FUTURE FUELS CRC

Understanding the implications of a Renewable Gas Target for Australia's gas networks

Deep Dive Report

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Policy options to support future fuels deployment

Authors:

Jim Hancock, Suraya Abdul Halim, John Kandulu, Virginie Masson, Liam Wagner

Project team:

Researchers: Jim Hancock (Lead), Suraya Abdul Halim, John Kandulu, Laurence Lester, Virginie Masson, Liam Wagner

Industry Partners: Dennis Van Puyvelde (Lead), Victoria Baikie, Rachel Cameron, Eliza Cochrane, Tania Coltman, Jordan McCollum, Damien Moyse, Michael Probert, Kiran Ranbir

Future Fuels CRC: Jeremy Harris, Benjy Lee, Stephen McGrail

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PROJECT INFORMATION	
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Project title	Policy options to support future fuels deployment
Research Program	Research Programs 1 and 2
Milestone Report Number	4. Finalisation of First Report
Description	This project is designed to allow stakeholders to better assess the implications of policy options for a national Renewable Gas Target (RGT) and their implications for the broader adoption of future fuels. It considers alternative approaches to the design and implementation of a national RGT, their implications for Australia's future fuels mix and their implications for economic outcomes in the Australian States and Territories. Furthermore, this project will enhance stakeholder confidence with respect to potential policy and regulatory frameworks and their impacts on the sequence of events and investments necessary to ensure success and manage risks. This project will develop a broader understanding of the implications of RGT mechanisms for future fuels. It will explore a number of aspects of the design of an RGT to inform stakeholders on the likely outcomes of alternative RGT policies for the future fuels sector and the broader economy. The details of the policy scenarios will be discussed and agreed with the reference group, as will an appropriate baseline scenario which may relate to a policy "do nothing" scenario or a more concerted economywide intervention such as a carbon price.
Research Provider	The University of Adelaide
Project Leader and Team	Lead: A/Professor Jim Hancock, University of Adelaide Ms Suraya Abdul Halim, University of Adelaide Dr John Kandulu, University of Adelaide Dr Laurence Lester, University of Adelaide Dr Virginie Masson, University of Adelaide A/Professor Liam Wagner, University of Adelaide
Industry Proponent and Advisor Team	Lead: Dr Dennis Van Puyvelde (ENA) Jordan McCollum (APGA) Rachel Cameron (Australian Gas Infrastructure Group) Jenny Thai (Australian Gas Infrastructure Group) Tania Coltman (Jemena) Hugh Smith (ATCO)

	Kiran Ranbir (ATCO) Eliza Cochrane (AusNet Services) Michael Probert (Department of Planning and Environment - NSW) Sophie Gove (Department of Environment, Land, Water and Planning - Victoria) Damien Moyse (Department of Environment, Land, Water and Planning - Victoria)
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Executive Summary

This report considers ways in which renewable gases might be supported in Australia's energy mix and in particular the role for and nature of a Renewable Gas Target (RGT).

Australia is in transition to a zero-emissions energy supply. Renewable electricity has a major part to play in this transition but there is also a role for renewable gas. The optimal structure of a low-cost, secure, zero-emissions energy supply remains unclear, and it depends on the costs of renewable gases vis a vis electricity. The adoption of renewable gases into the energy mix is at an early stage and substantial reductions in their costs can be anticipated. However, there will need to be an increased adoption of renewable gases if these cost reductions are to be achieved.

This Report presents learnings and conclusions from a deep dive on evidence and experience with RGT-type mechanisms. It reviews current developments in the policy environment for renewable gas in Australia and overseas. It considers the learnings from Australia's Renewable Energy Target in the electricity sector and other historic schemes targeting reductions in energy emissions. It reports the results of stakeholder consultations. And it considers issues around the design of a RGT from an economics perspective and sets out some possible configurations of an RGT.

There has been substantial progress on decarbonisation of the Australian electricity sector over the last two decades, with strong growth in the market share of renewable electricity generators. In contrast, the gas sector has not had the same progress, and it remains reliant primarily on fossil-fuel gas. There is, however, a very high level of activity and interest around the development of alternative, renewable gases, primarily biomethane and green hydrogen at this stage. The gas sector finds itself at an early stage in its transition to renewables, when compared with the electricity sector.

Renewable gases have a potentially important role in supplying energy to:

- distribution network customers who otherwise will need to electrify (especially residential and buildings);
- industrial heat users for whom electrification is not a realistic option;
- transport, especially for transport forms which cannot electrify, but also as an alternative to electric vehicles; and
- gas fired generation, which is and will remain important for firming the electricity supply system.

The role for renewable gas has not yet entirely become clear, but it is apparent that it will have some role, and it will be to Australia's advantage to ensure that it is able to make use of renewable gases subject to broad cost competitiveness criteria. At this early stage the cost competitiveness of renewable gas is improving, and it is desirable that these improvements be spurred along by active efforts to integrate renewable gases into the energy system.

Moreover, while a move to electrification of the Australian energy system seems highly likely, there will be substantial costs associated with this, which raises the question of how far and how rapidly electrification should proceed and to what extent it can satisfy Australia's clean energy needs.

This is where a RGT has its role. It can contribute positively in a number of ways to the Australian energy policy agenda, including:

- emissions reductions
- developing a renewable gas supply chain in the domestic market
- energy security
- building the hydrogen export industry

The motivation of this study is to consider how a RGT might be effectively designed and implemented to support the adoption of renewable gases.

Renewable gas promotion in Australia

Renewable energy policy in Australia is influenced by the Commonwealth Government and State Governments. The actions of the distinct levels of government often reinforce each other but may also at times cut across each other. Most energy market regulation is the preserve of the States although in practice some is determined by multi-jurisdiction bodies. For example, east coast electricity and gas markets, operate subject to codes that are agreed on by state energy ministers.

The Australian Government and most State Governments have in place initiatives to support and promote renewable gas. The Australian Government's National Hydrogen Strategy directly targets growth of hydrogen production. And Australia's Safeguard Mechanism is approaching the task of reducing emissions with more vigour, which tips the commercial balance in favour of renewable energy sources generally. A number of States also have schemes to reduce fossil fuel emissions from energy, and they vary in the emphasis placed on renewable electricity and renewable gas as final energy sources. There is also considerable effort under way to remove barriers to the adoption of renewable gas—regulatory barriers, skill requirements—and to pilot test the use of renewable gases in the energy mix. But notwithstanding these efforts, there is as yet no coordinated national effort to that sets a clear target for the uptake of renewable gases in the domestic energy mix. This is in stark contrast to the electricity sector, where the growth of renewable electricity generation has been fostered for more than two decades by Australia's Renewable Energy Target.

Past Australian experiences with energy targeting

Australia has experience with the use of target schemes to change its energy mix. The Renewable Energy Target has promoted the growth of renewable generation Australia-wide, such that it now accounts for a substantial share of the Australian energy mix. The New South Wales Greenhouse Gas Abatement Scheme, which ran from 2003 to 2012, created an obligation for electricity retailers and large users to assist reducing NSW's greenhouse gas emissions, either by reducing or offsetting their own emissions. The Queensland Gas Electricity Scheme (QGES), which began in 2005 and closed in 2014, was established to promote the use of natural gas by the electricity generation sector and to reduce emissions. While the targets of these schemes differ from what is anticipated with a Renewable Gas Target, and the detailed mechanisms must inevitably be different, they still offer useful learnings for the design of a RGT. The RET especially gives a good example of a long-running scheme that has steered the electricity market in the direction of renewable sources notwithstanding the tensions that arise with such a transition.

Overseas initiatives

Australian policymakers are not alone in their interest in fostering renewable gas. There are numerous initiatives in place overseas, and they vary widely in terms of the renewable gases supported, the ways that they are to be integrated into energy supply chains, the incentive structures used to support them and their ambition.

There is variety in the types of renewable gases targeted overseas. Some schemes target green hydrogen, while others target biomethane and biogas. Some countries also have schemes to promote the uptake of blue hydrogen, seeking to move away from fossil-fuel methane in anticipation of (more) cost-competitive green hydrogen. Although emission reductions are a key consideration, in some countries renewable gas development is also motivated by energy security concerns that are more pressing than in Australia.

Interventions to promote renewable gas also vary greatly in the ways that they seek change. Some schemes have a degree of neutrality about how goals are delivered—for instance the United Kingdom's Green Gas Support Scheme involves a reverse auction to provide renewable gas to the gas networks and is broadly neutral as to which providers should be selected. In other countries there are initiatives that selectively support particular producers often with an eye to testing and proving the particular technologies that they have under development.

Most of the broadly targeted renewable gas support schemes are in their early stages, having been in operation for no more than a year or two. This means that there are few mature renewable gas target schemes that can tell us what has been learned after five or ten years of operation. An exception is the adoption of biomethane in parts of Europe, but this does not address the challenges that arise with green hydrogen.

Stakeholder perspectives

During the study we carried out consultations with industry, consumer and government stakeholders to identify their experiences, concerns and insights on the use of RGT-type mechanisms in the Australian gas supply sector. The consultations were exploratory, intended to alert us to the range of views held by parties affected in potentially different ways by a RGT. They were not designed to estimate the prevalence of particular views in the population or sub-populations. Nor did we seek formal organisational views, although naturally the individuals that we spoke to were influenced by organisational perspectives.

During the consultations we heard a wide range of views around a number of issues arising with a possible Renewable Gas Target, including:

- whether there should be a RGT;
- what were the goals that might be furthered with a RGT;
- the role of a RGT in decarbonisation;

- technical issues to be considered if a RGT were implemented;
- gas price issues;
- institutional arrangements;
- scope of the RGT;
- equity issues and concessions; and
- efficiency considerations.

There were diverse opinions and respondents varied considerably in what they see as important.

A synthesis of issues arising

It is clear that the question of whether a RGT should be implemented, and how it should be designed, cannot be resolved without determining the objectives that are being pursued. The two most commonly cited objectives from the stakeholder consultations were emission reductions and development of a renewable gas supply chain. These objectives would lead to different design choices: an emissions-focussed scheme would ideally seek to credit renewable gases according to the emissions that they avoid, whereas a scheme focussed on supply chain development would seek to target parts of the supply chain where the potential for cost reductions is good.

A RGT could use a technology-focussed “command-and-control” approach or it could focus on economic incentives in a “market-based” approach. We argue that the best outcomes are more likely if a market-based approach is used in which incentives align well with the fundamental objectives of the scheme.

Certificate schemes provide a useful infrastructure for market-based schemes because they allow a separation between the destinations of renewable gas and the allocation of the costs of subsidising renewable gas. This separation is important in so much as there is variation across gas users in their capacity to take up renewable gas in lieu of fossil-fuel gas. With separated destinations for the renewable products and renewable certificates, renewable gas can be allocated efficiently across potential users and the costs can be allocated independently of that, for instance to all gas users.

In the design of a RGT there is a decision to be made about whether to use bilateral transactions to transfer the costs of renewable subsidies to liable parties, or whether to use a pooled arrangement. The bilateral approach has been used effectively for the Renewable Energy Target, but pooled approaches are also used effectively in the National Electricity Market and by the Emission Reductions Fund. During consultations there appeared to be more enthusiasm for a bilateral transactions approach, but we are agnostic as to whether it is economically superior to a pooled approach.

Questions arise around which fuels should be supported and to what extent, with the answers to these dependent on chosen objectives. There are also questions about who should pay. The answer to this also depends to some degree on objectives—for instance if the objective is emission reductions the case for imposing on gas users is stronger than if it is for gas supply chain development. If the emphasis is on emission reductions, imposing the cost on gas consumers will discourage fossil-fuel gas consumption at the margin. If the emphasis is on supply chain development, the rationale for targeting cost recovery specifically at existing gas customers is weaker, and the case for support from broad-based revenues through the budget is stronger.

There is also a question as to whether it would make sense to have a single, encompassing RGT that covered diverse energy uses such as transport and stationary combustion. Renewable gas in stationary combustion primarily competes with fossil-fuel gas and electricity. Renewable gas in transport competes with petroleum and will increasingly compete with electricity. Delivery modes and uptake prospects may also differ greatly between stationary and transport use. These considerations might warrant a segmented RGT, or separate RGT mechanisms, for stationary use and transport.

The design of a RGT would also need to take into account interactions with Australia’s Safeguard Mechanism and overseas carbon border adjustment mechanisms of the type recently introduced in Europe.

Possible configuration of a RGT

There are numerous dimensions to the design of a RGT, including its ambition, and this means that there are endless possible configurations. To crystallise thinking, we have set out a “RET-like RGT”, this being a design that picks up most of the relevant features of the Renewable Energy Target. This mechanism is set out in the table below. It is presented to crystallise thinking about the design choices that arise. We do not claim that it is the optimal version of a RGT, if one were to be implemented. Each of the “dimensions” listed in the table is an aspect of the policy choice and in the report we discuss some of the alternatives.

A RET-like renewable gas target mechanism

Dimension	Specification
Certification	1 Renewable Gas Certificate (RGC) for each 1TJ of accredited renewable gas. Registry and compliance oversight by Clean Energy Regulator.
Certificate price	Market determined.
Transaction structure	Bilateral between eligible suppliers and liable parties.
Geographic limits	Open to Australian producers. No sub-national distinctions.
Eligibility	Any Australian-produced renewable gas provided to a designated use may generate a RGC.
Renewable gas	A gas which uses renewable primary energy inputs and has net zero emissions in aggregate across production, storage, delivery and consumption.
Designated use	Stationary combustion in Australia—industrial, commercial, residential and gas-fired generation but not transport or exports.
Segmentation	None: target may be met by any renewable gas and any use.
Liable parties	Retailers and large domestic users of gas whose gas does not come from a retailer.
Shortfall	RGC liability minus certificates surrendered, which may be negative.
Shortfall carry forward limits	Shortfall carry-forward permitted subject to sinking in following year, and required to be within plus and minus 10 per cent of liability
Interaction with Safeguard Mechanism	Emissions from gas consumption assessed at average emissions per TJ of all RGT-liable gas supplies
Concessions	None
Ambition	Proportion of renewable gas in total domestic gas consumption (total gas = natural gas plus renewable gas): • 2026: 1 per cent • 2030: 5 per cent • 2035: 20 per cent • 2040: 50 per cent • 2045: 85 per cent • 2050: 100 per cent
Penalty	$80,000 per RGC not surrendered, adjusted in line with CPI until 2030; review of post-2030 arrangements in 2030

Conclusions

We close with some overarching reflections on a RGT, its role and the possible case for it. A key issue is that the renewable gas sector is at a relatively immature stage with significant prospects for cost reductions. It is unclear to what extent renewable gas will be competitive with electricity and thus how much of Australia's final energy needs it will contribute. But given the fundamental importance of energy to Australia's prosperity it is important to ensure that the potential of renewable gases is properly developed and tested.

1. Introduction

This Report presents learnings and conclusions from a deep dive on evidence and experience with Renewable Gas Target-type mechanisms. It reviews current developments in the policy environment for renewable gas in Australia and overseas. It considers the learnings from Australia's Renewable Energy Target in the electricity sector and other historic schemes targeting reductions in energy emissions. It reports the results of stakeholder consultations. And it considers issues around the design of a RGT from an economics perspective and sets out some possible configurations of an RGT.

The Australian Government intends to decarbonise the Australian economy over the coming three decades, with a substantial part of the effort coming over the next decade. Energy emissions account for nearly 80 per cent of Australian emissions today, and decarbonisation of the energy sector is thus the single most important component of the decarbonisation agenda.

There has been substantial progress on decarbonisation of the Australian electricity sector over the last two decades, with strong growth in the market share of renewable electricity generators.

In contrast, the gas sector has not had the same progress, and it remains reliant primarily on fossil-fuel gas. There is, however, a very high level of activity and interest around the development of alternative, renewable gases, primarily biomethane and hydrogen at this stage. The gas sector finds itself at an early stage in its transition to renewables, when compared with the electricity sector.

Renewable gas is a term used to describe gases that can be used as a source of clean energy. They are "clean" in the sense that they can be incorporated into the energy mix without causing any new net emissions. Their main role is as a substitute for natural gas, but they may also substitute for other emitting fuels such petroleum products in transport, remote generation, etc.[1] The two forms of renewable gas which appear closest to commercial viability and widespread adoption are:

- biomethane, which is gas obtained by purifying biogas released by the breakdown of biological materials (purification involves removing a number of unwanted components, especially carbon dioxide)[2]; and
- renewable hydrogen, also referred to as "green" hydrogen, which on current technologies is hydrogen produced by separating hydrogen from water using electrolysis.

There is a potential for the development of other renewable gases, but none are as close to commercial viability as biomethane and renewable hydrogen.

The Australian Government released a national Hydrogen Strategy in 2019 and most States are actively engaged with the development of renewable gas supply chains, with an eye to both domestic substitution and export market opportunities. Initiatives under consideration or in progress include a range of enabling measures—regulation, certification, infrastructure development and adaptation—and also a range of pilot projects to prove up the role of renewable gases.

Renewable gases have a potentially important role in supplying energy to:

- distribution network customers who otherwise will need to electrify (especially residential and buildings);
- industrial heat users for whom electrification is not a realistic option;
- transport, especially for transport forms which cannot electrify, but also as an alternative to electric vehicles; and
- gas fired generation, which is and will remain important for firming the electricity supply system.

The role for renewable gas has not yet entirely become clear, but it is apparent that it will have some role, and it will be to Australia's advantage to ensure that it is able to make use of renewable gases subject to broad cost competitiveness criteria. At this early stage the cost competitiveness of renewable gas is improving, and it is desirable that these improvements be spurred along by active efforts to integrate renewable gases into the energy system.

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[1] This definition is similar to that of Australian Gas Networks (not dated). A somewhat narrower specification requires that renewable energy be used to produce renewable gas, which rules out gas produced from net-zero but non-renewable sources such as hydrogen produced from fossil-fuel gas with full carbon capture and storage or hydrogen produced with nuclear energy.

[2] Biogas is a gas captured from decomposing organic wastes from agricultural produce, landfills and wastewater treatment facilities.

Moreover, while a move to electrification of the Australian energy system seems highly likely, there will be substantial costs associated with this, which raises the question of how far and how rapidly electrification should proceed and to what extent it can satisfy Australia's clean energy needs.

This is where a Renewable Gas Target has its role. It can contribute positively in a number of ways to the Australian energy policy agenda, including:

- emissions reductions
- developing a renewable gas supply chain in the domestic market
- energy security
- building the hydrogen export industry

The motivation of this study is to consider how a RGT might be effectively designed and implemented to support the adoption of renewable gases. The next section discusses methodological issues. The following two sections discuss contemporary developments in Australia and Australia's Renewable Energy Target, which provides a model for an RGT and has been in operation for two decades now. That is followed by a discussion of contemporary developments in a number of overseas jurisdictions. The following section reports on stakeholder consultations regarding a RGT. The next two sections deal with a synthesis of issues arising from the deep dive and a discussion of the design aspects arising for a RGT. A final section offers board conclusions.

The report does not, and cannot, reach a conclusion about whether a RT should be implemented. Experimentation with new components in the energy mix inevitably brings with it some risks. But a failure to fully explore the alternatives, putting everything on electrification, brings risks of its own. We hope that this report can assist decisionmakers to think through the relevant issues and identify the range of alternatives available to them as they grapple with this issue. It is fundamentally important to Australia's prosperity and successful transition to net zero.

REFERENCES

Australian Gas Networks (not dated), *What is Renewable Gas?* https://www.australiangasnetworks.com.au/what-is-renewable-gas

2. The research task

2.1 RESEARCH QUESTIONS

The primary outcome sought by this project is to develop a better understanding of the contribution that a RGT could make to the development of a renewable gas market and industry in Australia and how it can be an effective market development mechanism for the renewable gas industry. To address this issue, there needs to be a clear understanding of how an RGT could work in practice and what the key design choices are.

The role and structure of a RGT cannot be considered in isolation of broader policy concerns. In particular, it is important to consider efforts to reduce emissions and efforts to restructure Australia's energy mix. This is especially the case given the change in policy under the new Australian Government. It has moved away from the previous Government's "technology not taxes" approach, adopting a more ambitious emission reduction trajectory. This will require more impactful policy settings, but the specific interventions to achieve faster emission reductions are yet to be decided.

The output of this research will facilitate improved decision-making processes around the implementation of RGT mechanisms. It will enhance the knowledge bases of FFCRC stakeholders and assist them to contribute to policy-making processes. One aspect of this is ensuring that the role of future fuels is properly addressed in whole-system decarbonisation and possibly a net-zero transition.

To achieve these outcomes, there is a need to develop a better understanding of the impact that policy and regulation relating to RGTs will have on the deployment of future fuels and how they interact with the rest of the energy system—especially the electricity and gas systems and markets. In particular, there is a need to:

- Understand the way in which RGT mechanisms may impact on the provision and uptake of future fuels in the Australian energy mix
- Undertake a review of the performance of similar policies and the potential unintended consequences of portfolio/technology deployment targets on similar markets (e.g., the electricity market)
- Provide industry with the evidence needed to engage with other stakeholders around RGT and related energy and emission policies to facilitate the development of Future Fuels in the Australian energy mix
- Draw out knowledge from industry partners about how RGTs might impact on their business, and synthesise this with broader evidence
- Understand the how the introduction of RGTs might affect the interface between gas and electricity markets given the potential for co-firing and distributed deployment of H2 creation and the competing roles of electricity and gas in Australia's final fuel mix
- By developing a more informed perspectives on the RGT, develop capacity to identify the nature of possible unintended implications for future fuels in the energy transition

The review will address issues such as:

- Why might we need a national RGT? (e.g. economic aspects, potential social benefits, international relations)
- How is the need for an RGT affected by broader policy settings on emissions and energy? (e.g., emission taxes, quotas – cost-effectiveness of an RGT)
- What are the relative advantages and disadvantages of a national RGT scheme versus implementing State-based RGTs?
- What issues arise if seeking the harmonisation of State-based schemes?
- What fuels would qualify for certificate eligibility? Related to this, what are the relative advantages and disadvantages of implementing a source-neutral approach to emissions reductions versus the fuel/technology-specific RGT approach?
- What might be the implications of an RGT for Australia's future energy mix?
- What might be the distributional implications of an RGT?
- What implications does an RGT have for infrastructure needs? And how would its costs be allocated?
- What implications might an RGT have for the competitiveness of heavy industry?

The study does not seek to quantify the benefits of emission reductions, but it is strongly relevant to the identification of cost-effective emission reduction strategies.

2.2 RESEARCH METHODS

This deep dive examines and synthesises the existing evidence and experience relating to RGT-type interventions in Australia and in overseas renewable energy leaders. It includes a combination of desktop analysis of policy approaches around renewable gases, stakeholder consultations regarding views of a RGT, and a synthesis of these elements to identify potential design choices for a RGT and pros and cons associated with those design choices.

The desktop analysis identifies and describes selected policies in Australian and overseas jurisdictions that support the development and adoption of renewable gases in the domestic energy mix. These policies come in multiple forms, including some that target renewable gas directly and others that support it indirectly. For instance, some policies explicitly support the development of green hydrogen, while others directly discourage emission reductions, and therefore potentially give indirect support to renewable gas adoption. We pay particular attention to Australia's Renewable Energy Target, given its long standing and centrality in the decarbonisation of the Australian electricity market.

We carried out consultations with industry, consumer and government stakeholders to identify their experiences, concerns and insights on the use of RGT-type mechanisms in the Australian gas supply sector. The consultations were exploratory, intended to alert us to the range of views held by parties affected in potentially different ways by a RGT. They were not designed to estimate the prevalence of particular views in the population or sub-populations. Nor did we seek formal organisational views, although naturally the individuals that we spoke to were influenced by organisational perspectives.

Synthesis of the desktop review and stakeholder experience to feed into specifications, parameters and shocks for macroeconomic modelling.

3. The emerging policy environment for renewable gas in Australia

- The Australian Government and all State Governments are committed to reduce emissions to net zero by 2050 but the policies to achieve this are not fully identified
- There are some broadly targeted policies to reduce emissions—e.g. the Safeguard Mechanism—that give some encouragement to renewable gases in place of carbon-emitting energy supplies, but these incentives have limited power given the current technologies and market structures
- There are a number of Government schemes commencing and mooted that set targets for renewable gas in the gas supply—e.g. the NSW Government's NSW Hydrogen Strategy and the Western Australian Government's Renewable Hydrogen Target for its gas-fired generation sector
- Some State Governments are placing substantial emphasis on electrification as the primary means to decarbonise the energy demands currently met with fossil-fuel gas
- All States see some role for renewable gas and are investigating what is needed to support it
- The States have supported numerous and diverse pilot projects that address the challenges of introducing renewable gas—especially hydrogen—into the gas supply chain
- Australian and State Governments have also been reviewing and amending various regulatory schemes so that they can admit renewable gases under appropriate conditions
- Some other States also have substantial renewable gas initiatives in planning and delivery stages

Renewable energy policy in Australia is influenced by the Commonwealth Government and State Governments. The actions of the distinct levels of government often reinforce each other but may also at times cut across each other. Most energy market regulation is the preserve of the States although in practice some is determined by multi-jurisdiction bodies. For example, east coast electricity and gas markets, operating subject to code that are agreed on by state energy ministers.

The Australian Government and most State Governments have some initiatives to promote renewable gas. In some case Australian Government policies are applied uniformly across the States - e.g., the Renewable Energy Target. Policies are also implemented by government spending but spending measures may not achieve uniformity across locations.

3.1 AUSTRALIAN GOVERNMENT

The Australian Government has a commitment to reduce emissions to 43 per cent below 2005 levels by 2030, and to achieve net zero emissions by 2050. In September 2022 it set these targets in legislation. It also required that amended targets be embedded in the objectives of certain statutory authorities whose activities affect emission reductions. Even so, there is still much uncertainty about how the 2030 and 2050 targets will be achieved.

The Safeguard Mechanism

The Safeguard Mechanism is an Australian Government regulatory mechanism that has a potentially important role in Australia's efforts to reduce carbon emissions. Introduced in 2016, it applies to Australia's largest greenhouse gas emitting facilities and places a limit—a "baseline"—on the "Scope 1" emissions that each facility may release.[3]

For the Safeguard Mechanism to operate effectively it is necessary to have a calculation of the actual emissions from facilities. Large emitters are required to measure and report emissions under the National Greenhouse and Energy Reporting Act 2007 and supporting legislation and regulations.

[3] "Scope 2" emissions are emissions produced at the site of the facility. Scope 2 emissions are emissions induced by producing energy for the facility at a different location, the most significant example of this being the emissions arising from electricity supplied to the site but generated at distant power plants. "Scope 3" emissions are emissions arising from other activity induced by the facility, e.g. emissions from the production of cement used on site but produced at a separate facility.

Emissions are reported at the level of a facility. In general, "facility" has its natural meaning as an activity on a distinct site. The exception to this is the grid-connected electricity generators; in their case, the electricity grid is treated as a facility and the generators connected to it are treated collectively under the Safeguard. Gas pipelines are also treated as facilities in respect of their fugitive emissions.

Facilities which emit more than 100,000 tonnes of CO2-e are subject to the Safeguard Mechanism. DCCEEW (2022a) reports that around 215 large industrial facilities are covered by the Safeguard Mechanism. This includes facilities in the mining, manufacturing, transport, oil, gas, and waste sectors. These facilities contributed 28 per cent of Australia's national emissions in 2020-21.

Each facility has a baseline set for it. The facility is required to keep its emissions of CO2-e, net of any Australian Carbon Credit Units (ACCUs) that it surrenders to the Government, below its baseline. ACCUs can be purchased on market and in the June quarter 2022 prices were around $35/t CO2-e. There are some smoothing and exceptional circumstances treatments available to emitters that have difficulties complying with baselines. In addition, facilities may choose between alternative calculations for their baseline, which allows them to shop for the most favourable treatment.

Since the inception of the Safeguard Mechanism, baselines have been set on either "fixed" or "production-adjusted" bases at the discretion of reporting facilities. Under the fixed approach, the baseline stipulates a tonnage of emissions. Under the production-adjusted approach, the baseline stipulates emissions per unit of output, so that the allowable emissions depend on output; if output increased allowable emissions would increase; conversely, if output decreased allowable emissions would decrease. Almost all entities now operate under the production-adjusted approach.

The production-adjusted approach is potentially deficient in that it has no traction over some changes in emissions. It does not credit emission reductions that are attributable to reducing output at an emitting facility. Nor does it place any restraint on emission increases associated with a rise in output from an emitting facility. Thus the production method will not credit emission impacts arising from contractions or expansions in the activity of emitters. Yet emission reductions of this type are just as valuable to the stabilisation of global temperatures as emission reductions achieved through technology and process improvements. Efficiency goals would be furthered by incentivising them.

Facilities in the scope of the Safeguard currently account for 28 per cent of Australia's emissions, and some broadening of coverage could materially increase the scheme's power. However, the Government has indicated that it will not lower the threshold for participation in the Safeguard below the current 100,000t CO2-e. This means that any policy leverage on the remaining 72 per cent of emissions will need to come from other mechanisms. Direct emissions from activities such as agriculture, heating of buildings (commercial and residential) and transport are almost entirely out of scope.

The Government has announced reforms to the Safeguard Mechanism whereby it will drive deeper cuts in emissions but with improved options to secure those reductions at least cost. While key aspects of the reforms have been announced, the details have not yet been published. Key changes are that facilities under the Safeguard are required collectively to cut emissions by 4.9 per cent per year until 2030; there is thus a "hard" cap on emissions under the Safeguard. The decline rates for baselines vary across facilities according to assessments of their needs. A credit mechanism will be established so that facilities which face high costs of abatement can outsource some of their emission reductions to facilities which are able to deliver them at lower costs—see Box 3.1 for a discussion of challenges arsing in the establishment of a credits and trading regime. However, facilities will not be able to use offsets from outside the facilities in scope of the Safeguard Mechanism. New facilities will have their baselines set with reference to international best practice, which means zero net emissions for new gas developments.

National Hydrogen Strategy

Australia's National Hydrogen Strategy, published in 2019, sets a framework to develop a hydrogen industry in Australia. To this end, it seeks to accelerate the commercialisation of hydrogen, reduce technical uncertainties and build up our domestic supply chains and production capabilities (Commonwealth of Australia 2019). Because there is a need to evolve the supply chain, and this requires the development of critical mass, the Strategy seeks to concentrate production and consumption in regional hubs that will foster domestic demand. As lessons are learned and technologies are developed this may assist the spread of hydrogen production and use to other regions.

Box 3.1: Challenges implementing tradeable credits under the Safeguard Mechanism

- There is at present substantial headroom in the Mechanism. Introducing Safeguard Mechanism Credits while this headroom exists could actually undermine emission reductions. Facilities would be able to buy unused headroom and diminish their own efforts to reduce emissions. It should be possible to address this issue by choosing an appropriate trajectory for the aggregate baseline. But the more aggressive the trajectory of emission reductions the greater the cost burdens on covered facilities, at least in aggregate if not for every facility
- What would happen in respect of new, large emitters that might emerge? Of particular concern here is major new oil and gas developments which may have very substantial fugitive emissions. Should they be required to reduce or offset their own emissions external to the Safeguard or should they be included in it? Allowing new emitters to buy room under the baseline would increase pressure and costs on existing emitters in the transition to net zero. However, it is probably misleading to assess this issue purely in the context of the Safeguard. If Australia wants to allow substantial new emitting activities and at the same time achieve a net zero trajectory it is inevitable that some emitters—new and existing—must be displaced
- What would be the initial allocation of baseline across individual facilities under an aggregate baseline? This is essentially a question about how to allocate a valuable resource—the right to emit—across potential users of that resource—emitters. With a proper credit and trade mechanism in place, there is a prospect that the initial allocation could be is neutral on efficiency grounds, for emission rights could simply trade to their highest valued uses. The decision about the initial allocation therefore is fundamentally an equity question
- How would baselines be equitably allocated? Economic analysis can give limited guidance on this question. Without wishing to endorse any particular approach, the following might be relevant
- There may be a case to allocate entirely to incumbents with sunk costs, meaning that new entrants would need to buy their way in. An alternative treatment would be to reserve some rights for new entrants
- Allocations could take into account the difficulty of the emission reduction task in different industries and activities. Baselines would reduce more slowly for hard-to-abate industries
- Allocations might take into account the exposure of the activity to an emission reduction burden. Activities with high adverse impact would then receive a baseline with a less rapid rate of decline. However, this approach is problematic (as has been demonstrated in previous episodes). If the intent of policy is to protect the communities that live and work in particular regions, assigning emission rights to an entity that operates in the region may not work well. The entity may ultimately sell its emission rights and scale back operations, with the result that shareholders gain the benefits of the emission reductions but exposed communities get little or nothing

The Strategy also reflects the view that a strong domestic hydrogen sector will reinforce the development of hydrogen production for export. Although the scale of the overseas hydrogen market remains highly uncertain, major overseas markets which currently take Australian energy exports in the form of coal and LNG will introduce hydrogen into their energy mixes, and it is important that Australia be ready to engage with these changed demand patterns. Australia has a relative abundance of land which is well suited to renewable energy production and if logistical challenges with transport can be overcome Australia is likely to have considerable strengths as a hydrogen producer and exporter.

The Strategy acknowledges that there are risks associated with developing hydrogen capability but points out that there are also risks in not acting early. To deal with uncertainties and risks, it is intended that the Strategy will be adaptive. At this stage its emphasis is on actions that remove market barriers, efficiently build supply and demand, and accelerate Australia's global cost-competitiveness. The aim is to ensure that Australia is well placed to scale up quickly as markets develop.

The development of Hydrogen hubs is integral to the Strategy. The Strategy says that hubs *"may be at ports, in cities, or in regional or remote areas, and will provide the industry with its springboard to scale. Hubs will make the development of infrastructure more cost-effective, promote efficiencies from economies of scale, foster innovation, and promote synergies from sector coupling"* [p. viii]. In addition, the Strategy notes that the development of hubs is only part of the story. There is also a need to establish *"clear regulatory frameworks and ensure development has a positive influence on energy prices and energy security"* [p. viii]. The Strategy also note the importance of Australia engaging at the international level to develop the institutions needed to support hydrogen trade, including certification of origin, transport protocols, technical specifications, etc.

The Strategy identifies numerous actions that are required to support the implementation of the Strategy. These actions fall under the broad themes of "national coordination; developing production capacity, supported by local demand; responsive regulation; international engagement; innovation and research and development (R&D); skills and workforce; and community confidence" [p. ix]. The actions are framed *"in relation to exports, transport, industrial use, gas networks, electricity systems, and cross-cutting issues such as safety, skills, and environmental impacts"* [p. ix]. The actions contained in the Strategy address a wide range of issues in considerable detail.

The Strategy is now three years old and there has been progress on a number of fronts in respect of the actions identified in it. Many of these developments are discussed in the sections on State initiatives that follow.

One of the issues raised in the Strategy is the need for a mechanism to certify the origin of hydrogen. Without it, there would be little to distinguish hydrogen produced from emitting energy sources and hydrogen produced from renewables. The Clean Energy Regulator is at present developing a Guarantee of Origin scheme which will serve to track and verify emissions associated with hydrogen and renewable electricity. It may expand in the future to cover other products such as metals and biofuels. (DCCEEW 2022b, c).

There is, however, no wholistic Commonwealth scheme to incentivise the development of green hydrogen or other renewable fuels. A renewable gas target could be implemented, along the lines of the Renewable Energy Target, or some other scheme, but at this stage the Australian Government has not indicated any intention to proceed in this direction. A broad-based price or quota on emissions would also provide encouragement to the development of renewable gases, but there is no suggestion from the Government that it is considering anything along these lines. (The nearest thing to action on this front is the possibility of more ambitious baselines on the Safeguard Mechanism, but most emissions are out of scope of this.) It is possible as well that emission penalties will be imposed in international markets—for instance as under the EU Carbon Border Adjustment Mechanism—but this remains an uncertain prospect.

3.2 NSW GOVERNMENT

System-Wide View

The NSW government has introduced a broad policy agenda to achieve its energy security and climate change aspirations. With the introduction of the Energy Security Safeguard, the state has committed to a reliable and secure supply of electricity (DPIE, 2022a). In conjunction with its plan to improve energy system reliability for the State, the NSW government has also developed its own comprehensive Hydrogen Strategy (NSWHS) to create a multi-technology approach to its future energy system (Nelson et al., 2022). In this system-wide view, we present the three schemes which form the NSW Safeguard. In the subsequent section, we unpack the proposed NSWHS and its main policy components.

The NSW Government's ESS includes several initiatives which develop the state's energy infrastructure and promote the transition to a low-carbon economy. The three schemes, which fall under the state's broader agenda of energy security and sustainability, are efficiency, demand reduction and the development of renewable energy generation capacity and the associated transmission infrastructure needed to carry the new capacity.

The NSW government has implemented its Energy Savings Scheme to assist households and businesses save on their energy bills and to reduce carbon emissions for the state. Since its inception, the ESS has worked toward a target of energy savings of 13% by 2030 with an expected end date of 2050 (McGovern, 2018, Byrnes et al., 2013, DPIE, 2015). The design of the energy savings scheme allows a number of eligible energy savings activities to receive assistance (Berry and Marker, 2015). The program creates financial incentives for households and businesses to invest in energy-efficient technologies and practices such as solar panels, LED lighting, and energy-efficient appliances. These incentives come via the sale of energy-saving certificates purchased by electricity retailers (the liable parties) to meet the required energy-saving targets. Other initiatives in the ESS also include promoting energy savings by providing information and resources to households and developing community programs to encourage the take-up of energy-efficient technologies and practices.

The Peak Demand Reduction Scheme (PDRS) is a program instituted by the NSW government to reduce peak electricity demand and improve the security and reliability of the state's energy system (DPIE, 2022a, Murugesan et al., 2022). The PDRS is closely aligned with the ESS and sets an energy savings target for electricity retailers and large energy users (equivalent to their share of electricity sales each year). Energy users create Peak Reduction Certificates (PRCs) for eligible activities, such as reducing energy usage during peak demand hours. The PDRS and ESS work together to slow the growth of peak demand within the state. The two programs combined work to diminish the need for building additional generation or transmission and distribution network infrastructure (which are primary drivers in growing electricity costs).

The Electricity Infrastructure Roadmap (EIR) aims to ensure that the state has a reliable and secure supply of electricity (DPIE, 2020). The key driver of the EIR is an additional 17GW transmission network investment with 12GW of new renewable energy generation capacity and up to 2GW of long-term storage by 2030. The NSW government authority Energyco is currently conducting bi-annual tenders for the private construction of new generation and transmission capacity within its planned renewable energy zones.

NSW Hydrogen Strategy

The New South Wales state government has developed its NSW Hydrogen Strategy (NSWHS) to rapidly scale up the production and use of hydrogen within the state by 2030 (DPIE, 2022b). The key outcome of the NSWHS is to have 8PJ (~66kt) of hydrogen produced via renewable energy at a target price of $2.8/kg by 2030 (OECC, 2022). Furthermore, the NSWHS focuses on growing the hydrogen industry in NSW and supporting the transition to a low-carbon economy. The plan includes critical enabling factors, such as infrastructure and regulatory frameworks, as well as supporting the development of hydrogen hubs and the growth of the hydrogen industry.

Enable Industry Development

Pillar 1 of the NSWHS focuses on industry development to rapidly scale up the production and use of hydrogen within the state by 2030. The main drivers which will provide support for the hydrogen industry scale-up are as follows:

- The development of infrastructure associated with hydrogen production, storage, and distribution
- Providing land access for hydrogen generation
- Hydrogen hubs and facilitation of industrial cooperation between users, government and producers
- Port infrastructure to support the export of hydrogen to international markets

To support the growth of the hydrogen industry, the NSW government is also working to establish regulatory frameworks to ensure the safe and efficient use of hydrogen (DPIE, 2022b). This policy includes establishing standards for hydrogen production, distribution, and usage and supporting the development of skills and innovation in the hydrogen sector.

The proposed framework for the NSWHS lays out the market-based certificate scheme where hydrogen producers generate the certificates for each GJ of green hydrogen (OECC, 2022). Natural gas retailers and large non-retail users are then liable to surrender certificates based on their share of natural gas usage within NSW. Liable parties then purchase certificates from generators of green hydrogen, who use the certificate revenue to cover part of their cost of production and thus lower the price at which they can viably sell hydrogen to end users (OECC, 2022).

To ensure certificate price stability at the end of the scheme, a window of opportunity for new installations limits eligibility to generators who commence by 2033. Also, existing producers eligible under the scheme will continue to receive incentives until the end of 2040. The policy also sets out a clear definition of green hydrogen which can only be produced by renewable energy sources (this includes biomass and native timber). It explicitly excludes hydrogen generated via steam methane reforming (SMR) - (OECC, 2022).

The NSWHS will also rely on the Australian Government's Clean Energy Regulator's Guarantee of Origin (GO) scheme as a mechanism to support eligibility decisions and to determine quantum of credit allowable.

Infrastructure and Hubs

Pillar 2 of the NSWHS supports the growth of the NSW hydrogen industry through the development of infrastructure and hubs. The policy includes a commitment of $70 million for new hydrogen hubs in the Hunter and Illawarra regions, which have been identified as areas with existing proximity to large energy users of fossil fuels and energy generators (DPIE, 2022b).

The development of refuelling networks for strategic freight routes and precinct roadmaps for decarbonisation in the Hunter and Illawarra regions is also being strengthened. This approach will help to promote the use of hydrogen as a clean and efficient fuel source for transportation and other applications.

In addition to developing hydrogen hubs, Pilar 2 of the NSWHS also focuses on developing green hydrogen power plants (DPIE, 2022b). This plan includes constructing a new gas power station at Tallawarra B, which will be able to use gas and hydrogen. The development of green hydrogen power plants will support the transition to a low-carbon economy and provide a clean and reliable source of electricity. The potential to use hydrogen blended with natural gas in existing electricity generation assets has proved to be a successful initial step towards broader uptake in the electricity sector as a primary fuel (DPIE, 2022b, OECC, 2022).

Rapid Expansion of the Scale of Hydrogen

Pillar 3 of the NSWHS focuses on the rapid expansion of hydrogen use to drive the average cost of hydrogen from $5.80/kg to $2.8/kg across the supply chain (OECC, 2022). This drop in average cost is achievable through economies of scale and various schemes and exemptions to reduce the cost of green hydrogen production (DPIE, 2022b, OECC, 2022).

The NSWHS plans to promote the realisation of economies of scale through network concessions for electrolysers. In requiring 90% of electrolysers to be installed on the existing network infrastructure, the cost of hydrogen production is expected to be reduced by $1.3 per kilogram. These efforts will minimise the cost to other consumers and support the growth of the hydrogen industry.

In addition to network concessions, the NSWHS also provides exemptions from specific energy programs for hydrogen production. This includes exemptions from the ESS, the PDRS, and the Green Power Program. Forecasts indicate that these exemptions will reduce the cost of hydrogen production by $0.8 per kilogram.

The NSWHS also features a target for hydrogen production, motivated in part by energy security concerns. The government will invest in green hydrogen production as a measure to ensure the security of the state's energy supply. Hydrogen production is expected to reach 67,000 metric tons per year, equivalent to approximately 8PJ per year, by 2030.

To support the transformation of industry and the transition to a low-carbon economy, the NSWHS will support the implementation of hydrogen in high-carbon intensive industries, such as the heavy industry and chemical sectors. This support includes financial assistance to build electricity and hydrogen-specific infrastructure by risk-sharing through public-private partnerships and co-funding or underwriting (DPIE, 2022b).

A market engagement model has also been integrated into the NSWHS. It promotes the use of hydrogen by large industrial natural gas users. This model seeks aggregation opportunities and the creation of hubs to pool resources and infrastructure. This initiative is particularly relevant for the heavy industry and chemical sectors, which can benefit from using hydrogen as a clean and efficient fuel source.

Finally, the NSWHS targets hydrogen use in the government fleet. By 2030, it is expected that 20% of government vehicles will be powered by hydrogen. To support this initiative, 1,800 heavy vehicles are to be purchased, with an expected demand for 10,000 metric tons of hydrogen (DPIE, 2022b).

NSW Pilot Projects

The NSW pilot hydrogen projects are small-scale projects that test and demonstrate the feasibility of hydrogen as a reliable energy source within the state. One pilot project is the Hydrogen Energy Supply Chain (HESC) project which demonstrates the feasibility of producing hydrogen using renewable energy sources and transporting it to consumers. The HESC project depends on constructing a pilot plant to produce hydrogen (using wind and solar power), a small-scale hydrogen refuelling station, and a fleet of hydrogen-powered vehicles.

The Jemena Pilot project in Western Sydney is a power-to-gas project which transforms excess renewable electricity into hydrogen gas, which can then be blended into the existing natural gas network. Jemena’s Horsley Park facility was used to inject blended hydrogen via the Central Trunk and Eastern Gas pipelines, which supply natural gas to the Sydney gas network. The pilot project also took advantage of hydrogen as a storage medium and later used it to generate electricity (DPIE, 2022b).

Another pilot project in NSW is the Newcastle Hydrogen Hub, a collaboration between The University of Newcastle, the City of Newcastle, and the Commonwealth Scientific and Industrial Research Organisation (CSIRO). The Newcastle Hydrogen Hub is developing a hydrogen production facility that will use renewable energy to produce hydrogen, which will then fuel a fleet of hydrogen-powered vehicles (DPIE, 2022b).

3.3 VICTORIAN GOVERNMENT

Victoria’s current energy policy seeks to address the need for climate change actions and energy security (e.g. affordability and reliability). The energy sector is one of the leading contributors to carbon emissions’ but at the same time, it also plays a vital role in maintaining stable economic growth. In order to address this growing tension between energy security, sustainability and economic prosperity, the Victorian State Government is developing a clear pathway to transitioning its energy sector.

Firstly, the Victorian Government has committed to a 50% emissions reduction by 2030 and an overall net zero carbon emissions position by 2050. In order to achieve this goal, the government has targeted improvements in energy efficiency and the transition of energy production to more renewable sources. With this commitment to emissions reduction, the Victorian government also faces growing concerns regarding energy costs across all sectors within the economy (DELWP, 2022c, DELWP, 2022d). Initiatives proposed by the Victorian government for the electrification of the energy system and renewable gas substitution in the gas system, are designed to limit adverse impacts on energy costs (particularly on residential households (Chai et al., 2021)) and further, provide a mechanism for transitioning away from the domestic electricity and natural gas markets, along with minimising their exposure to international natural gas prices (Foster et al., 2017, Wagner et al., 2014).

System-Wide View

Since the introduction of the original Victorian Renewable Energy Target (VRET) in 2006 and its subsequent iteration in 2017, the state produced 26% of its electricity from renewables in 2020 (Clean Energy Regulator, 2022). The ambitious policy of 95% renewable energy production and a net-zero system raise the need for substantial initiatives from government.

One of the tactics used by the government is to invest heavily in the creation of six Renewable Energy Zones (REZ's) (DELWP, 2022d), to phase out fossil fuel use in the electricity sector. These REZs include: Central North, Western and South Western Victoria; Murray River; Ovens Murray and Gippsland. These regions have the highest availability of renewable resources but face challenges in accessing the current grid infrastructure. The REZs will require centralised planning of transmission access and integration into the National Electricity Market. For some time now, transmission access has been identified as one of the key barriers to entry for large scale renewable energy penetration (Foster et al., 2013b, Byrnes et al., 2013).

To address the need for co-ordinated renewable energy technology, transmission access and market integration, the government plans in 2022/2023 to re-establish the State Electricity Commission (SEC) of Victoria, which had been disestablished in the privatisation of the electricity sector in the 1990's (Abbott, 2006). The role of the SEC will be to plan new transmission lines for the new REZs and to minimise climate change risks (Energy Safety Victoria 2022), in particular increasing bush fires (Foster et al., 2013a). Furthermore, the Victorian Government has played an active role in the VRET auction which provides a support mechanism via a Contract-for-Difference (CfD between the strike price of the reverse auction contract and the prevailing sport market price), in order to provide a ten-years of support for renewable energy generators (VRET1 and VRET1).

As electrification takes hold in Victoria (DELWP, 2022c), the gas supply system will go through significant transition. The Government envisages that residential space conditioning, water heating and cooking will largely move away from gas fuel to electricity (DELWP, 2022d) and it provides incentives to encourage this. However, during this transition there will be trials (discussed below) of the use of hydrogen and biomethane in the distributed gas system to lower overall carbon emissions (DELWP, 2022b). There is a long history of gas in Victoria, where it became widely used in the 1960's following the development of gas fields in Bass Strait. There will be users who will find it difficult or impossible to transition away from gas and renewable gases are needed to take over from natural gas (Bartels et al., 1996, DELWP, 2022b).

The Victorian government is keen to maintain a supportive economic environment for industries that rely on gas and it has proposed several initiatives to take advantage of the existing infrastructure. One such initiative is the Victorian Renewable Hydrogen Industry Development Plan (VRHDP), where the government places emphasis on state-wide planning and the use of existing gas infrastructure for its renewable energy future (DELWP, 2022b). The key elements of this policy indicate that the hydrogen supply chain will have several clear benefits which enable the reduction of carbon emissions, integration of existing networks and the development of export markets for green hydrogen. Furthermore, the VRHDP also addresses the needs of sectors such as transport and industrial applications which have previously been seen as hard to decarbonise (e.g., Aluminium and Steel production) and its potential to enhance reliability and stability of the electricity grid.

Victorian Gas Substitution Roadmap

The Victorian Gas Substitution Roadmap's (VGSR) broad goal is to complement existing policy, helping to lower carbon emissions and containing adverse impacts on consumer energy costs. The VGSR features a series of policy themes (energy efficiency, electrification, substitution of the natural gas with hydrogen and biomethane) to reinforce the sustainability of the state's energy system. Through this Roadmap, the Victorian Government aims to provide a secure, reliable and safe energy supply, which it believes is of paramount importance.

The VGSR has two main approaches to lowering emissions and reducing the overall cost of energy to households and business which were originally proposed in the Victorian Energy Upgrades scheme (VEU). These are, firstly, to assist in the upgrade of household appliances and to support improved energy efficiency in buildings, secondly, to substitute for current and prospective natural gas with electricity and, to a more limited extent, renewable gases

(DELWP, 2022d). The substitution of hydrogen into the natural gas network has been proposed in the VGRS as a way for households to reduce carbon emissions and to decrease overall energy costs.

The major themes in the Victorian policy landscape are: Electrification and Energy Efficiency; Hydrogen and Biomethane substitution and the prospects associated with Hydrogen pilot projects within the state.

Electrification and Energy Efficiency

The two combined measures of efficiency and electrification are largely focused on ensuring that new housing has the option to be completely electric and that other residential, commercial and industrial energy users are supported to electrify when possible or, failing that, to be able to access renewable fuels as a substitute. Further policy initiatives proposed under the electrification framework include increased transparency by energy retailers to support more meaningful comparisons on energy contract offerings. In addition, a bill payment support scheme and the incoming standards for payment assistance will help avoid disconnections and will minimise energy poverty spirals for retail consumers (Chai et al., 2021).

The VGSR/VEU scheme will assist consumers by means of an indirect capital subsidy (discounted products via accredited providers) on a range of household items such as whitegoods, space conditioning, hot water systems, building fixtures and in-home energy use metering/displays. The Victorian government has also committed to a consumer awareness campaign which will demonstrate to households the opportunities available to them to reduce energy use via appliance upgrades. The existing schemes/policies which are complementary to the announced reforms in the VGSR include the Solar Homes program, Solar Business Program, and the Big Housing Build Program.

Changes to Victorian planning laws will also have a direct effect on energy consumption by households. There will no longer be a requirement for newly built houses to be connected to the gas network (DELWP, 2022d). Developers of new estates/subdivisions were previously required to connect to the gas network if they were no more than 3km away from the existing reticulated system. Consumers will still have the option to connect to the gas network, but the necessary infrastructure is less likely to be in place at new developments.

Changes to the National Construction Code (NCC), and the realignment of the Victorian Plumbing Regulations (2018), will also improve the rate of energy efficiency improvements for newly constructed dwellings (DELWP, 2022d). The proposed changes to the code will increase the minimum building efficiency from 6 to 7 stars, with improved standards for construction materials and fixed appliances, such as space conditioning (heating and cooling), hot water systems and lighting.

An analysis by Sustainability Victoria in 2015 (Victoria, 2015) previously suggested that, based on a small sample of 60 existing dwellings with the state, significant energy efficiency gains could be achieved. In Victoria, the average star rating for energy efficiency is only 1.8 stars for all dwellings in the sample. Dwellings constructed prior to 1991 have 1.57 stars, for those constructed between 1991 and 2005, it is 3.14 stars. The most notable non-structural upgrades to housing in the study is associated with space heating, with a fixed appliance upgrade to 80% of dwellings (in the sample) resulting in a ~6.24GJ/year reduction in gas usage. These upgrades average in cost to ~$1100 with an average payback of 8.8 years (Victoria, 2015).

The VGSR also describes its positive impact on energy efficiency in public housing via the Big Housing Build policy framework. The current social housing stock (~64,500 dwellings), accounts for ~2.5% of the total number of households within the state. With the expected boom in public housing construction (Victoria, 2015, DELWP, 2022d), it is worth noting that this additional stock will only likely rise to ~3-3.5% of the total dwellings in the state (DELWP, 2022d).

In this review of the Roadmap, the energy efficiency gains appear highly dependent on a number of factors that need further clarification in the plan. As a result, greater consideration needs to be placed on scope and scale of energy efficiency improvements, the overall costs per unit of peak demand reduced/deferred ($/MW) and the overall energy consumption saved ($/GWh).

Hydrogen and BioMethane Gas

The Victorian government's net-zero emissions and affordability goals require the use of renewable hydrogen and biomethane. Renewable gases such as these are expected to play a significant role in the decarbonisation of the gas sector. The Victorian Government will invest in pilot projects and infrastructure and also using its purchasing power to increase demand and thus the scale of renewable gas production. The substitution of renewable gases for natural gas in the reticulated gas network will enable the remaining 50% of users who are unable to electrify to maintain a reliable energy supply (DELWP, 2022a). In the early stages of the of the development of the hydrogen sector, the state government is investing in infrastructure and co-funding pilot facilities to assist to de-risk the sectors development. However, while the potential purchasing power of state in its energy usage has been detailed, no direct targets have specified the amount of hydrogen or biomethane within its policy targets.

As well as decarbonising the domestic gas system, the Victorian Government also sees a role for renewable gas helping to insulate the Victorian economy from volatile international energy costs and their impacts on consumer energy costs within the state (DELWP, 2022a). In these early stages, pilot projects have been initiated by industry and government to explore the potential deployment of renewable gases as a substitute for methane in the reticulated gas networks.

The focus of many pilot projects in Victoria highlights issues of mobility (CSIRO 2022a). These projects range from fuelling fleets of cars to options for public transport and are solely focused on delivering hydrogen via renewable energy production. Furthermore, it is also worth noting that these projects are still either in the green field or construction phase of their lifecycle. There is one project at Laverton North that will focus on the production of methanol from renewable energy and waste for transportation, which is of particular interest to the long haul trucking industry.

The Hydrogen Energy Supply Chain project has already demonstrated its potential for the export of hydrogen. The AGL-led project in collaboration with Japanese industrial partners has demonstrated the ability to export hydrogen into international markets (CSIRO 2022a). That project has produced hydrogen by gasifying brown coal but provides useful learnings for the export of hydrogen produced by other means.

Renewable gases are also expected to have an important role in electricity system reliability. With an increase in the deployment of renewable energy capacity and the retirement of fossil fuel-based electricity generators, there is an increasing role for gas-powered firming generation, and renewable gases can replace natural gas in that task. (Wagner, 2016, Reedman et al., 2015).

3.4 QUEENSLAND

System-Wide View

Queensland's main emissions reduction and renewable energy targets are to:

- Achieve a 70% renewable energy target by 2032
- Lower electricity emissions to 90% of 2005 levels by 2035-36
- Achieve a 30% economy-wide emissions reduction target on 2005 levels by 2030
- Deliver a reliable, secure energy system with competitively priced energy

Historically, Queensland has met most of its energy demand through coal-fired electricity generation (80%) followed by gas-fired and hydroelectric generation (EPW, 2022e). A small but non-trivial contribution comes as well from generation fired by bagasse, a sugar industry by-product. Baseload coal and dispatchable gas and hydroelectric generation have effectively minimised energy shortfalls in a system that is characterised by fluctuating daily and seasonal demand and limited storage capacity. There is a high prevalence of coal fired generation in the generation mix.

Queensland has large coal seam gas (CSG) reserves and relatively small reserves of conventional gas. Most of the CSG is extracted from the Bowen and Surat basins whilst conventional gas is extracted from Cooper and Eromanga Basins. Most of Queensland's natural gas is currently produced from processed CSG, which is converted into either natural gas for use in industrial and manufacturing processes and electricity generation or liquified natural gas (LNG) for export. The majority of Queensland's natural gas production plants are located in Bellara (approximately 66km northeast of Brisbane) and Roma (approximately 620km west of Brisbane) (Business Queensland, 2022).

Natural gas currently provides 21% of Queensland's total primary energy consumption, with electricity generation accounting for over 75% (DCCEEW 2022d). Residential and small-scale commercial use account for less than 3% of consumption. This is largely because Queensland has warm climate and, therefore relatively low demand for heating, compared to other Australian states (DNRME, 2016).

Historically, Queensland has produced electricity with bagasse-fired electricity generation facilities built between 1950 and 1970 to take advantage of, as well as support, Queensland's sugarcane industry. However, bagasse is available in quantity only during the sugarcane crushing season, meaning that bagasse-fired power plants are typically underutilised. Further, bagasse has increasingly become less competitive than solar and wind as a source of renewable energy due to recent technological advancements in solar and wind.

Queensland's energy system is currently evolving rapidly. It has ageing coal-fired power stations and there is an increasing demand for renewable energy and renewable energy generation capacity. In 2016, the Queensland government approved 17 large-scale renewable energy projects to generate an additional 1,200 MW of renewable electricity, with solar and wind farms making up 91% of the additional capacity and bagasse making up the remaining 9%. However, the availability of wind and solar energy relies on underlying weather conditions and seasons, and therefore brings with it a need for firming, as is the case in other States. Natural gas is, therefore, likely to continue to play a major role of supplementing power supply during peak loads, at times of low renewable resource availability, and when there is insufficient output from baseload coal generation and storage capacity.

Renewable Gas

Development of renewable gas production is high in the Queensland Government's priorities as it sets strategies for meeting future demand and achieving emissions reduction and renewable energy targets.

Queensland's renewable gas policies are mostly focused on developing its renewable hydrogen industry for use in electricity generation and for exporting to take advantage of its abundant renewable energy supplies (DSDILGP, 2022a). These include:

- Converting existing gas turbines to running on renewable hydrogen or a renewable hydrogen blend
- Installing new gas turbines that can be fuelled by renewable hydrogen or a renewable hydrogen blend
- Developing a renewable hydrogen industry and technologies, including establishing electrolysis production facilities and supporting distribution network infrastructure, with a focus on exporting renewable hydrogen
- Repurposing existing coal-fired power stations by reinvesting in new renewable hydrogen production and distribution infrastructure to minimise stranded-asset costs

Emissions Reduction Policy Targets and Interventions

In May 2019, the Queensland government published the Queensland Hydrogen Industry Strategy 2019-2024, which outlines Queensland's vision to increase its competitiveness as a producer of renewable hydrogen in the global market (DSDILGP, 2019). As part of the strategy, the Queensland Hydrogen Industry Development Fund was established to provide financial support for new hydrogen projects, including new renewable hydrogen projects. Queensland's Zero Emission Vehicle Strategy 2022–2032, published in March 2022, outlines guiding principles for achieving its emissions reduction and renewable energy targets, including supporting development of a renewable hydrogen industry (TMR, 2022).

The Queensland Energy and Jobs Plan, released in September 2022, is Queensland's main vehicle for articulating its emissions reduction and renewable energy visions and targets (EPW, 2022c). The Plan includes aspirations for Queensland to have no regular reliance on coal-fired generation and to have eight times more renewable energy capacity than 2022 levels by 2035. The Plan's outlines measures to enhance energy system reliability by investing in production of low- to no-emission gas for generating electricity at peak times and to provide storage, firming and dispatchable power capacity. The Queensland SuperGrid Infrastructure Blueprint, which outlines planned infrastructure investments to achieve Queensland's emissions reduction and renewable energy targets, includes a plan to invest in a new 200 MW hydrogen-ready gas peaking power station. The Queensland government has established the Queensland Renewable Energy and Hydrogen Jobs Fund to finance renewable hydrogen projects with the objective of increasing blending of hydrogen with natural gas in the short-term and accelerating a shift towards renewable hydrogen as the main source of dispatchable power for meeting peak load electricity demand in the long run.

The Plan outlines steps to develop Queensland's renewable hydrogen industry. These are organised around the objectives of promoting production of competitive renewable hydrogen, both to meet increasing domestic demand for renewable energy and to harness the opportunity to export renewable hydrogen. To this end, the Plan proposes development of Queensland Renewable Energy Zones to serve as bases for producing new renewable energy and hydrogen, including development of renewable hydrogen hubs. One of the major planned projects is the Central Queensland Hydrogen Project, which proposes commercialised production and liquefaction of renewable hydrogen for domestic consumption and large-scale production for exporting to Japan (Queensland Treasury, 2022).

On 20 July 2022 the Queensland Government released the 2022-2032 Queensland Hydrogen Industry Workforce Development Roadmap, which outlines planned investments for developing Queensland's renewable hydrogen industry to support delivery of the Plan.

Main investments for Promoting Renewable Gas Production

The following investments have been planned or made by the Queensland government (EPW, 2022b) to support the development of Queensland's hydrogen sector under the Roadmap:

- $28.90 million has been allocated towards development of a hydrogen demonstration plant and refueller network from the Queensland Renewable Energy and Hydrogen Jobs Fund
- $23.92 million has been allocated to support development of hydrogen infrastructure, with $9.72 million allocated towards renewable hydrogen infrastructure projects under the Queensland Hydrogen Industry Development Fund (DSDILGP, 2022b)
- A $20 million Hydrogen Training Centre of Excellence for developing a workforce to support development of Queensland's renewable hydrogen industry
- A $15 million co-investment has been planned to develop a hydrogen export facility
- A $5 million project to establish a renewable hydrogen plant in Townsville funded through the Queensland Government's Hydrogen Industry Development Fund (DES, 2022c)
- A $4.3 million Renewable Hydrogen Production and Refuelling Project to supply renewable hydrogen in Queensland as well as supplying a hydrogen refuelling station in Brisbane (CSIRO 2022b)
- A $1.1 million project to establish a renewable methane production demonstration plant near Roma (ARENA, 2022)
- $0.60 million of financial support has been committed to support development of a Future Energy Exports Cooperative Research Centre
- A $0.25 million grant has been awarded to support development of a green hydrogen pilot plant for export
- $0.10 million has been allocated towards supporting a National Hydrogen Technology Clusters Program, which includes three renewable hydrogen clusters

Other Interventions

Further, the following initiatives have been launched to support development of Queensland's hydrogen industry:

- Addition of hydrogen-powered Fuel Cell Electric Vehicles (FCEV) to the state Government's fleet (EPW, 2022a)
- Development of a Hydrogen Super Highway and the east coast hydrogen refuelling network along major roads and highways in Queensland, New South Wales and Victoria (EPW, 2022d)
- Construction of the Kogan Creek Renewable Hydrogen Demonstration Plant, a renewables-based demonstration hydrogen production facility (CSIRO 2022c)
- A feasibility study has been conducted for a new plant that will use green hydrogen to produce ammonia (DES, 2022a)
- The Queensland government has partnered with Iwatani Corporation of Japan to develop a green hydrogen production electrolysis plant that will produce renewable hydrogen to export to Japan (DES, 2022b)

3.5 SA GOVERNMENT

System-Wide View

South Australia has an objective to reduce emissions to more than 50 per cent below 2005 levels by 2030 and then to net zero by 2050 (DEW 2020). The South Australian Government Climate Change Action Plan 2021–2025 identifies several subsidiary objectives that support this goal, these being:

- Accelerate the renewable energy economy
- Develop a world-class renewable hydrogen industry
- Attract and grow businesses and industries powered by renewables
- Support the agriculture sector to adapt, innovate, and reduce net emissions
- Support expansion of carbon farming and blue carbon
- Support the uptake of low and zero emissions vehicles and fuels

The South Australian electricity generation mix has a very high renewable share, second only to Tasmania. But unlike Tasmania, which has relied on renewable electricity in the form of hydroelectric for decades, the high renewable component in South Australia is the outcome of two decades of major changes in the energy mix. Starting from almost zero 20 years ago, renewable generation has been developed under the auspices of the RET and further encouraged by a very pro-renewable SA Government policy stance. South Australia's last coal fired generators ceased operation in 2016. Electricity is now generated from wind and solar (61 per cent) and gas (39 per cent).

The Climate Change Action Plan also sets out actions to meet net zero emissions target, including two new renewable energy targets:

- to achieve 100% net renewable energy generation by 2030; and
- to achieve a level of renewable energy that is 500% of current local grid demand by 2050, allowing South Australia to export renewable energy, green hydrogen and other low emissions products locally (to New South Wales and Victoria) and internationally (particularly to Asian neighbours) (DEW 2020)

To reach this goal, the Government says that substantial investment will be needed in new grid transmission capacity, renewable energy infrastructure and green manufacturing capability (DEM 2020)

In November 2021, the South Australian Productivity Commission (SAPC) led an inquiry into South Australia's renewable energy competitiveness. The bulk of the recommendations in the published inquiry in June 2022 were in reforming land planning codes and streamlining regulatory processes to further enhance South Australia's competitiveness in renewable energy (SAPC 2022).

Renewable Gas

In 2017 South Australia created a $150 million Renewable Energy Fund, providing loans and grants to eligible projects including hydrogen storage. A further $8.2 million was allocated to fund a public transport pilot project which involved six hydrogen-fuelled public busses, a refuelling station and facilities to produce hydrogen (DPC 2017).

In 2017 South Australia published its Hydrogen Roadmap for South Australia (DPC 2017) and this was followed in 2019 by South Australia's Hydrogen Action Plan (South Australia 2019). The Hydrogen Action Plan aims to scale up renewable hydrogen production for export and domestic consumption by facilitating investment in hydrogen infrastructure.

Following the recommendations of the SAPC inquiry in 2021, the SA Department of Energy and Mining released its Hydrogen and Renewable Act Issues Paper in November 2022, a consultation paper on its proposed Act which will regulate large-scale hydrogen and renewable energy projects in South Australia (DEM 2022). The proposed Act is to provide a 'one window to government' licencing and regulatory system for the lifecycle of these projects by addressing existing constraints in planning, environmental and land access regulatory frameworks.

In early 2021, Hydrogen Park South Australia became the first facility in Australia to successfully provide a cleaner blended gas, comprising five per cent renewable hydrogen, into a sector of the Adelaide distribution system.

Prior to its election in March 2020 the South Australian Government announced its Hydrogen Jobs Plan (South Australian Labour Party, 2022). The Hydrogen Jobs Plan is a commitment to deliver lower electricity prices for South Australia by improving the firming services that support renewable generation. The Plan allows for the construction of large hydrogen electrolysers which will both serve as flexible loads and support hydrogen-fuelled firming services to complement renewable electricity generation. This includes the construction of a $593 million project within the Whyalla City Council by 2025 which includes:

- 250 MWe of electrolysers (i.e., creating hydrogen from water using renewable energy) operational during times of excess solar and wind generation
- 200 MW of hydrogen-fuelled power generation (powered by the electrolysers)
- Hydrogen storage for 3,600 tonnes of hydrogen (or the equivalent of two months of hydrogen consumption for power generation) to store excess hydrogen produced

The two-year construction period is expected to begin by the middle of 2023 to be operational by December 2025. The project aims lower electricity prices and is targeted to improve grid stability by addressing some of the limitations in the South Australian region of the National Electricity Market (NEM), particularly the market concentration in on-demand electricity, and at times the very low daytime demand for electricity. It could reduce the amount of firming required for the electricity network through the addition of large flexible loads (electrolysers) to the grid and by providing firming services to renewable energy generators. The electrolysers serve to increase demand for renewable energy, while increasing the ability of the market operator to match demand and supply during periods of low renewable generation. It also aims to serve as a catalyst for renewable hydrogen exports by providing a demonstration plant and creating domestic demand for hydrogen (SAPC 2022).

3.6 WA GOVERNMENT

System-Wide View

The Western Australian Government has a target of net zero emissions statewide by 2050 (Western Australia 2023). It has announced its intention to introduce legislation this year to provide a framework for emission reductions.

At this stage the Government has not nominated interim statewide emission targets, but it has committed to reduce its own emissions by 80 per cent by 2030. It is notable in this context that WA Government owns generators that provide more than half of WA's grid electricity. In addition, it owns more than two-thirds of the State's coal-fired generation capacity, with all of this scheduled to close by 2030. The Government anticipates up to $3.8 billion of investment in renewable generation assets and supporting infrastructure in the transition (Synergy not dated; Carroll 2022). Greening of the electricity sector is thus a key element of the Government's 2030 target.

Renewable gas

In 2019 the Government released its *Western Australian Renewable Hydrogen Strategy,* followed in 2020 by the *Western Australian Renewable Hydrogen Roadmap.* The Strategy covered issues such as:

- development of a renewable hydrogen export industry—short term (2022) goal of implementing a project exporting renewable hydrogen from Western Australia and longer term (2030) goal of achieving a market share of global hydrogen exports roughly in line with its share of LNG today (12 per cent)
- blending renewable hydrogen in natural gas networks— deploy some renewable gas in the WA distribution network by 2022, and up to 10 per cent renewable hydrogen in pipelines and networks by 2030
- adoption of renewable hydrogen in remote areas—used in at least one site by 2022 and widely used in mining haulage vehicles by 2030

Western Australia set up a Renewable Hydrogen Fund to provide grants in support of feasibility studies and capital works projects that further the renewable hydrogen strategy.

By mid 2022 Western Australia had more than 30 hydrogen-related projects of diverse types at various stages of planning (Western Australia 2022). These include very large-scale hydrogen production projects.

More recently, the Western Australian Government has commenced consultations on a possible Renewable Hydrogen Target for generation in the South West Interconnected System (i.e. the electricity grid serving Perth and the south west of the State, covering most of the State's population but not the major mining and energy projects in the north).

Under the mooted scheme, hydrogen producers would produce hydrogen from renewable electricity by electrolysis, subject to a guarantee of origin scheme, and sell it to gas generators. Objectives of the scheme include industry development (foremost), decarbonisation of the grid, improvements in grid reliability and stability, reducing reliance on fuels at risk of price escalation, and decarbonisation of the WA economy.

The Consultation Paper for the scheme notes that Hydrogen generators have a potential role in the system in terms of peaking generation, energy storage, system services and reserve capacity.

Preliminary thinking is that the scheme could operate as a certificate-based scheme, with a certificate being awarded for every 1 MWh of electricity produced with renewable hydrogen. In this form the scheme depends on the electricity output and not the quantum of renewable gas input; an "efficient" producer that produced more electricity with 1 PJ of renewable gas would receive more certificates than a less efficient electrolyser. While this design could work well within the electricity system, it would not be as well suited for, nor align well with, a renewable gas target in, say, the gas distribution network.

The Consultation Paper raises the possibility that the liability could lie with electricity retailers and large customers (similar to the liability arrangements under the Renewable Energy Target—see subsequent section).

It is notable that the scheme, as currently envisaged, puts all of the onus for support on the electricity sector, especially consumers. To the extent that there are spillovers that fall outside the generation sector—e.g., reductions in the cost of green hydrogen for distribution networks and reductions in the cost of green hydrogen for export—the costs of supporting them would lie in the electricity sector. The scheme would thus appear to be at least neutral in terms of the evolving electricity-gas mix and might even support gas.

One of the distinctive features of the scheme is that it is confined to the use of renewable gas for electricity generation. The Consultation Paper notes that there are other possibilities and that also under consideration is

> "a use-agnostic renewable hydrogen certificate scheme which could be available to multiple sectors. This would be similar to the Renewable Hydrogen Target for electricity generation, in that it would place an obligation on liable entities (such as electricity and gas retailers) to purchase certificates, but the hydrogen produced could be used for any purpose, such as to displace diesel, natural gas and grey hydrogen used as a feedstock for chemical processing" [Energy Policy WA, 2022, p. 7]

The Consultation Paper also floats "straw man" target levels for the renewable gas target, putting forward 1 per cent, 5 per cent and 10 per cent scenarios. The 10 per cent option would have most impact on the uptake of green hydrogen for generation but would also have the largest cost. A decision as to the optimal level would require benefit cost analysis.

3.7 TASMANIAN GOVERNMENT

System-Wide View

Tasmania has an enviable electricity generation position. Since 2021, 100% of the state's electricity consumption has been generated by renewable sources (Clean Energy Council 2022). The Tasmanian government has also legislated a more ambitious 200% target by 2040 (the excess above 100% to be exported), with a net-zero Carbon Emissions target by 2050 (DSG, 2020a). Tasmania will significantly increase its supply of electricity to the rest of Australia. It has available substantial wind, tidal, wave, and solar resources and the development of a new transmission interconnection to Victoria will assist with the development of these resources (DSG, 2020a). With a bird's eye view of these policies, it is clear that the state's energy position has attracted some risks. Tasmania's isolation from other states in the national electricity market is a significant risk. An additional risk is its single interconnection, which has suffered several issues since its installation (DSG, 2022).

The Tasmanian electricity market plays a crucial role in the Australian National Electricity Market (NEM) by providing a secure and reliable supply of electricity from renewable sources (DSG, 2022). The Basslink transmission interconnector (500MW capacity) allows Tasmania to import and export electricity via Victoria, providing greater stability and security of supply for the entire NEM. Tasmania needs to address several challenges around a lack of supply and interconnection to become a more dependable importer and exporter of energy.

One example of its interconnection issue is the events of 22nd December 2015 and subsequently. On this day, Basslink experienced a fault that caused it to trip and disconnect from the mainland grid (Basslink, 2015), which resulted in extensive and prolonged blackouts throughout the state (Baines, 2016). The Basslink fault continued for several months, which caused significant disruptions to the Tasmanian electricity market, as the state needed to rely on its own generation and storage to meet its electricity needs. The outage also led to higher electricity prices in Tasmania, as the state had to import electricity from the mainland at a higher cost (Rockliff, 2016).

This interconnectivity issue continued well into 2016 and has played a significant role in Tasmania's energy policy landscape. To address this issue, the state government has designed its energy plan to include more reliable connectivity, with a second undersea interconnection known as Marinus Link currently in the planning phase. Marinus Link features a capacity of 1500MW to support the interconnection between Tasmania and Victoria. Marinus Link will significantly increase Tasmania's export capacity for renewable energy.

Despite the encouraging features of Marinus Link, it is still in the planning and approvals phase, and for the present Tasmania remains in a vulnerable security of supply position with high reliance on Basslink and run of the river hydro generation. While Marinus Link can improve the security and reliability of electricity in the state, the Tasmanian government has also adopted several policies to strengthen its current position and ensure a resilient power system.

In light of its position within the NEM, the state government has presented several policy instruments to assist in its 2040 goal of 200% renewable energy (DSG, 2020a, DSG, 2022). To develop a greater understanding of the policy frameworks proposed by the Tasmanian Government, we will now explore the main themes of the Renewable Action Plan (DSG, 2020a) and its associated Coordination Framework (DSG, 2022).

In line with the agendas of its mainland counterparts, the state will establish several renewable energy zones to harness its generation potential and seek additional demand for its electricity (DSG, 2022). By attracting demand for renewable energy to the state, the government will develop and increase access to infrastructure for industrial and large energy users (DSG, 2022). It has also flagged the opportunity to develop a market-based mechanism to attract the construction of renewable energy generation and transmission-level infrastructure (such as the one proposed by the Victorian government). It also proposes the renewable energy zones as a focal point for engagement via benefit sharing and community co-investment.

The economic transformation of Tasmania is an important goal for the state's Renewable Energy Plan. A Renewable Energy Guarantee of Origin Scheme is currently under consideration to allow the traceability and verification of all renewable energy sources within the state. The Renewable Energy Plan also develops the prospect of a Bioenergy Vision (Biofuels from local sources such as biomethane and tallow). Additionally, the state is also developing a plan to decarbonise its gas use via the utilisation of locally produced renewable hydrogen and biogas (DSG, 2021). The first step of this plan is to establish the feasibility of a 5 PJ/year renewable methane production module for Tasmania. Further studies into the viability of biomethane and hydrogen blending in the gas network will examine the scope to increase blending of renewable fuels to 10% of domestic gas use.

The state government also intends to use its market power to reduce spot price volatility in the local wholesale market to lower the risk of retail power price increases. This technique of using state-owned assets to bid in a way that reduces volatility is similar in design to Queensland's (O'Brien, 2017). To further assist consumers, the state has created an assistance program for energy users to improve their energy efficiency, which includes appliance upgrades and technology switching.

The state has also developed a scheme to develop long overdue Demand Side Management (DMS) participation for medium to large energy users. The design of DSM allows system and market operators to create opportunities for users to curtail demand during peak periods of electricity use, thereby reducing system load and improving system stability and the security of supply.

Tasmania's Renewable Hydrogen Action Plan

The Tasmanian Government has developed a Renewable Hydrogen Action Plan (RHAP) to take advantage of the state's renewable energy potential to produce hydrogen for domestic consumption and export (DSG, 2020b). The RHAP focuses on developing a hydrogen sector that facilitates economic growth, supports the Government's ambitions of 200% renewable energy generation, and assists the transition to a zero-carbon future. The two main themes in the RHAP are: Production of Hydrogen for domestic use and export and Financial and Regulatory support for the hydrogen industry to facilitate scale-up.

Theme 1: Production, Demand, and Exports

To rapidly scale the renewable gas sector to produce hydrogen, and promote its use domestically within the state, the main initiatives identified by the state are as follows:

- Investigate the potential for hydrogen use in the medium to heavy transport sector (freight and public transport)
- Use government purchasing power to create demand for hydrogen via its vehicle fleets
- Examine the potential for hydrogen blending of up 10% in the existing natural gas networks
- HydroTas to explore hydrogen production at the King and Flinders Island facilities
- Potential for Hydrogen use in Antarctica
- A green ammonia plan and its uptake by the agricultural sector
- The potential export facility at the Bell Bay advanced manufacturing zone

The Tasmanian government's plan to scale the sector via the above catalysts complements its mature plans to deploy further renewable energy generation potential. This theme heavily relies on expansion of renewable generation capacity and an upgraded interconnection to the NEM.

Theme 2: Financial Support and Economic Development

The RHAP focuses on delivering a 200% renewable energy system by 2040 and several spill-over effects to the Tasmania economy. The attraction of investment from domestic and international partners to finance the growth of industries likely to demand hydrogen is a high priority for the state. The state has already reached in-principle agreement with Fortescue Metals Group (FMG) to invest in renewable hydrogen within the state (FMG, 2021), boosting electricity demand by 250MW. These renewable energy zones are also closely aligned with the Hydrogen Hubs programme recently announced by the Commonwealth Government (DISER, 2021).

In summary, the financial assistance and economic and regulatory developments that the state has committed to include:

- Development of the Bell Bay Hydrogen Hub

- $20M Tasmanian Renewable Hydrogen Fund to support feasibility studies for future producers and potential domestic users
- $20M in concessional loans to kick start hydrogen production developments
- Electricity supply arrangements include the relief from transmission and distribution network charges for the generation of onsite hydrogen
- Electricity and pipeline infrastructure access agreements
- Support for further wind energy penetration and effective integration into the NEM

Pilot Projects

The Bell Bay Hydrogen hub is the proposed site for a hydrogen production and export facility and an R&D and industry engagement centre. The industry has undertaken feasibility assessments in collaboration with state and federal government assistance. These assessments, all at Bell Bay, are as follows:

- Origin Energy's export scale hydrogen and ammonia plant (420,000t/year)
- ABEL Energy's 100 MW hydrogen and methanol export facility
- Grange Resources 90-100 MW hydrogen project to provide process heat at its Port Latta facility

The three feasibility studies' outcomes demonstrate that green hydrogen production and use in Tasmania is technically feasible (Barnett, 2022). However, several consistent themes have emerged from these studies, which indicate risks associated with the economic feasibility of the projects. The prospect for these projects is held back by uncertainty of availability and pricing of electricity supply and market maturity. Origin and ABEL energy (Origin, 2022, ABLE, 2022) also identified uncertainty concerning product pricing and the inability to negotiate binding offtake agreements as crucial aspects of the risk associated with project progression.

3.8 NT GOVERNMENT

System-Wide View

The NT Government plans to reach zero emissions by 2050 and to that end proposes the complete electrification of natural gas use by residential consumers. The government has an option to blend renewable gases up to 10%, but it is unlikely to progress this concept given the small number of consumers (~1130 households) connected to the reticulated system and the lack of feedstock to produce biogas (OSE, 2021). Furthermore, most residential consumers with non-electrical appliances for hot water and cooking use liquefied petroleum gas bottles which negate the prospect of blended renewable gases.

The NT's electricity system relies mainly on natural gas and diesel fuel generation, with only a small proportion derived from renewable energy sources (OSE, 2022, UC, 2021). The NT's electricity sector is composed of three separate power systems; Darwin Kimberly Interconnected System, Alice Springs Power System and Remote Power Systems, which supply townships and remote communities. The NT's Electricity System Plan sets a 50% renewable energy target by 2050, which will require the rapid expansion and integration of renewable generation assets (UC, 2021). The Plan proposes the installation of 320MW solar PV, which will be supported by 110MW battery storage to meet its renewable energy target.

The NT Government plans to install a further 100MW of battery storage to ensure system stability and security of supply. With the need to retire over 200MW of aging natural gas-fired generation assets, the territory will invest in smaller, more efficient duel-fuelled generation options. One duel-fuelled option includes the integration of hydrogen and biogas into the electricity system (OSE, 2022). However, it is likely that natural gas will continue to feature in the electricity generation profile for some time (OSE, 2022). In addition to these policy targets, the NT Government will also allocate virtual power plants and demand side management in line with the other States' energy policies (OSE, 2022, UC, 2021).

Hydrogen Master Plan

The NT Government has developed a Hydrogen Master Plan to attract investment and establish significant exports to South East Asia (OSE, 2021). The government is proposing to utilise the Middle Arm Sustainable Development Precinct as a focal region for future renewable hydrogen industry development. The Precinct is to include a hydrogen production facility and enabling export infrastructure (OSE, 2021).

In order to scale up hydrogen production within the Territory, some domestic electricity generation use cases identified for renewable hydrogen are diesel displacement and blending hydrogen with natural gas in electricity generation (OSE, 2021, OSE, 2022, UC, 2021).

The plan is still in the early stages of development. Developing a hydrogen sector within the territory will require significant investment in electricity generation and transmission infrastructure in a short period (by 2030). Further planning and development of the Darwin Kimberly Interconnected System and the Alice Springs Power System will be needed to allow substantial growth of hydrogen in the NT domestic energy mix.

3.9 ACT GOVERNMENT

The ACT has adopted an energy and climate policy to reduce its Greenhouse Gas (GHG) emissions to zero by 2045. Much like the Australian state of Tasmania, the ACT is fortunate to derive 100% of its electricity needs from renewable sources. Similar to the Tasmanian government, the ACT government holds a privileged position of quickly adapting its energy system to achieve a zero GHG emissions target.

The ACT is a relatively small component of the National Electricity Market (NEM) and is integrated within the NSW region. The ACT Government has a goal of zero GHG emissions by 2045 while at the same time ensuring system reliability and improving consumer affordability. The government is developing an Integrated Energy Plan (IEP), which focuses on delivering a Pathway to Electrification (EWER, 2022) and supports its GHG elimination goals.

The ACT has identified improved reliability of the electricity supply as a priority. It has identified distributed energy resources (DER), battery storage and future investment in electricity generation capacity as needed to help provide reliable electricity. DER, also known as Distributed Generation (DG), has been shown to improve system reliability and reduce carbon emissions by generating electricity close to the point of demand (CSIRO 2009, Lilley et al. 2012, Reedman et al. 2015). Furthermore, DER is complemented by the deployment of battery storage across the distribution network to reduce electricity demand during peak periods.

The ACT government has identified that if natural gas use were to be replaced by electricity in the current network, major capacity issues could develop across the network (AECOM, 2020). Based on current demand estimates, if natural gas were eliminated from the supply chain by 2045, electricity demand would increase by at least 40-60% (AECOM, 2020). The government has recognised that this significant shift in demand would require major upgrades to the distribution network and peak demand management via distributed battery storage (AECOM, 2020).

The IEP also addresses the reduction of energy costs for all its users. Using similar instruments as the central states in this report (e.g., Victoria and New South Wales), schemes within the territory have been created to increase consumer appliance efficiency. Energy experts in the field support this view, as many have identified that increasing the energy efficiency of household space conditioning is a high priority for electrification (EWER, 2022) to reduce energy costs. In addition to these efficiency improvements, the territory promotes solar PV and battery storage to households.

The ACT government has considered introducing biogas and hydrogen into its energy system as part of its decarbonisation plan (EWER, 2022). From a biogas perspective, there are concerns over the availability of feedstock for the production process. Currently, the territory produces ~0.7PJ/year as landfill gas, potentially expanding to ~2PJ/year if compostable green waste is converted. This would represent around 22% of current gas demand and is thus a significant potential contribution to decarbonisation, even though it falls well short of the total replacement of natural gas.

In the past, the ACT has considered introducing a blended hydrogen gas target of 10% (AECOM, 2020). However, a feasibility report (AECOM, 2020) and the associated policy announcements do not support replacing natural gas with hydrogen for domestic use. To meet net zero by 2045, the ACT government prioritises total replacement of natural gas. The total replacement of natural gas with a 100% hydrogen substitute would require a large expansion of renewable generation within or around the territory.

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4. History of energy targeting in Australia

- Australia has a depth of experience with energy target policies across state jurisdictions and nationally
- Many of the key market players are familiar with certificate-based schemes to promote changes in the energy mix
- There is a supporting infrastructure in place for the Renewable Energy Target and this is a potentially useful model for pursuing renewable gas market targets
- Energy target schemes have been used to set directions for energy markets while still preserving scope for adjustment in light of emerging circumstances
- There have been and will continue to be substantial challenges transitioning Australia to clean energy but many of these would arise however the transition was pursued
- There are some aspects of target mechanisms which could, with hindsight, have been designed better
- The energy target policies reviewed here have generally been successful in promoting the outcomes that they target

4.1 THE RENEWABLE ENERGY TARGET

The Renewable Energy Target (RET) is an Australian Government scheme. It was introduced in 2001 to assist in decarbonising the Australian economy by increasing the supply of renewable electricity and displacing the production of electricity from fossil fuels.

Origin of the RET

In 1997, in the lead-up to the COP3 at Kyoto, the Government announced that it would introduce a Renewable Energy Target. The Prime Minister said that “targets will be set for the inclusion of renewable energy in electricity generation by the year 2010. Electricity retailers and other large electricity buyers will be legally required to source an additional two per cent of their electricity from renewable or specified waste-product energy sources by 2010” (cited by Stone 2000).

A number of design considerations had to be addressed in the implementation of the MRET. There were questions of scope, eligibility and scheme design. The Regulatory Impact Statement prepared in support of the legislation (Australian Greenhouse Office 2000) discusses some of these.

Firstly, while it was apparent that electricity supplied over the networks was in scope, should self-generators be included as well? Self-generators generate and consume their own electricity, and this may be from fossil-fuel sources. But they are not captured by a mechanism focused on wholesale market purchases. The advantages of inclusion were (a) increasing the breadth of the scheme and (b) maintaining neutrality between self-generation and market purchases and entities relying on them. For example, a self-generating aluminium producer would gain some advantage over an aluminium producer that purchased electricity on the market, if self-generators were excluded. However, as a practical matter, the amount of generation in question was relatively small. Moreover, self-generation involved some innovative, energy-conserving activities that might not qualify strictly as renewable, such as co-generation, and it might be undesirable to disrupt this. In the event, self-generators were excluded from the RET at implementation.

Secondly, while there was a case for including a wide range of renewable generation types, should waste coal mine gas be included as a renewable gas? Waste coal mining gas contains methane which has a very high global warming impact. But most of this impact can be avoided by flaring the gas. Capturing the heat for generation can avoid further emissions by displacing other fossil-fuel generation, but these gains are relatively small. The risk of using a RET to target waste coal mine gas emissions was that it might promote inefficient integration of waste coal mine gas into the electricity system when the most efficient choice would be simply to flare the gas or use it for some other heating purpose. In the event, electricity generated from waste coal mine gas was ruled not to be an eligible renewable source, at least at the outset of the scheme.

Thirdly, there was the question of how the RET should be implemented. The Regulatory Impact Statement considered the following options and compared them with a non-intervention base case (Option 1):

- (Option 2): Introduce a production subsidy for renewables generators funded by a fixed levy on all electricity users

- (Option 3a and 3b): Develop a tradeable certificates market to support a legal requirement for individuals to contribute to an increase in the amount of renewables in the electricity supply mix, with either a technology-neutral approach or with targets for specific technologies; or
- (Options 4a and 4b): Establish a centralised purchaser of renewable energy to meet the target, funded by either
- a levy on electricity users; or
- government

AGO recommended Option 3a. Its pros and cons versus the other options were, respectively:

- Option 1 would not achieve desired reductions in emissions
- Option 2 might be somewhat simpler to administer but Option 3a would provide more certainty over the amount of renewable electricity that would be introduced and might be less vulnerable to gaming
- Option 3b was said to have additional complexity, compliance cost and uncertainty and that its advantages were not strong enough to support it
- Option 4a was regarded as workable but inferior to Option 3a insomuch as it denied electricity purchasers the ability to source their own renewable electricity and to engage in their own renewables procurement strategies; and
- Option 4b, centralised purchases funded by government, was not supported but no explanation was given

The RET at its inception

The Mandatory Renewable Energy Target (RET) commenced operation in 2001. The scheme was established by the Renewable Energy (Electricity) Act 2000 (the Act) with a focus exclusively on the electricity market. The objects of the Act are:

(a) to encourage the additional generation of electricity from renewable sources; and

(b) to reduce emissions of greenhouse gases; and

(c) to ensure that renewable energy sources are ecologically sustainable

Under the Act, electricity retailers and large electricity buyers are required to increase the share of their electricity coming from renewables. The scheme required an increase in renewable supplies ramping up to 2 per cent of forecast demand by 2010. Pre-existing or "baseline" supplies from existing renewable generators—such as the Snowy Hydroelectric Scheme and Tasmanian hydroelectric generators—could not be credited, but expansions of output above baselines were eligible.

Regulations under the Act stipulated renewable energy sources eligible for the scheme. The most significant of these are generation from solar and wind. Also eligible are hydro, ocean, tide, eligible biomass, geothermal-aquifer, hot dry rock, landfill gas and sewage gas. Fossil fuels and waste products derived from fossil fuels were declared to be ineligible, with the result that waste coal mining gas was at the start excluded.

In principle new installations of small-scale generators—such as residential rooftop solar—were eligible but their numbers were miniscule when the RET commenced in 2001. The primary involvement of small customers in the scheme was in respect of new installations of solar water heaters, which were eligible. Solar water heaters do not generate renewable electricity but had been included in the scheme as a displacement technology; they displace fossil-fuel generation used to power electric water heaters. Instead of metering their output, small generators and solar water heaters could have their output for REC purposes "deemed", using an approved calculation basis.

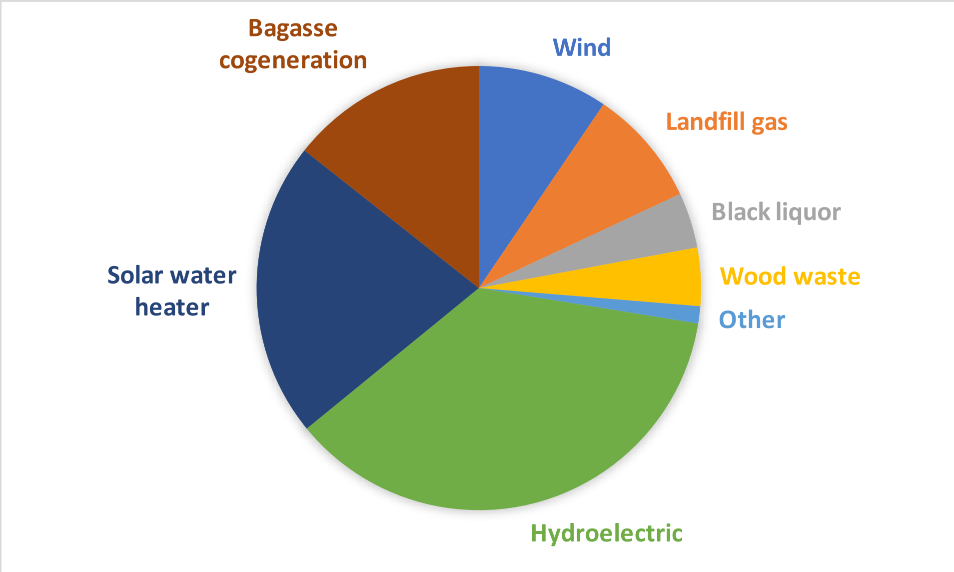
As well as introducing the renewable electricity requirement, the Act introduced a tradable certificate scheme and associated regulatory arrangements. Accredited renewable generators are assigned a baseline as part of their accreditation (which could be zero) and were empowered to create a Renewable Energy Certificate (REC) for each 1 MWh of renewable electricity that they generated in excess of baseline. They can then sell those certificates on to other parties with obligations under the MRET (retailers and large users). Those parties then surrender the certificates to the MRET administrator in fulfilment of their obligations under the scheme.

The Act imposes a liability on retailers and large electricity customers (i.e., those purchasing electricity in the wholesale market) to surrender RECs. The liability is calculated by applying a renewable power percentage to the total amount of electricity taken by the purchaser. If a liable entity has a shortfall on the certificates it is required to surrender, it can roll up to 10 per cent of its liability over to the next year. It is required to pay a shortfall charge on any shortfall beyond 10 per cent of its liability.

In 2002, the first full year of operation of the scheme, 2.2 million RECs were created (Office of the Renewable Energy Regulator—ORER—2003). This amounts to 2.2 terawatt hours (TWh) of REC-eligible electricity generation, which can be compared with 240 TWh generation from all sources in Australia in 2002-03 (DCCEEW 2022).[4] RET-eligible generation thus accounted for less than 1 per cent of the electricity supply.

The fuel mix for the RECs created in 2002 differs greatly from the renewable generation mix in Australia's electricity system today—wind was a small component and there was almost no solar generation. In diminishing order of contribution, the main fuel sources for RECs were hydroelectric (37 per cent), solar water heating (22 per cent), bagasse cogeneration (14 per cent), wind (9 per cent), landfill gas (9 per cent), wood waste (4 per cent), black liquor (a by-product mainly of pulp and paper manufacturing—4 per cent) and sewage gas (1 per cent)—Figure 4.1. Small solar and wind generation units accounted for less than 0.01 per cent.

Figure 4.1 Share of total RECs created in 2001 by source



Source: SACES calculations with data from ORER (2003).

2009 Amendments

Substantial Amendments were made to the Act in 2009, 2010, 2015 and 2022.

In 2008, the Rudd government announced its intention to introduce a cap-and-trade emissions trading scheme, the Carbon Pollution Reduction Scheme, commencing in July 2010. The Government committed to reducing Australia's greenhouse gas emissions to 60 per cent below 2000 levels by 2050. By 2020, emissions were to be reduced by either 5 per cent or 15 per cent, with the more ambitious target to be adopted if a concerted international effort to reduce emissions were to eventuate.

In this context, the renewable energy target was amended in 2009. The renewable target was increased to 20 per cent of forecasted demand by 2020, which amounted to 45,000 GWh.

In addition, scheme eligibility was extended to waste coal mine gas power plants, which had been precluded under the initial rules.

The rules were also changed to provide more support for the adoption of solar photovoltaic small systems (many of which would be on the roofs of residential and small commercial electricity customers). The Australian Government had in place an $8,000 rebate (Solar Homes and Communities Plan) but it was announced that this would cease. In its place, a mechanism called Solar Credits was introduced. Solar Credits multiplied the number of RECs able to be created for small generation units (Office of the Renewable Energy Regulator 2010). And, in concert with this, the States were, to varying degrees, providing support through mechanisms such as premium feed-in tariffs (these being the payments or credits that owners of small systems receive from their retailers when they supply their unused electricity into the distribution network).

[4] The 2.2 million RECs include 0.5 million from solar water heater, which strictly-speaking is not renewable generation.

The Solar Credits scheme, also known as the REC multiplier, was applied to the first 1.5 kilowatts (kW) of capacity installed for systems connected to a main electricity grid and up to the first 20 kW of capacity for off-grid systems. Solar Credit multiplier allowed up to 5 times the amount of RECs to be created, and the scheme was scheduled to end in June 2015. These solar credits were tradeable. Installations of solar systems rose to strong levels, and this in combination with the multiplier meant that a large volume of RECs was created and entered in the market. As a consequence, on 5 May 2011, the Minister announced that the Solar Credits multiplier was to be reduced and phased out completely by 2013. This will later lead to the decision to focus on large-scale systems and small-scale systems separately.

As it turned out, the Government was unable to legislate the CPRS that it announced in 2008. But from 2012 it introduced a Carbon Pricing Mechanism, which was aimed at a 5 per cent reduction in emissions by 2020 and an 80 per cent reduction by 2050. A carbon price was applied to large emitters in 2012-13 and 2013-14, with an emissions trading scheme then to apply from July 2014.

2011 Amendments

In January 2011 the Renewable Energy Target was split into two parts:

- The Large-scale Renewable Energy Target — this scheme creates a financial incentive to establish and expand renewable power stations such as solar farms, wind farms and hydro-electric power stations and deliver the majority of the 2020 target
- The Small-scale Renewable Energy Scheme — this scheme creates a financial incentive to install solar panels, wind, hydro systems, solar water heaters and air source heat pumps

The reforms reflect difficulties in applying the RET to increasingly prevalent small-scale behind-the-meter renewable generators such as residential electricity customers. The Large-scale Renewable Energy Target was effectively a continuation of the existing scheme. Large-scale renewable generators generate renewable electricity. They earn income from sales of electricity into the market and from selling the certificates that they create. But it is not practical for small customers to participate in the market in this way.

The new Small-scale Renewable Energy Scheme changed incentives for small customers to investigate in renewable energy sources behind the meter, including solar panels and small-scale wind and hydro, solar water heaters and air source heat pumps (Clean Energy Regulator 2022). It involves the issue of small-scale energy certificates, which credit small-scale electricity installations for their estimated generation output for 15 years or until 2030. These certificates can then be sold on to liable electricity purchasers which can surrender them to meet RET obligations.

It is quite common for the customers who install equipment that is eligible under the SRES not to have involvement in the creation or trading of small-scale technology certificates. Instead, the vendor of the small-scale system lodges the paperwork and sells the certificate to a retailer. Under competitive conditions, the vendor is subject to competitive forces which encourage it to pass on the value of the certificate in a lower installation price for the equipment.

2012 Review

In 2012, the Climate Change Authority carried out a statutory review of the RET. The Authority said that the RET had boosted renewable generation and caused reductions in greenhouse gas emissions. It also noted that this came at a cost to consumers who were “already experiencing large increases in electricity prices for other reasons” [Climate Change Authority 2012 p. v]. The Authority also noted that the policy environment had changed significantly since the introduction of the RET, with a number of government initiatives in place to promote emission reductions, most notably the Carbon Pricing Mechanism. It concluded that:

> “The Authority believes the RET has a continuing role to play in supporting investment in renewable generation in an uncertain policy environment. The review therefore focusses on possible improvements in the RET, rather than challenges its continued existence.
>
> “The real challenge for the Authority has been to reach recommendations that would represent an appropriate balance between promoting investments in renewable generation to reduce Australia’s greenhouse gas emissions, on the one hand, and containing the costs of the arrangements to electricity users on the other.” [p. v]

The Authority made a number of observations and proposed a number of modifications to the scheme with the aims of:

- increasing confidence and predictability

- managing overall costs to electricity users and providers
- providing flexibility and choice; and
- streamlining administration and compliance costs

Among other things, it recommended that:

the targets under the LRET should continue to be specified in gigawatt hours and should not change

- no new waste coal mine gas power stations should be admitted
- no new displacement technologies should be admitted
- the SRES should remain separate from the LRET
- if the growth of small-scale systems is having excessive price impacts, consideration should be given to managing it outside the SRES (for instance by feed-in tariffs)
- the scheme should remain technology-neutral and should not seek to promote diversity in the technologies employed in renewable generation

Box 4.1 has more details of the Authority's observations and recommendations.

2015 Amendments

There was a change of Government in 2013 and the new Government repealed the emissions trading scheme for 2014-15 and onwards, replacing it with an Emission Reduction Fund. In contrast to the emissions trading scheme, under which emitters generally were required to meet the costs of imposed emission reductions, the Emission Reduction Fund makes payments to support projects which can reduce emissions or capture carbon.

In the first half of 2014 the new Government appointed a panel, chaired by Mr Dick Warburton AO LVO, to carry out a review of the RET. The Warburton Review found that that the RET target of 45,000 GWh in 2020 would substantially exceed the share of 20 per cent of electricity consumption that was originally intended. It said that the RET was an expensive way to reduce emissions and that it would be more cost effective to pursue cheaper solutions such as land management and increased energy efficiency.[5] It recommended measures to slow the growth of the renewables target and to diminish the displacement of existing fossil-fuel generators. In 2014 the Climate Change Authority carried out its second Review of the RET. It concluded that

> "The RET arrangements are not perfect but, in the Authority's view, they are effective in reducing emissions (at reasonable cost) in the centrally important electricity sector. Given the absence of effective alternative measures bearing upon this sector, the Authority does not favour any significant scaling back of the 2020 LRET target of 41,000 GWh." [Climate Change Authority 2014 p. 7]

In 2015, drawing on the Warburton Review, and with household electricity consumption falling, the Government put the view that targets stipulated in the Act were excessively detached from actual demand and putting undue pressure on fossil-fuel generators. In response, it amended the 2020 RET target, reducing it from 45,000 GWh of renewable electricity to 33,000 GWh.

The announcement of the review and subsequent changes in targets contributed to a drop in confidence in the renewable market.

The Finkel Review

In October 2016, the Council of Australian Governments (COAG) energy ministers agreed to an independent review of the national electricity market to take stock of its current security and reliability and to provide advice to governments on a coordinated national reform blueprint. An Expert Panel was constituted to conduct the review, with Dr Alan Finkel appointed as Chair.

In its report, the Panel presented a *Blueprint for the Future Security of the National Electricity Market* focussed on increased security, future reliability, rewarding consumers, and lower emissions. It said that pursuit of these outcomes should be underpinned by an orderly transition, better system planning and stronger governance.

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[5] At face value the Direct Action program procured emission reductions at low cost. However, there are considerable difficulties in establishing the counterfactuals to be used to measure projects' emission reductions. Burke (2016) argues that the emission reductions achieved by the scheme are overstated. To the extent that this is correct, the apparent unit cost of emissions from the approved applications would be understated.

Box 4.1 Findings and recommendations from the Climate Change Authority 2012 Review

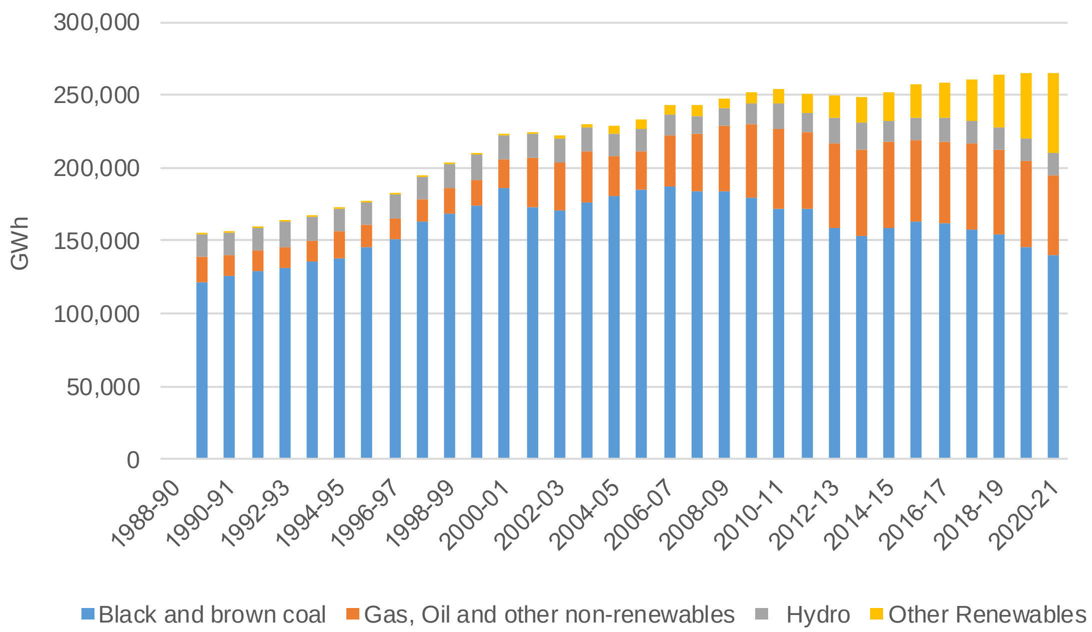
- confidence is important to long-term investment plans, and this includes confidence that policy settings will be sustained in the long-term
- submissions to the Review had called for: no changes to the LRET; winding back the LRET targets, ramping up the LRET targets; and abolishing the LRET
- it recommended that there be no further changes to the LRET quantities
- it did not support calls to introduce a floating target and said that for reasons of investor confidence the target should remain fixed in gigawatt hours
- the shortfall charge is sufficient for compliance with the target, but it should be adjusted if changed market circumstances require it
- the SRES should remain separated from the LRET
- while there were concerns about the rapid growth of small-scale renewables they would be better dealt with outside the SRES, e.g. by adjustments to feed-in tariffs
- the settings of the liability and exemption framework (i.e. which market participants must purchase and surrender certificates) appeared to be operating effectively
- the exemption for self-generation should continue in its current form
- LRET eligibility and accreditation arrangements were working well and should continue
- waste coal mine gas power stations which have LRET eligibility should remain eligible but no new waste coal mine gas power stations should be admitted
- the scheme should retain a focus on measures that replace existing generation with renewable
- displacement technologies that have eligibility under the scheme should remain eligible, at least until a better targeted scheme to suit them is put in place, but no new displacement technologies should be admitted
- the rate of adoption of systems under the SRES, and creation of certificates associated with those systems, had put pressure on electricity prices but these pressures were likely to abate
- the scheme should retain flexibility to create an environment less supportive of small-scale installations but should not seek to cap them
- the practice of deeming 15 years of small-scale certificates could be replaced by one in which certificates are deemed only until 2030
- the scheme should remain technology neutral and should not seek to promote diversity in renewable energy sources, although it might be in the remit of other agencies to pursue that
- heavy industry electricity consumers that receive partial exemption certificates should be allowed to trade them widely
- large electricity users should be allowed to opt in to managing the liabilities arising from their electricity consumption
- exemptions for trade-exposed heavy industry should be streamlined and reviewed by the Productivity Commission
- some reporting arrangements for the SRES should be simplified

The Finkel Panel proposed a new Clean Energy Target designed to encourage low emissions generation into the market in a technology neutral way. Under the new mechanism, new low emissions generators such as wind, gas, or the combination of coal with carbon capture and storage, would receive incentives to enter the market. The Renewable Energy Target (RET) would continue to its scheduled 2020 end for new participants but would not be extended. To support an orderly transition, existing generators would be required to give three years notice of closure.

The Australian electricity system today

The RET has achieved its goal of increasing the share of renewables in the Australian generation mix. Renewables have grown significantly, especially over the last decade—Figure 4.2. Today they account for about 20 per cent of the generation mix.

Figure 4.2 Australian electricity generation by source



RET Impact on Electricity Costs

Direct estimates suggest that the cost to liable retailers and large users of meeting their RET obligations was of the order of $20 to $25 per MWh in 2022—Box 4.2. Data from AEMC (2021), based on surveys of retailers' own cost estimates, suggest a cost in 2021/22 of about $16 per MWh. The difference may in part reflect different pricing bases: the direct calculation is based on 2022 spot prices whereas the AEMC survey-based estimate may capture historic costs.

ACCC (2022) data indicates average residential prices of 26c per kWh, or $260 per MWh, for residential customers in 2021/22. This suggests that the costs of the RET are of the order of 6 to 10 per cent of residential customer prices. The percentage might be a little larger for business customers, which typically negotiate better electricity prices, especially large users.

Box 4.2 A direct estimate of REC costs

Liable parties are required to surrender both large-scale generation certificates (LGCs) and small technology certificates (STCs).

In 2022 the renewable power percentage was 18.64 per cent, meaning that a retailer supplying 1 MWh of electricity would be required to surrender 0.1864 Large-scale Generation Certificates (LGCs) (Clean Energy Regulator, not dated). Since the beginning of 2015 the price of LGSs has almost always been in the range $30 to $90 per certificate, and in September 2022 they were trading at about $65 per certificate (Clean Energy Regulator 2022b). Assuming a price of $65 per LGC, a liable party receiving 1MW of electricity would have to purchase and surrender about $12 worth of certificates.

The small-scale technology percentage in 2022 was 27.26 per cent (Clean Energy Regulator 2022c). During 2022 the price of STCs was in the range of $39 to $40 (Demand Manager 2022—the regulations that permit the creators of STCs to sell them to the Clean Energy Regulatory for $40 have the effect of putting a floor under the market price). Assuming a price of $40 per STC, liable parties would need to surrender about $11 worth of STCs per MWh sold by retailers or procured from non-retail sources.

The combination of these two elements suggests that the cost of REC obligations to liable retailers and large electricity users in 2022 was in the range $20 to $25 per MWh at 2022 prices.

The impact on prices for electricity consumers is likely to have been smaller. Not all of the costs of the RET will have been passed on to end customers, with some instead passed back to generators by means of a downward impact on wholesale electricity prices. The true allocation of the cost impacts between electricity users and established generators is unclear, particularly because the counterfactual to the RET is unclear. But there have been widespread reports of coal-fired generators suffering adverse price shocks from the growth of renewables, and to such an extent that some brought forward plant retirements.

Abatement costs under the RET

The Productivity Commission (2023) recently released estimates of the "fiscal cost" of emission reductions under the RET.[6] These estimates rely on a range of assumptions, including assumptions about what type of alternative generation is displaced by the introduction of renewable generation and assumptions about how much of the increase in renewable capacity is attributable to the RET. Here we report the situation when full additionality is assumed, i.e. assuming that in the absence of RET none of the renewable generators would be in place. In that case, the Commission estimates that the cost of emissions reductions with LGCs is in the range of $60 to $110 per tonne of CO2-e abated with a central estimate of $68. It estimates that the cost of reductions under STCs was in the range of $57 to $105 per tonne of CO2-e with a central estimate of $65 per tonne CO2-e. The fiscal costs are greater if additionality is less than 100 per cent—i.e. if some of the new renewable capacity would have been installed anyway in the absence of the RET.

RET Issues and Challenges

Australia has seen a very substantial increase in the role of renewable electricity sources since the introduction of the RET. This is due to a variety of factors, including government schemes, changing consumer preferences and consumer activism, changes in the willingness of capital markets to finance fossil-fuel generation, and technological improvements and cost reductions in renewable technologies. While the exact contribution of the RET cannot be reliably separated from these other influences, it seems safe to say that it has contributed significantly to changes in the profile of Australia's electricity supplies.

The challenges arising during the RET's implementation and operation occurred mainly due to the fast growth in renewable electricity supplies. These challenges can be grouped into four broad areas:

- Network stability and Security
- Market Behaviour and Adequacy
- International Trade Reliance and Dependence
- Affordability for Consumers

Network Stability and Security

Impact of weather-dependent technology on network stability and security

The rising proportion of renewable plants in Australian generation portfolio affects the predictability of dispatch and the stability of the electricity network. The network has the challenge of responding quickly to sudden changes in renewable output, thus affecting the network's security. These difficulties are exacerbated by the geographic grouping of similar weather-dependent technologies, which sometimes can also be located in areas of the grid where the transmission capacity is insufficient (AER 2022).

The intermittency of renewables creates a need for firm generation which can provide large volumes of electricity at short notice, such as batteries, hydroelectric plants, or gas-peaking plants (CSIRO 2018). But the currently available technology is costly and there is a significant and ongoing reliance on fossil-fuel gas to provide firming. The price of firming supplies remains relatively high (RBA 2020).

Small scale solar has also introduced a variability in electricity demand and has at times created challenges for electricity networks. They have had to receive electricity from households' and small customers' solar installations, with networks that were not originally designed for this purpose.

Compromised viability of the remaining coal-powered generators

The rapid influx of grid and solar rooftops over the last decade or so, and especially more recently, has changed the shape of wholesale electricity prices. Those changes, backed by investors and push for decarbonisation,

[6] Fiscal costs measure the cost to budget of an abatement activity. These costs differ from whole of economy resource costs of that abatement activity. Whole of economy resource costs would be a preferable indicator if the task was to prioritise an efficient approach to emission reduction.

compromise the economic viability of the NEM's 16 remaining coal-fired power stations. As energy companies switch to renewable, earlier coal closures arise, and fewer investments are made to maintain current fossil fuel generators. Five coal-fired power plants are currently scheduled to close by 2030 (AER 2022). Decarbonisation of electricity of course requires a reduced reliance on coal generation.

Market Behaviour and Adequacy

Effects of target changes on investors' confidence in renewables

Renewable energy targets stipulated in the Act were expressed as a fixed gigawatt hours amount of electricity that had to be sourced from renewable generators each year. The scheme started by targeting an additional 2 per cent by 2010, and in 2009 the targets were then increased to 20per cent of the forecasted demand by 2020. The choice of a fixed amount of electricity was meant to provide certainty to renewable electricity market participants. It was successful in that respect, but this meant that demand variations fell on coal and gas generators. When electricity demand grew more slowly than was forecast after 2009, the demand shortfall had to be absorbed mainly by less-than-anticipated output from coal generators.

In 2015, following the recommendations of the Warburton Review (Parliamentary Library 2014-15), and with household electricity consumption falling, the then Government concluded that targets stipulated in the Act were too detached from the actual demand, putting undue pressure on generators. The Act was subsequently amended to account for the lower than expected levels of demand. The target was reduced from 41,000 GWh per year to 33,000 GWh per year. While these changes bolstered the market position of traditional generators, they did so at the expense of renewable generators.

Transition to renewable energies and the rise of negative prices on the NEM

In recent years there has been an increased incidence of negative prices in the NEM.

Traditionally, negative bids have arisen from the preference for baseload coal generators to keep producing electricity rather than switch off, due to the high costs of restarting. If the negative price is expected to last for just one bidding period, it may be a better financial outcome for a coal-fired generator to dispatch at a negative price than to shut down and incur restart costs in the next period. A negative price outcome under these circumstances is consistent with efficient dispatch decisions and need not be problematic.

Wind and solar generators have variable supply. This is true both individually and collectively, as renewable generators tend to be exposed to similar time-of-day and weather influences. Renewable generators thus bring with them a heightened frequency of oversupply and negative price episodes. The growth of renewable generation has increased the frequency of episodes of oversupply and negative prices.

Also, frequent rebidding is becoming a more widespread strategy across the industry in order to manage negative pricing risk (ARENA 2021b).

As negative pricing intervals become more common, extreme negative pricing intervals also make up a greater proportion of total negative price events (ARENA 2021b). One concern is that hedging contracts divert bidding behaviour in unusual ways. A generator's hedge position ensuring a fixed price for electricity sold into the market decreases the exposure of that generator to negative prices, and in turn, affects its bidding strategies (AER 2022). As hedging products are currently more adapted to fossil-fuel generators (see below), it offers them the ability to somewhat acquire some level of protection against the negative bidding behaviour which is often associated with renewable energy generators whose marginal cost is very low. Late rebidding however may affect the price of hedging contracts, as it withholds accurate information from market participants (ARENA 2021b).

If negative pricing outcomes simply reflect episodes of negative SRMC, then they may not have any inherent inefficiency. But ARENA have identified that some bidding strategies appear to depart from SRMC and to the extent that this happens it brings into question the efficiency of dispatch in the NEM.

ASX standard contracts and suitability to weather-dependent output

The ASX hosts a number of electricity futures contracts. However, the markets for these contracts are deepest for baseload electricity traded in flat 24-hour blocks, and rather thin for contracts that align with parts of the day most relevant to renewables. For this reason, there is a need for the market to offer energy retailers the ability to manage prices during peak periods of the day (AER 2022).

Although the development of new hedging products is currently taking place, there remain gaps related to risk management products related to renewable energy (ARENA 2021a).

Voluntary surrender of RECs

From the outset of the RET there was no requirement that certificates generated should be surrendered. A renewable generator could simply hold on to a certificate that it generated meaning that this certificate could not be used by a liable party. Subsequently, amendments were made that allow the holder of a certificate to surrender it without credit towards the RET.

The voluntary surrender of certificates boosts the amount of renewable electricity in the system above the levels required by the RET. It tends to increase the displacement of fossil-fuel generation and it exacerbates the challenges in adapting to an increased renewable fraction. Voluntary surrender mechanisms are potentially beneficial in so much as they create a channel for consumers who are willing to pay for more ambitious emission reductions to do so. However, the question of how they interact with a mandatory target is complicated: to what extent does the RET already accommodate the preferences of consumers with a strong appetite for emission reductions.

Co-existence and cannibalisation of competing schemes

Several initiatives to promote renewable electricity were developed outside the RET and at times without much coordination with it. This created complexities for market participants as schemes often overlapped. These schemes include:

- During the first decade of the RET some States introduced quite generous feed-in tariffs to encourage rooftop solar
- There were also some State-based white certificate schemes. The NSW Energy Savings Scheme (ESS) (NSW Climate and Energy Action 2022) was established in 2009 to provide a financial incentive for owners or tenants of homes and businesses to reduce energy consumption or improve the efficiency of energy use. Similarly, the Victorian Energy Efficiency Certificates (VEECs) (Essential Services Commission 2022) were established under the Victorian Energy Efficiency Target Act 2007 and commenced on 1 January 2009. Each VEEC represents one tonne of carbon dioxide equivalent (CO2-e) abated by specified energy-saving activities known as prescribed activities
- In 2016, the Australian Renewable Energy Agency (ARENA) launched the $100 million Large-scale Solar (LSS) funding round

These differing policy instruments have at times complemented and at times conflicted with one another. They have also added to the complexity and uncertainty faced by potential investors in renewables.

International Trade Reliance and Dependence

Overreliance on imports to supply components for renewable energy generation

Despite some existing preference for locally made products, most components associated with renewable energy generation are imported (e.g. solar panels and wind turbines). The supply chain has a very high reliance on China: for example, its share in all the manufacturing stages of solar panels (such as polysilicon, ingots, wafers, cells and modules) currently exceeds 80 per cent and this is expected to reach 95 per cent by 2025 (IEA, 2022).

There are risks in having a supply chain so heavily dependent on one country, especially when there are heightened geopolitical risks with supply chains involving that country, as is the case with China.

Affordability for Consumers

Increase in prices for consumers

Electricity prices in real terms have been at quite high levels in recent years—Figure 4.3. It is necessary to look past unusual influences in the last three years: prices were artificially depressed by the COVID activity restrictions in 2020 and 2021 and have been boosted this year by record-high gas prices. But in 2017-18 and 2018-19, which were more “normal” years, it can be seen that prices were above long-run averages.

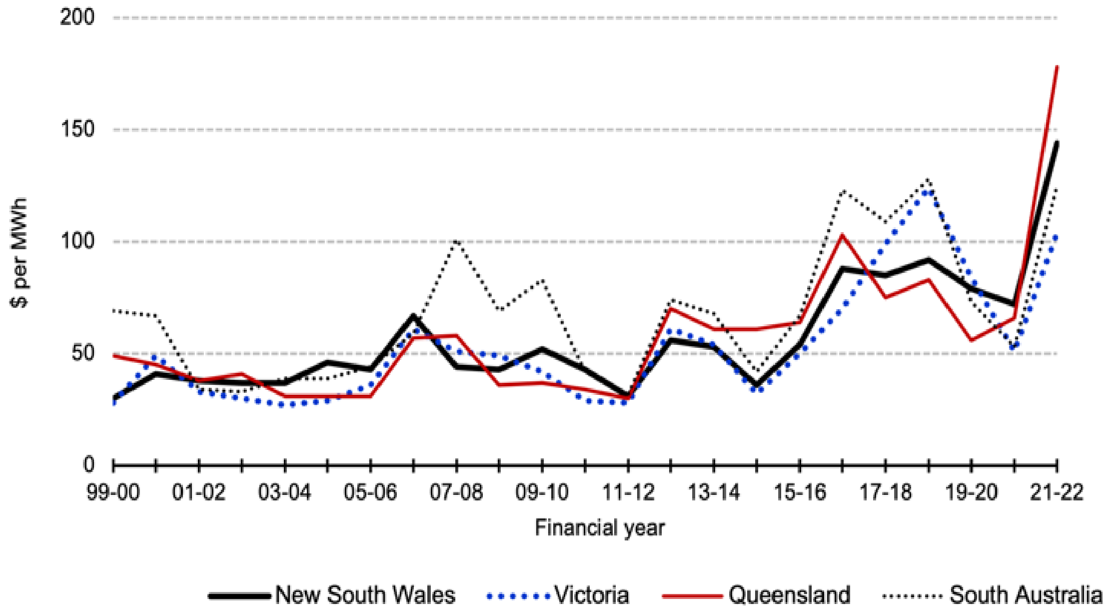
At times of low renewable and reduced coal-fired generation, the NEM is reliant on expensive gas generation to meet daily energy needs. As coal-fired generation retires, gas-powered generation is expected to help meet firming demand, particularly during times of low renewable output.

Unintended consequences from the costs of other sources of energy

The war between Russia and Ukraine has led to many countries applying sanctions on Russia, and also Russia curtailing its own exports, which has caused major increases in the price of all fossil fuels, including coal and gas. As a result, the short-run marginal costs of gas fired generators have risen sharply, with the result that wholesale market prices have been pushed up at those times when gas is in the generation mix. This in turn has translated into higher electricity prices for consumers. The sharp increase in domestic and overseas thermal coal spot prices since the start of the year also contributed to the price increase (RBA 2022a).

Figure 4.3 CPI-adjusted electricity spot prices

Annual volume weighted average 30-minute prices - regions



Source: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/annual-volume-weighted-average-30-minute-prices-regions

Learnings for an RGT

Distinguishing renewable electricity and the RET

In reflecting on lessons to be learned from the RET, it is important to distinguish impacts arising generally from the introduction of renewable generation and those arising specifically from the RET.

Renewables could have been introduced to Australia's electricity supply with policy mechanisms alternative to the RET e.g., hypothetically governments could have built their own renewable power stations and dispatched them into the market. Had this happened, it is likely that most of the main challenges seen in Australian electricity markets over recent years would still have arisen. Most importantly:

- coal-fired generation would have been displaced
- diurnal, random and possibly seasonal supply-demand imbalances would have become more pronounced
- relatedly, the need for electricity storages, especially short-term storages, would have grown significantly; and
- we would still, today, be unsure about which storage technologies will "win" and, particularly, what roles will in then future be played by batteries, pumped hydro, gas powered generation (both natural gas and hydrogen), and demand-side management and storages (e.g. EV batteries)

Conversely, had the RET been a scheme with low ambition at all times, many of these consequences might never have arisen.

Many of the challenges encountered throughout the RET's implementation emanated not so much because of the transition to renewables itself, but more from the pace of the transition. For example, it placed pressures on networks that had not been designed with an eye to the variable character of renewable generation.

Decarbonising the gas supply

A key learning from decarbonisation of the electricity system has been the storage challenges that have arisen as stable baseload generation has been replaced by variable renewable generation. Challenges of this type should be considered and allowed for in a roll out of renewable gas, but they are probably of much less significance. The costs of storing electricity are high enough to present a major challenge for electricity system design. This is probably less of an issue for gas, although it needs to be considered.

Technology neutrality

The RET was in the main technology neutral (the exception to this being the different treatments of wholesale market and small-scale generation, differences that were necessary for practical purposes). The absence of a stated preference over competing technologies was in one respect a desirable trait of the RET aimed at maintaining a healthy competitive environment in research, development and investment choices. It allowed diverse solutions to the decarbonisation challenge and has kept the system open to those alternative technologies as they evolve.

Fugitive methane

When the RET commenced, fugitive methane in the form of waste coal mining gas was specifically excluded. A few years later, the rules were changed to admit the emissions from some mines. Then, later, the scheme closed to any new waste coal mining gas. The RET does admit generation from landfill gas.

The treatment of fugitive methane under the RET has not been entirely consistent, and this probably reflects the challenge of working out how fugitive methane should be treated. A similar issue arises for the RGT in respect of biomethane.

Small-scale electricity generation

The need to accommodate small-scale generation within the RET framework has posed challenges and there have been some significant adjustments to the RET along the way to meet them. Part of the challenge is that the costs of creating and trading certificates for large scale generators are modest against the value of certificates created, but for small customers this is not so and alternative mechanisms have been needed.

Were it the case that small scale renewable gas production was allowed under an RGT this would also need to be considered. At present this does not seem to be an issue, but it should be anticipated in scheme design.

Certificate based scheme

The certificate-based infrastructure of the RET appears to have won broad acceptance. There have been changes made along the way to adapt the certificate scheme in light of issues arising, but none of these seem insurmountable. This does not rule out that other mechanisms to promote renewable electricity also might have worked well.

Integration of incentive schemes

The RET has existed alongside a number of other schemes to promote renewable electricity and at times there has not been very much coordination between schemes. When this reflects conflicting national and State objectives this may be unavoidable. But policy designers should at least seek to harmonise their schemes where practical, to simplify the operating environment for industry and to give as clear directions as possible. (Nelson et al 2022) argue that there is a need to build a nationally consistent and integrated energy and climate policy. To this end they suggest changes such as expanding the use of LGCs, using certificates when issuing contracts for difference, the creation of some fungibility between LCGs and ACCUs, and using LGCs to guarantee the origin of ‘green hydrogen’.

Planning ahead to blend the old and the new

Attention should be given to integrating the maintenance, adaptation and in some circumstances orderly decommissioning of current infrastructure as part of the introduction of renewable gas. Also, assessing and contributing towards the complementarity of technologies for specific projects could help attract government support.

Making it an attractive offer

The RET provided incentives to switch to renewables and signalled a long-term direction of change. An RGT should seek to do the same. These incentives should be developed strategically and in partnership with states and territories to avoid multiplication of schemes and conflicts between them.

Building a strategic supply chain

Strategic international partnerships should be established early to avoid reliance by default on current suppliers. The avoidance of supply chain disruption is paramount to instil confidence in investors and maintain the pace of development necessary to meet the specified targets.

Regulatory engagement

The electricity market is a regulated market. Decisions have to be made about what decisions will be left to market participants and which decisions are to be taken or influenced by regulators. The regulatory role is and must be active, ready to respond to changing circumstances, seek to promote effective markets and reduce uncertainty when possible and subject to the caveat that some degree of uncertainty is inescapable and must be borne by somebody. The same considerations arise in respect of gas markets and an RGT.

Communicating with the community

New renewable technology uptake can only be achieved with support from the community. Awareness of the characteristics of new technology such as environmental impact, reliability and costs are all considerations that will impact an end-user decision to adopt or switch to the new technology. Communicating early and clearly regarding what is needed to adopt the new technology is key to successfully swaying a market that is becoming accustomed to solar technology.

4.2 NEW SOUTH WALES GREENHOUSE GAS REDUCTION SCHEME

The New South Wales Greenhouse Gas Abatement Scheme (GGAS) commenced operation on 1 January 2003 and was renamed as the Greenhouse Gas Reduction Scheme in 2007. GGAS created an obligation for electricity retailers and large users to assist reducing NSW's greenhouse gas emissions, either by reducing or offsetting their own emissions. It ceased operation on 30 June 2012 (IPART 2023). The scheme was also extended into the Australian Capital Territory for part of this period.

At its inception it was envisaged that GGAS would become redundant and cease when a national emissions trading regime was introduced. GGAS was implemented not long after the RET was introduced; it has a broader scope of allowable emission reductions and there were some provisions to allow for overlap between the two schemes.

When GGAS commenced, it was able to build on a voluntary greenhouse gas benchmark scheme that had applied to NSW retailers for 6 years, albeit without imposing any penalties on them for failures to meet benchmarks (IPART 2013).[7]

The objectives of GGAS were to:

- "reduce greenhouse gas emissions associated with the production and use of electricity; and
- "encourage participation in activities to offset the production of greenhouse gas emissions." [IPART 2013 – p. 29]

GGAS was a certificate-based scheme. Electricity retailers, and generators supplying electricity directly to consumers, were required to purchase and surrender NSW Greenhouse Abatement Certificates (NGACs) if the emissions attributed to their electricity sales or supply exceeded benchmark quantities.[8] Large consumers taking electricity directly from generators could take over the liability to surrender certificates from the supplying generators.

NGACs were created by accredited organisations in line with emission reducing activities such as:

- reducing emissions from existing generators
- generating electricity using low emission technologies
- improving energy efficiency
- sequestering carbon in forests
- reducing emissions from industrial processes in large energy consuming industries (IPART 2023)

GGAS allowed certificates to be created by generators anywhere in the NEM, so long as they outperformed benchmarks, and by other accredited activities carried out in New South Wales.

With GGAS and the RET operating in parallel there was a prospect that electricity consumers would carry excessive costs and an excessive emission reduction task as a result of imposing a State scheme on top of a Commonwealth scheme with similar objectives. Consequently, a proportion of Renewable Electricity Certificates were recognised under the GGAS. This meant that abatement activity occurring under the RET was creditable under GGAS. The proportion of abatement activity accounted for by RECs increased over time, reaching 27.8 per cent in the final year of GGAS' operation (IPART p. 17).

IPART (2013) reports that, in the design of the GGAS, it was decided to impose the certificate obligation on retailers instead of distribution networks because this led to greater competition in the sourcing of certificates (and associated emission reduction efforts). If the obligation were imposed on distribution networks, regulated networks would have sourced certificates and there would have been a need to make allowance for it in regulated revenues. It was suggested that this model might diminish the incentives for efficient sourcing of certificates.

[7] The discussion here draws substantially on IPART's (2013) exit review of GGAS.
[8] If all electricity users purchased their electricity from retailers, then all final electricity consumption could be brough in scope by imposing liability on retailers only. But some large users buy on wholesale markets or generate their own electricity.

Another possibility was a cap-and-trade system imposed on generators. In this model generators that performed better than baselines would generate certificates that could be sold to generators which performed worse than baselines. IPART (2013) reports that this approach was seen as impractical, as NSW electricity supplies were in part sourced from generators located outside New South Wales.

The implementation of GGAS involved setting annual per capita targets for carbon emissions, and individual benchmarks were then calculated for retailers/large consumers based on their share of electricity sales and consumption. The scheme also provided for a calculation of attributable emissions for each liable party. Liable parties were required to either bring their attributable emissions down to benchmark or purchase and surrender abatement certificates to offset excess attributable emissions. Some credits were also allowed for certificate surrenders under the RET.

In its exit review, IPART concluded that GGAS "stimulated a wide range of accredited abatement projects" [p. 2]. It both demonstrated the feasibility of a market-based based mechanism to deliver emission reductions and established some of the regulatory apparatus to put such a scheme into operation. It also had strengths in implementation, which IPART described as:

- "encouraged the lowest cost, most efficient means of abatement
- "achieved a high level of compliance, primarily by establishing an effective audit framework and encouraging a culture of compliance
- "kept administration and compliance costs low
- "established an effective and easy to use registry, which facilitated the registration, transfer and surrender of certificates
- "made significant improvements to methodologies for measuring and verifying emission reductions." [p. 2]

IPART found that the administration and compliance costs of the scheme were low. It estimates that the impact on delivered electricity prices in New South Wales was less than 2½ per cent. And it reports a Grattan Institute estimate that it delivered emissions reductions at costs of $15 to $40 per tonne CO2-e , which was less costly than for some other emission abatement schemes, including the RET.

However, IPART found, there were some weaknesses in implementation and related lesson for improvement. It highlighted the importance of:

- "setting achievable but challenging targets and providing a transparent mechanism for adjusting them over time
- "establishing penalties and shortfall allowances as a means of ensuring compliance and managing risks of potential supply shortfalls
- "providing sufficient flexibility in the design so that unforeseen issues can be addressed
- "minimising the risks and uncertainties inherent in regulatory markets and facilitating market development
- "establishing market confidence in abatement certificates and their value as a tradeable commodity
- "establishing a strong regulatory regime that ensures the integrity of the scheme
- "limiting the ability to surrender certificates from unrelated schemes." [p. 18]

4.3 QUEENSLAND GAS ELECTRICITY SCHEME

The Queensland Gas Electricity Scheme (QGES), which began in 2005 and closed in 2014, was established to promote the use of natural gas by the electricity generation sector and to reduce emissions (Wagner et al., 2014, Cotton and Trück, 2011). The overarching goal of the scheme was to promote the use of coal seam gas in Queensland, many design features are of interest to Future Fuels stakeholders, and we will present a brief review of the scheme and its outcomes. While coal seam gas is not renewable, the mechanisms used to promote it are potentially relevant to renewable gases.

With early discoveries in the 1980s of Coal Seam Gas (CSG) within Queensland, the industry spent over a decade exploring the Surat and Bowen basins to establish the scale of the new resource. This led to commercial production which commenced in 1996 (Towler et al., 2016). Given the size of the domestic natural gas market and CSG's higher production cost, the QLD Government stimulated local gas demand in the power sector via the QGES to assist in growing the local CSG sector (Wagner, 2014, Foster et al., 2015).

The scheme commenced with an initial 13% target, whereby eligible electricity generators created certificates (known as Gas Electricity Certificates, GECs) for every MWh of generation. Operated under the then Electricity Act 1994 (QLD, 1994), eligible generators could produce electricity from natural gas, CSG, liquified petroleum gas and waste gases. In conjunction with its goal of creating demand for CGS within the state, the scheme also acted to reduce emissions from electricity generation, which has predominately used black coal as its primary fuel type (Wilson, 2007, Foster et al., 2015). The scheme offered generators an additional revenue stream, offsetting the higher cost of natural gas to generate electricity (compared to black coal).

While QGES provided incentives to favour CSG-fired generation over coal-fired generation, it also favoured CSG generation over renewable generation. In the early years of the scheme this was probably of limited consequence, as there was very little renewable generation in Queensland and therefore little risk of displacing it. But over time, as renewable generation became more significant, this began to emerge as an issue. Relatedly, there was a growing potential inconsistency between the coals of the RET (decarbonising electricity) and QGAS (gasifying electricity).

Electricity retailers became the liable parties under the QGES, and were required to surrender GECs to the state government (Cotton, 2015). Liable parties unable to surrender sufficient GECs under the scheme were penalised at the rate of $11.50/MWh, which then rose at the rate of CPI year on year (QLD, 2009, QLD, 2014).

When the Australian Government announced its intention to introduce a carbon price in 2013, the Queensland Government reviewed QGES and concluded that it would be duplicative of the carbon price mechanism and create unnecessary administrative burdens. It decided to terminate the QGES ahead of schedule, with the creation of certificates ceasing at the end of 2013 and the surrender of certificates ceasing mid 2014 (Queensland 2014).

The main direct benefit of the QGES is undoubtedly the firming of CSG resources and the establishment of one of the world's largest Liquified Natural Gas (LNG) sectors (Wagner, 2014, Towler et al., 2016). The scheme was also important in expanding the gas-fired generation sector in Queensland.

However, QGES has drawn criticism for some aspects of its design and implementation. The rapid development of CSG resources created a scenario known as ramp gas, leading to many generators relying on cheap uncontracted gas (Wagner, 2009). This reliance on cheap gas masked the opportunity cost of gas to producers. The adverse consequences of this for domestic became apparent with the establishment of international linkage of domestic gas to the Japanese market, which led to a significant jump in local gas prices (Wagner, 2014). As a result of this linkage, many local power producers chose to either lower or halt production and sell their contracted natural gas for export, which resulted in the greater use of coal-fired generation (Tlozek, 2014).

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5. Renewable gas promotion overseas

- Renewable gas targets do feature internationally at the country and member region (European Union) level, however they tend to be country-specific in their design and implementation
- In some countries the goal of enhanced energy security is a significant objective alongside emissions reduction
- There is a range of policies that are being implemented by different countries in addition to, or in place of, renewable gas targets to support market development
- Most renewable gas target schemes are immature, having been in operation for only a few years, but some biogas initiatives have been in place for several years

This chapter provides an overview of the approach to renewable gas in a number of overseas jurisdictions. Support for renewable gas adoption can be direct, such as in the form of renewable gas targets, or indirect, such as emission limits. For this reason, we have canvassed the emission reduction landscape broadly as it relates to energy.

Intercountry comparisons are made difficult by the fact that renewable gas schemes are all country-specific (with the exception of some EU-level initiatives). There is great diversity.

There is variety in the types of renewable gases targeted. Some schemes target green hydrogen while others target biomethane and biogas. Some countries also have schemes to promote the uptake of blue hydrogen, seeking to move away from fossil-fuel methane in anticipation of (more) cost-competitive green hydrogen. Although emission reductions are a key consideration, renewable gas development is also motivated by energy security concerns in some countries, for instance in parts of Europe.

Interventions to promote renewable gas also vary greatly in the ways that they seek change. Some schemes have a degree of neutrality about how goals are delivered—for instance the United Kingdom's Green Gas Support Scheme involves a reverse auction to provide renewable gas to the gas networks and is broadly neutral as to which providers should be selected. In other countries there are initiatives that selectively support particular producers often with an eye to testing and proving the particular technologies that they have under development.

All of the broadly targeted renewable gas support schemes are in their early stages—i.e. they have been in operation for no more than a year or two. This means that there are no mature renewable gas target schemes that can tell us what has been learned after five or ten years of operation.

5.1 EUROPEAN UNION FRAMEWORK

The EU's 2030 Climate Target Plan sets a goal of reducing net greenhouse gas (GHG) emissions by 55% of 1990 levels by 2030 (EC 2022a). To achieve this goal, the European Commission (EC) has established the 2030 Climate and Energy Framework, which outlines EU-wide targets and policy objectives, including the European Green Deal. The European Green Deal provides a package of policy initiatives, including the Renewable Energy Directive, which is the main policy framework for promoting renewable energy across all sectors of the EU (EC, 2021d). Under the Renewable Energy Directive, the EC has set a target of 32% for the share of renewable energy in the EU energy mix by 2030. All 27 EU countries are required to submit National Energy and Climate Plans outlining how they will contribute to achieving this target. Each EU country is also required to submit a progress report against its National Energy and Climate Plan every two years (EC, 2018).

The European Green Deal provides three main strategies for developing the EU's renewable gas sector, including the Hydrogen Strategy, the Strategy for Energy System Integration, and the Methane Strategy (EC, 2020b, EC, 2020c, EC, 2020a). The Hydrogen Strategy sets a goal of increasing the capacity of renewable hydrogen electrolysers to 40 Gigawatts (GW) and the amount of renewable hydrogen produced every year to 10 million tonnes by 2030. Further, EU countries have committed to prioritise development of renewable hydrogen produced using mainly wind and solar energy. The Strategy for Energy System Integration recognises the important role for renewable gases, including use of Power-to-gas (P2G) technologies to store and transport surplus renewable energy. The Methane Strategy recognises the importance of reducing methane emissions in the agriculture sector by supporting biogas production from agricultural waste. The Methane Strategy also includes plans to revise the regulatory framework in order to facilitate development of the biogas market.

The EC's 2022 'Fit for 55' policy reforms aim to reduce net GHG emissions by at least 55% by 2030. Under Fit for 55, the Renewable Energy Directive will be revised to set a new renewable energy target of 40% by 2030 to accelerate GHG reductions. Further, The EC's 2022 REPowerEU Communication provides a set of proposals to revise the Renewable Energy Directive and to put in place new initiatives for reducing dependence on Russian fossil fuels and promoting production of renewable hydrogen and biomethane (EC, 2022b). Specifically, the REPowerEU Communication includes plans to phase out dependence on fossil fuels from Russia by 2030. To achieve this, the EC has laid out plans to invest €27 billion towards increasing biomethane production and €37 billion towards increasing electrolyser capacity to 65 GW EU-wide by 2030 (van Rossum et al., 2022).

In addition, the EU has established other policy initiatives for promoting renewable gas under the Renewable Energy Directive, including the 2021 New EU Framework to Decarbonise Gas Markets, the 2022 REPowerEU Communication and the 2005 EU Emissions Trading System.

The New EU Framework to Decarbonise Gas Markets, or The Framework, outlines policy measures for developing the renewable gas sector, in particular biomethane and renewable hydrogen, in line with the Renewable Energy Directive (EC, 2021a). Specifically, the Framework proposes the following revisions to the Gas Directive and Gas Regulation, which are the main instruments for promoting the renewable gas sector under the Renewable Energy Directive (EC, 2021b, EC, 2021d, EC, 2021e, EC, 2021a):

- Introduction of new EU-wide legislation to incentivise development of renewable gas markets, and development of distribution and trade infrastructure in order to integrate renewable gas into the natural gas network and facilitate trade and supply across EU borders
- Introduction of new policy interventions to make it easy for renewable gas producers to access the gas grid by removing taxes levied on cross-border interconnections between EU Member States and reducing tariffs at injection points into the existing EU pipeline network by 75% (Baker Botts, 2022)
- Establishment of consistent EU-wide terminology and a certification system for renewable gases and facilitation of access of biomethane to the natural gas grid through extending the Guarantee of Origin scheme from renewable electricity to renewable gas to enable cross-border trade of biomethane (EBA, 2022)

The EU Emissions Trading System (EU ETS) is one of EU's main instruments for achieving its emission targets under the Renewable Energy Directive and the European Green Deal (EU, 2005). The EU ETS is a cap-and-trade scheme involving all 27 EU Member States, Iceland, Norway, Liechtenstein and the United Kingdom. Under the EU ETS, all eligible installations are required to present their tradeable carbon emission allowances to cover their yearly carbon emission requirements or pay fines. The EU ETS promotes investments in innovative, renewable energy technologies, including renewable gas technologies. Funds raised through fines collected from the EU ETS are used to fund various programs for promoting renewable energy, including renewable gas.

5.2 FRANCE

France's main policies for promoting renewable gas are:

- The 2020 National Energy and Climate Plan, which sets a goal of increasing the share of biogas in France's renewable energy mix to 34-41% compared to 1990 by 2030 (IEA, 2021a)
- The 2019 French Strategy for Energy and Climate, which lists several objectives, including increasing the share of clean industrial hydrogen to 20-40%, installing 10-100 Megawatts (MW) of power-to-gas (P2G) facilities and increasing the number of hydrogen vehicles to 20,000-50,000 by 2028 (MTES, 2019)
- The 2020 National Strategy for the Development of Decarbonised and Renewable Hydrogen, which outlines ambitions to expand its electrolyser capacity to 6.5 GW by 2030 to increase the production of decarbonised hydrogen. To achieve this, the French government has committed €7 billion to support development of decarbonised hydrogen between 2020 and 2030 (MTES, 2020)

The main policy interventions that have been implemented to achieve these goals are:

- Feed-in tariffs (FIT) and Feed-in Premiums (FIP) for biogas to electricity and heat
- FIT for biomethane injection into the natural gas grid
- Subsidies for biogas and renewable hydrogen

The following sections provide descriptions of these policy interventions. Other interventions for promoting renewable gas are also summarised.

FIT and FIP schemes for biogas to electricity and heat

Between 2011 and 2016, France implemented a FIT scheme for electricity produced from biogas. The scheme guaranteed a tariff, which was paid to biogas producers that used agricultural waste for a period of 20 years. Under this scheme, biogas electricity plants and biogas combined heat and power plants with a capacity of less than 500 kilowatts (kW) were eligible for a tariff of €0.12-€0.13/kWh (MTES, 2022).

In 2016, FIT for electricity produced using biogas was replaced with a scheme that combined FITs and FIPs. Under the revised scheme, producers with a capacity of less than 500 kW are still eligible for the FIT scheme at revised tariff rates whilst producers with a capacity of more than 500 kW receive a premium tariff of up to €0.04/kWh granted through tenders on top of the sale price received on the electricity market (MTES, 2022). The premium tariff is calculated as the difference between a base tariff, set at the start of each year, and the tariff obtained by the producer for the sale of renewable electricity on the wholesale market. Although the mechanism for the FIP differs for the FIP differs from that for the FIT, its end result is similar.: it guarantees the electricity price received by the biogas generator.

The FIT and FIP schemes are financed through levies paid by electricity consumers and tax revenues from excise duties charged to oil and coal consumers. The average levy paid by electricity consumers to fund administration of FIT and FIP schemes is €22.5/MWh.

FIT for biomethane injection into the natural gas grid

The FIT scheme for injecting biomethane into the gas grid was established in 2011. Under this scheme, producers of biomethane are guaranteed the right to sell a stipulated volume to a natural gas supplier at a fixed price for a period of 15 years (IEA, 2021b). The fixed price is determined by the government and varies between €0.05-€0.13/kWh (RES LEGAL, 2019a). The natural gas supplier then factors the cost of biomethane into the prices it charges to gas customers. Administration costs of the FIT for biomethane injection into the gas grid scheme are borne by natural gas consumers through a surcharge.

In 2021, France implemented a revised FIT scheme, now funded by the state budget, to prioritise injection of biogas into the natural gas grids over electricity generation. The main objective behind the revision was to mitigate the risk of natural gas infrastructure turning into stranded assets in future with the demand for natural gas projected to decrease. Under the revised scheme, biogas plants with a capacity of more than 300 MW and located in an area served by a natural gas network are obligated to inject their biogas into the natural gas network.

The revised FIT scheme provides biogas producers a 15-year contract with a purchase guarantee of a fixed amount of biogas at a fixed tariff of €103/MWh.[9] One of France's objectives under its 2020 Multiannual Energy Plan is to achieve an average tariff rate of €60/MWh by 2028 (RES LEGAL, 2019a).

Subsidies for biogas and renewable hydrogen

The French government pays small and medium biogas plants a tariff rebate of up to 40% of the total cost of connecting biomethane facilities to the natural gas distribution network (Biogas World, 2020). The state government funds this scheme through its Heat Fund.

The French government has also invested €100 million to subsidise the purchase of hydrogen trucks, buses and coaches (Bloomberg Law, 2018). Under this scheme, a grant of up to €50,000 is available for the purchase or rental (for a period of at least two years) of electric and/or hydrogen trucks, buses or coaches (Trans.INFO, 2022).

In addition, France's 2021 National Recovery and Resilience Plan includes a commitment to invest €1.9 billion towards funding renewable hydrogen Research Development and Demonstration (RD&D) projects (NRRP, 2021). A total of €625 million has been allocated between 2020-2023 to fund the development of France's Hydrogen Hub Initiative under the National Strategy for the Development of Decarbonised and Renewable Hydrogen (MTES, 2020).

Other interventions

In addition to the previously outlined schemes, the following interventions have been implemented:

- Legislation: Most cities in France have established low-emission zones, which regulate vehicle access in cities to reduce air pollution and traffic congestion. EVs are exempt from access restrictions (TRUE, 2020)
- Tax benefits: Use of biogas or biomethane mixed with natural gas is exempt from the domestic consumption tax on natural gas (Biogas World, 2020). End users of renewable electricity, including electricity generated using biogas, are eligible for a reduced VAT rate of 7% (RES LEGAL, 2019g)

[9] Biomethane produced for heating purposes is conventionally denominated in MWh equivalents where 1 cubic foot of biomethane is equivalent to 2.9×10^{-4}.

5.3 GERMANY

Germany's Integrated National Energy and Climate Plan (NECP) sets a goal of increasing manure digestion capacity by 30% by 2025 and installing manure storage facilities country-wide on up to 70% of biogas production plants (Winquist et al., 2021). Germany's 2020 National Hydrogen Strategy includes ambitions to expand its hydrogen generation capacity to 5 GW by 2030 (BMWK, 2020). The Strategy includes a commitment of €8 billion to support construction of refuelling stations and fuel cell heating facilities and to fund various international green hydrogen projects.

The following interventions have been implemented in Germany to promote renewable gas:

- FITs for biogas electricity generation
- Auctions
- H2Global scheme
- Financial support for international green hydrogen projects
- Offshore wind subsidy scheme
- RD&D support
- Levy reduction for renewable energy

The following sections provide descriptions of these interventions. Other measures taken to promote renewable gas in Germany are also listed.

Feed-in Tariffs

In 2000, Germany introduced its Renewable Energy Act (EEG) to support the development of renewable energy by guaranteeing all renewable electricity producers a fixed electricity price, or FIT, which is set higher than the electricity market price and is available for 20 years. Electricity generators operating biogas plants with a maximum capacity of 75 kW are eligible to receive FITs under this scheme. The FIT rates for electricity produced using biogas range from €0.08-0.10/Kwh (Gustafsson and Anderberg, 2022).

The difference between the fixed FITs and the market electricity price is paid by electricity consumers through a surcharge levied in proportion to their power consumption. In 2013, the EEG surcharge was €0.05/Kwh (Future Policy, 2022). In 2015, consumers paid a total of €20 billion in renewable energy surcharges, although only a small component of this - €0.2 billion - was for biogas generation (Radowits, 2022).

Auctions

Germany's FITs were replaced by a tender system, which was introduced in 2014 following a reform of the EEG. The target for new renewable biomethane installations available for tendering between 2021 and 2028 is 150 MW. Under this scheme, renewable electricity generators, including renewable gas, with a minimum capacity of 150 kW can sell their electricity to registered electricity suppliers at a price that is determined in an auction. Generators that offer the lowest price for their electricity win the auction and are guaranteed their offer price for 20 years. Producers receive the difference between the monthly average of the wholesale market price of electricity and the auctioned tariff, or the market premium, from grid operators. The average electricity price ranged from €0.04-0.08/Kwh in 2021 (Gustafsson and Anderberg, 2022).

The auction scheme is funded by the EEG surcharge (€0.07/kWh), which accounts for approximately 20% of electricity consumers' bills on average (Clean Energy Wire, 2021). The total cost of auction payments made to generators was €27 billion in 2015 (ECOFYS, 2015).

H2Global scheme

The German government recognises that Germany does not currently have enough renewable energy to produce green hydrogen and will have to import green hydrogen in the medium to long term. Germany's H2Global scheme subsidises large-scale green hydrogen production in partner countries with surplus renewable electricity for import into Germany. Germany's National Hydrogen Strategy includes a budget of €2 billion to promote 31 potential international partnerships through funding production of green hydrogen from renewable energy sources (IEA, 2021g). Through H2Global, the German government has also spent a total of €900 million to subsidise the price of imported green hydrogen in 2021 (Renewables Now, 2016).

Under the H2Global scheme, Germany has partnered with Morocco to build one of the world's biggest solar power plants, which will support Africa's first green hydrogen production plant. Germany will import some of the green hydrogen produced from this project to help meet its green hydrogen demand. In addition, Germany has signed agreements to partner with various countries with surplus solar and wind energy power, including Saudi Arabia, Australia, Chile, Namibia, Canada, Japan, United Arab Emirates and Ukraine.

Financial support for international green hydrogen projects

The German government funds several international projects involving development of its green hydrogen generation, storage and transportation capacity as well as several international green hydrogen RD&D projects to promote green hydrogen technology. The German government has provided grants worth up to 45% of total project costs. The maximum amount of funding provided under this scheme is €15 million per project. The total budget for this scheme is set at €150 million per year. A total of €350 million has been allocated to fund the scheme by 2024 (BMWK, 2021).

Offshore wind subsidy scheme

Germany has introduced a pilot subsidy program for the development of 980 MW of offshore wind electricity to support green hydrogen production through electrolysis in the German North Sea by 2027. Under this scheme, a tender will be awarded to the bidder with the lowest subsidy requirement to establish an offshore wind farm and grid connection. The price of electricity generated under this scheme is capped at €0.06/kWh. The total budget for the scheme is €50 million (Recharge, 2021b).

RD&D support

The National Hydrogen Strategy includes aspirations for Germany to become a global leader and exporter of green hydrogen technology and other P2G technologies. From 2006-2016, Germany invested a total of €700 million in green hydrogen RD&D projects. A total of €1.4 billion was allocated towards funding development of hydrogen and fuel cell technologies between 2016 and 2026. €700 million was allocated to fund development of fuel-cell based heating technologies, and €25 million was allocated to fund RD&D, including development of green hydrogen technologies.

Levy exemption

Germany's 2021 EEG included a revision of the EEG levy, a surcharge levied at electricity consumers, to exclude renewable electricity used to produce green hydrogen by electrolysis (IEA, 2021g). Under this intervention, renewable electricity consumers that produce green hydrogen are exempt from paying the EEG surcharge of €0.06/kWh (Clean Energy Wire, 2020). Exemption from paying the EEG levy effectively reduces the average cost of producing green hydrogen by €3.00/kg (Argus, 2021a) thereby making green hydrogen more competitive.

Other interventions

In addition to the previously outlined interventions, a total of €7 billion has been set aside in Germany's national budget under the National Hydrogen Strategy to fund the following green hydrogen initiatives:

- Converting eligible natural gas pipelines to hydrogen pipelines under Germany's Gas Network Development Plan 2022-2032 (BNetzA, 2022)
- Allocating €2.1 billion towards provision of purchase grants for New Energy Vehicles (NEVs), including FCEVs, and €3.4 billion for the construction of a refuelling and charging infrastructure (BMWi, 2020)
- Funding a tender system for electrolysis services, and provision of subsidies for building green hydrogen production plants, and conducting pilot programmes (IEA, 2021g)
- Establishing a €55 million hydrogen-powered steel production plant (IEA, 2021g)

5.4 THE NETHERLANDS

The Dutch government has outlined plans for increasing the production of biomethane to 70 PJ per year by 2030 under its 2019 Climate Agreement (EZK, 2019). In addition, the Government Strategy on Hydrogen sets a goal of increasing the Netherlands' electrolyser capacity to 3-4GW and the number of FCEVs to 300,000 by 2030 (EZK, 2020).[10] The Dutch government also plans to increase the share of hydrogen, which included renewable hydrogen, in the national natural gas grid to a maximum of 20% (IEA, 2020b).

The following policy interventions have been implemented to promote renewable gas in the Netherlands:

- Premium tariff scheme
- Tax deductions and exemptions
- RD&D support.

The following sections provides descriptions of these policy interventions. Other interventions for promoting renewable gas in the Netherlands are also summarised.

Premium tariff scheme

In 2011, the Dutch government established the Stimulation of Sustainable Energy Production scheme (SDE+). This is a competitive auction-based scheme that awards funding to the most cost-effective renewable energy generators. In 2020, the SDE+ was expanded into the Sustainable Energy Transition Incentive Scheme (SDE++), which supports combined heat and power production using biogas and renewable hydrogen production through electrolysis (IEA, 2020b). Under the SDE++, a premium is granted to successful bidders, on top of the wholesale price of electricity, gas or heat for a period of up to 15 years to promote renewable energy. Successful bidders are required to present Certificates of Origin to the Netherlands Enterprise Agency to prove that the energy produced was generated using renewable sources.

A sliding feed-in premium is provided to cover the difference between the cost of renewable energy production and the wholesale price for electricity, gas or heat. The amount of premium paid to biogas producers ranges between €0.05/kWh and €0.09/kWh (RES LEGAL, 2019b). The total funding allocated to SDE+ was €12 billion in 2017 and 2018. The SDE++ scheme is funded through the Surcharge for Sustainable Energy Act (ODE) levy paid by non-renewable energy consumers.

Tax deductions and exemptions

The following tax deductions and exemptions are implemented in the Netherlands to promote renewable energy, including biogas and renewable hydrogen:

- Consumers of electricity generated from renewable sources of energy are exempt from paying the ODE levy (FIN, 2022a). The ODE levy was €0.03/kWh in 2020 (StatLine, 2022)
- FCEVs are supported through tax deductions. Employees that receive FCEVs get a lower additional taxable income rate (8% of their vehicle’s purchase price) than employees that receive fossil fuel company vehicles (22% of their vehicle’s purchase price)
- Owners of FCEVs are exempt from paying a vehicle registration tax, which costs €1,122 per year on average for passenger vehicles (IEA, 2020b, FIN, 2022b)
- The Environmental Investment Allowance (MIA) is a tax scheme that offers the opportunity for private enterprises to deduct an extra amount of up to 36% of their investment cost from their total taxable profit for eligible investments listed in the Environmental and Energy List, including biogas and renewable hydrogen technologies. Under the MIA, FCEVs are eligible for up to €50,000 of the investment cost. The total state budget for the MIA scheme was €99 million in 2018 (RES LEGAL, 2019f)

RD&D support

The Netherland’s Demonstration Energy and Climate Innovation grant scheme (DEI+) supports hydrogen RD&D projects through provision of research grants. In 2018, the total allocation for supporting hydrogen RD&D projects was €11 million, or 5% of the total energy RD&D budget. Most of the RD&D focused on cost-effective production

[10] A 1.0 MW solar plant capacity for powering an electrolyser means that the solar plant generates 1.0 MW output of direct power that can be used by up to 1.0 MW of electrolyser(s). If the 1.0MW output-power was “plugged” into an electrolyser of 2.0 MW, the electrolyser plant would be operating at 50% of its capacity.

of hydrogen from electrolysis. The maximum amount of research grant provided in 2022 is €15 million per RD&D project (EGEN, 2022).

Other interventions

In addition, the Dutch governments has implemented the following measures:

- International partnerships: the Dutch government has invested €134 million in construction of large-scale P2G plants in Denmark. The investment will be used to develop technologies for producing renewable hydrogen from wind energy for end use in the transport sector (IEA, 2021f). The Netherlands has also partnered with Portugal to develop renewable hydrogen production technologies (IEA, 2022g)
- Hydrogen blending: the Netherlands plans to increase the demand for renewable hydrogen for transport by increasing the blending obligation for companies that deliver fuels to the transport sector. Under this scheme, companies are obliged to deliver an annually increasing share of renewable energy. The obligation rate was 16.4% in 2020 (NEa, 2020)

5.5 SWEDEN

The Swedish National Strategy for Green Hydrogen has set a goal of expanding Sweden's hydrogen electrolyser capacity to 5 GW by 2030 and 15 GW by 2045 (Enlit, 2021). In addition, the Swedish Energy Agency has awarded research funding for several renewable hydrogen technology development projects. There is no official strategy for biomethane or energy gases in Sweden to date (Energigas Sverige, 2021). However, in 2018, the Swedish biogas industry launched a proposal for a National Biogas Strategy, which includes ambitions to increase biogas production to 10 TWh equivalent by 2030 (Energigas Sverige, 2022).[11]

The following interventions have been implemented to promote renewable gas in Sweden:

- Biogas tax exemption
- Biogas subsidy scheme
- Renewable energy quotas
- Grants for construction of green hydrogen refuelling stations

The following sections provide descriptions of these schemes. Other interventions for promoting renewable gases in Sweden are also summarised.

Biogas tax exemption

In Sweden, energy and carbon dioxide taxes are levied on producers, importers and suppliers of fossil fuels for heating purposes. Biogas producers are exempt from paying carbon and energy taxes for biogas used for transport or heating. The carbon tax rate is €118/tonne (Finansdepartementet, 2022) and the energy tax rate is €0.04/kWh (NUS, 2021).

Biogas subsidy scheme

In January 2015, the Swedish government introduced a subsidy scheme for biogas used for electricity, heating, or as vehicle fuel. Under this scheme, a subsidy of up to €0.04/kWh was provided to biogas producers. In 2016, a total of €7 million was granted to 51 biogas producers under this scheme. The total budget for the subsidy programme is €36 million and the subsidy scheme is scheduled to end in 2023 (IEA, 2019b, Miljödepartementet, 2020).

Subsidies are also granted for biogas plant installations through the Rural Development Program, which is funded by the Swedish government and the European Union. Under this program, a total of €26 million was allocated to support biogas production by farmers from 2014-2020 (IEA, 2019a). The Rural Development Programme offered various forms of investment support, including start-up grants, and technical support for young entrepreneurs setting up biogas production plants.

[11] 1 cubic foot of biomethane is equivalent to 2.9×10^{-4} MWh

Renewable energy quotas

The Swedish Electricity Certificates Act obliges electricity suppliers to prove that a set percentage quota of their electricity was generated from renewable energy sources, including biogas. Electricity suppliers can prove that they have fulfilled the obligations by buying tradable renewable energy certificates (RECs), which are issued to eligible renewable electricity generators for each MWh of renewable electricity produced. The current quota obligation is 27%. In 2017, the average price for RECs was €12/MWh. Electricity suppliers that fail to satisfy their quota obligation are required to pay a fine of 150% of the average value of an REC (RES LEGAL, 2019e). Electricity suppliers typically pass on the cost of meeting their quota obligations to electricity consumers by imposing a surcharge. Sweden and Norway have had a common electricity certificate market since 2012.

Grants for construction of green hydrogen refuelling stations

In January 2022, the Swedish government set aside €52 million to support construction of green hydrogen refuelling stations throughout the country. The refuelling stations enable FCEVs to refuel. Under this scheme the Swedish government has awarded grants worth €2 million per station, on average. (Hydrogen Central, 2022a, IEA, 2022h).

Other interventions

Sweden has also implemented the following measures to promote renewable gas:

- Subsidies for RD&D and renewable hydrogen production: Sweden's 2021 Recovery and Resilience Plan includes plans to offer financial support for projects that develop and implement renewable energy technologies including green hydrogen production (IEA, 2021h)
- Non-renewable energy bans: Sweden introduced a ban on extraction of uranium and fossil fuels, including coal, oil, and natural gas in July 2022
- Hydrogen vehicle subsidies: the Swedish government covers 20% of the purchase price for fuel-cell powered trucks weighing more than 3.5 tonnes (IEA, 2022a)
- Wind-to-hydrogen projects: a Swedish local government authority has partnered with green hydrogen producers to produce green hydrogen through electrolysis using wind power (Hydrogen Central, 2022b)

5.6 DENMARK

Denmark's 2018 Energy Agreement includes a proposal to allocate €32 million every year towards supporting the expansion of biogas production and development of biogas technology over a 20-year period (KEFM, 2018). The Danish government's Green Gas Strategy projects that biogas will account for 70% of gas consumption in 2030 (Bech-Bruun, 2022).

In addition, the 2021 Government's Strategy for Power-to-X (PtX) sets a goal of building 4-6 GW of electrolysis capacity powered by offshore wind by 2030 (KEFM, 2021). The strategy also includes a proposal to allocate €168 million towards supporting the expansion of PtX capacity, including P2G, in Denmark.

To achieve these goals, the Danish government has implemented the following policy interventions:

- Biogas subsidy scheme
- PtX subsidy scheme

The following sections provide descriptions of Denmark's biogas and PtX subsidy schemes. Other interventions for promoting renewable gas are also summarised.

Biogas subsidy schemes

The Danish Energy Agency administers three types of state-funded biogas subsidy schemes:

Production of electricity using biogas

Under the biogas subsidy scheme, renewable electricity generators receive a premium tariff of up to €0.11/kWh and a guaranteed bonus of up to €0.06/kWh, on top of the sale price received on the wholesale electricity market, over a period of 10 years (RES LEGAL, 2019c).

In 2020, Denmark implemented changes to the biogas subsidy scheme, including closing the biogas to electricity scheme to new applicants, and establishing a cap on production subsidies by setting a limit on the amount each generator can receive in subsidies under the scheme. The cost of administering this scheme is borne by electricity consumers through renewable energy surcharges.

Injection of biogas into the natural gas grid

Under the biogas subsidy scheme, a premium tariff of €1.34-€3.50/Gigajoule (GJ) is paid to biogas producers, on top of the market price of natural gas, for converting their biogas to biomethane and injecting it into the national natural gas grid (RES LEGAL, 2019c).

Biogas premium tariffs

In Denmark, a premium tariff for biogas for heating purposes is paid at a rate of €0.06/kWh for biogas used in a combined heat and power unit. The tariff rate is €0.04/kWh for biomethane used for transport or industrial purposes (RES LEGAL, 2019c). Contracts under this scheme are allocated through competitive bidding. The state government bears the cost of administering this scheme. Denmark committed to allocate €32 million every year for 20 years towards expanding the use of biogas in the transport sector and for industrial processes under its 2018 Energy Agreement.

PtX subsidy scheme

Denmark's 2021 Government's Strategy for PtX proposed a budget allocation of €168 million towards a PtX subsidy scheme for supporting the production of hydrogen and development of green hydrogen technologies (CSIRO, 2022b). To date, the Danish government has allocated €115 million towards funding RD&D projects focused on developing the Danish green hydrogen value chain. An additional €54 million has been allocated to fund RD&D focused on developing PtX technologies (Offshore Energy, 2022).

Other interventions

In addition to the biogas subsidy and PtX subsidy schemes, the following interventions have been implemented to promote renewable gas in Denmark:

- Legislation: The Danish government restricts the application of inorganic fertilisers in agricultural production to promote use of biogas digestate and biogas production. Further, disposal of organic waste on landfill is restricted in Denmark, and waste treatment incurs a fee to promote use of organic waste in biogas production (FBCD, 2020)
- Tax exemptions: Consumption of renewable electricity, including biogas, is exempt from energy taxes of up to €0.1/kWh levied on consumers of fossil-fuel based electricity (EA, 2015, Skatteministeriet, 2022)
- Technical assistance: The Danish Biogas Task Force supports biogas projects by providing free technical assistance with installation and operation of biogas production plants (Bundgaard et al., 2014)

5.7 NORWAY

The Norwegian Biogas Association has set a target for biogas production to reach 10 terawatt-hours in Norway by 2030, but this has not been adopted as government policy. Norway's Ministry of Transport has set a goal for all city buses to use zero-emission vehicle technologies or biogas by 2025 (IEA, 2022e).

The IEA's review of Norway's 2020 Hydrogen Strategy and 2021 white paper, which includes a Hydrogen Roadmap, found that the Norwegian government has plans to support low-carbon hydrogen development, but has not outlined specific plans for promoting green hydrogen production (IEA, 2022e).

The following main policy interventions have been implemented in Norway to promote renewable gas:

- Renewable energy quotas
- RD&D support

The following sections provide descriptions of these schemes. Other interventions for promoting production of renewable gas in Norway are also summarised.

Renewable energy quotas

Norway's Electricity Certificates Act obliges electricity suppliers to meet a minimum renewable power percentage by acquiring tradable certificates to prove that a set annual percentage of their electricity was generated from renewable sources. All renewable energy technologies are eligible for certification under this scheme. Norway and Sweden have a common electricity certificate market.

The quota obligation is set annually as a percentage of the total amount of megawatt-hours of electricity sold or consumed by suppliers. The 2022 quota obligation is 19% (RES LEGAL, 2019d). In 2016, the average price of tradable certificates was €0.02/kWh and a total of 26 million tradeable electricity certificates were issued (NVE, 2016). Electricity suppliers that fail to meet their quota obligation pay a quota obligation fine equivalent to 150% of the weighted average certificate value. Electricity suppliers typically pass on the costs of meeting their quota obligation to their consumers by adding a surcharge to the electricity bill.

RD&D support

The Norwegian Hydrogen Strategy includes plans for increasing the number of pilot and demonstration projects in the country with a focus on renewable gas technology development and commercialisation. In 2020 and 2021, the Norwegian government allocated €14 million towards RD&D in electrification of its water and ground transport sectors (CSIRO, 2022c). In March 2022, Norway's Ministry of Petroleum and Energy allocated €20 million towards RD&D projects focused on renewable gas production. The Norwegian government also funds RD&D projects for developing biogas production technologies through its Innovation Norway program, which also supports small-scale production of biogas in the agriculture sector through investment grants.

Other interventions

In addition to the renewable energy quotas and RD&D support, Norway has implemented the following interventions to promote renewable gas:

- Incentives for biogas vehicles: in January 2022, the Norwegian parliament voted to simplify the application process for financial support to purchase biogas vehicles and to exempt owners of biogas vehicles from paying toll road charges (IEA, 2021c, EBA, 2021)
- Hydrogen market development: in 2021, Norway allocated €18 million towards development of hydrogen infrastructure and markets (IEA, 2021e, CSIRO, 2022c)

5.8 THE UNITED KINGDOM

The UK's 2021 Biomass Policy Statement states that bioenergy, 21% of which is biogas, is expected to play a significant role towards helping the UK government realise its vision for a net-zero economy by 2050 (IEA, 2021d, BEIS, 2021a). The UK's Department for Business, Energy & Industrial Strategy (BEIS) projects that future domestic supply of sustainable biomass, including biomass used in biogas production, could meet around 10% of UK's total energy demand by 2050 (BEIS, 2021a).

The UK government's 2021 Hydrogen Strategy includes ambitions to increase the production capacity of low-carbon hydrogen, including green hydrogen, to 10 GW by 2030 (BEIS, 2021d). The 2021 Net Zero Strategy commits up to UK£100 million to fund expansion of the UK's electrolyser capacity to up to 250MW by 2023 and to 1 GW by 2025 (BEIS, 2021c, Hydrogen Economist, 2022).

Great Britain's Office of Gas and Electricity Markets (Ofgem) administers the following environmental and social schemes to increase the production of biogas:

- Renewable Heat Incentive Schemes
- Green Gas Support Scheme (GGSS) and the Green Gas Levy (GGL)
- Renewable energy FIT scheme
- Smart Export Guarantee (SEG)
- Renewables Obligation (RO)
- Renewable Energy Guarantees of Origin (REGO)

A description of these schemes is provided in the following sections. A description of the UK government's Green Hydrogen Support Scheme, which is the main scheme for promoting renewable hydrogen is also provided. Other interventions for promoting renewable gas in the UK are also summarised.

Non-Domestic Renewable Heat Incentive (NDRHI) Scheme

The NDRHI scheme is a program that provides financial incentives to increase the uptake of renewable heat for businesses, the public sector, and non-profit organisations in Great Britain. The NDRHI also supports biomethane injection into the gas grid. Eligible biogas plant installations receive quarterly payments over a period of 20 years to generate biogas, which is used for heating. In 2020, biomethane produced under the NDRHI scheme accounted for 1% of the total heat energy used in buildings (BEIS, 2021a). The average tariff rate under this scheme is £0.04/kWh (Ofgem, 2022d). The NDRHI scheme closed to new applicants in March 2021 (Ofgem, 2022c).

Green Gas Support Scheme (GGSS)

The GGSS opened in November 2021 with the goal to support installations of anaerobic digestion (AD) biomethane plants to increase the proportion of biomethane produced in the gas grid. Under the GGSS, quarterly tariffs are paid to registered biomethane producers who inject biomethane into the gas grid in England, Scotland, and Wales for a period of 15 years (BEIS, 2022a) . The GGSS requires that at least 50% of the biomethane generated utilises waste or residue feedstocks (BEIS, 2021a).

Tariffs for biomethane injection announced at the launch of GGSS in April 2022 are:

- Tier 1: Up to 60,000 MWh - £0.06/kWh
- Tier 2: the next 40,000 MWh - £0.04/kWh
- Tier 3: Above 100,000 MWh - £0.02/kWh (HFS, 2021)

The total annual GGSS budget for 2022/23 (April 2022 to April 2023) is £37 million, based on expected tariff payments estimated using data from GGSS applications submitted in 2022/23.

Table 5.1 provides a summary of projected budget allocations between 2021/22 and 2025/26, including: 1) the annual budget cap for applications to participate in the GGSS, 2) the allocated budget to fund applications for tariffs, 3) the total value of tariffs granted and 4) available budget for new applications.

Table 5.1. Green Gas Support Scheme budget allocation between 2021/22 and 2025/26

	FY 21/22	FY22/23	FY23/24	FY24/25	FY25/26
Annual Application Budget cap[11]	£37,000,000	£37,000,000	£65,000,000	£97,000,000	£130,000,000
Budget allocated (TG applications received)	£233,938	£5,428,656	£25,452,361	£36,014,372	£37,840,848
Budget committed (TGs granted)	-	£3,397,957	£16,677,258	£22,218,404	£23,189,811
Remaining budget available	£36,766,062	£31,571,344	£39,547,639	£60,985,628	£92,159,152

Source: https://www.ofgem.gov.uk/publications/green-gas-support-scheme-ggss-quarterly-report-issue-2

By March 2022, 11 applications for tariff guarantees were received (the scheme opened to applications on 30 November 2021). Of these applications, eight had been issued with a provisional tariff guarantee notice and five were granted a tariff guarantee. None of the 11 applications had progressed to be registered on the scheme by 09 August 2022.

The GGSS is funded by the Green Gas Levy (GGL), a quarterly levy paid by all licensed fossil fuel gas suppliers in Great Britain (Ofgem, 2022b). The total GGL charged to each fossil fuel gas supplier is calculated based on the total number of meter points served by the supplier and a GGL levy rate, which is published by the Secretary of State on a yearly basis. The current GGL levy rate is £2.10 per meter per year (BEIS, 2021b). Under this scheme, suppliers who supply 95% or more of eligible renewable gas within a scheme year may be exempt from some requirements of the levy.

The total number of licensed fossil fuel gas suppliers obligated to pay the GGL under the scheme was estimated at 98 as of 31 March 2022. There were no levy payments made by fossil fuel gas suppliers by 09 August 2022 (Ofgem, 2022b).

Renewable energy FIT scheme

The renewable energy FIT scheme requires participating licensed electricity suppliers in Great Britain to make payments on electricity exported into the national grid by accredited renewable energy generators. The FIT scheme closed to new applicants in 2019. Under the FIT scheme, anyone who had installed eligible renewable energy technologies, including biogas plants, could apply for accreditation for up to 5 MW (Ofgem, 2022a).

Owners of accredited renewable energy installations, or FIT generators, register and submit quarterly meter readings of the amount of electricity generated to a licensed electricity supplier, or FIT licensee. FIT generators receive quarterly payments from FIT licensees based on the submitted meter readings for up to 25 years. The average tariff rate is £0.14/kWh for electricity generated using biomethane (Ofgem, 2022a) .

Administration costs of the renewable energy FIT scheme are recovered from all the other licensed electricity suppliers in Great Britain, or non-FIT licensees, based on their share of the electricity supply market.

Smart Export Guarantee (SEG)

The SEG requires licensed electricity suppliers in Great Britain, or SEG licensees, to pay small-scale generators, or SEG generators, for up to 5 MW of low-carbon electricity exported into the national grid, including electricity generated using biomethane (Ofgem, 2022g).

Under this scheme, SEG licensees determine the rate at which they will pay SEG generators and SEG generators choose their preferred SEG licensee. SEG generators are paid by their chosen SEG licensee for electricity generated based on export meter readings and the licensees' tariff rates. The highest SEG tariff rate as of May 22 was £0.08/kWh (Ofgem, 2022g).

Renewables Obligation (RO)

The RO places an obligation on licensed electricity suppliers in the UK to source a proportion of their supply, currently 30%, from eligible renewable sources, including biogas (DECC, 2010). The obligation, expressed in MWh, is set yearly based on a prediction of the total amount of electricity that will be supplied. A fixed number of tradeable Renewables Obligation Certificates (ROCs) is issued to eligible renewable electricity generators based on the annual obligation level expressed in ROCs/MWh (Ofgem, 2022f).

Suppliers can meet their annual obligation by presenting ROCs and/or making a payment into a buy-out fund. The buy-out price for the 2021/22 obligation period is £50.80 per ROC (Ofgem, 2021). This is the amount suppliers will need to pay for each ROC they do not present towards compliance with their 2021/22 obligation. Administration costs of the RO scheme are recovered from the buy-out fund.

Renewable Energy Guarantees of Origin (REGO)

The REGO scheme provides transparency to consumers in EU countries about the proportion of electricity that suppliers source from renewable energy generators, including biogas. The REGO scheme is consistent with UK electricity suppliers' requirement to comply with their fuel mix disclosure obligations and to meet their proof of supply requirements (Ofgem, 2022e).

Under this scheme, a REGO certificate per MWh of eligible renewable output is issued to generators of renewable electricity. The REGO certificate serves as proof to customers that a given share of their energy was produced from renewable sources. Renewable generators of any size in the UK can apply for the REGO scheme.

Green Hydrogen Support Scheme

In July 2022, the UK government launched its Green Hydrogen Support Scheme, which will provide financial support to electrolyser-based projects via tender bids. The first round of contracts will be awarded in July 2023 (Hydrogen Economist, 2022).

Other interventions

The UK has also implemented the following measures to increase the production of renewable hydrogen:

- In April 2022, the UK government developed a Hydrogen Business Model and Net Zero Hydrogen Fund to provide long-term financial support to electrolytic hydrogen projects (BEIS, 2022b)
- In September 2018, the UK government launched a £60 million Low Carbon Hydrogen Supply Competition to fund RD&D projects aimed at developing hydrogen technologies, including green hydrogen (BEIS, 2018)
- In August 2021, the UK government announced a £240 million Net Zero Hydrogen Fund, which provides financial support for low-carbon hydrogen production projects, including electrolytic hydrogen production (BEIS, 2022c)
- In March 2021, the Zero Emission Bus Regional Areas scheme was launched to fund delivery of electric and hydrogen powered buses across England. The total funding available for the scheme was £270 million as of 26 March 2022 (DFT, 2021)

5.9 THE REPUBLIC OF KOREA

The Republic of Korea's 2019 Hydrogen Economy Roadmap is the main policy framework for promoting renewable gas in South Korea (MOTIE, 2019). Under its Hydrogen Roadmap, the Korean government aims to increase power generation from fuel-cell electricity to 17 GW and support production of six million FCEVs, 60,000 fuel cell buses, and 1,200 hydrogen refuelling stations by 2040.

South Korea's 2019 Hydrogen Roadmap also includes ambitions to develop large-scale renewable energy production facilities to increase its capacity to produce green hydrogen. The Hydrogen Roadmap also outlines aspirations to begin importing green hydrogen and to invest in new pipelines for distributing green hydrogen by 2030 (Stangarone, 2021).

The three main policy interventions that have been implemented by the Korea government to date to promote renewable gas are:

- FCEV subsidies
- Renewable Portfolio Standard (RPS) scheme
- Regulatory reforms
- RD&D support

The following sections provide descriptions of these schemes. Other interventions for promoting renewable gas in South Korea are also summarised.

FCEV Subsidies

The Korean government funds a scheme that provides subsidies for purchasing eligible FCEVs. The subsidies are provided through a grant application process. Under this scheme, successful applicants receive grant assistance to buy a FCEV at a subsidised price from a registered manufacturer, or importer who receives the subsidy from the state and local governments.

South Korea's total budget for its subsidy scheme for hydrogen and electric cars in 2022 is US$2 billion. Under this scheme, a subsidy of up to US$34,715, or 50% of the average price, is provided for purchasing a hydrogen vehicle (Stangarone, 2021). Public transportation and commercial FCEVs also receive a subsidy with electric buses receiving up to US$62,280 and electric trucks getting up to US$155,702 per vehicle in subsidy.

In addition, South Korea provides subsidises of up to US$1.2 million per station, or 50% of the installation cost of a hydrogen refuelling station. The Korean government has also allocated US$27 million towards subsidising construction costs of hydrogen production facilities and operation costs of hydrogen charging stations for vehicles (HMC, 2021).

RPS scheme

South Korea's RPS scheme is currently the main policy for increasing electricity generation from renewable energy, including biogas and green hydrogen.[12] Under the RPS scheme, electricity producers generating over 500MW per year are required to meet their renewable energy obligation rates by generating renewable electricity, including using biogas and hydrogen fuel cells (Stangarone, 2021, IEA, 2020c). The current regulatory mandate under the RPS scheme requires electricity suppliers to supply a minimum of 10% of their electricity from renewable sources by 2023. Yearly obligation rates are reviewed and adjusted every three years.

Under the RPS scheme, electricity producers can meet their obligation rates by either generating renewable electricity or by purchasing Renewable Energy Certificates (RECs). RECs are traded in the electricity market operated by Korea Power Exchange (KPX), a quasi-governmental agency. KPX sets the total number of tradeable RECs available on the market each year depending on the amount and type of renewable electricity produced each year. Electricity producers who do not meet their obligation rate through purchase of RECs are obliged to pay a penalty of up to 150% of the weighted-average market value of their total required RECs.

A weighting system is used to assign a value to each tradeable RECs depending on the type and total amount of renewable electricity generated and represented by the REC. The weighting system improves the price competitiveness of advanced renewable technologies and mitigates over adoption of cheaper options. For example, hydrogen fuel cell electricity is assigned a weight of 2.0 and onshore wind is assigned a weight of 1.0.

In 2021, a review of Korea's Hydrogen Economy Law was proposed, including a proposal to establish a Clean Hydrogen Energy Portfolio Standards (CHPS) and a new national clean hydrogen certification system to promote fuel cell electricity generation (IPHE, 2022). The Korean government has also announced plans to assign higher weights to RECs for electricity generated using green hydrogen to promote green hydrogen.

[12] Before establishing the RPS scheme in 2012, South Korea had a biogas FIT scheme which paid a tariff rate of up to US$0.07/kWh for electricity generated using biogas between 2001 and 2011 (Koo, 2017).

Regulatory reforms

South Korea's 2019 Hydrogen Roadmap includes plans to revise regulations, including relaxing restrictions on approval processes for installation of hydrogen refuelling stations to encourage construction of refuelling stations. The following regulatory interventions have since been implemented:

- In 2020, South Korea introduced the Hydrogen Economy Promotion and Hydrogen Safety Management Law to provide a legal framework for supporting the hydrogen industry. In addition, a Hydrogen Economy Committee was established to oversee issues related to hydrogen industry promotion, distribution, and safety to fast-track review and approval processes for proposed investments
- South Korea's Green New Deal was developed in 2020 to relax regulations and make hydrogen-powered trucks and commercial vehicles eligible for subsidies with the objective of making all hydrogen vehicles eligible for state subsidies by 2025
- In 2020, South Korea's Ministry of Trade, Industry and Energy released its 5th Community Energy Supply Basic Plan, which includes policy measures to fast-track approval procedures for installation of fuel cell electricity facilities

RD&D support

The Korean government funds the following RD&D projects to develop renewable hydrogen technologies under its Hydrogen Industry Promotion Projects initiative:

- A US$10 million demonstration projects for a bespoke hydrogen production station powered by biogas from food waste (PetrolPlaza, 2022)
- A US$32.6 million Hydrogen Model City Project, which will develop a pilot city that uses hydrogen for cooling, heating, electricity, and transportation to create a Hydrogen Industry Cluster in the city of Ulsan by 2023 (FuelsCellsWorks, 2019)
- In 2019, the Korean government announced plans to invest $44 million in P2G technology projects (BusinessKorea, 2019)
- The Korean government have funded RD&D projects to support development of technologies for producing biomethane from organic waste from cities (IEA, 2020a)

Local government interventions

The following interventions by various local government authorities have also contributed to promotion of renewable hydrogen in South Korean:

- Local governments in South Korea provide a subsidy of 20% of the purchase price of a hydrogen passenger vehicle with the central government contributing 30%
- The city of Ulsan has supported the growth of its hydrogen industry by committing to set up 60 hydrogen refuelling stations by 2030
- The city of Daejon has invested in a Hydrogen Industry Life-cycle Safety Support Center for testing and inspecting various hydrogen equipment to improve hydrogen safety

Other interventions

In addition to the previously outlines measures, the Korean government has implemented the following interventions:

- RD&D support: In 2021, South Korea made a joint commitment to collaborate on a Clean Hydrogen Mission including funding green hydrogen RD&D projects (EC, 2021c). In 2019, the Korean government introduced its 'hydrogen cities' initiative to select three cities that will become pilot hydrogen-powered cities (AEA, 2020)
- Subsidies: In 2021, the Korean government allocated US$6 million towards constructing hydrogen fuel supplying facilities (MBN, 2021)
- Taxes: In 2018, taxes on imported gas were reduced by 80% and taxes for coal were increased by 30% (IEA, 2020a)

5.10 JAPAN

Japan's main policies for promoting renewable gas are:

- The 2017 Basic Hydrogen Strategy, which includes plans to increase the supply of green hydrogen as a strategy for enhancing energy security and reducing carbon emissions in electricity generation, transport, heating, and industrial processes (METI, 2017)
- The 5th and 6th Strategic Energy Plan, which list biomass, including biomass used for biogas production, as an important source of energy in its ambitions to diversify its portfolio of energy sources and enhance energy security (METI, 2018, EU-Japan Centre, 2021)[13]
- The 2019 Strategy for Developing Hydrogen and Fuel-Cell Technologies, which includes aspirations to increase the number of FCEVs to 800,000, fuel cell buses to 1,200, and hydrogen stations to 320 by 2025 (METI, 2019)
- The 2021 Basic Energy Plan, which sets a goal of increasing the share of renewable electricity to 38% by 2030 with hydrogen and ammonia accounting for 1% of the total electricity generation (Tsukimori, 2021)

The main policy interventions for achieving these policy goals are:

- FIT scheme
- FIP scheme
- Auction schemes for renewable energy projects
- Subsidies for green hydrogen projects
- International partnership programs

A description of each of these policy interventions is provided in the following sections.

FIT scheme

Japan's FIT scheme was established in 2012 to provide fixed government payments for electricity generated using renewable energy sources, including bioenergy (mostly solid biomass plants) over a fixed period. Under the FIT scheme, general transmission and distribution system operators, or TDSOs, are obligated to purchase energy generated from eligible renewable energy generators, or FIT generators, who are guaranteed to have all of their generated energy purchased at a fixed price by their registered TDSO over a period of 20 years. The FIT rate for biogas production is €0.31/kWh (EU-Japan Centre for Industrial Cooperation, 2021). Administration costs for the FIT scheme are funded by end users of electricity through renewable energy surcharges. In 2019, biogas producers with a combined total capacity of 85 MW were registered under the FIT scheme.

FIP scheme

The Japanese government introduced a FIP scheme for renewable power sources in April 2022 to allow renewable energy generators with a minimum capacity of 10MW to sell their electricity at a premium, on top of the wholesale market price. The average premium price for 2022 is US$0.01/kWh (Wakabayashi and Kawamura, 2022). Although eligible, biogas producers have not applied to participate in the FIP scheme to date because the average capacity of biogas plants in Japan is less than 4.5GW (EU-Japan Centre for Industrial Cooperation, 2021).

Auction schemes

Since 2017, the Japanese government has held competitive auctions for bioenergy projects. By October 2020, Japan had conducted two biomass auctions with average bid prices ranging from US$0.12/kWh to US$0.18/kWh (IRENA, 2021). Although eligible, biogas projects have not been contracted through Japan's renewable energy auctions because biogas producers have not submitted any bids to date.

Green hydrogen subsidies

Japan's 2021 Green Innovation Fund includes an allocation of US$3 billion to subsidise large-scale green hydrogen projects, including construction of large-scale biogas power plants to support green hydrogen production (Allen & Overy, 2021). The Japanese government has also allocated US$34.1 million towards provision of subsidies for the construction of hydrogen fuel stations at US$2 million per station (FuelsCellsWorks, 2021). In addition, Japan's

[13] Biogas currently accounts for 1.5% of biomass energy in Japan with most of its biogas used in electricity generation (EU-Japan Centre for Industrial Cooperation, 2021).

US$488 billion Stimulus Package includes budget for subsidies for RD&D projects focused on developing renewable hydrogen technologies (IEA, 2022d).

International partnership programs

Japan has established the following international partnership programs:

- The Australian Clean Hydrogen Trade Program was established in 2022 under the Australia-Japan Clean Hydrogen Trade Partnership. The total amount of joint investment between Japan and Australia under this program is US$104 million (DFAT, 2022)
- The Memorandum of Cooperation on Hydrogen between Japan and UAE includes a provision to support production and transportation of renewable hydrogen from UAE to Japan (METI, 2021)
- The Japan and Indonesia Cooperation Agreement on Decarbonization Technologies, includes a provision to promote low-carbon hydrogen production (IEA, 2022c)

5.11 CHINA

China's main policies for promoting renewable gas are:

- The National Development and Reform Commission, which includes ambitions to increase biomethane production to 1 billion GW equivalent by 2030 through incentivising replacement of coal with biogas in rural households (IEA, 2022b)
- China's 14th Five-Year Plan (2021-2025), which outlines aspirations to support green hydrogen production and to develop green hydrogen production technology (CSET, 2021)
- China's Medium and Long-Term Planning for the Development of Hydrogen Energy Industry (2021-2035), which includes plans for expanding green hydrogen production capacity to 100-200 kilotons by 2025 (Xu and Patton, 2022)
- The 2020 New Energy Vehicle Industrial Development Plan (2021-2035), which set a target for yearly sales of new energy vehicles (NEVs), including fuel cell electric vehicles (FCEVs) of 20% of total vehicle sales by 2025 (ICCT, 2021)

Policies for promoting renewable gas in China have mainly focussed on promoting use of hydrogen in the transport sector due to the rapid growth of the Chinese car market.

The main schemes for promoting renewable gas in China are:

- Biogas subsidies
- Subsidies for FCEVs
- RD&D support
- NEV Mandatory standards and credit score scheme

The following sections provide descriptions of these schemes. Some other interventions by provincial and municipal governments for promoting renewable gas in China are also summarised.

Biogas subsidies

China has subsidised development of biogas infrastructure, particularly installation of household biogas production plants, under its Economic and Social Development Plans since the 1970s (He, 2021). China's 2003 National Rural Biogas Construction Plan set the subsidy value at US$117 per household per plant, or 33% of the total costs of installation. In addition, provincial and municipal governments have provided subsidies of up to US$234 per household to cover the cost of building materials and technical assistance (Energypedia, 2022). Between 2003 and 2007, China's total budget for subsidies for biogas plant installation was US$519 million (Gu et al., 2016). In 2007, the National Development and Reform Commission published the Medium and Long-Term Development Plan for Renewable Energy, which included providing a subsidy of US$149 per household per plant. Between 2001 and 2010, a total of US$2.7 billion of central government funds were invested in subsidies for biogas plants for rural households (Zheng et al., 2020).

In 2015, the central government of China suspended provision of subsidies for household biogas plant installations and replaced it with subsidies for construction of large-scale biogas plants and RD&D projects (Zheng et al., 2020).

Subsidies for FCEVs

China established its New Energy Vehicle Policy in 2009 and revised it in 2012 to focus on incentivising uptake of NEVs, including FCEVs, through providing subsidies. Specifically, the central, provincial and municipal governments provided subsidies of US$29,873-US$74,682 per vehicle for purchasing a FCEVs with a minimum capacity of 30kW. (CSIS, 2022).

The NEV subsidy program for FCEVs was phased out in April 2020 and was replaced by subsidies for RD&D projects in 10 pilot cities aimed at developing fuel cell technology.

RD&D support

The central, provincial, and municipal governments in China have funded RD&D projects for developing biogas technology since late 1990s. In 2009, China funded RD&D projects through subsidies of up to 45% of the total project cost. In 2010, the total budget for biogas RD&D projects was US$746 million with a focus on developing the construction technology for medium-to-large biogas plants. Between 2015 and 2017, the central government funded 65 biogas RD&D projects and by 2018, 34 large-scale biogas plants and 6,737 large-scale biogas plants were constructed (Zheng et al., 2020).

In 2020, China introduced a reward-based scheme to accelerate regional hydrogen demonstration projects in city clusters with a focus on funding RD&D projects aimed at addressing impediments to uptake of FCEVs. Under this scheme, successful municipal governments will get up to US$245 million in subsidies to fund RD&D projects to develop FCEV technology by 2023 (CSIRO, 2022a). By May 2021, 35 projects related to fuel cells, FCEVs and hydrogen refuelling stations worth a total of US$17 billion were approved (Recharge, 2021a).

In addition, provincial and municipal governments provide subsidies to support businesses that produce, transport, and distribute hydrogen, particularly hydrogen refuelling stations, to reduce the price of hydrogen and increase uptake of hydrogen-powered vehicles (CSIRO, 2022a).

NEV mandatory standards and credit scheme

China implements a credit scheme that requires vehicle manufacturers and importers that sell more than 30,000 vehicles per year to meet a mandatory NEV credit requirement under the New Energy Vehicle Policy. NEV credits are calculated and assigned to every passenger vehicle produced or imported in a year depending on the type of energy used and energy use efficiency. FCEVs with an electric range of more than 350km are assigned a maximum credit score of 5.0 and fossil vehicles are not assigned a credit score (DieselNet, 2022).

In 2022, the NEV credit requirement was specified at 16% of the total number of fossil fuel vehicles produced or imported in 2022 (Argus, 2020). Vehicle manufacturers and importers with an NEV credit deficit can buy NEV credits from manufacturers and importers with surplus NEV credits to meet their NEV credit requirements.

Other interventions

In addition to the previously outlined schemes, the following interventions have also been implemented by the central, provincial, and municipal governments:

- Increasing electrolyser capacity: the China Hydrogen Alliance has set a target of 100-GW electrolyser capacity by 2030 to increase production of renewable hydrogen
- Provincial policy interventions: 15 provincial governments have announced plans to install hydrogen refuelling stations, develop P2G technologies and blend hydrogen into the gas grid (CSIRO, 2022a)
- Decarbonised heating: China aims to phase out sales of coal and oil stoves and boilers and gas heating appliances that are not compatible with hydrogen power by 2035. Other provincial governments have also announced similar plans (e.g. Northern China's Clean Heating Plan) (IEA, 2022b)
- Decarbonised hydrogen: China is investing in retrofitting Carbon Capture, Utilisation and Storage technologies in existing fossil-based hydrogen production plants (IEA, 2022b)

Disincentivising coal: China's 13th Five-Year Plan (2016-2020) established a 900 GW, or 15%, cap on the share of coal-fired electricity and imposed a nationwide coal tax of 2-10% to promote renewable energy, including renewable gas (IEA, 2022b).

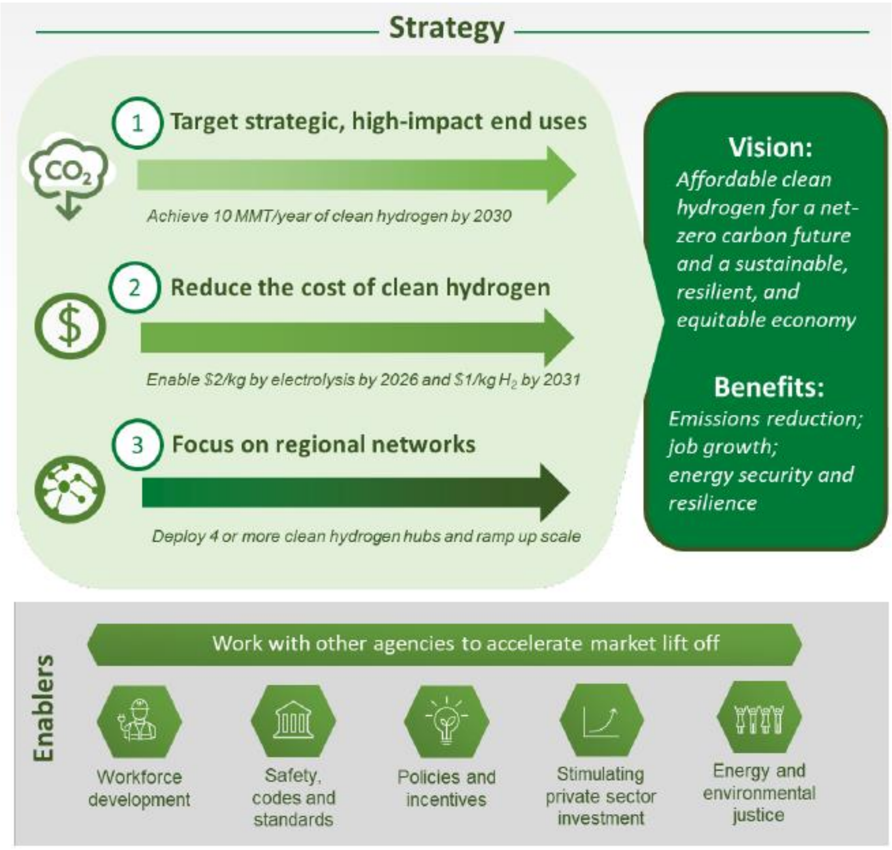
5.12 UNITED STATES

The United States' key emission reduction goals are:

- a 50-52% reduction in emissions from 2005 levels by 2030
- 100% carbon pollution-free electricity by 2035
- net zero GHG emissions by 2050 (Department of Energy 2022)

The National Clean Hydrogen Strategy and Roadmap of 2022 (the Roadmap) aligns with the national emissions reduction goals. The main objective of the Roadmap is to ensure that clean hydrogen is developed and adopted based on three key strategies, including targeting high-impact end-uses, lowering the cost of clean hydrogen and focusing of existing regional distribution infrastructure networks (Figure 5.1).

Figure 5.1. The national strategies for clean hydrogen and the Department of Energy's Hydrogen Program mission and context



Source: DOE (2022)

Specifically, clean hydrogen adoption will focus on hard-to-decarbonise industries with limited options under the Roadmap, developing electrolysis capabilities, optimising on availability of resources such as waste, water and other resources across regions, and minimising transport and infrastructure costs and local economic benefits by developing hydrogen hubs.

The main initiatives under The National Clean Hydrogen Strategy and Roadmap include:

1. Two active projects to jumpstart the use of hydrogen for steel manufacturing, with the potential for 5,000 tonnes per day of steel production
2. Several analyses to assess the cost and life cycle emissions to produce hydrogen carriers, including methanol, ammonia, and methylcyclohexane
3. DOE's HyBlend initiative was launched in 2020 to address knowledge gaps in blending hydrogen in natural gas, bringing together DOE National Labs and industry
4. The world's first trigeneration system at a wastewater treatment plant to co-produce power, heat, and hydrogen through a high-temperature fuel cell

The Infrastructure Investment and Jobs Act (IIJA), also known as the Bipartisan Infrastructure Law (BIL), was signed by President Biden on November 15, 2021, to deliver a more equitable clean energy future for the United States. In addition, the Inflation Reduction Act (IRA) was signed into law in August 2022, providing a Hydrogen Production Tax Credit to incentivise the production of clean hydrogen.

The Inflation Reduction Act

In August 2022 the Inflation Reduction Act (IRA) was signed into law by President Biden. The IRA seeks to reduce inflation by reducing the deficit, reducing prescription drug prices and promoting clean energy. It seeks to promote the development of clean energy supply chains by incentivising RD&D and production of renewable energy and renewable energy storage technologies (IRS, 2022a). Under the IRA, US$391 billion of federal funding has been allocated towards various clean energy promotion programs across the US, including awarding tax credits, grants and loans to accelerate investments in renewable energy technologies to reduce carbon emissions by 40% by 2030 (McKinsey, 2022).

The IRA has introduced tax credits to support nascent climate technologies like energy storage and green hydrogen.

The majority of the IRA funding (US$251 billion) has been allocated towards provision of tax credits, with producers and consumers of alternative fuels such as renewable biogas and hydrogen eligible to claim up to US$0.50 per gallon in tax credit from January 2023. Capital infrastructural investments in renewable electricity, including electricity produced in landfill biogas facilities and with renewable hydrogen (except liquefied hydrogen), will also be eligible for tax credits and loans (IRS, 2022b). Generators of zero carbon electricity will be eligible to claim up to US$30 per Mwh and renewable hydrogen producers can claim up to US$3 per kilogram from January 2024. The IRA also provides up to US$7,500 tax credit for electric vehicles purchased after December 2009.

A total budget of US$30 billion has been allocated towards grants and tax credits that will be awarded to electric utilities to support renewable electricity generation, including use of renewable hydrogen technology and electricity storage for intermittent renewable sources.

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6. Stakeholder perspectives

- There were diverse views regarding the desirability of a RGT, with some stakeholders supportive, some opposed and some agnostic
- Stakeholders could see a number of possible objectives for a RGT including: emissions reduction, development of a renewable fuel supply chain, energy security, development of the hydrogen export sector and as a support to electrification
- Stakeholders had varying views on the role of gas going forward: some believed that electrification is the main mechanism to decarbonise gas while others thought that renewable gas is important
- Many stakeholders did not express about the desirability of a Renewable Gas Target or were agnostic, while some were in favour most commonly on the grounds of developing and proving the technology.
- Stakeholders raised a number of issues with a RGT and a renewable gas transition more generally such as gas price issues, institutional arrangements, scope of the RGT, equity issues and concessions and efficiency considerations
- Opponents of a RGT believed either that electrification is the path to emission reduction or that existing gas users would be able to continue their current practices long term
- Supporters of a RGT believed that there are substantial gas uses that cannot be met with electricity and that development of a renewable gas supply chain at competitive cost is therefore necessary
- It will be important to engage deeply with a wide cross section of stakeholders to help them better understand the RGT policy options available (including not proceeding with a RGT) and also other complementary policies that have the ability to most effectively develop the Australian renewable gas market

We carried out consultations with industry, consumer and government stakeholders to identify their experiences, concerns and insights on the use of RGT-type mechanisms in the Australian gas supply sector. The consultations were exploratory, intended to alert us to the range of views held by parties affected in potentially different ways by a RGT. They were not designed to estimate the prevalence of particular views in the population or sub-populations. Nor did we seek formal organisational views, although naturally the individuals that we spoke to were influenced by organisational perspectives.

This section summarises the views put to us by stakeholders during consultations. We completed interviews with 21 stakeholder organisations with a wide range of perspectives. The profile of respondents was: 5 networks, 2 retailers, 5 State Government agencies, 2 Australian Government agencies, 2 potential producers of renewable gas, 4 gas consumers/representatives and 1 appliance manufacturer.

Stakeholders for the consultations were selected with the aim of providing a diverse range of opinions. We aimed for individuals who were likely to have insight into at least some aspect of the renewable gas supply chain and those affected by it. There was no attempt to select a representative sample of any particular population—indeed it is unclear what that population would be.

We are very grateful to those who provided their time to speak with us. They helped us to a wider and deeper appreciation of the issues that people see as important. We made a commitment to participants to treat their comments as confidential and consistent with this we have not identified the participating individuals.

6.1 DESIRABILITY OF A RENEWABLE GAS TARGET

Many stakeholders did not express a view about the desirability of an RGT or were agnostic. Some stakeholders were in favour, most commonly on grounds of developing and proving the technology.

> *"Complete electrification is not feasible. Investing in infrastructure to support hard-to-abate gas-dependent energy-intensive industries would enable decarbonisation of those industries where electrification is not feasible."*

On the other hand some consumer representatives were opposed or very sceptical.

> *"The agenda for an RGT is motivated by stakeholders with a vested interest in sustaining distribution networks that would be stranded under electrification … The role for policy is stopping new expansions and encouraging gas consumers to switch to electricity through subsidies."*

“I have no particular interest in paying a levy to extend the life of an asset of a gas supply company if that's not an efficient way of me transitioning”

“I I'm very skeptical of the value and the merit of blending generally and that certainly when it comes to hydrogen … what we're talking about is ultimately is substituting … up to 10% of the volume, not even the energy that's in the gas network currently. And then there's no real way to just sort of slowly ratchet that up. You kind of get to that 10% and you're stuck there and your next jump is you've got to go to 100. Really, unless you wanna get people to start changing their appliances every few years, which is just unrealistic.”

Several stakeholders who were opposed suggested that electrification is the path to net zero for the gas sector.

“our view is that you shouldn't be setting a renewable gas target. You're effectively creating a market for a product that doesn't exist. Our view is that you should be setting a decarbonization target for gas … basically you would electrify … the gas sector … and when I'm talking about the gas sector, I'm talking about the low pressure, household, distribution networks, is dying.”

“Our view is that you should be setting a decarbonisation target for gas … basically you would electrify.”

6.2 THE PURPOSE OF A RENEWABLE GAS TARGET

Five objectives for a RGT were identified by stakeholders:

- emission reductions
- developing a renewable gas supply chain in the domestic market
- energy security
- building the hydrogen industry for export
- supporting a transition from gas to electricity for distribution network customers

Some of these may overlap.

what we're seeing across the states is that the issues here potentially cut across a number of different focuses of interest: emissions, energy security and just sort of general sort of cost issues around energy plus then also state development issues … around hydrogen industries as well”

“Strategically, safeguarding energy security by improving affordability, reliability and sustainability of energy. Operationally, creating financial incentives for specific activities, e.g. green hydrogen production. Also supporting industry and economic development to overcome market failures arising from large up-front capital expenditures to change the supply chain.”

Emissions reductions

Stakeholders noted that renewable gases have zero or near zero emissions and, since they replace fossil fuels in the gas mix, they will reduce emissions from gas consumption.

“We would just think about emissions reduction as the sort of overarching objective here”

“You can electrify the gas supply, you can use carbon offsets, or you can also introduce renewable gases.”

“one would be the emissions reduction objective, to rely on … renewable gas rather than natural gas, probably as the primary one”

Developing a renewable gas supply chain in the domestic market

A number of respondents see a RGT as a measure to encourage development of a renewable gas supply chain in the domestic gas market. Respondents emphasised the need for a complete, joined-up supply chain if end customers are to access renewable gases. Supply chain discontinuities were seen as particularly acute for those supply chains that include the gas networks (in contrast, for example some developments may involve consuming renewable gas at the point of production, thus obviating the need for gas network services) .

“you're trying to commercialize certain supply chains or ...specific types of technology ... it's about trying to achieve this market transformation with a particular type of technology … part of it is also trying to address market failures like you get with energy efficiency … like your split incentives and up front capex and all that sort of stuff … that’s what the financial incentive is attempting to achieve”

"And so I think if you were to say what is the objective of renewable gas target, it's to give the market the incentives and confidence for supply chain to be established to start to resolve the transition of the gas system in parallel to the electricity system"

"the challenge with hydrogen at the moment is the overall economics of it and getting production at scale and something that can you know is competitive with other alternative fuel sources … a renewable gas target can bridge that gap or help accelerate the technology development that enables reduction in costs and improve the competitive [position of renewable gas] … the benefit of the renewable gas target is it kind of kicks the process along a bit."

Some respondents said, in the context of Australia's net zero goal, that the development of a renewable gas supply chain is particularly important for gas-dependent industries which do not have an electrification alternative. In the absence of a renewable gas supply chain they may need to cease operations, install costly technologies or source offsets.

"Offsets are going to become more and more competitive with really difficult to decarbonize sectors such as some industrial processes."

"with the new Australian government's policy on the Safeguard Mechanism…It's not quite a carbon tax, but there's a strong financial incentive as part of that design for industry to reduce its gas use…they will be looking to make emissions reductions so that they're not forced to buy ACCUs or something else to offset that."

"the primary objective of a renewable gas target is to introduce renewable gas into the market and the secondary benefit would be once you get that renewable gas at large scales, you really get into emission reductions. But the initial stages would be just to get the technology into the market" [0:7:15.510]

Energy security

Some respondents see the development of a renewable gas supply chain as supportive of energy security.

"the idea of … locally produced renewable gases is quite attractive from an energy security perspective"

"we don't produce natural gas in New South Wales, so it doesn't surprise me that from an industry and fuel security point of view, they've gone 'it would be good to have some actually made in the state'*".*

"the gas system and the electricity system bolster each other and there's an increased ability for that to occur in a renewable gas/renewable electricity world is definitely there … as we move towards the energy security conversation, the ability to fuel our nation on hydrogen rather than imported petroleum, I think is a very important conversation we're having especially right now"

"its about supply security of energy as well … we're already seeing that supply security issue play out in the market today … and if you can decarbonise gas, that's gonna be the most effective from a price perspective as well as an energy security perspective for our supply of energy domestically"

Building the hydrogen industry

A number of respondents said that a renewable gas target could be seen as a mechanism to bring the renewable hydrogen industry to scale with a view to its role as an export industry.

Orderly transit of gas customers to electricity

One respondent said that an RGT could be useful as a mechanism to contain emissions while households and small customers transition from gas to electricity.

6.3 DECARBONISATION AND A RENEWABLE GAS TARGET

Electrification and its limitations

There was wide variance in respondents' views on the degree of electrification that will be needed to achieve Australia's emission reduction goals.

Several respondents, especially from government and end user organisations, envisage a scenario in which household and commercial gas users all transition to electricity over time. The distribution networks cease to operate. Only a minority of industrial gas users continue to use gas.

In contrast, several respondents envisage a future in which barriers to the adoption of renewable gas on the distribution networks are overcome, and households and commercial customers turn to renewable gas in place of fossil-fuel gas.

Most respondents agreed that there would be some sectors that will have an ongoing need for a combustive fuel like natural gas and that renewable gas could be the path to decarbonisation for these energy users.

> *"some roles for gas, for example its use in industrial processes or in high industry heat can't easily be replaced with an electrical alternative so you need to continue providing that through a gaseous fuel … decarbonising that gaseous fuel with renewable gas allows those processes to continue operating and heat to be supplied to them but with whilst reducing emissions at the same time."*

Emission reductions from biomethane and green hydrogen

Some respondents said that biomethane can only make a limited contribution to decarbonisation. They said that there is not enough biomethane to replace prospective fossil-fuel gas consumption going forward.

> *"the problem with biomethane is … even if we got every last bit of it … it's really not going to satisfy the levels of demand"*

Delays to electrification

Some respondents mentioned a risk that an RGT could delay decarbonisation.

> *"Governments should commit to investigations and not schemes because investigations may reveal that an RGT may distort the market and slow down the broader decarbonisation agenda"*

> *"You might delay people switching to a low lower carbon alternative … [a] perverse outcome might be that … [it] in some ways slows down the trajectory to net zero."*

Some respondents emphasised that an RGT's contribution to net zero will be most effective if it is part of a clear long-term plan that allows affected parties time to adapt.

6.4 TECHNICAL CONSIDERATIONS

Safety impacts

Some respondents touched on the issue of safety challenges. The introduction of renewable gases to networks, and especially hydrogen, would bring with it new safety challenges.

> *"biogas is probably more realistic than hydrogen … we know how to manage the safety around that … and you don't have to do too much rejetting of appliances"*

Some respondents expressed a high degree of confidence in the networks' ability to integrate hydrogen safely, albeit at a cost. Supplying gas to high safety standards was seen as a core capability and cultural attribute in the industry.

> *"From a safety point of view I don't see any risk at all because we are one of the safest infrastructure industries in the world. We have a track record of managing composition … I don't see there being actual increased safety risk for anyone "*

Network limitations

We heard mixed views on the capacity of pipelines to transport hydrogen.

Some respondents with a network perspective said that there are parts of the distribution network which would require only modest work to adapt for hydrogen.

> *"a lot of work that's been done around networks around the country has been to upgrade them to modern plastic networks, and they're fully capable of handling 100% hydrogen. There are some parts around the network which will need to be upgraded … some of the seals, some of the valves, some of the metering … the actual physical distribution network is now ready to handle 100% hydrogen. The pipelines probably different story, but from a from a distribution side, the networks are technically ready to handle 100% hydrogen."*

> *"Most of our pipes have been upgraded within the last sort of 10 years. So they are relatively compatible with 100% hydrogen and we would just have to upgrade a few more if we want to do the whole network,"*

But some customer representatives thought the challenges were more substantial.

> *"there's no way we're gonna waste capex on making a DNSP [distribution network service provider] 100% hydrogen viable … yeah, you can stick 10% in, but you know beyond that you run into problems."*

Appliance compatibility issues

Respondents said that biomethane that is processed to network purity standards presents no issues for appliances. From the point of view of the operation of appliances, it makes no difference whether the methane molecule comes from fossil-fuel reserves or is from biological processes.

One respondent in the appliance manufacturing sector said that their own preliminary tests indicate that most and possibly all of their current mass-produced models can operate effectively with hydrogen mixes above 20 per cent. They have not investigated the hydrogen compatibility of their older models in the installed appliance stock.

One respondent in the appliance manufacturing sector said that retrofitting appliances to raise existing limits on hydrogen content is likely to be costly. Replacing burners and control mechanisms in existing small appliances in residences and commercial appliances would be impractical and prohibitively costly. Adapting larger scale bespoke appliances—e.g. swimming pool heating systems, furnaces—would also be very challenging in many instances, not least because of the need to reassess burner designs and configurations case by case. The growing use of software for appliance control further complicates any attempts at retro-fitting.

One respondent in the appliance manufacturing sector said that with adequate advance warning—several years—hydrogen-using mass-produced household and commercial appliances could probably be brought to market with little or no cost premium over natural gas models. With enough time, hydrogen appliances can be designed, parts sourced, software adapted to the needs of the fuel, safety checks carried out, installation protocols prepared, approvals secured, etc. in an efficient and effective way. The problem arises when existing models have to be reconfigured to different specifications on short notice, as has sometimes been required in response to regulatory changes.

6.5 GAS PRICE IMPACTS

Short term

Respondents generally thought that the short-term impact of an RGT would be to increase gas prices, with the economic incidence of the subsidy to renewable gases passed on to gas consumers. But with a small renewable gas proportion, the price impact could be small.

Long term

In one view, an RGT increases gas prices in the future, therefore promoting a migration of customers away from gas to electricity. Customers who find electrification difficult or impractical remain as users of gas. The price impacts of the RGT are then amplified: network charges must then be recouped across a smaller customer base, leading to further increases in prices. In the end result, there is a smaller gas customer base facing higher prices. This dynamic of price feedbacks from a shrinking customer base is colloquially referred to as a “death spiral”.

> *“You know, at the end of the day if this target is brought in and it increases gas prices to households further … It's only going to accelerate the train. People just go,* ‘I've had enough. I'm not paying this … anymore. I've just had an electrician in who's just told me I can halve my energy bill by going electric.’*”*

> *“ if we were to do something that where there are some costs that sit on gas and not sitting on other energy types, even if they have emissions associated with them, it will push people off gas and potentially a little sooner than otherwise would have, and that might start something of a death spiral in spreading those costs across fewer and fewer of the remaining customers.”*

Some respondents put forward an alternative view, in which the RGT supports the use of gas, and consequently mitigates against a migration away from gas, so that there is no “death spiral”.

Stakeholders mentioned a number of factors that they see as important in determining gas prices in the long-term. How much can green hydrogen production costs be reduced? What additional network costs might be incurred? Can appliance compatibility issues be resolved? How much “thinning” of the customer base as a result of electrification? What view will economic regulators take on adapting the gas networks for renewable gas?

6.6 INSTITUTIONAL ARRANGEMENTS

Legal incidence of the RGT

Should the liability to fulfill a renewable gas target be on retailers or networks? None of the respondents endorsed imposing an RGT at the network level (as is seen in some overseas schemes).

A network representative said that placing the liability on networks is inconsistent with the existing market structure.

"you're actually then tinkering with the actual current commercial framework … the way that the commercial framework works at the moment is that we don't own gas … we only procure gas for our losses … so the idea of us even being gas buyer is a bit silly … economically inefficient if you ask me"

and

"there is a market already created for the transactional ownership and responsibility for procuring the commodities … [and] there's a clear market for the transportation and management of those commodities through the system to deliver it in the same quality and reliability."

and

"it tinkers at the edges of your current market structure, which is unnecessary …it's not as if you've got hundreds of gas retailers in Australia … the idea of having a renewable gas target imposed upon retailers or major users who are self-contracting users is quite a simple thing …so the transactional payload, the transactional cost, is quite small … they've got systems in place already to trade and manage those things"

Some alluded to the fact that they buy a physical gas supply for delivery

"I'm a wholesale participant, so I physically buy gas, it gets delivered physically at particular points, and then it gets transported to our plants. So that's unlike electricity"

Certificate scheme

Most respondents envisaged an RGT as a certificate-based scheme. The fact that Australia's MRET is certificate-based was probably influential in this respect.

"the RET is a nice easy comparator because we get how it works in terms of, you know, certificates and trade and obligations on retailers, all those sorts of things. It's a nice, well known beast"

However, it was also said that a RGT would require attention to challenges that did not arise with the MRET:

"there are some difficulties applying that straight model to gas given that we're dealing with molecules, not electrons … electrons are … generic. Whereas molecules … you could have methane, hydrogen or some mixture of other gases"

Other mechanisms to promote renewable gas

Respondents were sceptical about a model in which networks directly purchase renewable gases to satisfy a renewable fraction.

In some overseas models there is a single vendor of gas off the network. The separation into retail and transmission/distribution roles in Australia is not in place. In this case a renewable target is simply imposed at the system level without certificates. Respondents thought that this model was not well suited to the Australian model, which emphasises competing retailers purchasing gas (fossil-fuel and renewable) and paying networks for transport services.

Some respondents said that fiscal support to develop green hydrogen should be on-budget

" if the Commonwealth or States want to try and promote a hydrogen production industry using renewable energy do it through direct grants. I mean that is the most effective way because for decades Australians, electricity and gas bills have been used as a quasi state tax system to fund projects"

National or State schemes

There was a widely held view that a national RGT scheme is likely to be better than State-based schemes. It would likely be more supportive of lowest-cost sourcing and minimising implementation, administration and compliance costs. It would diminish arbitrary differences in operating environments that confront organisations that operate across jurisdictions.

"we're involved in some of the national gas law changes to accommodate hydrogen … there's a strong push from industry. They'd prefer consistency across the states in the regulatory and probably subsidy framework as opposed to every state doing their own thing. That's consistency is definitely being pushed for by industry and government … the people sitting around the table are definitely saying consistent regulatory framework is probably best for everybody."

Numerous respondents made the point that, regardless of what is in principle the best approach, the States are actively involved in developing their industrial bases, reducing emissions and securing energy supplies, and they will retain these interests. It was noted that they have also been more active than the Commonwealth in the pursuit of renewables.

Ideally, a national scheme should probably be preferred … But I think politically, just getting it started in individual states would probably be a better option because I think we may get that off the ground much quicker. Getting a uniform national scheme will need to be signed off by all the industry ministers and some of those are quite opposed to renewable gas. So I think pushing it through individual state schemes would be the best option."

A few respondents said that, with a developing technology and market structure, there may be some advantages from having individual States experiment with their own policy designs.

"it's difficult to get any kind of agreement from various governments across the country on what the right approach is … and that that provides its advantages as well. There are some upsides to that because you test different ideas and concepts and you can work through the pros and cons"

6.7 ROLE OF REGULATED NETWORKS

A number of respondents thought that networks should maintain their position as deliverer of gas and should not be directly involved in the sourcing of renewable gas.

One respondent noted that the networks could potentially buy renewable gas to meet their obligations to replace "lost gas". It was noted though that the lost gas fraction is small, at just a few per cent, and the aspiration is always to drive it lower, so there would only be limited scope to support renewable gas development.

Some respondents noted that the networks have a leadership role in the evolution of the supply chain by virtue of their prominent role. It was said that at present an attempt by a network to finance pilot renewable gas facilities could fall foul of its exclusion from gas production/retailing functions. There is also a question as to whether economic regulators would allow any costs for pilot activity.

6.8 INTERACTION WITH OTHER SCHEMES

A number of respondents noted the importance of taking into account existing renewable gas and emission initiatives. Otherwise, there is a risk of building in perverse incentives that slow or prevent transitions to optimal renewable energy sources.

The Safeguard Mechanism

Some respondents were concerned about the juxtaposition of a RGT with the Safeguard Mechanism. Would requirements under an RGT be additional to those under the Safeguard? Would they receive credit, either in the RGT or in the Safeguard?

"you need to look at what's happening with the Safeguard Mechanism and where that policy work (review of the Safeguard] is going … my main concern would be that you don't impose almost double burdens on these industries so that they're required to reduce their emissions under that and purchase certificates or whatever for renewable gases. You want them to have some form of mutual recognition …but I don't know you need an entire carve out necessarily"

Voluntary emission reduction efforts

Some respondents noted the role played by voluntary schemes to reduce emissions in Australia. It was said that these schemes have contributed to emission reductions. It was acknowledged that some, but not all, schemes have integrity problems, and it was suggested that regulatory responses to the Chubb Review are likely to resolve some of these problems.

An RGT would need to be cognisant of these integrity issues: one would not want to see retailers selling a renewable gas component that is required of them as an additional "green" product to customers.

"the approach with the renewable gas certificates is … that you know there is the actual renewable gas being produced and put into the gas networks. So that protects us a bit from some of those risks around people seeing it as not doing anything. But the additionality question remains as in how many projects would have come online anyway and what is the difference I'm making with doing that voluntary purchase. But at the moment in renewable gas, we're at a stage where there is no market and we really just need to get it going"

Respondents said that voluntary emission reduction schemes have the potential to reduce emissions further than would be achieved by existing regulatory mandates alone. To the extent that an RGT displaces surplus voluntary reductions then its benefits to net zero will be smaller.

Respondents emphasised the importance of proper accounting mechanisms to support voluntary schemes—for instance to support the issue of certificates and process their surrender—and said that the same issues arise with an RGT.

6.9 ELECTRICITY-GAS INTERACTIONS

Electrification

Electricity and gas are substitutes for each other in the final energy mix. The fundamental question for the gas supply industry going forward is the extent of "electrification". Electrification is, in large part, the replacement of gas and petroleum products by electricity. Numerous stakeholders believe that electrification is the best path to decarbonising gas.

> *"I would have probably an inherent bias to say that it is more efficient to electrify things than to continue using gas things with renewable gas, but that might be quite wrong"*

Respondents noted that there are also complementarities between electricity and gas. Gas and renewable gas have a potentially important role in electricity firming. Electricity, and especially renewable electricity, has an important role in the production of renewable gas.

It was noted that electricity generated from locally-sourced biomethane is credited as renewable in the RET. But if a generator purchased biomethane and had it fed into the network, then took gas from the network for generation, it would not be credited as renewable under the RET. This creates an incentive to use biomethane without the use of the network., and it may have contributed to a pattern whereby biomethane is used for generation in small-scale and relatively inefficient generators.

> *"There is no supply chain for renewable gas yet … There are mature technologies in biomethane production but with no established market mechanism for customers to recognise in the absence of an RGT. As a result, renewable gas molecules are converted to electricity just because there is a RET even when renewable gas would be most efficiently used to displace natural gas"*

It was noted that under the NSW Hydrogen Scheme some of the costs of supporting hydrogen developments are effectively placed on electricity consumers. The scheme allows hydrogen producers to transmit electricity at zero cost under some circumstances. Since the hydrogen does not contribute to the transmission networks regulatory revenue, that revenue must be met from other customers. It was suggested that the structure of the exemption limits the free transmission mainly to situations when there is excess network capacity, in which case the electricity-for-hydrogen load might be construed as simply using spare capacity without much additional burden on existing electricity consumers.

Some respondents were concerned about potentially anomalous treatments across electricity and gas.

> *"Renewable gas does not operate in isolation, we should have a means of supporting electrification in sectors where switching to renewable gas would be cost ineffective."*

Some respondents pointed to an inconsistency in the support given to renewables in the electricity and gas sectors. It was said that renewable electricity had received major development support over a long period through the Renewable Energy Target. But renewable gas has not had commensurate support. Policy makers should not fall into the trap of assuming that renewable gas has no widespread prospects. Cost and operability improvements in renewable electricity have vastly exceeded expectations over recent decades and there is a potential for renewable gas to do the same.

6.10 SCOPE OF THE RGT

What gases should be in scope?

Far the most often mentioned renewable gases were biomethane and green hydrogen. Some respondents mentioned ammonia as a hydrogen derivative and synthetic methane.

Some respondents were of the view that all renewable gases should be eligible. Others felt that the scheme should be targeted, e.g. at green hydrogen when the purpose of the scheme is to build a supply chain for green hydrogen. Responses to this question varied according to views about the objective of the scheme.

> *"Let the market decide. All options should be considered as long as they are technically feasible and safe."*

> *"If the objective is to decarbonise the network, renewable biomethane should be considered."*

One respondent flagged the importance of biomethane in the near term as the production technology

> *"We would definitely prefer a short term target with biomethane if investment was flowing through to that area, just because of the network asset upgrades you need for hydrogen, and it would just make it a lot more of a low regrets cheaper option in the short term"*

Some respondents argued that the scheme should be open to blue hydrogen, either subject to some threshold of emissions capture or with a credit based on the fraction of emissions reduction.

> *"90% decarbonised hydrogen, for example from 90% emission capture after accounting for leakages, can be assigned certificates with a commensurate value equivalent to 90% of the value assigned to green hydrogen certificates."*

One respondent argued that grey hydrogen (hydrogen from fossil fuel sources without capture) should be allowed in a transition so that adapting the gas network to hydrogen is not delayed waiting for green hydrogen. One respondent said that an RGT should be open to pink hydrogen (hydrogen from nuclear-generated electricity). Most respondents thought that only green hydrogen should be in scope, in some case because they believed that there is little prospect of a true blue hydrogen product.

Most respondents thought that biomethane should be in scope on the grounds that it has net zero emissions (or better) under defensible carbon accounting mechanisms.

One respondent argued that renewable synthetic methane does not receive the attention that it should:

> *Renewable synthetic methane. When I say that, I'm referring to methane produced through the process of methanation of renewable hydrogen and atmospherically acquired CO2, CO2 acquired from the short carbon cycle … it's a mature technology. People aren't talking about it and that frustrates the hell out of me personally. But the thing that really needs to be done for an Australian context is we need to get someone to do a genuine techno economic analysis on it relative to hydrogen so that we can start asking the question: Is it more cost effective to methanate or to change the infrastructure and customer appliances?"*

One respondent was concerned that the inclusion of biomethane might delay the development of green hydrogen as it is an easier option.

Which producers should be in scope?

Most respondents thought that renewable gas producers who supply into the gas networks should be in scope. This was related to the common view that the purpose of the RGT is to build the grid-delivered renewable gas supply chain.

One respondent raised the concern that if an RGT promotes localised production of renewable gases, especially behind the meter, it could exacerbate stranding risks for some pipeline assets.

> *"Incentivising onsite production of hydrogen could lead to large amounts of stranded natural gas infrastructure assets"*

An alternative view is that support could be provided to any renewable gas producer which displaces fossil-fuel consumption. In this view, renewable gas produced and consumed behind the meter in electricity firming, or for some industrial applications, or in transport, could be included. However, there was only limited support for this idea.

Which gas consumers should be in scope

Most respondents thought that if there was to be an RGT requirement it should apply to consumers of gas from the grid. This view was related to the idea that renewable gas would be supplied into the grid, that consumers of gas from the grid were the beneficiaries of the renewable gas, and therefore they should pay for it.

A smaller number of respondents thought there was a case for imposing the RGT on all domestic consumption of gas, both on-grid and off.

> *"The RGT should apply to all domestic gas"*

Another respondent said that incentivising the input of renewable gas into the grid in preference to off grid might impact the availability of renewable gas for heavy industry that needs it.

> *"The New South Wales Renewable Fuel Scheme is trying to set up a new hydrogen sector and provide a decarbonization pathway for hard to abate sectors, knowing that biomass may not be sufficient for a lot of that and so decarbonising heavy transport, decarbonizing industry like fertilizer production and ammonia and explosives, all those chemical processes will need a feedstock … do we design the target in a way that*

it doesn't need injection into gas networks … It enables it, allows it, but it doesn't have to be. And how much better is the outcome if we do that"

Those with this view noted factors such as the equity of sharing the burden of renewable industry development across all gas users, neutrality of incentives for consumption on- and off-network, and pursuing a broad support base to keep the per customer cost burden associated with an RGT as low as possible.

"[if industrial users are exempted] residential users could end up cross-subsidising industrial users who would also benefit from the upgrades"

"under the NSW Renewable Fuel Scheme, a hydrogen tax was introduced, and a tax was levied on gas users, but there were other beneficiaries of new gas coming into the network to meet the target and gas users perceived the RFS as inequitable"

There was some uncertainty regarding the appropriate treatment of gas fired generation. Some respondents thought that it would be inconsistent for gas generators to be in or out of scope simply by virtue of being connected to the networks or not. Respondents also noted the need to take into account regulatory and other frameworks specific to the electricity-sector that could impact on the gas mix.

Respondents were generally opposed or agnostic about including gas exports in the RGT. Several respondents suggested that it was inconsistent with current emission accounting frameworks for Australia to seek to target emissions overseas. One respondent said that if the hydrogen would benefit from the industry development support provided by the RGT than that might be a case for including it. One respondent suggested that the revenue base provided by gas exports is so large that its inclusion could help to keep any imposts on the unit cost of gas low.

Actual delivery versus system perspectives

We found that stakeholders frequently think of the renewable gas supply chain in terms of specific suppliers and consumers. From this perspective, there was some concern that consumers who pay for renewable gas should receive the renewable gas that they pay for, and that consumers that receive renewable gas should be the ones that pay for it.

An alternative view, which we think of as a system perspective, has the system collectively buying renewable gas, gas consumers sharing the cost of fossil-fuel and renewable gas between them, but not seeking to provide a uniform renewable fraction to each consumer.

Some respondents thought in terms of a system perspective. They saw advantages in having renewable gas sent to the end user best placed to use it, e.g. the end user with lowest infrastructure, delivery and conversion costs. This could be important if one wanted to move the renewable fraction beyond what is feasible in "blending" scenarios. One could then have some consumers remaining on a blended supply and others consuming pure hydrogen.

6.11 INEQUITABLE IMPACTS AND CONCESSIONAL TREATMENTS

Low income households

Some respondents said that an RGT might be particularly adverse for lower-income gas consumers. It was suggested that lower-income consumers have below average capacity to electrify.

"for somebody who doesn't have that income and doesn't have that ability to [electrify] they will be stuck facing higher and higher costs at some point a network won't work and so you will just have to shut it down."

Firstly, their limited financial resources make it difficult for them to fund the up-front costs of new appliances. Secondly, lower-income households are disproportionately in rental properties, and it is difficult for a tenant to initiate the purchase of new appliances: they have uncertain tenure over which to defray the costs and landlords may not be receptive to funding the new appliances needed for electrification.

Trade exposed heavy industry

There was a variety of views as to what concessions should be made to trade exposed heavy industry in the advent of an RGT. One respondent said:

"we have members who love exemptions and members who don't, because the more exemptions you have, the more that has to be paid for by those who remain"

Some respondents thought that no concessions should be made.

“it's still going to be cheaper than electrification for them and … if we want to decarbonise our industries, it is a lot of those industries that need to come on that journey. So I'd suggest no … This is this is happening for them really … it's so that the manufacturers and those trade exposed industries have access to a lease cost net zero energy pathway that supports that continued business viability … So no, I don't think so. Might sound callous and quick to judge and might get a lot of negative feedback, but considering the goal and the purpose of developing a renewable gas target, it doesn't fit.”

Other respondents thought that no additional burdens should be imposed on these sectors. Some said that it is problematic that emitting industries are responding to numerous emission reduction policies without proper coordination.

Some respondents said that in the event that emission penalty mechanisms are introduced in overseas markets, such as punitive tariffs or a carbon border adjustment mechanism, the consequences of an RGT could be less adverse for heavy industry than it might seem at face value. It would be important, however, that the RGT be structured in such a way as to receive credit in those overseas markets.

Some respondents said that if assistance to trade exposed firms is desirable it should be provided frugally and designed carefully. It might be better to provide explicit budgetary assistance than to provide RGT concessions. It might also be desirable to put time limits and phase-out schedules on any concessions provided.

“We should consider exemptions of trade-exposed heavy industry as with the RET. However, the broader the base the better, like with consumer taxes, because once exemptions are in place it is difficult to remove them.”

“Protection for trade purposes can be considered in the short-term, but not on an ongoing basis.”

6.12 ECONOMIC EFFICIENCY CONSIDERATIONS

Neutrality across energy types

A number of respondents commented on the need to support efficient fuel choices.

It should be neutral on gases … solve for the most economically efficient at the time, potentially considering the short term that might be biomethane, long term you'll incentivise hydrogen”

Related to this, there was a concern that a RGT might distort fuel choices, especially if it was too limited in its scope

“you're effectively trying to pick winners. You're saying renewable gas target, there's only two renewable gases, biomethane and hydrogen … it doesn't make sense creating that market”

Neutrality across locations

Respondents were generally of the view that allowing gas retailers to source renewable gas at the lowest cost location—including out-of-state locations—would be consistent with securing renewable gas at least cost. If the objective were to secure some specified quantity of renewable gas at least cost, then retailers should be able to procure their renewable gas inputs where they see fit, taking into account the combination of production, network and other costs incurred.

“[it's in] the nature of state governments to want to see development in the state for use in the state … I'm a great supporter of the concept of a national electricity market. I'd be a great supporter of the concept of a national hydrogen market or a national renewable gas market if were to be put in place because we have all sorts of inefficient locational decisions made by state governments for political reasons that end up costing taxpayers and industry”

the more location neutral you could be, in terms of across states, the better … that's gonna get you the more efficient outcome if you are not saying you have to have a certain amount produced within a certain state.

“you potentially should seek location neutrality. But then political overlay might come in as well, that … certificates for [a State] should be used in [that State] if consumers [from that State] are paying for it”

“Victoria writes off biomethane simply because Victoria does not have biomethane production capability in Victoria, yet Victoria is connected by four pipelines to all but one State in Australia, all of which have the potential to produce biomethane and have it piped to Victoria for less than the cost of electrification”

Some respondents acknowledged the importance of industry development objectives for State Governments, and said that, on these grounds, preference might be justified for local (in-state or specific region) supplies.

Neutrality across consumers

One respondent said that there is a risk that gas network customers cross-subsidise transport-sector consumers of hydrogen.

> *[A situation can be envisaged] "where domestic gas customers are essentially subsidizing vehicle customers for hydrogen. Someone can produce hydrogen for transport purposes and create a certificate for that. But it's only the gas distribution network customers that are obliged to hand over those certificates. So it's essentially cross subsidizing other customers accessing hydrogen rather than the customers that are actually paying the price for it"*

> *"your molecule, so long as it displaces a molecule from a fossil source, should be valid. So a behind the meter solution … [if included] has brought that solution on and participants can actually grab that certificate like they can with a with an LGC. I think that brings more value, scope and flexibility. Which again I think you want with a target because you want you want the lowest cost solution to develop around building these solutions."*

> *"The highest valued uses of renewable gases are in transport and gas-powered generation, not buildings. A RGT should not distort the allocation of renewable gas to its highest uses."*

Efficient investment

One respondent said that for efficient investment it is necessary to have an appropriate amount of risk left with investors in the renewable gas sector.

> *"You don't get the development of an efficient renewable gas scheme by pushing all risk onto taxpayers or consumers, which is what I perceive in some cases ... you need to open up the question that what is the appropriate sharing of risk between the investors?"*

One respondent noted that the target mechanism avoids picking individual projects for support and that there may be efficiency advantages in this

> *"looking at things like the renewable energy target … you can see that this type of target mechanism is really quite effective in not just throwing money at individual projects, but enabling a market based approach to building up renewable energy production industries"*

A couple of respondents raised a concern that there is an insufficient appreciation of very large electricity network costs that will be incurred to support electrification.

> *"we've got huge changes with electric cars. But even without that, we still in places struggle in the distribution of the electricity network. And it requires a huge investment to go 100% electric. Whereas gas has a good distribution system in place already. It seems madness to just walk away from that investment."*

One respondent thought that the additional network costs from electrification would be smaller than the rise in electricity consumption.

> *"Infrastructure expansions required for electrification are not so large … space heating and hot water do or can run off-peak without additional infrastructure need. This story may be complicated by the rise in electric vehicles."*

6.13 RISK

There was general agreement that risk is unwelcome to all parties potentially affected by an RGT but less clarity on how it should be allocated and minimised.

Price vs quantity risk

Respondents generally thought that price risks were more troubling for firms and customers than quantity risks. It was thought that market participants would probably rather have a clear horizon of price premia to be paid for renewable gases, with uncertainties and attendant risk left on the quantitative side.

> *"The RGT should ensure long-term stability of renewable gas prices to enable producers to factor certificate revenues into their financial models to inspire investor confidence."*

Regulatory risk

Regulatory risks were commonly cited as a concern.

> *"Managing political influence from stakeholders with a vested interest in preserving the existing gas infrastructure"*

A number of respondents commented on what they saw as unnecessary risks: policies introduced without proper design or on very short notice. Regulatory risk can be contained by having a well specified plan with adequate lead times to key policy changes.

> *"Communicating the regulatory framework that will be implemented in the next ten years would reduce revenue uncertainty for businesses in the gas sector and consumers and increase investor confidence in new capital infrastructure."*

Diversification

One respondent suggested that distributed renewable gas production may offers some risk reductions vis a vis supplies that are delivered by a single pipeline.

6.14 POLICY PROCESSES: FORMATION AND IMPLEMENTATION ISSUES

Policy choices

Respondents said that policy makers need to be clear about their objectives, as this will affect the design of a RGT.

> *"If it is emissions reduction that we're trying to achieve here, how does it fit with the other suite of options in front of us to achieve emissions reduction? Can we do this in some other ways and is this an optimal way to achieve that, or a least cost way of achieving those emissions reductions."*

Some respondents said that before any decision is taken regarding an RGT policymakers need to carefully assess costs and benefits. They need to take into account behind-the-meter costs as well as gas and network cost impacts—e.g costs of replacing appliances.

> *"it's quite possible that … investigation will reveal that something like a renewable hydrogen target places all kinds of imperfections in the market that actually distract from the main game and cause investment in the wrong places … [what is needed is] a big piece of critical thinking to this which says we want the answer, not an analysis that gives us the answer we've already decided on … get closer to figuring out what is the right solution by potentially eliminating some things that aren't the right solution"*

> *"Policy makers need to take a long view, with good analysis. They need to preserve options. And they need to form a view that integrates gas and electricity."*

One aspect that was mentioned a number of times was what was said to be a weakly justified presumption against renewable gas on the part of some States.

> *"The ACT, in their recent analysis of whether or not they should get rid of their gas distribution networks … completely disregard the ability to purchase renewable gas in from interstate and say because we can't produce enough in the ACT, we're not gonna pursue it."*

Some respondents said that it was important for policy makers to be alert to potential adverse impacts on vulnerable consumers.

Policy implementation

Respondents said that policy makers need to approach change management effectively. They said that there are examples of how it should not be done, for instance with overly short implementation frames.

> *"We need to know well in advance before transporting hydrogen that … we need to upgrade this part of a network."*

Policymakers need to provide a clear roadmap covering both the trajectory of the scheme and also addressing issues like eligibility, coverage and technical standards. There needs to be detailed consideration of logistics in advance. For example, they need to take account of impacts on gas users with existing appliances already installed. Disruption needs to be kept to a minimum.

> *"having a long-term plan, milestones and staging hydrogen percentage requirements through an RGT with enough lead time for product developers could reduce the cost impact on gas users"*

Some respondents said that policymakers need to think about how they would manage the transition from 5-10% blending (the easy bit) to more ambitious longer-term targets, i.e. approaching 100% targets (the hard task).

> *"Would a dual network system for distributing 100% hydrogen and 10% blends be more cost-effective considering the cost of retrofitting existing gas infrastructure, appliances and the avoided cost of disrupting gas supply to users and the cost of ensuring safety?"*

A number of respondents mentioned that there may be consumer resistance to hydrogen on safety grounds. A social license will need to be secured to assuage consumer concerns about cost, disruption and safety.

Some respondents mentioned the importance of robust accounting mechanisms and schemes to create and surrender certificates.

> *"One of the most important things to complement an RGT is a transparent and effective mechanism for verifying and linking certificates with claimed or purchased zero-emission renewable gas consistent with NGER reporting and Australian Carbon Credit units.'*

"Potential investors would like to know how long they can contract for and customers would like to recognise the displacement benefit of a renewable gas contract. A 10-15 year investment would encourage investment in the market as long as there's a credible certification scheme that both small- and large-scale gas users can use in their reporting similar to the Corporate Emissions Reduction Transparency scheme"

7. Designing a RGT mechanism: synthesis of issues

- The optimal design of a RGT mechanism depends on the objectives that it pursues
- A RGT can be pursued with command-and-control and/or market-based mechanisms
- Where market-based mechanisms are implementable they have advantages in supporting the achievement of emission reductions at lowest cost
- It is useful to consider the following key questions as a starting point for RGT design - Which fuels? Who bears the burden of costs with renewable gas? and Who uses renewable gas?
- Interactions with other schemes need to be carefully considered-for example the Safeguard Mechanism, State schemes and overseas schemes such as the European Union's Carbon Border Adjustment Mechanism

7.1 OBJECTIVES OF A RENEWABLE GAS TARGET

In any policy design exercise, it is important to have clarity over objectives, because objectives have large implications for scheme design.

There were several possible objectives for a RGT that were suggested to us in stakeholder consultations, these being:

- emissions reductions
- developing a renewable gas supply chain in the domestic market
- energy security
- building the hydrogen industry
- orderly transit of gas customers to electricity

These objectives share some common consequences, but each has a different policy emphasis, and may lead to different design choices. For instance, the goal of emissions reduction might be addressed as part of an economy-wide emissions quota or tax, with an emphasis on least-cost emission reductions. In contrast, the development of a renewable gas supply chain might seek to target particularly those supply chain links which are seen as the most underdeveloped, or presenting the most challenging barriers, or having the greatest potential for cost reductions.

A RGT may of course target multiple objectives simultaneously. For example, a RGT mechanism might subsidise the use of renewable gas in the gas supply, thus changing its competitive position with fossil-fuel gas, increasing its market share, and reducing the consumption of fossil-fuel gas and the emissions from it. But that RGT mechanism could also go further, requiring the renewable gas subsidy to be met by consumers of fossil-fuel gas, which would create a further incentive to diminish emissions.

The most obvious configuration of a RGT is one which targets a specified proportion of renewable gas in an existing fossil-fuel gas supply. In an economic analysis, this scheme can be interpreted as two distinct interventions. Firstly, the scheme provides a subsidy to the inclusion of renewable gas in the gas mix. This subsidy lifts sub-commercial renewable gas initiatives to viability. Secondly, the scheme imposes a notional tax on fossil-fuel gas to finance the subsidy to renewables. The economic incidence of this notional tax could fall on fossil-fuel gas suppliers and/or on end users of gas. In the long-run, if it is effective, the incidence of the notional tax is likely to fall mainly on gas consumers through higher prices.

Emissions reduction

The Australian Government has set the goal of reducing emissions by 43 per cent (from 2005 levels) by 2030 and by 100 per cent by 2050 ("net zero"). Achievement of these goals will require major changes in Australia's energy mix, with clean fuels and energy sources replacing the carbon-emitting energy supplies that Australia relies on at present. This transition requires the development and adoption of new technologies and also changes in the behaviour of energy consumers. These changes will not occur without government interventions to encourage them.

Australian Governments—Commonwealth, State and local—already have in place numerous interventions that seek to reduce emissions. But the current suite of interventions is probably not sufficient to deliver the planned 43 per cent reduction by 2030 or net zero by 2050; more will be needed. There is also a question as to whether current policies are well structured to reduce emissions at minimum cost.

One important component in the decarbonisation of Australia' energy supplies is the decarbonisation of its gas supply. In 2021, Australia had 79 Mt CO2-e of emissions from the combustion of gas (IEA 2022a). A further 5.6 Mt CO2-e were emitted as fugitives from natural gas production/supply in 2020 (DCCEEW 2022a).[14] These emissions are significant: they amount to about one-sixth of Australia's 498 Mt CO2-e total emissions in 2020.

At present, policy makers are placing a substantial emphasis on electrification as the means to decarbonise gas: i.e. gas users replacing their gas appliances with electric appliances, and the electricity to power those electric appliances then being sourced from renewable electricity generators. But replacing fossil-fuel gas with renewable gas can also contribute to the decarbonisation of the gas supply. Renewable gas has a significant potential to help reduce Australia's carbon emissions from gas consumption.[15]

The impact on emissions of boosting the domestic consumption of renewable gas depends on the quantity of emissions avoided from displaced fossil-fuel consumption *and* the quantity of emissions caused by the renewable gas itself (which may be none). For example, if the provision of one unit of renewable gas displaces the consumption of carbon-emitting fuels with one tonne of CO2-e, and generates no emissions of its own, then the renewable gas has saved one tonne of CO2-e.

From this perspective there are two important questions to be addressed:

- How much does a unit of renewable gas—say 1 PJ—displace emissions from the consumption of other carbon-emitting fuels?
- What is the emission impact of consuming the renewable gas itself?

The question of how much carbon-emitting fuel is displaced by a renewable gas is not entirely straightforward. On a petajoule-for-petajoule comparison, a reasonable starting point might be to assume that 1PJ of renewable gas displaces 1PJ of fossil-fuel gas. But this may not always be so. Firstly, there may be differences in the thermal efficiency of renewable gas appliances relative to fossil-fuel gas appliances, there may be differences in network losses, etc. Therefore, the calorific requirement for renewable gas in lieu of fossil-fuel gas may not be one-for-one. Secondly, if there are technical challenges using gas—for instance if new capital investment in an appliance was required—some end-users may electrify with the result that the reduction in fossil-fuel gas exceeds the amount of renewable gas introduced.

In addition, the emission impact of consuming the renewable gas depends on both any combustive emissions and also any upstream impacts in the supply chain for the renewable gas. These components are likely to depend on the particular renewable gas under consideration.

Domestic gas supply chain

The objective of developing the renewable gas supply chain rests on the idea that there is a potential for substantial reductions in the cost of renewable gas supplies. With renewable gas operating at small scale, or not at all, the renewable gas supply chain has the potential to reduce costs as its scale grows, and as a result of the learning that occurs with the implementation of renewable gas supply activities.

There is broad consensus that reductions in the unit costs of renewable gas supply are likely over time, but there are divergent views on the scale of cost reductions that may be achieved. The scope for cost reductions would seem to be greater for immature products such as green hydrogen and smaller for more mature products like biomethane. But there is considerable uncertainty about what will be achieved. Those who see a strong potential for cost reductions point to the experience of solar panels, which have had cost reductions of more than an order of magnitude since the 1980s.

When thinking about potential cost trajectories it is relevant as well to distinguish between cost reductions that will simply "arrive" in Australia independent of efforts made here, and the cost reductions that will arise form efforts made here. The example of solar electricity illustrates this well: a large part of the reductions in the costs of solar generation reflects falls in the prices of panels on world markets which have been driven by factors outside Australia. But the growth of solar panels in Australia's electricity supply has also led to substantial learning: learning

[14] On top of this, the inventory records 17 Mt CO2-e emissions from oil and gas venting and flaring. It is understood that the majority of this relates to production for offshore markets.
[15] In some quarters there is a view that renewable gas cannot get to the necessary scale at feasible cost, and quickly enough, to assist with rapid decarbonisation. This has led some policy makers and energy reform advocates to implement and promote policies that promote electrification, with renewable gas planned to have a much more modest role in the energy mix than gas does today.

about how to install panels, learning about how to integrate them into grids, learning about storage challenges, etc. And this learning also assists reducing the systemic costs of using solar generation in Australia.

The arguments around supply chain development are akin to "infant industry" arguments.[16] Over recent decades policy makers in Australia have been wary of infant industry arguments, and have been keen to see that policy design is appropriately structured to support early-stage growth and does not mutate into an ongoing subsidy for sub-commercial activities. Moreover, targeting needs to emphasise sectors that have a strong potential for reducing costs and raising productivity—there are myriad industries that do not exist in Australia for good reason and an infant industry policy that sought to support any sub-viable industry into existence would ultimately undermine productivity and living standards in Australia. These considerations are relevant to a RGT mechanism.

Cost reductions in supply chains can be expected with scale and learning. Were it the case that the renewable gas supply chain was owned by a single owner, then it might be argued that these cost reductions could be internalised by that owner, and that no incentive was justified to support the development of the supply chain. But in reality there are parallel physical supply chains with different ownership, and also different owners of links in the supply chain—e.g. renewable gas production, transport and storage, appliances. Developments in parallel supply chains in upstream and downstream links are likely to spoil over to other participants. If these spillovers are expected to be substantial they give a rationale for a policy intervention, such as a RGT mechanism, that boosts the uptake of renewable gas.

The renewable gas supply chain depends on having supporting institutional infrastructure in place—regulatory arrangements, certification and accreditation—and there is a strong case for governmental support in this regard as individual players cannot implement this individually. The case for "scaling up" support would be strongest for gases in the early stages of development, such as green hydrogen.

7.2 MECHANISMS

In principle there are numerous mechanisms that can be used to pursue a policy objective—quantitative constraints, taxes and subsidies. Often these instruments are able to achieve similar outcomes in terms of impact on the desired target. And, if accompanied by corrective redistributive transfers ("side payments") they can achieve the same distribution of costs across affected parties.

For example an emission tax could be imposed on an emitter and a lump sum payment made to it, to compensate it for its expected tax payments. We could estimate the change in emissions that would arise. A similar outcome could be achieved by requiring the emitter to reduce emissions by the same amount, and reimbursing it for any costs arising from that decision.

While these different mechanisms may be very similar in their economic substance, they may also be very different in their appearances. And appearances matter for political economy. For example, tradeable permits may be more palatable than on-budget measures, like taxes for example.

"Command-and-control" versus "market-based" approaches

When a policy maker intervenes to change the behaviour of firms and individuals to serve an environmental goal, or an industry development goal, or some other goal, there are a number of ways in which this might be done. Two approaches which stand at opposite ends of the intervention spectrum are *command-and-control* approaches and *market-based* approaches. The two approaches differ in that command-and-control tends to pursue a fundamental policy goal indirectly while the market-based approach pursues it directly.

In both cases there will be an overarching policy objective. This might, for example be emission reductions. To pursue the objective, a regulator might mandate energy efficiency standards for buildings, in the belief that these would then translate to lower emissions. This is an example of the command-and-control approach. Alternatively, the regulator might impose a tradable emissions quota, with each emitter required to buy quota in line with their emissions. This is an example of the market-based approach.

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[16] "Infant industry" arguments are along the lines that an industry that is not present in a country could be established on a viable ongoing basis with some temporary support to allow it to overcome obstacles to its establishment. While the argument may be legitimate in principle, there are many examples around the world of "infant industries" that never grow up to become financially viable without support.

The market-based approach leaves a high level of discretion to market participants about how a policy goal is to be achieved. This is illustrated by the previous example. Under the efficiency standards approach the regulator stipulates what steps should be taken to reduce emissions and who should take them. Under the tradable quota approach, it is left to potential emitters to work about between themselves, in the market, how the emission reductions are delivered.

With either approach, the overarching policy goal needs to be determined by the policy maker. For example, if there is a concern about emissions and a desire to impose a binding restriction on them, the objective will need to be identified by the policy maker. Command-and-control and market-based approaches both offer ways to respond to a policy concern, but they cannot identify that concern themselves.

Command-and control mechanisms target the underlying policy objective indirectly. They tend to focus on a particular type of solution to a problem and omit alternative solutions. But if it is hard for the regulator to know what the best solution to a problem is, and it often is, there are risks that the regulator may choose a less than ideal response. The polluting firm, with its deeper and closer knowledge of its operations, might know a better way—a lower cost way, having in mind all the details of its facilities and operations—to achieve the fundamental objective.

Command-and-control mechanisms come in numerous forms and vary a lot in the extent to which they restrict regulated firms' choices. A regulation that prescribes the technology to be used will tend to be highly prescriptive. A less prescriptive approach is to use a performance standard. A performance standard leaves the facility operator more discretion over the approach to meeting the regulatory goal. The operator can identify the range of technologies that could be used to meet the performance standard and choose the least cost approach.

A good example of the performance standard approach is the Safeguard Mechanism as it currently operates in Australia. Virtually all covered facilities are subject to an emission rate per unit of output. They have substantial discretion over how best to achieve this. However, the Safeguard still fails to minimise the cost of emission reductions because it sets targets for individual firms with the result that some firms with high abatement costs are required to reduce emissions, when in fact it would be more cost effective to shift the emission reduction effort to firms with lower abatement costs.[17]

In the market-based approach, the regulator puts in place economic incentives to achieve its desired policy goal but leaves the market to determine who makes the contributions needed to achieve the goal and how they make them. The advantage of a market-based approach is that it leaves greater discretion to market players as to how to achieve a desired policy goal. Market participants who can cheaply contribute to the goal are incentivised to take on a large part of the effort to achieve the goal whereas those participants who find it costly to contribute to the goal do less. And the regulator does not need prior knowledge of which participants are low-cost or high-cost, but instead relies on the market to find a cost-minimising approach.

The point can be illustrated with reference to the Renewable Energy Target (RET), which was explained in detail in an earlier section. The RET is a market-based instrument *within the electricity market*.[18] It requires electricity retailers and large users to surrender certificates in proportion to their aggregate electricity consumption. However, renewable energy percentages are non-uniform across regional electricity markets: some regions produce more Renewable Energy Certificates than are required and transfer them to electricity consumers in markets which produce less RECS than required. In contrast, a command-and-control approach might require each regional electricity market to satisfy its renewable energy percentage with local renewable generation.

A potential advantage of a well-designed market-based approach is that it achieves a policy goal at lowest cost. In the case of an emission target, for example, firms with low costs of emissions reduction reduce their emissions a lot and firms with high costs of emission reductions do not reduce their emissions much. The emission reductions are taken where it is least-cost to achieve them, and as a result the overall emission target is achieved at least cost.

In principle, a command-and-control approach can achieve exactly the same pattern of emission reduction effort as a market-based instrument. But in practice regulators will find it difficult to identify in detail the lowest cost

[17] Reforms to the Safeguard that would allow firms to trade emission credits have been proposed by the Government. These reforms have the potential to improve its efficiency, but complex issues need to be addressed. Firstly, under the present Safeguard targets, many facilities have a surplus on their targets, and if these are not removed tradability could actually increase emissions of covered firms. The introduction of tradability needs to be accompanied by more demanding targets. Secondly, targets are at present, for most facilities, expressed as emissions per unit of output, meaning that aggregate emissions are not effectively constrained. Thirdly, there are questions about what treatment new facilities should receive.

[18] The RET does not determine the contribution of the electricity sector to emissions reductions; the emission reductions to be delivered are imposed as targets (roughly speaking). In contrast, a whole of economy emissions tax would leave it to the market to decide how much of the emission reduction task should be carried out by respectively by electricity generation, transport, stationary combustion, agriculture, etc.

approach to emissions reduction. Experts with deep and ongoing involvement in regulated facilities—for instance engineers and finance experts that work there—will often have better knowledge of how best to reduce emissions at individual facilities and how much it will cost to do so.

While experts within emitting facilities have information about the lowest-cost approaches to reducing emissions, they may not have incentives to share it with regulators. In a command-and-control system, regulated entities may have an incentive to overstate the costs of reducing emissions, either because they see a potential to increase the financial support that they receive from government or because they hope to secure a less demanding emissions reduction target. With a market-based scheme, the regulated entities use their knowledge of emission reduction costs to make decisions about whether to buy permits and emit or abate. The regulatory regime does not rely on the disclosure of information that will not be forthcoming.

For a market-based approach to work, the regulator needs to effectively monitor the performance of regulated entities against an outcome of interest. And it must establish a suitable mechanism to provide incentives to modify behaviour. For example, imposing an emissions limit on a firm can only work if the regulator has some objective basis for measuring the firm's emissions. Without that, it may be better imposing a technology that produces desirable results.

Quantitative targets versus subsidies/taxes

Market-based policies may change market outcomes by means of quantitative targets or with subsidies/taxes. Here we will consider the issues in the context of a "good" that a government intervenes to promote. A lesson is that in many cases economic incentives, and desired policy outcomes, can be approximately delivered either by quantitative interventions or by subsidies. The equivalence is approximate insomuch as there may be different enforcement and compliance costs and risks for the two approaches.

The key to the equivalence argument is that in the quantitative approach, government requires the consumer to purchase a specified amount of the good. In the subsidy approach, the government can set a subsidy at the rate that induces the consumer to purchase the same quantity of the good. Moreover, the quantitative and subsidy approaches can also deliver the same distributive outcomes, i.e. the same allocation of the costs.

An illustration of the equivalence of the two approaches is given with Figure 7.1, which shows supply and demand curves for a good. The free market equilibrium, in which there is no direct government intervention is shown as (Q_0, P_0). Now the government imposes the quantity Q_1 and requires the consumers to buy this quantity. As a consequence, the market price is forced up to P_1^g, so the market outcome is (Q_1, P_1^g) and the aggregate cost to consumers is $p_1^g \times Q_1$. Alternatively, the government uses a subsidy s to bring about this outcome. The subsidy raises the demand curve by s to D_1, for consumers are willing to pay an extra s at any given quantity, for this amount is met by the subsidy. The new equilibrium is at (Q_1, P_1^g), as with the compulsory purchase approach. Consumers pay $p_1^n \times Q_1$ in the market and government levies a lump-sum tax to cover the cost of subsidies, equal to $s \times Q_1$. The aggregate cost to the consumer is $(p_1^n + s) \times Q_1$, and since $p_1^g = p_1^n + s$ this aggregate cost is equal to $p_1^g \times Q_1$, which is identical to the cost under compulsory purchase.

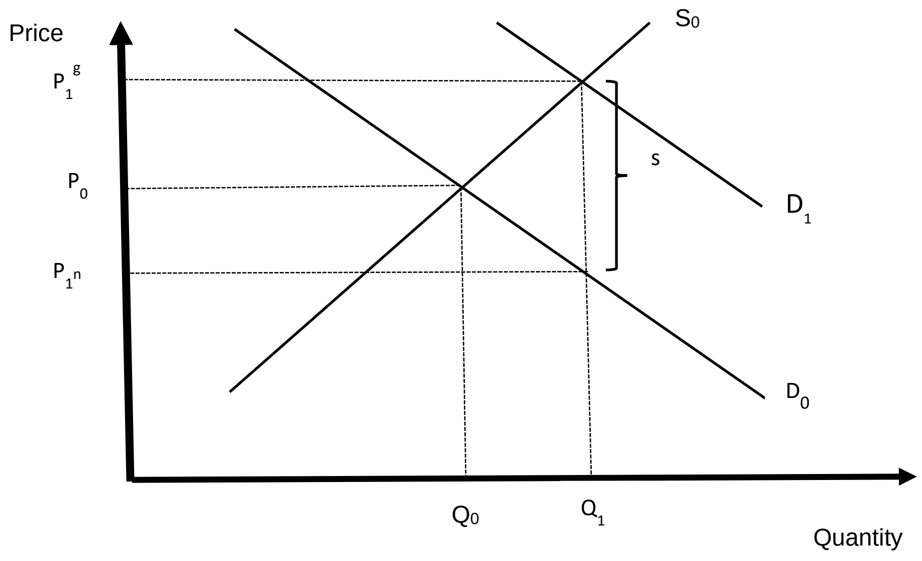
While the example demonstrates the equivalence of outcomes under the two schemes, it also illustrates that there may be significant practical differences between them in terms of the administrative apparatus required to implement them. The choice of approach may therefore come down to which is the easiest to implement. Political considerations may also play a role, for two schemes that are equivalent in an incentive/outcome sense may still draw quite different reactions from consumers/electors.

A more substantial point of difference emerges when we allow for uncertainty. Suppose that there is uncertainty about the true nature of the demand or supply curves, as must inevitably be the case if we are considering a policy that will impact several years into the future. In that case, imposing a quantitative target will give us a degree of certainty over the quantity with the uncertainty falling onto the price outcomes. In contrast, imposing a subsidy gives certainty over the price impact, and leaves the uncertainty on the quantity response.

This raises the question: which is worse, price or quantity uncertainty and risk? In a famous paper Weitzman (1974) concludes that the answer is uncertain, depending on specific market circumstances, but that it will be more common for market participants to prefer price uncertainty over quantity uncertainty.

It should also be acknowledged that there is not necessarily a strong connection between the type of instrument and the nature of uncertainty, depending on how the instrument is managed. A quantitative control, for example, could be periodically adjusted in line with emerging prices, so as to preserve some desired price impact. Arguably this has been the de facto approach with the Renewable Energy Target: while it sets quantity targets, these targets have been adjusted from time to time in light of emerging prices.

Figure 7.1 Quantitative and subsidy approaches to boosting consumption of a good



These considerations are directly relevant to the selection of a RGT mechanism. A RGT mechanism could set out year-by-year renewable gas quantity targets, with implicit subsidies to be determined in the market. Or it could explicitly set out subsidies year-by-year, with quantities to be determined in the market. The goal of net zero in 2050 might add weight to the case for a quantitative target, but even so the pricing impacts in the interim are a political reality that will need to be accommodated, especially as the renewable gas share grows to a point at which it can have a significant impact on gas costs.

Certificate scheme

Under a certificate scheme the producer of a product, say a renewable gas, produces the product and creates a certificate for each unit of the product. The product can be sold into the relevant market, where its value will be determined by its value in use. The certificate can be sold separately, assuming there is a market for it, in which case it creates an extra income stream for the producer.

Since the producer earns income both from sales of the product and sales of certificates, the certificate revenue can make production viable even when the income from product sales alone falls short of costs. The certificate revenues are thus effectively a subsidy to production.

There are potentially two main markets for certificates. Firstly, they may be purchased voluntarily by organisations which want to support the product, perhaps for their own marketing or investor-relations purposes. Secondly, they may be purchased by organisations that are compelled to purchase, as is the case with electricity retailers and large users with the RET.

Under a model with compulsory purchase of certificates, qualifying suppliers of the good create a certificate for each unit they create. Liable end users are required to buy certificates according to a formula that determines their liability. And the physical distribution of the targeted good over end users may be quite different to the distribution of certificates. For example, under a green hydrogen certificate scheme, the green hydrogen producer might sell all of its product to a nearby gas-powered generator and a more distant gas-powered generator might use entirely fossil-fuel gas, with both producers required to purchase green hydrogen certificates. The green hydrogen product itself is sold at a price consistent with its efficacy in generation. The subsidy to green hydrogen production—delivered by selling certificates—is met by both generators.

The certificate scheme plays an important role in de-linking the obligation to support growth of the new product form the actual consumption of it. There is potential for considerable inefficiency if an aggregate renewable gas target were delivered by setting individual consumption targets, as end users may vary substantially in the costs that they face to deliver renewable gas, adapt appliances, etc. The introduction of certificates means that the desired allocation of costs in support of renewable gas can fairly easily be implemented, while allowing the consumption of the gas to be determined efficiently.

A certificate scheme requires administrative support to set rules, support integrity, etc. The administrator would check that the certificates issued by eligible producers meet eligibility requirements. It would also check the integrity of transactions in certificates, under both voluntary and compulsory models. This integrity might, for example, involve a surrender mechanism whereby parties that "use" a certificate surrender it. The Clean Energy Regulator supports the certificate transactions that underpin Australia's RET.

Quantitative restrictions: pooled vs bilateral purchase models

Policy interventions can be pursued using purchasing pools or by means of bilateral transactions. This can be illustrated for the case when a government wants to use certificates to increase the supply of a good to some targeted level. The good could, for example, be renewable gas.

Pooled model

In the pooled approach, a pool could be set up which purchases certificates on commercial terms from providers. Funds to defray the cost of certificate purchases are raised either by selling certificates to liable parties who are required to buy them and sell them or by some other mechanism such as a levy imposed on some activity or sector, or direct support from a government budget.

One example of a pooled market of this type is Australia's Emission Reduction Fund. The Fund is effectively a pool which pays private sector organisations to deliver emission reductions against baselines. The costs of the fund are met by the Australian Government.

Another example of a pooled market is the National Electricity Market (NEM). The NEM comprises five linked pools.[19] These pools buy electricity at a reference nodes from generators who are responsible for the cost of delivering their electricity to the reference node. Retailers and large users then buy their electricity from the pool and incur additional costs delivering that electricity to end consumers and recover costs from those consumers.

One common way of implementing a pooled purchase model is to use a tender to procure the desired goods from the market. Typically, this would involve a "reverse auction" to select providers, determine how much they will be paid and thus determine the costs of the pool. Box 7.1 elaborates on the reverse auction process.

The designer of the scheme must also determine how to recover the costs of the pool purchase. The costs might be covered by budget funding, or the scheme might impose the costs on a consumer group. The question of who pays is addressed in a subsequent section; for now, it is noted that a pooled purchase scheme requires a funder.

Bilateral transactions model

A bilateral transactions model seeks to achieve a quantitative outcome and to distribute the costs of achieving that outcome, as is the purpose of a pooled scheme. But in contrast to the pooled scheme, the bilateral scheme requires liable parties to purchase the targeted goods—e.g. a renewable gas certificate from eligible suppliers or intermediaries. The scheme administrator regulates the creation and surrender of certificates, but does not itself purchase and sell them.

Bilateral transaction models tend to be more appealing when the products offered on markets are heterogenous, i.e. when they differ in important aspects. For example, housing markets operate on a bilateral transaction basis and there are good reasons for this because each potential buyer has distinctive needs and each house offered has distinctive features. Bilateral transactions allow an efficient matching. But these matching arguments are unlikely to apply with a renewable gas certificate: certificates are absolutely identical and as such have the characteristics of a commodity market. One RGC is as good as any other for a party required to surrender RGCs, and one customer is as good as another for a vendor of RGCs. This not to say that a bilateral transactions approach is a bad approach for RGCs, only that there are unlikely to be any significant advantages in terms of matching buyers and sellers.

There appears to be acceptance of, and support for, bilateral transaction mechanisms. This is probably attributable in part to familiarity: the RET is based on bilateral transactions and that design may be formative in the mind of gas market participants.

[19] New South Wales (including ACT), Victoria, Queensland, Western Australia and Tasmania.

Box 7.1 Uniform price and discriminatory price auctions

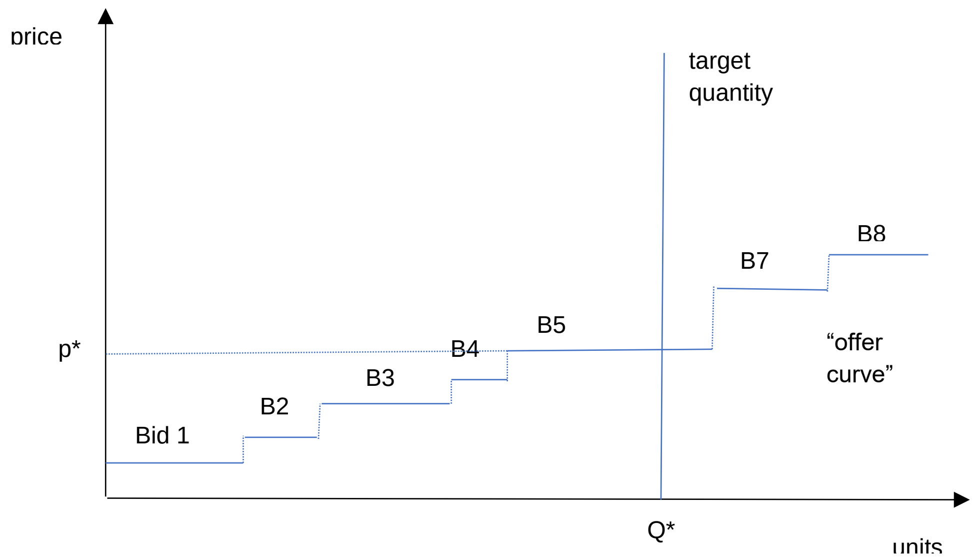
A “pooled purchase” model can be implemented by means of a “reverse auction”: The scheme manager chooses a “target quantity” of renewable gas that it wants to secure in the system—this is shown as Q* in Figure 7.1. Eligible renewable gas producers make offers to the scheme manager to provide a specified quantity of gas at a specified price. In the diagram, the scheme manager receives bids B1 to B7, each involving a quantity and price. These bids can be ranked in ascending order of price to form an “offer curve”. A “clearing price” is identified, this being the price at which the offer curve and the target quantity intersect. Those renewable producers whose bids were equal to or less than the clearing price are then contracted to provide their offered quantities and the marginal bid—B5 in the diagram—is contracted for a fraction of her offer.

What price are the successful bidders paid? One possibility is to pay each successful bidder the clearing price p*, in which case some bidders are paid more than their bids. This auction mechanism is called a “uniform price auction”. Another possibility is that every bidder awarded a contract is paid their bid, which mechanism is called a “discriminatory price auction”. A well-known example of the uniform price format is the National Electricity Market: bidders receive the spot price rather their bid. In contrast, the Emissions Reduction Fund uses a discriminatory price format.

The discriminatory price auction has a superficial appeal to the pool operator on grounds of cost minimisation: at face value numerous bidders are paid less than the market clearing price. However, this conclusion is unsound, as we can expect bidding behaviour to differ across the two mechanisms. In the uniform price auction, it is optimal for a bidder to bid the minimum price they are willing to accept (WTA), knowing that if his bid is successful he will receive the market clearing price.[20] In contrast, it will not be optimal for a bidder in a discriminatory price auction to bid as low as his WTA. Instead, his strategy is to increase his bid above WTA but taking into a complicated tradeoff: on the one hand a higher bid will increase his return if it is successful, but on the other hand it increases the chance that he will miss out on a profitable contract.

What then are the cost implications of these two different auction formats? The answer is “it depends”, but under some circumstances the cost of buying the targeted good will be the same under uniform price and discriminatory price, in which case we say the two auction formats are “cost equivalent”. For example, the formats will be cost equivalent if we have a competitive market, with no collusion, and perfect information.

Figure 7.2 Operation of a purchasing pool



20 The WTA amount can be interpreted as the tipping point for the bidder. At a price below WTA he would not wish to win the auction. At a price above WTA, he gains a surplus, so wants to win. And if the price is equal to WTA he is indifferent about winning or losing.

In addition, the bilateral transactions approach probably appeals to governments because it is "off budget". With a pooled fund, the compulsory payments into it are likely to be treated as taxes and the outlays from it as government expenditures. With the bilateral transactions model, the burden of costs and the allocation of payments is the same, but it is not on the budget.

There may also be some transaction cost advantages to a bilateral market for parties who want to hedge risk. In a bilateral transactions market, a liable party might enter into a long-term contract with a certificate creator, and thus remove some uncertainty over the terms that will apply to its future procurement of RGCs. (And the purchaser might even own the producer creating the RGC.) If a pooled purchase model were in place, hedging arrangements would require a different set of contracts—e.g. contracts for difference in which creators and users of REGCs make side payments to each other that effectively lock in their prices regardless of the settlement price in the pool.

7.3 TARGETING

Which fuels?

The decision about which fuels to include in a RGT will depend on the objectives of the scheme. If the objective is emission reductions, then all renewable fuels should be included in line with their impact on emissions.

If the objective is supply chain development, it may be better to have a RGT that focuses on specific renewable gases and sectors. For example, if a RGT were established to develop the green hydrogen supply chain, then there would be no strong case for allowing biomethane.

Who pays?

When designing a scheme of compulsory contributions, the scheme designer asks: Who should pay? And how? One solution is for central government to fund the scheme directly, but this is effectively saying that the taxpayer at large pays, which might not be supported. An alternative solution might be a voluntary contributions model, but in many cases this would not work. A third solution is for the scheme to impose the costs on some other targeted group (i.e. not taxpayers in general). The group to be targeted might be chosen according to a benefit principle, efficiency considerations, equity considerations, or some notion of rights.

The benefit principle is the idea that the beneficiaries of an intervention should pay for it. Consider the case of a renewable gas target. One notion of benefit might be that gas-dependent consumers have available, in the future, an emission-free gas supply, and that they should therefore meet the costs of a RGT. An alternative notion might be that contributions be allocated in line with the emissions associated with current consumption: customers pay for the benefit of being allowed to emit into the (overstretched) atmospheric carbon sink. This distinction illustrates that if one seeks to apply a benefit principle, it is important to be clear what the scheme objectives are.

The efficiency principle is the idea that the policy design should seek to secure maximum aggregate benefit at minimum aggregate cost, without heed to the distribution of the costs and benefits. The development of green hydrogen might be more beneficial to end users with hydrogen furnaces than those without. The benefit principle would say that the cost recovery should be targeted at end users with hydrogen furnaces. But an efficiency principle might call for a widely distribution of the cost burden, with the regulator not going through the costly exercise of tailoring the burden to individuals' circumstances.

If an equity principle were pursued, the scheme designer might take into account notions of "capacity to pay" for end users. For instance, in water pricing there are sometimes concessional prices for small volume purchases. It is interesting that while these schemes may appear at face value to be equitable, they sometimes produce outcomes which are the opposite to what they intend. Policies that target equity at a high level, taking into account broad measures of wellbeing, such as consumption or income, often perform better than schemes which operate at the level of individual commodities.

Decisions about who should pay ultimately require normative or ethical decisions. Economic analysis plays a positive role in identifying the consequences of different scheme designs and how they work. And economic analysis can help to identify good and bad policies one an ethical objective is provided. But the choice of that ethical objective ultimately comes down to values and is not arrived at purely as a logical conclusion.

In the case of the Renewable Energy Target, costs of the subsidies in the scheme are met in the main by end users of electricity. In the case of the Emissions Reduction Fund, costs are met by the taxpayer at large. The Safeguard Mechanism pushes the cost of reducing emissions on to large emitters, who may to some extent pass these costs forward to consumers, depending on market structure.

Concessions

The question will arise whether there should be any concessional treatments provided under a RGT. In consultations it was suggested that households, or a subset of them, and trade-exposed heavy industry might be candidates. (But some of the parties we spoke to were firmly opposed to any concessions.)

A policy such as an RGT is likely to operate most efficiently, both in terms of its allocative effects and its transaction costs, if no concessional treatments are granted. However, the introduction of a RGT might raise equity issues. It is helpful to distinguish the equity arguments relating to, on the one hand, impacts on investors and, on the other, impacts on communities exposed to structural adjustment (i.e. community-wide job losses and associated consequences). The way in which concessions are, or should be, designed is significantly influenced by who the intended beneficiaries are.

Owners of facilities may argue that they should not be subject to an RGT because it exposes them to costs that were not anticipated when investment decisions were made. No business in Australia operates in a climate of absolute certainty, nor in a climate of absolute regulatory certainty. While there are strong arguments for governments to design regulation carefully, and to implement it in a stable way with adequate lead times, this does not mean that governments should never change regulations, including introducing new regulations. The imperative of reducing Australia's emissions has been in the public discussion, albeit debated, for decades. The RGT ultimately is intended to benefit gas customers by bringing to market new clean gas sources to replace fossil fuel gas.

Sometimes it is argued that concessions should be provided to particular industries or facilities because they are trade-exposed and at risk of closure, with adverse effects for local economies. In this case, the intended beneficiaries of the concession are workers and small, locall suppliers to the trade-exposed activity. It might be better to provide support to those communities directly, in the form of adjustment assistance, rather than to grant concessions to major regional employers who may or may not use the assistance to the benefit of local communities. For example, if compensation for adverse impacts is paid to the owners of facilities which become non-viable, there is a prospect that the compensation goes to shareholders, who may be anywhere, while the facility closes with adverse local impacts.

If concessions are intended for a vulnerable group such as low-income households facing higher energy costs, better outcomes are likely to be achieved if the concession is delivered "lump sum" and not as a concession in the price of energy. For example, suppose government wants to assist a household facing a $100 energy cost increase. On the one hand, if the government pays $100 to the household, then the household may use the funds to cover the higher energy costs without modifying its behaviour. But it might reduce its energy consumption, and keep part of the $100 support payment for other purposes. On the other hand if the $100 is delivered through reduced energy prices, there is no incentive to reduce energy consumption and no opportunity to deploy the savings to other consumption activity.

There may on occasion be a strong case for a concession. But when there is, it should be designed to phase out. Consideration should also be given to funding the concession from the government budget and locating it in a proper budget review process.

Segmented schemes

A RGT could be specified as a scheme that targets renewable gas to particular end uses, via segmented targets and schemes, or it could be established as a scheme with a single overall target without any sectoral requirement. These schemes produce different outcomes, both in terms of the allocation of renewable gas to end consumers and in the allocation of the cost burdens involved in supporting renewable gas.

To illustrate, there could be separated targets requiring 10 PJ of renewable gas content in gas delivered over the distribution network, 20 PJ in transport uses and 30 PJ in gas-fired generation (GFG)—a 'sectoral targets' approach. Suppose, also, that in each case certificate-based schemes were employed. Qualifying suppliers would then generate 10 PJ of distribution network certificates, 20 PJ of transport certificates and 30 PJ of GFG certificates.

The scheme would also need to specify who has liability to purchase, and surrender, the certificates created. What of the allocation of liabilities? One approach would be to require retailers and large users in distribution to surrender 10PJ of certificates (shared between them in line with their share of delivered gas); retailers and large users in transport to surrender 20 PJ of certificates; and gas-fired generators to surrender 30 PJ of certificates. But this allocation is not essential to the segmented approach: the scheme could for example require gas-fired generators to surrender 10 distribution network certificates, 20 transport certificates and 30 GFG certificates.

The alternative to the segmented approach is to simply require that 60 PJ of renewable gas be supplied across these sectors without prescribing the destinations—a 'use-agnostic' approach. If a certificate-based scheme was used, there would be a single type of certificate for renewable gas fed into the system. The liability could be imposed on users of gas, or on somebody else, as outlined previously.

The potential advantage of the use-agnostic approach is that it would allow the market to determine which final users take the 60 PJ of renewable gas. It allocates the renewable gas to the users which place the highest-value on it or, alternatively, have the lowest-cost of adapting to it. Talking purely in hypotheticals, it might be the case that replacing transport equipment with hydrogen-using equipment is relatively expensive whereas numerous gas-fired generators are already hydrogen-capable, and in that case the market outcome might be to use most of the hydrogen in gas generation. On the other hand, it might be the case that the price per PJ of petroleum was higher than the price per PJ of natural gas, and the adaptation costs were low in both sectors, in which case the highest valued use of renewable gas might be as a petroleum substitute, in which case the market outcome would see a lot of the renewable gas to petroleum substitution. Whatever the reality, it would guide the market outcome.

One of the advantages of a market process is that an energy planner does not need to know the most cost-effective allocation of renewable gas in substitution for other fuels: the market determines it and can adapt to changing circumstances as well.

It is important to note that the market allocation could be expected to be (roughly) the same regardless of the way in which liabilities are allocated. The market determines who uses the renewable gas. The allocation of liabilities determines who pays the subsidy for renewable gas. And there is no connection between who uses the renewable gas and who pays the subsidy.

While the use-agnostic market leaves the allocation of renewable gas to the market and secures the most cost effective allocation within the market, this does not mean that it is the best approach. A primary purpose of a renewable gas target is to pursue objectives that are outside the goals of market participants' narrow self-interest. The optimal structure of the renewable gas target will depend on the objectives of the scheme. If, for example, the purpose was simply to boost production of green hydrogen, to build scale economies in production, the planner might be indifferent as to the end use, in which case a use-agnostic approach would likely be preferable. But if, on the other hand, the purpose was to build supply chains to overcome initial barriers to uptake of renewable gas, then the planner might indeed set separate targets for different sectors, to ensure that there is progress in the development of supply chains for all three sectors.

7.4 INTERACTION WITH OTHER SCHEMES

Safeguard Mechanism

If a RGT were implemented attention would be needed to how it interacts with other schemes such as the Safeguard Mechanism. Relatedly, there is a question as to whether the Safeguard should accommodate the RGT or vice versa.

There are some risks that the Safeguard could distort gas consumption patterns under a RGT mechanism even with a fixed RGT. The issue is that if renewable gas is treated as emissions-free in the calculation of Scope 1 emissions, then facilities under the Safeguard have an incentive to increase their physical consumption of renewable gas. That gas is then transferred to them by gas users that are not subject to the Safeguard. The end result is that the RGT is met but patterns of consumption are distorted to maximise the credit in the Safeguard.

An alternative approach would be for the Safeguard to apply an average emission factor to gas supplied, and not to recognise the facility-specific renewable/fossil-fuel gas mix. This would remove the Safeguard-driven incentive to shift renewable gas across gas users. Safeguard facilities would still have an incentive to bring into production genuinely incremental supplies of renewable gas, but they would be rewarded for this by the creation of RGCs, not through the receipt of extra credits under the Safeguard.

If the issue were approached from within the RGT, the creation of RGCs could be limited to gas supplied to non-Safeguard facilities and the liability to non-Safeguard gas users. If a Safeguard facility claimed that there was renewable gas in its energy mix, that renewable gas could not have a RGC issued against it.

Implications from the changing international environment

At present there are essentially no measures applied against Australian exports in respect of the emissions arising from production activity in their domestic supply chains. But this may not continue.

The European Union (EU) has implemented a Carbon Border Adjustment Mechanism (CBAM) commencing 1 January 2023. At present the CBAM applies to imports of iron, steel, cement, fertilisers, aluminium and electricity from non-EU nations. Its primary purpose is to address problems of "carbon leakage": the phenomenon whereby production activity is located outside the EU and out of reach of its emission standards, but with its products imported into Europe. Not only does this defeat the emission reduction goal but it actually has the potential to displace production which otherwise would take place in Europe. The EU says that the CBAM is consistent with international trade law, as it seeks only a neutral treatment of emissions for goods produced within and outside the EU.

The CBAM requires importers of in-scope commodities to buy and surrender carbon certificates sufficient to cover the calculated emissions content in the imported goods (European Council, Council of the European Union 2022).[21] If the imports have been subjected to a carbon price in their country of origin, then this can be offset against the liability at the EU border.

Australian exports to the European Union are subject to the CBAM, and since Australia does not have a carbon price no offsets are available at the EU border. Direct exports of the commodities currently subject to the CBAM are a small component of Australia's exports to the European Union and the direct impacts will for the present be relatively small. But in 2026 the European Union will review the list of commodities subject to the CBAM, and it is possible that agricultural commodities will be brought into scope, which would subject a much greater value of exports to the CBAM.

The CBAM will also have indirect impacts on Australia's exports to other nations which export to the European union. Where those countries become subject to the CBAM on exports that are produced with Australian inputs then there may be an induced impact on Australian exports. The potential for this is especially significant for Australia's exports of fossil fuels: the CBAM incentivises countries to seek alternatives to fossil fuels and to impose financial penalties on domestic emissions. The strength of these direct impacts is unclear at present, but they may be larger than the impacts via direct exports.

There is a possibility that countries outside the European Union which are pursuing emission reductions will also implement mechanisms like the CBAM. Mechanisms like this allow those Governments to provide a degree of reassurance to domestic industry that emission restraints will not cause offshoring of production.

These considerations need to be taken into account in the design of an RGT. There would be advantages if the RGT were to qualify as an emission price mechanism under the CBAM offset provisions. These advantages are small at present, but they could be more significant in a future scenario where the CBAM applies to a broader range of Australian exports or other countries bring in CBAM-type mechanisms.

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Weitzman, Martin L (1974), "Prices vs. quantities", *Review of Economic Studies* 41(4), pp. 477–491.

[21] For a detailed examination of the CBAM and its implications for Australia see Young (2022).

8. Possible configurations of an RGT in Australia

- There are endless possible permutations of a RGT
- To crystallise thinking, this section sets out a "RET-like RGT mechanism" which takes on many of the features of the RET, adjusted to the renewable gas context
- Key design dimensions of a RGT include: certification, determination of certificate prices, transaction structure, geographic limits, eligibility of gases, eligibility of uses, inbuilt segmentation, allocation of liability, operational details, interaction with the Safeguard Mechanism, concessions and scheme ambition

This section considers the possible configuration of a RGT in Australia. To set the scene, a prototype RGT mechanism is presented, based loosely on the RET.

Following that, the dimensions of the RGT design choice are discussed further. There are many choices to confront in designing a RGT. While a RET-like model is a good way to frame thinking, this does not mean that the prototype presented here is a “best” model.

8.1 A RET-LIKE RENEWABLE GAS TARGET MECHANISM

Table 8.1 sets out an example of a RGT mechanism, loosely based on the design of the Renewable Energy Target (“a RET-like RGT”). The example is purely illustrative and, although it has been shaped by what might be practical, it is not suggested that it represents an optimal design.

Under this design a renewable gas manufacturer might, hypothetically, produce and sell renewable gas to a retailer for $15,000 per TJ. In that case it would also create one RGC for each TJ of renewable gas. If it sold the RGC for $60,000 then its total receipts would be $75,000 per TJ. These values are purely illustrative.

Each 1 per cent of renewable gas would amount to about 11,000TJ of renewable gas per year at current levels of domestic gas consumption and thus 11,000 RGCs.[22]

The penalty component, which is set at $80,000 in this scenario, is important both for giving force to the scheme and for setting an upper limit to the exposure faced by liable parties. To see how the penalty translates to an upper, suppose that fossil-fuel gas is offered in the market at $15,000 per TJ and renewable gas costs $140,000 per TJ to produce. If 1TJ of renewable gas is directly substitutable for 1 TJ fossil-fuel gas, the renewable gas commands only $15,000 per TJ in the market, and its producer needs to sell a RGC at $125,000 to bridge the cost gap. But with the RGC price at $125,000, it would be cost effective for the liable party simply to pay the $80,000 penalty instead, and not purchase a RGC. The result is that the renewable producer cannot cover costs and renewable gas is not supplied or used.

The impact of the scheme on gas prices depends on the costs of fossil-fuel gas, renewable gas and their market shares. If the price of renewables were $75,000 per TJ and natural gas cost $15,000 per TJ, then the scheme would increase the price of gas by $600 per TJ, or about 4 per cent, for each 1 per cent of renewable gas target. This highlights the importance of achieving major reductions in the costs of renewable gas at an early stage if the scheme is to lead to a significant rise in the renewable gas share without imposing a major cost burden on gas users.

[22] In 2020/21, 1,136PJ of gas was used in the domestic economy. A further 4,747 PJ was used for LPG production, most of which went overseas. See DCCEEW (2022) p. 9. 1,100PJ of gas is 1.1 million TJ of gas and 1 per cent of this is 11,000TJ. If certificates are issued at 1 RGT per TJ, this implies 11,000 RGCs.

Table 8.1 A RET-like renewable gas target mechanism

Dimension	Specification
Certification	1 Renewable Gas Certificate (RGC) for each 1TJ of accredited renewable gas. Registry and compliance oversight by Clean Energy Regulator.
Certificate price	Market determined.
Transaction structure	Bilateral between eligible suppliers and liable parties.
Geographic limits	Open to Australian producers. No sub-national distinctions.
Eligibility	Any Australian-produced renewable gas provided to a designated use may generate a RGC.
Renewable gas	A gas which uses renewable primary energy inputs and has net zero emissions in aggregate across production, storage, delivery and consumption.
Designated use	Stationary combustion in Australia—industrial, commercial, residential and gas-fired generation but not transport or exports.
Segmentation	None: target may be met by any renewable gas and any use.
Liable parties	Retailers and large domestic users of gas whose gas does not come from a retailer.
Shortfall	RGC liability minus certificates surrendered, which may be negative.
Shortfall carry forward limits	Shortfall carry-forward permitted subject to sinking in following year, and required to be within plus and minus 10 per cent of liability
Interaction with Safeguard Mechanism	Emissions from gas consumption assessed at average emissions per TJ of all RGT-liable gas supplies
Concessions	None
Ambition	Proportion of renewable gas in total domestic gas consumption (total gas = natural gas plus renewable gas): • 2026: 1 per cent • 2030: 5 per cent • 2035: 20 per cent • 2040: 50 per cent • 2045: 85 per cent • 2050: 100 per cent
Penalty	$80,000 per RGC not surrendered, adjusted in line with CPI until 2030; review of post-2030 arrangements in 2030

8.2 DIMENSIONS OF THE POLICY CHOICE

There are a number of dimensions to the design of a RGT-type measure.

Quantitative targets or subsidies?

There are numerous design possibilities, including:

- The RET-like RGT effectively stipulates a required quantity of renewable gas year by year over the life of the scheme. (This required quantity is determined as a defined portion of forecast gas consumption.) This design sets the quantity of renewable gas that must be produced and used over several years. Gas retailers and large customers are then subject to a “renewable gas fraction”, which is set shortly before the start of each year, based on the stipulated renewable gas quantity and the forecast of total gas supply for the year ahead. In this model, gas retailers and large users are subject to some uncertainty insomuch as the renewable gas fraction evolves over time.[23] The price of RGCs evolves over time and both producers and gas users face uncertainty in respect of it.

- An alternative approach would be to hold the renewable gas fraction strictly fixed and to have the renewable gas quantity change over time in line with emerging gas consumption trends. This would introduce uncertainty over the renewable gas quantity that would be required in each year. This would tend to shift risks towards renewable gas producers and these risks would tend to discourage entry. In this case both producers and gas users remain exposed to price risk.
- Another alternative would be to fix the price of RGC's on a forward-looking basis. In this case the RGC value is effectively a declared price subsidy to renewable producers. The quantity of renewable gas produced would be variable and the number of RGCs issued also would be variable. Retailers and large users would be required to purchase a share of the total RGCs in line with their share of the total gas supply. This model leaves the quantity of renewable gas to be determined in the market, subject to emerging cost and demand trends, and leaves renewable gas investors facing uncertainty as to how much they can sell.

Each of these schemes could allow for periodic reviews of the targets. These reviews could add to or diminish the risks faced by market participants. For instance, periodic reviews of the target might be seen as an oversight mechanism to avoid the impacts of unexpectedly high RGC prices. But reviews would also be a chance to change the ambition of the scheme, which would add a degree of uncertainty to decisions about investments.

Market participants may enter into arrangements that change the risk allocations embodied in the RGT mechanism design. For instance, renewable producers and liable parties may form side contracts that reallocate the risks assigned to them by the RGT design, possibly in concert with financial intermediaries. For example, under the RET-like RGT mechanism, gas users may enter into long-term contracts with renewable gas producers which removes the price uncertainty associated with a sequence of annual on-market RGC purchases. Or end users may buy renewable gas producers, so that they are exposed to RGC prices as both purchasers and vendors, thus neutralising the impact of emerging price changes.

Bilateral transactions or pooled scheme

The RET-like RGT mechanism is structured around bilateral transactions between renewable gas producers, who create RGCs, and liable parties, who require RGCs to satisfy surrender obligations. Liable parties buy RGCs from eligible producers. Eligible producers sell/supply their renewable gas to gas users who may be entirely unconnected to the entities purchasing RGTs. Transactions in the renewable gas product itself are quite separate from the scheme.

Another alternative would be to establish a pooled scheme. Prior to the beginning of each year, the pool administrator would call for tenders from renewable gas producers to provide RGCs to it. Tenderers would offer one or more quantity/price offers. The pool administrator would place the offers in rank order and identify the price at which the offers were sufficient to meet the target quantity. The administrator would declare an RGC pool price equal to the price of the market clearing offer and each accepted offer would receive this pool price.[24] All offers at below the declared pool price would be accepted in their entirety and offers at the pool price would be accepted up to a fraction sufficient to meet the RGT.

To illustrate, suppose that the marginal renewable producer has a production cost of $75,000 per TJ and expects to receive $15,000 per TJ from selling the gas to a retailer. It therefore needs to receive $60,000 per TJ from the pool, so it bids in one RGC at $60,000.

The pool operator needs to recover the costs of the RGCs purchased, plus its administrative costs, from liable parties. It would make a prediction of the liability base for the coming year—e.g. aggregate sales and use of gas

[23] The complicating factor here is that when the schedule of renewable gas quantities is declared it is based on a long-term forecast of total gas supply. But the year-ahead forecasts of total gas supply that are made consecutively over time will depart from the original forecasts, because of unanticipated trends in gas consumption. This means that the renewable gas fractions as set on an annual basis will depart from the originally intended renewable gas fractions, at least if the renewable gas quantity target is held fixed.

[24] An alternative would be to set the price equal to the price of the first offer to miss out. At face value this would seem to ensure a higher price paid. But this is not necessarily the case when strategic dynamics are allowed for. Further attention would need to be given to market microstructure.

by retailers and large users—and it would then declare an RGT contribution per unitof gas sold to be paid by liable parties. It is likely that the actual liability base and the predicted liability base would ultimately differ, giving rise so surpluses or deficits on the pool. Any surplus or deficit would simply be rolled into the next-year pool, with next year RGC prices being higher to recover a deficit or lower in the event of a surplus. (The NEM provides a good example of the pooled purchase model, albeit considerably more complex than what would be required for the RGC, which does not raise any delivery or standby capacity issues).

To illustrate, if the gas price was $15,000 per TJ, the RGC price was $60,000, the RET was 1 per cent, and there were no administration costs, the pool operator would impose a levy of about $400 per TJ of gas taken on retailers and large users to cover the RGC costs.

A variant to this scheme would have the pool call for long/term offers—e.g. an offer might be to provide 50 RGCs per year for the next 10 years at a price of $50,000 per RGC. The required payments from liable parties would still be calculated annually on an emerging basis.

At the political level, it may be an issue that a pooled scheme is likely to be treated as involving taxes and government expenditures in public sector accounting frameworks. A bilateral scheme is not, even though its economic substance may be essentially identical.

State or national scheme

The RGT could be imposed with a uniform set of rules across the States (a “national scheme”). Or there could be different schemes in each State, with a variety of different policy settings. States could make their own choices about most of the design parameters outlined here.

Geographic sourcing of renewable gas

We assume that there are no barriers to interstate trade in renewable gas, consistent with constitutional free trade provisions. However, transport costs are a natural barrier to trade—and there is no pipeline between the eastern States and Western Australia.

The RET-like RGT mechanism is location neutral basis. Users of gas in one region can claim credit for renewable gas produced in a different region. There might not even be any prospect of physical delivery, e.g. Victorian gas consumers could surrender RGCs that were created from renewable gas production in Western Australia.

A RGT could instead have an element of local preference, e.g. only allowing RGT credit to renewables produced within the State.

Eligible renewable gases

The RET-like RGT mechanism is specified here to admit gases which use renewable primary energy inputs and have net zero emissions in aggregate across production, storage, delivery so long as they are supplied to an eligible use. Renewable gases are credited on the basis of their energy content.

At this stage biomethane and hydrogen appear to be the most prospective substitutes for fossil-fuel gas. Synthetic methane has also been suggested as an alternative. Other renewable gas supplies may emerge in the future.

A broader eligibility criterion could admit renewable gases which have net zero emissions in their supply chain, even if not from renewable primary energy sources—e.g. blue hydrogen with full carbon capture and storage and nuclear. We are not aware of any alternatives close to feasibility in this category.

Another alternative would be to credit renewable gases on the basis of their assessed impact on emissions. This is not entirely straightforward, and there would need to be guidelines to calculate the emissions associated with displaced gases and also to calculate the emissions associated with the renewable gas in its supply/use chain. If this approach were taken there might also be fractional allowance for some gases, e.g. blue hydrogen with incomplete capture and storage of carbon.

If the emphasis is more on supply chain development, the certificate allowances might depart from uniform energy-supplied or emissions-displaced bases. Different gases would receive different credits per unit energy depending on the degree of support to be provided to each. Alternatively, different gases might have different certificates, e.g. green hydrogen certificates and biomethane certificates.

Any consideration of what gases should be eligible should also be cognisant of evolving mechanisms in international markets. For example, it may be easier to secure recognition for a scheme that credits only renewable gases produced from renewable energy.

Segmented schemes

The RET-like RGT mechanism is structured as a uniform scheme. Renewable gas producers receive the same RGC credit for any eligible use of their gas. The disposition of that gas across end users is left to be determined in the market, according to commercial conditions.

Alternatively, an RGT could be composed of a number of segmented schemes. With segmented schemes, factors such as the ambition of the scheme could be differentiated across customer sectors. For instance, there could be a transport sector scheme requiring a certain proportion of renewable gas in the transport energy mix. Alongside, there could be a gas powered generation (GPG) scheme, requiring a different proportion of renewable gas in gas powered generation. And there could be a different scheme specific to gas delivered on the distribution networks. In the segmented approach, the target sets the quantities of renewable gas going to various end uses.

Liability to surrender certificates/allocation of costs

Under the RET-like RGT mechanism outlined above, the legal liability to surrender RGCs sits with retailers and large domestic gas users whose gas is not provided by a retailer. The economic incidence can be assumed to rest with stationary gas consumers in line with their gas consumption (i.e. retailers pass on their liability to their customers).

There are many other possible allocations. Two specifications that have a broader scope of liability than the RET-like RGT mechanism are:

- RGCs could be purchased by the Commonwealth Government, meaning that the taxpayer at large carries the liability and covers the cost of the scheme.
- The liability to surrender could be determined based on all final energy uses—coal, gas, electricity and petroleum. Legal incidence would rest with retailers and large users.

The liability could also be set more narrowly, being imposed on sectors such as gas-fired generation, large users (manufacturing) or smaller customers (commercial uses and households).

Liability could also be imposed on Australian exporters in respect of their energy exports.

Interaction with other schemes

Under the RET-like RGT mechanism, the Safeguard Mechanism would make allowance for reduced emissions as a result of renewable gas in the gas supply. However, it would not take into account (so would not need to assess) the renewable/fossil fuel mix of gas consumed, but would instead apply average emissions per TJ system-wide.

An alternative would be to make allowance for the Safeguard Mechanism in the RGT design. Parties who are liable under the Safeguard would be exempt from liability in the RGT mechanism. The Renewable Gas Target would be maintained, but the liability and thus the costs would be spread across gas users not subject to the Safeguard.

Integration with State schemes would be more challenging. The best approach is almost certainly to allow the States to adjust their scheme designs as they see fit in light of the RGT. Adjusting the RGT to align with one or other State schemes is more difficult because what aligns well with, say, New South Wales, would not necessarily be what aligns well with, say, Western Australia.

Concessions

The RET-like RGT mechanism specified here does not include any concessions for any liable parties.

An alternative would be to have concessions available to some large users where they can be shown to have trade-exposed activities that would be substantially adversely affected by an RGT.

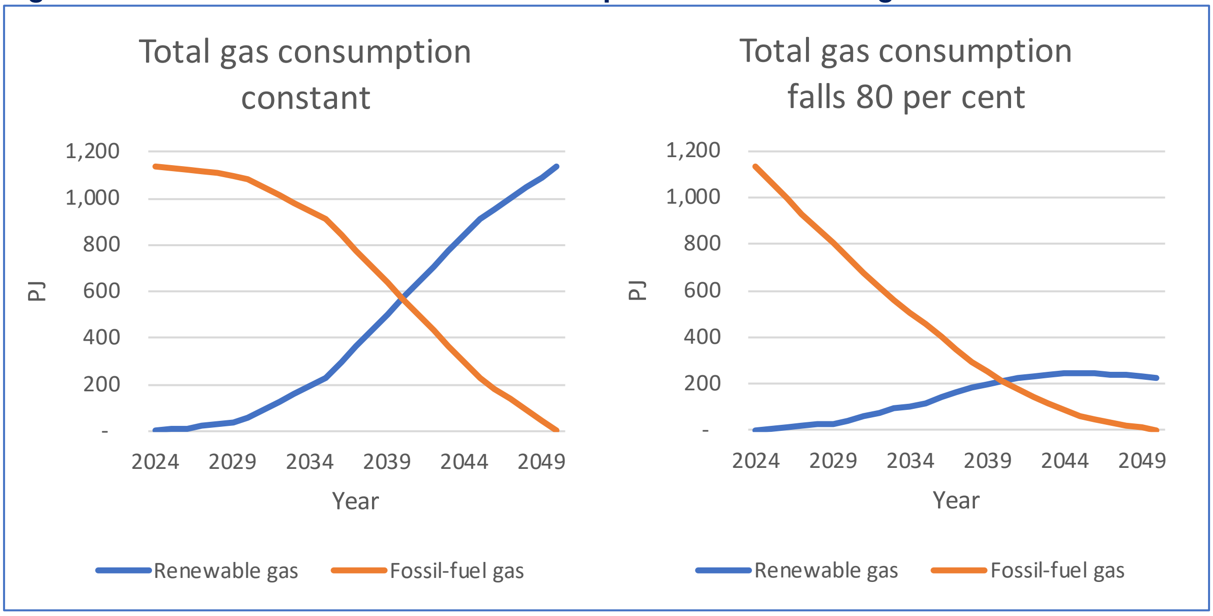
Ambition of scheme

There are myriad alternatives to the schedule set out for the RET-like RGT mechanism, both more and less ambitious.

The ambition presented is somewhat arbitrary but it has the features:

- it reaches net zero in 2050; and
- it embodies an adoption curve with slow adoption at the beginning, faster adoption as market share becomes substantial, and then slower adoption as it approaches a complete replacement of fossil-fuel gas—consistent with the shape of adoption curves that are commonly seen for numerous products.

Figure 8.1 Alternative scenarios for 100 per cent renewable gas



The ambition probably depends on the objective of the scheme. On the one hand, if the purpose is to eliminate emissions from gas, a high ambition may be desirable. On the other hand, if the purpose is to allow renewable gas to achieve scale and learning benefits, a lesser ambition may be appropriate, with the RGT terminating once a critical mass has been achieved.

It should be noted as well that the targets here are specified as a percentage of total gas, not as physical volumes and the percentage renewable target is compatible with widely varying gas volume scenarios. Figure 8.1 illustrates. In the left hand panel, gas volume is constant at 1,136 PJ out to 2050, and renewable gas volume thus rises to 1,150PJ. In the right hand panel, total gas volume falls 80 per cent to reach 227 PJ in 2050, and the renewable gas volume rises only to 227 PJ.

Penalty

The penalty is important because it sets a threshold value at which liable parties may choose to pay a penalty rather than meet their obligation to purchase renewable gas.

The penalty at $80,000 is rather arbitrary, but is thought to be interesting because it is consistent with a green hydrogen production cost of about $12.50 per kg, which is probably feasible today, and is well above the production costs that are anticipated. This penalty would thus strongly incentivise the adoption of green hydrogen (and indeed any other renewable gas that could be produced at comparably low costs).[25]

What would a RGC penalty at $80,000 mean for the cost competitiveness of green hydrogen? Assuming there were no additional costs of adapting infrastructure and appliances, it would mean that green hydrogen was feasible so long as its cost premium over fossil-fuel gas was no more than $80,000 per TJ. So if the cost of fossil-fuel gas were $15,000 per TJ then green hydrogen would be viable so long as it could be produced for less than $95,000 per TJ. Hydrogen production costs are often discussed in $ per kg, and this threshold value translates to about $12.50 per kg.

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Department of Climate Change, Energy, the Environment and Water (DCCEEW) (2022), *Australian Energy Update 2022*. https://www.energy.gov.au/

[25] With the penalty at $80,000, a renewable gas would be cost competitive so long as its cost premium over fossil-fuel gas was no more than $80,000 per TJ. (This assumes that there are no extra substitution costs, e.g. network upgrades or appliance replacement.) So if the cost of fossil-fuel gas were $15,000 per TJ then the renewable gas would be viable so long as it could be produced for less than $95,000 per TJ. Hydrogen production costs are often discussed in $ per kg, and this threshold cost translates to about $12.50 per kg, based on a hydrogen energy output of 135 GJ per tonne.

9. Conclusions

The approach to designing a Renewable Gas Target depends substantially on the purpose of the RGT. The main possibilities, not all mutually exclusive, are:

- emissions reductions
- developing a renewable gas supply chain in the domestic market
- energy security

If the purpose of the scheme is to support emission reductions by displacing fossil-fuel gas, the scheme should in a static sense seek to align the incentives for renewable gas production with the extent of fossil-fuel gas displacement. The scheme would seek to raise renewables in the gas mix to the point at which the marginal cost burden associated with renewable gas supply matches the marginal benefit of emissions abatement.

It is too narrow a view to regard a RGT as purely a mechanism to pursue static emission reductions. Renewable gas technologies and supply chains are immature, especially for green hydrogen. There is a clear potential for large reductions in production costs. Although the magnitude of savings that can be realised is highly uncertain, the experience with solar photovoltaic panels over the last few decades is salutary. Cost reductions with this technology exceeded most prior expectations as deployment and development of the technology proceeded.

Aside from scale-related technological improvements, there are also costs in reengineering the "operating system" of the gas market to accommodate renewable gases. Regulatory arrangements and standards need to change, markets need to evolve to accommodate the new products, and end users need to develop experience with them. A RGT can push this process of adaptation and learning along.

Each of the objectives may be of concern from a fundamental efficiency perspective—they are not mutually exclusive. When renewable gas displaces fossil-fuel gas then it makes a valuable contribution to reducing Australia's emissions. When a firm operating in one part of the renewable gas supply chain expands output, there may be spillover benefits to other firms in the supply chain—upstream, downstream and parallel. These benefits may be in the form of transferable knowledge, scale benefits and reengineering of the market and supply chain infrastructure. Because spillovers do not accrue to the firm that causes them, there is a tendency to underinvest, and a RGT can help to correct this. Similar issues arise in connection with energy security: while, in principle, energy security measures could be perfectly targeted at end users who fund them, the reality is that this is not practical and there is a broader public good from improved energy security. While these benefits can be recognised, it is much more difficult to quantify them.

The question of who should pay for interventions in renewable gas development is not easily answered. Although a natural starting point is to leave it to gas consumers, similar to the approach taken with renewable electricity, this risks pricing pressures that lead to an accelerated departure of customers from gas to electricity. Just how that would play out is, however, very uncertain.

In Australia the State Governments have had and will continue to have a leading role in the development of renewable gas. It is notable that there are considerable differences in approach and ambition across the States. The Australian Government has also played a lead role in planning for renewable gas, especially since the release of the national hydrogen Strategy in 2019. It will need to remain active seeking to maintain an appropriate level of consistency in regimes developed by the States. At present the States have a strong element of local preference in their renewable gas development activities, and while this may be appropriate at the infant industry stage it would be potentially inefficient if this approach were to be locked in beyond the start-up stage.

Around the world governments are, to varying degrees, looking to renewable gas as a component of a restructured energy mix. While there are good grounds to favour market neutral approaches in established product markets, the large-scale investments and lock-ins that arise in the energy sector suggest that governments should be wary of leaving it to the market to settle on a single solution. A RGT will help to test the contribution that renewable gases can make to the Australian energy mix and will reduce the risk that their potential is lost in a mass electrification process.

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www.futurefuelscrc.com

info@futurefuelscrc.com

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