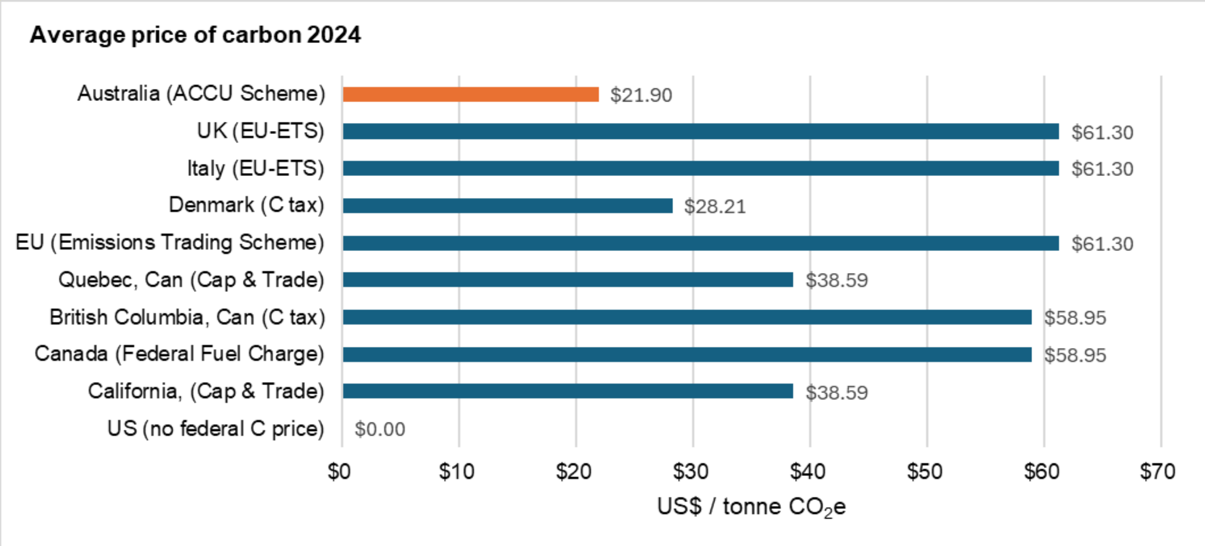

Figure 21. Average price of carbon (normalised to US dollars) in 2024 by jurisdiction and scheme.

Supply-side government supports

Capital Supports

The challenges of financing biomethane project development and substantial up-front capital expenses were identified by several interviewees from Australia as challenging market growth. Capital supports are intended to bolster early-stage development of biomethane production. More than one interview noted that a particular challenge, was to fund early pre-finance phases to undertake feasibility assessments before projects were deemed bankable. Some suggestions were that governments could provide direct grants for pre-feasibility studies or repayable loans if the project went ahead.

Grants for capital in many jurisdictions subsidise a fixed proportion of capital costs to establish biomethane plants and infrastructure.(77) Capital grants have the advantages of being simple to administer and are attractive for derisking large upfront investments instantly. The approach of Denmark, and more recently that of Italy, suggest that capital supports can be an effective (albeit expensive) way to kickstart a country's biomethane production capacity. In Italy, more than €1.7 billion investment in capital supports covers 40% of investment costs to upgrade existing biogas plants to biomethane plants, and for building new plants. In Denmark, investment grants covering up to 40% of the capital costs of biogas plants played a key role in establishing the country's early anaerobic digestion capacity.(77) In the US, capital tax credits have been used to incentivise biomethane investment, although from 2025 these will only be given for investment in renewable electricity generation (including using biogas). Alongside a feed-in tariff and feed-in premium for grid injection, these capital supports have successfully catalysed a more than three-fold increase in biomethane production over the past two years. However capital supports do not address the cost gap between biomethane and natural gas and should therefore be combined with other biomethane incentive mechanisms. As such, capital supports could be considered as a supplementary mechanism in the Australian landscape.

Feed-In Tariffs, Feed-in Premiums, Contracts for Difference

Of the countries examined in this case study, feed-in tariffs are currently being employed in Italy and the United Kingdom. They also formed a central part of Denmark's supportive biomethane policy from 2012 until 2018 (with ongoing support for existing applicants until 2038). Guaranteed feed-in tariffs were also successful in stimulating biomethane investment in France between 2011 and 2020.(66) In Italy, all-inclusive feed-in tariffs are available to biomethane facilities with a production capacity equal to or lower than 250 Sm3/h (with larger facilities instead eligible for a premium tariff).(388)

Feed-in premiums are variable top-up payments paid above a pre-specified benchmark market price.(77) They are typically designed to cover the difference between the market price and the estimated production cost of biomethane plus margin.(66) They can be implemented with a fixed price, or with a sliding price that varies according to the market value of gas or other factors, making them a flexible support mechanism. For instance, feed-in premiums can be modified to account for a specific plant's carbon footprint, or can be modified on an annual basis to allow budgetary flexibility.(66)

The efficacy of feed-in tariffs for driving biomethane uptake has been clear in all three countries surveyed. Italy experienced four-fold growth in its installed biomethane capacity over the two-year period that their feed-in tariff was in effect. Denmark also saw tremendous growth in biomethane production driven by its Energy Agreement, which included a generous feed-in tariff and substantial investment grants.

In Italy, feed-in premiums are available for installations producing more than 250 Sm^3/h (smaller installations instead receive a fixed feed-in tariff). These tariffs are "equal to the difference between the reference tariff, reduced by the percentage discount offered and accepted in the competitive procedures, the average monthly price of natural gas and the average monthly price of guarantees of origin."(388) Feed-in premiums have also been implemented in the Netherlands, Estonia, and Denmark.(66)

A contract for difference is a risk-hedging mechanism designed to ensure stable prices. It operates like a feed-in premium, but with an obligation for the beneficiary to pay money back if market prices exceed a predetermined "strike price". This effectively guarantees a specific energy price to a biomethane producer.(66)

In 2023, the European Commission approved a €1.5 billion contract for difference scheme in France to support new biomethane installations that have a projected annual production of biomethane of more than 25 GWh per year. Under the scheme, financial support is granted in the form of two-way contracts for difference for a duration of 15 years. The amount of aid corresponds to the difference between the strike price, determined in the tender offer of the beneficiary ('pay as bid'), and the market price of natural gas. If, however, the market price of natural gas is higher than the strike price, the difference between the two prices must be paid back to the State.(389)

Commentators have noted, in the context of solar, that feed-in tariffs can result in boom-and-bust cycles, with "generous feed-in tariffs creating elevated rates of installation, and a slump in investment following the schemes' closure".(58) This dynamic is evident in the United Kingdom and Denmark. In the United Kingdom, the conclusion of the Non-Domestic Renewable Heat Incentive was followed by widespread stakeholder uncertainty,(349) and it was replaced a year later by another feed-in tariff under the Green Gas Support Scheme. In Denmark, installation of new biomethane plants stalled once the feed-in tariff was removed, and some Danish stakeholders were sceptical as to whether the subsequent tendering system would effectively stimulate new biomethane production capacity.

A feed-in premium or contracts-for-difference mechanism would similarly provide biomethane producers with long-term revenue stability. Unlike a feed-in tariff, feed-in premium mechanisms generally leave the responsibility of finding a buyer of the gas and the gas green value to the producer, making feed-in premiums a higher risk mechanism from their perspective. This may be a particular obstacle for smaller producers. For this reason, feed-in tariffs and feed-in premiums could both be used depending on the plant's capacity, as has been implemented in Italy.

Tender/Reverse Auction

Biomethane tendering involves putting out a call for a specified quantity of biomethane. The Biomethane Industrial Partnership Europe notes that "Past experience records market failure examples in the attempt to support biomethane production. Those are related either in the tendering price being too low to de-risk investment or changing conditions of inputs (feedstock) or output (biogas, digestate, CO_2). When the tendering price is too low experience shows either no bids or the winning bids are blocking a biomethane production quota with unlikely fruitful investments. […] Unbalanced tendering conditions, such as tendering criteria, eligibility and price that is not considering the GHG intensity of the end-use, will likely lead to biomethane market failure."(66) It is worth noting that the same caveat also applies to other incentive mechanisms.

Tender processes can be distributed through the other incentive mechanisms discussed in this report. For example, feed-in tariffs and feed-in premiums can be made available upon success of a tendering process, rather than being guaranteed to all biomethane producers. This can be used to improve the cost efficiency of tariffs, by allowing tenderers to compete on discounted tariff rates, and to generate greater certainty around government costs.(66) Following the conclusion of feed-in tariffs under its *Energy Agreement*, Denmark has shifted to a tender-based model of biomethane support.

Timing and sequencing of policies from initiation, to scale up and market stabilisation.

An industry stakeholder noted that based on Australia's growing policy momentum around biomethane, all that was missing was 'that initial push' from policy to get further projects underway. Studies have emphasised the value of appropriate policy mixes at different stages in the market's development, particularly in the initiation phase. EU countries have favoured unconditional and all-in financial incentives such as feed-in tariffs during the early stages of biomethane development, followed by a transition to more market-exposed mechanisms such as feed-in premiums or auctions and certification schemes as the industry matures.(311) On the other hand, to continue growth in demand for biomethane and encourage investment in new projects, the Canadian provinces of Quebec and British Columbia and the US and California, have incrementally increased mandated quotas under their renewable fuel and gas obligation schemes.

Australia's policy framework for green hydrogen under its National Hydrogen Strategy and Hydrogen Headstart Program already provide an appropriate mix of policies to initiate a market. These policies have subsequently made Australia the world's leading country in the most hydrogen projects under construction or development as at 2024. On the supply side these include: a $4 billion investment which will include funding feed-in premium guaranteed for 10-years to cover the gap between production costs and the market price of green hydrogen and Production Tax Incentive currently being legislated which will offer companies a time-limited and uncapped refundable tax offset of $2 for every kilogram of eligible renewable hydrogen produced for up to 10 years, under the $22.7 billion Future Made in Australia plan. Capital supports available for hydrogen projects include: concessional finance under the National Reconstruction Fund ($15 billion allocated) and the $300 million Advancing Hydrogen Fund under the Clean Energy Finance Corporation (CEFC); $300 million committed to grants by the Australian Renewable Energy Agency (ARENA) for hydrogen R&D projects, feasibility studies and pilot and demonstration plants.

Similarly, **Australia's Renewable Energy Certificate** scheme has been highly effective in increasing solar installations, with these government supports directly attributable to Australia having the world's largest share of rooftop solar (Clean Energy Council). These schemes could be emulated or expanded to make biomethane an eligible technology.

Recommendation: Based on Victoria's proposal of a Renewable Gas Target, we propose that similar design features used in Canadian provinces of mandated targets for gas retailers with a cost-distribution model between voluntary customers and a small portion spread across the entire gas customer base could be a feasible policy option. The government could also consider expanding existing policy schemes for hydrogen to include biomethane as a renewable gas.

Point 4: An enabling regulatory framework is needed to boost feedstock supply and underpin a robust biomethane sector.

Australian representatives interviewed recognised there are several key policy areas for attention to promote the development of biomethane across its value chain. These areas include the classification, access to and availability of waste for use in production; the ability of wastewater treatment plants to receive waste from other sources; policies to prevent flaring of gas; and classification of digestate to enable downstream use. Linked to these issue areas our review of other jurisdictions suggests that regulatory frameworks present a number of low-hanging fruit for policy options, which would provide immediate incentivisation for biomethane production in Australia without requiring major reforms or substantial costs. These include banning venting, removing carbon credits for flaring, mandating the collection and use of biogas from landfills and municipal waste streams, prohibiting the burning of cereal straw, and facilitating the commercial use of digestate as a fertiliser.

A 2022 report, Analysis of Regulatory Barriers Impacting Agricultural Biogas Development in Canada was written on the basis that past studies had shown that "two of the biggest barriers to the development of agricultural biogas plants are: (1) provincial energy and waste management policies, and (2) regulatory barriers." The report found inconsistencies in regulatory frameworks between provinces. 'Common ***regulatory barriers*** across Canada include long regulatory timelines, rigid definitions of agricultural biogas and on-farm feedstock requirements, lack of technology understanding and awareness, lack of government support and recognition of environmental benefits of biogas, lack of communication among regulatory bodies, and overly onerous regulatory requirements and specifications that don't apply specifically of agricultural biogas.' Other non-regulatory barriers raised by stakeholders included challenges connecting to distribution networks (for natural gas and electricity), securing financing, and project economics.

Feedstock regulations and Incentives

In Denmark, a ban on sending organic waste to landfill is in effect. This creates a need to dispose of organic waste, driving additional feedstocks to anaerobic decomposition facilities. Most Danish municipalities have implemented mandatory source separation of organic wastes for households and businesses, creating an additional waste stream. Denmark has also capped the maximum input share of energy crops for biomethane at 4% to curb land use change.

Producing biogas and biomethane from agricultural feedstocks tends to be more expensive than using landfill gas and municipal waste streams. However, agricultural waste and sequential crops also represent the largest source of potential feedstocks. To facilitate the feasibility of anaerobic digestion of agricultural waste streams, case study countries have adopted a number of strategies. The United Kingdom has attempted to address agricultural feedstock availability through direct funding of research and development. The Biomass Feedstocks Innovation Programme funds innovative ideas that address barriers to the production of sustainable UK biomass feedstocks through breeding, planting, cultivating, and harvesting.

> "One of the things that makes biogas investors nervous and even customers – industrial customers – is this idea or this perception that SAFs is the only thing that's really being supported and somehow it's going to soak up all of the available feedstocks, which is nonsense because the reality is HEFA and alcohol to jet are the two main pathways that everyone's focusing on for SAFS which does not compete with straw or, you know a bunch of other residues and waste that are organic waste that are available in the market. They're very different feedstocks. So there's room for both."

Further lessons from Denmark for Australia come though the way they deal with the burning of straw stubble following harvest which can be carried out by farmers to cheaply clear fields. Denmark prohibited stubble burning in 1990 (399) while stubble burning is regulated at the state level in Canada and the United States. In Australia, stubble burning is currently permitted by law. Banning stubble burning in Australia would reduce the emissions released by the fires, and would also create a surplus of agricultural waste suitable for use as a feedstock in anaerobic digestion.

Flaring or Venting of Landfill Gas

Canada has proposed regulations aimed at reducing methane emissions from landfills, requiring landfills to capture as much methane as possible. These regulations aim to reduce methane emissions by around 50% by 2030,(395) and are accompanied by a proposed $2.4 billion in funding for essential infrastructure, including landfills.

European Council Directive 1999/31/EC states that "Landfill gas shall be collected from all landfills receiving biodegradable waste and the landfill gas must be treated and used. If the gas collected cannot be used to produce energy, it must be flared."(396) In line with this requirement, Denmark, Italy, and the United Kingdom have mandated the collection of landfill gas.(397,398)

In Australia, venting of gas is still permitted. Prohibiting the venting of landfill gas would achieve a dual purpose of reducing extremely potent methane emissions from landfill gas, while simultaneously creating an additional incentive to use this gas for energy production.

Under the ACCU, carbon credits are currently awarded for flaring biomethane. While flaring converts methane into less harmful carbon dioxide, providing offsets for this is nonetheless a perverse incentive in that it financially rewarding the direct release of CO_2 when more environmentally friendly uses are available.

Permitting and Approvals Processes

As outlined above the approval process associated with constructing a biomethane plant can be lengthy and difficult. It may require a multitude of approvals and permits, potentially including land use permits, development approvals, environmental permits, and approvals for the management and transport of waste or hazardous materials. In addition to the documentary evidence from Canada stakeholder interviews indicated that long timeframes for approvals could have severe effects on the viability of biomethane projects and the pace of biomethane capacity development.

Gas Specification and Grid Access

Case study countries differ in their regulation of biomethane gas injection. One key difference relates to gas quality standards, which regulate the allowable quantity of impurities such as oxygen, siloxane, and ammonia.(106) These standards can influence the cost of biomethane production. Australia's relatively stringent gas standards have been identified as imposing unnecessary costs on biomethane producers. As blended hydrogen is now allowed in the Australian gas network, any modification to these laws should seek to apply inclusively to all renewable gases. Several countries have implemented various kinds of preferential access arrangements for biomethane to their gas networks, including Italy,(400) Belgium, Finland, Germany, Spain, and Switzerland. Other, such as Denmark, Finland, and Ukraine, have implemented guaranteed access to the gas grid via 'right to inject' laws.(77)

Australia presently lacks regulations ensuring equitable gas connection access for renewable gas producers. There is no obligation for pipelines operators to allow pipeline access.(22) Several Australian stakeholders indicated that problems had arisen in attempting to connect to gas networks, or in negotiating agreements for the transit of gas through the network. This could be addressed through right to access laws, and by empowering a government body to facilitate gas swaps for renewable gas.(108) Further in Australia, there are few laws in place to ensure that renewable gas producers are treated fairly in their dealings with pipeline operators, shippers, and retailers.

Consideration should also be given to how new biomethane connections to the gas grid are funded. In Australia, grid connection costs are currently paid by the biomethane producer. In France and Germany, grid operators are obligated to cover significant proportions of the grid connection costs (60% and 75% respectively).(77) Another option is for the government to fund grid connections.

Facilitating the Sale of Digestate

As discussed digestate can be an important by-product of biomethane production, adding to the business case for project development. Regulations relating to the storage, transport, and use of digestate may influence the commercial viability of selling digestate as a product, and consequently the commercial viability of biomethane plants. In Demark and the United Kingdom, waste forms an important part of the biomethane business case. In Australia, however, various regulations and permitting requirements make it difficult to use digestate as a product. Australia's federal legal system creates additional challenges for harmonising digestate laws between states and territories. Nonetheless, stakeholders have indicated that providing clarity about the circumstances under which digestate may be lawfully used, and streamlining this process as much as possible, would increase the ability of biomethane producers to use digestate as an additional revenue source.

The United Kingdom has reduced barriers to the use of digestate by allowing digestate to be spread without a licence, provided that it meets quality standards. In Demark, digestate use is linked to feedstock provisioning, with farmers dropping off manure at biogas processors and picking up digestate. In both case studies, stakeholders indicated that regulations did not act as a barrier to digestate use. The Biomethane Industrial Partnership Europe has argued that "assigning value to only manure as a way of incentivising the replacement of fossil-based fertilisers, without including digestate, also leads to biomethane market failure."(66)

Recommendation: increasing feedstock supply and digestate are key components that can increase the success of biomethane projects. Regulations that could redirect and increase organic feedstocks available for biomethane production include bans of flaring of landfill gas and on-farm stubble burning. Each state should develop an end of waste (EOW) code that specifies outcomes that need to be achieved for digestate to be deemed a resource rather than a waste, as a first step for its uptake in the ag sector, that clearly outlines the requirements for the registered resource producer as well as conditions for the use of the resource.

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