Australia's National Science Agency

Multi-sector energy modelling 2022: Methodology and results Final report

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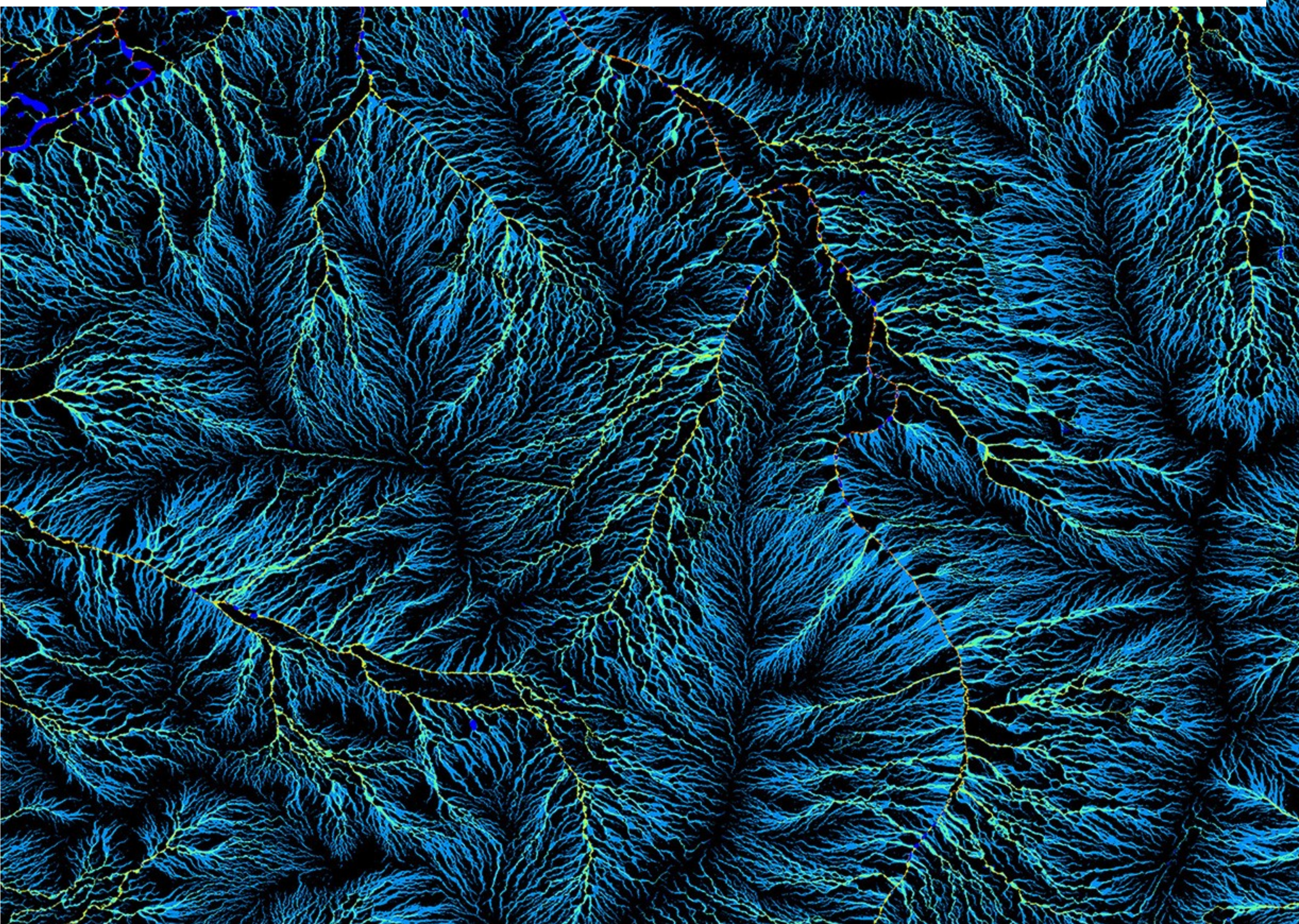

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Contents

Figures

Tables

Acknowledgments

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Executive summary

AEMO commissioned CSIRO and Climateworks Centre to complete multi-sector modelling of four decarbonisation scenarios and to quantify the changing influences that will affect electricity demand under various emissions targets across the period 2021-22 to 2053-54. This project is an update of the multi-sector modelling that was undertaken by CSIRO and Climateworks Centre in 2021 (Reedman et al., 2021). Those modelled scenarios were since adapted by AEMO to explore new key contexts such as Australia's updated 2030 emissions targets and alternatives to electrification (particularly biomethane). Changes to the modelling methodology include updated assumptions for electrification and energy efficiency uptake, carbon budgets reflecting the most recent climate science, and a land-based sequestration modelling approach that allows for optimisation against a cost curve. In addition, the regional scope was extended from the National Electricity Market (NEM) to include Western Australia for the first time.

The modelling provides insights into the key dynamics and linkages across sectors that may impact the electricity sector under the decarbonisation scenarios provided by AEMO. The AusTIMES model utilised for this project provides a whole-of-economy approach and the ability to cost-optimise across power generation, transport, industry and buildings sectors to meet national decarbonisation objectives.

The four scenarios defined by AEMO for this modelling are:

- Progressive Change: Market-led net zero emissions by 2050, with a slower economic outlook driven by barriers to global trade and slower recovery from the COVID-19 pandemic. Includes Australia's updated commitment to a 43% reduction of emissions by 2030.
- Exploring Alternatives: Technology-led change to explore alternative pathways to electrification. A key feature of this scenario is the investment in biomethane and associated biomethane targets in the gas system. Domestic and international action limits global temperature rise to well below 2°C compared to pre-industrial levels.
- Step Change: Consumer-led change with a focus on energy efficiency, distributed energy resources (DER), digitalisation and increases in global emissions policy ambition compared with Exploring Alternatives. Domestic and international action limits global temperature rise to well below 2°C compared to pre-industrial levels.
- Hydrogen Export: Represents a world with very high levels of electrification and hydrogen production, including a higher capacity for Australia to expand its exports of "green commodities" to global consumers. Strong international decarbonisation objectives limit global temperature rise to 1.5°C over pre-industrial levels.

Key findings from CSIRO and Climateworks Centre's modelling are outlined below.

A significant decarbonisation coupled with growth in capacity of the electricity system is central to all modelled cost-effective pathways to meet Australia's new 2030 emission reduction targets

When compared with modelling completed in 2021, current modelling shows that Australia's strengthened level of ambition in its updated 2030 emissions reduction target has contributed to a narrowing gap in electricity sector emissions between the modelled scenarios.

For example, coal-fired generation completely retires in all scenarios (seen in Figure ES- 1). The Progressive Change scenario explores a future where near-term constraints on fossil fuel retirement limits the role the electricity system can play towards Australia's 2030 emissions reduction targets. In spite of these constraints, coal-fired generation in this scenario declines by 44% by 2030, compared to 22% in the Net Zero 2050 scenario previously modelled by CSIRO and Climateworks Centre in 2021. This reflects in part the fossil fuel retirements that have been announced since the previous modelling was completed.

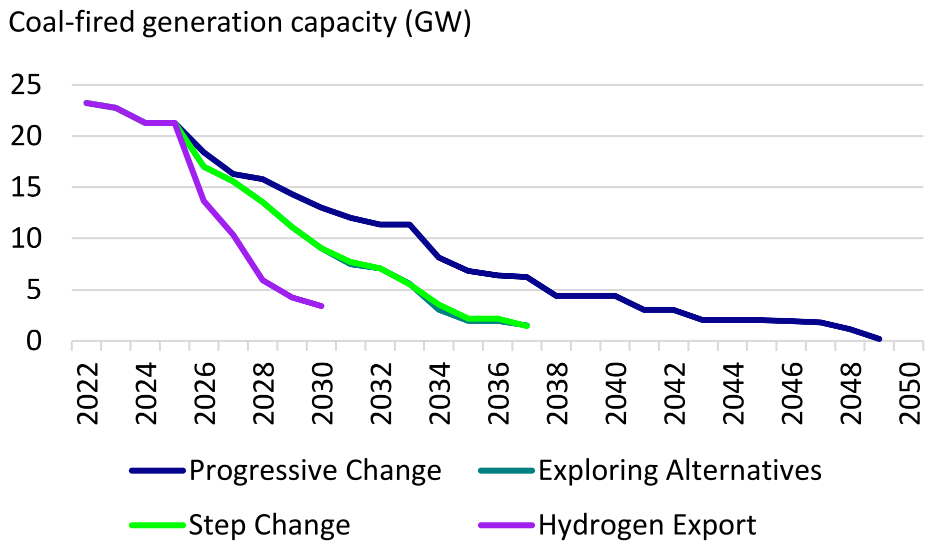


Figure ES- 1 Coal-fired generation capacity by scenario for NEM

Electrification presents as one of the most cost-effective options to reduce economy-wide emissions in all modelled scenarios

While the multi-sector modelling scenarios were designed to explore implications of different technology options on the transition to net zero emissions, a result that consistently emerged from the modelling was the significance of electrification in decarbonising the economy. Given the cost-optimisation approach of the AusTIMES model used for this project, consistently high take-up of electrification suggests it is one of the most cost-effective emissions reduction strategies across all scenarios (alongside the other strategies with consistently high take-up by the model, energy efficiency and renewable energy). In most scenarios, electrification reaches a similarly high scale by 2054, largely driven by the transport and industry sectors (see Figure ES- 2). It is notably lower only in Progressive Change, which explores a future with limitations on electrification uptake. Hydrogen Export demonstrates the significant potential of short-term electrification, driven largely by opportunities being unlocked in heavy industry, alongside a more rapid decarbonisation of the electricity grid.

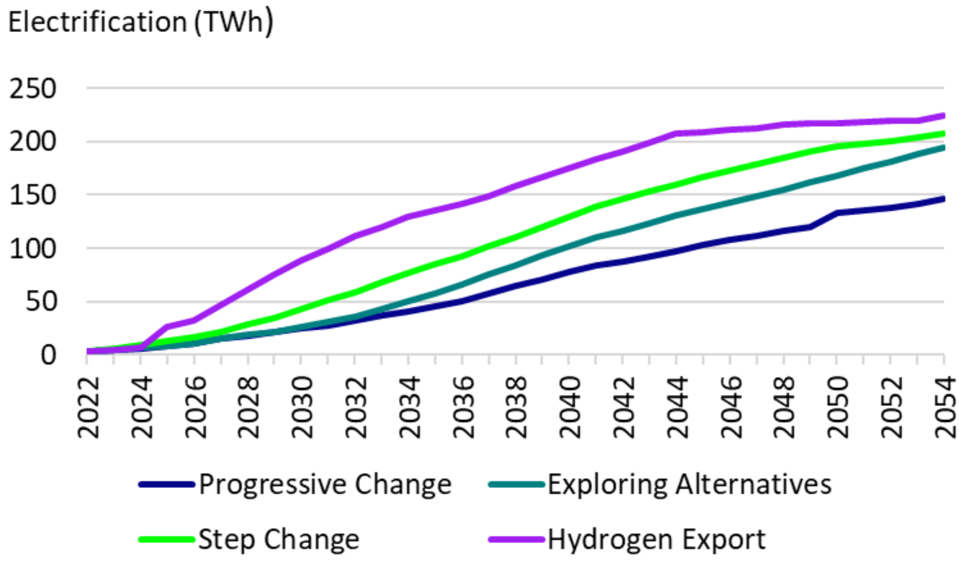


Figure ES- 2 Added electricity demand due to electrification in the end-use sectors (buildings, industry and transport) across all scenarios, for NEM states and Western Australia combined

The modelling reaffirms that effort is required across all four pillars of decarbonisation to meet the Paris Agreement objectives

As in the 2021 multi-sector modelling, the modelling approach in 2022 requires solutions across the four pillars of decarbonisation (Figure ES- 3):

1. Energy efficiency, to improve energy productivity and reduce energy waste
2. Decarbonising electricity to zero or near-zero emissions
3. Electrification and a shift away from fossil fuels to zero- or near-zero emissions alternatives
4. Non-energy emissions reductions and emissions sequestration

These pillars play a role in all scenarios, but present slightly differently, reflecting the diversity of the modelled pathways towards net zero emissions.

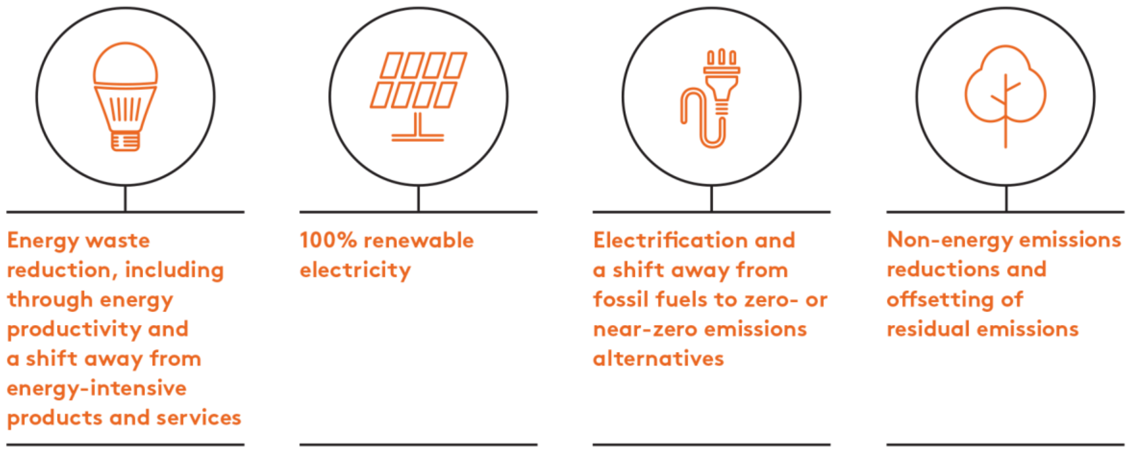


Figure ES- 3 The four pillars of decarbonisation, from ClimateWorks Australia et al. (2014)

The first pillar, energy efficiency, is critical for reducing both energy wastage and the cost of investment required for the other three pillars. Energy efficiency provides significant benefits across all four scenarios even in scenario narratives assuming a more restricted role for energy efficiency, varying from 68 TWh of avoided electricity in the NEM in 2054 in the Progressive Change scenario, to 122 TWh avoided in 2054 in the Hydrogen Export scenario. Corresponding figures for WA are 10 TWh avoided electricity in 2054 in Progressive Change and 21 TWh avoided in Hydrogen Export. All scenarios also feature strong decarbonisation of the electricity grid, which supports electrification as a key solution to reduce emissions across all sectors of Australia's economy.

All four scenarios show that a significant long-term effort is needed from emissions sequestration. In Hydrogen Export, the 1.5°C temperature goal requires a faster effort from emissions sequestration in the short-term – however this can be achieved within the maximum historic rates of improvement in land use, land-use change and forestry (LULUCF) emissions in Australia.

Alternative fuels can play a role in decarbonising the economy, but require technical barriers to be overcome

The scenarios in the multi-sector modelling explore the role of alternative fuels including biomethane and hydrogen in decarbonising the economy, and what implications this may have on the electricity system. The modelling showed that both have potential to play a role, but assumes that barriers have been unlocked in order for those solutions to become competitive with electrification (see Figure ES- 4). For example, high penetration of hydrogen is limited by constraints on blending with natural gas in pipelines; the Hydrogen Export scenario illustrates greater potential for hydrogen use in the domestic end-use sectors but this is underpinned by an assumption that these constraints have been overcome. Biomethane faces fewer technical barriers at an end-use level, and this sees it play a role as a drop-in fuel where there is a strong push towards net zero emissions such as towards 2050 in Progressive Change. The Exploring Alternatives scenario showed that assuming greater cost reductions and introducing explicit targets for biomethane use can see it play a somewhat increased role, but the modelling results suggest it still contributes a minor role in decarbonisation compared to electrification and renewable energy.

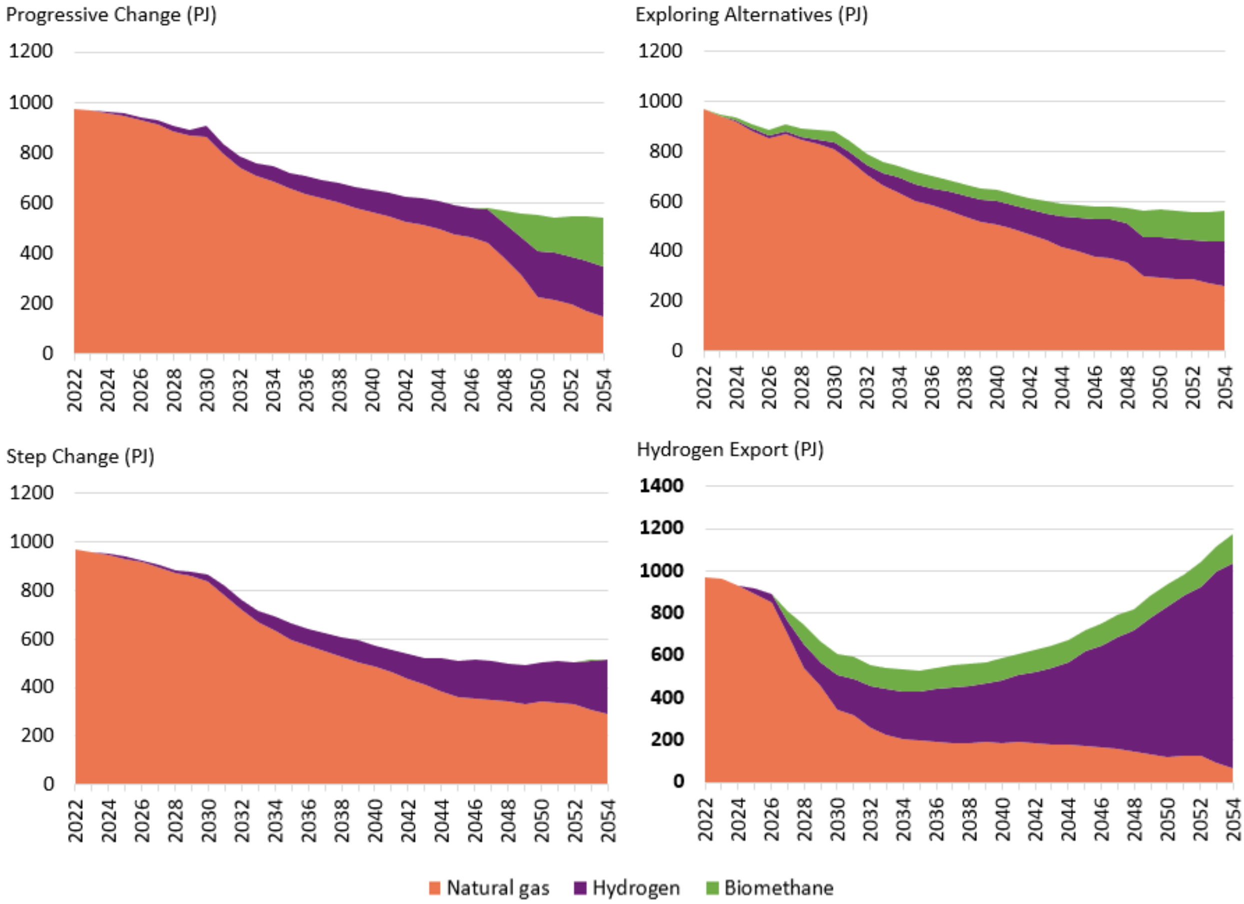


Figure ES- 4 Gaseous fuel mix in the scenarios in buildings and industry, showing the relative contributions from natural gas, hydrogen and biomethane (which is not taken up in Step Change). Results include NEM-connected states and Western Australia combined. Exported hydrogen is excluded.

Decarbonised electricity systems and green hydrogen production could enable significant green industry growth opportunities, particularly in Western Australia

The Hydrogen Export scenario explored the opportunities for green industry growth. This scenario reaffirms previous modelling that showed Australia's abundant energy resources could support a large-scale hydrogen export industry, as well as a green steelmaking industry supported by zero-carbon electricity and hydrogen. The opportunity in both hydrogen export and green steelmaking in Western Australia could be of a similar scale as the NEM combined. Although there are many pathways by which these opportunities could be captured across regions of Australia, the modelling shows that growth of these industries in Western Australia implies substantial expansion of the state's electricity system in line with the NEM (see Figure ES- 5).

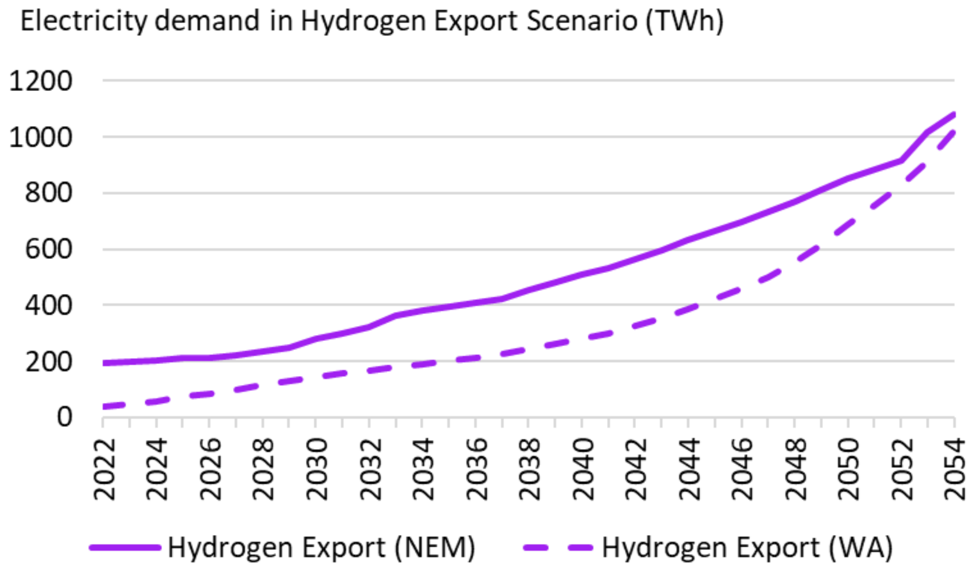


Figure ES- 5 Underlying electricity demand in the Hydrogen Export scenario for the NEM and Western Australia

1 Introduction

The CSIRO and Climateworks Centre were commissioned by the Australian Energy Market Operator (AEMO) to assist in producing projections of electricity and fuel consumption, and emissions for the state and territory economies connected to the National Electricity Market (NEM) and for Western Australia (WA). This modelling was engaged to better understand the interplay between various sectors as Australia's economy and energy sectors change over coming decades. Specifically, the report provides projections for four scenarios with varying technology and emissions profiles, resulting in varied fuel uptake across end-use sectors.

The four scenarios will be covered in more detail in Section 2.1, but are broadly defined as:

Progressive Change: Market-led net zero by 2050 scenario, with a slower economic outlook driven by barriers to global trade and slower recovery from COVID-19. Global progress towards net zero ambitions progresses in line with currently announced policies and ambitions, including Australia's updated commitment to a 43% reduction of emissions by 2030.

Exploring Alternatives: Technology-led change to explore alternative pathways to electrification towards a national emissions abatement end-goal. This scenario reflects a pathway based around current state and federal government environmental pledges and the resulting transitioning of Australia's economy to a net zero level of emissions by 2050. It is centred around a broad mix of technologies being utilised, using central forecasts of DER, electric vehicles and energy efficiency. A key feature of this scenario is the investment in biomethane and associated biomethane targets in the gas system. Domestic and international action rapidly increases to achieve the objectives of the Paris Agreement, to limit global temperature rise to well below 2°C compared to pre-industrial levels.

Step Change: Consumer-led change with focus on energy efficiency, distributed energy resources (DER), digitalisation and increases in global emissions policy ambition compared with Exploring Alternatives. As with the Exploring Alternatives scenario, domestic and international action rapidly increases to achieve the objectives of the Paris Agreement, to limit global temperature rise to well below 2°C compared to pre-industrial levels.

Hydrogen Export: This scenario represents a world with very high levels of electrification and hydrogen production, fuelled by stronger decarbonisation targets and technology cost improvements than the other three scenarios. These technology cost reductions improve Australia's capacity to expand its exports of "green commodities" to global consumers, including hydrogen and other energy-intensive products such as green steel, supporting stronger domestic economic outcomes relative to other scenarios. Strong international decarbonisation objectives lead to faster actions enabling the achievement of the ambition of the Paris Agreement, limiting global temperature rise to 1.5°C over pre-industrial levels.

CSIRO and Climateworks Centre modelled these four scenarios to analyse the effects of multi-sector interactions on regional and sectoral consumptions and emissions for the NEM-connected states and territories (i.e., New South Wales, Australian Capital Territory, Victoria, Queensland, South Australia and Tasmania) and for Western Australia (WA) for the period 2022-23 to 2053-54.

This report outlines the methodology and scenario assumptions, and is structured as follows:

- Section 2 briefly discusses scenario narratives and the key assumptions that do or do not vary by scenario.
- Section 3 outlines the methodology, providing an overview of the AusTIMES model and key aspects of modelling decarbonisation scenarios
- Section 4 discusses NEM and WA level projection results for the four scenarios focussing on emission outcomes, fuel mix changes in the electricity and end-use sectors, hydrogen and emissions sequestration from the land use sector.

2 Scenario definition and key assumptions

2.1 Scenario overview

The four scenarios modelled in this study are Progressive Change, Exploring Alternatives, Step Change and Hydrogen Export. A short narrative for each scenario is provided below with the settings for the key drivers summarised in Table 2-1. The scenario titles and narratives were defined by AEMO and provided to the CSIRO and Climateworks Centre to inform the selection of modelling input assumptions.

2.1.1 Progressive Change scenario

This scenario includes lower assumed economic growth than historical trends following a slower global recovery from the COVID-19 pandemic, and ongoing regional conflict disrupting international energy markets and supply chains. The challenging economic conditions lead to the greatest relative risk of industrial load closures.

Uptake of distributed solar PV and other DER technologies are dampened due to supply chain issues. Renewable energy development trends continue to be driven by jurisdictional developments, and coal capacity features less economic retirement compared to the other scenarios. Uptake of energy efficiency measures is muted across all end-use sectors.

Global progress towards net zero ambitions progresses in line with currently-announced policies and ambitions, including Australia's updated commitment to a 43% reduction of emissions by 2030. State emission reduction targets are excluded (see section 2.2.1).

As with all scenarios, economic utilisation of land-use sequestration offsets may offer a means to address sectors that are harder to decarbonise.

Key features of the *Progressive Change* Scenario are:

- The COVID-19 recovery is slow. More insular trade policies and increased protectionism take hold globally. Australia's population growth is relatively lower than other scenarios, with falling birth rates and immigration levels, partly due to sustained impacts on global mobility.
- In search of cost savings, consumers continue to install distributed solar PV, though at lower rates than recently – the reduction partly due to relatively higher costs of panels and inverters due to supply chain issues.
- Similarly, investment in household battery storage and electric vehicles (EVs) does not grow as fast as other scenario forecasts, due to more muted cost reductions, the impact of lower disposable incomes, vehicle supply chain issues, softening in peak demand price signals, and longer vehicle replacement cycles.
- Electrification of heating appliances to transition away from gas is more muted in the near term due to challenging economic conditions.

- Government policy reflects current commitments, particularly the 43% emissions reduction by 2030 and net zero emissions by 2050 (as well as some state-based commitments, excluding state emission reduction targets). Lower economic activity reduces total energy requirements.

2.1.2 Exploring Alternatives scenario

The *Exploring Alternatives* scenario reflects a pathway based around current state and federal government environmental pledges (excluding state emission reduction targets; see section 2.2.1) and the resulting transitioning of Australia's economy to a net zero level of emissions by 2050. It explores alternative pathways to electrification in reaching net zero emissions, under the same decarbonisation objective as *Step Change* (section 2.1.3). Contrary to *Progressive Change*, other key drivers such as population and economic growth, and technology cost reductions, adopt best estimate forecasts.

It is centred around a broad mix of technologies being utilised, using central forecasts of DER, electric vehicles and a moderate uptake of energy efficiency. A key feature of this scenario is the investment in biomethane and associated biomethane targets in the gas system.

Internationally, economic and population growth are both at moderate levels relative to the other three scenarios, and there is an ongoing international collaboration in areas of free trade and progress towards sustainability.

As with all scenarios, economic utilisation of land-use sequestration offsets may offer a means to manage sectors that are harder to decarbonise.

Key features of the *Exploring Alternatives* Scenario are:

- Moderate growth in the global and domestic economy is observed following recovery from the pandemic.
- Australia achieves its updated nationally determined contribution (NDC) of reducing emissions by 43% on 2005 levels.
- Higher investment and policy targets for biomethane in the gas system compared with the other three scenarios.
- Uptake of DER, energy efficiency measures, and the electrification of the transport sector reflect current trends in distributed investments and policy considerations, and is higher than the *Progressive Change* scenario.
- The costs of VRE and storage technologies continue to fall and are increasingly competitive with existing fossil-fuelled generation, at a level higher than *Progressive Change*.

2.1.3 Step Change scenario

This scenario includes a global step change in response to climate change, supported by technology advancements and a coordinated cross-sector plan that tackles the adaptation challenges at a higher level than *Exploring Alternatives* or *Progressive Change*. Domestic and international action increases to achieve the less stringent temperature goal of the Paris Agreement, to limit global temperature rise to well below 2°C compared to pre-industrial levels.

Rapid transformation of the energy sector is enabled by rapidly falling costs for battery storage and VRE, which enables greater consumer investment in distributed energy resources compared with *Exploring Alternatives* or *Progressive Change*. The transformation of the transport sector in particular is influenced by a combination of technology cost reductions affecting zero emissions vehicles, and manufacturers eliminating internal-combustion engine vehicles from new vehicle production lines (and eventually removing them from the road entirely).

Continued advancements in digital technologies enable a greater role for consumers to manage energy use efficiently and provide flexibility to the system compared with *Exploring Alternatives* or *Progressive Change*. Sustainability has a stronger focus, with consumers, corporations, developers, and government also supporting the need to reduce the collective energy footprint through adoption of greater energy efficiency measures compared with *Exploring Alternatives* or *Progressive Change*.

This scenario also considers a greater level of technology breakthrough in energy efficiency and fuel switching compared to *Exploring Alternatives* and *Progressive Change*, which increases the productivity of energy use. Energy efficiency improves by changes in building design, smart appliances, and digitalisation.

As with all scenarios, economic utilisation of land-use sequestration offsets may offer a means to manage sectors that are harder to decarbonise.

Key features of the *Step Change* Scenario are:

- Moderate growth in the global and domestic economy is observed following recovery from the pandemic.
- Higher levels of awareness towards the impacts of climate change from increasingly energy literate consumers result in a greater degree of individual consumer action to reduce emissions compared with *Exploring Alternatives* or *Progressive Change*. This is aided by continued advancement in digital technologies, innovation in business models enabling consumer engagement, and market reforms.
- Strong climate action underpins rapid transformation of the energy sector (and broader global economy) to achieve the less stringent temperature goal of the Paris Agreement, limiting global temperature rises to well below 2°C relative to pre-industrial levels. Domestically, government policy and corporate objectives are aligned with the need to decarbonise the Australian economy, going beyond existing climate policy.
- Currently legislated or materially funded state-based renewable energy policies and targets are achieved, with future electricity sector investments influenced by policy measures that reduce cumulative emissions over time. State emission reduction targets are excluded (see section 2.2.1).
- This scenario assumes that the scale of hydrogen production connected to the NEM is limited, either technically or economically, such that hydrogen production does not materially impact the NEM's investment or operation. This is in contrast with the *Hydrogen Export* scenario. Only limited hydrogen export facilities are connected to the NEM in this scenario.
- The degree of electrification is higher than *Progressive Change* or *Exploring Alternatives*, particularly from the transport sector, where EVs soon become the dominant form of road passenger transportation. This includes continued innovation in transport services, such as ride-

sharing and autonomous vehicles, that may influence charge and discharge behaviours of the EV fleet, including vehicle-to-home discharging trends.

- Consumers also switch from gas to electricity to heat their homes. Stronger electrification from other sectors compared to *Progressive Change* or *Exploring Alternatives* is expected as a means to decarbonise manufacturing and other industrial activities.
- Overall, the scenario assumes stronger rates of technology cost decline for consumer devices such as DER, and energy efficiency and energy management systems.

2.1.4 Hydrogen Export scenario

This scenario represents a world with higher levels of electrification and hydrogen production than the other three scenarios, fuelled by stronger decarbonisation targets and technology cost improvements. These technology cost reductions improve Australia's capacity to expand its exports of "green commodities" to global consumers, including hydrogen and other energy-intensive products such as green steel, supporting stronger domestic economic outcomes relative to other scenarios.

Strong international decarbonisation objectives lead to faster actions enabling the achievement of the more ambitious goal of the Paris Agreement, limiting global temperature rise to 1.5°C by 2100 over pre-industrial levels. This is matched domestically with strong economy-wide actions in line with global ambition.

Continued improvements in the economics of hydrogen production technologies enable the development of a significant renewable hydrogen production industry in Australia for both export and domestic consumption. Strong global decarbonisation action provides a high level of international demand for this production capacity, supplementing declining exports of traditional emissions-intensive resources in this scenario. In the long-term, technical barriers that prevent high uptake of hydrogen in the gas supply network are also overcome, allowing for up to 100% hydrogen in gas supply distribution networks.

The 1.5°C decarbonisation objective leads to a higher degree of electrification and energy efficiency investments across many sectors than the other three scenarios. Increased access to domestic hydrogen production and refuelling infrastructure increases the competitiveness of hydrogen fuel-cell vehicles in heavy transport.

As with all scenarios, economic utilisation of land-use sequestration offsets may offer a means to manage sectors that are harder to decarbonise.

Key features of *Hydrogen Export* are:

- Strong global and domestic action to address climate change and reduce emissions accelerates action to decarbonise. This is enabled through strong economic activity and global investments to meet the preferred objective of the Paris Agreement to limit global temperature rise to 1.5°C.
- Capitalising on significant renewable resource advantages and economic and technological improvements in hydrogen production, Australia establishes strong hydrogen export partnerships to meet international demand for clean energy.

- The export of green hydrogen and other energy-intensive products such as green steel, supports stronger domestic economic outcomes relative to other scenarios, which again causes a higher rate of migration to Australia.
- Both domestic and export hydrogen demand is fuelled, at least in part, by grid-connected electrolysis powered by additional VRE development.
- Strong economy-wide decarbonisation objectives provide significant opportunities to fuel switch towards electricity and hydrogen. The energy transition in Australia is embraced by consumers, as they seek clean energy and energy efficient homes and vehicles.

2.1.5 Summary

A summary of the four scenarios as distinguished by their key drivers is in Table 2-1.

Table 2-1 AEMO scenario definitions

Model Input Assumptions	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
Economic growth and population outlook	Lower	Moderate	Moderate	Higher
Energy efficiency improvement	Low	Moderate	Higher	Highest
Demand Side Participation (DSP)	Low	Moderate	Higher	Higher
Distributed PV (per capita uptake tendency)	Lower	Moderate	Higher	Higher
Battery storage installed capacity	Low	Moderate	Higher	Higher
Battery storage aggregation / VPP deployment by 2050	Low	Moderate	Higher	Higher
Battery Electric Vehicle (BEV) uptake	Low	Moderate	Higher	Higher
Fuel Cell Electric Vehicle (FCEV) uptake	Low	Low	Low	Moderately low*
BEV charging time switch to coordinated dynamic charging by 2030	Low	Moderate	High	Moderate/High
Non-Transport electrification	Low	Low to moderately high	Moderately high	Moderately high
Hydrogen uptake potential	Minimal (industry, transport and some pipeline blending)	Minimal (industry, transport and some pipeline blending), limited export	Minimal (industry, transport and some pipeline blending), limited export	High domestic and exports
Biomethane uptake potential	Minimal	7.5% by volume blending target for reticulated gas by	Minimal	Minimal

		2030, 10% by volume 2035. Faster cost reductions		
International Energy Agency (IEA) 2021 World Energy Outlook (WEO) scenario	Stated Policy Scenario (STEPS)	Announced Pledges Scenario (APS)	Sustainable Development Scenario (SDS)	Net Zero Emissions by 2050 case (NZE2050)
Representative Concentration Pathway (RCP) (mean temperature rise by 2100)	RCP4.5 (2.5-2.7°C)	RCP2.6 (1.7-1.8°C; interpreted as 1.8°C)	RCP2.6 (1.7-1.8°C; interpreted as 1.8°C)	RCP1.9 (<1.5°C)
Decarbonisation target	43% by 2030. Net zero by 2050	At least 43% by 2030. Net zero by 2050 Emissions trajectory to limit warming to less than 1.8 degrees	At least 43% by 2030. Net zero by 2050 Emissions trajectory to limit warming to less than 1.8 degrees	At least 43% by 2030. Net zero by 2050 or earlier Emissions trajectory to limit warming to less than 1.5 degrees

*More uptake of FCEVs in heavy vehicles

2.2 Key assumptions

This section outlines the key data assumptions applied to implement the scenarios.

2.2.1 Emissions targets and constraints

Cumulative emissions constraints for Australia consistent with each scenario narrative are provided in Table 2-2. See Section 3.6 and Appendix B for the full derivation of these constraints.

All scenarios also include explicit emissions targets in 2030 and 2050 in alignment with Australia's current commitments under the Paris Agreement. Specifically, net zero emissions by 2050, and a Nationally Determined Contribution (NDC) to reduce emissions by 43% on 2005 levels by 2030. The emissions budget target in Australia's NDC (4.381 Gt CO2-e from 2021-2030) was not explicitly incorporated in the scenarios (DISER 2022b).

The specific application of these targets varies by scenario, and is summarised in Table 2-2. Note that Progressive Change assumes Australia meets its 2030 emission reduction target exactly, whereas the other scenarios are able to achieve deeper reductions as guided by their carbon budgets. Similarly, net zero emissions by 2050 is an exact target provided for Progressive Change, Exploring Alternatives and Step Change. In Hydrogen Export it is considered an upper bound; however, the carbon budget for this scenario implies that net zero emissions would likely be reached earlier than 2050.

While some state policies are incorporated in the electricity sector, state-based emission reduction targets are not included in these modelled scenarios. This is primarily due to modelling challenges. Specifically, AusTIMES does not currently have a representation of the full scale of emissions sequestration from different methods at a state level. It also does not have the capability to model the trading of emissions credits across state borders, where such activities may be allowed under the relevant state legislation. As any net zero emissions target at a state level requires a robust understanding of the contribution of negative emissions within or outside of that state's boundaries, such targets were not possible to model under the current setup of AusTIMES.

Table 2-2 Cumulative emissions constraints and emission target assumptions by scenario

Model Input Assumptions	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
Global emissions outcome	Broadly consistent with limiting global warming to 2.6°C above pre-industrial levels.	67% chance of limiting global warming to below 1.8C, with no temperature overshoot.	67% chance of limiting global warming to below 1.8C, with no temperature overshoot.	50% chance of limiting global warming to 1.5°C above pre-industrial levels, with no temperature overshoot.
Cumulative emissions constraint for Australia (from 1/1/2021)	9.280 Gt CO2-e (Based on Climateworks Centre analysis for the cumulative emissions bound of a trajectory that achieves Australia's 2030 and 2050 committed emissions targets, with headroom – see Section 3.6)	7.124 Gt CO2-e (Based on relevant global carbon budget; see Appendix B)	7.124 Gt CO_2-e (Based on relevant global carbon budget; see Appendix B)	3.423 Gt CO_2-e (Based on relevant global carbon budget; see Appendix B)
Click here to enter text.Decarbonisation target/s	**In line with** Australia's 2030 commitments under the *Paris Agreement* (43% reduction on 2005 levels by 2030) Economy-wide net zero emissions **by** 2050	Emissions fall **below** Australia's 2030 commitments under the *Paris Agreement* (43% reduction on 2005 levels by 2030) Economy-wide net zero emissions **by** 2050	Emissions fall **below** Australia's 2030 commitments under the *Paris Agreement* (43% reduction on 2005 levels by 2030) Economy-wide net zero emissions **by** 2050	Emissions fall **below** Australia's 2030 commitments under the *Paris Agreement* (43% reduction on 2005 levels by 2030) Economy-wide net zero emissions **by or before** 2050

2.2.2 Electricity sector

The input assumptions that vary by scenario are shown in Table 2-3.

Table 2-3 Electricity sector input assumptions that vary by scenario

Model Input Assumptions	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
Generator and storage build costs	CSIRO GenCost 2022 Current Policies	CSIRO GenCost 2022 Current Policies[1]	CSIRO GenCost 2022 Global NZE post 2050	CSIRO GenCost 2022 Global NZE by 2050
Generator retirements	In line with expected closure years, or earlier if economic or driven by decarbonisation objectives beyond 2030.	In line with expected closure years, or earlier if economic or driven by decarbonisation objectives beyond 2030.	In line with expected closure year, or earlier if economic or driven by decarbonisation objectives	In line with expected closure year, or earlier if economic or driven by decarbonisation objectives

Fuel price settings (natural gas)	NEM: Lewis Grey Advisory (2022), Progressive Change WA: Rystad Energy (2022), Low case: Progressive Change	NEM: Lewis Grey Advisory (2022), Exploring Alternatives WA: Rystad Energy (2022), Exploring Alternatives	NEM: Lewis Grey Advisory (2022), Step Change WA: Rystad Energy (2022), Base case: Step Change	NEM: Lewis Grey Advisory (2022), Hydrogen Scenario WA: Rystad Energy (2022), High case: Hydrogen Export
Fuel price settings (coal)	WoodMackenzie High price	WoodMackenzie Central	WoodMackenzie Low price	WoodMackenzie Low price
Installed capacity of distributed generation and customer owned storage	DER adoption modelling, Progressive Change (Graham and Mediwaththe, 2022)	DER adoption modelling, Exploring Alternatives (Graham and Mediwaththe, 2022)	DER adoption modelling, Step Change (Graham and Mediwaththe, 2022)	DER adoption modelling, Hydrogen Export (Graham and Mediwaththe, 2022)

1. At the time of multi-sector modelling, GenCost 2022 Current Policies was mapped to the Exploring Alternatives scenario. This mapping differs to the IASR which maps to the GenCost 2022 Global NZE post 2050 scenario

There are a number of data assumptions for the electricity sector that do not vary by scenario. These assumptions mainly relate to existing generators, some elements for new generation technologies, and state or national policies. These assumptions apply to all scenarios. The assumptions that are not varied by scenario are outlined in the ISP assumptions workbook and are listed below for the NEM (Table 2-4) and the *Whole of System Plan 2020* (ETT, 2020) used for the South West Interconnected System (SWIS) (Table 2-5) and include the recent WA Government announcement on closure of state-owned coal-fired generators.

Table 2-4 ISP assumptions workbook used across the scenarios for the NEM

Assumption	Source
Nameplate capacity of existing generators	“Maximum capacity” tab https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-and-assumptions-workbook.xlsx?la=en
Cost and performance data on existing power stations	“Existing Gen Data Summary” tab https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-and-assumptions-workbook.xlsx?la=en
Expected closure year	Generating unit expected closure year – October 2022 https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2022/generating-unit-expected-closure-year.xlsx?la=en
Capacity factor constraint (Coal)	Maximum capacity factor 75% NSW coal “Generation limits” tab https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-and-assumptions-workbook.xlsx?la=en
Regional reserves	“Reserves” tab https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-and-assumptions-workbook.xlsx?la=en
Regional cost factors	“Regional Cost Factors” tab https://aemo.com.au/-/media/files/major-publications/isp/2022/iasr/draft-2022-forecasting-assumption-update-workbook.xlsx?la=en

GHG emission factors	"Emissions intensity" tab https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-and-assumptions-workbook.xlsx?la=en

Table 2-5 Assumptions used across the scenarios for the SWIS

Assumption	Source
Nameplate capacity of existing generators	"Existing Plant Params" tab https://www.wa.gov.au/system/files/2020-11/Whole-of-System-Plan-Appendix-B%20%283%29.xlsx
Cost and performance data on existing power stations	"Existing Plant Params" tab https://www.wa.gov.au/system/files/2020-11/Whole-of-System-Plan-Appendix-B%20%283%29.xlsx
Expected closure year	"Thermal generator developments" tab https://www.wa.gov.au/system/files/2020-11/Whole-of-System-Plan-Appendix-B%20%283%29.xlsx WA Government announcement 14 June 2022: https://www.mediastatements.wa.gov.au/Pages/McGowan/2022/06/State-owned-coal-power-stations-to-be-retired-by-2030.aspx
Regional reserves	335 MW (AEMO)
GHG emission factors	"Existing Plant Params" tab https://www.wa.gov.au/system/files/2020-11/Whole-of-System-Plan-Appendix-B%20%283%29.xlsx

2.2.3 Renewable policies

National and state/territory renewable policies included in all scenarios are listed in Table 2-6. Recent announcement of an updated renewable energy target in Queensland was included in all scenarios. This was not the case for the updated Victorian renewable energy target, as at the time of modelling it was pending the outcome of the 2022 Victorian state election.

Table 2-6 National and State/Territory Renewable Policies

Policy	Description
Renewable policies (national)	Renewable Energy Target (RET) consisting of: large-scale RET (LRET): 33,000 GWh of large-scale renewables, so that 23.5% of Australia's electricity in 2020 will be generated from renewables (33,000 GWh maintained until 2030). Small-scale renewable energy scheme (SRES): incentives for home-owners and small businesses to install eligible small-scale renewable energy systems and solar water-heating systems.

Renewable policies (state)	Queensland Renewable Energy Target (QRET): 50% renewable electricity generation by 2028, 70% renewable generation by 2032, 80% renewable generation by 2035. Victoria Renewable Energy Target (VRET): 40% renewable electricity generation by 2025; 50% renewable electricity generation by 2030. Tasmanian Renewable Energy Target (TRET): 100% renewable electricity generation by 2022; 150% renewable electricity generation by 2030; 200% renewable electricity generation by 2040. NSW *Electricity Infrastructure Investment Act 2020*: The Act sets out minimum objectives that by the end of 2029, construction of renewable generation infrastructure that produces at least the same amount of electricity in a year as 8 GW in New England, 3 GW in Central-West Orana and 1 GW of additional capacity. The Act also includes a minimum target of the construction of 2 GW of long-duration (8 hours or more) storage infrastructure by the end of 2029 in addition to Snowy 2.0. The annual construction trajectory of energy generating capability that is specified in the Consumer Trustee's Infrastructure Investment Opportunities Report over the period until the minimum objective is met will be applied as a modelling input (providing a development floor that the model can exceed if appropriate). That trajectory outlines 33,600 GWh of equivalent generating capacity by the end of 2029. Current DER policies (Graham and Mediwaththe 2022)

2.2.4 Hydrogen production and export

There are five hydrogen production pathways specified in AusTIMES:

- Proton exchange membrane (PEM) electrolysis;
- Alkaline electrolysis (AE)
- Steam methane reforming (SMR)
- SMR with carbon and storage (CCS), and;
- Brown coal gasification with CCS.

Based on the demand for hydrogen which is a combination of exogenous inputs (e.g. export demand for hydrogen) and endogenous outcomes (e.g. optimal uptake of fuel cell vehicles in road transport; hydrogen reciprocating engines in the electricity sector; least cost fuel switching in buildings, uptake across industry and non-road transport), AusTIMES optimised investment in production capacity and operation to deliver hydrogen to end-users at least cost (including emissions costs).

Cost and performance data for non-electrolyser production pathways were initially developed in the *National Hydrogen Strategy*, then subsequently updated in the *Technology Investment Roadmap* process led by DISER and are now available as part of GenCost2022 (Graham et al., 2022). Cost and performance data for electrolyser production pathways are mapped to the relevant global scenario (see Figure 2-1 and for the PEM and SMR cost projections, respectively), although the differences between the scenarios was expanded to better account for uncertainty and to differentiate across the scenarios.

Table 2-7 Mapping of global scenario to hydrogen production costs

Model Input Assumptions	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
Hydrogen production process capital costs	CSIRO GenCost 2022 Current Policies	CSIRO GenCost 2022 Current Policies[1]	CSIRO GenCost 2022 Global NZE post 2050	CSIRO GenCost 2022 Global NZE by 2050

1. Added a footnote to table? “At the time of multi-sector modelling, GenCost 2022 Current Policies was mapped to the Exploring Alternatives scenario. This mapping differs to the IASR which maps to the GenCost 2022 Global NZE post 2050 scenario.”

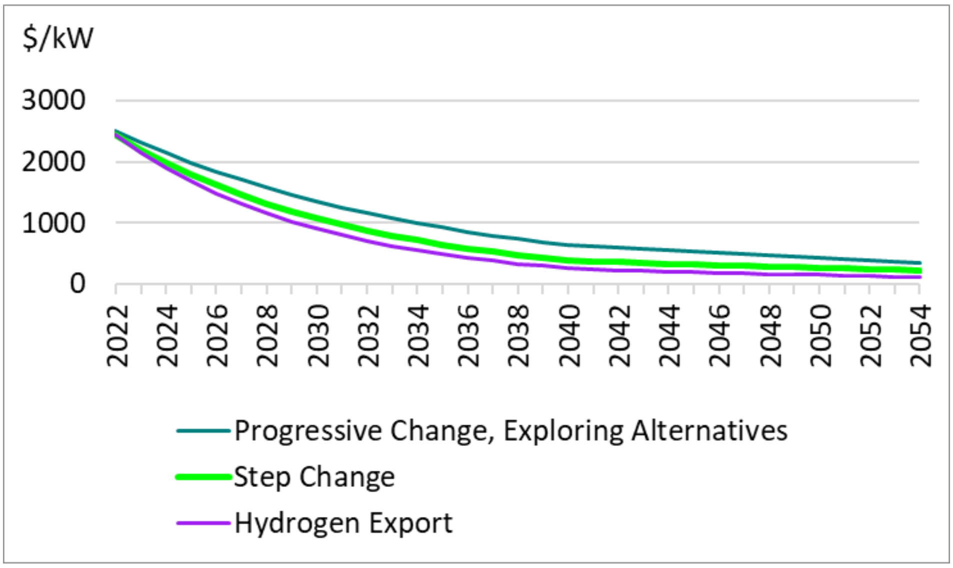


Figure 2-1 PEM Electrolyser capital costs by scenario

Table 2-8 SMR technology capital costs by scenario ($/kW)

	Progressive Change, Exploring Alternatives		Step Change		Hydrogen Export	
	SMR	SMR + CCS	SMR	SMR + CCS	SMR	SMR + CCS
2022	1300	2110	1300	2110	1300	2110
2023	1295	2106	1295	2106	1295	2106
2024	1291	2101	1291	2101	1291	2101
2025	1286	2097	1286	2097	1286	2097
2026	1282	2092	1282	2092	1282	2092
2027	1277	2088	1277	2088	1277	2088
2028	1273	2083	1273	2083	1273	2083
2029	1268	2079	1268	2079	1268	2079
2030	1264	2075	1264	2075	1264	2075
2031	1260	2070	1260	2070	1260	2070
2032	1255	2066	1255	1841	1255	2066
2033	1251	2062	1251	1836	1251	2062
2034	1246	2058	1246	1832	1246	2058
2035	1242	2053	1242	1828	1242	2053
2036	1238	2049	1238	1823	1238	2049
2037	1233	2045	1233	1819	1233	2045
2038	1229	2041	1229	1815	1229	2041
2039	1225	2036	1225	1811	1225	2036

2040	1220	2032	1220	1807		1220	2032
2041	1216	2028	1216	1802		1216	2028
2042	1212	2024	1212	1798		1212	2024
2043	1208	2020	1208	1794		1208	2020
2044	1203	2015	1203	1790		1203	2015
2045	1199	2011	1199	1786		1199	2011
2046	1195	2007	1195	1782		1195	2007
2047	1191	2003	1191	1778		1191	2003
2048	1187	1999	1187	1774		1187	1999
2049	1183	1995	1183	1769		1183	1995

For the *Hydrogen Export* scenario, the assumptions in Table 2-9 relate to electrolysers that are connected to the NEM/SWIS/NWIS, and excludes electrolysers connected to non-regulated (or privately owned) networks or off- or remote grids.

Table 2-9 Hydrogen export assumptions (Mt)

Scenario	2030	2040	2050
Exploring Alternatives and Step Change	NEM: 0.07 SWIS: 0.0375 NWIS: 0.0750	NEM: 0.14 SWIS: 0.125 NWIS: 0.25	NEM: 0.21 SWIS: 0.19 NWIS: 0.4
Hydrogen Export	NEM: 0.75 SWIS: 0.30 NWIS: 0.63	NEM: 2.42 SWIS: 0.98 NWIS: 1.99	NEM: 7.8 SWIS: 3.2 NWIS: 6.4

No hydrogen export in assumed in *Progressive Change*. The basis for *Exploring Alternatives* and *Step Change* volumes is an assumption of growth of 0.07 Mtpa (600 MW electrolyser capacity) per decade for the NEM. Estimates for WA were based on AEMO's assessment of current projects plus the WA government renewable hydrogen roadmap.

Export volumes in the *Hydrogen Export* scenario are based on Australia maintaining its share of global LNG trade in hydrogen based on the mapped IEA scenario (IEA-NZE) which is consistent with the WA Government hydrogen strategy for example.

The export amount for the NEM in the *Hydrogen Export* scenario in 2050 represents a reduction of almost 50% from last years' assumption of 15 Mtpa (compared to around 8 Mtpa now) - this is due to inclusion of some export from WA, and a recognition that not all projected hydrogen production will be connected to regulated grids. This year, small amounts of hydrogen export are also assumed in the other scenarios, compared to zero last year, based on analysis of the current pipeline of projects in Australia.

Regarding the assumptions of hydrogen blending in gas distribution networks (see also Section 2.2.7), all scenarios assume that that a 10% hydrogen blending share by 2030 (buildings and industry), can be introduced without physical modifications and with little impact on the system, consistent with near-term government aspirations and current developments (e.g., Hydrogen Park South Australia, Hydrogen Park Gladstone, HyP Murray Valley). In the Hydrogen Export scenario, it is assumed that barriers and technical challenges arising from hydrogen use in appliances can be overcome and that 100% hydrogen is possible in the longer-term by 2050. This is consistent with continued upgrade of distribution pipelines from cast iron to polyethylene in Australia, and trials and demonstrations already underway in the UK.

2.2.5 Biomethane production

Biomethane (also known as "renewable natural gas") is a near-pure source of methane produced either by "upgrading" biogas (a process that removes any CO_2 and other contaminants present in the biogas) or through the gasification of solid biomass followed by methanation (IEA, 2022). In response to stakeholder feedback from the 2021 multi-sector modelling, biomethane has been included as a decarbonisation option for industry and residential and commercial buildings in this year's work.

There are two different production pathways specified in AusTIMES:

- Anaerobic digesters using municipal solid or animal waste as feedstock
- Gasification and methanation of lignocellulosic sources (Native Forest residues, Crop/stubble/grasses, and Plantation and short rotation trees).

The national quantity of available feedstocks from municipal solid waste, animal wastes, and lignocellulosic sources are drawn from Butler et al. (2021) and shown in Table 2-10.

Table 2-10 Feedstock estimates for biomethane production

	2020	2030	2040	2050
Livestock (kt)	234	234	234	234
MSW (kt)	6517	9044	9994	10943
Native forest residues (PJ)	151	151	151	151
Crop/stubble/grasses (PJ)	1005	1005	1005	1005
Feedstock Plantation and SRT (PJ)	207	548	675	801

MSW: Municipal solid waste; SRT: Short Rotation Trees

Livestock is used to proxy animal waste

State/territory shares of the national quantum are proxied from the state/territory quantities of forestry, agriculture, and organic wastes and residue feedstocks sourced from ENEA Consulting and Deloitte (2021). Production of biogas (the precursor to biomethane) from anaerobic digestion is a mature technology and no future cost reductions are expected. Capital cost reductions in gasification and methanation are accounted for, with a lower cost trajectory applied in the *Exploring Alternatives* scenario (Table 2-11).

Table 2-11 Investment cost for gasification and methanation ($/GJ/year)

	2020	2030	2040	2050
Progressive Change, Step Change, Hydrogen Export	151.38	119.29	94.38	93.66
Exploring Alternatives	151.38	64.03	31.91	31.91

2.2.6 Emissions sequestration

Emissions sequestration (or negative emissions) is required for the economy to meet net zero emissions while residual emissions are still occurring. Land-based emissions sequestration, direct air capture (DAC) and carbon capture & storage (CCS) are the primary methods considered in AusTIMES. All sequestration in Aus-TIMES is assumed to occur domestically within Australia – the use of international offsets is not considered.

Land-based sequestration

Land-based emissions sequestration is represented in AusTIMES as a discrete category of emissions for communication purposes, but could be considered under the same ANZSIC codes (03, 051) as "Forestry and logging".

Land-based emissions sequestration is modelled based on a cost-curve approach, using inputs aligned to DISER (2021-LTER) that are in turn derived from the Land-Use Trade-offs (LUTO) model. Specifically, the cost curve associated with *Conservative, High Threshold* scenario from Table 15 of DISER (2021-LTER) was incorporated into the model, as shown in Table 2-12. This provides the volume of sequestration that would be profitable to supply, up to maximum thresholds, where delivery of carbon credits would provide higher economic return than competing agricultural land uses. It is based on a scenario that does not consider the use of international offsets towards Australia's climate targets.

Table 2-12 Land sequestration cost curve in AusTIMES, derived from DISER (2021)

Supply price ($/t CO2-e)	0	10	20	30	40	50	60	70	85	100	150	200	250	300
Total land sequestration supply available (Mt CO2-e)	8.1	9.9	11.9	16.4	21.1	25.9	30.6	35.4	54	78	168	245	306	368

The LUTO model provides spatial analysis across the Australian intensive use zone, comprising 85.3 MHa of non-contiguous cleared cropping and intensive grazing agricultural land. This land is currently dominated by beef and sheep grazing, and cereal cropping. Within LUTO, economic returns for each 1km^2 parcel of land are calculated for a range of possible land uses, including carbon forestry (based on a shadow carbon price).

Due to modelling limitations, this is a simplified approach that excludes a variety of land-based sequestration methods that are available today or becoming increasingly widespread, including options such as savanna burning, mixed-use carbon plantings, or even 'blue carbon' methods. While it is hoped that modelling capabilities in this space will increase in future, it is useful to consider the carbon forestry sequestration curves produced in this report as a total amount of land-based sequestration. Realistically, this sequestration could be met through a different range of methods.

Regional sequestration levels are based on the proportion of uptake from each state in the original maximum LUTO output (Bryan et al., 2016) and proportions do not vary between scenarios. Such outputs represent the carbon forestry sequestration expected from plantings in that state. Costs of sequestration are applied nationally, and emissions under carbon budget constraints are optimised nationally, so the contribution from individual states is not a specific consideration beyond these applied shares.

Technical sequestration

The technical emissions sequestration options in AusTIMES include direct air capture (DAC) and select applications of carbon capture and storage (CCS).

While generally considered a higher cost option compared to other abatement and sequestration technologies, cost and technical parameters for DAC have been introduced to AusTIMES for the 2022 multi-sector modelling. DAC is currently a non-mature technology that is yet to be demonstrated at scale, and as such there is a wide range of uncertainty around the costs and technical effectiveness. For this study, best-estimate costs and technical parameters were drawn from the literature. Most parameters including initial capital cost assumptions, O&M costs, electricity and heat requirements and efficiency are derived from Fasihi et al. (2019), with the assumption that efficiencies and costs improve over time in line with cost analysis from IEA (2022).

Table 2-13: Technical and cost parameters for direct air capture (DAC) in AusTIMES, drawn from Fasihi et al. (2019) and IEA (2022)

Parameter	Unit	2020	2030	2040	2050
Capital cost	A$/tCO2	$1,132	$487	$399	$311
Fixed operational cost	% Capital cost p.a.	4%	4%	4%	4%
Lifetime	Years	20	20	20	20
Electricity demand	kWh electricity/tCO2	250	225	203	182
Low-temperature heat demand	kWh thermal heat/tCO2	1,750	1,500	1,286	1,102

Carbon capture and storage is available as an option for select applications including hydrogen production (SMR+CCS or Coal+CCS, discussed in Section 2.2.4), electricity generation (where it is generally not taken up), and heavy industry. Specifically, for process and energy emissions in chemical manufacturing, gas extraction, LNG liquefaction, alumina, metal ore mining and steelmaking. Cost and technical assumptions for industrial CCS are drawn from background research under the Australian Energy Transitions Initiative. These technologies are fully-costed in AusTIMES and the model may choose to implement them as part of its cost optimisation. Typically, CCS is one of the most expensive solutions to decarbonise industry, and is not taken up at a large scale when compared with other sequestration methods.

2.2.7 End-use sectors

This section specifies the key assumptions, including definitions and quantification, for the end-use sectors of AusTIMES. More details on the structure of end-use sectors in AusTIMES can be found in Appendix A.

Two broad categories of actions are used to model the variation in energy demand from end-use sectors over time:

- Energy efficiency, which refers to investments in technology that avoid energy consumption that would otherwise be demanded by the end-use sectors; and
- Fuel switching, including electrification. Electrification has an added efficiency benefit where equipment powered by electricity generally has higher energy efficiency than what is being replaced, for example gas boilers replaced by hot water heat pumps.

Energy efficiency and electrification improvements are implemented in the model using three main approaches:

- **Autonomous:** This only applies to energy efficiency. All end-use sectors experience a business-as-usual energy efficiency improvement at **no cost** which is known as autonomous energy efficiency. The rates of efficiency gain do not vary across scenarios, and range from 0.45%-1.41% p.a. in residential buildings, 0.11-0.95% p.a. in commercial buildings, and -0.09% (efficiency reduction; particularly in some mining subsectors where operations become more energy intensive as mines expand) to 0.54% p.a. in industry. These are detailed for each end-use sector in the following sections. These are informed by long-term energy efficiency trends such as improvements that have been observed in HVAC energy efficiency over time, and other external sources including ASSET (2018).
- **Endogenous:** This applies to both energy efficiency and electrification. These are **costed** options which are implemented if they are economically attractive based on a combination of capital costs, equipment lifetime and fuel costs, subject to uptake constraints. The final uptake of endogenous efficiency is determined by the model and not an input. This category largely represents technologies that are commercially available today. Examples for the buildings sector include technologies such as LED lighting, heat pump hot water systems, and improved HVAC systems. In industry, this captures a broad range of technologies under the broad categories of process improvements, small equipment upgrades and large equipment upgrades. The uptake of endogenous energy efficiency and electrification is constrained to different levels depending on the scenario; further details are provided later in this section.
- **Exogenous:** This applies only to energy efficiency. These are **non-costed** options that capture emissions abatement potential from the development and implementation of innovative, but uncertain, technologies. Cost data for these options is limited therefore the potential is explored by exogenously imposing the levels of uptake to align with the scenario narratives based on extensive research previously conducted for the *Decarbonisation Futures* report (Butler et al., 2020). These options are applied in the residential and commercial buildings sectors only.

The impacts of energy efficiency and electrification as they pertain to electricity forecasts are illustrated in Figure X. The stacked area of this graph represents the total amount of electricity that would be consumed without the impacts of energy efficiency. Actual final energy consumption is the sum of baseline consumption in the end use sectors (net of energy efficiency impacts) and added consumption due to electrification.

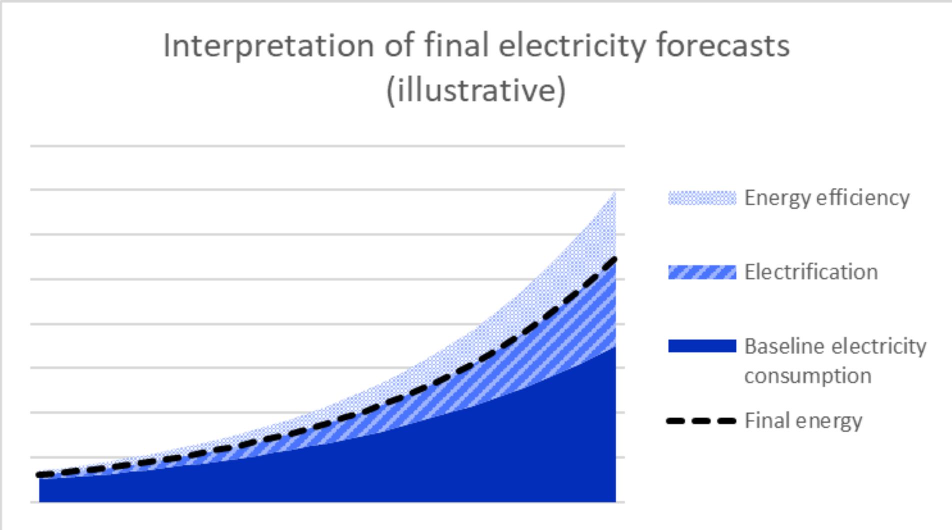


Figure 2-2: Illustrative interpretation of energy efficiency, electrification and final energy consumption as it pertains to electricity. Final energy is the sum of baseline consumption (net of energy efficiency) and added consumption due to electrification.

The modelled exogenous energy efficiency levels are informed by technologies such as chilled beams that are currently available and taken up by a selection of leading buildings. However, a gap currently exists between market-leading buildings that will tend to implement these sorts of options, and the worst-performing buildings (including new builds built to minimum code standards and existing buildings built before the introduction of energy standards and which have not been retrofitted for higher energy performance). Take-up of these options across the entire building stock would represent a significant step change in action and ambition in line with 1.5°C targets. Therefore, these exogenous energy efficiency options are applied only in the Hydrogen Export scenario.

Maximum constraints on the uptake of endogenous energy efficiency and electrification are varied by scenario. Depending on the sector, these are applied on the basis of either annual uptake constraints on deployment of energy efficiency or electrification technologies, or an upper limit on the overall share of energy that can be avoided or displaced over time, or a combination of these two approaches. These assumptions are detailed in the remainder of this section. AusTIMES incorporates base constraints that are broadly representative of the maximum feasible penetration of electrification or energy efficiency technologies under the least restricted case. Specifically:

- In **industry**, the maximum annual uptake rate of electrification technologies is based on the assumed rate at which technology could be replaced at equipment end-of-life, effectively a maximum annual technology build rate. This rate can be varied by scenario. Each subsector is also subject to a maximum total share of technically feasible electrification over time (Madeddu et al. 2020).

- In **residential buildings**, upper limits on electrification uptake are based on the assumption that relevant end uses are able to fully electrify by 2050. Energy efficiency uptake limits are based on savings potentials for relevant end uses derived from ClimateWorks Australia (2016).
- In **commercial buildings**, upper limits on electrification vary by end-use by 2050, based on research derived from ClimateWorks Australia (2016). Energy efficiency uptake limits are based on savings potentials for relevant end uses derived from ClimateWorks Australia (2016).

Limits and uptake rates are varied by scenario, largely based on comparative analysis between scenarios from the IEA's World Energy Outlook (2021). Scenario electrification settings (outlined below) are either mapped to relevant values based on ratios between their mapped IEA World Energy Outlook scenarios (with NZE2050, mapped to Hydrogen Export, as the highest available limit), or in the case of Progressive Change and Exploring Alternatives, were iteratively developed to more closely align to the scenario narratives. Before 2025, most scenarios are subject to more constrained limits to represent less divergence expected in the immediate term.

Residential buildings

Table 2-14 below details the key input assumptions for the Residential sector.

Table 2-14 Residential buildings input assumptions

Model Input Assumptions	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
Household activity projection (millions of dwellings)	2016 ABS census on number of dwellings (driven by ABS Series II household projections) scaled to BIS Oxford Economics Macroeconomics Forecasts on population growth			
Compound annual growth rates: (net increase in dwellings)	1.19% p.a. from 2021 to 2055	1.38% p.a. from 2021 to 2054	1.38% p.a. from 2021 to 2054	1.69% p.a. from 2021 to 2055
Autonomous energy efficiency	Ranging from 0.45 % p.a. to 1.41% p.a. depending on end use (does not vary by scenario)			
Multiplier on maximum energy efficiency uptake limits	0.73x	0.75x	0.88x	1.00x
Exogenous energy efficiency potential	None	None	None	Limited (~5 PJ/yr avoided by 2050)
Multiplier on maximum electrification uptake limits	Pre-2025: 0.36x Post-2025: 0.72x	Pre-2025: 0.36x Post-2025: 0.72x	Pre-2025: 0.72x Post-2025: 0.94x	Pre-2025: 0.72x Post-2025: 1.00x
Hydrogen uptake potential	Endogenously determined based on production cost of hydrogen compared to that of other gaseous fuel options. See Section 2.2.5 for more details.			
	Maximum 10% by volume blended in pipelines by 2030	Maximum 10% by volume blended in pipelines by 2030	Maximum 10% by volume blended in pipelines by 2030	Maximum 10% by volume blended in pipelines by 2030

	Maximum 10% by volume blended in pipelines by 2050	Maximum 10% by volume blended in pipelines by 2050	Maximum 10% by volume blended in pipelines by 2050	Maximum 100% blended in pipelines by 2050
Biomethane uptake potential	Endogenously determined based on production cost of biomethane compared to that of other gaseous fuel options. See Section 2.2.5 for more details.			
	No explicit upper or lower bound at an end-user level	Minimum target of 7.5% and 10% by volume blended in gas network by 2030 and 2035, respectively	No explicit upper or lower bound at an end-user level	No explicit upper or lower bound at an end-user level

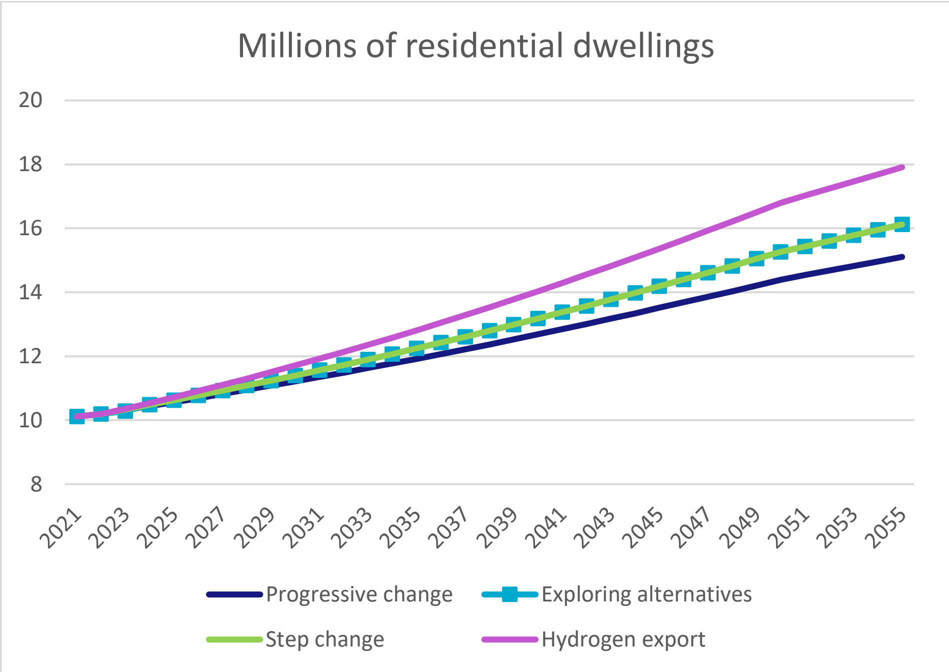


Figure 2-3 Residential baseline activity projection for the four scenarios in all states and territories excluding NT (note: Exploring Alternatives and Step Change share the same projections)

Commercial buildings

Table 2-15 below details the key input assumptions for the Commercial sector.

Table 2-15 Commercial buildings input assumptions

Model Input Assumptions	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
Commercial activity projection (millions m2 of floorspace)	Uniform across all scenarios at compound annual growth rate of 2.09% p.a. from 2020 to 2050. This is informed by floorspace projections for commercial building archetypes from the Commercial Buildings Baseline Study (Pitt and Sherry, 2012). There is no clear indication of how the difference in economic growth impacting gross value added (GVA) of commercial sectors affects building stocks (i.e. the same building can have different economic activity). Therefore, the difference in economic growth is not considered in the commercial buildings floorspace projection.			
Autonomous energy efficiency	Ranging from 0.11% p.a. to 0.95% p.a. depending on end use (does not vary by scenario)			

Multiplier on maximum endogenous energy efficiency uptake limits	0.73x	0.75x	0.88x	1.00x
Exogenous energy efficiency potential	None	None	None	Limited (~29 PJ/yr avoided by 2050)
Multiplier on maximum electrification uptake limits	Pre-2025: 0.36x Post-2025: 0.72x	Pre-2025: 0.36x Post-2025: 0.72x	Pre-2025: 0.72x Post-2025: 0.94x	Pre-2025: 0.72x Post-2025: 1.00x
Hydrogen uptake potential	Endogenously determined based on production cost of hydrogen compared to that of other gaseous fuels. See Section 2.2.5 for more details.			
	Maximum 10% by volume blended in pipelines by 2030 Maximum 10% by volume blended in pipelines by 2050	Maximum 10% by volume blended in pipelines by 2030 Maximum 10% by volume blended in pipelines by 2050	Maximum 10% by volume blended in pipelines by 2030 Maximum 10% by volume blended in pipelines by 2050	Maximum 10% by volume blended in pipelines by 2030 Maximum 100% blended in pipelines by 2050
Biomethane uptake potential	Endogenously determined based on production cost of biomethane compared to that of other gaseous fuels. See Section 2.2.5 for more details.			
	No explicit upper or lower bound at an end-user level	Minimum target of 7.5% and 10% by volume blended in gas network by 2030 and 2035, respectively	No explicit upper or lower bound at an end-user level	No explicit upper or lower bound at an end-user level

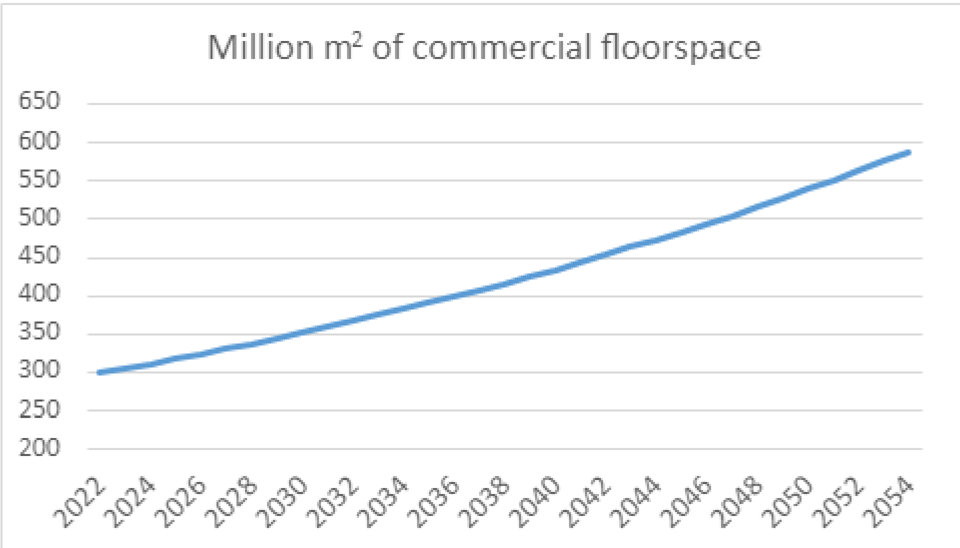


Figure 2-4 Commercial baseline activity projection (million m^2 of floorspace) (uniform across the four scenarios) in all states and territories excluding NT

Industry and agriculture

Table 2-16 below details the key input assumptions for the industrial sector.

Table 2-16 Industry input assumptions

Model Input Assumptions	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
Industrial activity projection	Activity growth rates of most industrial subsectors are based on the Gross Value Added (GVA) projections of ANZSIC Divisions B to E provided by BIS Oxford Economics Macroeconomic Forecasts, except coal and natural gas mining, and green steel production.			
Compound annual growth rates:	Overall, 1.49% p.a. from 2021 to 2054	Overall, 1.54% p.a. from 2021 to 2054	Overall, 1.54% p.a. from 2021 to 2054	Overall, 1.37% p.a. from 2021 to 2054
Coal export projections	Consistent with IEA STEPS at -0.6% p.a. from 2020 to 2050	Consistent with IEA APS at -1.7% p.a. from 2020 to 2050	Consistent with IEA SDS at -3.6% p.a. from 2020 to 2050	Consistent with IEA NZE2050at -7.0% p.a. from 2020 to 2050
Natural gas export projections	Consistent with IEA STEPS at 0.7% p.a. from 2020 to 2050	Consistent with IEA APS at -0.4% p.a. from 2020 to 2050	Consistent with IEA SDS at -0.8% p.a. from 2020 to 2050	IEA NZE2050at -2.4% p.a. from 2020 to 2050
Green steel activity projection	None	None	None	50Mt/yr of green steel nationally[1] by 2050
Autonomous energy efficiency	Varies by subsector, between -0.09% efficiency decline and 1.73% improvement per year			
Multiplier on maximum annual endogenous energy efficiency uptake rate	0.71x	0.78x	0.89x	1.00x
Exogenous energy efficiency potential	None	None	None	Limited (~22 PJ/yr avoided by 2050)
Multiplier on maximum annual electrification uptake rate	Pre-2025: 0.17x Post-2025: 0.17x	Pre-2025: 0.17x Post-2025: 0.33x	Pre-2025: 0.33x Post-2025: 0.78x	Pre-2025: 0.33x Post-2025: 1.00x

[1] Refers to steel produced via low- or zero-emissions hydrogen-based direct-reduction iron (DRI) methods. Figures based on an uptake curve aligned to the Targeted Deployment scenario from Australia's National Hydrogen Strategy. Note that the model is allowed to endogenously determine the optimal location and production route for steel Australia-wide.

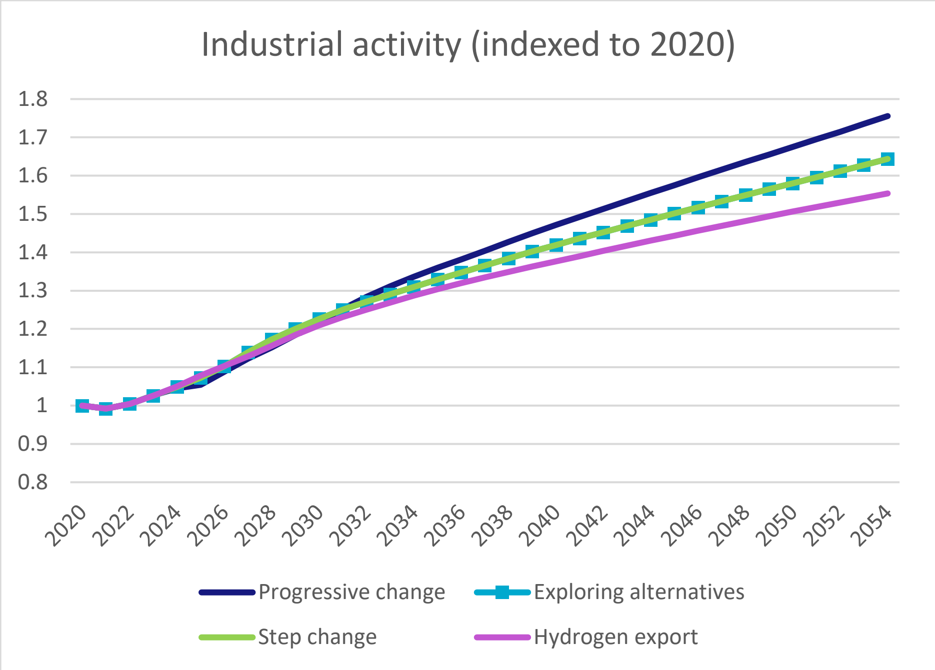


Figure 2-5 Industrial baseline activity projection for the four scenarios in all states and territories excluding the NT, based on BISOE modelling provided by AEMO. This currently excludes additional demand for green steel

Table 2-12 below details the key input assumptions for the agricultural sector.

Table 2-17 Agriculture input assumptions

Model Input Assumptions	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
Agricultural activity projection	Activity growth rates are based on the Gross Value Added (GVA) projections of ANZSIC Division A provided by BIS Oxford Economics Macroeconomic Forecasts.			
Compound annual growth rates (industrial GVA)	1.39% p.a. from 2021 to 2054	1.63% p.a. from 2021 to 2054	1.63% p.a. from 2021 to 2054	1.90% p.a. from 2021 to 2054
Autonomous energy efficiency	0.4% p.a. is assumed across all subsectors (consistent with analysis of long-term energy efficiency trends that have occurred)			
Multiplier on maximum annual endogenous energy efficiency uptake rate	0.71x	0.78x	0.89x	1.00x
Exogenous energy efficiency potential	None	Minimal (~0.2 PJ/yr avoided by 2050)	Minimal (~0.2 PJ/yr avoided by 2050)	Minimal (~0.5 PJ/yr avoided by 2050)
Multiplier on maximum annual electrification uptake rate beyond 2025	0.33x	0.59x	0.78x	1.00x
Non-energy emissions abatement (e.g. enteric fermentation reduction methods	Moderate (~30 Mt/yr avoided by 2050)	Moderate (~30 Mt/yr avoided by 2050)	Moderate (~33 Mt/yr avoided by 2050)	High (~85 Mt/yr avoided by 2050)

and improved manure management)	

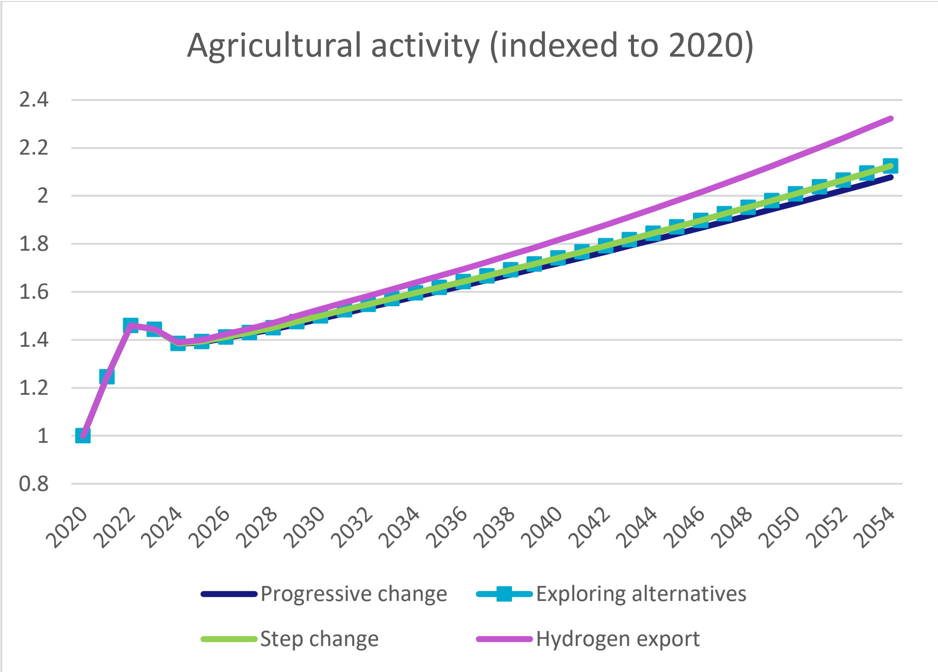


Figure 2-6 Agricultural baseline activity projection for the four scenarios in all states and territories excluding the NT, based on BISOE modelling provided by AEMO

Transport

Adoption modelling of alternative vehicles (plug-in hybrid electric vehicles, battery electric vehicles, and fuel cell electric vehicles using hydrogen) has been conducted by CSIRO, under a separate consultancy, in parallel to the multi-sector energy modelling. The varying inputs be scenario are outlined below (Table 2-18). For more detail, please refer to Graham (2022).

Table 2-18 Transport sector inputs that vary by scenario

Model input Assumptions	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
Activity growth	Lower	Moderate	Moderate	Higher
Timing of cost[1] parity of short-range electric vehicles with ICE	2035	2030	2027	2025
ICE vehicle availability	New vehicles unavailable beyond 2065	New vehicles unavailable beyond 2045	New vehicles unavailable beyond 2040	New vehicles unavailable beyond 2035
Cost of fuel cell vehicles	High	Medium	Medium	Low
ICE commercial services collapse / no longer viable to operate[2]	NA	2055	2050	2045

Degree to which state targets met in 2030	Underachieved by 30 percentage points	Underachieved by 15 percentage points	Achieved	Overachieved by 15 percentage points

1. Upfront sales costs of vehicle, not whole of vehicle running cost. Short range is less than 300km. Long range electric vehicles do not reach upfront vehicle cost parity due to the additional cost of batteries of around $5000. However, they do reach cost parity on a whole of travel basis around 3 years after the dates for short range upfront vehicle cost parity.

2. Special purpose vehicles exempted. NA Not applicable because the event is too far out from the projection period to be relevant. However, a similar collapse would be expected at some time in the future.

ICE: Internal Combustion Engine

The vehicle cost assumptions for the *Progressive Change, Step Change and Hydrogen Export* scenarios are framed relative to *Exploring Alternatives*. In the *Progressive Change* scenario, it is assumed that the cost reductions are delayed by 5 years to 2035. In the *Step Change* scenario, cost reductions are brought forward 3 years to 2027[2]. For *Hydrogen Export* which has stronger global climate change policy ambition cost reductions are brought forward by 5 years to 2025. This would also reflect a supply chain rebound whereby the current high prices for raw materials is met with strong investment in new capacity, supporting future cost reductions.

All state and territory government have developed electric vehicle strategies. These strategy documents contain the detail for how each region intends to enable adoption of electric vehicles and the various policies are documented in Graham (2022). An alternative view is taken by scenario on how successful the package of policy measures will be in reaching 2030 electric vehicle sales targets. The assumptions in Table 2-13 show the degree to which these targets are met. The key reasons for underachievement are likely to be supply chain issues associated with electric vehicles numbers and models available as well as the limited range of impact of the subsidies. Overachievement could reflect stronger than expected global electric vehicle manufacturing ramp up, lower electric vehicle costs in the relevant scenario and additional policies not currently announced either by state or the commonwealth.

Economic and population growth impacts both passenger and freight transport demand across road and non-road transport. Demand projections by transport segment are consistent with Graham (2022). The uptake of alternative vehicle technologies by scenario is an input into AusTIMES for the multi-sector modelling. The assumptions impacting this potential uptake are documented in Graham (2022).

Non-road transport

The non-road transport consists of domestic aviation, domestic shipping, rail and other transport (i.e., transport related services from ANZSIC Division I). Similar to road transport, fuel consumption is dominated by oil-derived liquid fuels namely diesel (rail freight, shipping), kerosene (aviation), fuel oil (shipping) and gasoline (general aviation, recreational boating). Decarbonisation options include biodiesel, bio-synthetic paraffinic kerosene (sustainable jet fuel) and electrification. Hydrogen or ammonia are potentially other options for some segments of non-road transport (shipping, rail) but these options were not included in this modelling.

Until recently, the main option considered for decarbonising aviation is sustainable jet fuel which is a drop-in fuel for existing turbine aircraft currently using kerosene. This fuel can be blended with

[2] This is two years later than in CSIRO's 2021 projections to acknowledge that there are more difficult supply chain constraints than previously expected.

kerosene up to 100% based on numerous successful trials over the last two decades. Previously, aviation was not considered a candidate for electrification due to range limitations and weight considerations. However, with further improvements in battery technology, the success of electric-based drone technology in non-passenger applications and the continued proliferation of transport-on-demand business models in cities, electrification of aviation is considered to be more plausible and is gaining traction in some segments like regional flights (<1000km range). Currently, delivery models being considered are diverse and include: hybrids (single electric engine added to aircraft with other conventional propulsion), pure electric with modified air frame, vertical aero propeller / helicopter designs, hydrogen fuel aircraft designs and electric on-ground taxiing power. However, it is unclear if any of these designs could replace some long-haul aviation. It is more likely to be adopted for shorter route aviation.

The electrification of shipping is not commonly considered. This is because shipping already has access to some of the lowest cost liquid fuels available and potentially the range limitation of electricity. In addition, their diesel engines are more easily adaptable to alternatives such as natural gas and hydrogen (not modelled). As a result, CSIRO does not include electrification of marine transport in our projections.

The electricity consumption projections for passenger rail are similar to the projected rail passenger demand in Graham (2022). This is estimated by multiplying the extrapolated trend in rail energy requirements per passenger kilometre. For rail freight and aviation electrification, CSIRO estimates the total overall energy demand for each non-road transport sector before estimating the electricity demand for each non-road sector in accordance with the assumptions outlined in Table 2-19. The adopted assumptions are a subjective assessment of potential technology readiness for the non-road sector based on the scenario narratives.

Table 2-19 Rail freight and aviation electrification assumptions

Scenario	Electrification commencement date		Maximum share by 2050 (%)
	Rail freight	Aviation	
Progressive Change	2048	2047	3
Exploring Alternatives	2037	2032	7
Step Change	2035	2030	10
Hydrogen Export	2030	2027	20

There are several transport sector assumptions that do not vary by scenario. These are listed in Table 2-20.

Table 2-20 Transport sector inputs that do not vary by scenario

Model Input Assumptions	Data sources
Energy balance	*Australian Energy Statistics (DISER, 2020b)*
Vehicle stock, scrapping rate	*ABS Catalogue No. 9309.0 - Motor Vehicle Census, Australia, 31 Jan 2021* (ABS, 2021a)

Average vehicle kilometres travelled	*ABS Catalogue No. 9208.0 - Survey of Motor Vehicle Use, Australia, 12 months ended 30 June 2020* (ABS, 2020b)
GHG emission factors	*National Greenhouse Accounts Factors 2021* (DISER, 2021-NGAF)
Maintenance costs	ATAP (2016); RACQ (2018)
Registration, insurance costs	State/territory government websites
ICE vehicle fuel efficiency improvements	Graham and Havas (2021)
Retail fuel price components	Australian Institute of Petroleum
Fuel excise rates	Australian Taxation Office
Subsidies	Current policies on stamp duty, registration exemptions or direct financing retained until 2030
Biofuel mandates	NSW - *Biofuel (Ethanol Content) Act 2007*, historical take-up of ethanol and biodiesel is from the *Office of Fair Trading*. QLD - The *Liquid Fuel Supply (Ethanol and Other Biofuels Mandate) Amendment Act 2015*
Biofuel availability	Maximum amount of bioenergy available from lignocellulosic feedstocks that can be sent to biomass to liquids (BTL) processes. 2030: 674 PJ; 2050: 776 PJ*

*CSIRO estimates

2.3 Changes from the 2021 Multi-Sector Modelling report

In 2021, CSIRO and Climateworks Centre were commissioned by AEMO to provide similar multi-sector modelling outputs to this piece of work, ahead of the 2022 Integrated System Plan. The outcomes of this work were documented in the Multi-Sector energy modelling report prepared by CSIRO and Climateworks Centre for AEMO (Reedman et al., 2021).

Between the 2021 and 2022 multi-sector modelling projects, a number of changes were made. These are summarised below.

2.3.1 Modelled scenarios

Four scenarios were modelled for AEMO in the 2021 Multi-sector Modelling project: Net Zero 2050, Step Change, Strong Electrification and Hydrogen Superpower. A different set of scenarios has been modelled in the 2022 Multi-sector modelling, as outlined in Section 2.1, and several of these relate directly to the scenarios in the 2021 modelling.

Progressive Change shares similar settings to the 2021 Net Zero 2050 scenario, with one key difference being the increased whole-of-economy emissions target in 2030, which is in line with the increase in the Australian Government's 2030 commitments under the Paris Agreement confirmed in 2022 (Albanese, 2022).

Step Change is largely analogous in settings to the 2021 Step Change scenario.

Exploring Alternatives is a new scenario in the 2022 modelling work. It is largely modelled as a variation or sensitivity on Step Change with a focus on alternative technology assumptions, notably on biomethane costs and uptake.

Hydrogen Export shares similar settings to the 2021 Hydrogen Superpower scenario. It is constrained by a 1.5-degree carbon budget and features a strong role for hydrogen exports. This is at a reduced level in the NEM-connected states compared to last year, due to inclusion of some export from WA, and a recognition that not all projected hydrogen production will be connected to regulated grids.

The Strong Electrification scenario from 2021, which was considered a 1.5-degree constrained sensitivity alongside the Hydrogen Superpower scenario, was not modelled in 2022.

2.3.2 Regional scope of work

AusTIMES is a national whole-of-economy model and was run including full coverage of all states and territories in the 2021 multi-sector modelling. However, in 2021, results were reported only for the NEM-connected states and territories (New South Wales, Victoria, Queensland, South Australia, Tasmania and Australian Capital Territory). The development of inputs and assumptions was also focused primarily on these states and territories.

For this modelling, AusTIMES was once again run including full coverage of Australia. However, the regional scope of outputs reported, and of input development, was expanded to consider Western Australia. Western Australian results are referred to in the results section of this report (Section 4) alongside results for NEM-connected states. This means that the regional coverage of this study includes all Australian states and mainland territories except the Northern Territory.

2.3.3 Carbon budget approach

In the 2021 multi-sector modelling, the approach to ensure alignment with scenario carbon budgets involved iteratively adjusting a carbon price trajectory to achieve the desired outcome. In 2022, this approach was updated and the carbon budget, or cumulative emissions constraint, is now applied as a binding constraint in AusTIMES in lieu of a carbon price trajectory. This allows for a more accurate link to the decarbonisation objective for each scenario. As it results in an effective shadow price on emissions within AusTIMES, that drives decarbonisation in a similar way to an explicit carbon price trajectory, it is not a significant contributor to differences in the modelled outcomes when compared to the 2021 approach.

In addition to this, the carbon budget calculation approach documented in Appendix B was updated to incorporate the latest science on carbon budgets from the IPCC's Sixth Assessment Report (Arias et al. 2021) and the most current approach for translating this to an Australian level, based on consultation with Australian-based IPCC experts (Nicholls, Z, Pers. Comm., 15 July 2022).

2.3.4 Emissions sequestration in AusTIMES

The approach to emissions sequestration in AusTIMES, documented in Section 2.2.6 has been updated between the 2021 and 2022 Multi-sector modelling work. Previously this relied on an exogenous trajectory based on a previous modelling exercise from the Land-Use Trade-Offs (LUTO) model. This has been updated based on a cost-curve approach from more recent LUTO modelling used by DISER (2021a), with additional expansions in technical sequestration from Direct Air Capture (DAC), and additional applications of Carbon Capture and Storage (CCS) in industry. The implication of this is that sequestration occurs as a cost optimisation against emission reductions elsewhere in the economy – which may alter the profile of sequestration uptake, to be discussed in section 4.3.

2.3.5 Hydrogen

In the 2021 Multi-sector modelling work, it was assumed that all hydrogen production for export was grid connected. In this year's work, it was assumed that 50% of hydrogen production for export is grid connected.

The export amount for the NEM in *Hydrogen Export* scenario in 2050 represents a reduction of almost 50% from last years' assumption of 15 Mtpa (compared to 8 Mtpa now) - this is due to inclusion of some export from WA, and a recognition that not all projected hydrogen production will be connected to regulated grids. This year, small amounts of hydrogen export are also assumed in the other scenarios, compared to zero last year, based on analysis of the current pipeline of projects in Australia.

For hydrogen blending in gas networks, this year's work accounts for blending based on a volumetric basis at low blends rather than an energy basis in the 2021 Multi-sector modelling work.

2.3.6 Biomethane

Biomethane was not a fuel option in the 2021 Multi-sector modelling work. Its inclusion in the 2022 work reflects the development of some pilot projects, interest in renewable gas in some jurisdictions, and a response to Forecasting Reference Group (FRG) feedback.

2.3.7 Approach to electrification and energy efficiency

In the 2021 multi-sector modelling work, the approach to modelling energy efficiency and electrification uptake in industry and buildings was heavily reliant upon hurdle rate assumptions. The hurdle rate acted as an artificially-raised technology-specific discount rate for particular applications of energy efficiency and electrification, representing various non-cost barriers to uptake. This approach had precedence as a method for representing non-cost barriers in an economical model, but also presented challenges. In particular, specific discount rates are very sensitive to other model parameters and it can be difficult to determine appropriate scenario-specific rates. It also has the potential to disincentivise energy efficiency and electrification uptake in the long-term.

To address this challenge in the 2022 Multi-sector modelling work, a new approach was developed to control energy efficiency and electrification uptake via a combination of annual uptake rates or penetration rates, that could vary by scenario based on relativities observed in the IEA WEO 2021 scenarios, to which the 2022 Multi-sector modelling scenarios are mapped (See Section 2.1.5 for scenario mapping, and section 2.2.7 for a full description of the updated approach).

3 Methodology

3.1 AusTIMES model overview

CSIRO implemented the four specified scenarios in the AusTIMES model, which is an Australian implementation of The Integrated MARKAL-EFOM System (TIMES) that has been jointly developed under the International Energy Agency (IEA) Energy Technology Systems Analysis Project (ETSAP)[3]. CSIRO is a Contracting Party to ETSAP and has developed an Australian version of the TIMES model (AusTIMES) in collaboration with Climateworks Centre, a joint partner on this project.

The TIMES energy system modelling framework has been used extensively in over 20 countries. TIMES is a successor to the MARKAL energy system model. The model satisfies energy services demand at the minimum total system cost, subject to physical, technological, and policy constraints. Accordingly, the model makes simultaneous decisions regarding technology investment, primary energy supply and energy trade. Extensive documentation of the TIMES model generator is available from the ETSAP website[1].

The TIMES model generator is a partial equilibrium model of the energy sector. In the energy domain, partial equilibrium models, sometimes referred to as 'bottom-up' models, were initially developed in the 1970s and 1980s (e.g. Manne, 1976; Hoffman and Jorgenson, 1977; Fishbone and Abilock, 1981). Partial equilibrium models are used because the analysis of energy and environmental policy requires technological explicitness; the same end-use service (e.g. space heating, lighting) or end-use fuel (e.g., electricity, transport fuel) can often be provided by one of several different technologies that use different primary energy resources and entail different emission intensities, yet may be similar in cost (Greening and Bataille, 2009). This means that in different scenarios, consumption of various primary energy sources may vary across sectors and technologies.

Partial equilibrium modelling allows the incorporation of various technologies associated with each supply option and allows a market equilibrium to be calculated. It also allows for competing technologies to be evaluated simultaneously, without prior assumptions about which technology, or how much of each, will be used. Some technologies may not be taken up at all. This allows flexibility in the analysis: detailed demand characteristics, supply technologies, and additional constraints can be included to capture the impact of resource availability, industry scale-up, saturation effects, cost reductions and policy constraints on the operation of the market.

The advantage of using a system model approach rather than an individual fuel / technology / process modelling approach is that the infrastructure constraints can be explicitly included, such as life of existing stocks of assets (e.g., plant, buildings, vehicles, equipment, appliances) and consumer technology adoption curves for abatement options which are subject to non-financial

[3] https://iea-etsap.org/ [accessed 19 July 2022]

investment decision making. By using a system approach, we can account for the different impact of abatement options when they are combined rather than implemented separately.

3.2 Main structural features

AusTIMES model has the following structural features:

- Coverage of all states and mainland territories (ACT, NSW, NT, QLD, SA, TAS, VIC, WA)[4]
- Time is represented in annual frequency in financial years (2022-2054)
- End-use sectors include agriculture (8 sub-sectors), mining (11 sub-sectors), manufacturing (21 sub-sectors), other industry (5 sub-sectors), commercial and services (11 building types), residential (3 building types), road transport (10 vehicle segments) and non-road transport (aviation, rail, shipping)
    - Each sector has information regarding energy consumption and assumed efficiency gains, as well as options regarding which primary energy sources can be consumed, additional costed fuel switching or efficiency improvements, options for avoiding non-energy emissions and potential for carbon capture and storage (CCS)
- Representation of fuel types across the end-use sectors:
    - Industry and agriculture: Oil (mainly diesel), black coal, brown coal, natural gas, hydrogen, biomethane, electricity and other bioenergy (e.g., bagasse in existing applications, biodiesel)
    - Residential buildings: Natural gas, liquid petroleum gas, hydrogen, biomethane, wood and electricity
    - Commercial buildings: Oil (as reported in Australian Energy Statistics), natural gas, hydrogen, biomethane and electricity
    - Transport: oil (mainly petrol, diesel, kerosene, fuel oil), biofuels (ethanol, biodiesel), liquid petroleum gas, natural gas, electricity, hydrogen.
- Electricity sector (more details in Section A.1)
- Five hydrogen production pathways including two electrolysis pathways: proton exchange membrane (PEM); and alkaline electrolysis (AE); steam methane reforming (SMR); SMR with CCS; brown coal gasification with CCS.

3.3 Model calibration and inputs

The AusTIMES model for this study has been calibrated to a base year of 2020 based on the latest state/territory level energy balance that was available upon commencement of this modelling (DISER 2021-AES), national inventory of greenhouse gas emissions (DoEE 2019), stock estimates of vehicles in the transport sector (ABS 2021a), data on the existing power generation fleet (AEMO,

[4] For this work, the modelling results are only presented for the NEM-connected states and territories and Western Australia (WA).

2020,2021; ETT, 2020) data source for WA and installed capacity of distributed generation (Graham and Mediwaththe, 2022).

For this particular work additional inputs were sourced from AEMO and its third-party consultants regarding economic activity, population growth, distributed energy resources, capital costs of generation technologies, projected uptake of DER (i.e., rooftop solar PV, behind-the-meter batteries), and projected road and non-road transport demand, electric and fuel cell vehicle uptake for road transport, and minimum electrification of non-road transport (i.e., rail and aviation). The assumptions applied are discussed in Section 2.2.6.

3.4 Objective function

TIMES is formulated as a linear programming problem. The objective function minimises total discounted system costs over the projection period (inter-temporal optimisation) while adhering to specific constraints. TIMES is simultaneously making decisions on investment and operation, primary energy supply, and energy trade between regions.

While minimizing total discounted cost, the model must satisfy a large number of constraints (the equations of the model) which express the physical and logical relationships that must be satisfied in order to properly depict the energy system. Details on the constraints are available in Part I of the TIMES model documentation.[5]

Additional structural details of the AusTIMES model are outlined in Appendix A.

3.5 Implementation of decarbonisation objectives in AusTIMES

The implementation of decarbonisation objectives in AusTIMES has a number of options:

1. Implementing an annual carbon price trajectory per scenario that results in sufficient emissions reduction to meet the scenario objective
2. Implementing annual emission reduction target/s that reaches the desired quantum of emissions in a particular future year
3. Specifying a cumulative emissions constraint across a certain time period.

The modelling for all scenarios in this report used a combination of the second and third options, specifying annual emissions targets in line with Australian Government commitments under the Paris Agreement, while also applying a cumulative emissions constraint to either represent a carbon budget that is consistent with the global emissions target, or representative of a cumulative emission constraints implied by other bounds on the rate of decarbonisation considered feasible in that scenario. Specific settings are discussed in Section 2.2.1.

[5] https://iea-etsap.org/docs/Documentation_for_the_TIMES_Model-Part-I.pdf [accessed 19 July 2022]

3.6 Carbon budgets and cumulative emissions constraints

Cumulative emissions constraints were set for all four scenarios, which represented the total cumulative emissions allowed between 2021-2050. For three scenarios (Step Change, Exploring Alternatives and Hydrogen Export), this constraint represented a national carbon budget for Australia consistent with a particular temperature outcome. These budgets were developed, based on the method used by Meinshausen (2019) and updated by Nicholls and Meinshausen (2022). This approach involves the conversion of a global carbon budget into an Australian-specific budget by considering:

- The translation of a global carbon dioxide budget into a carbon dioxide-equivalent budget including other GHG emissions (Meinshausen 2019)
- An assumption that Australia's 'fair share' of the global carbon budget is 0.97% (consistent with the modified contraction and convergence approach from Garnaut 2008; Meinshausen et al. 2019)
- Subtraction of historical emissions up to 2021.

The full methodological approach including interim calculations is provided in Appendix B, and specific carbon budgets for each scenario are documented in Section 2.2.1.

For the Progressive Change scenario, a carbon budget was not derived from a global budget based on the above approach. Instead, the emissions boundaries for that scenario were based on the assumption that Australia meets its current 2030 (43% below 2005 levels) and 2050 (net zero emissions) targets as committed under the Paris Agreement (DISER 2022a), with appropriate headroom for emissions to reduce at a linear or non-linear rate. An indicative trajectory was plotted that first assumed a linear reduction in emissions from now until the 2030 target, and then the 2030 target until net zero by 2050. Then, an allowance of 20% higher emissions in 2025 and 75% higher in 2045 was applied. This was developed through several iterative rounds of modelling, balancing the allowance for this scenario to choose a decarbonisation trajectory freely while achieving reasonable outcomes. The effect is a cumulative constraint that allows the scenario the freedom to meet the specified targets under its own trajectory, while not delaying all action to a specific point in 2030 or 2050 (which tends to occur without a cumulative emissions incentive). This led to an implied cumulative emissions constraint of 9.280 Gt CO_2-e (Table 3-1), which was applied as a constraint alongside carbon budgets for the other scenarios in the model.

Table 3-1 Cumulative emissions constraint for Progressive Change (applicable to all GHG emissions) from 2021

Scenario	Australian cumulative emissions constraint (All GHGs; from 2021)	Justification
Progressive Change	9.280 Gt CO2-e	Based on Climateworks Centre analysis for the cumulative emissions bound of a trajectory that achieves Australia's 2030 and 2050 committed emissions targets, with headroom.

3.7 Link to distributed energy resources (DER) and electric vehicle adoption modelling

In parallel to the multi-sector energy modelling, AEMO has also commissioned consultants to project the uptake of embedded solar PV and behind the meter batteries, referred to together as

DER. Similar work has also been performed on projecting adoption of alternative vehicle technologies.

As outlined in this Section, the uptake of rooftop solar PV, behind the meter batteries, and alternative vehicles, is also determined within AusTIMES. Recognising that the uptake of these technologies have economic and non-economic drivers, and to ensure consistency, the uptake of these technologies by scenario was used as an input into AusTIMES for the multi-sector energy modelling.

Uptake trajectories from Graham (2022) and Graham and Mediwaththe (2022) are inputs into the 2022 Multi-sector modelling.

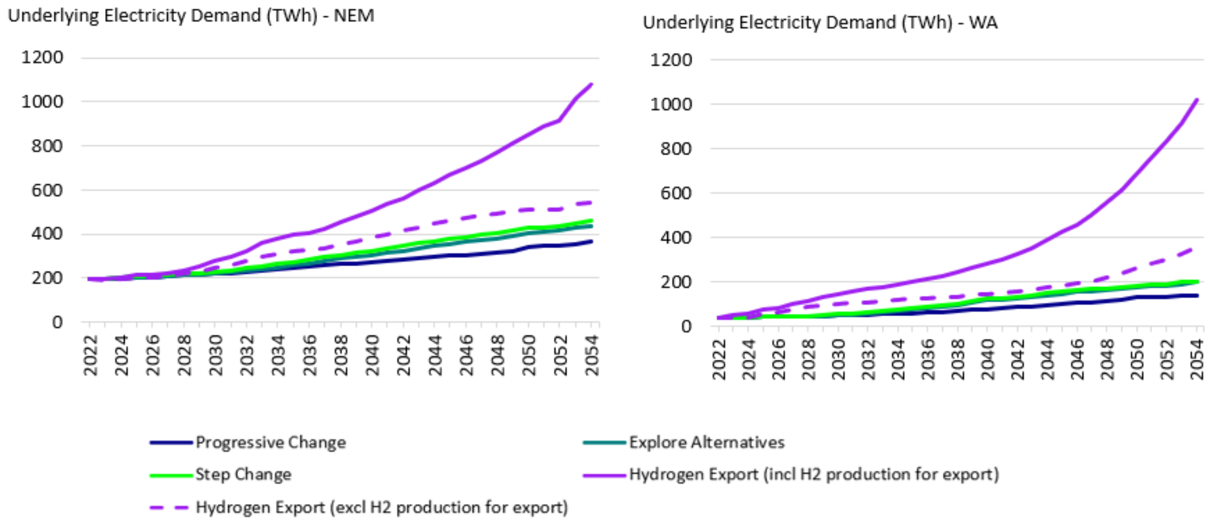
4 Projection results

4.1 Underlying electricity demand

Consistent with the 2021 Multi-Sector Modelling, underlying electricity demand in all modelled scenarios, shown in Note: electricity demand includes off-grid demand

Figure 4-1, increases in the long term. Underlying electricity demand here refers to end-use demand for electricity in all sectors, which could be met by either grid or off-grid electricity. Underlying electricity demand for Western Australia, as well as underlying demand for other fuels, refers to demand aggregated across the entire state of Western Australia and is not limited to only demand serviced by the South-West Interconnected System.

The slowest long-term demand increase is projected in the Progressive Change scenario (reaching 363 TWh in the NEM by 2054; 139 TWh in Western Australia), as expected due to its slow economic growth conditions and limited availability of electrification. This is mostly consistent with the Net Zero 2050 scenario in the 2021 multi-sector modelling, except that there is no longer a sharp increase in electricity demand in the late 2040s, due to other solutions such as bioenergy playing a larger role than electrification in the final push towards net zero emissions. Step Change and Exploring Alternatives sit somewhat higher, driven by a combination of added electricity for electrification and hydrogen production (438-460 TWh in the NEM by 2054; 198-204 TWh in Western Australia). This is an increase on the 2021 Step Change scenario due largely to greater electrification uptake, but is close to the scale in the 2021 Strong Electrification scenario, which otherwise does not have a modelled equivalent in 2022. Hydrogen Export sees by far the largest increase in demand It sees 1,080 TWh underlying demand in the NEM by 2054 (similar in scale to the 2021 Hydrogen Superpower scenario, and a 4.5-fold increase on current levels) plus a similar 1,019 TWh in Western Australia alone (a 25-fold increase). The overwhelming majority of final electricity demand in Hydrogen Export is for the production of hydrogen via electrolysis. When electricity demand for export-oriented hydrogen production is excluded, underlying electricity demand is much closer, (although still higher) in the long-term than Step Change and Exploring Alternatives. This reaffirms the significance of hydrogen production, and in particular, hydrogen production for exports, as a key determinant for future electricity demand in Australia, both in the NEM-connected states and Western Australia.



Note: electricity demand includes off-grid demand

Figure 4-1 Projected electricity demand from the end-use sectors for the NEM (left) and Western Australia (right). Hydrogen Export demand is shown both including and excluding electricity for export-oriented hydrogen production. Electricity for domestic hydrogen production is included in all charts.

4.2 Emissions

In 2022, the Australian Government announced an updated target of 43% reduction in emissions by 2030 compared to 2005 levels (Albanese 2022). This target is more stringent than the 26-28% target that was in place when undertaking the 2021 multi-sector modelling, and has been incorporated into all scenarios in this study (see section 2.2.1). This drives one of the most significant differences in emission outcomes when compared to the 2021 multi-sector modelling; reducing the divergence between Step Change and the least ambitious scenario (Progressive Change in this modelling; Net Zero 2050 in 2021). Step Change and Exploring Alternatives follow a similar near-linear trend to 2050 as the 2021 Step Change scenario. However, the trajectory for Hydrogen Export has steepened relative to the 2021 Hydrogen Superpower scenario, reflecting a combination of the updated carbon budget science (section 3.6), starting from a higher 2022 baseline, and having access to greater short-term decarbonisation opportunities in industry.

All scenarios achieve, or in cases where the cumulative emissions constraint is the limiting factor, over-achieve the revised target, with emissions falling below government projections (DCCEEW 2022b). This is driven by emission reductions in all sectors, though most impactful are those in industry and the power sector. In both sectors, strong reductions are achieved in the 2030s that are particularly pronounced in Hydrogen Export, and relatively diminished in Progressive Change. The power sector in particular is expected to steadily decarbonise towards near-zero emissions under all scenarios, driven both by competitive costs in renewables, and the fact that it is a key enabler for emission reductions in the other sectors via electrification.

The final emissions trajectories in Figure 4-2 are the product of residual economy-wide emissions from the modelled sectors, and negative emissions from land-based or technical sequestration (see section 4.3).

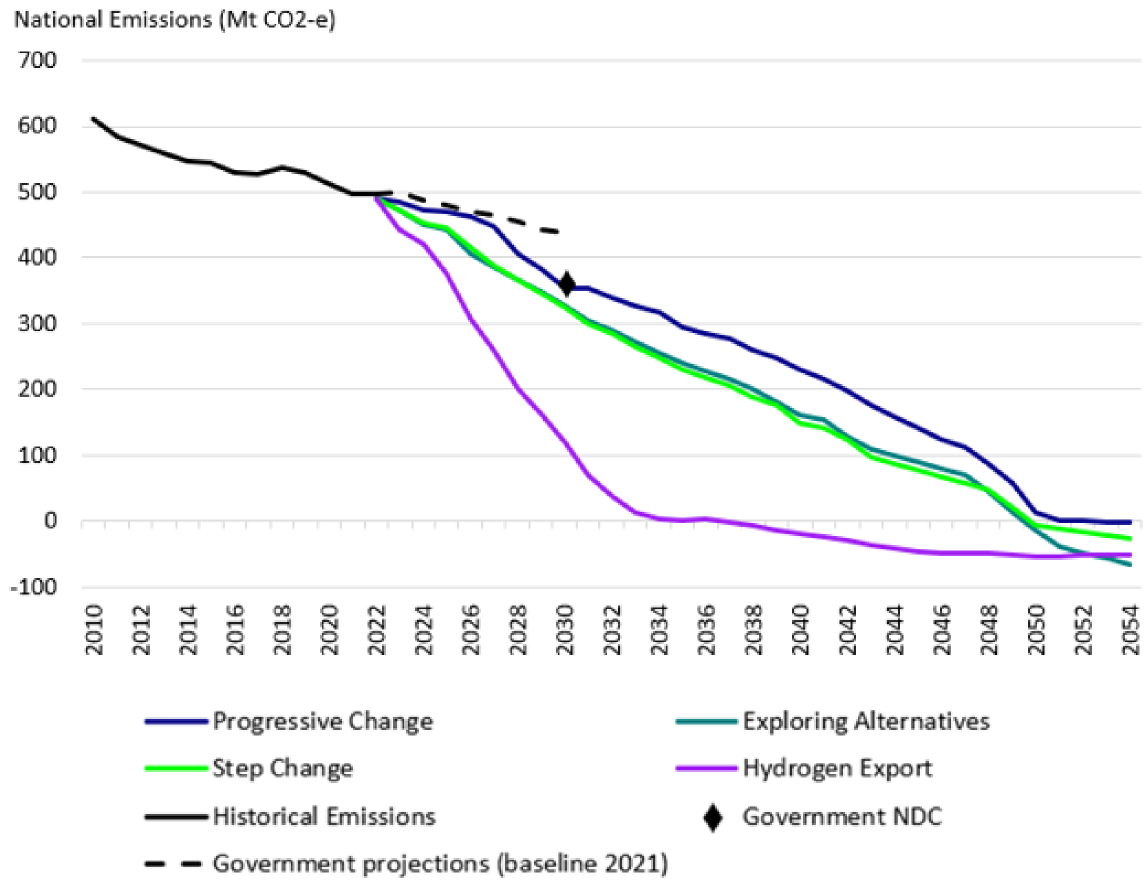


Figure 4-2 National net emissions in the four scenarios, compared to historical emissions (DCCEW 2022a), emissions projections (DCCEEW 2022b) and Australia's 2030 target submitted under the Paris Agreement, which was updated in 2022 (43% reduction on 2005 levels by 2030; DISER 2022b).

The emissions outcome in Hydrogen Export stands out as distinctly different to the others due to the large difference between a 1.5-degree carbon budget compared to a 1.8-degree budget (as in Exploring Alternatives and Step Change). Net zero emissions is achieved earlier; technically being achieved in 2036-37, although emissions reach near-zero by around 2032. This compares to net zero emissions in 2050 in the other scenarios, but is consistent with other modelling studies on 1.5-degree aligned decarbonisation pathways for Australia, such as *Decarbonisation Futures* (Butler et al. 2020) that see net zero emissions reached by around 2035. In most sectors, emission reductions are markedly deeper in Hydrogen Export compared with the other scenarios.

As discussed in section 2.2.1, the outcome of net zero emissions by 2050 in Progressive Change, Exploring Alternatives and Step Change is constrained based on the current federal government's 2050 commitments. The net zero by 2050 commitment is also broadly aligned with what is expected for a 1.8-degrees (or similar) carbon budget for Australia. Given the agreement under the UNFCCC for countries to take 'common but differentiated' actions, countries like Australia are expected to reach net zero emissions earlier than the global date for net zero emissions under well below 2°C or 1.5°C scenarios. For example, the IEA's Sustainable Development Scenario (between 1.5-2 degrees) sees global net zero emissions reached by 2070 (compared to 2050 for Australia in the modelled Step Change scenario), and their 1.5-degree roadmap sees global net zero emissions reached by 2050 (compared to 2036-37 for Australia in the modelled Hydrogen Export scenario) (IEA 2020; 2021).

4.3 Emissions sequestration

Achieving net zero emissions in all scenarios requires a dual effort from economy-wide emission reductions, and emissions sequestration (or negative emissions). This modelling approach considered sequestration from both land-based and technical methods, and excludes the use of international offsets (see section 2.2.6).

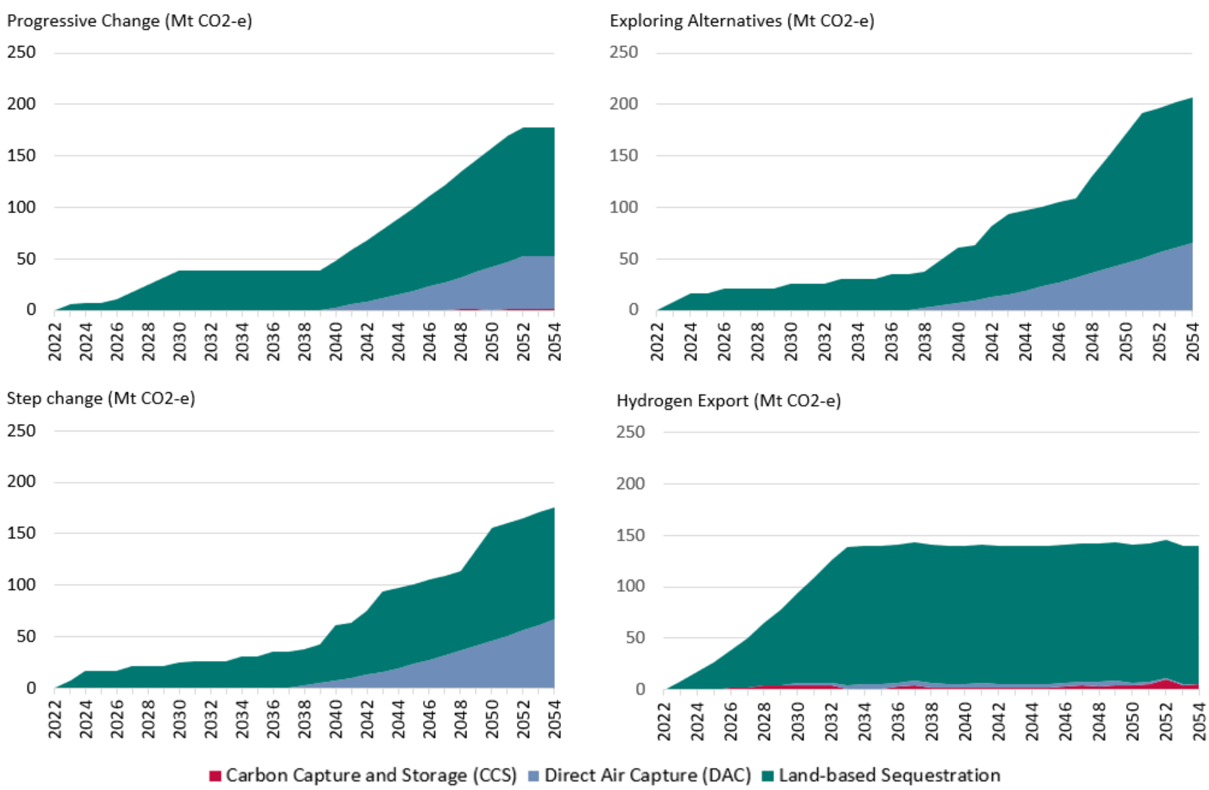


Figure 4-3 Total GHG emissions sequestered in each scenario, showing the relative components from land-based sequestration and technical sequestration (direct air capture, and carbon capture and storage).

Total annual sequestration in all scenarios, shown in Figure 4-3, reaches a similar order of magnitude by 2054 - between 139-207 Mt/year met via a combination of the above methods. In Progressive Change, Exploring Alternatives and Step Change this is met by a combination of 30-37% technical sequestration (mostly direct air capture) and 62-70% land-based sequestration by 2054. Based on assumptions used by DISER (2021) that inform the land sequestration cost curve used in this study, this level of land sequestration uptake could represent up to 5.2 million hectares of on-farm plantings in Step Change (1.2% of total agricultural land use in Australia), or

6.3 million hectares in Exploring Alternatives (1.5% of total agricultural land use in Australia)[6], alongside other methods. While the modelling approach in this study provides results on the portion of sequestration met via land-use and technical means, it should be noted that the actual balance of these solutions is highly dependent on technological development – with technical sequestration not yet proven at these scales. If this technical progress did not eventuate, more of this sequestration effort may come from land-based methods, including but not limited to the land-based methods considered in this study.

While CCS options are considered in all scenarios, they contribute only a very small portion towards the total sequestration effort across the scenarios. This reflects the fact that CCS is a high-cost option only available for specific use cases (e.g. in industry and hydrogen production – see section 2.2.6), and is unlikely to be a viable option across most sources of emissions. CCS levels are slightly higher overall in the Hydrogen Export scenario, which reflects the fact that higher cost options are taken up under a stronger decarbonisation objective.

The level of uptake of sequestration depends on the strength of emissions targets and other decarbonisation options available in those scenarios. For example, land sequestration increases towards 2030 in Progressive Change, reflecting the need to meet the national 2030 emissions target by that year, while balancing against tighter restrictions on other decarbonisation options compared to the other scenarios.

The land sequestration outcomes of Hydrogen Export are the most distinctive of the scenarios, reflecting the very different decarbonisation settings implied by the 1.5-degree carbon budget. Initial uptake reaches nearly 135 Mt CO2-e/year by the early 2030s. While more rapid than other scenarios, the average annual increase in sequestration over this period (less than 15 Mt CO2-e/yr) is below the maximum annual rate of change in LULUCF emissions observed in Australia in the past decade (DCCEEW 2022a). This scenario is able to achieve net zero emissions at a point of lower sequestration volume than the other scenarios through greater effort in emission reductions across the other sectors of the economy – including industry in particular. This reflects the balance of action required across all sectors of the economy to meet the near-term decarbonisation objective; this cannot be met by action in one sector, or land sequestration in isolation.

After Hydrogen Export reaches net zero emissions by 2036-37 in line with its 1.5°C carbon budget, there is reduced incentive in the model to continue decarbonising at the same pace. Given Direct Air Capture is not yet a mature technology, the model is unable to deploy this at scale until the late 2030s; therefore, even if DAC becomes more cost-effective in the long-run, it is still not cost effective to 'switch' from already-established land sequestration to DAC. The sequestration profile would look different in a scenario where the incentive to decarbonise continues - i.e. to draw emissions down further to achieve a more stringent temperature goal after overshoot.

The updated emissions sequestration approach described in Section 2.3.4 has resulted in different outcomes when compared to the 2021 multi-sector modelling, where land sequestration was largely an exogenous input and DAC was not considered. The final annual sequestration by 2050

[6] Based on total agricultural land use area of 427 million hectares (DAFF 2022).

reaches similar or slightly higher levels in 2050 in Progressive Change, Step Change and Exploring Alternatives when compared to the 2021 Net Zero 2050 and Step Change scenarios, although the uptake profile differs based on the cost optimisation that is being undertaken within Aus-TIMES. The maximum annual sequestration in Hydrogen Export is slightly lower than the Hydrogen Superpower scenario in 2021, but is achieved sooner. One distinct difference is that sequestration no longer falls after achieving net zero emissions, as it did in the 2021 1.5°C scenarios. This is due to a more realistic representation of land sequestration within AusTIMES, where it is viewed as a long term investment.

4.4 Electricity generation

Historically, coal-fired generation has dominated the electricity generation mix in the NEM. Despite the historical dominance of non-renewable centralised electricity generation, there has recently been significant growth in the deployment of distributed rooftop solar photovoltaic (PV) systems, especially on residential buildings, followed by large-scale renewable generation (primarily wind and solar). Due to falling technology costs, renewable targets and decarbonisation goals, renewables deployment is expected to accelerate coinciding with an ageing coal-fired generation fleet.

Under all four scenarios, the projected generation mix shows significant change for the NEM from its current level of around 60% of coal-fired generation (Figure 4-4). Falling costs of renewable generation and storage technologies, an ageing coal generation fleet, and the cost competitiveness of electrification in a future with strong emissions reduction targets are the key drivers to an increasing share of variable renewable energy (VRE), mainly in the form of utility-scale solar PV and wind farms over the projection period.

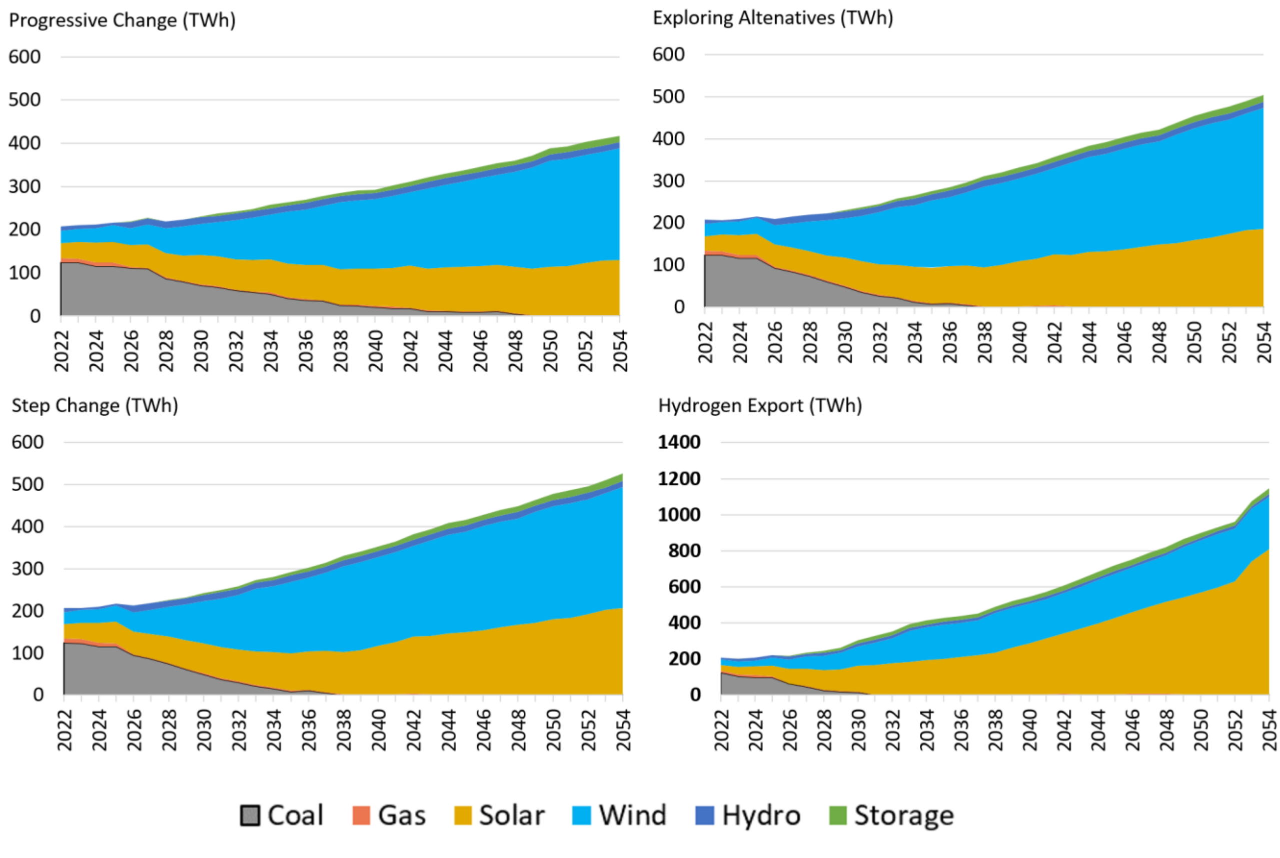


Figure 4-4 Electricity generation mix for the NEM regions

In Progressive Change, moderate growth in demand in conjunction with state renewable energy targets (QRET, TRET, VRET and *NSW Electricity Infrastructure Roadmap*) transitions the NEM away from coal-fired generation to an increasing share of VRE, mainly in the form of onshore wind farms and utility-scale solar PV. As the share of VRE increases over time, there is an increasing need for dispatchable storage (pumped hydro and batteries) to maintain system balance. Brown coal transitions out in the late 2030s with black coal retired by the late 2040s in this scenario.

This transition is accelerated across the other three scenarios with a more rapid reduction in coal-fired generation. The proportion of coal-fired generation declines over time, with it phased out the earliest in the Hydrogen Export scenario (2031). In Exploring Alternatives and Step Change, brown coal exits by 2033 and black coal exits by 2038.

Although there is some uptake of new peaking gas-fired generation in the scenarios, there is no uptake of coal- or gas-fired generation coupled with CCS, or of nuclear. Based on the cost assumptions used in the modelling (see Section 2.2.2), the bulk of capacity additions are renewable technologies – mainly onshore wind generation, utility-scale and rooftop solar PV – coupled with storage technologies, especially dispatchable storage including utility-scale and behind-the-meter batteries and pumped storage hydro.

This supply transformation results in the decline of electricity sector emissions in the NEM (Figure 4-5) from current levels of around 140 Mt to minimal emissions in all scenarios. Small amounts of gas-fired generation remain, an important complement to storage technologies to firm renewable energy resources, resulting in some emissions even late in the horizon to near-zero emissions by the 2040s in all scenarios, except Progressive Change.

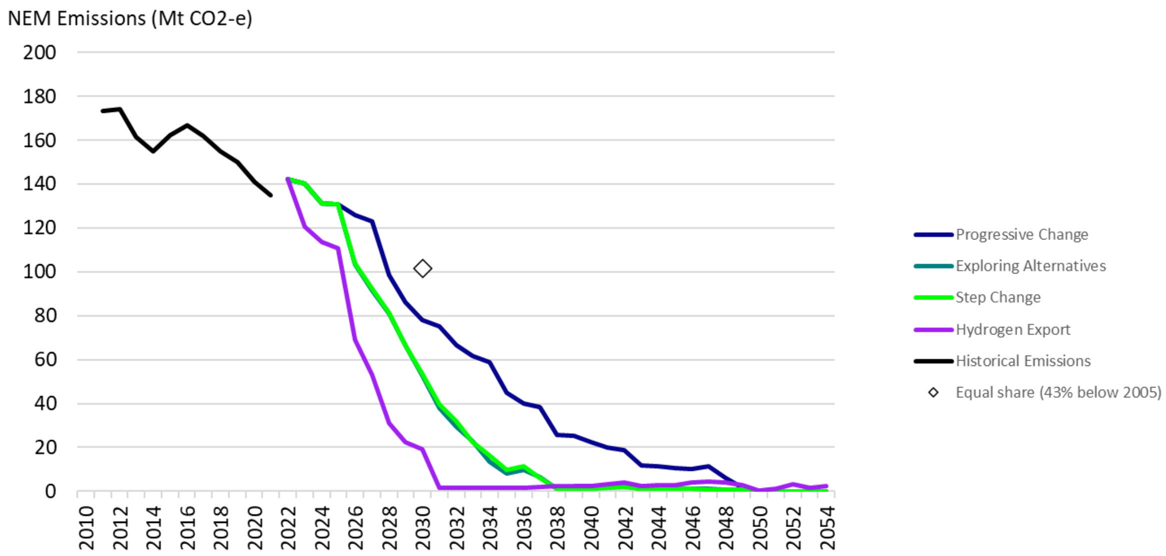


Figure 4-5 Electricity sector emissions in the NEM

The marker on Figure 4-5 shows the equal share of the 43% emissions reduction target in 2030 (2005 NEM emissions were around 178 Mt). The electricity sector is a relatively low-cost abatement sector of the economy and also assists other sectors to decarbonise. This is a typical finding in an economy-wide emissions reduction target that the power sector does more than its fair share of economy-wide abatement. Compared to the 2021 multi-sector modelling, emissions are lower in the near-term because of the more stringent NDC around the 2030 period: Net Zero 2050 scenario was around 86 Mt, compared to 78 Mt in 2030 for Progressive Change.

For the SWIS in Western Australia, there is also a transition away from coal-fired generation with non-state owned coal-fired generation persisting beyond 2030 in the Progressive Change scenario (Figure 4-6). In all scenarios it is assumed that all state-owned coal-fired generators are retired by 2030 in line with the WA Government announcement in August 2022. The modelled results are also consistent with the WA Government commitment that no new gas-fired generators are commissioned after 2030.

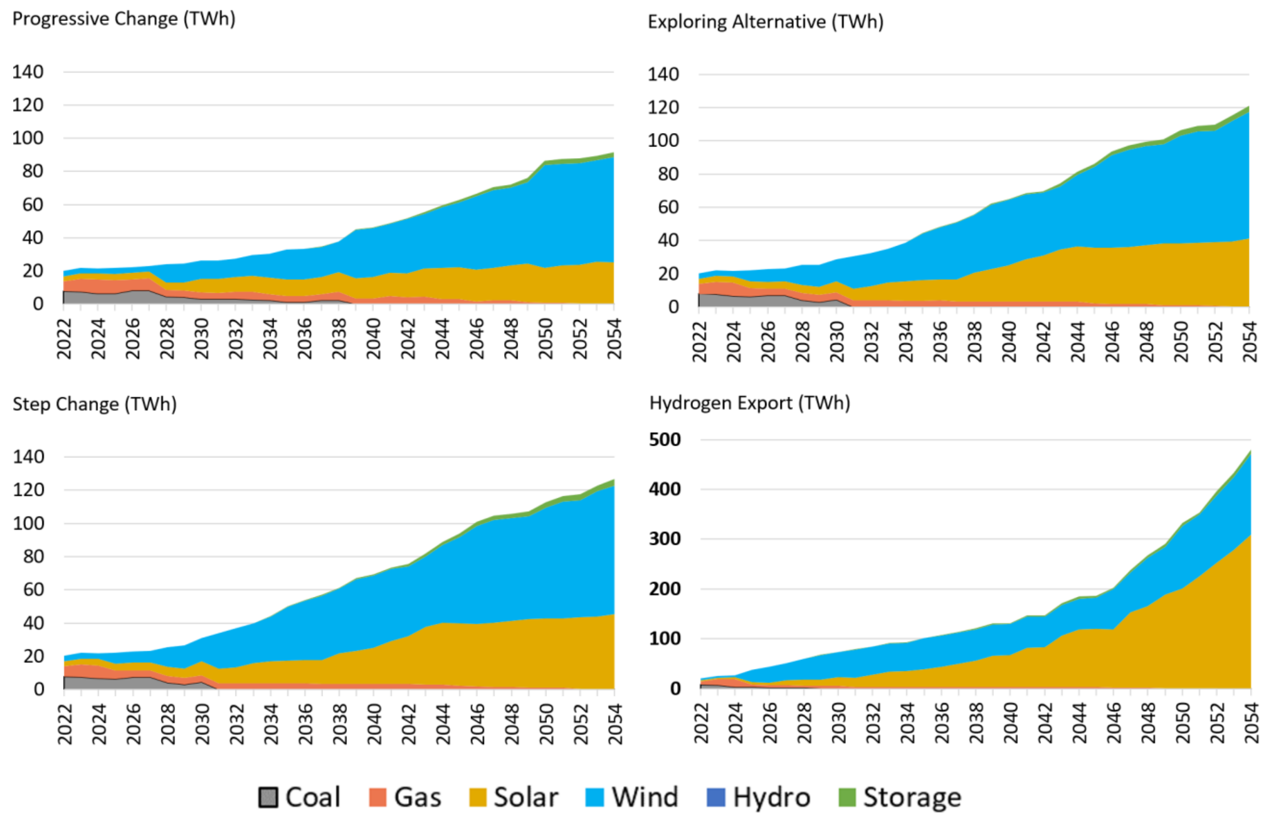


Figure 4-6 Electricity generation mix for the SWIS

Compared to the NEM, gas-fired generation persists in all scenarios, however the transition to a high-VRE system is similar across all scenarios to that observed for the NEM. Overall, the scale of the transformation in the SWIS is more pronounced due to relatively high electrification (see section 4.6.1) and significant production of hydrogen, especially in the Hydrogen Export scenario.

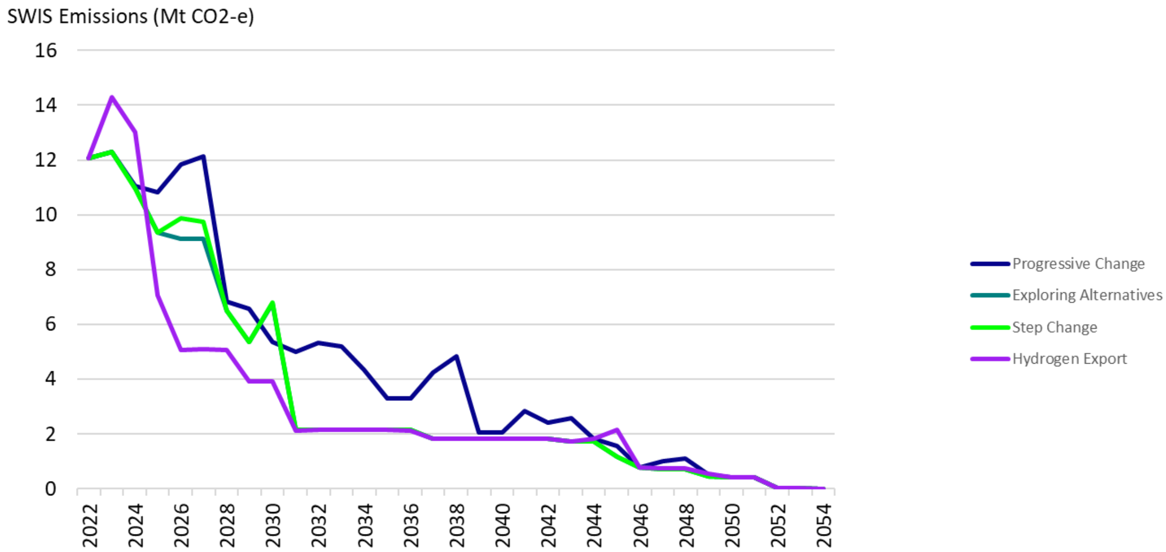


Figure 4-7 Electricity sector emissions in the SWIS

Electricity sector emissions in the SWIS (Figure 4-7) decline from current levels of around 12 Mt to low emissions in all scenarios. The amount of gas-fired generation that remains means emissions decline to around 2 Mt after the exit of coal in all scenarios except for Progressive Change, and reach less than 0.5 Mt by 2050.Volatility in emissions occurs around the timing of coal-fired plant retirements from increased gas-fired generation or generation from remaining coal units and coincide with increased hydrogen production.

4.5 Gaseous fuel demand and production

While there is a large focus on electricity sector implications in this report, the whole-of-economy AusTIMES modelling approach used for these scenarios models dependencies between demand for all fuels. This includes the outlook for gaseous fuels including natural gas, hydrogen and biomethane across the end-use sectors. Total demand for these gaseous fuels across the end-use sectors (residential, commercial and industry; but excluding transport and electricity) is shown in Figure 4-8 for the NEM-connected states, and Figure 4-9 for Western Australia.

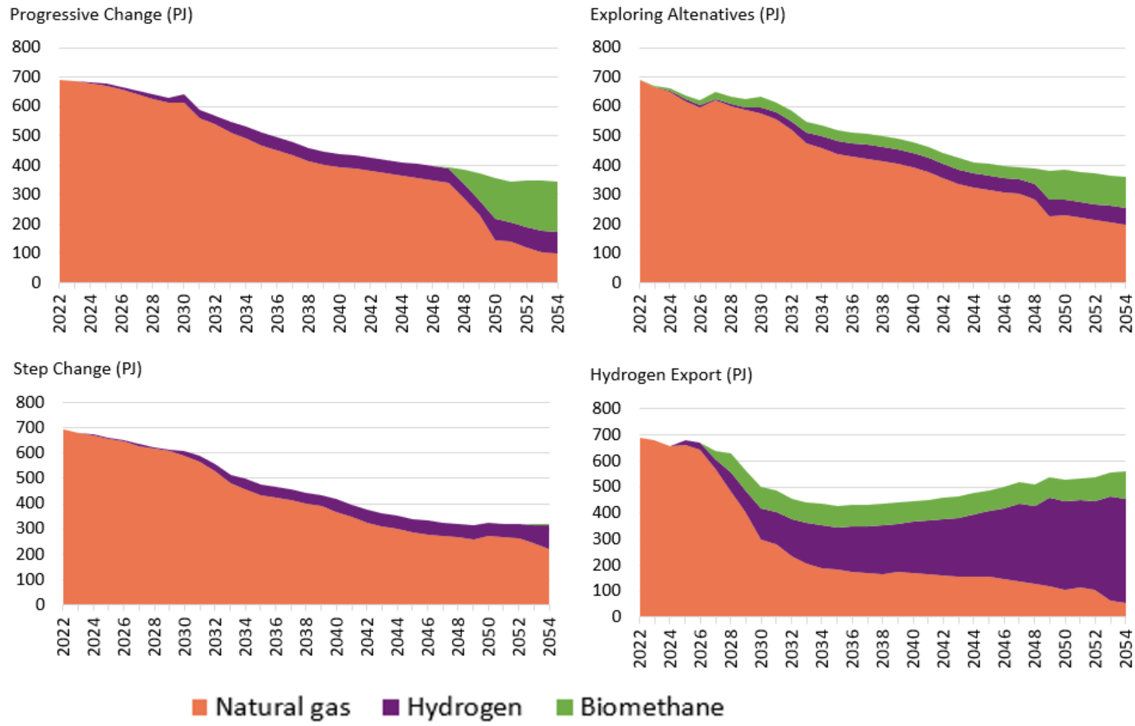


Figure 4-8 Detailed gaseous fuel demand (natural gas, hydrogen and biomethane) in buildings and industry in the four scenarios, for NEM states. Hydrogen Export data excludes hydrogen produced for export.

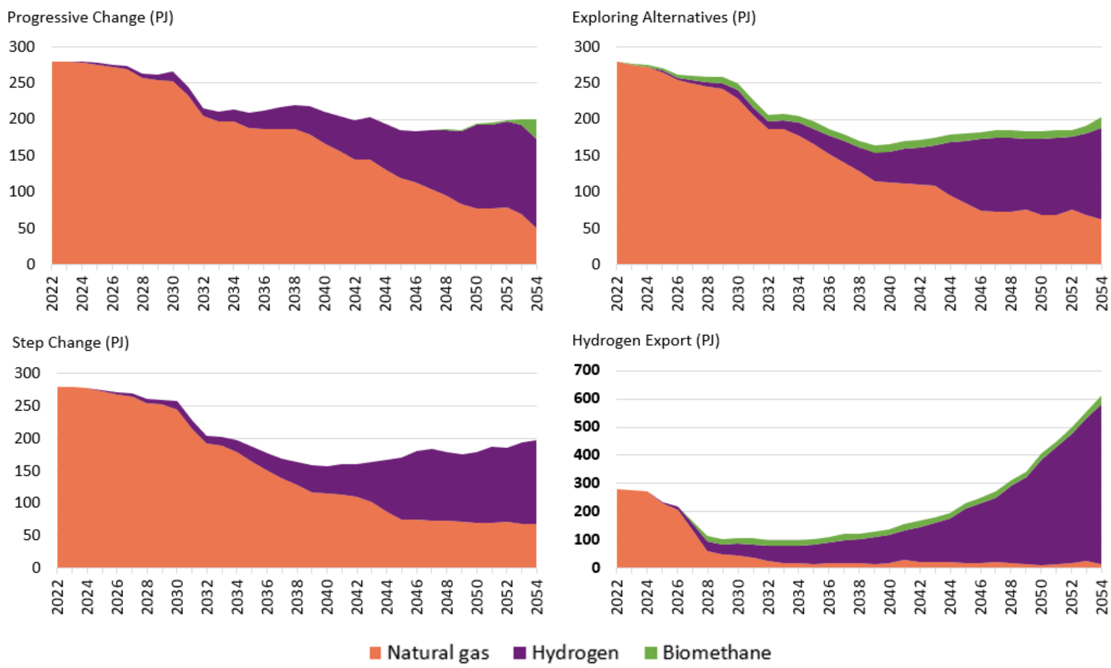


Figure 4-9 Detailed gaseous fuel demand (natural gas, hydrogen and biomethane) in buildings and industry in the four scenarios, for Western Australia. Hydrogen Export data excludes hydrogen produced for export. However it

does include hydrogen used in DRI steelmaking, which drives the large increase in that scenario (note the different scale).

4.5.1 Natural gas demand

The present gaseous fuel mix in the end-use sectors is almost exclusively dominated by natural gas, which declines across every sector and scenario to varying degrees due to a combination of electrification, energy efficiency, or switching to alternative fuels.

Sections 4.6.2 to 4.6.4 outline specific fuel outcomes for the end-use sectors, showing that the decline in natural gas is particularly prominent in buildings due to the lower barriers to electrification in that sector and cost savings across the lifetime of equipment. Natural gas use in the residential and commercial sectors approaches zero by 2050, steadily decreasing for most of the modelling period for the Exploring Alternatives, Step Change and Hydrogen Export scenarios, with some accelerated declines post-2045 in the Progressive Change scenario. The predominant driver of the transition away from natural gas in all sectors is electrification. This is consistent with similar decarbonisation scenario modelling studies, including the 2021 multi-sector modelling that sees residential gas fully electrify by 2050 in several scenarios (Net Zero 2050, Step Change and Strong Electrification), and Climateworks Centre's *Decarbonisation Futures* (Butler et al., 2020) which sees a similar long-term outcome in all scenarios. Compared to the 2021 multi-sector modelling, there is a stronger decline in natural gas demand in industry due to electrification in most scenarios – particularly when comparing the 2021 Net Zero 2050 scenario to Progressive Change. This reflects the greater representation of industrial decarbonisation opportunities in this modelling. However, the large displacement of gas in the 2040s in the 2021 Net Zero 2050 scenario is no longer occurring.

Another factor impacting long-term natural gas demand in industry is the deployment of alternative fuels (hydrogen and biomethane). For instance, industrial natural gas demand sees some accelerated declines post-2045 in the Progressive Change and Exploring Alternatives scenarios as biomethane use ramps up. The Hydrogen Export and Progressive Change scenarios have the largest declines in industry natural gas use by 2050 due to significant uptake of biomethane and hydrogen towards the end of the projection period. However, despite this industry is responsible for the majority of residual gas demand in 2050, with natural gas making up 9% and 12% of industry energy demand in NEM-connected states in 2050 in Hydrogen Export and Progressive Change respectively (107 PJ and 129 PJ by 2050). Alternative fuel outcomes are discussed in detail in the following sections.

4.5.2 Demand for hydrogen

Final hydrogen demand is determined by a combination of endogenous domestic demand in the end-use sectors, and exogenous hydrogen export assumptions (see section 2.2.4). While Figure 4-8 and Figure 4-9 show domestic demand for hydrogen in the scenarios, total demand for hydrogen, for both domestic purposes and exports, is shown in **Error! Reference source not found.**. This demonstrates the significant impact of the hydrogen export industry on total demand in the Hydrogen Export scenario.

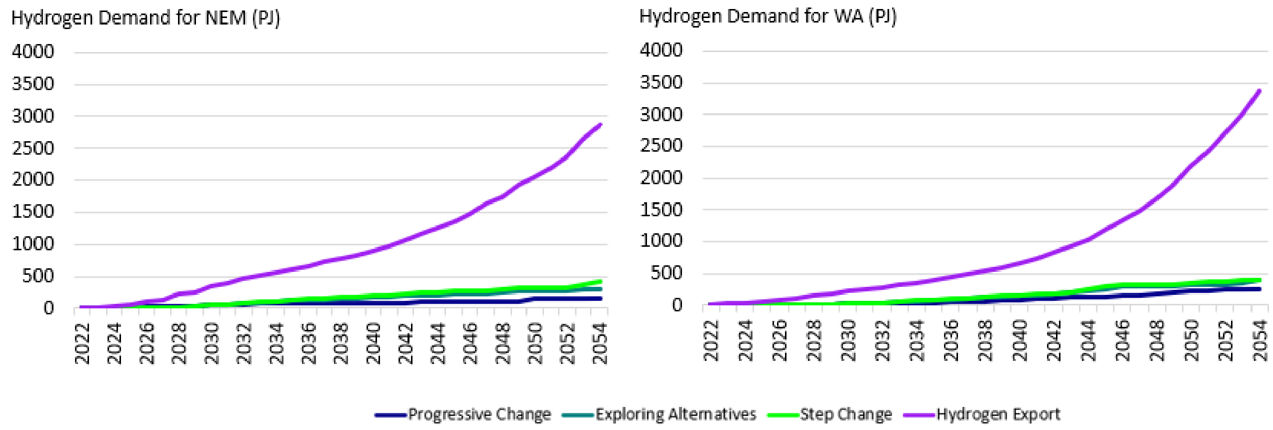


Figure 4-10 Total demand for hydrogen in the four scenarios, including for domestic purposes and exported. Results for NEM-connected states and Western Australia are shown on the same scale.

In the Progressive Change, Exploring Alternatives and Step Change scenarios, small amounts of hydrogen are blended into the gas network from 2024 onwards to meet residential, commercial and industry energy demand in the NEM-connected states. In 2050, hydrogen makes up 4%, 3% and 3% of final energy demand across the residential, commercial and industry sectors in NEM-connected states (or 72 PJ, 54 PJ and 54 PJ) respectively.

In the Hydrogen Export scenario, hydrogen is used to meet a higher portion of residential and commercial final energy demand, steadily increasing from 2025 onwards, meeting 16% of residential energy demand and 6% of commercial energy demand by 2050 in the NEM-connected states. In the Industry sector, hydrogen use steadily increases from 2024 to meet 21% of industry final energy demand in the NEM-connected states in 2050. Across residential, commercial and industry sectors, hydrogen makes up 18% of final energy demand (338 PJ) in 2050 in this scenario. This result is largely driven by the assumption that gas networks can receive 100% hydrogen by 2050 in this scenario (section 2.2.6), overcoming technical barriers to do so. Unlike other options such as electrification, where equipment capital costs and flow-on impacts to the electricity generation sector are considered, AusTIMES is not capable of reflecting all costs associated with exceeding current technical limits on hydrogen blending in gas networks. Therefore, this is an imposed assumption. It does not necessarily reflect a least-cost outcome if all costs associated with the switch to 100% hydrogen networks and appliances are considered.

The limited role of hydrogen in scenarios with low blending limits (Progressive Change, Exploring Alternatives and Step Change at 10% of blended gas supply by volume) compared to Hydrogen Export (with a 100% blending limit by 2050) demonstrates that until present barriers to hydrogen blending limits can be removed, it can play only a limited role in displacing natural gas demand in the network. A notable exception is in industry, where there is potential for direct-supply of hydrogen to replace large uses of natural gas via various delivery mechanisms.

Compared to the 2021 multi-sector modelling, blending assumptions for hydrogen are more restricted, now being considered on a volumetric rather than energy basis. This restricts the role of hydrogen in buildings in most scenarios. However, greater industrial opportunities for hydrogen use are available – which can be seen in some scenarios.

Industrial demand, including from direct supply (i.e. any source other than the reticulated network, which could be dedicated to particular industry sites), is the key driver behind hydrogen playing a consistently larger role in Western Australia compared to the NEM-connected states. In all scenarios, hydrogen makes up greater than 50% of gaseous fuel demand in Western Australia by 2050, reaching up to 92% of gaseous fuel demand in the Hydrogen Export scenario. This reflects the significant potential for relevant Western Australian industries to utilise hydrogen via direct supply, due to its favourable economics in that state.

4.5.3 Demand for biomethane

Biomethane fulfils a somewhat different role in decarbonising natural gas compared to hydrogen, given that it is chemically equivalent to natural gas and able to be blended at no maximum limit. Therefore, while hydrogen is ultimately limited by physical constraints on blending, biomethane uptake is limited only by cost and supply-side constraints (section 2.2.5). The scenario outcomes show that biomethane cost reductions and set targets (as implemented in the Exploring Alternatives scenario) can play a small role in increasing its presence in the energy mix. The lower physical barriers to blending also allow it to play a role where there is a need to rapidly displace a large portion of residual natural gas use.

A prominent example of this is in the Progressive Change scenario where biomethane plays a role in the longer-term, ramping up from 2047 in the residential sector and 2048 in the commercial sector to meet 8% and 5% of final residential and commercial energy demand in the NEM-connected states respectively, to assist with the push to net zero emissions by 2050. Industrial biomethane use similarly ramps up from 2048 onwards, meeting 9% of final energy demand in NEM-connected states by 2050. The ramp-up of decarbonisation solutions to reach net zero by 2050 in this scenario is comparable to the Net Zero 2050 scenario from the 2021 Multi-Sector Modelling; however updates to the approach to electrification (Section 2.3.7) and introduction see biomethane fulfilling some of the role that electrification was previously playing to reach this target.

In the Exploring Alternatives scenario where biomethane blending targets are in effect, biomethane use steadily grows from 2023 onwards, reaching 6% and 1.5% of residential and commercial energy demand in 2050 respectively in the NEM-connected states. In the industry sector, biomethane steadily increases from 2023 onwards, meeting 7% of final industry energy demand in 2050. However, despite the greater incentives to biomethane uptake in this scenario, the economics of biomethane see it remain as a much smaller driver of the decline in natural gas demand when compared with electrification.

In the Hydrogen Export scenario, biomethane is used to meet residential and commercial final energy demand, steadily increasing from 2027 in the residential sector and 2029 in the commercial sector. By 2050, biomethane use meets 5% of residential energy demand and 0.3% of commercial energy demand in the NEM. In the Industry sector, biomethane use steadily increases from 2027, to meet 5% of industry final energy demand in 2050.

In the Step Change scenario, biomethane is not taken up as a cost-effective option in meeting residential, commercial or industrial final energy demand between 2022 to 2050. This is largely due to the lower restrictions on electrification, which is seen as more cost-effective in the model, and the lack of any enforced targets or cost reductions on biomethane production.

Outcomes for biomethane demand in Western Australia are distinct from the NEM-connected states. While present in all scenarios except Step Change, and following some consistent patterns (such as the ramp-up towards 2050 in Progressive Change) the relative role is much more diminished compared to other fuels, comprising no more than 14% of final gaseous fuel demand by 2054 in Progressive Change, and less in the other scenarios. This reflects the more favourable economics of hydrogen as an alternative fuel in Western Australia, partly due to lower natural gas prices.

The design of the scenarios modelled in this study assume that a biomethane industry can be established in the given timeframes; in reality, an established biomethane industry does not yet exist. Further study is needed to understand other long-term constraints on its role in the gas network, including how quickly supply chains can transition from natural gas to biomethane, and what the implications may be for fugitive emissions. Even in the modelled scenarios that assume establishment of a significant biomethane industry, the most cost-effective pathways for buildings and industry remain electrification and energy efficiency.

4.6 End-use sectors

4.6.1 Electrification and energy efficiency

Final electricity demand in the end-use sectors is influenced by a range of determinants, including energy efficiency and electrification uptake. The final uptake of electrification, measured as additional electricity demand, is shown in Figure 4-11 for the NEM-connected states and Figure 4-12 for Western Australia. Energy efficiency can result in avoidance of energy demand from most fuel types, although the results presented here focus on avoided electricity demand as a result of energy efficiency. This is shown in Figure 4-13 for the NEM-connected states and Figure 4-14 for Western Australia.

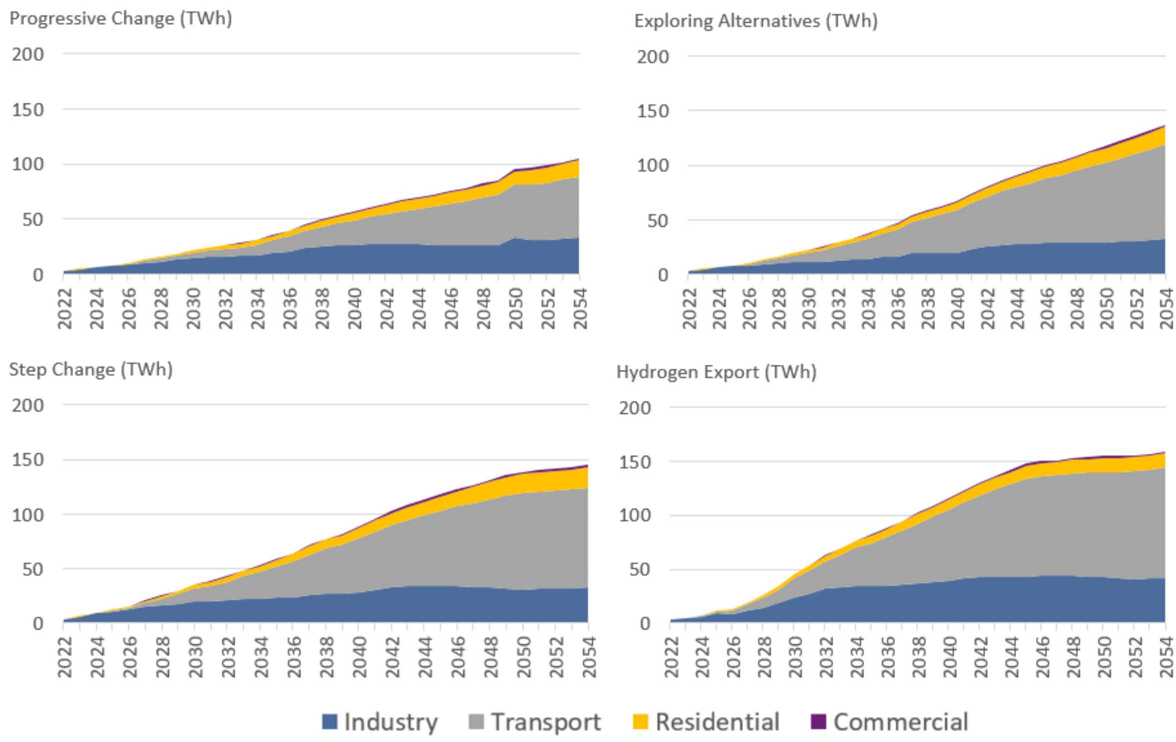


Figure 4-11 Additional electricity demand as a result of electrification in all end-use sectors (including transport) in NEM-connected states. Electrification in industry, residential and commercial buildings is a discrete category of technology investment in AusTIMES. Any additional demand for electricity post-2022 in the transport sector, which has a very low historical electricity demand, is counted as electrification.

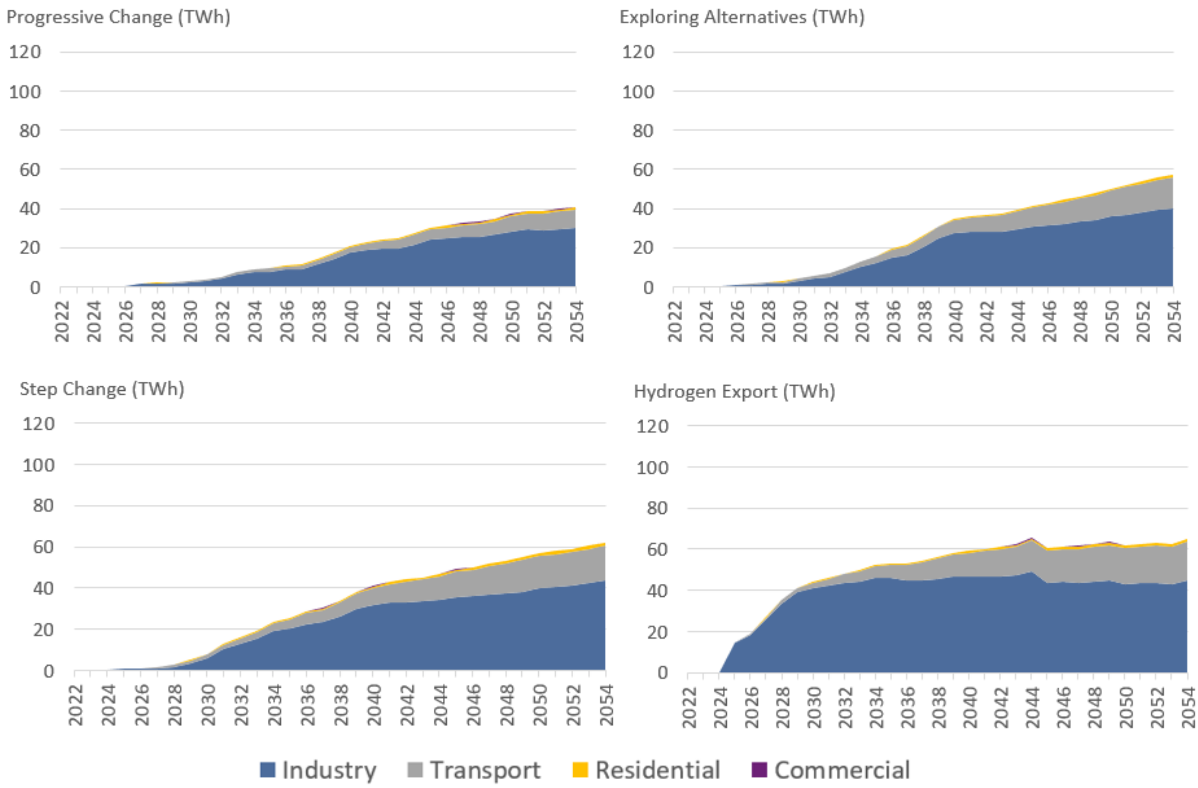


Figure 4-12 Additional electricity demand as a result of electrification in all end-use sectors (including transport) in Western Australia. Electrification in industry, residential and commercial buildings is a discrete category of technology investment in AusTIMES. Any additional demand for electricity post-2022 in the transport sector, which has a very low historical electricity demand, is counted as electrification. Some fluctuations may occur during years where the relative economics of electrification versus other decarbonisation options crossover.

Electrification is a key feature of all four scenarios, reflecting the consistent cost-effectiveness of electrification up to reasonable limits in each scenario under the cost structures represented in the model (including equipment switching costs and generation requirements, but similar to gas networks, not detailed infrastructure costs).

Uptake of electrification occurs earlier and faster in the Step Change and Hydrogen Export scenarios for all sectors, reaching a total of 139 TWh and 155 TWh in 2050 compared to the Progressive Change and Exploring Alternatives scenarios, which reach 96 TWh and 118 TWh in 2050 respectively. This reflects the higher short-term limits on electrification in those scenarios (section 2.2.7). Industrial electrification outcomes in Hydrogen Export are distinct from the other scenarios, with electrification occurring much earlier and faster, reaching 43 TWh in 2050, compared to a range of 30-34 TWh in 2050 across the other scenarios. This reflects the significant potential of industrial electrification that is able to be unlocked in a scenario with much more ambitious decarbonisation objectives. There is also significant divergence in electrification levels within the transport sector between scenarios, the lowest being in the Progressive Change scenario which reaches in 48 TWh in 2050 compared to the highest level reached in the Hydrogen Export scenario of 97 TWh in 2050.

In general, total electrification in the NEM by 2050 in the scenarios sits slightly lower than the 2021 multi-sector modelling. This is partially due to the exclusion of an equivalent to the 2021 Strong Electrification scenario, which exceeded 200 TWh electrification by 2050, but also due to Progressive Change no longer exhibiting the ramp-up of electrification in the 2040s that previously occurred in Net Zero 2050 (this effort is now largely being driven by biomethane). Step Change, however, sees similar levels of electrification reached in 2050 in both modelling exercises.

While there are similarities in the profile of electrification uptake in Western Australia compared to the NEM-connected states, the final scale and breakdown is influenced by differences in the current energy mix across sectors. For example, much lower residential natural gas demand in Western Australia compared to NEM-connected states (particularly Victoria) diminishes the opportunity for residential electrification. However, a very significant portion of Western Australia's decarbonisation opportunity lies in heavy industry, which is where the overwhelming majority of electrification occurs in the scenarios.

Similar to NEM-connected states, electrification occurs earlier and faster in the Hydrogen Export scenario, reaching 62 TWh across all sectors in 2050. This is particularly significant in the Industry sector, where rapid uptake from 2025 onwards, sees electrification levels reach over 40 TWh in 2030 and ranges between levels of 40-50 TWh until the end of the period. This is followed closely by the Step Change scenario, which reaches 57 TWh across all sectors in 2050, with electrification levels in industry steadily increasing from 2025 onwards to reach 40 TWh in 2050. In contrast, the Progressive Change scenario reaches the lowest level of total electrification in 2050 (37 TWh) driven by much smaller electrification uptake rates in both the industry and transport sectors compared to the other scenarios.

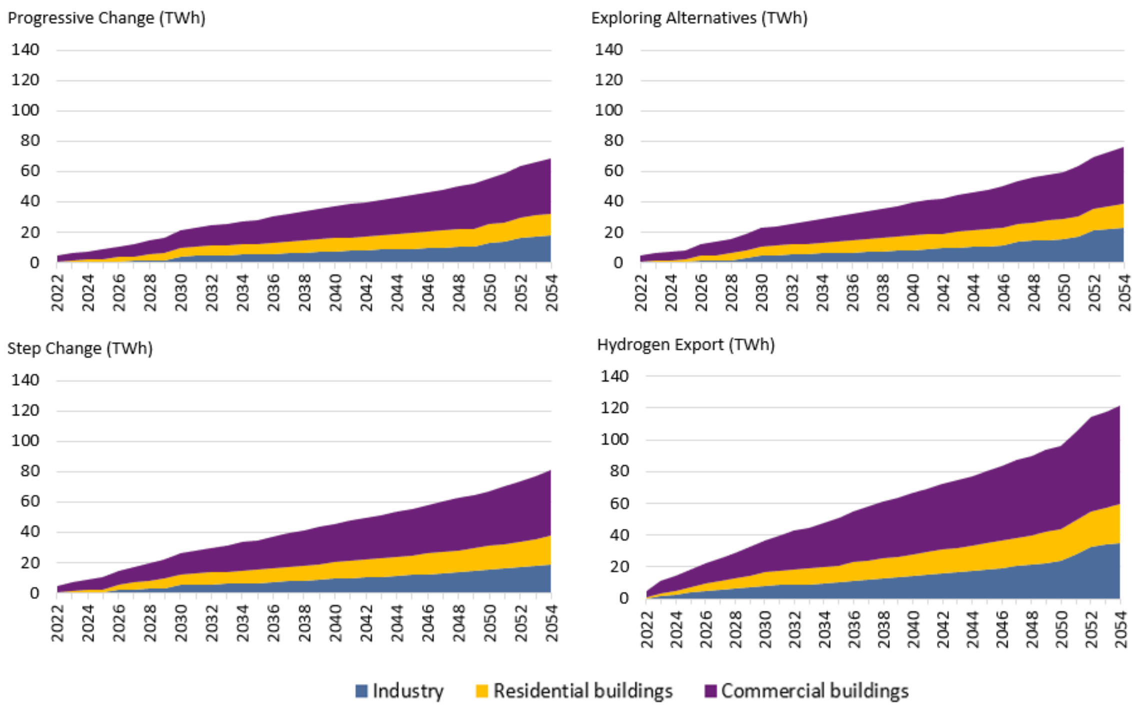


Figure 4-13 Avoided electricity demand as a result of energy efficiency in all end-use sectors, in NEM-connected states. Note energy efficiency is not an investment option available in transport in AusTIMES.

Figure 4-14 Avoided electricity demand as a result of energy efficiency in all end-use sectors, in Western Australia. Note energy efficiency is not an investment option available in transport in AusTIMES. Note the different scale for Hydrogen Export.

As discussed in Section 2.3.7, the approach to varying energy efficiency assumptions across the scenarios has been updated in this Multi-Sector Modelling work, compared to the 2021 modelling. The relative difference in maximum energy efficiency uptake rates are now broadly aligned to settings mapped to outcomes from different IEA scenarios. This has led to some differences in the final uptake of energy efficiency, and overall profile of energy efficiency uptake in this year's scenarios when compared to 2021.

Energy efficiency uptake in electricity, across all sectors, is the highest in the Hydrogen Export scenario (122 TWh avoided electricity in the NEM by 2054; 21 TWh avoided in Western Australia), due to having the least restricted uptake settings in line with its strong decarbonisation objective. Hydrogen Export also features a role for 'exogenous' energy efficiency options in buildings, based on the technical progress assumed to underpin its strong decarbonisation objective. This leads to a larger uptake of energy efficiency in the commercial sector in particular.

Step Change sees the second-highest uptake of energy efficiency, reflecting its scenario settings and narrative that features an increased role for energy efficiency compared to other scenarios with similar decarbonisation settings.

The Progressive Change and Exploring Alternatives scenarios show the lowest uptake of energy efficiency improvements (69-76 TWh avoided in the NEM in 2054; 10-11 TWh in Western Australia), sitting just behind Step Change and reflecting the more restricted role for energy efficiency in their narratives.

To focus on impacts on the electricity system across the scenarios, energy efficiency outcomes here are reported for avoided electricity, and exclude the autonomous energy efficiency category that was included in the aggregated forecasts in the 2021 multi-sector modelling report. The relative role of energy efficiency in scenarios where there is a comparable equivalent from the 2021 multi-sector modelling has not shifted, however the forecasts here differ in profile, and achieve higher levels of energy efficiency in electricity by 2050. This reflects the updated approach to energy efficiency (Section 2.3.7). In 2021, an approach based on hurdle rates was taken, which can have the effect of favouring less energy efficiency over the long term. Avoided electricity in the 2021 scenarios ranged from 40-100 TWh in the NEM by 2050. In comparison, the limits-based approach this year sees more of a linear energy efficiency uptake trajectory in most sectors, reaching 70-120 TWh avoided electricity by 2050.

As with electrification, the primary driver behind different energy efficiency outcomes in Western Australia compared to the NEM-connected states is the current sectoral energy breakdown. Once again, the relative scale of industrial energy efficiency is higher. However, energy efficiency in the other sectors, and energy efficiency in total is much lower than the NEM-connected states combined due to lower baseline energy demand. Industrial growth, particularly in green steel, also impacts the energy efficiency forecast for Western Australia for Hydrogen Export, where there is greater baseline electricity use to enact efficiency measures upon.

4.6.2 Residential buildings

The mix of fuels in the total energy consumption for residential buildings is shown in Figure 4-15 for NEM-connected states and Figure 4-16 for Western Australia. The total energy consumption represents the net energy consumed after considering energy efficiency, electrification, hydrogen and biomethane uptake. The underlying baseline demand before these effects is driven by the population projections shown in Figure 2-3 and discussed in Section 2.2.6.

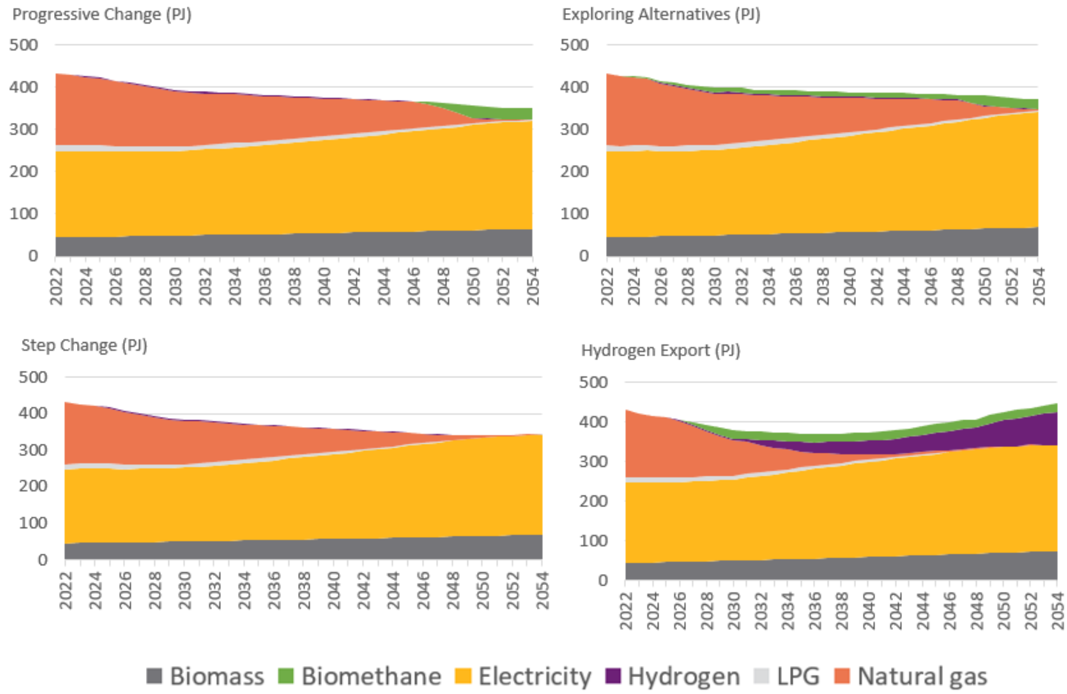


Figure 4-15 Fuel share in residential buildings across the four scenarios, for NEM-connected states.

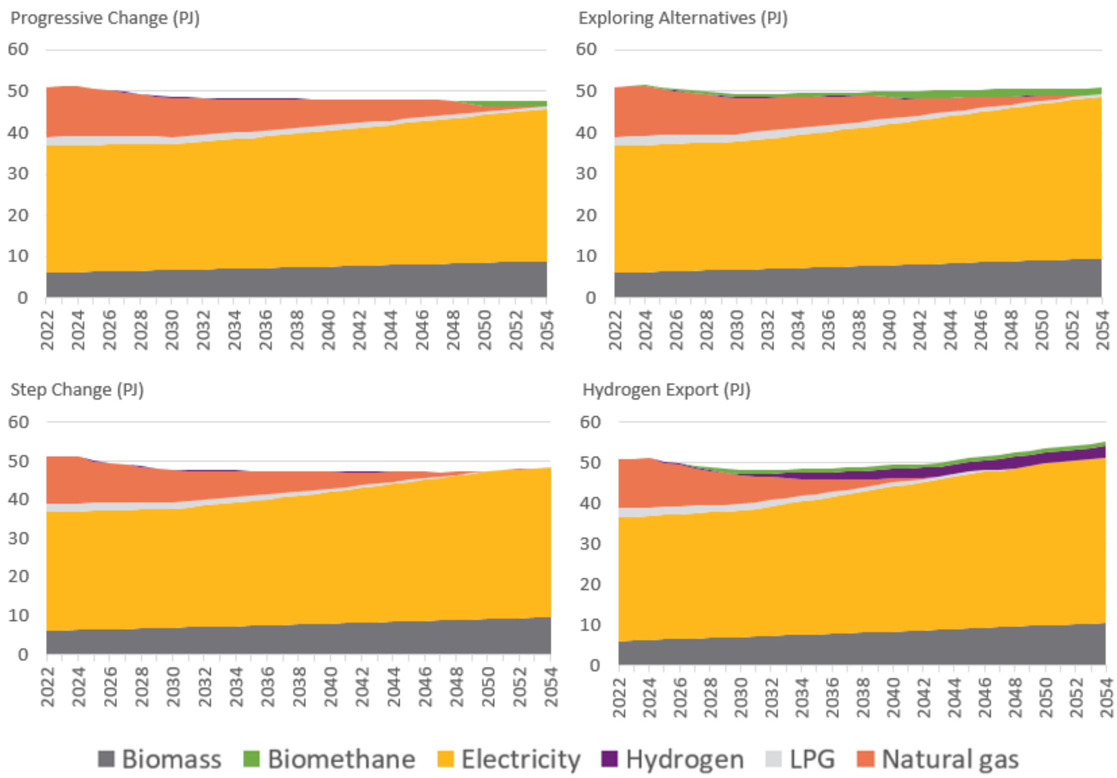


Figure 4-16 Fuel share in residential buildings across the four scenarios, for Western Australia.

Similar trends are seen across most scenarios, and are consistent with the 2021 multi-sector modelling, where gradual fuel switching from natural gas to electricity leads to a growing proportion of electricity consumption (most significant in the Step Change scenario where it reaches 79% of final energy demand in NEM-connected states by 2050). The relative impact of hydrogen and biomethane as residential fuels blended in natural gas pipelines can be seen in all scenarios, except in the Step Change scenario where biomethane is not used in the residential sector - a reflection of the more diverse decarbonisation options available in that scenario.

In all scenarios except Hydrogen Export, there is a very small amount of residential natural gas consumption remaining in 2050. In the Step Change scenario residential natural gas demand is near zero in 2050, making up 1% of final energy demand in NEM-connected states (5 PJ), closely followed by the Progressive Change and Exploring Alternatives scenarios which approach near zero residential natural gas demand post-2050, with natural gas demand making up 4% and 6% of final energy demand in the NEM-connected states in 2050 respectively. This is slightly increased compared to the 2021 Multi-Sector Modelling results, reflective of updates to the electrification and energy efficiency approach that lead to more divergence in the endpoint of electrification across scenarios, and the addition of biomethane as an additional decarbonisation option. It should be noted that many studies, including *Decarbonisation Futures* (Butler et al. 2020) see natural gas in buildings entirely displaced by 2050 under most decarbonisation scenarios. The AusTIMES model also does not consider costs associated with maintaining gas distribution networks, which would be an important consideration in determining the economic feasibility of maintaining blended gas networks under scenarios with low gas demand, and therefore low utilisation of the gas network.

In the Hydrogen Export scenario where hydrogen consumption becomes cost-competitive due to a booming hydrogen export industry, a higher proportion of hydrogen is blended in pipelines to service gas appliances. By the mid-2030s, the presence of hydrogen in gas distribution networks is growing, until alongside biomethane, it effectively displaces natural gas by 2050. This reflects the assumption that a 100% hydrogen distribution network is possible by 2050 irrespective of costs involved in upgrading the network, and results in hydrogen making up 16% of final residential energy demand in NEM-connected states in 2050. Updated cost assumptions regarding hydrogen production (section 2.2.4) have resulted in an increased long-term role for hydrogen in residential buildings when compared to the 2021 multi-sector modelling Hydrogen Superpower scenario. These results rely on the assumption that technical barriers for hydrogen blending can be overcome; in the absence of significant hydrogen blending, other studies on 1.5-aligned pathways such as *Decarbonisation Futures* (Butler et al. 2020) show that electrification and energy efficiency remain the most cost-effective decarbonisation pathways for buildings. The present 2022 multi-sector modelling results affirm the importance of significant electrification and energy efficiency across all four modelled scenarios.

In the Exploring Alternatives scenario, 69% of final energy demand in 2050 in the NEM-connected states is met by electricity compared to 79% in the Step Change scenario. Biomethane use in the Exploring Alternatives Scenario steadily increases from 2023 onwards, making up 6% of final residential energy demand in NEM-connected states 2050. Biomethane plays a longer-term role in the Progressive Change scenario, rapidly increasing from an initial use of 4 PJ in the NEM in 2047 to 27.5 PJ in 2050, making up 8% of final energy demand by 2050. This is in aid of the effort needed in the final decade of this scenario to achieve net zero emissions in 2050, under otherwise conservative settings for most decarbonisation solutions such as energy efficiency and electrification.

As noted in the 2021 multi-sector modelling, residential energy consumption from wood (biomass) does not have conversion pathways implemented in AusTIMES, and simply grows with residential activity projections. While wood is a significant energy source, it is also highly inefficient when compared with electricity; fuel switching to electricity is likely to only represent a small increase in electricity consumption. Wood also provides services with unconsidered externalities that may support continued consumption, and is also assumed in the model to be a net zero emission energy source. Further study is required to evaluate the economic, health and cultural drivers of fuel-switching from wood, and the implications of this on residential electricity demand.

Trends in residential energy demand in Western Australia generally follow those in the NEM-connected states, with the differences primarily driven by the different current-state energy intensity in the sector. For instance, the lower relative portion of natural gas diminishes the opportunity for electrification and alternative fuels. In all scenarios, residential natural gas demand in WA is fully (Step Change and Hydrogen Export) or near-fully displaced by 2050, reaching a maximum of 2-3% of final energy demand in 2050 in Exploring Alternatives and Progressive Change respectively. The share of electricity in residential buildings increases from 60% of final energy demand in 2022 to 80% in 2050 in Step Change, and 74-75% in the other scenarios, where biomethane and hydrogen (in the case of Hydrogen Export) play a slightly larger role. Similar to the NEM-state results, biomethane plays a longer-term role in the Progressive Change scenario, ramping up in 2049 to meet 3% of final energy demand in 2050. In the Exploring Alternatives scenario, biomethane use steadily increases from 2023 to meet 3-4% of final energy demand from 2040 onwards.

4.6.3 Commercial buildings

The mix of fuels in the total energy consumption for commercial buildings is shown in Figure 4-17 for the NEM-connected states and Figure 4-18 for Western Australia. The total energy consumption represents the net energy consumed after considering energy efficiency, electrification, hydrogen and biomethane uptake. The underlying baseline demand before these effects is driven by the floorspace projections shown in

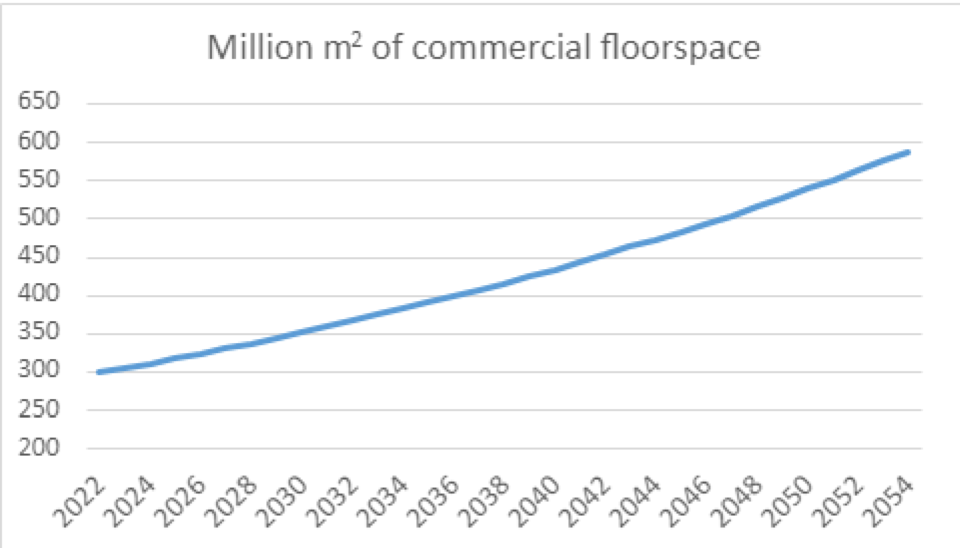


Figure 2-4 and discussed in Section 2.2.6.

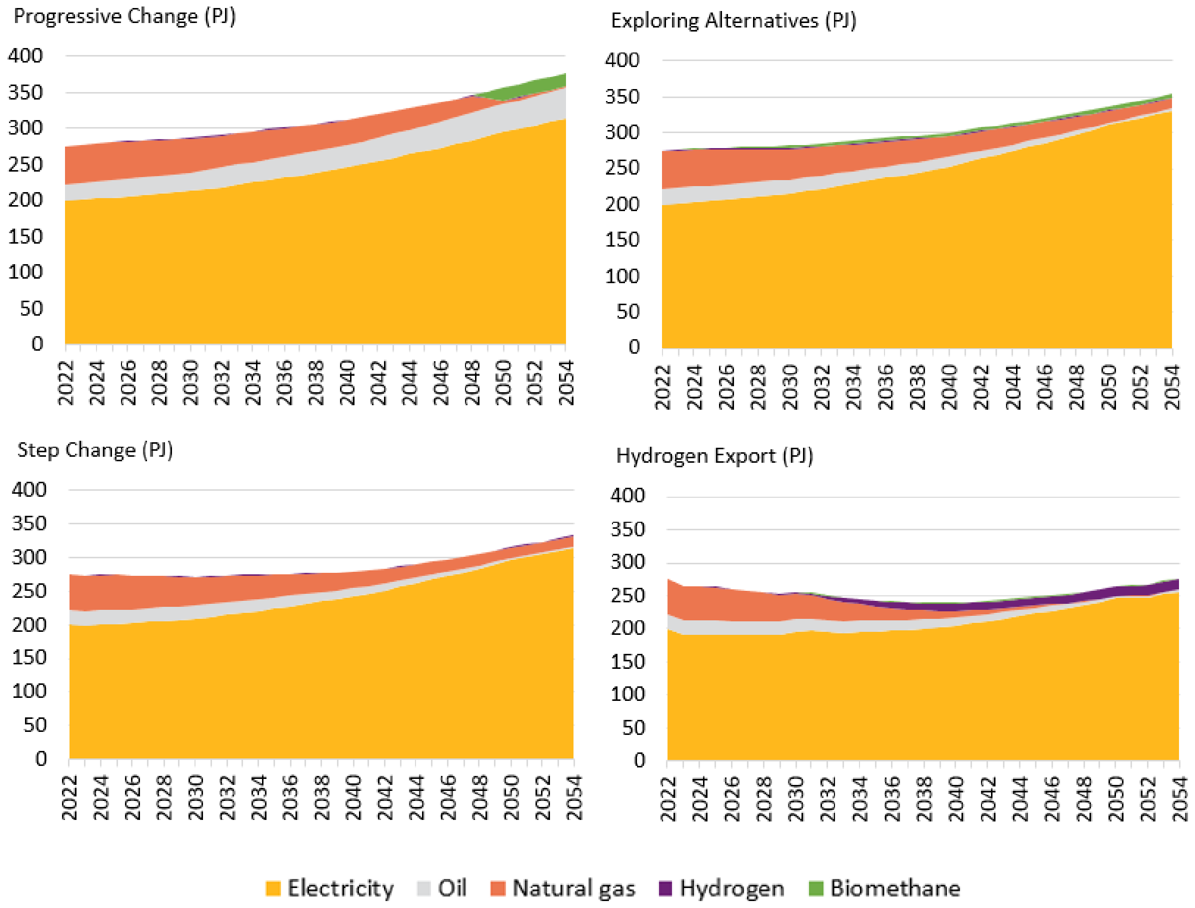


Figure 4-17 Fuel share in commercial buildings across the four scenarios, for NEM-connected states.

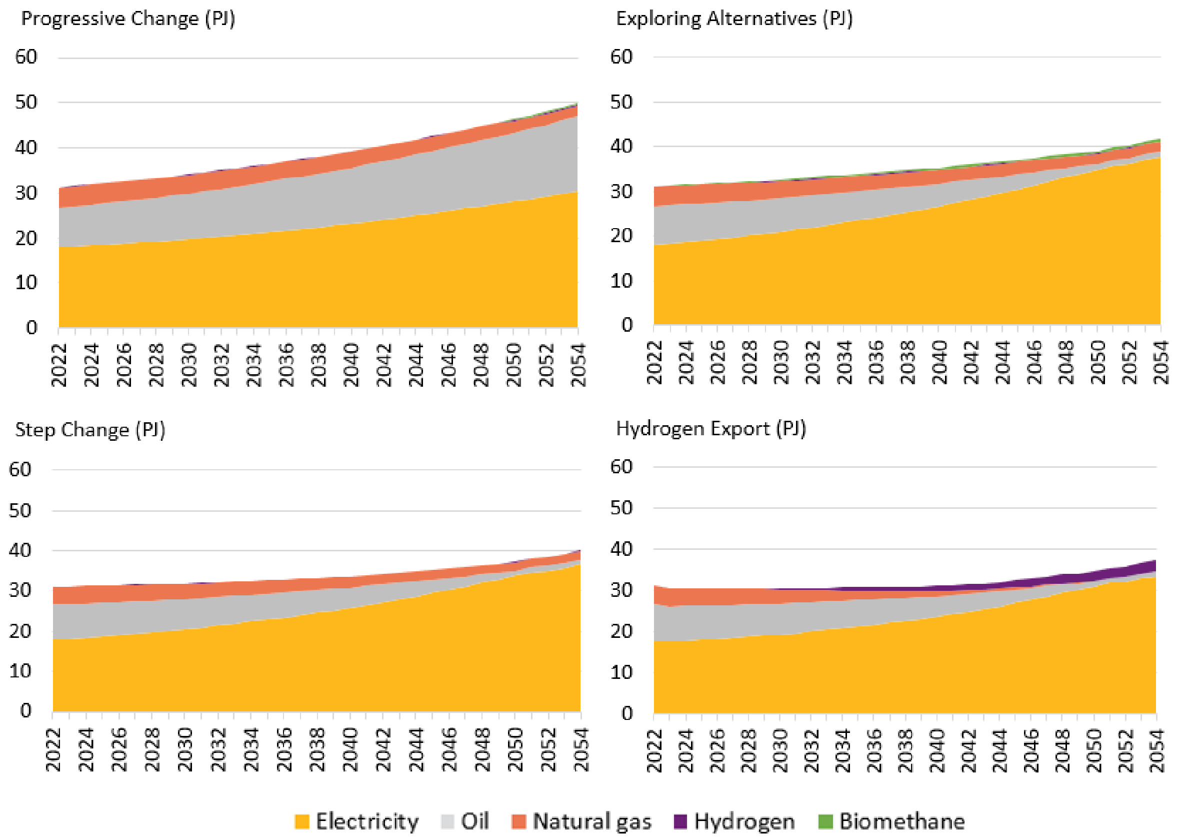


Figure 4-18 Fuel share in commercial buildings across the four scenarios, for Western Australia

As commercial buildings are already predominantly electrified, the potential for further electrification in commercial buildings is relatively small and variations in energy efficiency uptake is largely responsible for the difference in total energy consumption between scenarios.

Similar trends are seen across scenarios, where gradual fuel switching from natural gas to electricity leads to a growing proportion of electricity consumption (most significant in the Step Change scenario where electricity comprises 94% of energy demand in NEM-connected states by 2050 and natural gas, 5%). Natural gas use declines the most in the Progressive Change and Hydrogen Export scenarios, making up near zero final energy demand 2050, partly due to electrification but also largely due to the increased role of biomethane and hydrogen. Unlike in the residential sector, natural gas outcomes are lower in the long term in the commercial sector when compared with the 2021 Multi-Sector modelling. This reflects recent trends in the property sector to electrify non-residential new builds (GBCA 2022), which has led to adjustments in the baseline electrification limits for commercial buildings in AusTIMES, recognising that electrification is likely able to begin earlier than previously expected.

Similar to residential buildings, the relative impact of hydrogen and biomethane blended in natural gas pipelines can be seen in all scenarios, except in the Step Change scenario where biomethane is not taken up as a cost-effective fuel in the commercial sector. In most scenarios, hydrogen blending is limited by scenario assumptions on the maximum blending rate that is assumed technically feasible (10% by volume). However as with other sectors, the Hydrogen Export scenario assumes that up to 100% is possible by 2050 irrespective of network upgrade costs.

The impact of hydrogen is the most pronounced in Hydrogen Export, enabled by the rapidly growing hydrogen export industry and ability for the gas network to switch to 100% hydrogen, consistent with the residential sector. Hydrogen is blended into the gas distribution network from 2025 onwards, steadily increasing to meet 6% of commercial energy demand in NEM-connected states by 2050 in this scenario (a slightly lower result than last year's Hydrogen Superpower scenario in which hydrogen made up 8% of commercial energy demand by 2050). However, in all other scenarios hydrogen use is near zero in 2050, meeting less than 1% of final energy demand.

The impact of biomethane is most pronounced in Progressive Change, ramping up from near zero in 2048 to reach 5% of final energy demand in NEM-connected states in 2050 (or 18 PJ), reflecting a contribution in the effort towards net zero emissions by 2050. It is also featured in Exploring Alternatives, although this sees biomethane meet only 1.5% of final commercial energy demand in NEM-connected states by 2050.

Unlike the 2021 multi-sector modelling, exogenous assumptions to electrify commercial oil use have been included in Exploring Alternatives, Step Change and Hydrogen Export.

Trends in commercial fuel use in WA largely follow those in the NEM-connected states across scenarios. The most notable difference is higher oil consumption in the baseline data for Western Australia, which is reported via the Australian Energy Statistics (DISER 2021-AES) and assumed to represent a variety of end-uses. Pathways to electrify commercial oil are rudimentary in TIMES; and the difference between Progressive Change (where oil is assumed to remain; keeping at a share of 28-33% of final commercial energy use) and the other scenarios (where it is assumed to electrify) can be seen clearly for Western Australia. Natural gas use declines in all scenarios, meeting 6% of final energy demand in 2050, and is entirely displaced in the Hydrogen Export scenario by 2050, as hydrogen use steadily increases to meet 7% of final energy demand in 2050. Commercial electricity demand grows in all scenarios, from a baseline of 58% of final energy in 2022 to 61% by 2050 in Progressive Change, 89% in Exploring Alternatives and Hydrogen Export, and 91% in Step Change. Biomethane plays a limited role in commercial buildings – only meeting 1-2% of demand in 2050 in Progressive Change and Exploring Alternatives, but not being taken up in Step Change and Hydrogen Export where electrification plays a more substantial role.

4.6.4 Industry and agriculture

The mix of fuels in the total energy consumption for the industrial and agricultural sectors is shown in Figure 4-19 for the NEM-connected states and Figure 4-20 for Western Australia. The total energy consumption represents the net energy consumed after considering the effects of energy efficiency, electrification, biomethane and hydrogen uptake. The underlying baseline demand before these effects is driven by the activity projections shown in Figure 2-5, and discussed in Section 2.2.6.

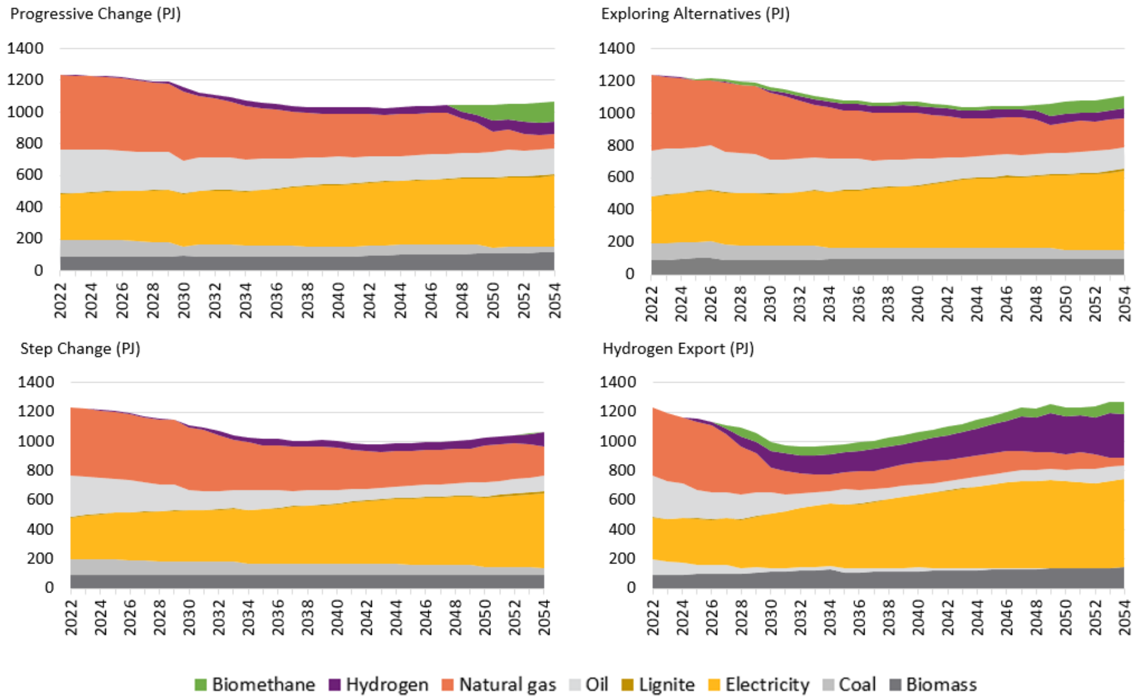


Figure 4-19 Fuel share in industry and agriculture across the four scenarios, for NEM-connected states. This includes consumption from off-grid sources – for example, the combustion of natural gas within the gas extraction industry itself. Exported hydrogen is excluded.

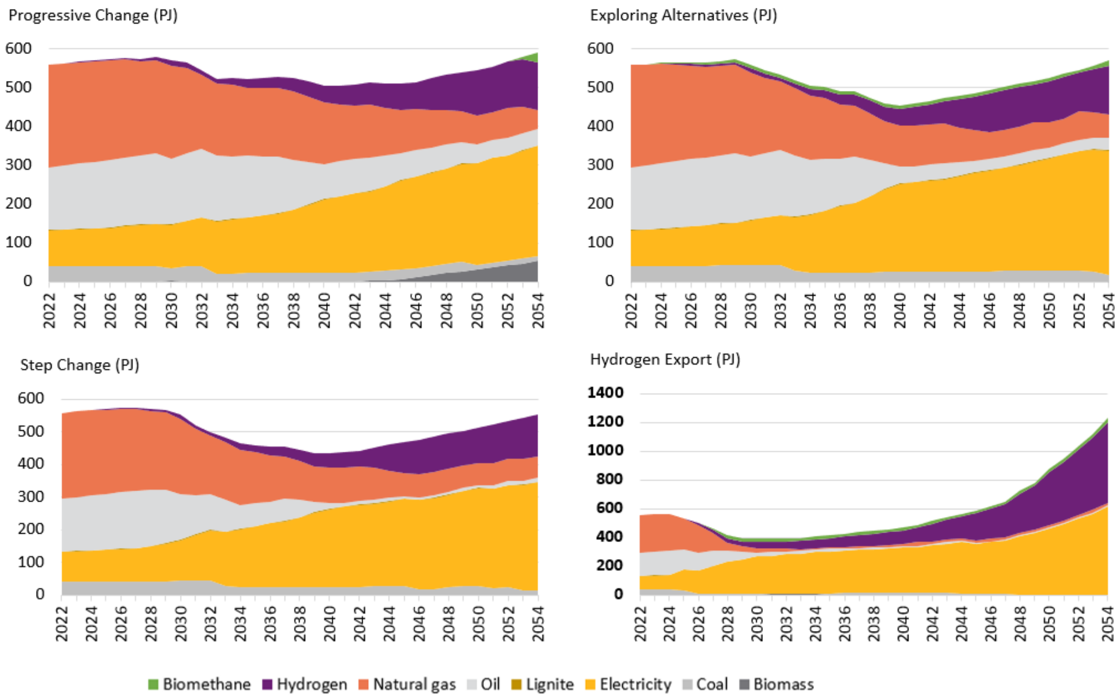


Figure 4-20 Fuel share in industry and agriculture across the four scenarios, for Western Australia. This includes consumption from off-grid sources – for example, the combustion of natural gas within the gas extraction industry itself. Exported hydrogen is excluded.

As in the 2021 multi-sector modelling, industrial natural gas demand declines in all scenarios, showing the steepest decline amongst all industrial fuels in the Progressive Change and Exploring Alternatives scenarios. This reflects the significant opportunities from decarbonising natural gas in industry, which starts at a share of 38% of industrial energy demand in 2022 in NEM-connected states (or 468 PJ) – including via alternative fuels and energy efficiency, but particularly significantly from electrification.

Natural gas demand in 2050 reaches the lowest level in the Hydrogen Export scenario, making up 9% of final energy demand in the NEM-connected states (107 PJ). While this is similar to the endpoint in the 2021 Hydrogen Superpower scenario, the decline in natural gas is more rapid in the short term, reaching 12% (or 119 PJ) of final energy demand by the mid-2030s. This steepness reflects the significant near-term decarbonisation objective in that scenario combined with greater representation of industrial decarbonisation opportunities than were considered in 2021. Industrial natural gas demand continues to declines more steadily in the other scenarios.

The overall timing of the transition from natural gas to electrification has accelerated when compared to the 2021 Multi-Sector Modelling. For instance, the 2022 Hydrogen Export scenario sees an earlier rapid reduction in natural gas use, around post-2028, compared to the 2021 Hydrogen Superpower scenario which sees this post-2035. This difference is due to a greater representation of decarbonisation opportunities, informed by modelling work for the Australian Energy Transitions Initiative. It also reflects the fact that stepwise changes in fuel use are more achievable in some heavy industry supply chains, where a single decarbonisation intervention could displace a large consumption of fossil fuel for a heavy user.

Despite these short-term differences, the long-term role of natural gas in industry and agriculture compared to the 2021 multi-sector modelling scenarios is similar. Remaining natural gas in 2050 in the Step Change and Hydrogen Export scenarios compared to the 2021 Step Change and Hydrogen Superpower scenarios are at similar levels (249 PJ and 107 PJ in NEM-connected states by 2050 compared to 255 PJ and 154 PJ by 2050, respectively).

The Step Change scenario retains the highest use of natural gas in 2050, making up 24% of final energy demand in NEM-connected states (249 PJ), while the Exploring Alternatives and Progressive Change scenarios retain a moderate level of natural gas use by 2050, making up 18% and 12% of final energy demand respectively (189 PJ and 129 PJ). The relatively higher role for natural gas in Step Change is due to a combination of two factors:

- Firstly, there is limited investment in biomethane and hydrogen as alternative fuels in this scenario.
- Secondly, under the updated approach to electrification used in 2022 (see section 2.3.7), each scenario is subject to maximum annual build rates for electrification technologies. There is some degree of freedom as to which fuels are electrified, with Step Change preferencing a greater degree of electrification from oil as opposed to natural gas compared to the other scenarios. This is also reflected in the oil demand outlook which declines most steeply in Step Change and Hydrogen Export scenarios, as does coal.

There are some limits to the degree to which some industrial fuels such as coal can be removed due to feedstock or reductant use. However, the Hydrogen Export scenario sees all coal demand displaced by 2050, partly aided by a shift to alternative steelmaking processes.

In all scenarios, hydrogen plays a role in displacing some natural gas use in industry and agriculture, as it becomes cost-competitive against other fuels. In certain subsectors, such as chemical manufacturing, hydrogen can be used to replace natural gas that would otherwise be used as a feedstock to produce ammonia. The impact of hydrogen is the most pronounced in the Hydrogen Export scenario with hydrogen use steadily increasing 2024 onwards to meet 21% of final industrial energy demand in NEM-connected states by 2050 (or 257 PJ). This is driven by a combination of the allowance for a 100% hydrogen gas network, and favourable economics of hydrogen production under that scenario. In contrast, less hydrogen is used in other scenarios, increasing from 2023 onwards to make up 5% of final industrial energy demand by 2050 in the Exploring Alternatives and Step Change scenarios (52 and 53 PJ in 2050 respectively) and 7% of final industrial energy demand by 2050 in the Progressive Change scenario (70 PJ in 2050).

Industrial and agricultural consumption of biomethane is present in all scenarios, with the exception of Step Change, consistent with other sectors. The impact is most pronounced in the Exploring Alternatives and Progressive Change scenarios. In the Exploring Alternatives scenario biomethane is blended into gas networks from 2023 onwards. Biomethane steadily increases over the modelling period to meet 7% of final industrial energy demand in the NEM-connected states in 2050, with a significant ramp up of use in the post-2045 modelling period, increasing from 23 PJ in 2047 to 74.5 PJ by 2050. Consistent with what is seen in the other sectors, in the Progressive Change scenario, biomethane plays a role in the longer-term, rapidly increasing from an initial use of 38 PJ in 2048 to 93 PJ in 2050, making up 9% of industrial final energy demand by 2050.

The industrial fuel outlook is a particularly key component of the Western Australian forecasts, and several unique characteristics of industry in that state drive distinct outcomes from the NEM-connected states. Across all scenarios, total industrial energy demand exhibits stronger growth to 2054 when compared with the NEM; reflecting the underlying activity growth opportunities available in Western Australia in the scenarios, but also the relative role of Hydrogen compared to electrification in displacing natural gas, as discussed in section 4.5.2. While electrification certainly plays a large role in industry in Western Australia, hydrogen also features particularly prominently. This is seen most clearly in Hydrogen Export, where hydrogen makes up 42% of final energy demand by 2050 (370 PJ), mostly attributable to the growth of a ‘green steel’ industry for exports. This is a similar feature to the 2021 multi-sector modelling for the NEM, although this study considers the implications for Western Australia for the first time, where much more relative growth is seen attributable to green steel compared to the NEM-connected states.

Industrial natural gas use phases out strongly in Western Australia in Hydrogen Export, reaching only 1% of final energy demand (11 PJ), due to combined impacts of hydrogen and electrification. It reaches 12-14% if final energy use in 2050 in the other scenarios (64-73 PJ). Hydrogen plays a strong role in other scenarios in Western Australia, reaching 20-21% of final energy demand (106-116 PJ) in Progressive Change, Exploring Alternatives and Step Change. Biomethane is not used in either the Progressive Change or Step Change scenarios in Western Australia, and meets 2% of final energy demand in 2050 in the Exploring Alternatives and Hydrogen Export scenarios (8 PJ and 20 PJ respectively). Electricity plays a slightly larger role in meeting final energy demand in 2050 compared to the NEM-states. This is seen predominately the Step Change scenario, electricity meets 59% of final energy demand, followed by the Exploring Alternatives and Hydrogen Export scenarios where electricity meets 55% and 53% of final energy demand in 2050 respectively.

4.6.5 Transport

The projected fuel consumption for transport in the NEM is shown in Figure 4-21. At the beginning of the projection period, most of the 1165 PJ energy consumption in 2022 is oil derived fuels of petrol and diesel in road transport (light and heavy vehicles) and kerosene in domestic aviation. The biofuel consumption is mainly low-blend ethanol (E10) in some Eastern states with a small amount of biodiesel consumption due to mandates in NSW and QLD (see Table 2-20). Similarly, there is modest liquefied petroleum gas (LPG) consumption in petrol ICE vehicles converted after market, although this consumption declines over time as its attractiveness diminishes due to announced increases in excise rates on LPG. Continued growth of demand for transport results in peak fuel use in the late 2020s in all scenarios except for Progressive Change due to its lower demand growth. However, as non-ICE drivetrains (i.e., hybrid, plug-in hybrid, and electric) continue to reduce in upfront costs, these vehicles become more economic and there is a switch away from oil consumption. This dynamic is most pronounced in the Hydrogen Export scenario.

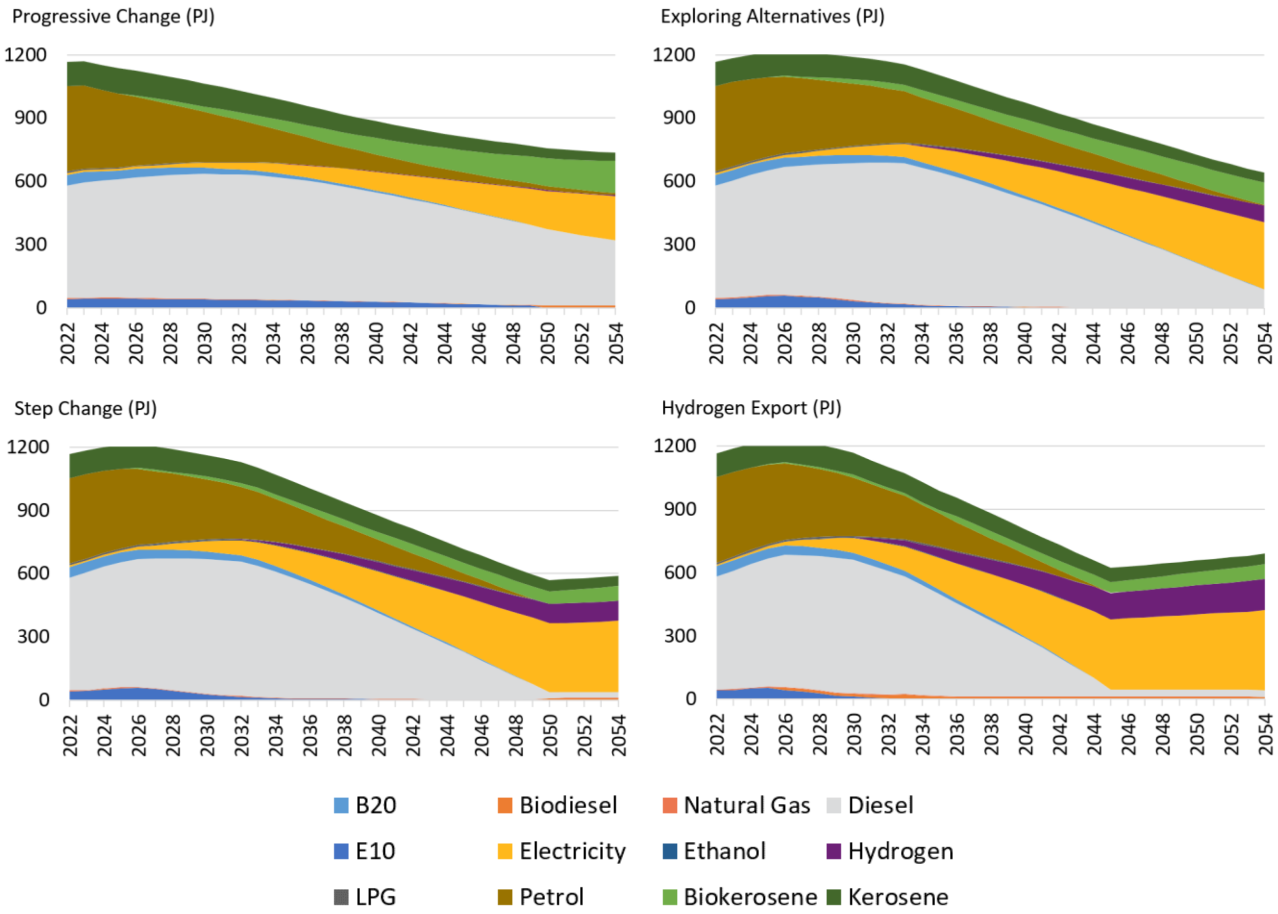


Figure 4-21 Fuel share in transport (both road and non-road) across the four scenarios for the NEM states

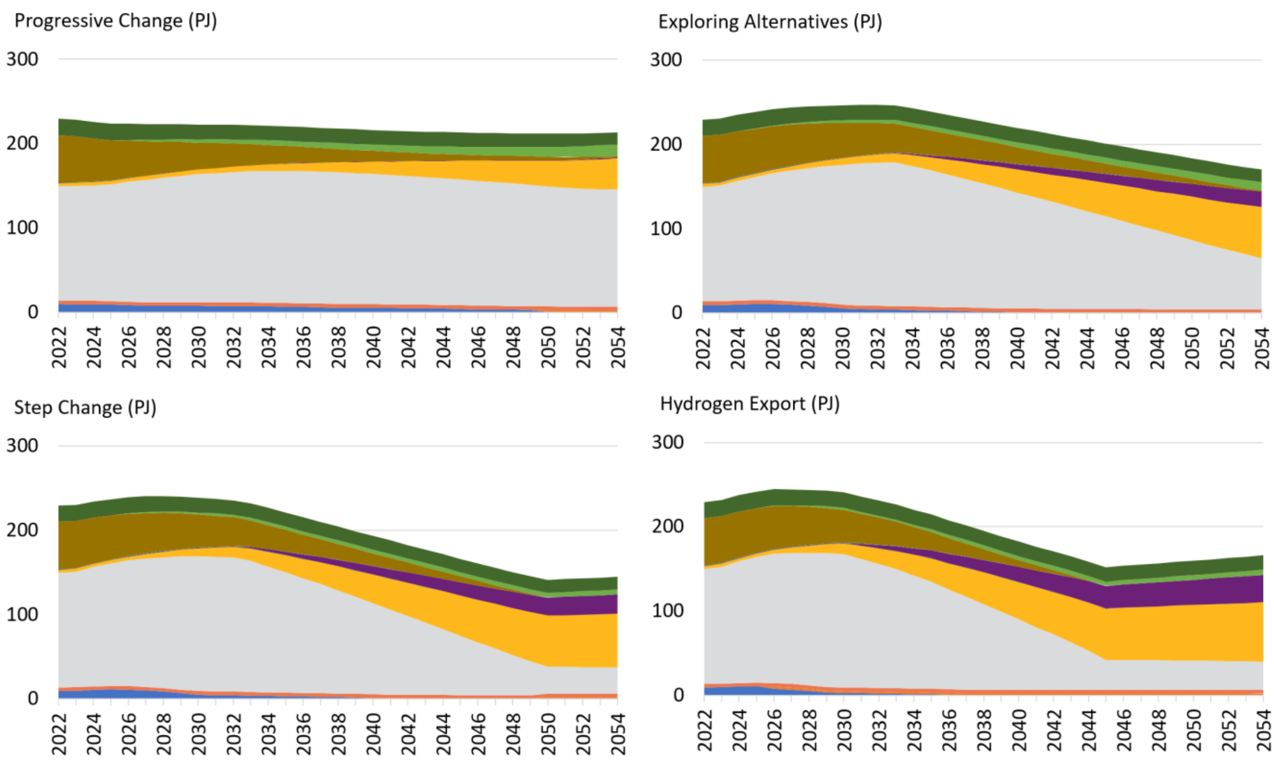
The electrification of road transport (and to a lesser extent rail and aviation) accelerates the decline in the overall level of fuel use, reflecting the greater efficiency of the electric drivetrain to deliver more kilometres per unit of energy. Informed by earlier work (Graham, 2022), this acceleration occurs in the mid-2030s as electric vehicles dominate new vehicle sales with ICE vehicles unavailable beyond 2035 in the Hydrogen Export and 2040 in the Step Change scenario. Dependent on vehicle size, electricity displaces over three times the same volume of liquid fuel to deliver vehicle kilometres (around 0.7MJ/km of electricity compared to around 2.5MJ/km for liquid fuelled medium sized car).

In the mid to late 2020s, at around the time electric vehicles are beginning to increase their share of sales, hydrogen fuel cell vehicles are also assumed to increase their sales from their current near zero vehicle stock. Fuel cell vehicles will be able to benefit from some co-learning in their costs since fuel cell electric vehicles and battery electric vehicles both use an electric drive-train, just with a different fuel storage and conversion step (i.e. with a hydrogen storage vessel and fuel cell replacing the battery components). Under our assumptions, fuel cell vehicles remain a much smaller share of the fleet than electric vehicles, at least in part due to availability of refuelling stations. However, the projected volume of hydrogen consumption is still quite high because their main area of adoption is in road trucks. Since each truck will consume many more times the fuel of a passenger car per year, the required volume of hydrogen demanded by the truck fleet is still substantial. Another reason for the greater hydrogen volume is that hydrogen fuel cell vehicles are not as energy efficient, requiring around twice the equivalent energy content per kilometre compared to electricity.

The kink in fuel consumption from 2045 onwards in the Hydrogen Export scenario and 2050 in the Step Change scenario reflects the deregistration of ICE vehicles from that year and a stable mix of vehicle-types across the various transport sectors in the presence of demand growth to the end of the projection period.

The moderate increase in biofuel consumption in the long-term reflects increased uptake in domestic aviation of bio-derived jet fuel as a ‘drop-in’ fuel for kerosene in existing turbine aircraft.

Similar dynamics in transport sector fuel consumption are observed for Western Australia across the scenarios (Figure 4-22).



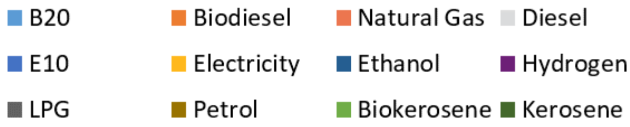


Figure 4-22 Fuel share in transport (both road and non-road) across the four scenarios for Western Australia

4.7 Hydrogen production

There are five possible hydrogen production pathways that were considered: steam methane reforming (SMR); SMR with carbon capture and storage (CCS); brown coal gasification with CCS; alkaline electrolysis, and; proton exchange membrane (PEM) electrolysis. The modelling framework optimises the production process and location of the hydrogen production as part of the least cost optimisation for each of the scenarios. However, there is a requirement that in the Hydrogen Export scenario, any hydrogen export is produced from renewable electricity to maintain consistency with the 2021 multi-sector modelling.

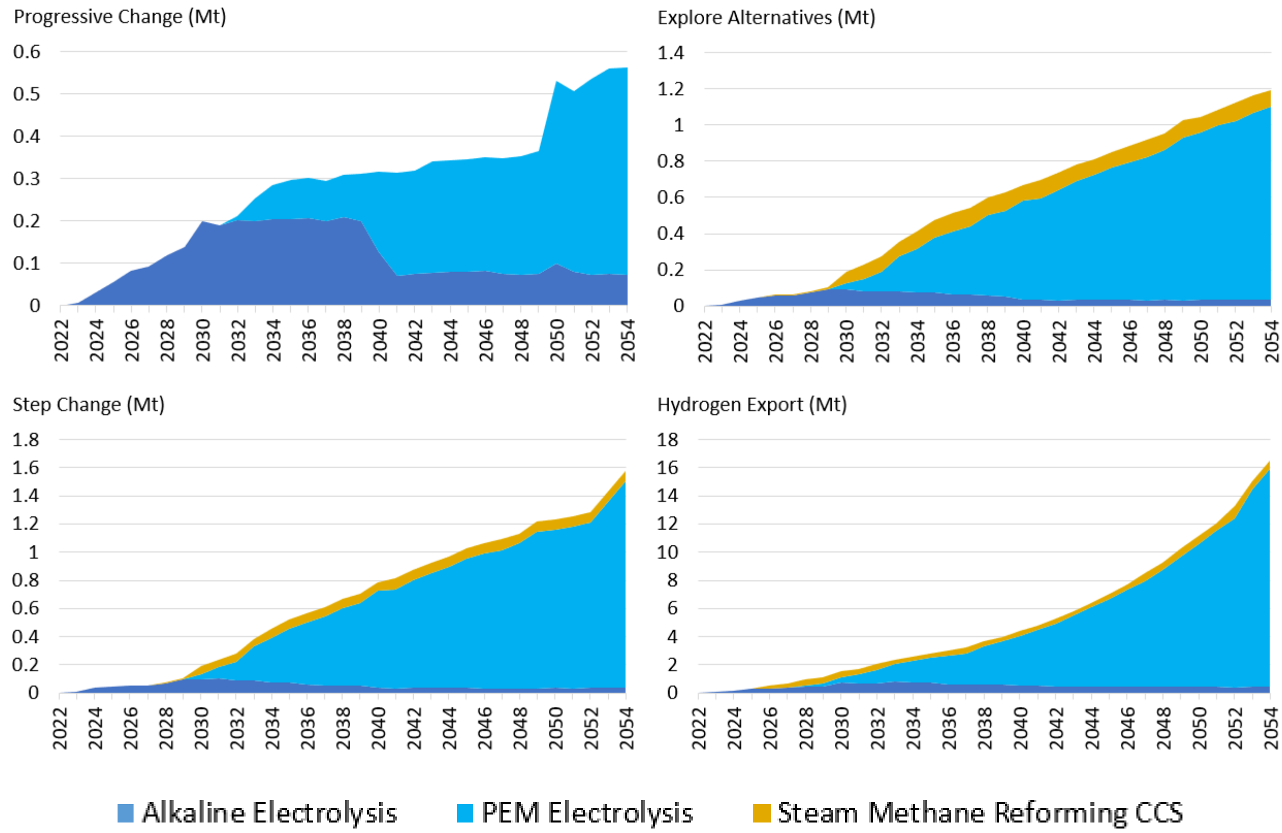


Figure 4-23 Grid-connected hydrogen production by process for the NEM

It is observed that early in the projection period in all scenarios, alkaline electrolysis is the least-cost production process due to its lower cost than proton exchange membrane (PEM) electrolysis. In all scenarios except Progressive Change there is some hydrogen produced from steam methane reforming with CCS, however over time PEM electrolysis is the preferred production process as capital costs decline and the electricity system transitions to high variable renewables. The scale of hydrogen production is most significant in the Hydrogen export scenario reflecting large export volumes and increased domestic use of hydrogen (see Section 4.5.2).

Similar patterns in hydrogen production by scenario are observed for Western Australia (Figure 4-24), with relatively more steam methane reforming with CCS produced hydrogen reflecting lower gas prices.

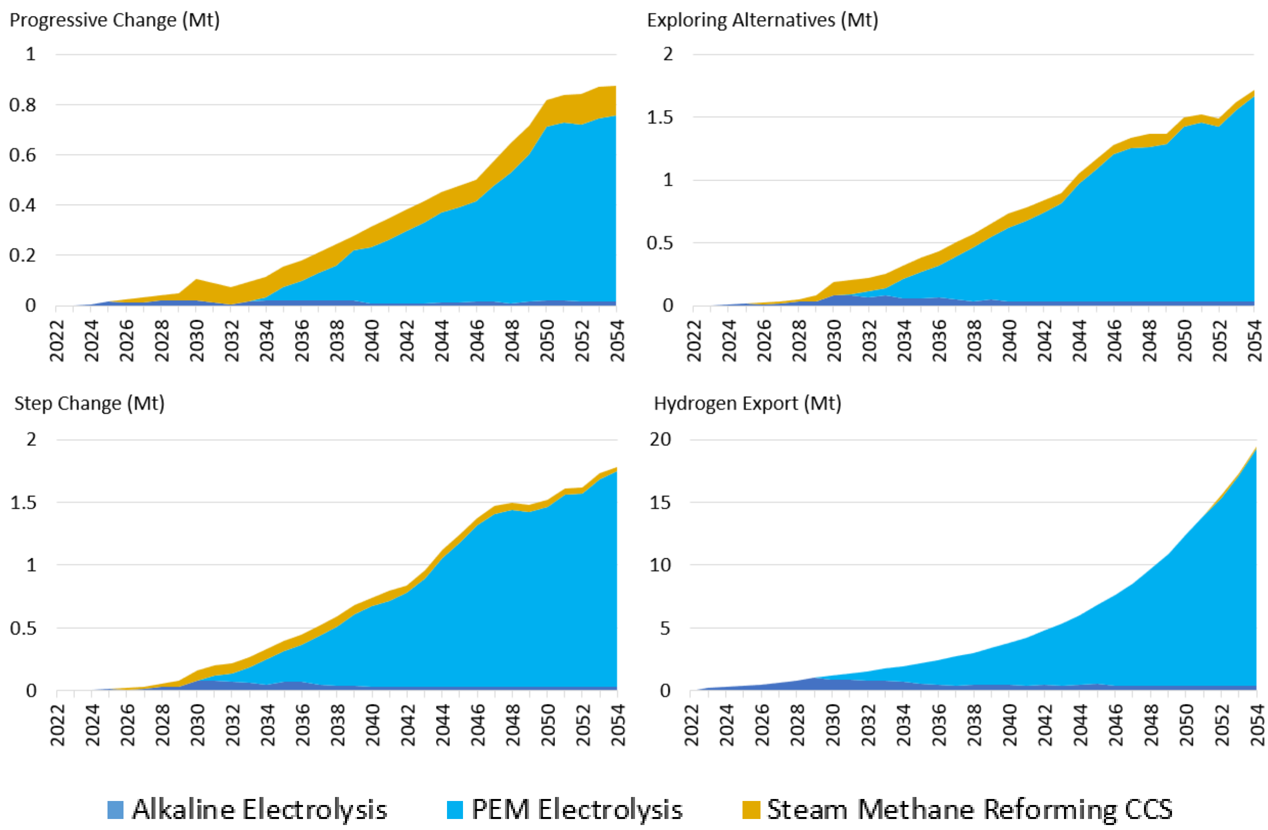


Figure 4-24 Grid-connected hydrogen production by process for Western Australia

Appendix A Structural detail of AusTIMES model

A.1 Electricity sector

In the TIMES framework, the power (electricity) sector is a transformation sector that converts forms of primary energy (i.e., coal, natural gas, renewable resources) into electricity that is a derived demand of the end-use sectors (see Section A.2). An advantage of the TIMES model is that different spatial and temporal scales can be implemented in different sectors. The electricity sector in AusTIMES has the following features:

- Electricity demand aggregated to 16 load blocks reflecting seasonal and time of day variation across the year
- 19 transmission zones: 16 zones in the National Electricity Market (NEM)[7]; South-West Interconnected System (SWIS); North-West Interconnected System (NWIS); and Darwin Katherine Interconnected System (DKIS)
- Existing generators mapped to transmission zone at the unit-level (thermal and hydro) or farm-level (wind, solar)
- Renewable resource availability at Renewable Energy Zone (REZ) spatial resolution for solar, on- and off-shore wind and tidal resources and sub-state (polygon) spatial resolution for geothermal and wave resources in the NEM
- Trade in electricity between NEM regions subject to interconnector limits
- 33 new electricity generation and storage technologies: black coal pulverised fuel; black coal with CO_2 capture and sequestration (CCS); brown coal pulverised fuel; brown coal with CCS; combined cycle gas turbine (CCGT); open-cycle gas turbine (OCGT); gas CCGT with CCS; gas reciprocating engine; biomass; biomass with CCS; pumped storage hydro (PSH) with 8 hours storage (PSH8); PSH with 12 hours of storage (PSH12); PSH with 24 hours of storage (PSH24); PSH with 48 hours of storage (PSH48); onshore wind; offshore wind; large-scale single-axis tracking solar photovoltaic (PV); large-scale concentrated solar thermal (CST); residential rooftop solar PV; commercial rooftop solar PV; hot fractured rocks (enhanced geothermal); conventional geothermal; wave; tidal; hydrogen reciprocating engine; diesel reciprocating engine; small modular nuclear reactor; grid battery with 1 hour of storage; grid battery with 2 hours of storage; grid battery with 4 hours of storage; grid battery with 8 hours of storage; residential battery; commercial battery.
- Current policies: national large-scale renewable energy target; Northern Territory, Queensland, Tasmania and Victoria Renewable Energy Targets; Small-scale renewable energy scheme; NSW

[7] The NEM zones reflect zones that were originally identified in AEMO's National Transmission Network Development Plan (NTNDP) publications, which has been replaced since 2018 with the Integrated System Plan (ISP).

Energy Security Target, NSW *Electricity Infrastructure Investment Act 2020*; the Snowy 2.0 energy storage project.

A.2 End-use sectors

A.2.1 Industry

Energy use in industry is significant and therefore is disaggregated into a number of sub-sectors. The mapping of AusTIMES to ANZSIC industry subsectors is displayed below (Apx Table A-1).

Apx Table A-1 Mapping of AusTIMES to ANZSIC industry subsectors

Aus-TIMES subsector (industry)	ANZSIC (2006) codes	ANZSIC Division
Industry - Coal mining	06	Division B
Industry - Oil mining	07 (part)	Division B
Industry - Gas mining	07 (part)	Division B
Industry - Iron ore mining	0801	Division B
Industry - Bauxite mining	0802	Division B
Industry - Lithium mining	0809 (part)	Division B
Industry - Copper mining	0803	Division B
Industry - Nickel mining	0806	Division B
Industry - Zinc mining	0807	Division B
Industry - Other non-ferrous metal ores mining	0804, 0805, 0809 (part)	Division B
Industry - Other mining	09	Division B
Industry - Meat products	111	Division C
Industry - Other food and drink products	112, 113, 114, 115, 116, 117, 118, 119	Division C
Industry - Textiles, clothing and footwear	13	Division C
Industry - Wood products	14	Division C
Industry - Paper products	15	Division C
Industry - Printing and publishing	16	Division C
Industry - Petroleum refinery	17	Division C
Industry - Ammonia	181 (part)	Division C
Industry - Fertilisers	1831	Division C
Industry - Explosives	1892	Division C
Industry - Other chemicals	181 (part), 182, 183 (part), 185, 189 (part)	Division C
Industry - Rubber and plastic products	19	Division C
Industry - Non-metallic construction materials (not cement)	201, 202, 209	Division C
Industry - Cement	203	Division C
Industry - Iron and steel	211	Division C
Industry - Alumina	2131	Division C
Industry - Aluminium	2132	Division C
Industry - Other non-ferrous metals	2133, 2139	Division C
Industry - Other metal products	212, 214, 22	Division C
Industry - Motor vehicles and parts	231	Division C

Industry - Other manufacturing products	239, 24, 25	Division C
Industry - Gas supply	27	Division D
Industry - Gas export (LNG)	07 (part)	Division B
Industry - Water supply	28	Division D
Industry - Construction services	30, 31, 32	Division E

Baseline energy use is disaggregated by subsector and fuel type (oil, bioenergy, black coal, brown coal, natural gas, electricity, hydrogen).

Growth in industry subsectors in AusTIMES is projected using several data sources, including:

- Forecasts of sectoral activity developed for the 2019 Australian National Outlook (CSIRO 2019), drawing on results of CGE analysis by the Centre of Policy Studies at Victoria University.
- Asset-level assumptions for alumina, aluminium, steel and petroleum refining facilities.
- Recent trends of changes in energy use by sector, drawing on historical data from the Department of Industry, Science, Energy and Resources (2021-AES)

AusTIMES can implement energy efficiency and electrification of technologies based on capital costs, equipment lifetime and fuel costs, if it is economically attractive. Assumptions on costs and savings are derived from a variety of sources and are updated over time. The total electrification allowed can be limited to reflect the levels expected in the scenarios.

Hydrogen and biomethane uptake in industry is implemented endogenously to service end-uses through pipeline blending with natural gas. In this case, similar to natural gas, hydrogen and biomethane are categories of fuel available to these end uses. AusTIMES can make the decision to switch natural gas demand to hydrogen and/or biomethane if it is economically attractive based on costs of fuels involved and the shadow carbon price (determined internally in the model based on scenario emissions objectives and the cost of available decarbonisation options). The fuel cost of hydrogen and biomethane is determined through optimisation of investment in fuel production capacity and operation to deliver fuels to end-uses at least cost. Assuming hydrogen replaces natural gas with existing pipeline infrastructure, the capital cost of switching from natural gas to hydrogen technologies is not considered. Costs associated with upgrading gas network infrastructure to accept high blends of hydrogen are also not considered. It is therefore necessary to explicitly set a limit on blended hydrogen in the gas network in modelled scenarios. Where that limit is assumed to be higher than currently understood upper limits, any costs associated with reaching that limit are not considered by the objective function.

In addition to hydrogen blended via the gas supply network, it is assumed that some subsectors may have access to a direct supply of hydrogen that could replace larger portions of natural gas use. This is particularly true for subsectors that may be very large natural gas users, or may currently be using natural gas as a feedstock to produce hydrogen. The subsectors affected are Alumina, Ammonia, Fertilisers, Explosives, Other chemicals, Iron and steel, and Petroleum refining. More restricted use cases for a direct supply of hydrogen are available in metal ore mining subsectors, and Gas Export.

A.2.2 Residential buildings

The stock of buildings is sourced from the Residential Buildings Baseline Study (EnergyConsult, 2020), 2016 ABS *Census* data, 2016 ABS populations and dwellings projection, *Australian Energy Statistics*, and the *Low Carbon High Performance* report (ClimateWorks Australia, 2016).

AusTIMES projects baseline energy consumption and can also implement energy efficiency and electrification of technologies based on capital costs, equipment lifetime and fuel costs, if it is economically attractive. Energy efficiency and electrification rates are scaled for different scenarios to match the level of ambition relevant to each scenario narrative.

The residential building types, end-use service demands and fuel types are listed below (Apx Table A-2).

Apx Table A-2 Residential building types, end-use service demands and fuel types

Building types	End-use service demands	Fuel types
Detached (separate houses) **Semi-detached (townhouses, duplexes)** **Apartments**	Space heating Space cooling Cooking Water heating Appliances Lighting	Electricity Natural gas Hydrogen Biomethane LPG Wood

All residential buildings experience an autonomous efficiency improvement at no cost. Additional endogenous energy efficiency and electrification options are available, at an additional incremental cost. Should these be economically attractive, they will be taken up in the model. Exogenous energy efficiency opportunities are applied to the Hydrogen Export scenario to represent a step change in action and ambition in line with 1.5C-aligned targets.

All assumptions on costs and savings are derived from the *Low Carbon High Performance* report (ClimateWorks Australia, 2016).

Hydrogen uptake in residential buildings is modelled as a category of fuel available for pipeline blending with natural gas. AusTIMES can make the decision to switch natural gas demand to hydrogen if it is economically attractive based on costs of fuels involved and the shadow carbon price. The fuel cost of hydrogen is determined through optimisation of investment in hydrogen production capacity and operation to deliver hydrogen to end-uses at least cost. Assuming hydrogen replaces natural gas with existing pipeline infrastructure, the capital cost of switching from natural gas to hydrogen technologies is not considered. Costs associated with upgrading the gas supply network to receive higher blends of hydrogen are also not considered.

A.2.3 Commercial buildings

The stock of buildings is sourced from the *Commercial Buildings Baseline Study (Pitt & Sherry 2012)*, *Australian Energy Statistics (DISER 2021-AES)*, and the *Low Carbon High Performance* report *(ClimateWorks Australia, 2016).*

AusTIMES projects baseline energy consumption and can also implement energy efficiency and electrification of technologies based on capital costs, equipment lifetime and fuel costs, if it is economically attractive. Energy efficiency and electrification rates are scaled for different scenarios to match the level of ambition relevant to each scenario narrative.

The commercial building types, end-use service demands and fuel types are listed below (Apx Table A-3).

Apx Table A-3 Commercial building types, end-use service demands and fuel types

Building types	End-use service demands	Fuel types
Hospital	Space heating	Electricity
Hotel	Space cooling	Natural gas
Law court	Water heating	Biomethane
Office	Appliances	Oil
Public building	Lighting	Hydrogen
Retail	Equipment	
Supermarket		
School		
Tertiary		
Data centre		
Aged care		

All commercial buildings experience an autonomous efficiency improvement at no cost. Additional endogenous energy efficiency and electrification options are available, at an additional incremental cost. Should these be economically attractive, they will be taken up in the model. Exogenous energy efficiency opportunities are applied to the Hydrogen Export scenario to represent a step change in action and ambition in line with 1.5C-aligned targets.

Hydrogen uptake in commercial buildings is modelled as a category of fuel available for pipeline blending with natural gas. AusTIMES can make the decision to switch natural gas demand to hydrogen if it is economically attractive based on costs of fuels involved and the shadow carbon price. The fuel cost of hydrogen is determined through optimisation of investment in hydrogen production capacity and operation to deliver hydrogen to end-uses at least cost. Assuming hydrogen replaces natural gas with existing pipeline infrastructure, the capital cost of switching from natural gas to hydrogen technologies is not considered. Costs associated with upgrading the gas supply network to receive higher blends of hydrogen are also not considered.

All assumptions on costs and savings are derived from the *Low Carbon High Performance* report (ClimateWorks Australia, 2016).

A.2.4 Agriculture

Energy use in agriculture is minimal although non-energy emissions are significant. The mapping of AusTIMES to ANZSIC industry subsectors is displayed below (Apx Table A-4).

Apx Table A-4 Mapping of AusTIMES to ANZSIC agriculture subsectors

Aus-TIMES subsector (agriculture)	ANZSIC (2006) codes	ANZSIC Division
Agriculture - Sheep and cattle	0141, 0142, 0143, 0144, 0145 (part)	Division A
Agriculture - Dairy	016	Division A

Agriculture - Other animals	017, 018, 019	Division A
Agriculture - Grains	0145 (part), 0146, 0149, 015	Division A
Agriculture - Other agriculture	011, 012, 013	Division A
Agriculture - Agricultural services and fishing	02, 04, 052	Division A
Forestry - Forestry and logging	03, 051	Division A

Note that for modelling purposes, non-energy emissions for mixed-use farms are categorised on the basis of agricultural activities. For example, livestock emissions in mixed grain-sheep farming are exclusively modelled under Agriculture – Sheep and cattle.

A.2.5 Transport

The transport sector is a significant and growing component of Australia's greenhouse gas emissions. AusTIMES has a very detailed representation of road transport. The road transport segments, vehicle classes, and fuel categories are listed below (Apx Table A-5).

Apx Table A-5 Road transport segments, vehicle classes, and fuel categories

Market segments	Vehicle types	Fuels
Motorcycles Small, medium and large passenger Small, medium and large light commercial vehicles Rigid trucks Articulated vehicles Buses	Internal combustion engine Hybrid/internal combustion engine Plug-in Hybrid/internal combustion engine Short-range electric vehicle Long-range electric vehicle Autonomous long-range (private) electric vehicle Autonomous long-range (ride-share) electric vehicle Fuel cell electric vehicle	Petrol Diesel Liquefied Petroleum Gas (LPG) Compressed or Liquefied Natural gas Petrol with 10% ethanol blend (E10) Diesel with 20% biodiesel blend (B20) Ethanol Biodiesel Hydrogen Electricity

Key inputs are ABS data on vehicle stock (ABS, 2021-MVC), average kilometres travelled (ABS, 2020b), BITRE (2019) and *Australian Energy Statistics* data (DISER, 2021-AES) on fuel use, NGA emission factors for fuel (DISER, 2021-NGAF), population/GSP projections, assumptions around future vehicle costs and efficiency improvements (Graham and Havas, 2021), oil price projections (Lewis Grey Advisory, 2022) and production costs on biofuels (Butler et al., 2001). The delivery price of electricity and hydrogen for road transport is endogenously determined within AusTIMES.

There is less detailed representation of non-road transport, implemented on a fuel basis. The market segments and fuel categories are listed below (Apx Table A-6).

Apx Table A-6 Non-road transport market segments and fuels

Market segments	Fuels
Rail	Diesel Electricity

Aviation – domestic Aviation- international	Avgas Kerosene Biofuel Electricity
Shipping – domestic Shipping – international	Diesel Petrol Fuel oil

Key inputs are BITRE (2019) and AES data (DISER, 2021-AES) on fuel use, NGA emission factors for fuel (DISER, 2021-NGAF), population/GSP projections, assumptions around activity and fuel efficiency improvements (Graham and Havas, 2021), oil price projections (Lewis Grey Advisory, 2022) and production costs on biofuels. The delivery price of hydrogen for aviation and shipping is endogenously determined within AusTIMES.

Appendix B Full carbon budget methodology

Global temperature rise is closely linked to the cumulative concentration of greenhouse gases in the atmosphere. The IPCC (Arias et al. 2021) has published global carbon budgets consistent with particular global temperature outcomes, which represent the cumulative amount of carbon dioxide that can be emitted above a particular baseline before a given temperature outcome is reached (Apx Table B-1). These carbon budgets involve inherent uncertainties, including:

- Actual historical emissions and warming since the period 1850-1900
- Transient climate response to cumulative emissions of carbon (TCRE) – the ratio of global average surface temperature change per unit CO_2 emitted. Uncertainties in this relationship are represented via percentiles – 33rd, 50th and 67th, interpreted as 33%, 50% and 67% chance of the cumulative emissions achieving a particular temperature rise respectively.
- Earth system feedbacks, including CO_2 that may be released through permafrost thawing.

Apx Table B-1 Global carbon dioxide budgets from the IPCC Working group I contribution to the Sixth Assessment Report (from Arias et al. 2021)

Global surface temperature change since 2010–2019	Global surface temperature change since 1850–1900[a]	Estimated remaining carbon budgets starting from 1 January 2020 and subject to variations and uncertainties quantified in the columns on the right					Scenario variation	Geophysical uncertainties[d]			
°C	°C	Percentiles of TCRE[b] $GtCO_2$					Non-CO_2 scenario variation[c]	Non-CO_2 forcing and response uncertainty	Historical temperature uncertainty[e]	Zero CO_2 emissions commitment uncertainty	Recent emissions uncertainty[f]
		17th	33rd	50th	67th	83rd	$GtCO_2$	$GtCO_2$	$GtCO_2$	$GtCO_2$	$GtCO_2$
0.43	1.5	900	650	500	400	300	Values can vary by at least ±220 due to choices related to non-CO_2 emissions mitigation	Values can vary by at least ±220 due to uncertainty in the warming response to future non-CO_2 emissions	±550	±420	±20
0.53	1.6	1200	850	650	550	400					
0.63	1.7	1450	1050	850	700	550					
0.73	1.8	1750	1250	1000	850	650					
0.83	1.9	2000	1450	1200	1000	800					
0.93	2	2300	1700	1350	1150	900					

1.5-degree and 2-degree climate scenarios typically show temperatures peaking between 2040-2060. Therefore, we consider the above and subsequent carbon budgets to be restricted from the baseline year to 2050, given that this reduces the chance of overshooting temperature levels (Meinshausen et al. 2018).

For the two scenarios that are constrained by temperature outcomes – Step Change and Hydrogen Export - an appropriate global carbon dioxide budget was selected from Apx Table B-1 as documented in Apx Table B-2.

Apx Table B-2 Global carbon dioxide budgets from 2020 for the relevant scenarios in this report

Scenario	Temperature outcome and probability	Global budget (CO_2 only; from 2020)	Justification
Step Change and Exploring Alternatives	1.8°C (67%)	850 Gt CO_2	67th percentile of '1.8' warming row from Apx Table B-1
Hydrogen Export	1.5°C (50%)	500 Gt CO_2	50th percentile of '1.5' warming row from Apx Table B-1

To align all assumptions with the approach used in Meinshausen (2019), it is necessary to adjust the start year of the carbon budget from a start year of 2020 to 2013. This is achieved by adding 278 Gt to each of the budgets (approximate global emissions between 2013-2019), resulting in the updated budgets in Apx Table B-3. (Meinshausen, 2019; Nicholls & Meinshausen, 2022).

Apx Table B-3 Global carbon dioxide budgets from 2013 for the relevant scenarios in this report

Scenario	Temperature outcome and probability	Global budget (CO_2 only; from 2013)	Justification
Step Change and Exploring Alternatives	1.8°C (67%)	1,128 Gt CO_2	Add 278 Gt to budgets from Apx Table B-2 representing global emissions from 2013-2019
Hydrogen Export	1.5°C (50%)	778 Gt CO_2	

The carbon budgets provided in Apx Table B-1 refer to temperature rise relative to an 1850-1900 baseline. However, it is useful to construct scenarios relevant to the Paris Agreement (UNFCCC 2015), which refers to a pre-industrial baseline. To account for this difference, we subtract an additional 222 $GtCO_2$ from all carbon budgets, which is based on an assumed additional warming of 0.1°C and the relative differences in budgets at that warming interval from the IPCC budgets, and is consistent with Nicholls & Meinshausen (2022). This results in the budgets in Apx Table B-4.

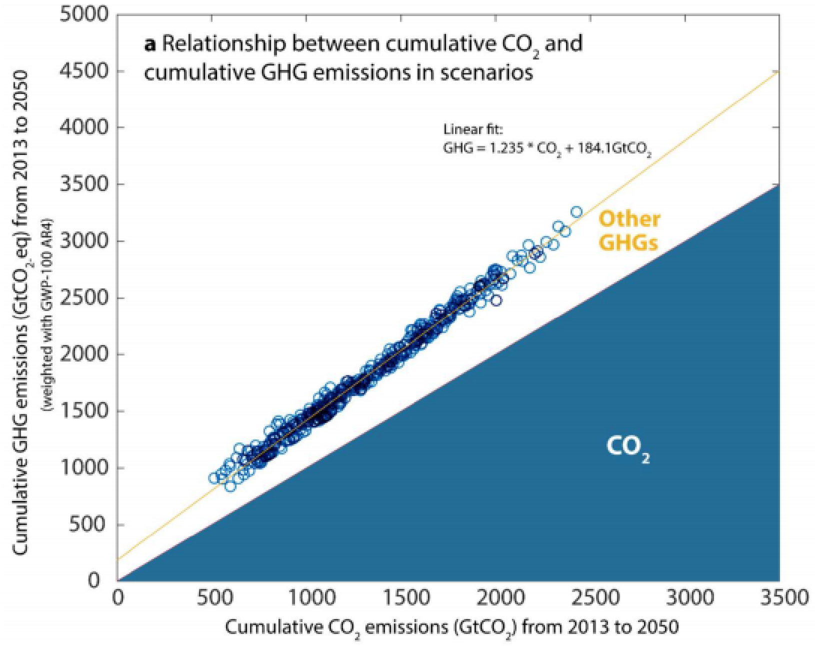
Apx Table B-4 Global carbon dioxide budgets from 2013 for the relevant scenarios in this report, adjusted to a pre-industrial baseline

Scenario	Temperature outcome and probability	Global budget (CO_2 only; from 2013)	Justification
Step Change and Exploring Alternatives	1.8°C (67%)	906 Gt CO_2	Subtract 222 Gt from budgets in Apx Table B-3. representing warming that already occurred from pre-industrial times until 1850-1900.
Hydrogen Export	1.5°C (50%)	556 Gt CO_2	

Up to this point, carbon budgets apply to carbon dioxide only. For accurate comparison with our modelling outcomes, greenhouse gases other than carbon dioxide (for example nitrous oxide and methane) must be considered. We take an approach by Meinshausen (2019) and updated by Nicholls and Meinshausen (2022) that adjusts the carbon budget based on the relationship between cumulative carbon dioxide and cumulative (total) GHG emissions across scenarios from the IPCC Assessment Report 6 database. The final relationship used is:

$$Cumulative\ total\ GHG\ emissions\ =\ 1.24 \times CO_2\ budget + 187.39$$

This equation aligns to the approach in Nicholls & Meinshausen (2022) (Nicholls, Z, Pers. Comm., 15 July 2022), and is an updated equivalent to the approach illustrated in Figure 1-1. This equation is applied to reach the global carbon budgets (actually total GHG budgets) in Apx Table B-5.



Apx Figure B-1 Relationship between cumulative CO2 and cumulative GHG emissions in 1.5°C scenarios. Illustrates the approach used to convert a CO2-only budget to a total GHG budget in units of CO2-equivalent (from Meinshausen et al. 2018)

Apx Table B-5 Global carbon budgets (applicable to all GHG emissions) from 2013 for the relevant scenarios in this report, adjusted from relevant global CO2-only budgets, before accounting for LULUCF accounting differences

Scenario	Temperature outcome and probability	Global budget (All GHGs; from 2013)	Justification
Step Change and Exploring Alternatives	1.8°C (67%)	1,311 Gt CO_2	Adjust budgets in Apx Table B-4 using the linear fit $1.24 \times CO_2 + 187.39$ (Nicholls, Z, Pers. Comm., 15 July 2022)
Hydrogen Export	1.5°C (50%)	877 Gt CO_2	

Differences in land use, land use change and forestry (LULUCF) accounting approaches used in national greenhouse gas reporting figures necessitate an adjustment to the global budget to ensure these emissions are not undercounted. We take the approach used in Nicholls & Meinshausen (2022) to adjust these, which is based on Grassi et al. (2021). Under this approach, 15% of the CO2-only portion of each budget is subtracted (Nicholls, Z, Pers. Comm., 15 July 2022). This is applied to reach the final global carbon budgets (actually total GHG budgets) in Apx Table B-6.

Apx Table B-6 Global carbon budgets (applicable to all GHG emissions) from 2013 for the relevant scenarios in this report, accounting for global LULUCF accounting differences

Scenario	Temperature outcome and probability	Global budget (All GHGs; from 2013)	Justification
Step Change and Exploring Alternatives	1.8°C (67%)	1,175 Gt CO_2	Subtract 15% of the budgets in Apx Table B-4from budgets in Apx Table B-5. (Nicholls, Z, Pers. Comm., 15 July 2022; Nicholls & Meinshausen 2022)
Hydrogen Export	1.5°C (50%)	793 Gt CO_2	

There are a number of methods that can be used to determine Australia's 'fair share' of the global carbon budget based on different 'burden-sharing' approaches. Our chosen approach aligns to that used by the Garnaut Review (2008), adopted by the Climate Change Authority (2014) and validated by Meinshausen et al. (2018) that takes Australia's fair share to be 0.97% of the global carbon budget, based on the modified contraction and convergence approach. Applying this percentage results in carbon budgets for Australia (from 2013) shown in Apx Table B-7.

Apx Table B-7 Australian carbon budgets (applicable to all GHG emissions) from 2013 for the relevant scenarios in this report

Scenario	Temperature outcome and probability	Australian budget (All GHGs; from 2013)	Justification
Step Change and Exploring Alternatives	1.8°C (67%)	11.397 Gt CO_2-e	Take 0.97% of the budgets in Apx Table B-6, representing Australia's 'fair share' under a modified contraction and convergence approach.
Hydrogen Export	1.5°C (50%)	7.696 Gt CO_2-e	

Finally, to produce carbon budgets relevant to modelling outcomes, it is necessary to adjust the budget to begin from 2021. This is achieved by subtracting Australia's emissions from 2013-2020 (4.273 Gt CO_2-e) to reach final national budgets from 2021-2050, in Apx Table B-8 (DCCEEW 2022). Sub-national carbon budgets (including for NEM-connected states) are not specifically considered. However, the cumulative emissions outcome for NEM-connected states can be considered an indication of the portion of this budget that those states could feasibly be constrained to in a given scenario.

Apx Table B-8 Australian carbon budgets (applicable to all GHG emissions) from 2021 for the relevant scenarios in this report

Scenario	Temperature outcome and probability	Australian budget (All GHGs; from 2021)	Justification
Step Change and Exploring Alternatives	1.8°C (67%)	7.124 Gt CO2-e	Subtract 4.273 from the budgets in Apx Table B-7 representing actual emissions from 2013-2020.
Hydrogen Export	1.5°C (50%)	3.423 Gt CO2-e	

Shortened forms

Abbreviation	Meaning
ABS	Australian Bureau of Statistics
ACCU	Australian Carbon Credit Unit
AE	Alkaline Electrolysis
AEMO	Australian Energy Market Operator
ANZSIC	Australian and New Zealand Standard Industrial Classification
AR5	IPCC Assessment Report 5
AR6	IPCC Assessment Report 6
AusTIMES	Australian TIMES
BEV	Battery Electric Vehicle
BITRE	Bureau of Infrastructure and Transport Research Economics
BTL	Biomass to Liquids
CCA	Climate Change Authority
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CGE	Computational General Equilibrium
CO_2-e	Carbon-dioxide equivalent (based on AR5 GWP)
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CWC	Climateworks Centre
DAC	Direct Air Capture
DCCEEW	Department of Climate Change, Energy, Environment and Water
DER	Distributed energy resources
DISER	Department of Industry, Science, Energy and Resources
DKIS	Darwin Katherine Interconnected System
DoEE	Department of the Environment and Energy
DRI	Direct Reduced Iron
DSP	Demand Side Participation
EAF	Electric Arc Furnace
EE	Energy Efficiency
EFOM	Energy Flow Optimization Model
ERF	Emissions Reduction Fund
ETSAP	Energy Technology Systems Analysis Project
EV	Electric Vehicle
FRG	Forecasting Reference Group
GBCA	Green Building Council Australia
GDP	Gross Domestic Product

GHG	Greenhouse gas
GJ	Gigajoule
GSP	Gross State Product
Gt	Gigatonne
GVA	Gross Value Added
GW	Gigawatt
GWh	Gigawatt hour
GWP	Global Warming Potential
HVAC	Heating, Ventilation, and Air Conditioning
ICE	Internal Combustion Engine
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
ISP	Integrated System Plan
kW	Kilowatt
kWh	Kilowatt hour
LED	Light Emitting Diode
LGC	Large-scale Generation Certificates
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
LULUCF	Land Use, Land-Use Change and Forestry
LUTO	Land Use Trade-Offs
MARKAL	MARKet ALlocation
Mha	Million hectares
MJ	Megajoule
MSM	Multi-Sector Modelling
Mt	Million tonnes
Mtpa	Million tonnes per annum
MW	Megawatt
MWh	Megawatt hour
NDC	Nationally Determined Contribution
NEM	National Electricity Market
NGA	National Greenhouse Accounts
NZE	Net Zero Emissions
NWIS	North West Interconnected System
OCE	Office of the Chief Economist
OCGT	Open-cycle gas turbine
PEM	Proton exchange membrane
PJ	Petajoules
PV	Photovoltaic
QRET	Queensland Renewable Energy Target

RCP	Representative Concentration Pathway
RET	Renewable Energy Target
REZ	Renewable Energy Zone
SGSC	Smart Grid Smart Cities
SMR	Steam Methane Reforming
SSP	Shared Socioeconomic Pathway
STC	Small-scale Technology Certificates
SWIS	South West Interconnected System
TIMES	The Integrated MARKAL-EFOM System
TRET	Tasmania Renewable Energy Target
TWh	Terawatt hour
UNFCCC	United Nations Framework Convention on Climate Change
VEEC	Victorian Energy Efficiency Certificate
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
VRET	Victorian Renewable Energy Target
WA	Western Australia

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