Heat, power and flexibility to future-proof Gladstone

OCTOBER 2025

ACKNOWLEDGEMENT OF COUNTRY

We acknowledge and pay respect to the Traditional Custodians and Elders – past and present – of the lands and waters of the people of the Kulin nation on which the Climateworks Centre office is located, and all of the Elders of lands across which Climateworks operates nationally. We acknowledge that sovereignty was never ceded and that this was and always will be Aboriginal land. More information.

ACKNOWLEDGEMENTS

We thank Climateworks staff who contributed to the development of this report, in particular, Niamh Blackwood, Roland Somlai, Tommaso Mattia Pretto, Tim Graham, Anna Malos, Katherine Quinn, Glen Currie, Tyra Horngren, Amrit Bhabra, Tessa Leach and Hugh Sheehan.

ABOUT US

Climateworks Centre bridges the gap between research and climate action, operating as an independent not-for-profit within Monash University. Climateworks develops specialist knowledge to accelerate emissions reduction, in line with the global 1.5°C temperature goal, across Australia, Southeast Asia and the Pacific.

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Climateworks Centre, 2025, *Heat, power and flexibility to future-proof Gladstone*.

ISBN: 978-1-7637231-5-3

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Executive summary

Gladstone, located in Central Queensland, is a key industrial hub producing essential heavy manufacturing goods such as aluminium, cement and chemicals. While vital to Australia's economic development, Gladstone's industries are currently emissions-intensive. Most of these emissions are from the production of industrial heat, as almost 80 per cent of energy used to generate heat comes from burning coal and gas.

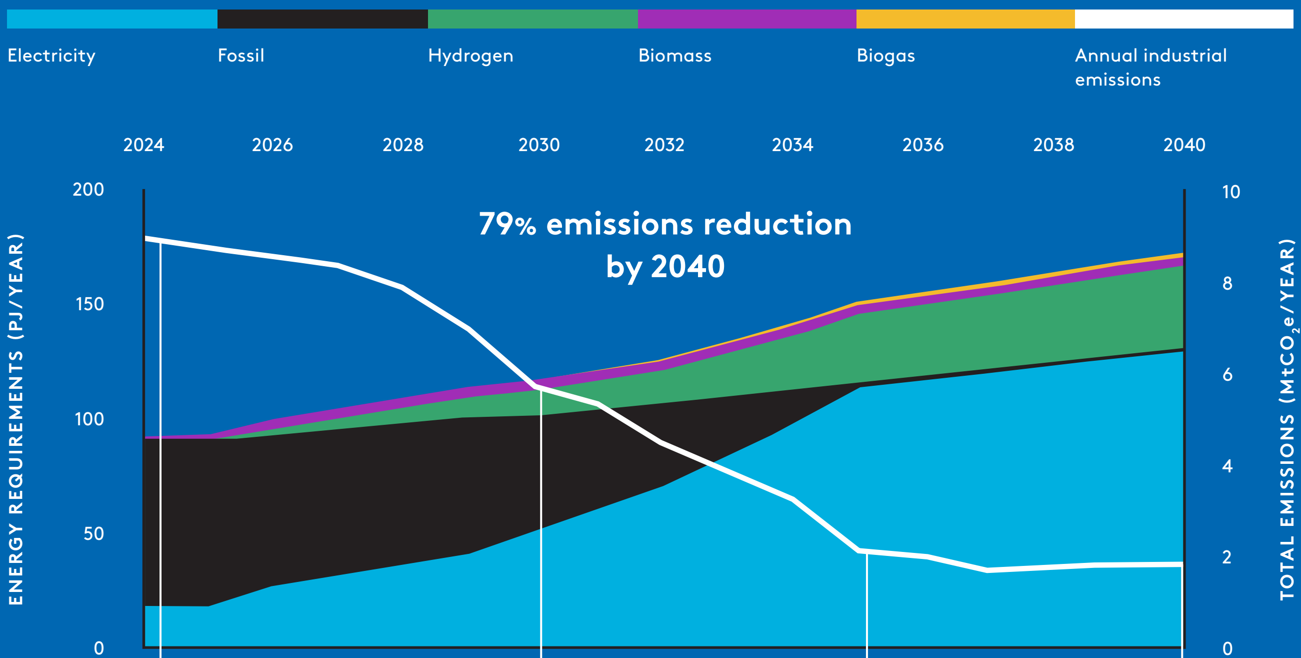
Industrial decarbonisation is critical to ensuring Gladstone's long-term economic resilience as the world transitions to a net zero economy under the goals of the Paris Agreement. With a strong concentration of emissions-intensive industries, Gladstone faces both significant risks and major opportunities in the shift to low-carbon manufacturing. Accelerating coordinated decarbonisation efforts in the region will be essential for Australia to meet its climate commitments while also securing regional prosperity.

This report focuses on two key opportunities for industrial decarbonisation in Gladstone: replacing fossil fuels used for industrial heat with low-carbon alternatives and complementing this shift with industrial energy demand management.

This offers a significant opportunity to reduce emissions while enhancing grid stability and securing Gladstone's prosperity in a decarbonising global economy.

Our modelling shows that Gladstone's industrial emissions could be cut by almost two-thirds by 2040 with a switch to low-carbon heat. More ambitious renewable energy plans could see an even greater reduction of close to 80 per cent.

Building on Climateworks Centre's previous work, this report presents a decarbonisation pathway for Gladstone's industrial heat. Key technologies include electrified heat, electrothermal energy storage, low-carbon fuels such as green hydrogen, biomass and biomethane, and carbon capture and utilisation (CCU). These technologies address both low- and high-temperature industrial processes.



	2025 – 2030	2030 – 2035	2035 – 2040
Alumina + aluminium	+ Fossil fuels begin to phase out through electrification of low-temperature heat at Gibbsitic facilities, biomass combustion, and increasing use of hydrogen for demonstration-stage calcination + Aluminium smelters switch to low-emissions electricity	+ Boehmitic facilities electrify low-temperature heat via electric boilers paired with double-digestion technologies + Hydrogen calcination scales up + Biomass share decreases as more facilities electrify	+ Electric boilers and hydrogen for calcination have completely displaced fossil fuels
Cement + lime	+ Fossil fuels begin to phase out through biomass combustion to provide high-temperature heat	+ Cement and lime facilities introduce CCU technologies + Biomass fuel share continues to increase	+ Combustion of biomass, waste fuels and hydrogen have displaced 75% of fossil fuels
Chemicals (explosives and sodium cyanide)	+ Facilities prepare for phase-out of fossil fuels through acquisition and installation of necessary assets and infrastructure	+ Chemical production facilities begin to phase out fossil fuels through biomethane combustion and deployment of electric boilers	+ Electric boilers and the combustion of biomethane have completely displaced fossil fuels
Hydrogen	+ Hydrogen production facilities begin to operate	+ Hydrogen production scales up	+ Hydrogen production has reached its peak to supply existing industry

Our modelling shows that by 2040, decarbonising Gladstone's industrial heat could result in a sevenfold increase in industrial electricity consumption to 36 terawatt hours (TWh) per year, compared to 2022. Green hydrogen will also be essential for long-term decarbonisation of high-temperature heat, with an annual demand of 296 kilotonnes (kt) per year by 2040 for Gladstone's existing industries. Biomass and biomethane can also play a short-term transitional role as easily substituted 'drop-in' alternatives to fossil fuels, particularly if Gladstone's access to large-scale renewable electricity or green hydrogen production is delayed.

The report highlights the significant role industrial demand response – a consumer-led adjustment of electricity use – could play in the transition. Flexible demand could help increase grid reliability and avoid costly infrastructure overbuild by enabling a more effective use of renewable energy for electrification.

Electrifying Gladstone's industries in flexible ways could more than double Australia's ability to stabilise the energy grid – providing up to 4.4 gigawatt (GW) of demand response capacity by 2040. Energy demand management for industrial heat could not only reduce demand at current peak periods by around 2 GW but also save Gladstone's industries $3 million a day in operating costs.

Critically, using electrothermal storage technologies in Gladstone's alumina sector could enable industrial flexibility at scale without compromising productivity, and represents the most cost-effective route for electrifying low-temperature heat.

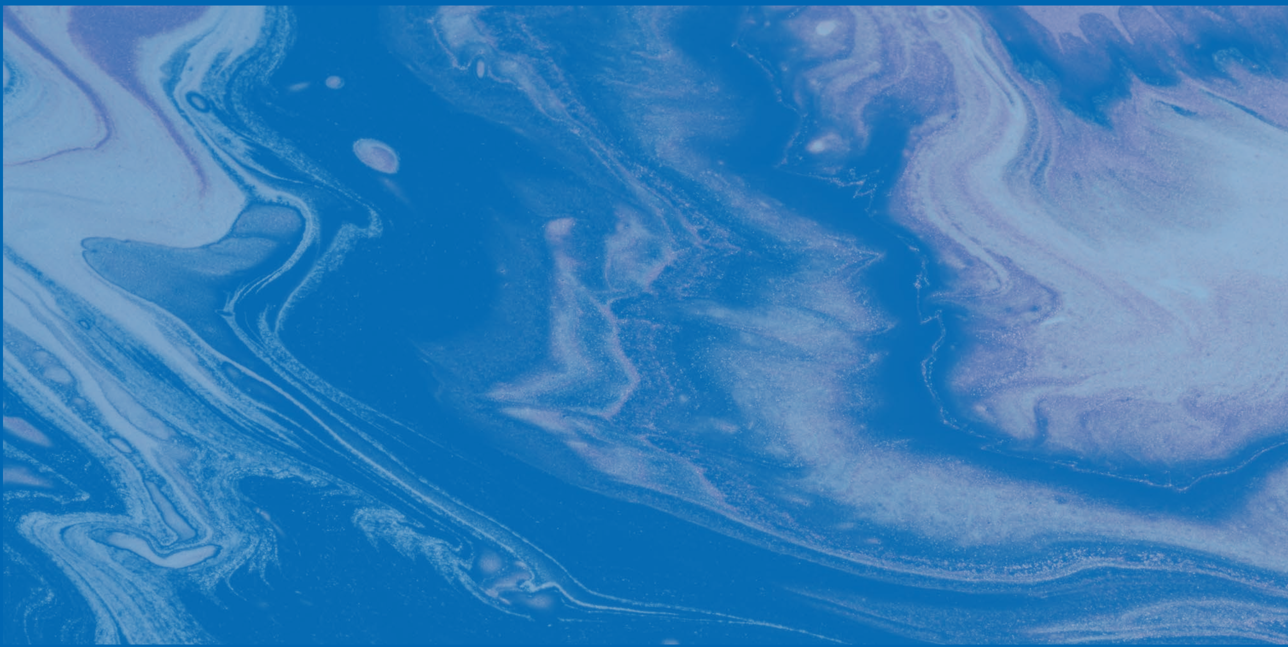
Our analysis shows electrothermal storage could fundamentally alter Queensland's energy landscape and reduce electricity costs, not just for industry but for consumers across the grid. Adding storage to Gladstone's industries could cut wholesale electricity prices by as much as 60 per cent, lowering costs for industry and consumers alike.

While the necessary technologies already exist, they face deployment barriers, including high upfront and operational costs for decarbonisation assets, limited supply of low-carbon fuels and renewable electricity, and energy planning that currently underestimates the scale and pace of industry's decarbonisation ambition.

To examine how other markets around the world have overcome these challenges, this report presents a series of case studies of best practices, including:

+ financing and de-risking strategies that are used to support industrial decarbonisation and the manufacturing of low-carbon goods
+ demand response programs that are used to encourage increased flexibility and the provision of demand response capacity.

While this report is focused on Gladstone, the industrial technologies, challenges and opportunities are not unique to Gladstone. The report sets out targeted recommendations to enable the net zero transition in Gladstone, as well as other Australian industrial regions like it. These actions could accelerate heavy industry's decarbonisation and the transformation of Australia's energy system, while also unlocking significant benefits for consumers across the grid.



Regulatory recommendations

- Explore how to create a renewable heat target for industry to complement existing renewable energy targets, providing industries with the clear signal needed for investment confidence.
- Implement a carbon leakage mechanism at the federal level to prevent emissions-intensive imports from competing with low-carbon domestic goods that bear additional costs, encouraging Australia's industries to invest in decarbonisation technologies.
- Explore how to create dynamic pricing structures for heavy industry's electricity consumption to encourage the cost-effective utilisation of Australia's renewable energy resources and make electricity more affordable.

Funding recommendations

- Develop a coordinated approach between public-sector funding bodies that supports upfront costs of low-carbon industrial heat, through targeting specific technologies and fuel types that address all industrial heat temperature ranges.
- Consider subsidies for downstream components of low-carbon supply chains, including metal processing and cement and chemicals production, to complement current subsidies for upstream components like hydrogen or renewable electricity.

Demand management recommendations

- Expand Australia's electricity demand response capacity by lowering barriers for participation and increasing incentives for long-term provision of services, to ensure a stable and accelerated path to electrification across Australia.
- Consider seasonal electricity demand response measures to reduce the need for gas-based peaking generation for grid reliability during periods when renewables are scarce.

1. Introduction

As the world transitions to a net zero economy to meet the Paris Agreement goals to limit global warming, industrial decarbonisation will be crucial for Australian companies to secure their long-term economic resilience. Direct emissions from the industry sector (known as scope 1 emissions) accounted for around 17 per cent of Australia's emissions in 2022.[1] Three-quarters of these emissions originated from a few large industrial facilities in the aluminium, cement and chemicals supply chains (Climate Change Authority 2024; DCCEEW 2023a). Collectively, the manufacturing sector contributes 6 per cent of Australia's gross domestic product and generates 21 per cent of Australia's total export value (Reserve Bank of Australia 2025; Australian Bureau of Statistics 2023). A coordinated and fast-paced decarbonisation of the regions where these manufacturing companies operate could enable Australia to meet its obligations under the Paris Agreement while ensuring these industrial regions remain prosperous.

As part of the Australian Industry Energy Transitions Initiative, Climateworks Centre identified the emissions reduction potential for five of Australia's largest emitting and most economically significant industrial regions, along with the actions needed to support their decarbonisation (Climateworks Centre and Climate-KIC 2023). Gladstone, in Central Queensland, was one such region and was recently the focus of Climateworks' report *Seizing Gladstone's low-carbon opportunity: A net zero industrial precinct approach* (Climateworks Centre 2025). This report detailed how nearly all emissions from the region's heavy manufacturing could be reduced through a place-based, net zero industrial precinct (NZIP) approach.

Gladstone's co-located existing industry, infrastructure and energy generation make it well suited for an NZIP approach. This involves a collaborative, regional approach to reducing emissions from heavy industry. By organising highly productive industrial zones like Gladstone and naming them NZIPs, collective industrial decarbonisation can be facilitated through coordinated investment and policies that promote regional prosperity. For an NZIP, industrial actors and government agencies can come together to implement technological, economic and policy solutions that reduce investment costs and risks, aiming to secure firm renewable energy and produce competitive low-carbon products that will be in demand as the world transitions to net zero. Working to reduce emissions of a whole NZIP, rather than one company at a time, could set regions up for success.

In the *Seizing Gladstone's low-carbon opportunity* report, we presented five recommendations to facilitate the adoption of an NZIP approach, not only in Gladstone but in other regions with clustered industrial facilities. These recommendations are:

+ Energy planning authorities create 'regional Integrated System Plans' for Gladstone and other major industrial regions, building on the Australian Energy Market Operator (AEMO) 'Green energy exports' scenario, resulting in new electricity infrastructure being built at the scale required.
+ Governments develop policies to support low-carbon industrial heat at scale, including national and state-level industrial heat strategies, financing models and a coordinated funding response to support early-stage technologies and deployment of low-carbon heat technologies at scale.
+ Energy demand management policy and energy efficiency mechanisms for heavy industry be expanded, optimising infrastructure development and costs for all energy users.
+ Governments enact measures to support early hydrogen demand in existing industries, catalysing a low-carbon hydrogen market in industrial regions.
+ Governments and industry endorse high-quality standards for low-carbon products, ensuring consistency between Australia's emissions intensity standards and international standards.

In this report, we focus on two of these recommendations – the decarbonisation of industrial heat at scale and industrial energy demand management – as these were identified as significant opportunities for decarbonising industry in Gladstone and industrial regions like it.

1 Based on Climateworks analysis, with industrial emissions data (excluding the waste subsector) drawn from the Climate Change Authority 2024 *Sector pathways review: Industry and waste and Australia's total emissions* drawn from the *Quarterly update of Australia's national greenhouse gas inventory: December 2022* (DCCEEW 2023a).

This report looks at the pathway to decarbonise industrial heat for some of Gladstone's major manufacturing industries (Figure 1) through an analysis of:

+ the technologies and fuels available to decarbonise industrial heat – and their benefits and challenges
+ Gladstone's sources of industrial demand management – and the untapped opportunity they present for Queensland's electricity security
+ ways to unlock low-carbon industrial heat and demand management, by applying examples of international best practice to the Australian context.

While this analysis focuses on Gladstone, the technologies, fuels, challenges and opportunities are not unique to it. The report therefore aims to inform decision-makers in Australian federal and state governments of the practical options to support industrial decarbonisation in industrial regions across Australia.

FIGURE 1: Scope of products and facilities included under Climateworks' Gladstone study

SUPPLY CHAINS IN SCOPE	FACILITIES IN SCOPE
+ Alumina + Aluminium	+ QAL alumina refinery (Rio Tinto) + Yarwun alumina refinery (Rio Tinto) + Boyne smelters (Rio Tinto)
+ Clinker + Cement + Lime	+ Fisherman's Landing Plant (Cement Australia)
+ Commercial explosives + Sodium cyanide	+ Orica Yarwun (Orica)
+ Green hydrogen + Green ammonia	+ H2Hub facility (H2U)

OUT-OF-SCOPE ACTIVITIES

+ Energy efficiency upgrades
+ Decarbonisation of process emissions
+ Uses of green hydrogen outside of decarbonising existing supply chains

BOX 1:

Climateworks' research methodology

This report uses findings of a modelled scenario, in which Gladstone follows a pathway to decarbonise industrial heat informed by industrial ambitions aligned to net zero by 2050 targets, and builds on a pathway found in Climateworks' previous report *Seizing Gladstone's low-carbon opportunity*. However, we have supplemented the pathway with additional analysis and additional or updated inputs (including bioenergy and the production of lime and sodium cyanide).

Notably, to better focus on Gladstone's existing industries, we have excluded the facilities, projects and energy demand associated with green hydrogen production for export that were included in our previous report. We note that the H2Hub facility has stated the intention to produce hydrogen for both domestic and export purposes, however the modelling in this report includes only the former. While some inputs to the current report have been provided confidentially by Australian industrial stakeholders, most inputs specific to the modelling are available in the Appendix.

Climateworks' heavy industry program has consulted Gladstone's industrial stakeholders and those across Australia, technology providers, governments, research organisations and NGOs to arrive at a technology pathway. The pathway is not intended to represent the stated goals or intentions of the companies in scope for the analysis.

1.1. Gladstone, in Central Queensland, serves as an ideal case study for the implementation of low-carbon heat and demand management as solutions for industrial decarbonisation

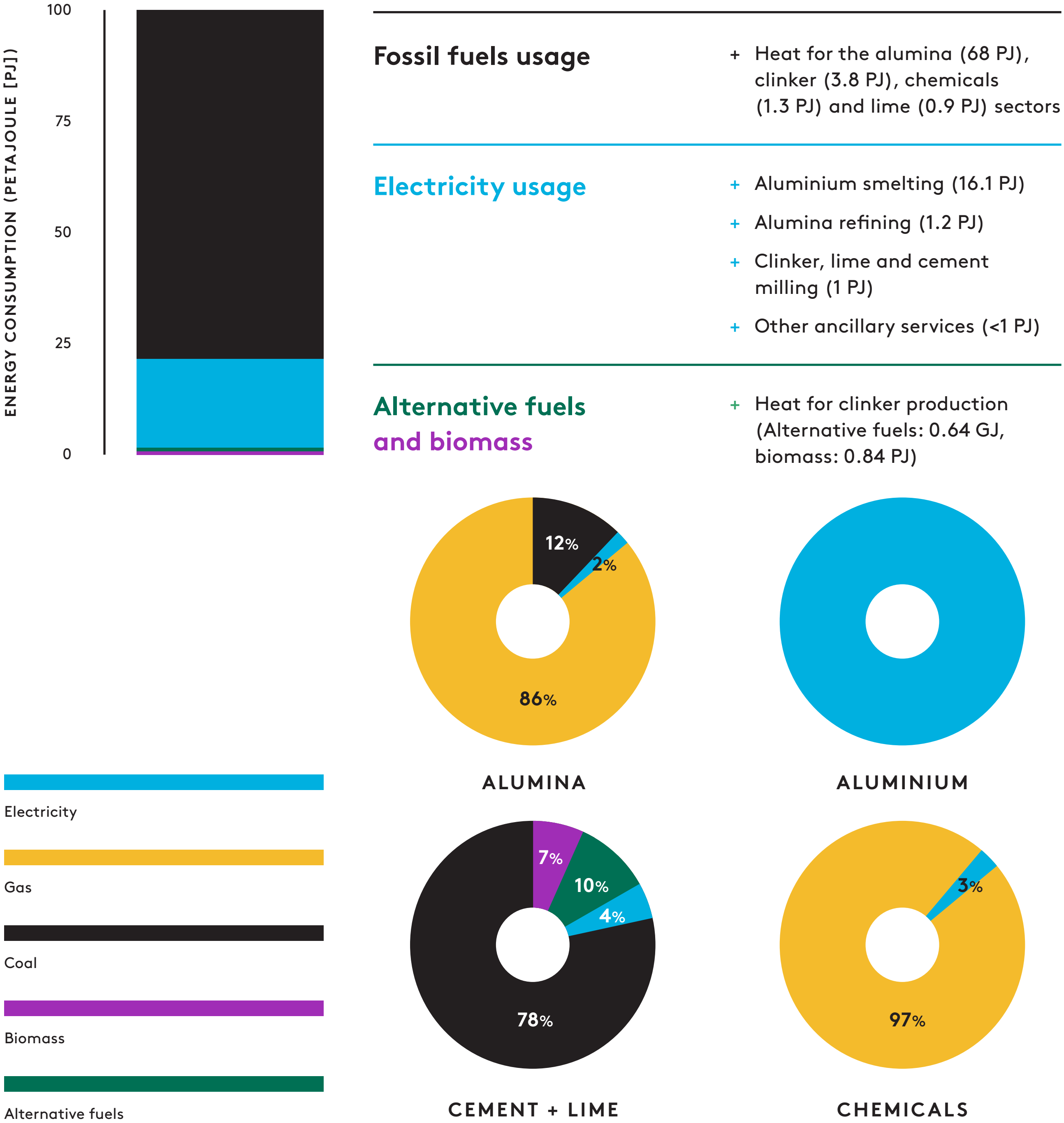
Gladstone produces heavy manufacturing products such as alumina, aluminium, clinker, cement, lime and various chemicals critical to the mining industry, with these products largely split between three companies – Rio Tinto, Orica and Cement Australia.[2] Roughly 5.6 million tonnes of alumina, around a third of Australia's total alumina exports, were exported via the Port of Gladstone in FY2022 (Gladstone Ports Corporation n.d.), and manufacturing contributes significantly to Gladstone's local economy, representing roughly 4,520 out of a total 24,267 jobs (Central Queensland Regional Organisation of Councils n.d.).

To maintain Gladstone's prosperity in a decarbonising global economy, implementing solutions for low-carbon heat will be critical. Gladstone's manufacturing sector is currently emissions-intensive and highly dependent on fossil fuels. Our analysis found that over 79 per cent of current, non-feedstock industrial energy consumption is fossil fuel-based, and used largely for heat generation through the burning of coal and gas (Figure 2).[3] A coordinated low-carbon heat strategy could therefore enable Gladstone's industrial stakeholders to meet their net zero commitments and ensure Gladstone's continued relevance through its transformation into a clean industry hub. As this heavy dependence on fossil fuels is common to Australian heavy industry as a whole, it is likely that a similar low-carbon heat strategy will benefit other industrial regions across Australia (Climate Change Authority 2024).

2 While Gladstone has a large liquified natural gas (LNG) manufacturing presence and is a significant energy user, LNG has been excluded from this study as its electricity source is not supplied by the electricity grid.

3 Industries in scope for this analysis are detailed in Figure 1. Non-feedstock energy consumption is defined as the energy used to provide heat or run industrial processes, and excludes the energy embodied within the raw materials for the manufactured products.

FIGURE 2: Non-feedstock energy consumption by Gladstone's industries in 2024



Climateworks' *Seizing Gladstone's low-carbon opportunity* report found that decarbonising Gladstone's industries could require significantly more electricity than is currently indicated in the AEMO 'step change' scenario. This means that the scale of planned utility-scale infrastructure and the pace at which it is to be built may be insufficient for Gladstone's industries to meet their decarbonisation targets.

Demand management, defined as a consumer-side shifting or reduction of electricity use, can mitigate the total quantity of electricity needed during periods of high consumption, while also enabling more efficient use of renewable energy resources. Demand management, as an industry-led solution for addressing Gladstone's energy requirements, is complementary to the supply-side build-out of utility-scale renewable energy infrastructure.

This could minimise the total quantity and costs of energy generation infrastructure that needs to be built. Recent studies have found that across Australia, savings from mitigated infrastructure costs through demand management could be up to $39 billion by the 2040s (Briggs et al. 2024). The fast-paced implementation of demand management practices in Gladstone, in coordination with energy system planners, can therefore be used to support the reliable and cost-effective decarbonisation of industry while also providing whole-of-network benefits across Queensland (Rio Tinto 2025a; Cement Australia n.d.; Orica 2024). Again, due to the identified need for industrial electrification across all of Australia's heavy industries, the recommendations for demand management implementation in this report could be applied to other Australian industrial regions with similar benefits to their surrounding communities (Climateworks Centre and Climate-KIC 2023).

BOX 2:

Climate inaction in Gladstone could compromise its future as a regional manufacturing hub

Gladstone's major heavy manufacturing companies – Rio Tinto, Orica and Cement Australia – have committed to net zero scope 1 and 2 emissions by 2050, with Rio Tinto and Orica also setting 2030 emissions reduction targets of 50 per cent and 45 per cent respectively (Rio Tinto 2025; Cement Australia n.d.; Orica 2024). These commitments recognise that decarbonisation strategies are more than just a tool to address environmental concerns or adhere to regulatory requirements; they are critical to ensure long-term organisational stability and profitability.

Volatile fossil fuel prices, high electricity prices and exposure to carbon penalty costs are some economic risks that industry recognises it is susceptible to if it fails to decarbonise. Recently, industrial leaders have acknowledged that high domestic natural gas and electricity prices have been responsible for Australian industries' reduced competitiveness or even shutting down entire manufacturing sectors (ABC News 2024; Unconventional Economist 2025). Meanwhile, domestic regulations, such as the Safeguard Mechanism or international carbon leakage mechanisms, can also levy financial penalties on companies that remain emissions-intensive. Securing long-term, cost-effective and low-carbon energy supplies for industrial processes is thus recognised as a crucial investment decision by Gladstone's companies.

These companies also recognise that they cannot bear the weight of this transition alone without exposing themselves to significant financial risk, and as such have all stated that achieving their net zero ambitions will require a cooperative partnership with government at all levels. Governments can best support this challenge through a consistent, enduring stance on decarbonisation goals via effective policy frameworks, supportive regulation and financial incentives to build investment confidence in decarbonisation. Failure to provide this certainty could result in the closure of Gladstone's industrial companies, and a resulting loss of jobs and regional prosperity.

2. Decarbonising industrial heat can address most of Gladstone's current fossil fuel use

This report aims to demonstrate how low-carbon industrial heat can be achieved through a coordinated, shared approach, even in heavy manufacturing facilities that require a broad range of process heat temperatures.

BOX 3:

Industrial heat temperature ranges

Industrial manufacturing requires a broad range of temperatures for its heating needs, with these temperatures depending on the industrial process involved, and could include processes like refining, melting, drying or activating chemical reactions. This heat is typically generated either directly through an electric heating element or via combustion of a fuel followed by delivery through a transfer medium, such as water, steam or gases. Heat-generation assets are typically co-located, owned and operated by the manufacturing facilities that they supply. While definitions for temperature ranges tend to differ based on the industry involved, this report classifies industrial heat grades into four ranges:

Very low temperature: Below 150 degrees Celsius (°C)

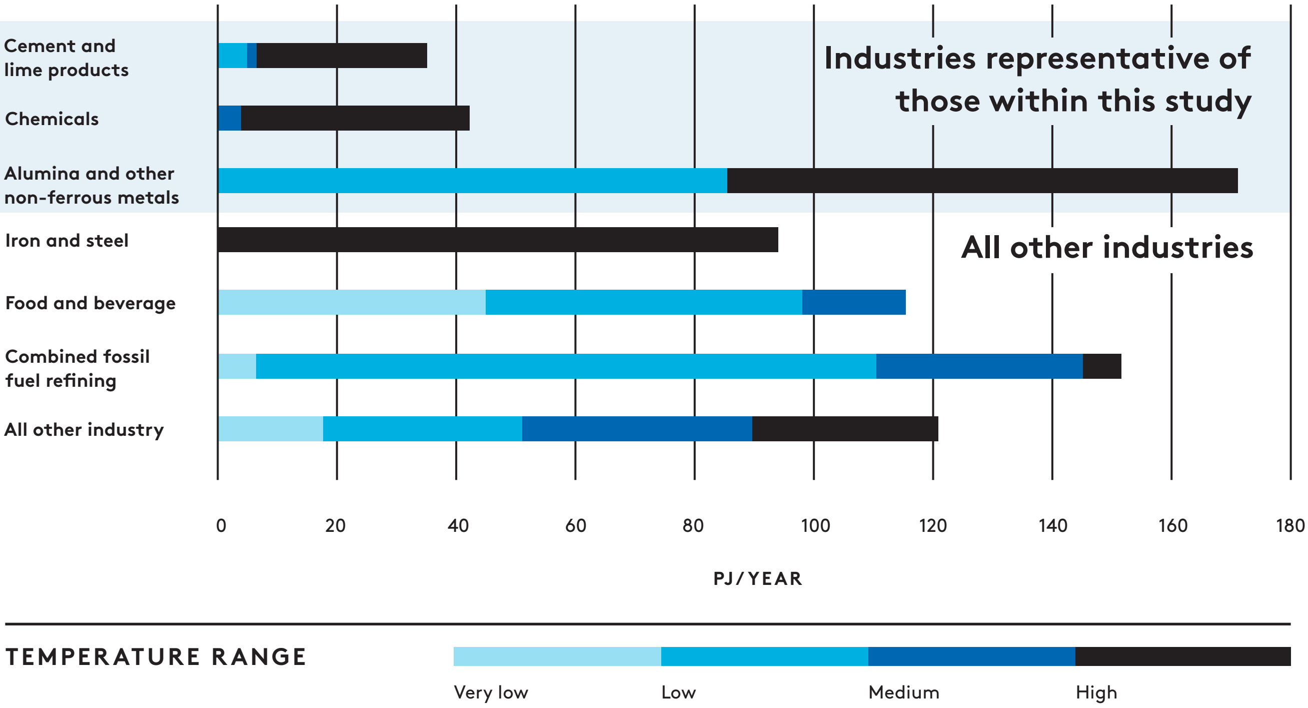
Low temperature: 150–250°C

Medium temperature: 250–1,000°C

High temperature: Above 1,000°C

The heavy manufacturing industries discussed in this report, described in Figure 1, mainly require a mix of temperatures from low- and high-temperature heat ranges (Figure 3). Compared to other major Australian industries like paper processing or food and beverage production, Gladstone's industries have a greater need for high-temperature heat to initiate chemical reactions, such as for the production of alumina or clinker.

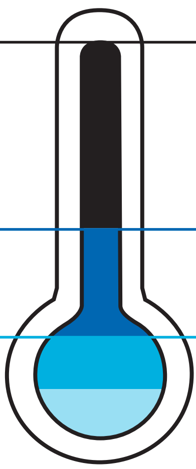
FIGURE 3: Industrial heat use by temperature and industry across Australia



Data source: Lovegrove et al. 2019

For our modelling, Gladstone's industries were divided into distinct industrial processes, further categorised by the grade of heat they require (Figure 4). Gladstone's industrial processes occupy each end of the temperature spectrum, with requirements typically above 1,000°C or below 250°C. Regardless of the temperature required, heat is currently typically supplied through the combustion of fossil fuels, producing temperatures of around 2,000 to 3,000°C. This method is highly inefficient as much of the energy is wasted, particularly for processes requiring low temperatures of less than 250°C. In aluminium smelting, heat is generated through an electrochemical process that consumes substantial quantities of electricity. Combined, fossil fuel combustion for heat and electricity for aluminium smelting comprises most of the current industrial fuel use, as detailed in Figure 2.

FIGURE 4: Temperature requirements for Gladstone's industrial processes



Above 1000°C	**High-temperature processes**	+ Alumina (calcination) + Lime (calcination) + Clinker (calcination) + Chemicals (sodium cyanide production)
250-1000°C	**Medium-temperature processes**	+ Alumina (digestion, Boehmitic ores)
0-250°C	**Very low/low-temperature processes**	+ Alumina (digestion, Gibbsitic ores) + Chemicals (nitric acid production) + Chemicals (ammonium nitrate production)

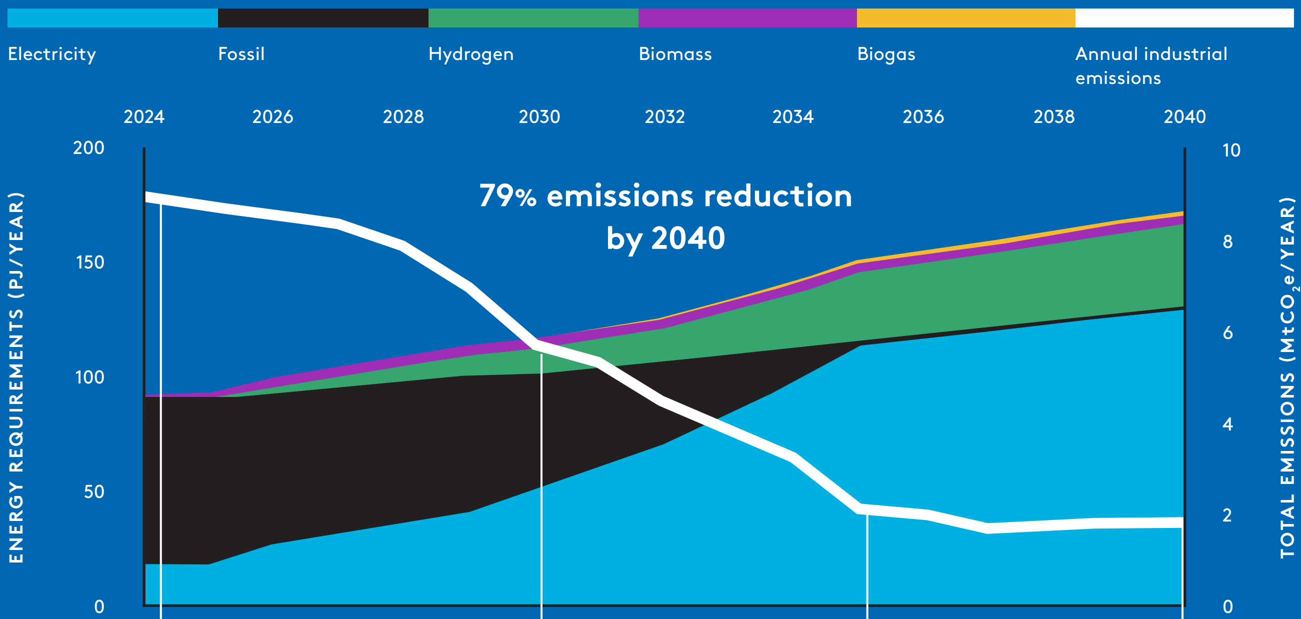
3. Low-carbon heat technologies already exist, but face deployment barriers

Climateworks has developed a pathway for decarbonising Gladstone's industrial heat to 2040 (Figure 5), aligned to the emissions targets of its industries and the specific activities they intend to take to achieve them.

In this way, Climateworks has quantified the net zero ambitions of all its industries. Incorporating region- and facility-specific inputs could see a reduction of all non-process emissions of 79 per cent by 2040.[4] This is equivalent to two-thirds of all scope 1 and 2 industrial emissions in Gladstone.

4 Non-process emissions are defined as all heat-related scope 1 emissions and all scope 2 emissions.

FIGURE 5: Technology deployment pathway for decarbonising Gladstone's industrial heat, including emissions reductions and energy requirements to 2040



	2025 – 2030	2030 – 2035	2035 – 2040
Alumina + aluminium	+ Fossil fuels begin to phase out through electrification of low-temperature heat at Gibbsitic facilities, biomass combustion, and increasing use of hydrogen for demonstration-stage calcination + Aluminium smelters switch to low-emissions electricity	+ Boehmitic facilities electrify low-temperature heat via electric boilers paired with double-digestion technologies + Hydrogen calcination scales up + Biomass share decreases as more facilities electrify	+ Electric boilers and hydrogen for calcination have completely displaced fossil fuels
Cement + lime	+ Fossil fuels begin to phase out through biomass combustion to provide high-temperature heat	+ Cement and lime facilities introduce CCU technologies + Biomass fuel share continues to increase	+ Combustion of biomass, waste fuels and hydrogen have displaced 75% of fossil fuels
Chemicals (explosives and sodium cyanide)	+ Facilities prepare for phase-out of fossil fuels through acquisition and installation of necessary assets and infrastructure	+ Chemical production facilities begin to phase out fossil fuels through biomethane combustion and deployment of electric boilers	+ Electric boilers and the combustion of biomethane have completely displaced fossil fuels
Hydrogen	+ Hydrogen production facilities begin to operate	+ Hydrogen production scales up	+ Hydrogen production has reached its peak to supply existing industry

The pathway shown in Figure 5 is reliant on:

+ the immediate electrification of heat where possible
+ fuel switching to low-carbon fuels like green hydrogen or bioenergy where technological or energy-supply constraints prevent electrification
+ the use of carbon capture as a last resort.

Achieving this will require a significant shift in Gladstone's energy use, with current fossil fuel consumption largely replaced by electricity and green hydrogen in our modelling. By 2040, electricity and hydrogen comprise 95 per cent of Gladstone's industrial energy use, leading to a sevenfold increase in industrial electricity consumption to 36 TWh per year, compared to 2022, and an annual green hydrogen demand of 296 kt (or 35 PJ)[5]. This displaces around 10 PJ of coal use and around 58 PJ of natural gas use.

Biomass and biomethane could also be important components of Gladstone's decarbonisation. These fuels are modelled as:

+ a long-term fossil fuel replacement for industries that are currently considered difficult to electrify (e.g. cement) or require specific chemical feedstocks (e.g. chemicals production)
+ a short-term, low-cost method of phasing out fossil fuels before renewable electricity and hydrogen are available at scale.

In our modelled pathway, at peak demand in 2032, 4 PJ of biomass and 8 PJ of biomethane could be required in Gladstone. By 2040, biomass and biomethane comprise a combined 3 per cent of Gladstone's energy mix.

These bioenergy-based fuels could play an important short-term role as transition fuels, particularly if large-scale renewable electricity or green hydrogen production is delayed. In such an event, it is likely that, to meet decarbonisation targets, industries will have to rely more on biomass and biomethane than what our modelling suggests.

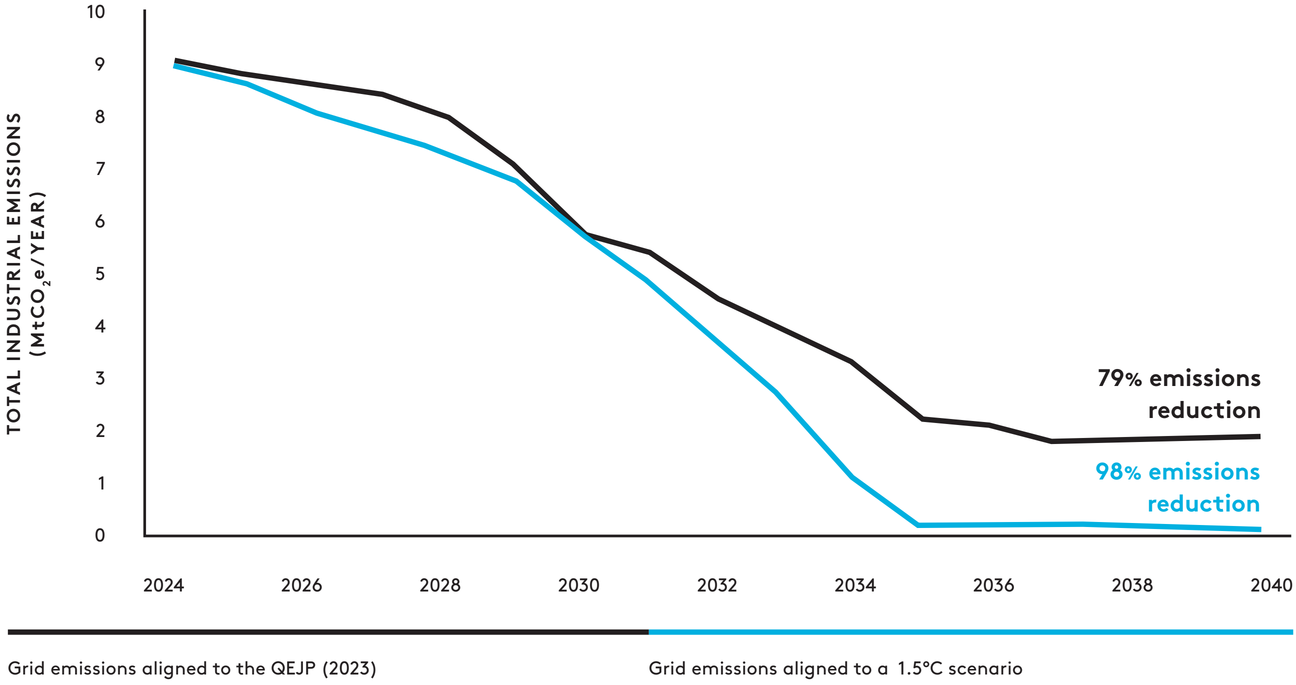
3.1. Completely reducing Gladstone's industrial heat emissions depends on a decarbonised grid

Our modelled pathway shows that Gladstone's industries could reduce their non-process emissions by 79 per cent by 2040, compared to their current levels. The bulk of the remaining emissions, totalling 1.9 million tonnes of carbon dioxide equivalent ($MtCO_2e$)/year, are other industrial scope 2 emissions from electricity generated for Queensland's grid. To calculate these emissions, Climateworks' modelling uses grid emissions intensities aligned to targets under the *Queensland Energy and Jobs Plan* (QEJP), which aimed to achieve an 80 per cent share of renewable generation in the grid by 2035 (DCCEEW 2024).The high degree of electrification in Climateworks' decarbonisation pathway, particularly in the alumina sector, means that reducing emissions beyond our modelled 79 per cent prior to 2040 is dependent on increasing the amount of Queensland's renewables generation above the targets in the QEJP.

Modelling in *Climateworks Centre decarbonisation scenarios 2023* shows how Australia's grid decarbonises in a scenario aligned to limiting global warming to 1.5°C (Climateworks Centre 2023). For Queensland, this equates to a renewables share of 99 per cent by 2040. Using this share of renewables and resulting grid emissions intensity, we found that Gladstone's industries could achieve a non-process emissions reduction of 98 per cent by 2040 (Figure 6).

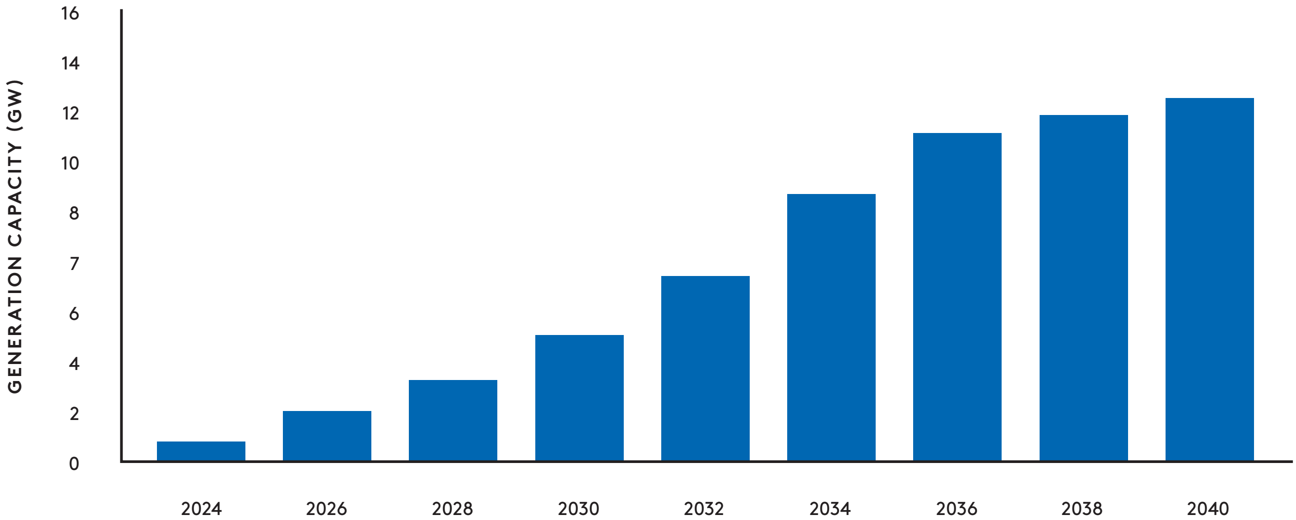
5 As this modelling focuses on Gladstone's existing industries, the electricity and hydrogen demand forecasts differ from those given in our *Seizing Gladstone's low-carbon opportunity* report, which includes low-carbon energy exports. Full details on the methodology can be found in the Appendix.

FIGURE 6: Sensitivity analysis of the impact of Queensland's grid emissions intensity on Gladstone's non-process industrial emissions



To decarbonise Gladstone's industrial heat with a 1.5°C-aligned share of renewables could require up to 14 GW of new renewables generation capacity by 2040 (Figure 7). While this is significant, encouragingly, Rio Tinto has already independently secured 2.7 GW of renewable energy, equivalent to 20 per cent of our modelled required capacity, for their Gladstone operations through wind, solar and battery projects (Rio Tinto 2025b). Furthermore, in AEMO's 2024 Integrated System Plan (ISP), the Renewable Energy Zones (REZs) surrounding Gladstone contain up to 92 GW of solar and wind capacity (AEMO 2024a). Using energy storage and demand management programs can also help reduce the amount of generation and transmission infrastructure needed in our modelling, as discussed in Section 4.

FIGURE 7: Combined wind and solar generation capacity required to decarbonise Gladstone's industrial heat with a 1.5°C-aligned share of renewables



BOX 4:

Process emissions

For some of the manufacturing industries discussed, decarbonising process (i.e. non-energy) emissions is of equal or greater concern than decarbonising industrial heat.

For example, for the cement sector, emissions produced from burning coal to heat limestone are only around 30 per cent of the total emissions produced. Instead, most emissions are produced from the limestone itself as it is converted into clinker or lime. Producing nitric acid – an important intermediate for the chemicals produced in Gladstone – also produces significant process emissions, as does the reduction of anodes in aluminium smelting. Addressing these emissions is an important component of the decarbonisation strategies of Gladstone's industries, but is outside the scope of this study.

3.2. Gladstone's industrial heat decarbonisation pathway: key technologies and fuels

Four key technologies or processes underpin Climateworks' industrial heat decarbonisation pathway for Gladstone's industries:

+ electrified heat
+ electrothermal energy storage (ETES)
+ switching to low-carbon fuels
+ carbon capture and utilisation (CCU).

Renewable electricity at scale will be required to power or facilitate these technologies or processes. However, we have also identified three additional key forms of energy or fuels – biomass pellets, biomethane and green hydrogen – that could be required at scale in Gladstone.

Our modelling shows renewable electricity could make up most of the energy needed to decarbonise Gladstone, primarily for the electrification of heat and the production of green hydrogen. Green hydrogen, biomass and biomethane, as low-carbon fuels, could also play a critical role in Gladstone's decarbonisation despite their small share in our modelled energy mix and the fact that their production is currently limited in scale in Australia. In the long term, green hydrogen could be the most compelling solution to decarbonise key heavy industry subsectors, such as the high-temperature requirements of the industries in this case study. Biomass and biomethane have the potential to rapidly scale up and enable industrial decarbonisation in the short term, if renewable electricity or green hydrogen are not made available at the scale or speed required to support industry's decarbonisation.

We have further categorised the technologies and fuels by the temperature ranges they are best suited for in our decarbonisation pathway for Gladstone's industrial heat, and how quickly they are likely to be deployed in Gladstone (Table 1). Under the right conditions, the development and deployment of these technologies could occur even faster (Climateworks Centre and Climate-KIC 2023).

TABLE 1: Applications of the key technologies, fuels and processes from this report for Climateworks' decarbonisation pathway

	LOW-TEMPERATURE HEAT APPLICATIONS (<250°C)	MEDIUM-TEMPERATURE HEAT APPLICATIONS (250–1,000°C)	HIGH-TEMPERATURE HEAT APPLICATIONS (>1,000°C)
Near-term (2025–2030)	+ Electrified heat + Electrothermal energy storage	+ Biomass pellets	+ Biomass pellets (co-fired with existing fossil fuels)
Medium- to long-term (2030–2040)		+ Biomethane + Electrified heat + Electrothermal energy storage	+ Biomethane + Electrolytic hydrogen + CCU (for clinker and lime)

In this section, we analyse the four key technologies relevant to Gladstone's industrial heat decarbonisation, as well as biomass and biomethane as low-carbon fuels. We discuss why they are attractive decarbonisation solutions, what the current or near-term regional barriers to their deployment will be, and what enablers would be required for their accelerated deployment. Tables 2 and 3 summarise these benefits and barriers.

While this analysis focuses on Gladstone, these technologies and fuels could also be used to decarbonise other industries in different regions, given the large temperature range that they address. As such, our identified enablers will likely also be relevant to stakeholders in those regions.

BOX 5:

Energy efficiency improvements and waste energy recovery are best addressed through a facility-led approach

Industrial energy efficiency improvements that reduce industrial energy consumption can take multiple forms, ranging from identifying and eliminating energy losses to the recovery of waste heat, and should be thought of as the first step in industrial decarbonisation. Through the Australian Industry Energy Transitions Initiative (Climateworks Centre and Climate-KIC), Climateworks identified that over 300 PJ of energy per year – around half the current electricity consumption in the National Electricity Market (NEM) – could be saved across industry by making processes and technologies more efficient.

In this report, however, we choose to focus our attention on other decarbonisation measures, as while energy efficiency improvements are important, our analysis found that they are best addressed through a facility-led approach rather than as part of a coordinated NZIP strategy. We note that this does not diminish their importance to the overall challenge of decarbonisation.

TABLE 2: Key decarbonisation technologies or processes for Gladstone's industries

	ELECTRIFIED HEAT	ELECTROTHERMAL ENERGY STORAGE	FUEL SWITCHING	CARBON CAPTURE AND UTILISATION
Description	Technologies that convert electricity to heat (e.g. electric boilers)	Technologies that generate heat electrically, but can also store this heat to be discharged later	Replacement of fossil fuels with low-carbon alternatives (e.g. bioenergy or green hydrogen)	Technologies that capture carbon dioxide from gaseous waste streams for use in other industries
Application in Gladstone	+ Alumina (digestion) + Chemicals (low-temperature heating)	+ Alumina (digestion) + Chemicals (low-temperature heating) + Cement (waste heat to power)	+ Alumina (digestion and calcination) + Chemicals (high-temperature heating) + Cement (kiln heat)	+ Cement (clinker and lime production)
Key benefits for industry	+ Commercially mature technology + Currently implementable for lower-temperature requirements of Gibbsitic alumina facilities	+ Is capable of turning intermittent renewable energy into a continuous heat supply + Can capture and convert waste heat back to electricity	+ Requires minimal retrofitting of existing assets + Bioenergy represents near-term options for reducing emissions + Hydrogen or biomethane represent one of the few options for decarbonising high-temperature heat	+ Represents a synergistic option to decarbonise both process emissions and process heat emissions for clinker and lime + Costs can be recovered by selling the captured carbon to other industries as a valuable feedstock
Key barriers to deployment	+ High capital costs to upgrade facilities with required electricity infrastructure + Large-scale access to electricity needed, and the high operational costs associated with round-the-clock access to electricity + Lack of planning at the federal or state level for electricity generation and transmission infrastructure at the scale required + Supply chain barriers to procure, install and maintain equipment	+ High capital costs to upgrade facilities with required electricity infrastructure + Large-scale access to electricity needed + Commercially immature for high-temperature applications + Lack of planning at the federal or state level for electricity generation and transmission infrastructure at the scale required	+ Biomethane and hydrogen are currently unavailable at the scales required + Hydrogen currently has high costs of production + Hydrogen requires new infrastructure, including transport and storage + Regulatory difficulties for biomethane supply and transport + Limited incentives for biomethane trading and use	+ High capital costs for asset installation + Technology is immature, with currently low capture rates + Limited federal and state government financial support for accessing these technologies + Need for a reliable off-taker of captured carbon

TABLE 3: Key low-carbon fuels for Gladstone's industries

	BIOMASS PELLETS	BIOMETHANE	GREEN HYDROGEN
Description	Pelletised wood waste from sawmills	Carbon-neutral methane produced from the decomposition of organic matter	Hydrogen produced through electrolysis using renewable electricity
Application in Gladstone	+ Alumina (digestion) + Clinker and lime (kiln heat)	+ Alumina (calcination) + Chemicals (low- or high-temperature heating) + Chemicals (feedstock)	+ Alumina (calcination) + Clinker and lime (kiln heat) + Chemicals (feedstock)
Key benefits for industry	+ Currently cost-competitive with natural gas + Can use existing industrial heating assets without significant alteration + Feedstock is currently in low demand	+ Currently cost-competitive with natural gas + Can use existing industrial heating assets without significant alteration + Is technologically compatible with existing natural gas pipelines for transport + Multiple sources of feedstock circumvent supply seasonality	+ Relevance to numerous industries, including hydrogen export industries, means that shared infrastructure for production can be used to dilute costs + Abundant renewable energy resource potential to use for hydrogen production + Abundant federal and state government funding is accessible to support production
Key barriers to deployment	+ Current production in Queensland is limited + Cost of transporting feedstock means the supply of biomass pellets around Gladstone is limited, restricting the scale of its application	+ Current production in Queensland is limited + Mismatch between the ideal production locations and existing pipeline infrastructure may limit Gladstone's access to biomethane in the quantities it requires + Regulatory challenges are hindering the injection of biomethane into existing natural gas networks	+ High current electricity costs result in correspondingly high hydrogen production costs + Lack of infrastructure planning for the electricity required to meet Gladstone's demand for domestic and export hydrogen + A domestic hydrogen market and off-taker certainty in Gladstone is still developing, creating investment challenges

3.2.1. Electrified heat

Electrified heat technologies for industry are typically electrically heated or heat-transfer steam generators, such as electric boilers or heat pumps. These technologies are capable of generating low-temperature steam at substantial pressures (<30 bar), and are commercially mature, especially for producing very-low temperature heat (<150°C). They are increasingly common for residential and commercial applications; however, for industrial applications, their implementation has been slow due to the difficulties in retrofitting them into brownfield facilities.

In industrial applications, electric steam-generation technologies offer energy-efficient alternatives to current coal or gas use, where much of the heat produced from fossil fuel combustion is wasted.

Heat pumps are particularly suitable for facilities that generate substantial quantities of easily captured waste process heat, such as in the chemical sector's exothermic processes, as this waste heat can be amplified and reused. While heat pumps typically result in substantial energy savings compared to electric boilers, they are more technically complex to integrate with existing facilities and cannot produce equivalent temperatures.

Electrified heat technologies for high temperatures, including electromagnetic, plasma-based or electric-arc heating, are currently being developed, with substantial industrial interest for applications in the alumina, cement and primary steelmaking sectors. However, these technologies are currently at the prototype or laboratory-testing stage of development and are unlikely to enter pilot-scale deployment within the next decade.

Potential for deployment in Gladstone

Our analysis shows that implementing electrified heat in just two of Gladstone's facilities can significantly reduce the region's emissions. Gladstone's two alumina refineries produce around 4 $MtCO_2e$ each year, representing 45 per cent of Gladstone's current non-process industrial emissions. Alumina emissions are largely derived from combusting fossil coal and gas for the low-temperature 'digestion' of bauxite ore.

The digestion process involves heating ore in a chemical bath to between 150–400°C. This temperature range is due to Gladstone's facilities using multiple ore types, and is a temperature far lower than the 2,000–3,000°C provided by burning coal and gas. Instead, commercially available, low-emissions electrified heat technologies can provide this low-to-medium-temperature heat with far greater energy efficiency. This could eliminate 2.8 $MtCO_2e$ per year and is technologically feasible to implement between the mid-2020s and the early 2030s.

In Gladstone, electrified heating can currently be used in facilities that process Gibbsitic-type ores, which require low-temperature heat, but not in facilities that process Boehmitic-type ores, which require medium-temperature heat and high pressures of around 400°C and 50 bar. Implementing double digestion technologies for Boehmitic ores, which involves a two-stage heating process, is expected to enable the use of electric boilers for these ores in the early 2030s (ARENA 2022). Heat pumps are also of significant interest to the alumina sector for waste heat recovery and low-temperature applications, particularly in the form of Mechanical Vapor Recompression (MVR) technologies. However, a recent pilot-scale demonstration at Alcoa's Wagerup Alumina Refinery in Western Australia found that retrofitting the existing refinery was financially unviable (Russell 2024).

Similar low-emissions electrified heat technologies can replace the natural gas currently used for low-temperature heat in Gladstone's chemicals facilities, such as for the pre-heating of feedstock chemicals in the nitric acid and ammonium nitrate production processes. However, there are additional barriers to their implementation compared to other industries. Currently, heat generated in chemical production facilities is typically recovered and reused throughout the facility and across multiple production processes, meaning that existing production assets are heavily interconnected. As such, the introduction of new electrified heating technologies would require a whole-of-facility retrofit, meaning that any modifications are best performed all at once. The financial barriers for integrating new electrified technologies in chemical facilities are therefore higher than for other industries, which can adopt a more piecemeal approach to electrification. These higher financial barriers could delay electrification until the associated capital and operational costs decrease sufficiently.

Barriers to deployment

One of the largest barriers to the adoption of electrified heat is the operational costs associated with electricity and the capital costs associated with installing the necessary on-site electricity transmission or storage infrastructure. Together, these costs represent a significant financial burden to industry (ARENA 2022; Lovegrove et al. 2019). Heavy industry typically operates throughout the day, requiring a constant, or firmed, electricity supply for consistent heat production. Costs for this electricity can be particularly high due to: 1) the inability of cheap solar generation to meet nighttime demand, and 2) the lack of sufficient utility-scale storage, requiring either expensive coal- or gas-generated electricity or large quantities of on-site battery storage. The relative infancy of low-carbon heat technologies compared to current fossil-fuelled assets means there are additional supply chain barriers related to a lack of expertise for the procurement, installation and maintenance of these technologies, further raising the costs involved (Lovegrove et al. 2025).

The other primary barrier to electrified heat, the lack of appropriate electricity infrastructure planning for industrial regions, is discussed in Climateworks' *Seizing Gladstone's low-carbon opportunity* report. In short, we found that AEMO modelling for the ISP, which is in turn used to inform state-level energy planning, may significantly underestimate regional energy demand in locations like Gladstone. This, in turn, means that industry is hesitant to make the non-trivial upfront investments for electrified assets, given the significant doubt that the required infrastructure to support it will be constructed. Industry's lack of investment and commitment consequently makes it difficult for government to plan for a larger-scale electricity grid, as government needs confidence that there will be sufficient demand for the additional power it would supply. This creates a 'chicken and egg' problem hindering investment in both the electricity grid and electrified heat.

3.2.2. Electrothermal energy storage

Electrothermal energy storage represents an opportunity to overcome the high operational costs of electrifying heat. ETES technologies convert electric energy to heat in the same manner as electric boilers, but can also store this heat in relatively cheap storage media like bricks or metal blocks over medium to long durations (2–72 hours) (MGA Thermal 2023). This stored heat can then be discharged to generate a continuous supply of heat on demand, typically in the form of steam up to 400°C. ETES assets that can provide higher-temperature heat up to 1500°C are currently under development (Systemiq 2024). These technologies can be thought of as functionally identical to electric boilers, but with the flexibility to charge when electricity is cheap, such as in the middle of the day when solar is abundant, and discharge when electricity prices are high. This means they can cost-effectively generate heat throughout the day, and can either support conventional electrified low-temperature heating assets or be used as a standalone replacement. Certain ETES technologies also allow for stored or recovered heat to be converted back into electricity with around 20 per cent efficiency, typically for on-site use, and are known as Combined Heat and Power (CHP) systems.

Potential for deployment in Gladstone

ETES technologies can be used in any industrial application that electric boilers or heat pumps are suited for (e.g. the alumina and chemicals industries in Gladstone), but are far more versatile. These technologies are also of interest to the chemicals and clinker or lime industries as CHP systems, as these facilities produce substantial, concentrated waste heat streams from high-temperature processes. Installing CHP-ETES assets at these heat discharge points can capture thermal energy that would otherwise be wasted and turn it into electricity.

As an example, a waste heat stream from a clinker kiln with 30 megawatts (MW) of of thermal energy can produce 6 MW of electricity, reducing the facility's electricity consumption and costs by a substantial amount.

Benefits of ETES technologies:

+ They are the cheapest option for producing continuous low-carbon heat at scale compared to other analogous technologies. ETES systems are more cost-effective than adding battery storage to electric boilers, and over the long term, can even outcompete gas or biomass-fuelled boilers (Systemiq 2024).
+ They can be constructed from readily available materials, circumventing the supply chain risks manufacturers face when using rare-earth minerals for batteries, and can be more easily scaled to the required size (Rondo Energy 2023).
+ They can enable industrial demand management practices, as their flexible nature means they are highly compatible with variable renewable energy (VRE) like wind or solar power. ETES technologies can be easily switched on or off, which can reduce electricity demand peaks and provide stability to the grid.

Barriers to deployment

ETES technologies have additional barriers to implementation beyond industry's need for certainty in the availability of enabling electricity infrastructure. While most ETES technologies are considered to be in the early commercially ready phase, with several megawatt-scale batteries operational or in construction around the world (*Covestro* 2024; Systemiq 2024), Australia currently has only demonstration-scale projects (*Covestro* 2024; Systemiq 2024; Heynes 2025).

As ETES technologies only charge during the day when electricity is cheap, they will require more electricity transmission infrastructure to accommodate this increased daytime consumption. This will partially shift the financial burden of industrial decarbonisation onto those responsible for transmission development. There is also the potential for changes in daily industrial electricity demand and, therefore, in Australia's energy ecosystem, if flexible electrified heating is implemented at scale. The implications of these changes, as well as an analysis of the potential cost savings and impact on Gladstone's energy consumption profile, are discussed further in Section 4.

3.2.3. Fuel switching to low-carbon fuels

Low-carbon fuels can completely or partially replace inefficient and heavily emitting fuels like coal and gas. This can help industries to rapidly decarbonise in the short term with minimal upfront costs, and provide medium- to long-term decarbonisation options for sectors that are currently technologically constrained from other solutions.

Bioenergy-based fuels, such as biomass and biomethane, can be used as short-term decarbonisation solutions, while green hydrogen, though currently costly to produce, is one of the few fuels that has significant potential to meet industry's long-term energy needs sustainably. These low-carbon fuels, due to their different capabilities and combustion temperatures, can be applied across a number of industrial processes.

Benefits of switching to biomass, biomethane and green hydrogen:

+ Switching can be done without a significant retrofit of existing assets, as these fuels are functionally equivalent to existing fuels. This, in turn, reduces the upfront costs of decarbonisation compared to alternative options, particularly those that require the purchase and installation of new assets (e.g. the integration of an electric boiler).

+ The technologies to produce biomass and biomethane are commercially mature, and their production costs are equivalent to natural gas (Enea and Deloitte for ARENA 2021a), further increasing their commercial viability.

Although these fuels can be easily integrated into industry, and production costs for biomass and biomethane are low, they are not currently available at scale in Australia. Low publicised off-taker interest has meant that domestic biomass and biomethane supply chains have not been established. While electrolyser technology to produce green hydrogen is mature, and significant state and federal government support exists, high production and capital costs restrict green hydrogen production at scale. Biomass and biomethane also face transport, regulatory and availability challenges, which will be discussed later in this section.

Green hydrogen is not discussed in detail in this report, as we have previously presented the barriers and solutions for its implementation at scale in other publications (Climateworks Centre 2025; Climateworks Centre and Climate-KIC 2023).

BOX 6:

The levelised cost of heat

Levelised cost of heat (LCOH) is a metric that assesses the cost of heat produced by various technologies, as a function of upfront capital costs, maintenance costs and fuel costs over the lifetime of the technology. Rising costs of natural gas in Queensland mean that the LCOH generated from natural gas ($21/gigajoule [GJ]) can be significantly higher than that of biomass and biomethane ($14/GJ) (ITP 2025, Enea and Deloitte for ARENA 2021a). The LCOH of electrified heat (using electricity from the grid) is however even higher at $28/GJ, and illustrates the need to reduce electricity prices through firmed renewables and demand management for electrified heat to be cost-competitive. Though the LCOH for biomass and bioenergy are low compared to natural gas, savings are only realised over a long-term period, meaning that industry's focus on short payback periods may hinder their adoption.

3.2.3.1. Bioenergy

Bioenergy, including biomass and biomethane, is considered carbon-neutral as the emissions produced from its combustion are part of the short-term carbon cycle (the exchange of carbon between the atmosphere and biosphere on an annual timescale), and so do not have the same long-term impacts on atmospheric carbon as fossil fuels (Bioenergy 2025).

Biomass and biomethane can be thought of as direct substitutes for natural gas and coal, respectively, in industrial heat applications. The technologies required to both produce and combust either of these fuels are well established, with high levels of technological and commercial readiness in Australia. The LCOH for either of these fuels is competitive with most fossil fuels (see Box 5), and requires minimal modification to existing assets (Enea and Deloitte for ARENA 2021a).

Strategic applications of these fuels can easily supply the temperature ranges required by Gladstone's industries. Burning biomethane produces temperatures of up to 1900°C – equal to that of natural gas – while burning compressed pellets of biomass can produce temperatures of up to 600°C (Mian et al. 2020).

To avoid using agricultural land for purpose-grown bioenergy, Climateworks' analysis of bioenergy's potential as a decarbonisation solution is limited to the use of Queensland's waste streams for feedstocks. However, if bioenergy is required in greater quantities – for instance, to enable industrial decarbonisation to keep pace in the absence of sufficient quantities of renewable electricity or green hydrogen – these waste streams may be insufficient, requiring alternative measures such as interstate exports or the increased use of purpose-grown feedstock crops.

There may also be competition for these waste stream feedstocks for producing biodiesel as an immediate 'drop-in' solution for decarbonising road and aviation transport that uses existing fossil fuel distribution infrastructure (Climateworks Centre 2023).

BIOMASS

While various solid biomass fuels exist, processed wood residue in biomass pellets is one of the most sustainable options. These pellets are manufactured by grinding waste from the forestry or sawmill industries, which is then compressed and dried to form a dense fuel. Sawmill waste is preferred, as forestry residues are typically left on-site for forestry health purposes. Biomass pellets can also be produced from agricultural waste streams; however, these are typically not fit for heavy manufacturing applications due to high variability in quality. In this analysis, we exclude biomass derived from purpose-grown crops and instead focus on pellet feedstocks derived from waste streams, as these possess the highest potential for emissions reductions, possess lower LCOH values and do not compete with food production for land use.

Potential for deployment in Gladstone

Our analysis finds biomass could be used as:

1. a short-term option to rapidly phase out coal and gas in alumina digestion, prior to electrification
2. a long-term option to reduce coal use in high-temperature heat processes in the clinker and lime sectors.

Although biomass is unable to supply the high temperatures required for clinker and lime production, which are also currently difficult to achieve through electrification, it can be co-fired with coal (VDZ 2021). Through co-firing, Climateworks models that biomass can replace up to 50 per cent of current coal use for clinker and lime production by 2040, reducing scope 1 process heat emissions by 0.45 Mt (94 per cent compared to current emissions). Meeting this demand would require up to 4 PJ/year of biomass pellets by 2040. Pilot studies for biomass use are already being carried out in Gladstone's facilities (Rio Tinto 2025).

Barriers to deployment

Complicating this potential demand for biomass is that Australia does not currently possess biomass pellet manufacturing capabilities at scale. Australia's few major manufacturers, which exported pellets to Japan, South Korea and the UK for use in electricity generation, have recently terminated their operations (Timberbiz n.d.). Current feedstocks are also limited in availability, as sawmills typically dispose of waste residues through the on-site generation of heat. Nonetheless, domestic interest in using biomass for industrial heat is rising, due in part to Australia's National Greenhouse and Energy Reporting Scheme (NGERS) recognising the use of biomass combustion as an eligible fuel for zero emissions energy reporting in 2024 (IEA Bioenergy, 2024). This, combined with the increasing electrification of sawmill facilities and a resulting reduced need for on-site biomass combustion, could represent an economic opportunity for sawmills to turn an underused waste stream into additional revenue – revitalising biomass pellet manufacturing in Australia.

Difficulties in cost-effectively transporting biomass further limit a domestic biomass manufacturing industry. Currently, biomass is transported by road and is therefore costly and potentially emissions-intensive. It is estimated that each year, up to 1200 kt of pellet feedstock could be available across Australia; however, the bulk of this is in Tasmania or New South Wales, in locations that are not within economically viable transport distances[6] of heavy industry (Lock and Whittle 2018). This means that there is likely a substantial mismatch between the demand from industrial regions and the availability of sustainable biomass supply for these regions. Additional support in the form of transport or procurement subsidies will therefore be needed if biomass is to serve as a transitory solution for low-temperature heat decarbonisation prior to electrification (Lin et al. 2024). Companies will also need to act quickly to secure the most economical sources of biomass.

BOX 7:

Biomass feedstock availability in Gladstone

Climateworks has analysed the biomass pellet feedstock potential available to Gladstone's industries using data from ARENA's Australian Renewable Energy Mapping Infrastructure (AREMI) database (Geoscience Australia n.d.). In this analysis, the feedstock potential was mapped by identifying sawmill residue from local government areas (LGAs) within an economically feasible (325 km) transport distance of Gladstone.

Our analysis found that LGAs within this radius have the potential to supply 229 kt of pellet feedstock per year, with 70 per cent of this potential feedstock found to the south of Gladstone, from the Gympie, Fraser Coast, Western Downs and North Burnett LGAs. The total quantity of feedstock can be converted into 2.9 PJ of pellets per year, which is a small fraction of the 46 PJ of heat demand for Gladstone's industrial processes currently supplied by fossil fuels that biomass is technologically capable of meeting. Even meeting Climateworks' modelled biomass demand for cement and lime production alone (4 PJ/year by 2040) will exceed the supply available from Gladstone and its surrounding areas.

The conversion of agricultural, rather than forestry, waste could increase this feedstock potential; however, the quality of the pellets produced is more variable and may not meet industrial requirements. Pellets could also be transported from more distant regions, however both solutions present additional financial barriers, potentially requiring support from government.

6 Economically viable transport distances between sawmills and point-of-use were determined to be no more than 325 km due to transport costs. For more information, refer to the cited study.

BIOMETHANE

Biomethane is a low-carbon fuel that is chemically identical to and is functionally interchangeable with fossil natural gas. Biomethane is the refined form of biogas, which is currently produced either from the anaerobic digestion of organic matter or from the capture of landfill emissions. Sustainable feedstocks for anaerobic digestion are crop residues, livestock waste or wastewater; however, Australia's large agricultural industry means that its crop residues have the highest potential to support biomethane production. We again exclude purpose-grown energy crops as a feedstock for biomethane.

Biomethane feedstocks are even less economically viable to transport over long distances than biomass feedstocks due to their low energy density. Furthermore, given the widespread nature of the agricultural industry, multiple regional production hubs co-located with concentrated agricultural activity could be required. Biomethane could then be injected into gas pipelines for transport to off-takers. A study commissioned by ARENA found that biomethane has the potential to represent 23 per cent of the total pipeline gas market by 2030 (Bioenergy Australia 2024).

Potential for deployment in Gladstone

Climateworks has found that the primary use cases for biomethane in Gladstone are:

1. the long-term replacement of natural gas for high-temperature heat, such as the incineration of waste gases in the production of sodium cyanide
2. the short-term replacement of natural gas for high-temperature heat in industries that plan to shift to low-carbon hydrogen in the long term, such as for the alumina calcination process
3. the short-term replacement of natural gas for low-temperature heat prior to electrification, such as in the explosives sector.

Biomethane is an important transitory option for the alumina and chemicals sectors to meet their decarbonisation targets – particularly as industries can readily substitute existing natural gas with biomethane. This transitory role is especially important if there are delays in securing the electricity or hydrogen needed for their long-term decarbonisation technologies.

As previously discussed, our modelling finds that biomethane consumption peaks at around 7.8 PJ in 2032, which then falls to 1.2 PJ by 2040. While biomethane will likely play a transitory role, the risk of biomethane producers having stranded assets in the long term is likely low, as studies forecast additional demand for biogas or biomethane from non-industry sectors, including for off-grid electricity generation, even under a business-as-usual scenario (Enea and Deloitte for ARENA 2021b).

Barriers to deployment

Gladstone currently does not have the necessary infrastructure for biomethane production or transport at scale. The current legislation and regulations also do not facilitate biomethane trading, meaning that investment in biomethane production remains limited. Significant advancements in infrastructure and policy development could enable biomethane use at scale (Enea and Deloitte for ARENA 2021b).

As stated previously, Australia's current biomethane production is limited, with only a single facility in New South Wales producing biomethane and injecting it into gas networks (*Malabar Biomethane Injection Plant* n.d.). Production is instead currently focused on biogas produced from capturing landfill emissions, and is typically burnt as is for electricity generation without being refined into biomethane

(LMS Energy 2021). Agricultural waste, however, which potentially accounts for 86 per cent of Australia's total biomethane potential, represents a far more abundant source of feedstock, and has the highest potential to support the scale of biomethane production required for industrial decarbonisation (Bioenergy Australia 2024).

Climateworks' analysis on biomethane's potential for Gladstone's industries (Box 7) found there are two major barriers that could hinder industries from accessing biomethane at scale, namely:

+ Ideal feedstocks for biomethane production may currently be used in other supply chains
+ Existing gas pipelines may not be well situated to connect ideal regional biomethane production hubs to off-taker locations.

In addition to these barriers, current regulatory measures disincentivise potential producers and off-takers from investing in biomethane. For example, current federal gas standards for injecting biomethane into existing networks means the costs of refining biomethane are high. The Future Fuels CRC has recently found these standards to be unnecessarily stringent (Australian Pipelines and Gas Association 2023). Additionally, biomethane derived from agricultural waste is not considered a valid emissions reduction activity under Australia's Carbon Credit Unit (ACCU) scheme (Clean Energy Regulator 2022). Less stringent standards for fuel injection into pipelines, or an expansion of feedstock sources for ACCU eligibility, could provide more certainty for biomethane producers to invest in the necessary production facilities.

BOX 8:

Biomethane feedstock availability for Gladstone

Climateworks has analysed the biomethane feedstock potential across Queensland using ARENA's AREMI database. In this analysis, the feedstock potential was mapped by identifying agricultural waste from the cotton, sorghum, straw and sugarcane industries across the state. Other sources of biomethane feedstock, such as wastewater or animal processing waste, were found to make up relatively small portions of Queensland's overall potential.

Our analysis found that Queensland has the feedstock potential to supply 69.5 PJ of biomethane per year. This far exceeds the 25 PJ of current fossil-fuelled industrial heat that biomethane is technologically capable of replacing in Gladstone. Around 95 per cent of this feedstock potential is derived from sugarcane waste, which is in Queensland's north, from LGAs surrounding the cities of Townsville, Mackay and Cairns. Lower concentrations of potential feedstock can also be found around Bundaberg, Toowoomba and Balonne in the south.

Unlocking this potential will require intervention by government and industry across the state. Most of this sugarcane waste is currently burnt on-site in sugarcane mills for disposal, with some of this energy also used for heat and power. Furthermore, pipeline infrastructure in Queensland's north (i.e. the North Queensland Gas Pipeline), where biomethane feedstock potential is concentrated, is not connected to Gladstone, restricting transport to industrial off-takers.

Increasing grid connectivity and encouraging sugarcane mills to electrify their low-temperature heat processes can free sugarcane waste to be converted into biomethane, which can be better used to address heavy manufacturing high-temperature heat demand. Implementing gas certificate trading – a trading scheme for Gladstone's industries to compensate producers for injecting biomethane into gas pipelines – can also encourage the production of biomethane without a costly extension of existing pipelines.

3.2.4. Carbon capture and utilisation

Carbon capture technologies separate and store carbon dioxide emissions from waste gas streams, typically through exposing these gas streams to a chemical bath. Heating these baths releases a carbon dioxide-rich stream, which is then stored for further use. These chemical absorption systems are currently used by the power generation and gas refining industries, and to date have been found to result in capture rates of around 80 per cent (Institute for Energy Economics and Financial Analysis n.d.).

Potential for deployment in Gladstone

Industries whose emissions primarily result from chemical transformation of feedstocks, such as the cement and lime sectors (see Box 4), can find it challenging to decarbonise, as alternative production methods are limited at scale in the near term. These are known as 'hard to abate' industries. Climateworks' findings suggest that Gladstone's cement and lime industries could reduce their fossil fuel consumption for industrial heat by around 75 per cent using biomass, hydrogen and fuels derived from industrial waste. However, industrial heat emissions comprise only around 30 per cent of total cement and lime scope 1 emissions (IEA 2023), meaning that the bulk of emissions remain unaddressed. However, as all scope 1 emissions[7] produced from these industries are typically concentrated in a single waste gas stream, carbon capture is an opportunity to mitigate both process emissions and the remaining industrial heat emissions.

Using the captured carbon dioxide (typically as a feedstock for low-carbon chemicals) is known as Carbon Capture and Utilisation (CCU). This is an avenue of interest to Gladstone's companies due to the potential for cost recovery through the sale of the captured carbon. Gladstone's industries have investigated the feasibility of producing green methanol using captured carbon dioxide and green hydrogen as a feedstock (Queensland Government 2022b).[8] Using the captured carbon in Gladstone itself could also reduce storage and transport costs associated with other carbon capture technologies. Stakeholder consultation has suggested that Carbon Capture and Storage (CCS), which typically involves the geological storage of captured carbon, is not viable in Gladstone due to the lack of suitable geological sites.

Barriers to deployment

There are, however, significant barriers to implementing CCU for heavy industry, which will require significant shifts in policy to overcome. The technology does not currently possess the >90 per cent capture rates required to meet industrial net zero targets, and is also cost-prohibitive to operate, with costs ranging from US$60–120 per tonne of carbon dioxide captured from the clinker and lime industries (IEA 2021).

7 Scope 1 emissions are those produced both from burning fossil fuels for heat, as well as from the chemical transformation of limestone.

8 We note that while the captured carbon embedded in these products can be released back into the atmosphere, further recycling of these subsequent emissions as a replacement for virgin fossil feedstocks through circular economy principles have been recognised to play a vital role in whole-of-economy emissions reductions (Ilinova and Kuznetsova 2022).

These high costs are attributed to the complexity of these technologies and the difficulties in retrofitting them to existing facilities. Compounding this problem is the limited state or federal government support for carbon capture technologies, including research and development, financing and appropriately crediting their use through ACCUs. Policy options addressing these areas can support the decarbonisation of some of Australia's highest-emitting industries.

3.3. Common barriers

Our analysis finds several common barriers to deploying key decarbonisation technologies or fuels in Gladstone. These include:

+ high capital costs of new decarbonisation assets, including the upfront cost of the asset and the costs associated with retrofitting the asset into existing facilities
+ high capital costs for on-site electricity infrastructure to support new electrified assets
+ limited availability of the required low-carbon fuels, despite high feedstock potential around Gladstone or Central Queensland
+ limited availability of the electricity needed to support new electrified assets and hydrogen production, despite the high renewable potential in REZs around Gladstone
+ high operating costs for new electrified decarbonisation assets
+ electricity generation and transmission planning by federal and state authorities that underestimates the scale and pace of the infrastructure build-out required to meet industry's decarbonisation ambitions.

In this report, Climateworks addresses strategies to overcome several of these barriers. Section 4 discusses how industrial demand management can reduce operational costs for electrified technologies without compromising productivity, while Section 5 focuses on approaches that state and federal governments can use to support industries with the financial burden of decarbonisation. A summary of our recommendations can be found in Section 6. Climateworks' recommendations for energy planning authorities to align their demand assessments with industrial decarbonisation ambitions to build electricity infrastructure at the scale required can be found in a previous publication, *Seizing Gladstone's low-carbon opportunity: A net zero industrial precinct approach*.

BOX 9:

The role of carbon capture in decarbonising 'hard to abate' industries across all of industry

Carbon capture has few use cases across most of industry, as there are typically more financially viable decarbonisation options. While carbon capture technologies typically have an 80 per cent capture rate, zero-emissions technologies are also anticipated to be available in most industries before 2050 (Climateworks Centre and Climate-KIC 2023).

However, carbon capture is one of the few scalable decarbonisation options for industries with significant 'hard to abate' process emissions, such as the cement and lime industries. In Gladstone, these industries have emphasised that carbon capture is the only economically viable option for reducing these process emissions.

The International Energy Agency (IEA) has identified carbon capture as vital to addressing emissions in 'hard to abate' heavy industries (IEA 2023). Climateworks' *Decarbonisation scenarios 2023* also identified carbon capture as responsible for reducing 65 per cent of process and industrial heat emissions from the cement sector by 2040 under its 1.5°C scenario (Climateworks Centre 2023). Climateworks' modelling in this report shows carbon capture, in combination with switching to low-carbon fuels, could reduce the industrial heat emissions associated with producing cement and lime in Gladstone by 98 per cent by 2040.

4. Demand management can alleviate some of the challenges in electrifying industrial heat

Australia's largest energy network, the National Electric Market (NEM), was created with the assumption that electricity could be generated with a certain degree of stability using coal and, eventually, gas-fired power plants. Stability from these fossil-fuelled generators is characterised by the ability to generate a predictably constant amount of energy.

Any increase in electricity consumption was expected to be met by a proportionate increase in generation. However, increasing shares of VRE, the high cost of fossil fuels, and increasing climate volatility mean the NEM is faced with a fundamental change to how it is used, how electricity is traded and how it is physically possible to provide adequate power.

Climateworks has found that the total expected VRE capacity in the NEM could rise by 600 per cent by 2050 under a 1.5°C-aligned scenario (Climateworks Centre 2023). Solar and wind represent the most economically viable generation methods today, due to their ability to provide cheap, low-carbon and decentralised power (Graham et al. 2024). However, their variability results in increased difficulties sustaining consistent generation on a daily and seasonal basis. Increased VRE, combined with increasingly volatile weather events, means that the stability of the NEM is at risk. Lack-of-reserve (LOR) events, used by AEMO to indicate a mismatch between electricity supply and demand, as well as high-price events, where NEM wholesale prices spike significantly above baseline averages, have become more commonplace. In 2023, there was a significant increase in LOR events, with nearly 120 forecasted in Queensland alone, while 2024 saw both record high and low wholesale prices for both New South Wales and Queensland, creating unfavourable economic conditions for both consumers and generators. To counter these events, demand management practices and the flexibility of large industrial loads will become increasingly instrumental to the cost-effective provision of Australia's energy security.

Demand management refers to a broad range of strategies aimed at influencing electricity consumption and generation to better match electricity supply profiles through both short-term adjustments and long-term trends. This includes behavioural adjustments, energy storage or load curtailment. Demand response is one such strategy, which involves using price signals or compensation to incentivise consumers to voluntarily modify their energy load (Demand response n.d.). This is typically used by transmission system operators (TSOs) to ensure the stability of the grid. This load can be modified by undergoing:

+ load shifting, where the load is either brought forward or delayed to a different time
+ load shedding, where the load is reduced or switched off entirely
+ load shimmying, where the frequency of the load is adjusted over a sub-second timeframe

Demand response is a rapidly implementable and cost-effective method to provide grid stability, and is complementary to the costly and lengthy build-out of additional generation and transmission infrastructure. The value of demand response resources, ranging from large energy consumers like industrial facilities to individual residences, is being increasingly recognised in Australia; these resources are known as 'Distributed Energy Resources'. Demand response is a strategic priority in ARENA's 2021 Investment Plan and is currently estimated to have benefits of between $8–18 billion, with this only increasing with a greater VRE share (Briggs et al. 2024).

BOX 10:

Flexible demand

Sources of flexible demand are key to industries' demand response capabilities. These include processes that can safely moderate electricity usage – such as adjusting the frequency of aluminium smelting pots or switching off clinker milling units – and using battery or thermal storage to alter the time that power is drawn from the grid.

Industrial flexibility is, however, currently limited – particularly in heavy manufacturing. This is because facilities tend to operate throughout the day, which limits their ability to shift their loads to alternative times. Facilities could also possess complex interdependencies between their processes, meaning load reduction for one process could affect significant proportions of the whole facility. Although increased electrification and storage technologies have significant potential to overcome these challenges, energy planners have a limited understanding of this flexible potential. This has led to an underdeveloped policy landscape and a lack of incentives for industry to adopt such enabling technologies and take part in demand response programs.

4.1. Demand management can complement battery storage for firmed grid electricity

Increasing shares of VRE will require firming to ensure a stable and reliable supply of baseload electricity. This firming is currently supplied mostly by costly fossil-fuelled 'peaking' generation facilities, which are power plants that only run during periods of high electricity demand. As these facilities are typically only infrequently used, the power they provide is associated with much higher electricity prices. However, Australia is also investing heavily in utility-scale battery storage, with a predicated annual battery storage capacity of 209 GWh by 2030.[9] Relative to the size of our network, Australia is committing to energy storage more than other comparable locations with similar networks, like France and Texas, both of which are planning for storage capacities two to four times less than Australia.[10]

Yet a business-as-usual approach to energy planning that forgoes demand management and relies on storage alone for firming will come at a substantial capital cost. Instead, combining short-term (or shallow) battery storage, long-term (or deep) storage (e.g. pumped hydro or

9 Climateworks analysis, based on data from AEMO's 2024 ISP (AEMO 2024).

10 Climateworks analysis, based on network data from Australia (Modo Energy 2025), Texas (Modo Energy 2024) and France (Rystad Energy 2023).

compressed-air storage) and demand management mechanisms could represent a synergised, low-cost approach to a firmed grid with high shares of renewables.

The provision of demand management at scale will require significant policy shifts and a whole-of-network change to how Australia consumes energy. In the short term, investment in battery storage will be the key enabler to accommodate an increasing share of VRE and provide the firming necessary while these policy changes are implemented. In the long term, demand response resources will be critical to providing flexibility for demand management at scale.

4.2. Sources of flexible demand in industry

Energy planners currently see electric vehicles and the residential sector as the largest opportunities for increased demand response, due to an underestimation of the scale of industrial electrification and industry's potential for flexibility (Briggs et al. 2024). While this can be partially overcome with greater discourse between energy planners and key industrial stakeholders, this lack of understanding currently restricts energy planners from harnessing the full potential of flexible demand in industry to complement the NEM's increasing share of VRE. This, in turn, will require a costly build-out of transmission, generation and battery storage infrastructure to compensate.

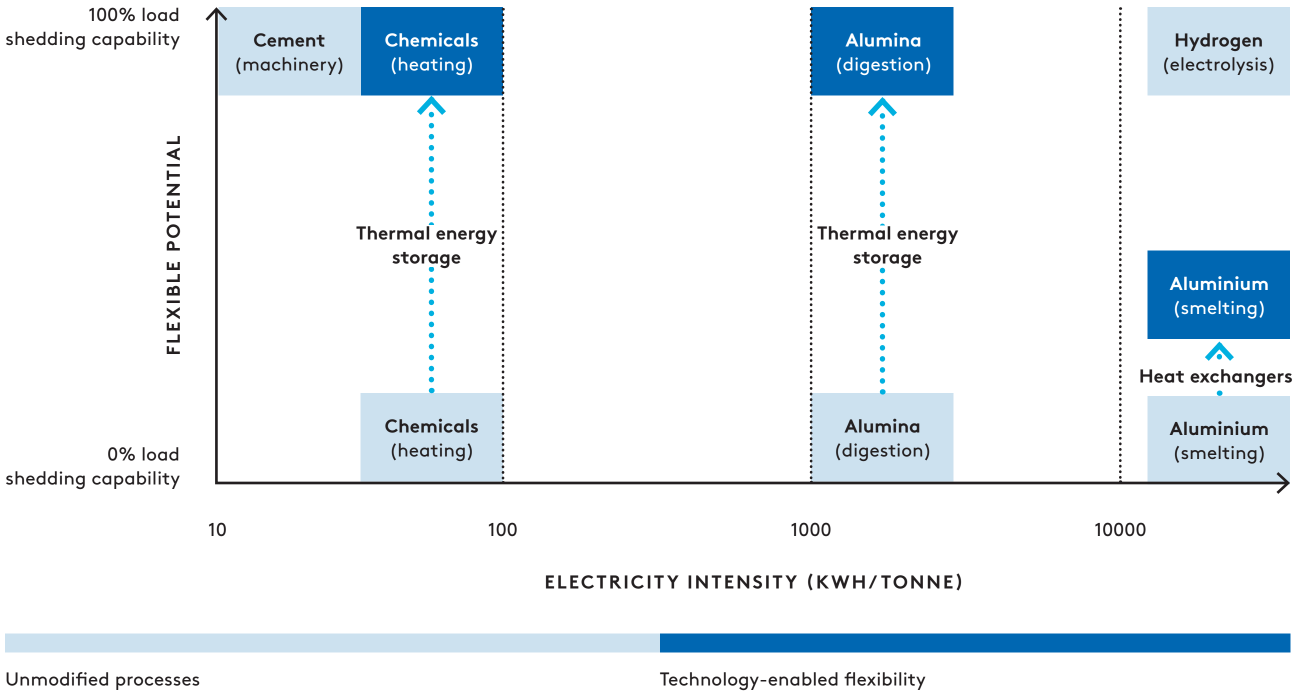
Electrifying Gladstone's industries in flexible ways could more than double Australia's ability to stabilise the energy grid. In this section, we identify potential sources of flexible industrial demand that could contribute to demand response capacity in the NEM, using Gladstone's industries as a case study. We follow this with an in-depth analysis of how thermal storage technologies could be paired with electrified industrial heat to unlock industrial flexibility at scale – facilitating the cost-effective decarbonisation of industrial heat while providing benefits to energy consumers across Queensland. However, implementing industrial flexibility and the provision of demand response services are typically not financially competitive activities for industry, due to the costs of enabling technologies or the financial losses to facilities associated with decreased productivity. To realise demand response benefits, governments or energy system operators can support industry to implement these activities, whether via the upfront capital costs of flexible assets or via a proportionate compensation for their services.

Ideal industrial processes to provide demand response capacity are those that:

+ consume large quantities of electricity
+ have a high energy intensity, as represented by the amount of electricity in kilowatt hours needed to produce a tonne of product
+ have a high potential for flexibility, as represented by their ability to quickly and safely power down or 'load shed'.

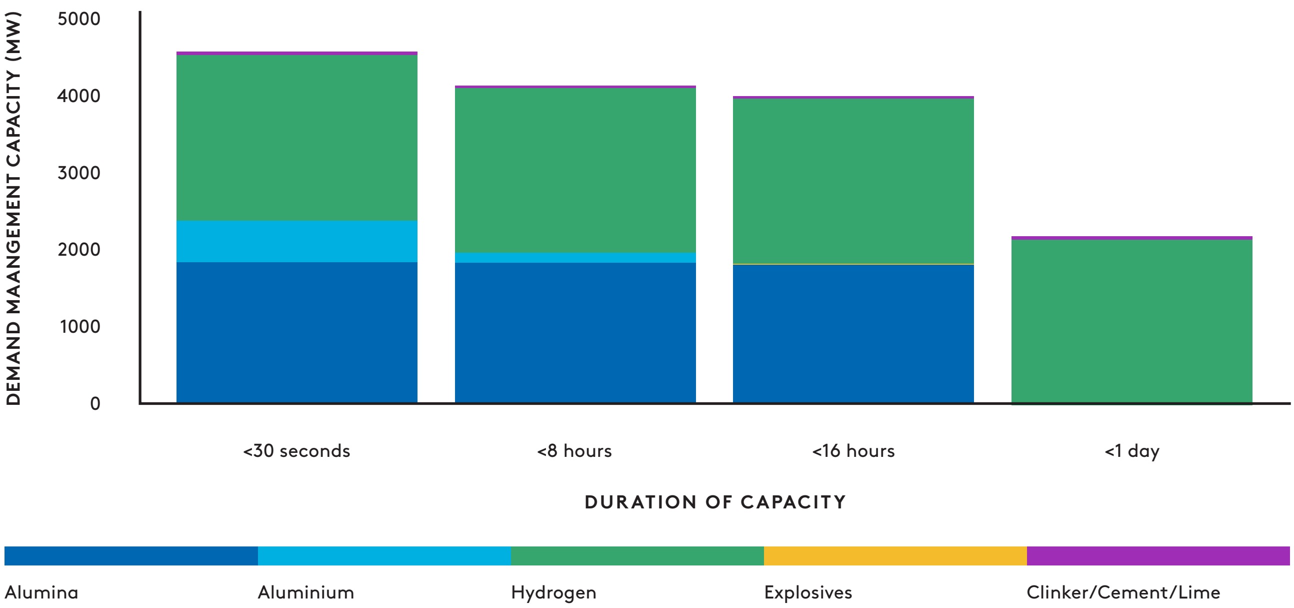
Figure 8 categorises Gladstone's industries according to these metrics; however, as seen in the figure, no existing industry in Gladstone currently meets these metrics exactly.

FIGURE 8: Flexible demand potential for industrial processes in Gladstone's industries



Electrifying Gladstone's industries alone could provide up to 4.4 GW of demand response capacity by 2040 (Figure 9). This more than doubles Australia's current capacity – from just one industrial region. This capacity is categorised by the length of time it could technically be provided, and ranges from under 30 seconds to a full day. As seen in Figure 9, just under 4 GW of Gladstone's demand response capacity could be activated for up to 16 hours without technical difficulties, with ETES-coupled, low-temperature electrified heat and the production of green hydrogen representing the bulk of this capacity. The alumina industry comprises most of the electrified heat share, and therefore contributes a large share of demand response resources.

FIGURE 9: Potential demand response capacity from Gladstone's industries in 2040



4.2.1. Hydrogen electrolyser flexibility

While still currently in development, the large-scale use of electrolysers for hydrogen production represents the highest potential for demand response capacity across industry. This process both consumes a substantial quantity of electricity and can instantaneously switch on or off with few adverse impacts. Indeed, several studies have suggested that the flexible production of hydrogen and dynamic electricity pricing will be the primary drivers for hydrogen reaching commercial viability (Wu and Li 2023).

4.2.2. Aluminium smelter flexibility

The aluminium industry currently represents the best source of existing demand response capacity, with several smelters around the world already providing these services (Hanley 2024; AEMO 2024b). While Gladstone's Boyne Island smelter is one of the largest single-facility loads in the whole of Queensland, one key limitation prevents it from being used effectively for demand response – its low potential for flexibility. This is because alumina feedstock needs to be kept in a molten state, with its solidification producing catastrophic results and irreparably damaging equipment. As such, most smelters in Australia can currently only participate in demand response by temporarily shutting down small batches of their smelting capacity, for a few hours at a time. This interruption must also be planned hours or days in advance, limiting the type of demand response services that can be provided (Golmohamadi 2022). By retrofitting smelters with enabling heat-exchanger technologies, smelters can unlock increased demand response capacity by partially increasing or reducing the power used for smelting by around 20 per cent, with the key benefit being the ability to provide this demand response capacity with little notice, and for any duration (Depree et al. 2022; Buckley 2020). However, a recent assessment of these technologies found their implementation to be financially unprofitable for Australian smelters, without a significant revision of Australian demand response compensation mechanisms (Butler 2020).

4.2.3. Cement processing flexibility

On the other hand, the cement industry in Gladstone, comprising clinker, cement and lime production, holds significant potential for flexibility, but is limited by its low total electricity demand. Electricity demand from Gladstone's cement facilities is several orders of magnitude less than that of alumina or aluminium production. Electrically operated machinery is used in cement facilities to transport, crush and blend the large quantities of feedstock, in the form of raw limestone and clinker nodules, as well as the finished cement product. The relatively inert nature of these feedstocks means that this machinery can be halted almost indefinitely, and with little notice needed. The duration of stoppage is only limited by the facilities' stockpiling capabilities, as currently, delivery of the raw material into kilns cannot be halted due to the high fuel costs of heating the kiln. As such, the size of storage silos is linked to the flexibility potential of this industry. Significant opportunities exist for grinder operations to be shifted to off-peak periods where electricity costs are low.

4.2.4. Alumina and chemicals production flexibility

As the alumina and chemicals industries require a constant supply of heat for chemical transformations (i.e. converting bauxite ore to aluminium hydroxide through the digestion process) their potential for flexibility is low. However, using ETES technologies can 'switch on' the required flexibility in these industries, which could greatly increase their demand response capacity and facilitate their decarbonisation, as discussed in the next section.

BOX 11:

Seasonal demand response

While shifting industrial loads from one part of the day to another can allow industrial demand to be better matched to the daily variation in renewable energy supply, longer-term demand reductions over two to three weeks in winter will have an equally important role in reducing the need for fossil gas-based peaking generation.

VRE generation across the NEM undergoes a several-week 'dunkelflaute' period in winter, referring to a 'renewables drought' period of minimal generation from both wind and solar assets. This dunkelflaute period also coincides with an increase in demand as more electricity is used for heating. For example, demand in Queensland increases by up to 2 GW in the winter. This supply and demand mismatch typically results in higher wholesale electricity prices, with average winter prices in Queensland $20/MWh higher compared to the rest of the year in 2024 (Australian Energy Regulator, n.d.). Short-duration storage assets like batteries or ETES technologies cannot address winter mismatches alone.

As the share of VRE generation increases in the grid, business-as-usual operations by industry during a dunkelflaute period will impose increasing costs on the whole of Queensland, arising from either the increased use of gas-fuelled peaking generators, or the overbuild of renewable energy infrastructure to compensate for reduced supply. An alternative to these costly routes could be the use of demand measures targeting overnight winter loads, which could reduce gas use and avoid investment in gas peakings, driving major reductions in energy consumers' costs.

An example of winter demand measures is using large-load shaping incentives, where new loads are designed to avoid overnight winter loads. Incentives could be applied through government support or connection agreements with energy providers. Another example is a winter reserve trader, where tenders are placed for existing large energy users to divert their planned maintenance and shutdown periods to winter months.

Examples of these measures have already been implemented around the world. New Zealand has requested that their largest industrial load, New Zealand Aluminium Smelters (NZAS), lower its consumption by 50 MW during the winter period (Meridian Energy 2025). At peak curtailment, this represents around 9 per cent of NZAS' electricity consumption. Future agreements will likely see this curtailment increase to double or triple this figure in the coming years.

4.2.5. ETES-enabled flexibility and its role in low-temperature heat electrification

As industrial processes transition from fossil fuels to renewable energy, electrifying low-temperature heat will rapidly become a major avenue for decarbonisation (Lovegrove et al. 2025). This will require cheap renewable electricity to be supplied at an unprecedented scale, and as the share of VRE generation grows in the Australian network, the requirement to match this variable generation to demand will become a bottleneck with serious ramifications for industries that are based on constant production. While the government-led rollout of demand management practices can encourage industry to change its consumption behaviour to a certain degree, many industries are currently operationally constrained from participating due to the technical limitations of their technologies.

As such, these industries are faced with the dilemma of choosing between the financial and reputational penalties associated with deferred decarbonisation, or the high costs associated with sourcing around-the-clock electricity, from either expensive, peak-demand electricity or costly large-scale battery assets, to ensure a constant supply. By enabling load flexibility, ETES technologies can overcome this hurdle. ETES technologies can draw in renewable electricity when it is cheap and dispatch it as heat when electricity prices are high.

Energy demand management through flexible heat could save Gladstone's industries $3 million a day in operating costs and reduce demand at current peak periods by around 2 GW. As this section will demonstrate, the combined upfront capital and ongoing operational costs associated with ETES technologies can be far cheaper than current fossil-fuelled or analogous electrified technologies, with our analysis suggesting ETES technologies can be the most cost-effective route for electrifying low-temperature heat. Our analysis further indicates that adopting ETES technologies at the scale required to decarbonise low-temperature heat in Gladstone's alumina industry alone could fundamentally alter Queensland's energy landscape and could significantly reduce electricity costs for industry and other consumers across the grid.

To lay the groundwork for this analysis, Climateworks has first modelled what Queensland's daily energy demand profile in 2040 could look like in Figure 10, under a:

+ 'step change' scenario, as represented by the orange line, using forecasts from the 2022 *Queensland SuperGrid Infrastructure Blueprint* (which draws from AEMO's 'step change' scenario in the 2022 Draft Integrated System Plan [Queensland Government 2022a])
+ 'step change with electrified heat' scenario, as represented by the blue line, incorporating the baseload demand required for continuously producing electrified heat for Gladstone's alumina industry in our 'step change' scenario.

Our 'step change with electrified heat' scenario was developed as loads associated with electrifying Gladstone's existing industry are excluded from AEMO's 'step change' scenario forecast (Powerlink 2023). We address this by incorporating an additional 1.8 GW of load spread uniformly throughout the day, derived from Climateworks' modelled demand for the alumina industry's electrified low-temperature heat requirements. Both demand profiles are characterised by periods of peak demand during the morning and evening, as the residential sector wakes up or returns home from work, and periods of low demand during the middle of the day (see Figure 10).

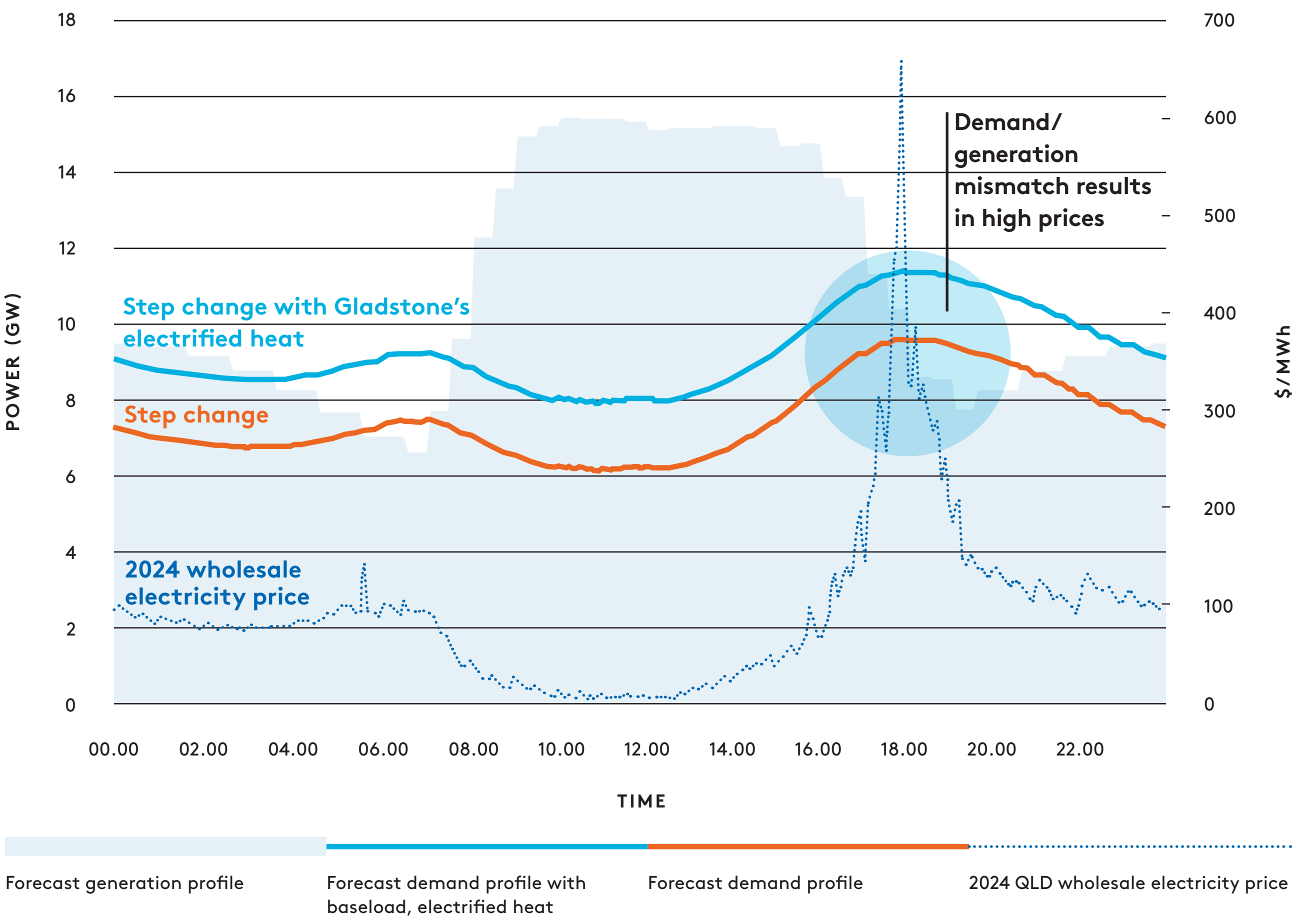
Climateworks' modelled generation profile for Queensland in 2040 is overlaid on the demand profiles and represented by the shaded blue background in Figure 10. This profile was calculated as a function of both the forecast 2040 generation capacity from the 2022 *Queensland SuperGrid Infrastructure Blueprint*, as well as daily capacity factors for solar and wind specific to Queensland (Queensland Government 2022a; Australian Energy Regulator 2022; Heath 2024). The generation capacity from the SuperGrid report, drawn from a 90 per cent mix of rooftop solar and utility-scale wind and solar farms, and around 10 per cent of gas or hydrogen peaking generators, can meet peak demand under AEMO's 'step change' scenario at all times.

In Figure 10, the daily wholesale electricity price in Queensland is represented by the dotted blue line. This was determined by averaging all of Queensland's prices from 2024 to obtain a year-averaged price summary, and has been included here to illustrate the correlation between supply and demand. As seen in Figure 10, prices are low during the middle of the day when demand is at its lowest and solar generation is at its maximum, and high when the inverse is true, peaking at around $650/MWh in the early evening.

The key takeaways from this comparison:

+ Including the load associated with continuously producing electrified heat shows a significant network-wide mismatch between peak electricity demand and peak electricity supply, particularly in the morning and evening periods.
+ This additional load would result in significant costs, not just to the alumina industry, but to all users across the grid, as wholesale prices rise accordingly during these peak demand periods.

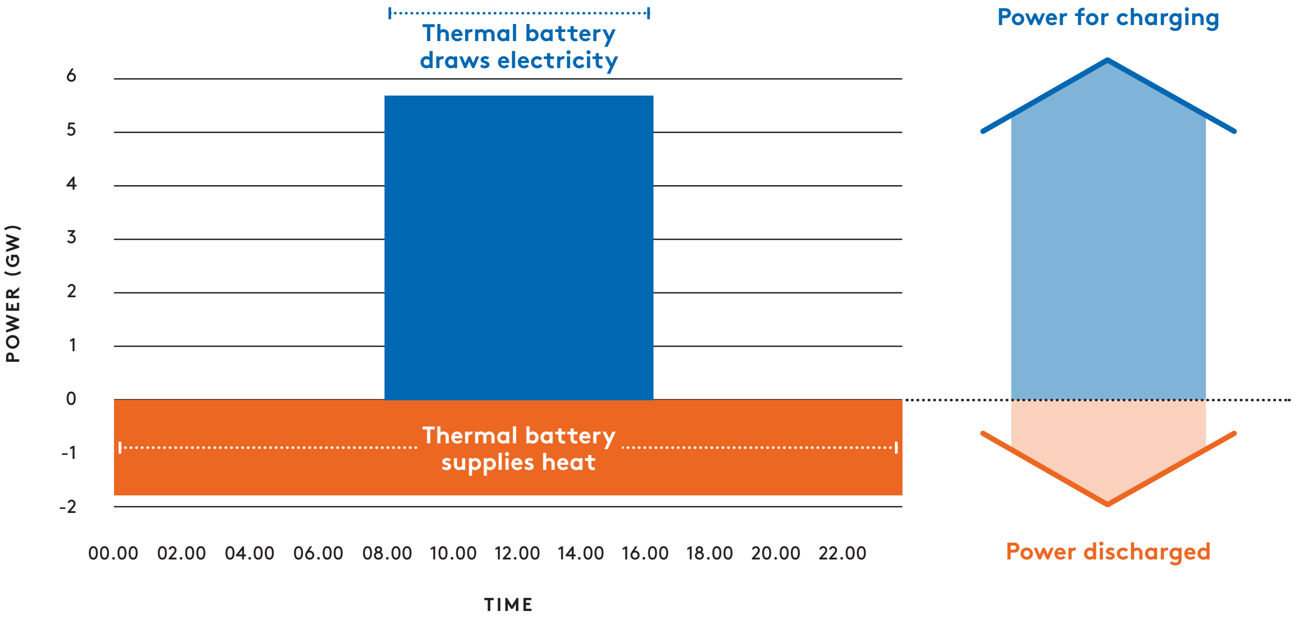
FIGURE 10: Climateworks modelled year-averaged daily energy profile for Queensland in 2040



To mitigate this mismatch, ETES assets can be used to shift industrial electricity consumption to match peak renewables production in the middle of the day. ETES assets can charge (i.e. convert electricity to heat) and discharge (i.e. release heat) simultaneously. Figure 11 depicts the ideal operating profile of an ETES asset, where the asset is charged for eight hours in the middle of the day, resulting in 16 hours of stored heat that is discharged during the morning and evening periods.

Simultaneous charging and discharging affords an uninterrupted supply of heat, facilitating a business-as-usual level of industrial productivity, while circumventing the need to draw electricity from the grid for 16 hours a day. While this operating profile does require more electricity during the day, relative to a continuous operating profile, cheaper daytime electricity prices mean that operating costs are significantly reduced.

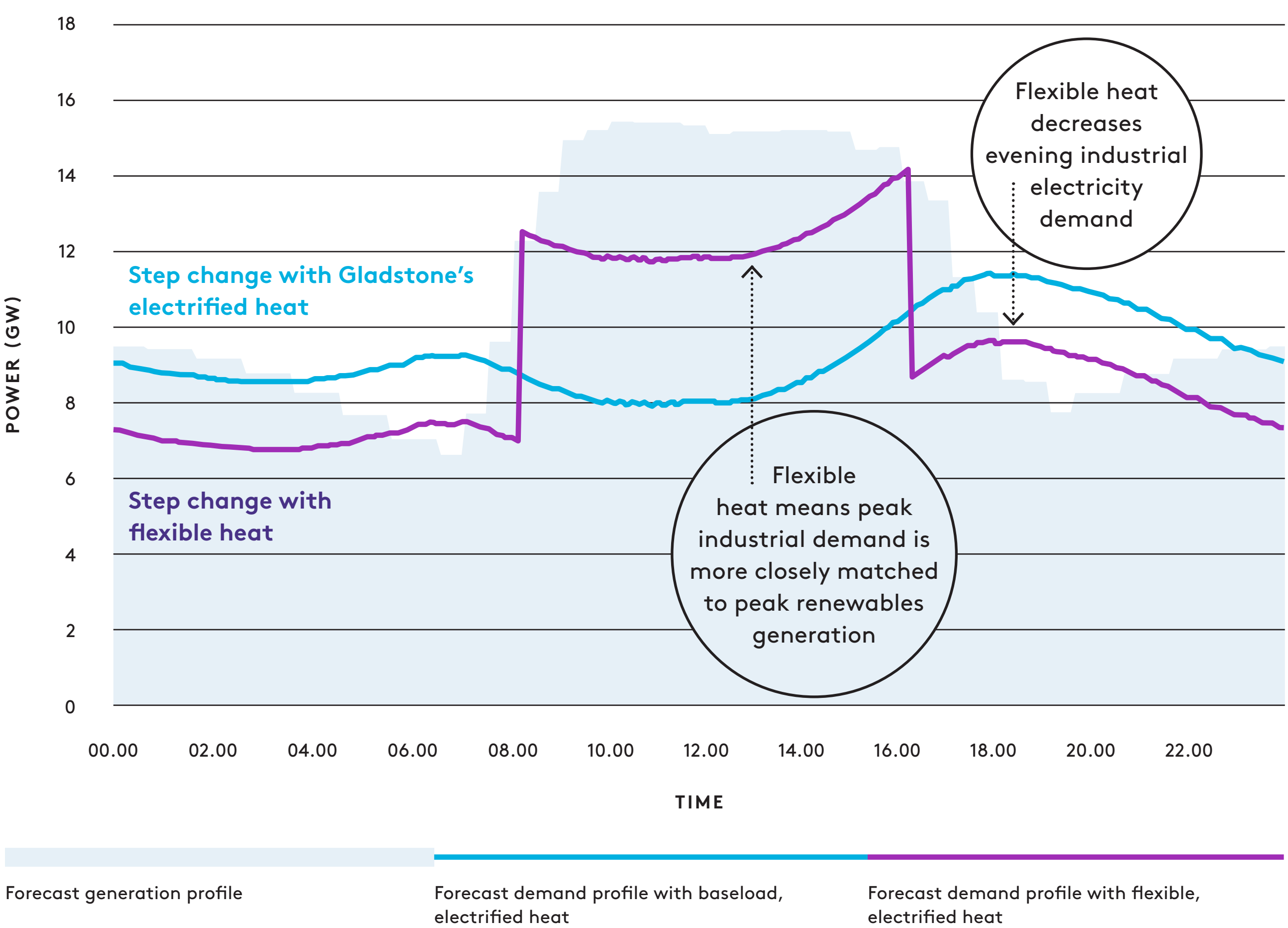
FIGURE 11: Ideal operating profile for an electrothermal energy storage asset



As seen in Figure 12, applying an ETES-enabled operating profile to the load for Gladstone's alumina industry's electrified heat requirements results in a third scenario for Queensland's daily electricity demand profile in 2040:

+ 'Step change with flexible heat' scenario, as represented by the purple line.

FIGURE 12: Impacts of ETES technologies on Queensland's electricity demand profile in 2040



Adoption of ETES technology at scale by Gladstone's alumina industry would transform Queensland's demand profile, reducing demand at current peak periods by 1.8 GW. Whole-of-network peak demand shifts from the morning and evening to the middle of the day, when it is more closely matched with peak renewables generation. While this analysis uses a binary-state ETES operating profile that is either charging at maximum capacity or not charging at all, a 'stepped' operating profile where the ETES asset is charging at a percentage of maximum capacity can likely better match Queensland's generation profile as solar generation ramps up and down.

Using an ETES-enabled, flexible operating profile means that industry can take advantage of cheaper electricity prices during the day to reduce the aggregated costs of electrifying its operations.[11] Table 4 compares the capital and operating costs of three heating assets – contemporary gas boilers, electric boilers and ETES batteries – if they were in use today, at the scale required to supply low-temperature heat requirements for Gladstone's alumina industry. Operating costs are determined using a gas price of $7/GJ to simulate the power purchase agreements (PPAs) that typical industrial entities have used to lock in cheap fossil fuels, noting that the current spot price for gas in Queensland is much higher at around $14/GJ. Electricity prices equivalent to the wholesale electricity prices calculated in Figure 10 are also used. Capital costs are calculated from both literature and industry data, and are averaged out over an assumed 30-year lifespan to give a daily cost (Defauw et al. 2022).

Energy demand management could save Gladstone's industries $3 million a day in operating costs. As seen in Table 4, ETES assets could be the most cost-effective form of electrified heat production. Flexible operating costs (at $1.06 million per day) could be four times lower when compared to continuously operating electric boiler operating costs (at $4.23 million per day). While the lifetime-averaged capital costs of electric boilers are cheaper than those of ETES assets, largely due to the maturity of electric boiler technologies, the aggregation of both costs still suggest that ETES assets are two and a half times cheaper than electric boilers for the provision of industrial heat.[12]

While operating costs for flexible heat are calculated to be roughly equal to those for gas-fuelled boilers, several factors, including carbon prices (i.e. those under the Safeguard Mechanism), expiring gas PPAs and volatile wholesale gas costs, will make a gas-centric business-as-usual approach increasingly expensive, and likely more costly than using an ETES asset.

11 Assuming that industry has access to either behind-the-meter renewable generation or dynamic electricity pricing structures.

12 While hourly wholesale electricity costs may shift in response to the mass uptake of ETES assets (see Figure 14), Climateworks finds that ETES-enabled heating still represents the most competitive electrified heating option.

TABLE 4: Cost comparison of three assets for low-temperature heat in Gladstone's alumina industry

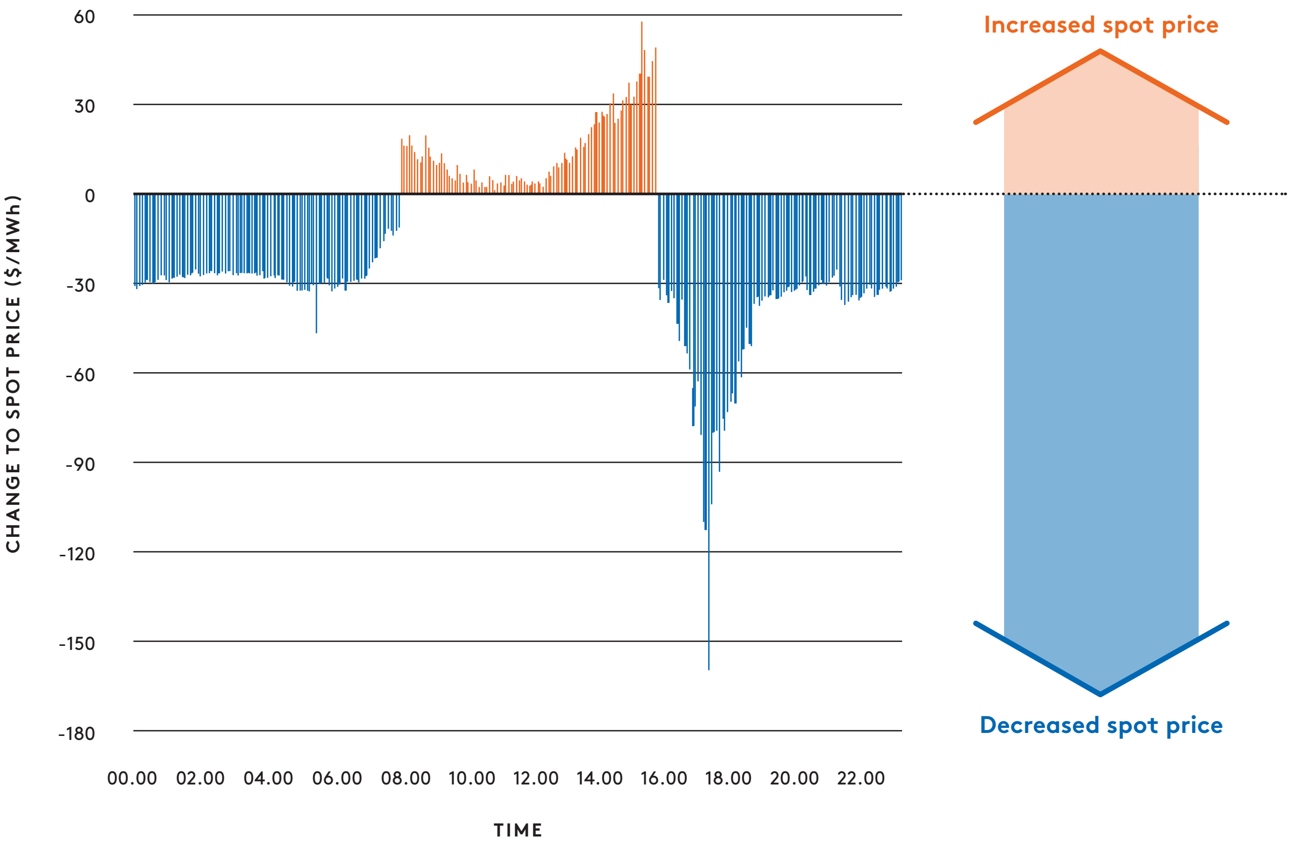
Heating asset	Operating costs	Capital costs (lifetime-averaged)	Aggregated costs
Gas boiler (simulated current PPA-derived fuel prices)	\$1.01 million/day	\$0.05 million/day	\$1.06 million/day
Electric boiler (continuous electrified heat)	\$4.23 million/day	\$0.13 million/day	\$4.36 million/day
ETES (flexible electrified heat)	\$1.06 million/day	\$0.70 million/day	\$1.76 million/day

Electrifying Gladstone's industries and adding heat storage could cut wholesale electricity prices by as much as 60 per cent, lowering costs for industry and consumers across Queensland. Climateworks has modelled what this change could look like in spot prices in contemporary markets, if ETES assets were to be implemented at scale today (Figure 13). These changes were modelled by calculating the change to spot prices as demand varies throughout the day. This is then applied to the amount of electricity shifted by using ETES assets, relative to the amount used by a continuously operating electric boiler.

As seen in Figure 13, spot prices increase during the middle of the day, due to the increased loads associated with ETES charging, and significantly decrease during the morning and evening when residential demand is at its highest (Mumtahina et al. 2024). The decrease in evening industrial electricity demand could reduce wholesale spot prices by up to \$160/MWh; however, this is offset by slightly higher middle-of-day price increases of up to \$5–60/MWh. Increased middle-of-day prices can likely reduce the frequency of negative price events, where the wholesale prices drop below \$0, which typically occurs when there is an oversupply of electricity. This can increase investor confidence in renewable generation projects by ensuring increased profitability and reduced curtailment (Brook n.d.).

Under a scenario where ETES assets are deployed at scale, the day-averaged spot price could be reduced by up to 60 per cent (Figure 13). Passing these reduced wholesale prices onto consumers could result in significant savings across Queensland, particularly to power bills in the residential sector.

FIGURE 13: Potential impacts of flexible heat on wholesale electricity prices compared to the continuous use of electric boilers



4.3. Demand response programs in the NEM

Increased industrial flexibility would facilitate industry's participation in demand response programs in the NEM. This participation could serve as a method of compensation to industry for its investment in flexibility, as well as a resource that energy planners could use to better support the grid. In this section, we analyse the major demand response programs in the NEM, and compare them to best-practice demand response programs around the world to suggest how they could better be used to support whole-of-grid energy security.

The NEM currently operates three major programs that provide grid-controlled demand response, namely the Frequency Control Ancillary Services (FCAS), the Reliability and Emergency Reserve Trader (RERT) and the Wholesale Demand Response Mechanism (WDRM). Collectively, participants in these programs provide a maximum potential capacity of around 4 GW, with this capacity used to improve grid reliability and provide emergency support. Participants are compensated for the availability of their services or for activating their capacity. AEMO funds this compensation through avoided network costs compared to a network without demand response mechanisms. Without demand response interventions from these programs, the cost for a market disruption can be around five to ten times the compensation supplied to program participants. These programs result in a net win for AEMO, program participants and the stability of the grid.

Increasing the scope of these programs, in line with how other energy markets around the world have used their demand response capacity, could lower energy costs for consumers and transform the provision of demand response capacity into an additional source of revenue for industrial participants.

4.3.1. Reliability and Emergency Reserve Trader (RERT)

The RERT program provides emergency demand response services, which uses either unscheduled generation (i.e. standby generators) or unscheduled curtailment (i.e. the reduction of consumer loads) during periods of large demand–supply mismatches. This prevents widespread grid instability and potential blackouts, acting as a 'safety net' for the network. These activations are a response to forecasted LOR events, with participants typically forewarned hours or days in advance.

Due to its mandate to mitigate potential emergencies, RERT prioritises both reliability and capacity, and retains the highest capacity among the NEM's demand response programs with approximately 2.5 GW of potential services. As such, typical participants are those who can provide an extended duration of reduced or shifted load, with past activations ranging from a single hour to several days. Participants are sourced through short-term contracts, where they are placed on retainer to provide demand response services for a given period, but are only compensated for activation at a rate of $36,000 per MWh of capacity provided.

RERT is currently used infrequently – only eight activations in the last five years. While this befits its purpose as an emergency-response measure, this also means the largest share of demand response capacity in the NEM cannot be used in its day-to-day stabilisation.

4.3.2. Frequency Control Ancillary Services (FCAS)

The FCAS program provides demand response capacity for network ancillary services. It involves a rapid, continuous injection or reduction of energy in the network to maintain the network's 'quality' of transmission when there is a sudden imbalance. These imbalances, arising from a sudden mismatch between generation and consumption, can lower the efficiency of transmitted power across the grid. AEMO has noted a significant rise in these mismatches in recent years, occurring, for example, when there is a fluctuation in renewable generation due to cloud cover or an unexpected stoppage of an industrial facility.

As demand response services for the FCAS program rely on rapid, short-duration adjustments, typical participants are those who can provide a rapid, automated response through quick alteration to their energy profile. Requests for services can occur hundreds of times in a year, with AEMO recording 137 significant events in 2024, totalling 25 minutes of load adjustment, with events typically on the second-to-minute time scale (AEMO 2025). The most valuable category of FCAS services is those that can respond within less than a second, known as the 'Very Fast Response', with a recorded capacity of 1.1 GW and 1.4 GW for frequency-lowering and -raising responses, respectively. Remuneration for FCAS services is provided in the form of passive compensation for availability, at around $10 per MWh.

As FCAS stabilises frequency disruption in the second-to-minute time scale, its capacity is limited in longer-term power disruptions.

4.3.3. Wholesale Demand Response Mechanism (WDRM)

The WDRM, as a wholesale demand response service, is a market mechanism that uses price-incentivised shifting or reducing of consumption. It allows consumers to freely and directly trade their demand response capacity on the wholesale electricity market in the same manner as generators. The intended outcome of this mechanism is to allow supply and demand market factors to incentivise the provision of demand response services by increasing compensation amounts during periods when demand response is most needed.

The WDRM has historically held a modest amount of demand response capacity. As of June 2025, the mechanism has access to 74 MW, or around that produced by a single utility-scale battery farm.

However, this is expected to double by the end of 2025, with another 95 MW (AEMC 2025). Nonetheless, despite this recent improvement in registered capacity, the WDRM total still remains a small fraction compared to what is registered under the RERT and FCAS programs, limiting the scale of services it can provide.

The Australian Energy Market Commission (AEMC) is currently reviewing the WDRM and is considering expanding the eligibility criteria for the mechanism to increase participation (AEMC 2025). This review is occurring in parallel to a proposed NEM reform, to facilitate a two-way market that better connects supply and demand, which the AEMC has suggested could be enabled through continued refinement of the WDRM.

4.4. Comparison with international case studies

Australia is currently using battery storage to shore up its firming requirements (see section 4.1). Energy markets in other locations have addressed their firming needs through a variety of technologies to take advantage of their local context. For example, baseload generation for firming in Texas and Singapore is provided by cheap oil and gas, while France and Norway have used nuclear and hydropower plants respectively. Australia is unable to implement these at the pace required due to high domestic costs or a lack of existing infrastructure. These markets, however, have also recognised that the use of baseload generation for firming capacity is only one part of the solution, and cannot solely provide the stability that their networks require in a decarbonising energy landscape. Instead, these markets have complemented their baseload generation with innovative demand response programs. A summary of the key shortfalls of demand response programs in the NEM, and how international energy markets have overcome these challenges, can be found in Table 5.

TABLE 5: Comparison of Australian and international demand response programs

Key shortfalls in Australian demand response programs	Key learnings from international demand response programs
RERT: Activated infrequently, despite possessing the largest demand response capacity.	**TEXAS**: Integration of emergency and non-emergency demand response programs has increased the frequency of capacity activation for whole-of-market benefits without compromising emergency response.
WDRM: Low profitability and participation, and high barriers to entry.	**FRANCE**: An efficient free-agent market design, allowing easy participant access to wholesale markets, means that demand response participation and capacity is high.
FCAS: Despite its status as the most frequently used program in the NEM, it has the potential to be used far more often.	**FRANCE**: High participation and capacity means that demand response is treated as a fundamental aid to the network and is used frequently for multiple services, including wholesale price cost reductions.
CROSS-PROGRAM FACTORS: Despite the significant potential for flexibility in the residential sector's energy consumption, energy planners have little capacity to use residential-sector resources for demand response services.	**NORWAY**: Heavily integrating smart meters in residential and small business appliances, combined with a communal outlook on the shared nature of energy resources, affords mass participation in demand response programs and a large capacity to be autonomously and rapidly drawn on.
CROSS-PROGRAM FACTORS: Steep non-compliance penalties and entry requirements to the demand response market disincentivises new participants from joining.	**SINGAPORE**: Effectively using incentives for compliance and a more forgiving penalty system has seen significant success in increasing demand response participants and capacity.

4.4.1. France: Notification d'Échanges de Blocs d'Effacement

As a major component of the European Union (EU) grid, France's energy network is an increasingly important stabilisation factor for the EU as the share of renewable energy, and grid volatility, in connected countries increases. This stabilisation is provided by France's fleet of nuclear power plants, which supply 70 per cent of the country's total energy mix. In the first half of 2024, France generated 272 TWh of electricity, and exported 16 per cent of this, providing stability to European energy markets like Italy, the United Kingdom and Germany.

In 2013, France developed a mechanism known as the Notification d'Échanges de Blocs d'Effacement (NEBEF) to account for the variable demand of the grids France is connected to and recent power shortfalls in its own grid from its lack of flexibility (Cabot and Villavicencio 2024). The NEBEF is to encourage entities to participate in demand response, with a focus on predictable load adjustment. Most demand response capacity has historically been sourced from aggregations of small entities (e.g. residential or small-business entities), which bid to provide demand response capacity on a free market, in a manner analogous to the WDRM program in Australia's NEM. Functionally, NEBEF is used in a similar manner to the NEM's FCAS program to supply rapid response; however, NEBEF capacity can also be used for longer durations to match a wider variety of needs.

Unlike Australia, which saw little success with free-agent wholesale demand response trading under the WDRM, this form of demand response participation largely comprises the NEBEF's total 4.5 GW capacity. With over 8,000 activations in 2024, 6,000 of which were activations of 15- or 30-minute intervals, this totalled 91 days of load adjustment – nearly a quarter of the year (RTE n.d.). In contrast, in the same year, the FCAS program performed 137 activations of four-second intervals or less, totalling just 25 minutes of load adjustment (AEMO 2025). These increased activations have resulted in lowered energy bills, particularly during the 2021–22 energy crisis spurred by the invasion of Ukraine, and facilitated a higher share of VRE in France's energy network (Cabot and Villavicencio 2024).

The frequency of demand response activations in the NEBEF is enabled by mass participation in a wholesale, price-driven market. This mass participation can be partially attributed to the financial incentives provided by dynamic tariffs in France, in use since the 1960s, which have a high degree of synergy with demand response. However, several key barriers that typically prevent the deployment of demand response in other markets have recently been lifted under the NEBEF – cited as a major factor in its success (Cabot and Villavicencio 2024). Factors enacted by the French government under the NEBEF include:

+ publishing an annual tender forecasting the required demand response capabilities, which provides increased certainty to NEBEF applicants on the financial return for their participation
+ reducing the bidding value for demand response services from 50 MW to 10 MW to motivate the entrance of smaller entities
+ providing a price premium for 'green' demand response capacities, which exclude sites that perform load reductions through self-generation using fossil-fuels.

4.4.2. Texas: Electric Reliability Council of Texas

The Electric Reliability Council of Texas (ERCOT) has recently invested heavily in expanding its demand response capacity, largely due to a recent climate-induced grid infrastructure failure. Texas currently possesses around 8.8 GW of demand response capacity amongst its various programs, which is provided predominantly by large generators and industrial loads.

Two of Texas' largest demand response programs are the Emergency Response Service (ERS) and the Rapid Response Service (RRS), which provide an analogous function to that of the NEM's RERT and FCAS programs, respectively, to maintain response capacity for emergencies. Expansion of these programs has been realised through:

+ favourable incentives for demand response participants, through prioritising the availability of capacity over its actual use and therefore paying for retention of services – compared to most programs in the NEM that provide remuneration based on activations alone
+ selective, simplified participation criteria that focus on loads that can be immediately curtailed, meaning Texas can prioritise industry, as entities with a large potential for load-shedding, to provide demand response capacity.

However, since 2023, Texas has recognised that there is a middle ground between emergency responders and rapid responders, which allows large-capacity demand response to be used more often. This inspired the creation of the ERCOT Contingency Reserve Service (ECRS), which sought to address the load uncertainties caused primarily by increasing VRE sources. A combination of the two aforementioned programs allows for near-instantaneous response akin to the RRS while also facilitating medium-term (i.e. two-hourly) curtailment from demand response resources that would otherwise be held in reserve under the ERS. The ECRS is intended to reduce the financial disruption to peak-demand energy prices caused by the integration of renewables and longer-duration storage projects in the grid by allowing demand response to be used not just as an emergency response, but as an economic resource. However, its recent inception and high-temperature weather events in 2023 have made its long-term impact on prices difficult to ascertain.

4.4.3.

Norway: Norwegian Energy Regulatory Authority

Norway's electricity market, regulated by the Norwegian Energy Regulatory Authority (NVE-RME), currently holds 4.1 GW of demand response capacity. With a total generation capacity of 40.3 GW, Norway possesses one of the highest ratios of demand response to generation capacity in the world. Unlike Australia, the residential (2.6 GW) and commercial (0.8 GW) sectors provide most of this capacity, rather than large energy consumers like industry.

Norway's extensive hydropower resources provide more than 90 per cent of its electricity, supporting an almost completely renewables-based power sector. Much like wind and solar, however, this supply is highly variable, particularly in the spring when hydropower reserves are at a low. To address this reduced capacity and its impact on the cost-effectiveness of industrial operations, the NVE-RME has turned to season-dependent demand response programs that largely focus on residential heating assets as a national source of demand response capacity.

A rapid adoption of electrically driven heat pumps for space and water heating, combined with large-scale, government-facilitated smart meters, means most residential buildings can adjust their electricity consumption remotely and automatically. While this process is incentivised using price-signalling through dynamic tariffs, there is also a cultural expectation for everyday consumers to participate in aiding the grid through communal use of their appliances. Implementing demand response in Norway has led to decreases in expected electricity prices, particularly during peak demand periods, and total system costs by exporting flexible electricity to the wider EU grid (Ahang et al. 2025).

4.4.4.

Singapore: Energy Market Authority

Demand response is a relatively new development in Singapore. Singapore's electricity network, administered by the Energy Market Authority (EMA), largely depends on natural gas, with a relatively small proportion of VRE generation. This suggests the current build-out of demand response capacity is viewed as an investment in the future of the grid, rather than addressing a need in the current network.

The highlight of Singapore's current approach to demand response programs is a novel, investigative methodology for learning what will best work for the network. Using exploratory 'regulatory sandbox' periods has allowed the EMA to test new demand response programs in safe and conducive conditions while providing the necessary safeguards to protect the consumers in the wider energy market. During these sandbox periods, both compliance thresholds and penalty amounts for demand response have been lowered to encourage more commercial and industrial companies to optimise their energy usage. In the context of demand response, non-compliance typically refers to a failure to deliver the agreed-upon capacity when required or failing to comply with energy market operational protocols during activations. Feedback from Climateworks' consultation has suggested that Australia's demand response programs possess high bars for compliance and strict penalties for non-compliance.

Singapore's exploratory approach to implementing demand response is possible largely due to the network's current limited reliance on demand response programs. This allows a degree of experimentation without fear of significant harm to the broader network. The window for such an approach in Australia is rapidly closing, due to an increasingly large integration of demand response programs in the NEM.

In the two years since the most recent sandbox period was launched, demand response capacity in Singapore has doubled, and two key findings from the study will be integrated into Singapore's evolving demand response program. These findings could assist the build-out of Australian demand response programs, and are as follows:

+ A clear relation between alleviating the severity of penalties and increased participation.
+ Penalties for failing to meet the response threshold were scaled by the degree of non-compliance rather than through a flat penalty, with remuneration reduced proportionately. This incentivises increased participation, with half-measures partially rewarded. This differs from the environment in Australia, where potential capacity providers are currently dissuaded from participating through fear of non-compliance.
+ A six-month trial period with two waivers for non-compliance reduced participant fear.

Providing a trial period allowed potential demand response participants to join with less fear of breaching the compliance threshold, and allowed them to gain familiarity with methods of participation.

5. Strategic public-sector funding can accelerate Gladstone's decarbonisation

In the Australian ETI, Climateworks found that tackling industrial decarbonisation could cumulatively require up to $190 billion by 2050 across Australia's largest industries – just for the necessary industrial abatement technologies. This represents a 62 per cent greater investment than business as usual (Climateworks Centre and Climate-KIC 2023).

The benefits of decarbonisation typically outweigh the financial penalties associated with a business-as-usual approach in the long term. However, in the short term, industries that are decarbonising their operations face financial risks compared to industries who adopt a business-as-usual approach.

Decarbonisation can incur substantial costs from both the initial upfront capital expenditure (CAPEX) in acquiring and installing new technologies, as well as the ongoing operational expenditure (OPEX) to power and maintain these technologies. The relative immaturity of these technologies can introduce greater uncertainty to profitability calculations compared to traditional technologies, which may hinder industries from accessing current methods of financing. This, combined with current highly volatile global markets and uncertain long-term forecasts on operational costs such as fuel or electricity prices, can substantially delay the critical investments needed for decarbonisation.

The public sector, through financing from state and federal government bodies, can play a catalytic role in enabling decarbonisation by mitigating some of the financial risks. Public-sector financial support for both upfront and operational costs will play an important complementary role in reducing the barriers for industry to access private-sector financing for clean energy technologies. These forms of financial support can best benefit 'late to abate' industries, where decarbonisation is not yet economical, but which can be reasonably expected to reach net zero through credible decarbonisation pathways. This public-sector financial support can also economically and socially benefit industry's surrounding communities and ensure the continued prosperity of industrial regions.

In this section, we first analyse the current landscape for public-sector financial support for key technologies and fuels identified as vital to decarbonising Gladstone's industries, and highlight the barriers preventing industry from making full use of this support. Following this, we present case studies of best-practice financial instruments or frameworks used to support industrial decarbonisation around the world, and suggest how these could be adapted for use in Australia. Many of the technologies and fuels that our funding support analysis focuses on are applicable to industries outside Gladstone, and we anticipate that these findings can be used by governments Australia-wide to better enable industrial decarbonisation.

BOX 12:

The role of public-sector support in developing Australia's utility-scale solar industry

While the cumulative investment required for industrial decarbonisation may seem high, with Australian Industry ETI findings suggesting Australia could need around $7.5 billion per year, public-sector support was proven a decade ago to be instrumental in overcoming a similar challenge by catalysing private-sector funding for the build-out of Australia's utility-scale solar industry.

In 2015, when Australia's utility-scale solar industry was small, early developers were hindered by a range of challenges common to any nascent industry. Potential investors lacked the confidence to commit capital for new projects, meaning the expertise necessary to overcome these challenges could not be developed.

To remedy this problem, ARENA and the Clean Energy Finance Corporation (CEFC) used government-backed financing to kick-start private-sector funding. Between the two organisations, an unprecedented $350 million in grants and concessional financing was provided to lift developer and investor confidence in funding solar infrastructure projects. Under the Advancing Renewables Program, ARENA provided gap funding to reduce the cost of individual projects, thus increasing the competitiveness of utility solar. At the same time, the CEFC provided projects long-payback loans to support them through lengthy development periods, and acted as a co-investor to spur greater confidence from private-sector financial institutions. Today, due to these efforts, utility-scale renewable projects see around $4 billion of investment per year.

5.1. Current public-sector support for CAPEX

High upfront capital costs are one of the largest barriers deterring industry from implementing low-emissions technologies. These costs cover investments needed for new assets, like electric boilers or CCU filters, the upgrades required to facilitate the combustion of hydrogen, or the installation of on-site supporting infrastructure like grid connections. These can be a significant financial investment for industrial companies, which can be compounded if existing fossil-fuelled assets have not yet reached their end of life, leading to unrecovered costs if they are replaced. New decarbonisation assets are also typically perceived as having higher risks due to their underdeveloped track records compared to mature high-emissions assets. Industries therefore cannot develop rigorous business cases demonstrating a return on investment (ROI) at the same speed or scale as more well-understood technologies.

Public-sector support will be needed to support industries with decarbonisation technology costs to accelerate decarbonisation in line with government-mandated emissions targets and preserve the prosperity of industrial regions. Though there is significant interest from private-sector investors to finance the purchase or installation of decarbonisation assets due to their role in emissions reductions, the high degree of uncertainty typically means these projects do not meet the investment criteria of these investors, who in turn cannot rationalise the investment decision. New private-sector sustainable finance models are currently being developed; however, low-carbon investments in the heavy manufacturing industry remain low, and are globally estimated to amount to US$15 billion annually (Cordonnier and Saygin 2023). It is estimated that these investments need to quadruple by 2030 to meet the 1.5°C Paris Agreement targets. Until sustainable finance markets have reached maturity, urgent public-sector support from governments will be needed.

Australian federal and state governments have developed several financial instruments that use public funds to de-risk or support the private-sector financing of low-carbon technologies – for instance, through blended finance approaches that encourage encourage public- and private-sector co-investment. By overcoming the current financial hurdles to implementing these early decarbonisation projects, public-sector support in the short term can bring down the costs of these technologies through learning-curve reductions and encourage their long-term, unsupported implementation at scale. Climateworks has identified viability gap funding, loan guarantees and concessional financing as three ideal public-sector financial instruments to encourage blended finance between governments, industry and private-sector investors (Box 12 and Table 6).

BOX 13:

Public-sector funding instruments

Viability-gap funding instruments are typically payments in the form of grants or deferred loans, and are used as short-term mechanisms to supplement the costs of commercially unviable but economically desirable projects. These can be used to support industry's investment in pilot studies to investigate the practicality and implementation methodology of new decarbonisation technologies, and are typically around several million dollars in value.

Loan guarantees are instruments used to encourage private-sector investment in decarbonisation projects with high perceived risks. Governments, as highly credit-worthy organisations, underwrite investments if the project underperforms and the borrower defaults. This can increase the total supply of financing available for such projects.

Concessional financing, typically in the form of debt or equity financing, is loans provided at more favourable terms (e.g. lower interest rates or lowered criteria for applications) than what is available in traditional financing markets to support favourable policy outcomes. These could be as much as several hundred million dollars in value and are ideal for projects which can demonstrate some degree of financial return. They are thus suited for the deployment of more mature technologies at scale. By providing industry with access to financing mechanisms, this can accelerate emissions reduction projects at a low cost to government.

TABLE 6: Public-sector financial instruments to support blended finance approaches for industrial decarbonisation

GOVERNMENT-BACKED FINANCIAL INSTRUMENTS	WHERE THEY CAN HELP	HOW THEY CAN HELP
Viability gap funding	+ Industrial pilot projects or studies	Encourages industry's investment in research and feasibility studies
Credit or loan guarantees	+ Industrial pilot projects or studies + Commercial deployment of early-stage technologies	Protects investors against the higher risk profile of decarbonisation technologies
Concessional finance	+ Commercial deployment of early-stage technologies + Commercial deployment at scale	Accommodates the lower short-term ROIs of decarbonisation technologies

Twenty state and federal government-backed financing pools, worth up to $21 billion, are available to Gladstone's heavy manufacturing for the upfront costs of decarbonisation technologies (see Appendix, Figure 16).[13] However, to be used effectively, these funds could be further streamlined to address specific objectives and industries.

The bulk of this funding is available through three organisations – the CEFC, the National Reconstruction Fund (NRF) and the Northern Australia Infrastructure Facility (NAIF) – in the form of credit guarantees or concessional financing. Gap funding in the form of grants is accessible through ARENA. Funds from the CEFC, NRF and ARENA are available Australia-wide, while those from the NAIF are broadly limited to industries located north of the Tropic of Capricorn. Low-carbon fuel producers, such as biomethane or biomass for industrial decarbonisation, can also access this $21 billion funding pool, with projects involving renewable electricity or hydrogen production able to access additional funding to a total of $42 billion.

An analysis of the eligibility criteria of these financing pools, in conjunction with industry consultation, has found several key challenges to effectively using this funding for industrial decarbonisation:

+ **A lack of targeted funding for the decarbonisation of industrial heat, despite its role in the production of most heavy industry emissions.**[14]

  Most financing pools within our analysis have broad decarbonisation or infrastructure-development mandates, with few operating funds that target just the industry sector, let alone industrial low-carbon heat. This means that heavy industry can find it difficult to decarbonise compared to other sectors (e.g. energy or transport), as the costly nature of decarbonising process heat can result in industry being outcompeted by these sectors for competitive funding applications.

13 The scope of eligible projects that can access the aggregated funding from these pools extends beyond the decarbonisation technologies discussed in this report.

14 We note that the sole funding stream for process heat decarbonisation in the last five years, ARENA's *Industrial Transformation Stream (Round 1)*, closed in Q1 2025.

+ **A lack of targeted funding for the decarbonisation of existing 'hard to abate' industries that are vital to Australia's growth.**

  These industries (i.e. the cement or chemicals industries) produce essential goods. Yet due to their technologically or commercially immature decarbonisation options, they struggle to access public-sector funding for decarbonisation, even under the lower criteria for bankability inherent to concessional financing schemes (such as those under the CEFC). Given the specific challenges that underpin financing these emissions-intensive industries, the business case for such projects is significantly disadvantaged compared to those from other industries. A lack of support for these companies to meet their emissions targets may mean that they reduce their presence in Australia, in turn leading to a reduced domestic manufacturing capacity.

+ **A lack of funding for carbon capture projects, which represent the highest-potential option for decarbonising the clinker and lime industries.**

  Of the 20 financing pools capable of addressing industrial decarbonisation, industry consultation has found that none could be used for carbon capture projects, despite their potential for deep emissions reductions for industry (Cordonnier and Saygin 2023). These ineligibilities hinder financing, even for projects intended as off-takers for captured carbon as a feedstock, and they compound the existing difficulties faced by industry in improving this technology's capabilities.

5.2. Current public-sector support for OPEX

Upfront costs of decarbonisation projects represent an immediate financial hurdle that industries are struggling to overcome. However, ongoing operational costs, particularly those related to energy expenditure, can represent a significantly greater (30–60 per cent) share of the levelised cost of production for heavy industry compared to capital costs.[15] Electricity prices and the cost of low-carbon fuels, like green hydrogen and bioenergy, could comprise the bulk of energy expenditure for heavy manufacturing as these industries transition away from the fossil fuels they access through cheap PPAs. While it is expected that similar PPAs could provide certainty as low-carbon electricity and fuel supply increases, currently, the short-term volatility of the associated prices results in uncertain estimates of ROIs or payback periods. This complicates industry's ability to develop business cases for investment to internal and external stakeholders.

State and federal governments can provide surety to industry to remedy this, ranging from developing long-term stable energy or product demand-side policies to direct financial support through subsidies or production credits that can bridge production costs and profitability (PA Consulting 2021). As these instruments typically provide ongoing support over several years, they can provide a measure of stability that companies can use to signal to investors the long-term profitability of decarbonisation.

Existing public-sector support for the ongoing costs of industrial decarbonisation is primarily focused on the production of green hydrogen and renewable electricity, which represent upstream components of industrial manufacturing production costs.

15 Mission Possible Partnership analysis, Gladstone Clean Industrial Hubs study for Central Queensland Statement of Cooperation.

These schemes, which are primarily funded or administered by the federal government, include:

- Capacity Investment scheme (CIS) – a revenue-underwriting scheme for the production and storage of clean electricity
- Large-scale Generation Certificates (LGCs) – tradable certificates that can be sold by clean electricity generators
- Hydrogen Production Tax Incentive (HPTI) – tax offset that returns producers $2 per kilo of hydrogen generated
- Hydrogen Headstart – production credit that returns producers the difference between the production cost and market price of hydrogen.

The CIS and Hydrogen Headstart are revenue-underwriting schemes that seek to provide long-term financial safety nets for large-scale renewable electricity and hydrogen projects respectively. They ensure a minimum level of profitability from the sale of clean energy by compensating producers with the difference between clean energy production costs and market prices, with this support provided over 10 to 15 years. The HPTI under the Future Made in Australia (FMA) Act is an alternative avenue to support hydrogen production by reducing the commercial gap between production costs and market prices and providing a refundable tax offset of $2 per kilogram of low-carbon hydrogen produced over a 10-year period.[16]

Both the currently active Critical Minerals Production Tax Incentive (CMPTI) and the under-development Green Aluminium Production Credit can also serve a similar function to the HPTI, by allowing heavy manufacturing industries to receive funding for ongoing production costs.[17]

These measures spur investor confidence in renewable energy or clean technology projects by reducing the risks of unforeseen factors affecting profitability, and encourage both the increased build-out of energy projects and the long-term reduction of energy production costs as the learning curve for these projects is brought forward.

LGCs on the other hand do not provide direct financial assistance. As tradable financial certificates, they instead create a financial incentive for producing renewable electricity through lowered barriers for trading this energy on wholesale markets. Operators of renewable electricity projects, such as wind or solar farms, create LGCs for each MWh of energy they produce. These can then be sold or traded to large energy consumers to meet either their legislated obligations under the federal government's Renewable Energy Target or voluntary corporate ambitions. This increases certainty in revenue sources for clean energy producers and represents another route to attract private capital.

The generation and sale of Safeguard Mechanism Credits (SMCs), under the federal government's Safeguard Mechanism scheme, can also incentivise decarbonisation by potentially offsetting some of the costs of reducing emissions. Industrial facilities covered under the Safeguard Mechanism are eligible to receive SMCs for each tonne of carbon reduced below their annual legislated targets (or 'baselines'), which can then be traded on markets for financial compensation to entities that have not met their targets. A recent report on the Safeguard Mechanism found that in 2023–24, 62 of the 219 covered facilities reduced their emissions below their annual targets, and were compensated by receiving SMCs totalling approximately $300 million (Clean Energy Regulator 2025).

16 Legislation restricts the application of both the HPTI and Hydrogen Headstart production credit to the same project by proportionately reducing the benefits received.

17 Much of Australia's existing industries, for example the steel or aluminium supply chains, produce metals which are ineligible for funding under the CMPTI.

SMC trading prices, however, are too low to function in isolation as an incentive for decarbonisation or a deterrent for failing to meet emissions targets. Current spot prices of around \$37/tCO_2e (representing the expected form of compensation) and current price caps at \$75/tCO_2e (representing the maximum cost companies have to pay to meet their Safeguard obligations) are well below the abatement costs for some 'hard to abate' industries (e.g. \$220/tCO_2e for the cement industry [IEA 2021]).

Another factor currently affecting decarbonisation costs is that clean energy production is still catching up to the scale required by industries (including for process heat), despite the number of public-sector support schemes described above. This means industries are currently struggling to access clean energy at competitive prices. A slow build-out of renewable energy and storage projects is resulting in volatile grid electricity prices from the ongoing use of costly coal and gas generators for firming capacity. These factors are impacting industry's timeframe for electrification and the investment confidence required to catalyse domestic hydrogen production.

To address industry's high operational costs for producing low-carbon products, measures must be introduced that target industry directly, such as the federal government's proposed Green Aluminium Production Credit currently under development, in addition to those targeting upstream processes in the supply chains, such as energy production.

5.3. International case studies

Implementing OPEX support schemes drawn from best-practice case studies in other markets can help Australia's industries remain competitive while accelerating industrial decarbonisation. In this section, Climateworks presents four relevant case studies, covering different support mechanisms enacted by entities around the world to overcome similar challenges to Australia, and highlights key insights that can be used to inform Australia's domestic policies. These support mechanisms include:

+ **Operating subsidies** – subsidising unprofitable components of decarbonisation activities
+ **Dynamic electricity tariffs** – variable fees for electricity tied to real-time supply and demand factors
+ **Anti-curtailment measures** – strategies to minimise the forced reduction or shutdown of renewable energy generation
+ **Production credits** – cash or tax refunds tied to the quantity of produced low-carbon goods.

5.3.1. Operational subsidies: SDE++ scheme, Netherlands

The Stimulation of Sustainable Energy Production and Climate Transition (SDE++) scheme is a multi-year operating subsidy for climate investments currently used in the Netherlands (Netherlands Enterprise Agency, 2023). It targets the large-scale implementation of technologies for 1) low-carbon energy production, with a focus on process heat and 2) emissions reductions, with an annual budget ranging between €10–15 billion. These subsidies are accessible by industries and not-for-profit organisations in the agricultural, electricity and built environment sectors.

5.3.1.1. How it works

The scheme operates by compensating the difference between the calculated cost price of clean energy produced, or the amount of emissions reduced, and any revenue generated. This results in an increased guarantee for the profitability of these projects. As this amount is dependent on revenue based on real-time market prices, no compensation is awarded if the project revenue outstrips production costs. These subsidies are allocated for periods of up to 15 years and are accessible during the operational period of the funded project. Applications are selected based on a competitive process and are weighted by a 'subsidy intensity' factor – determined as a function of the total monetary amount requested against the total emissions reduction potential of the technology or activity involved in the project.

Eligible projects must adhere to a specific yet comprehensive list of technologies and activities, which is reviewed annually. These technologies or activities are segregated into three application-focused 'domains', namely 'high temperature heat', 'low temperature heat' and 'molecules' (see Table 7). The bulk of the subsidy budget is equally split into funding streams aligned to each of these domains, referred to as a 'domain fencing' process. Eligible technologies outside these domains, such as renewable electricity generation and carbon capture, are funded from the remainder of the budget. Each round of funding, awarded annually, is divided into phases, which activate sequentially over the course of several weeks. The maximum amount that can be awarded is increased step by step during subsequent stages, with amounts ranging from a maximum of €75/tCO_2e in the first phase to a maximum of €400/tCO_2e in the last phase.

TABLE 7: Example eligible technologies categorised into SDE++ domains

DOMAINS		
High temperature heat	**Low temperature heat**	**Molecules**
+ Biomass combustion + Industrial heat pumps + Electric boilers	+ Solar thermal energy + Air-to-water heat pumps + Residual waste heat utilisation	+ Biomass fermentation (renewable gas) + Green hydrogen + Advanced renewable fuels

5.3.1.2. The benefits

The SDE++ program has been hailed as an effective tool to stimulate whole-of-economy decarbonisation (ABN AMRO 2023; International Energy Agency 2022). Projects funded in 2023 alone are forecast to be responsible for around 28 TWh of yearly generated capacity by 2038, with a diverse mix of clean energy, such as low-carbon heat, bioenergy and solar and wind (ABN AMRO 2023).

Four key elements of the SDE++ program that have led to its success:

+ **A specific focus on low-carbon industrial heat**

  The SDE++ program has a specific focus on the provision of low-carbon industrial heat, which is typically overlooked from an industrial decarbonisation policy perspective, and guides applicants through specific decarbonisation pathways via a comprehensive list of eligible technologies and fuels.

+ **Weighting applications on a 'subsidy intensity'**

  Weighting applications on a 'subsidy intensity' can ensure a standardised methodology to ensure maximum value from the awarded funding. A subsidy intensity factor is also self-correcting in that it reduces the awarded subsidy amounts as operating costs decrease (i.e. through cheaper electricity prices) or as the value of low-carbon products increases (i.e. through off-takers willing to pay a green premium).

- **Using domain fencing**

  Using domain fencing ensures that budgets are reserved for different heating application. This means technologies of different cost-to-emissions-reduction ratios are not competing if they can be used to decarbonise different industrial processes. This facilitates technologies that are less cost-effective in the short term but are necessary for a long-term whole-of-industry decarbonisation, and whose costs may fall as they are more widely deployed. This would ensure that 'late to abate' industries with currently expensive decarbonisation options do not need to compete for funding with industries that have access to more readily available solutions.

- **A phased application system**

  Using a phased application system ensures that applications involving the most cost-effective technologies for each domain are approved first, but also encourages applicants to minimise the asked-for amounts in their applications to have the greatest chance of receiving funding.

5.3.1.3. How it could be applied to Australia

Implementing targeted public-sector funding mechanisms, like the SDE++ scheme, that subsidised operating costs for low-carbon process heat (i.e. a supply-side measure) could provide industries with increased confidence to invest in the necessary technologies.

This mechanism could complement other supply-side measures, like the forthcoming Green Aluminium Production Credit, by supporting the use of low-carbon technologies (e.g. electrified heat boilers) that could benefit multiple industrial supply chains. It could also complement demand-side measures, like large energy consumers' legislated obligations to purchase LGCs under the Renewable Energy Target, by supporting the production costs of the legislated product.

A comprehensive list of technologies and fuels eligible for such a subsidy could be used to further increase investment confidence by signalling to industry and private-sector financing bodies what the best-practice pathways for decarbonisation look like. These could be aligned to nation-wide taxonomic standards similar to those under development by the Australian Sustainable Finance Institute (ASFI n.d.). Finally, implementing 'domain fencing' as used by the SDE++ scheme could ensure decarbonisation projects that address mutually exclusive end uses (e.g. high-temperature heat and low-temperature heat) are not in competition with one another, thus ensuring whole-of-industry decarbonisation.

5.3.2. Dynamic electricity tariffs: Octopus Energy's Agile tariffs, United Kingdom

Dynamic tariffs are the real-time adjustment of consumer-facing electricity prices in response to supply and demand. They have strongly influenced energy consumers to modify their energy consumption patterns, including their use of heating assets, which in turn can provide whole-of-grid benefits as well as cost savings to the consumer (IRENA n.d.).

5.3.2.1. How it works

The Agile tariff scheme is one such mechanism, and is used by Octopus Energy, the UK's largest electricity supplier. It adjusts electricity prices in half-hour intervals, based on day-ahead wholesale prices, to incentivise shifts in energy consumption for the following day. This affords consumers the opportunity to shift their energy consumption to periods of low demand or pricing, and conversely, incentivises consumers to avoid using energy during periods of high pricing. In this way, dynamic tariffs can be used to better match electricity supply and demand, particularly in energy systems with a high degree of variability in hourly electricity supply, such as Australia. The Agile tariff is for consumers who can shift large amounts of energy consumption, which for the residential and commercial sectors is enabled through automated smart metering coupled with batteries, solar and electric vehicles. Although the Agile tariff is intended for the residential and commercial sectors, industry can also benefit substantially from these pricing structures to reduce the operational costs of increased electrified industrial heat.

As a consumer-protection measure, the Agile tariff scheme partially insulates consumers from extreme wholesale price events during periods of low electricity supply by placing caps on customer-facing prices. But it also allows consumers to take advantage of low- or even negative-price events during periods of high electricity supply through a ‘plunge pricing’ component, where they can be paid for using this excess electricity.

5.3.2.2. The benefits

The Agile tariff, after an initial sixth-month trial period, has significantly impacted electricity consumption patterns. Consumers shifted their electricity consumption out of peak demand periods by 28 per cent, with the average consumer reducing their consumption during these peak periods by 16 kWh per month. This was found to have a proportionate reduction in carbon emissions of 4.5kg CO_2e per month due to a reduced need for fossil-fuelled generators at night. Most consumers (95 per cent) reduced their electricity costs compared to legacy fixed-cost pricing structures, with the average consumer saving £188 per year (Octopus Energy 2018).

From these initial results, Octopus Energy found it likely that wider uptake of dynamic tariffs could significantly shift overall peak energy consumption. This suggests using a demand management approach to ensuring energy security represents a cost-effective alternative to the costly build-out of transmission and generation infrastructure.

5.3.2.3. How it could be applied to Australia

In Australia, dynamic tariffs can encourage large energy users, like industry, to shift consumption to when supply is high. This can reduce the burden on the grid during periods when supply is typically low, as well as enable industry to electrify cost-effectively.

Recently, dynamic tariffs in Australia have faced several criticisms over their implementation for the residential and small-business sectors. Energy regulators, like the AEMC, and transmission systems operators have argued that these price structures can improve the efficiency of Australia’s electricity system and reduce the need for upgrades to the grid. This stance, however, has put them at odds with the Australian Energy Council, which represents energy retailers, such as Origin, AGL and Alinta, and which has called for a pause on these tariffs (Mercer 2024a). Its criticisms revolve around the high complexities and requirements for small customers to use these tariffs effectively, and include:

+ the difficulties faced by consumers in comprehending and relating a dynamic price structure to their usage decisions
+ the need for smart metering or storage capabilities to facilitate an automated response to price signals.

Unlike smaller consumers, industry could be well placed to circumvent these difficulties and have a proportionately higher potential to benefit from these dynamic price structures. The associated costs to overcome these barriers – for example, through dedicated teams that can respond to price signals, or the purchase and installation of enabling infrastructure – are likely to be relatively minimal at the scale industries operate on. This, combined with their large electricity consumption, could result in significantly increased savings at relatively minimal costs.

Implementing dynamic price structures will likely be needed as industry's electricity consumption increases in flexibility – driven by increased industrial electrification, increased renewables generation and the adoption of storage assets. Price incentives for consumers to avoid electricity consumption during peak demand periods can also reduce the need for costly fossil-fuelled firming, resulting in both reduced emissions and lowered whole-of-network costs, even for those not using dynamic tariffs. In this way, dynamic tariffs can complement demand response as a strategy for shifting industrial consumption behaviour to better match electricity demand and supply.

5.3.3. Anti-curtailment compensation: Energy Industry Act 'use instead of curtail' regulation, Germany

Germany's power grid currently suffers from regular congestion events due to a mismatch between where renewable energy is generated and where energy is needed, resulting in significant quantities of renewable energy being discarded, or 'curtailed'. Curtailment arises from bottlenecks in parts of the grid, limiting how much renewable energy can be funnelled through at once.

5.3.3.1. How it works

The Section 13k 'use instead of curtail' regulation under Germany's Energy Industry Act (EnWG), currently halfway into a two-year trial period, is intended to minimise curtailment activities and increase the competitiveness of flexible renewable technologies compared to fossil-based alternatives (Appunn 2016). It does so by incentivising the additional consumption of electricity during periods of peak renewable generation through price signals, in a similar manner to the dynamic tariffs described in the previous section.

Eligible applicants to the 13k scheme, which is limited to large-volume flexible consumers such as industries with electrified heat applications or operators of hydrogen electrolysers, are allowed to directly pre-purchase renewable electricity that would otherwise be curtailed through a simplified flat-rate procedure on a day-ahead market at standard spot prices. These consumers are then reimbursed for the difference between the spot price and a fixed '13k price'.

5.3.3.2. The benefits

The large-volume, flexible consumers that have used the 13k scheme's flexible prices have reduced their electricity costs by around 40 per cent, compared to wholesale or PPA prices (Aurora Energy Research 2024). Participants can also take advantage of further savings as they do not need to pay network distribution fees, in recognition of the grid-stabilisation services they are providing. Initial results from the two-year trial have also found that under the 13k scheme, electrolyser operators can increase their operating capacity by up to 35 per cent and reduce the levelised cost of hydrogen by up to 17 per cent (Aurora Energy Research 2024).

5.3.3.3. How it could be applied to Australia

A large component of Australia's energy market is made up of renewable electricity and therefore also undergoes a 'curtailment' process. Currently, 10 per cent of utility-scale renewables are curtailed annually, with AEMO forecasting this share of wasted energy to grow to 20 per cent by 2050 (Mercer 2024). In Australia, curtailment can arise from the grid 'bottlenecking' or, in the event of prolonged negative wholesale price events, from an overabundance of renewable energy (Purtill 15 February 2022). Increased curtailment is associated with higher overall electricity costs, which are passed on to consumers, as generators have to be compensated for their loss in production. Curtailment also decreases investor confidence in renewable energy projects, reducing the number of projects that are funded (PV Magazine 2024).

Reducing Australia's wasted renewable electricity by implementing anti-curtailment mechanisms like Germany's 13k scheme could increase the bankability of renewable projects (spurring increased investment in new renewable generation assets) and reduce the operating costs of flexible electrified industrial assets.

5.3.4. Production credits: Inflation Reduction Act, Section 45, United States of America

5.3.4.1. How it works

While made defunct by the current Trump administration, at the time of its introduction, the 2022 Inflation Reduction Act (IRA) sought to spur investment in clean energy and support the production of low-carbon manufacturing through one of the single largest investments in climate change- and energy-related issues across the world (United States Department of Energy 2022; United States House Committee on Ways and Means 2025). The Section 45 amendments to the Internal Revenue Code under the IRA focused specifically on subsidising low-carbon goods manufacturers' production costs by expanding the scope and monetary amounts awarded by production tax credits (Table 8). These production credits allowed manufacturers to reduce their tax liabilities based on the quantity of low-carbon goods produced, with no limit on the period that this compensation could be claimed over – representing a long-term subsidy for the ongoing costs of decarbonisation and clean manufacturing. Furthermore, Section 45 credits could also be sold on a private market (as transferable tax credits), streamlining monetisation for credit producers and making clean energy financing more appealing.

TABLE 8: Section 45 production credits relevant to heavy manufacturing

Production credit	Purpose	Credit amount
45Q – Carbon Capture and Sequestration Tax Credit	Offsets carbon capture costs for manufacturing applications	US$85 per tonne of CO_2e captured
45V – Clean Hydrogen Production Tax Credit	Offsets hydrogen production costs, scaled by the carbon intensity for production	Up to US$3 per kilogram of hydrogen
45X – Advanced Manufacturing Production Credit	Offsets the costs of refining critical minerals	10 per cent of production costs
45Y – Clean Electricity Production Credit	Offsets the cost of renewable electricity production through either generation or storage assets	US$0.15 per kilowatt hour
45Z – Clean Fuel Production Credit	Offsets the production costs of low-carbon fuels	US$1 per gallon of fuel

5.3.4.2.

The benefits

Section 45 credits were estimated to drive an additional installation of 146–308 GW of clean electricity projects by 2030, and have been found to result in a six-fold increase in carbon capture projects, with over 200 projects under development in 2024 (Crux Climate 2025; Stolark 2024).

Several key elements of the IRA's Section 45 amendments and their potential impacts on industrial decarbonisation:

+ **Credits cover upstream and downstream costs of low-carbon goods**

  The provision of Section 45 credits for both upstream production costs (e.g. electricity or hydrogen) and manufacturing costs (e.g. carbon capture or refining metals) means that operating costs are supported vertically throughout entire supply chains. This minimises the risk that industrial decarbonisation is held up by a single dependency.

+ **Credits support domestic manufacturing capabilities**

  By scaling the claimable production credit quantities by the degree to which manufacturing facilities comply with specific wage and apprenticeship requirements, Section 45 supports the expansion of domestic manufacturing capabilities.

+ **Credits are technology agnostic**

  The technology-agnostic nature of the Section 45 credits, which focuses on the application or outcome of the activity rather than the technology used, allows for increased flexibility for decarbonisation activities as the energy sector evolves over time. This represents an alternative methodology to the approach taken by the SDE++ scheme, where an exhaustive list of eligible technologies is updated annually to ensure that relevant technologies are supported under the subsidy scheme.

5.3.4.3.

How it could be applied to Australia

Uncertainty around long-term electricity and low-carbon fuel prices, like hydrogen, is making it difficult for industry to assess the profitability of decarbonisation technologies, hindering both industrial investments and private-sector financing. Although public support exists for upstream energy projects, industry needs more immediate, direct support to manage operational costs for producing low-carbon products. Expanding Australia's portfolio of production credits that can address multiple supply-chain components, like those under the IRA's Section 45 amendments, could greatly accelerate industrial decarbonisation. These credits could increase confidence for both industry and private-sector financing to boost investment in green manufacturing by signalling long-term, quantified, public-sector support. The federal government's proposed Green Aluminium Production Credit could be one such example.

6. Recommendations for industrial decarbonisation

To date, our work in Gladstone has found that deploying low-carbon heat and implementing demand management practices will be key components of a net zero industrial precinct approach to industrial decarbonisation.

This report identified technologies, fuels and practices that can be used for industrial decarbonisation and the barriers that lie in the way. In this section, we present discrete recommendations for federal and state governments across Australia to hasten industrial decarbonisation through a net zero industrial precinct strategy. These recommendations are aligned with three guiding principles:

+ Consistent, long-term policies instil confidence for industries to invest in low-carbon technologies and fuels.
+ Effective public-sector funding catalyses industrial investments and private-sector financing for decarbonisation.
+ Demand response programs improve the cost-effective integration of renewable electricity.

6.1. Regulatory recommendations

1. Explore how to create a renewable heat target for industry to complement existing renewable energy targets, providing industries with the clear signal needed for investment confidence.

Federal and state governments across Australia have implemented renewable electricity targets that focus on meeting a certain percentage share of renewable electricity in networks. These targets will ensure that the emissions intensity of the electricity system is reduced. A low-carbon source of electricity then enables industrial decarbonisation through electrification. Low-temperature heat can be readily decarbonised in this way; however, this fails to address temperature ranges or applications that cannot be electrified, which, as demonstrated in this report, comprise the bulk of heavy manufacturing energy requirements.

To supplement these targets, Climateworks recommends that governments develop a renewable heat target. This could take the form of phased emissions-led targets that seek to reduce the emissions intensities of assets that provide heat in incrementally higher temperature ranges by a certain percentage every year. For example, a commitment to achieve a certain renewable heat share for low-temperature industrial heat by 2030, medium temperature by 2035 and high temperature by 2040, with the associated emissions reductions aligned to Australia's goals set out in the Paris Agreement.

Implementing such a target would provide clarity and set a direction for industry to implement into its own long-term plans. These targets could also enable energy planning authorities to align their recommendations for energy infrastructure investments with industrial decarbonisation objectives and support proactive coordination rather than reactive project-by-project planning.

2. Implement a carbon leakage mechanism at the federal level to prevent emissions-intensive imports from competing with low-carbon domestic goods that bear additional costs, encouraging Australia's industries to invest in decarbonisation technologies.

Differences in carbon pricing mechanisms across markets can incentivise industries to relocate or trade in regions with lower compliance costs – known as carbon leakage. This can reduce incentives for existing industries in those regions to decarbonise so they remain competitive with lower-cost, emissions-intensive goods. To address this leakage, Australia is considering a 'carbon border adjustment mechanism' (CBAM), which imposes a carbon cost on imported goods to level the playing field. Preliminary findings under this review have suggested that Australia's heavy manufacturing industries, including the cement or lime, chemicals and aluminium supply chains, are most at risk of leakage (DCCEEW 2023b). Acceleration of a CBAM implementation would allow Australian low-carbon goods to remain cost-competitive with imports, in turn increasing industry's investment confidence in decarbonisation.

3.

Explore how to create dynamic pricing structures for heavy industry's electricity consumption to encourage the cost-effective use of Australia's renewable energy resources and make electricity more affordable.

Matching large industrial electricity consumption to when supply is most available to reduce the burden on the electricity grid is a practice increasingly used around the world. This is both to manage the integration of renewables into energy networks and to make industrial electrification more cost-effective. Flat-rate electricity pricing structures, however, are unable to pass on the cost benefits of cheap renewable electricity during periods of high supply.

State governments, working with industrial stakeholders and electricity distributors, can craft dynamic pricing structures for industry to encourage electricity use at a certain time. This can complement demand response practices as a price-incentivised method of reducing electricity use at a certain time. As was demonstrated in this report, incentivising industry to switch to more flexible forms of operation can reduce electricity costs across the whole network and promote increased grid stability.

6.2. Funding recommendations

4.

Develop a coordinated approach between public-sector fundings bodies that supports upfront costs of low-carbon industrial heat, by targeting specific technologies and fuel types that address all industrial heat temperature ranges

In this report, we identified that public-sector funding is not targeted to low-carbon industrial heat, despite it producing most industrial emissions. This has resulted in significant competition between industry and other sectors (e.g. energy or transport) for these pools of funding to support decarbonisation efforts. The complex and large-scale nature of industrial decarbonisation projects often results in these projects being passed over in favour of decarbonisation projects from other sectors. Industry cannot be expected to take on the significant financial risk presented by upfront capital costs of decarbonisation alone, and it currently faces difficulties accessing traditional financing sources due to the uncertainties around new technologies' profitability.

To de-risk private-sector investments for such technologies, public-sector funding bodies can target funding streams to the decarbonisation of industrial heat. We note that ARENA's recently terminated funding pool – Industrial Transformation Stream (Round 1) – partially served this purpose by providing funding to bridge the gap between the profitable and unprofitable components of process heat decarbonisation projects

(ARENA n.d.). Differentiating funding streams between different temperature ranges or applications of industrial heat could increase the effectiveness of public-sector support. This could be in a similar manner to the 'domain fencing' used by the Netherlands' SDE++ scheme to ensure that decarbonisation projects addressing mutually exclusive end uses (i.e. high-temperature heat versus low-temperature heat) are not in competition with one another, therefore ensuring whole-of-industry decarbonisation.

We see particular value in focusing this funding on existing 'hard to abate' industries that are important to national or state priorities. Goods such as cement or certain chemicals can be essential to Australia's continued growth, yet are currently emissions-intensive, with limited options for their respective industries to reduce emissions and remain competitive. Furthermore, these industries struggle to access public-sector financing for the few decarbonisation technologies available to them, even under concessional financing terms, due to the current unprofitability of these technologies. Targeted funding streams like the recently closed Critical Inputs to Clean Energy Industries grant program, which supported decarbonisation specifically for the cement, lime, alumina and aluminium industries, could help provide this much-needed support.

We also recommend that funding bodies coordinate efforts to address different stages of the innovation cycle – for instance, through the 'Front Door' model currently under development by the federal government (Treasury 2024). While organisations like ARENA are suited to support earlier stages of product and market development, targeted funding from public-sector financing institutions like the CEFC, NAIF and NRF in the form of concessional financing for process heat decarbonisation projects can support the large-scale deployment of mature technologies. A shared definition of what good looks like based on industry-specific decarbonisation pathways would aid this coordination. Funding bodies would benefit from aligning on eligible technologies or processes that can be funded – for instance, those that meet the sustainable economic activity criteria as defined by the Australian Sustainable Finance Taxonomy – to provide a clear direction and investment confidence for industries (ASFI n.d.).

5. Consider subsidies for downstream components of low-carbon supply chains, including metal processing and cement and chemicals production, to complement current subsidies for upstream components like hydrogen or renewable electricity.

Uncertainty in long-term electricity and low-carbon fuel prices is hindering industry's ability to determine the profitability of implementing decarbonisation technologies, reducing the likelihood of private-sector financing. While there are numerous public-sector schemes to support new renewable electricity and hydrogen projects as upstream components of industrial supply chains, industry will continue to struggle to conclusively demonstrate to financiers that low-carbon goods can be cost-competitive in the short term. Measures can be introduced that directly target industry to address the uncertainties in operational costs to produce low-carbon products.

The federal government can provide this support through production credits – for instance, by expanding eligibility for credits through Future Made in Australia. Introducing a production credit could level the playing field for clean manufacturers by allowing decarbonised products to be competitive with lower-cost emissions-intensive goods.

The federal government's proposed Green Aluminium Production Credit is one such example, and has been welcomed by the aluminium industry as a critical measure to industrial decarbonisation efforts (Lowrey 2025).

Production credits, like those under the United States' IRA Section 45 amendments, that reduce both upstream and downstream production costs can strategically spread public-sector support throughout industrial supply chains, preventing any one component from holding up decarbonisation efforts.

6.3. Demand management recommendations

6. Expand Australia's electricity demand response capacity by lowering barriers for participation and increasing incentives for long-term provision of services, to ensure a stable and accelerated path to electrification across Australia.

Energy planners could seek to use Australia's demand response programs to a greater extent, and consider them not just as grid-stability measures, but as an economic resource to maintain level prices in energy markets, as demonstrated in France, Texas and Norway. Increased use of demand response programs can, in the short term, significantly lower whole-of-network electricity costs and therefore cost of living, and in the long term, mitigate generation and transmission infrastructure build-out. An increased day-to-day use can be realised through increased ambition from energy planners. While Australia's two largest demand response programs – FCAS and RERT – are not currently treated as an economic resource, they have the technical capability to be used in this manner.

Treating these programs as an economic resource, however, would require expanding demand response capacity within Australia's energy markets, which could be enabled by incentivising participation from heavy industry, particularly as it electrifies. One such incentive could be using long-term contracts for demand response capacity providers, with these participants compensated for retaining their services, and not just their activation.

Alternative strategies to encourage participation could also be pursued, through both lowered restrictions for participation and lowered penalties for non-compliance. Demand response programs in the NEM have high standards for participants in terms of qualifying for these programs and complying with NEM protocols, with strict penalties for non-compliance. Adopting a trial participation period, like Singapore's 'regulatory sandbox' scheme, could encourage increased participation by affording new demand response providers an adjustment period to overcome any implementation challenges. During these periods, compliance thresholds and penalty amounts could be reduced or waived. Reduced remuneration for services rendered, instead of levying fines, can also serve as an effective but not overly harsh deterrent for non-compliance, functioning as a compromise between carrot and stick.

7. Consider seasonal electricity demand response measures to reduce the need for gas-based peaking generation for grid reliability during periods when renewables are scarce.

The ISP currently predicts that the energy system will increasingly depend on gas-powered generation for grid reliability during winter periods, when renewable generation is limited. A business-as-usual, round-the-clock approach to industrial operations that relies on an increasing use of costly gas-fuelled peaking generators (along with costly build-out of new gas infrastructure solely to meet these limited low-supply periods) could increase wholesale electricity prices and impose increasing costs to the grid.

Rather than building new gas infrastructure to meet these limited electricity demand periods, Australia could consider further use of seasonal electricity demand management services that target overnight winter loads, as an alternative that can reduce both costs and emissions. An example of a winter demand measure could be large-load shaping incentives, where new loads are designed to avoid overnight winter loads. Incentives could be applied through government support or connection agreements with energy providers. Another example is a winter reserve trader, where tenders are placed for existing large energy users to divert their planned maintenance and shutdown periods to winter months.

Appendix

This report is based on analysis conducted between October 2024 and May 2025 for a 'Net zero industrial heat and energy demand management for Gladstone' project, which was funded by the Queensland Department of State Development, Infrastructure and Planning.

This analysis included an assessment of both Gladstone's ambitions for decarbonising industrial heat and participating in industrial demand management and flexibility practices, as well as a review of international best-practice case studies for both activities.

The Gladstone industrial heat and demand management project was one of several projects that informed Climateworks' net zero industry and resources work and that informed the key findings presented in this report. The views expressed herein are those of Climateworks and are not necessarily those of the Queensland Government.

Modelling methodology, inputs and assumptions

Climateworks conducted energy and emissions modelling, focused on key existing and emerging industries in the Gladstone region, to understand industrial decarbonisation's implications on energy use.

The primary aims of the modelling were to illustrate the pace and scale of Gladstone's industrial emissions reduction activities and the quantity of energy required to enable them, as a function of the decarbonisation ambitions of Gladstone's industries, as well as the assumed quantity of industrial products produced each year.

Climateworks' modelling draws on the Australian Industry ETI scenario modelling where possible (for further technical assumptions, see the *Pathways to industrial decarbonisation – Technical report* [Climateworks Centre and Climate-KIC Australia 2023]). These scenarios are supply-chain specific, and some of Gladstone's industrial stakeholders (e.g. Rio Tinto and Orica) were involved in their development for the Australian Industry ETI. The modelling uses a 2022 baseline, as this was the last year with complete datasets available. Asset-level data was used to define the energy consumption and emissions intensity of operations.

In addition to the inputs from the Australian Industry ETI, Climateworks incorporated regionally appropriate inputs from Gladstone's industries, both directly from industrial stakeholders, or indirectly through publications that Gladstone's stakeholders have contributed to, such as those from *A roadmap for decarbonising Australian alumina refining* (ARENA 2022).

We also drew on modelling from the *Climateworks Centre decarbonisation scenarios 2023* to provide more up-to-date electricity grid emissions results than the Australian Industry ETI modelling (Climateworks Centre 2023). The modelling uses a 2022 baseline year, with asset-level energy and emissions data used to define the baseline. Future energy consumption and emissions are modelled at a sector level. Generation capacity estimates were made using a post-modelling analysis based on electricity consumption. The analysis is intended to illustrate the scale of wind and solar that could be required. The analysis assumes optimal conditions, including sufficient transmission and diversity of renewable energy sources, plus sufficient firming, inertia and system strength provisions.

Our modelling of the bioenergy resources available to Gladstone's industries drew on data sourced from the Australian Renewable Energy Mapping Infrastructure Project (AREMI) (ARENA, n.d.). For the biomass analysis, we defined ideal feedstocks as those categorised as sawmill residues from the AREMI database, within a transport distance of the Gladstone LGA as defined by a study conducted by the Australian Bureau of Agricultural and Resource Economics and Sciences (Lock and Whittle 2018). For the biomethane analysis, we defined ideal feedstocks as those categorised as agricultural waste from the cotton, sorghum, straw and sugarcane industries from the AREMI database, within the entirety of Queensland.

Our modelling of the whole-of-Queensland energy supply and consumption in 2040 and the impact of ETES-enabled, flexible heat production drew on further Climateworks analysis of forecast demand and generation in 2040 from the Queensland *SuperGrid Infrastructure Blueprint 2022*, which itself draws from AEMO's 'step change' scenario from the 2022 ISP (Queensland Government 2022a; AEMO 2022). Climateworks' modelled generation profile in 2040 is constructed from a mix of utility-scale and rooftop solar, wind and fossil-fuelled generators, and applies capacity factors for these forms of generation specific to Queensland (Australian Energy Regulator 2022; Heath 2024).

TABLE 9: Data sources and number of facilities used to define baseline

PRODUCT	NUMBER OF FACILITIES	SOURCES FOR BASELINE FOR EACH FACILITY
Alumina	2	A baseline of energy use, emissions and production has been developed based on existing facilities. Data sources from 2022 are used as much as possible. + scope 1 emissions (reported) + scope 2 emissions (calculated with high-level assumptions from desktop research) + energy consumption (Climateworks Centre and Climate-KIC, industry consultation and Climateworks analysis) + current production (desktop research, industry consultation and Climateworks analysis)
Aluminium	1	
Cement/clinker/lime	1	
Sodium cyanide/explosives	1	

Seven existing products are modelled: alumina, aluminium, cement, clinker, lime, ammonium nitrate explosives and sodium cyanide. Assumptions for future industrial activity (i.e. amount of production) in these sectors are aligned with the Australian Industry ETI 'Coordinated action' scenario (Figure 14).

FIGURE 14: Assumed production of Gladstone's existing industries (indexed)

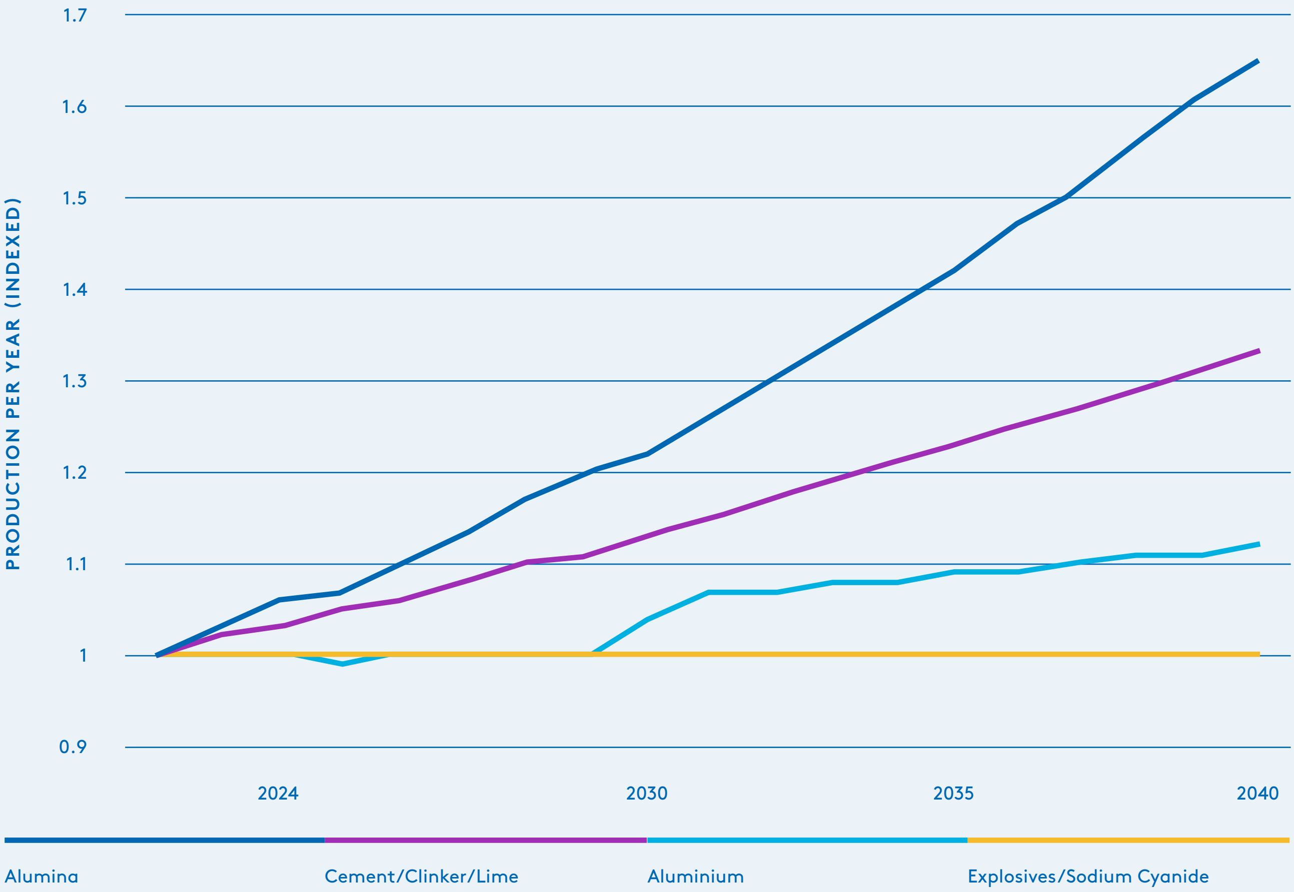


FIGURE 15: Summary of public-sector funds available to support the upfront costs of the decarbonisation technologies for Climateworks' industrial heat decarbonisation pathway for Gladstone

FUND	ALLOCATION	DECARBONISATION TECHNOLOGIES				LOW-CARBON FUEL PRODUCTION				
		Electrified heating assets	Thermal storage assets	CCS/U	Fuel-switching upgrades	Demand management/ flexibility upgrades	Biomass	Biomethane	Green hydrogen	Renewable electricity
AUSTRALIAN RENEWABLE ENERGY AGENCY (ARENA)										
Powering the Regions, Industrial Transformation Stream: Round 2	$2b	■	■		■	■	■	■	■	■
Advancing Renewables Program	Unknown		■		■	■			■	■
National Industrial Transformation (NIT) Program	$40m	■	■		■	■	■	■	■	■
Advancing Hydrogen Fund	$300m								■	
NATIONAL RECONSTRUCTION FUND (NRF)										
National Reconstruction Fund: Renewables manufacturing and low emissions technology	$3b	■	■		■	■	■	■	■	■
National Reconstruction Fund: Value-adding in resources	$1b	■	■		■		■	■	■	■
OTHER										
Northern Australia Infrastructure Facility	$7b	■	■		■	■	■	■	■	■
CLEAN ENERGY FINANCE CORPORATION (CEFC)										
CEFC General Portfolio	$9.5b	■	■		■	■	■	■	■	■
CEFC Rewiring the Nation	$20b					■			■	■
CEFC Clean Energy Innovation Fund	$200m						■	■	■	■
CEFC Powering Australia Technology Fund	$500m						■	■	■	■
QUEENSLAND STATE GOVERNMENT										
Queensland Jobs Fund: Industry Partnership Program	$416m	■	■		■	■	■	■	■	■
Queensland Jobs Fund: Strategic Investment Scheme[1]	$520m	■	■		■	■			■	■

1 Only applicable to companies that are planning facility expansions resulting in the net creation of 50+ jobs.

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Climateworks Centre, 2025, *Heat, power and flexibility to future-proof Gladstone*

Published by Climateworks Centre Melbourne, Victoria, October 2025

This publication can be downloaded at: www.climateworkscentre.org

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MONASH SUSTAINABLE DEVELOPMENT INSTITUTE

Co-founded by philanthropy and Monash University, Climateworks Centre is an independent not-for-profit working within the Monash Sustainable Development Institute.