Appendix A2. ISP Development Opportunities

December 2025

Appendix to the Draft 2026 Integrated System Plan for the National Electricity Market

We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

This is Appendix A2 to the Draft 2026 Integrated System Plan (ISP) which is available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp. AEMO publishes the Draft 2026 ISP pursuant to its functions under section 49(2) of the National Electricity Law (which defines AEMO's functions as National Transmission Planner) and its supporting functions under the National Electricity Rules. This document is generally based on information available to AEMO as at 1 July 2025 unless otherwise indicated.

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Executive summary

AEMO's *Integrated System Plan* (ISP) is a roadmap for the transition of the National Electricity Market (NEM) power system, with a clear plan for essential infrastructure that will meet future energy needs. The ISP's optimal development path (ODP) sets out the needed generation, storage, and network investments to transition to net-zero by 2050 through current policy settings and deliver significant net market benefits for consumers.

This appendix presents the ISP development opportunities for electricity generation and storages in the ODP for three scenarios – *Step Change, Slower Growth*, and *Accelerated Transition*. These scenarios reflect different levels of economic and technical advancements over the coming decades, investments in consumer energy resources (CER), and pace of decarbonisation – influencing the emissions intensity of the generation mix that supplies electricity consumers, as well as the use of electricity to substitute traditional fuels through electrification. All scenarios incorporate the effects of various federal and state public policies relevant to the energy transition as outlined in the 2025 *Inputs, Assumptions and Scenarios Report* (IASR)[1] that meet the National Electricity Rules (NER) requirements[2] and the Australian Energy Market Commission's (AEMC's) emissions targets statement[3].

This appendix also presents the impact on ISP development opportunities of key uncertainties through targeted sensitivity analysis. Development opportunities for distribution investments are discussed in Appendices A3 and A9.

ISP development opportunities in generation and storage across scenarios

The NEM's transition to a net zero economy is driven by renewable energy developments, supported by policies and assumed lowering of costs for these maturing technologies, firmed with storages of various depths and backed up by retaining and replacing gas-fired generation, in order to replace the capacity and electricity generation capability of coal generation. In addition, consumers are continuing to invest in their own energy assets and are assumed to increasingly integrate these to the power system, enabling bundling and coordination to respond to market signals via virtual power plant (VPP) opportunities. The need for new investments in generation and storage developments is also increasing as a result of rising electricity demand as sectors such as transport and industry switch from gas to electricity and residential and commercial consumers switch energy forms from gas to electricity for heating and cooking.

State and federal policies – including the Powering Australia Plan, the Capacity Investment Scheme (CIS), and regional renewable energy targets – influence the pace and location of new investments in utility-scale wind and solar, especially in New South Wales and Victoria.

Complementing renewable energy developments are new developments in storage technologies and flexible gas generation to firm variable renewable energy (VRE) resources and ensure the power system remains reliable and secure at all times, including during periods of dark and still renewable energy lulls as coal-fired generators and mid-merit gas generators retire.

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1 At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios.

2 As per NER 5.22.3(b), which acknowledges that AEMO must (or may) consider eligible government policies when identifying power system needs and in developing how the ISP contributes to achieving the national electricity objective.

3 AEMC, *Emissions targets statement under the national energy laws*, Guide, June 2025, at https://www.aemc.gov.au/sites/default/files/2025-06/Targets%20statement%20June%202025.pdf.

The Draft 2026 ISP projects a significant increase in VRE generation capacities across all three ISP scenarios. By 2049-50, utility-scale VRE is projected to grow from 23 gigawatts (GW) in 2024-25 to 81 GW in *Slower Growth*, 120 GW in *Step Change*, and 219 GW in *Accelerated Transition*. If including the capacity of rooftop and other small-scale solar, the scenarios represent 71%, 70%, and 72% of total capacity being operated from intermittent renewable resources, respectively.

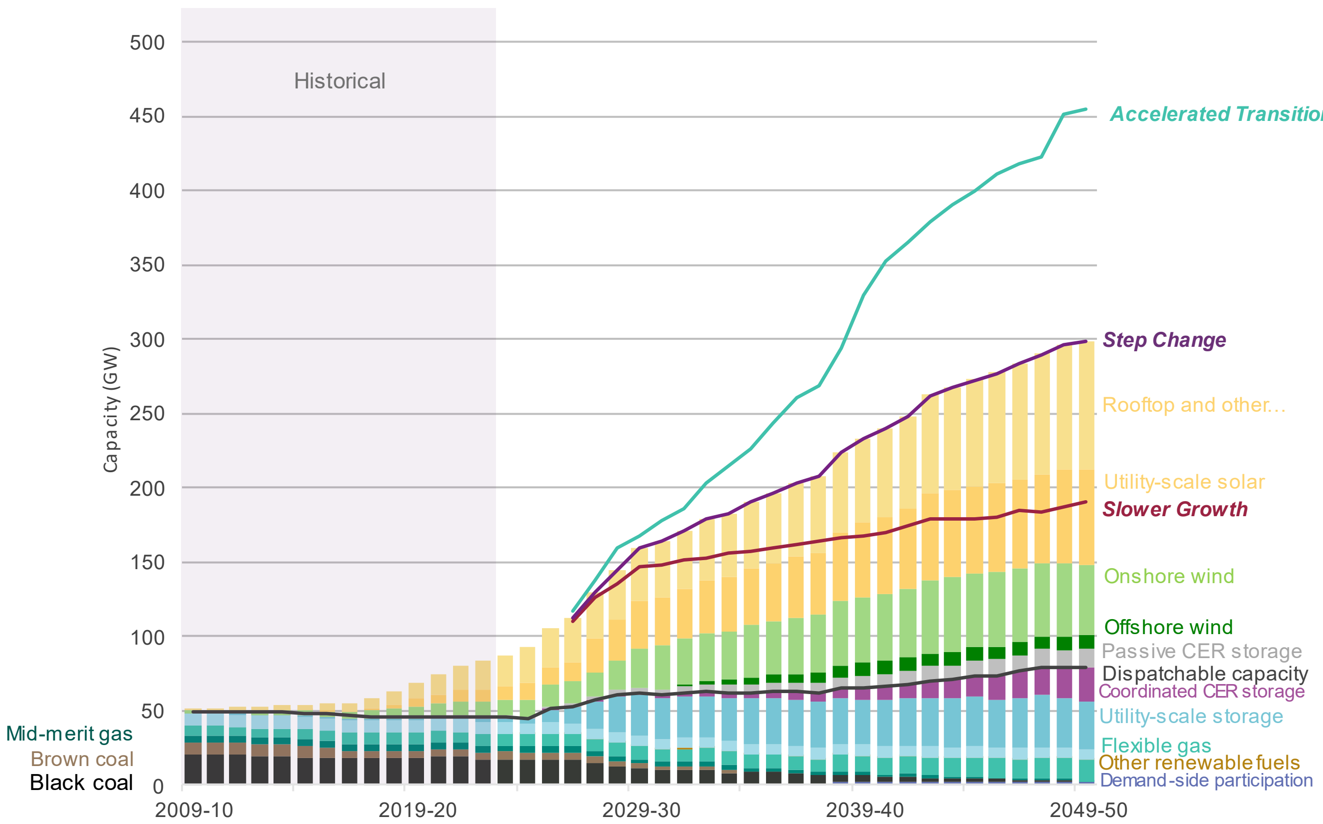
In the NEM's transition to 2029-30:

- Coal-fired generation capacity is projected to withdraw by at least a third, driven by emissions reduction policies and increasing availability of renewable generation, with capacity reducing from 21 GW currently to approximately 11 GW in *Slower Growth*, 13 GW in *Step Change*, and to 6 GW in *Accelerated Transition*. Coal operators are also assumed to investigate and implement flexible operating strategies, such as two-shifting or reducing minimum stable operating levels, to enable lower annual generation from these stations until they retire.
- Renewable generation capacity is needed to replace coal, and meet rising demand and government targets, with significant growth forecast throughout the outlook period, buoyed by lower assumed installation costs over time as the technologies continue to mature. Utility-scale VRE capacity across the NEM is projected to reach approximately 53 GW, 58 GW, and 69 GW under *Slower Growth*, *Step Change*, and *Accelerated Transition*, respectively. In addition, the NEM's existing 7 GW of hydro-electric generation capacity remains in place.
- Rooftop and other small-scale solar is projected to offset a significant portion of their own consumption, and are increasingly expected to combine with batteries. Consumer investments are projected to have a major role in the energy transition, and can reduce the need for utility-scale investments, particularly if bundled and coordinated via VPPs or vehicle-to-grid (V2G) charging of electric vehicles. Rooftop and other small-scale solar is projected to grow to 32 GW, 36 GW, and 38 GW in *Slower Growth*, *Step Change*, and *Accelerated Transition,* respectively, with CER storages providing between 4 GW/8 GWh and 7 GW/14 GWh of capacity across the scenarios.
- To complement and firm VRE developments, a mixture of storage depths is needed to provide intra-day energy shifting and seasonal firming when winter renewable energy output is lower than summer's. A total storage capacity of 31 GW/454 gigawatt hours (GWh) is projected in *Slower Growth*, 32 GW/461 GWh in *Step Change*, and 34 GW/466 GWh in *Accelerated Transition*. This includes the 13 GW/382 GWh of committed and anticipated capacity that is currently under active development.

To provide critical back-up power supply during renewable energy lulls, a flexible gas fleet of between 13 GW to 16 GW in aggregate capacity will be required by 2049-50 across all scenarios, replacing 9 GW mid-merit and older peaking gas capacity that is forecast or announced to retire between now and 2050 as the plants reach end-of-life. Flexible gas plants will provide supply for peak demand events, enable continued reliability during renewable energy lulls and support ongoing grid security as coal plants withdraw.

Figure 1 below shows the generation and storage development projected in the three scenarios for the ODP.

Figure 1 Historical and projected generation and storage capacity across the three core scenarios, 2009-10 to 2049-50 (GW)



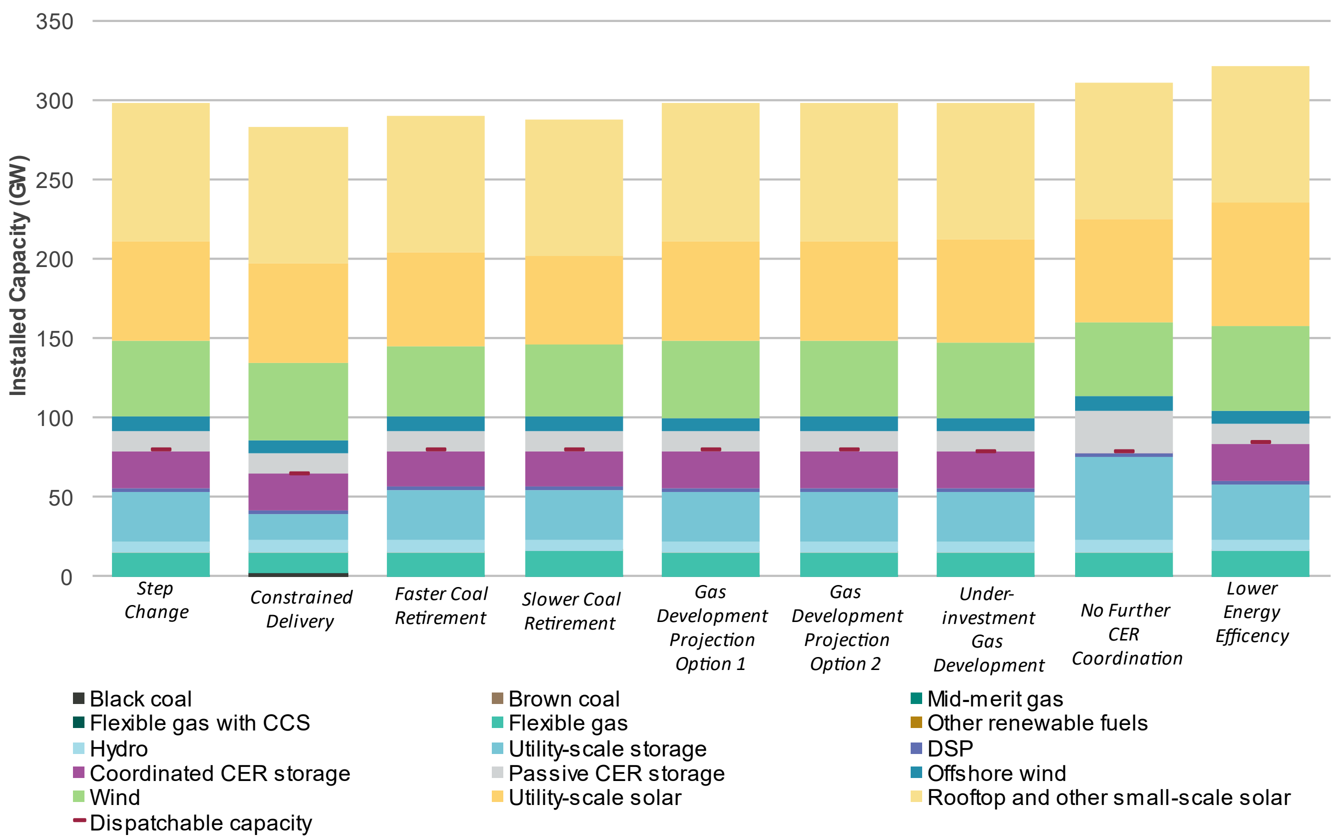
Sensitivity analysis demonstrates that the level of generation and storage developments needed to support the transition is not significantly influenced by uncertainties, unless the development of new infrastructure is constrained or speed of coal retirements vary

Using a scenario planning approach and assessment of individual uncertainties through sensitivity analysis, AEMO's modelling demonstrates that the ODP provides appropriate resilience, robustness, and the ability to adapt to future uncertainties. The sensitivities modelled in the Draft 2026 ISP explored a range of risks and uncertainties, including alternative assumptions on:

- the influence that potential development constraints may have on the NEM's developments,
- the different gas development projections that could ensure sufficient gas supply availability,
- the uptake and levels of coordination of CER,
- the levels of energy efficiency that impact the NEM, and
- the rate at which coal-fired generator capacities exit the NEM.

As shown in **Figure 2**, the scale of utility-scale solar and wind development is resilient to alternative assumptions assessed in the sensitivity analysis. The change in assumptions in some sensitivity analyses had greater impact on the medium-term generation and storage outlook, such as the *Constrained Delivery* sensitivity where delivery delays affecting generation, storage, and transmission developments reduce the pace of investments in the near term. Conversely, the effect of alternative gas development projections had relatively little impact on the aggregate NEM-wide development opportunities, but there are some locational differences that reflect the availability of gas for power generation. The coal retirement schedule sensitivities considered how the pace of investments in the NEM might change with different coal-fired generation capacity closure schedules. These sensitivities showed moderate changes in the generation and storage outlook compared to *Step Change*.

Figure 2 Generation and storage capacities by 2049-50 in *Step Change* and sensitivities to *Step Change* (GW)



AEMO's Draft 2026 ISP includes numerous appendices to provide more information on generation, storage, and electricity network opportunities and benefits. In particular:

- Appendix A3 provides information on renewable energy zones (REZs),
- Appendix A4 provides information on the operability of the power system, considering the NEM's developments,
- Appendix A6 contains detail on the ISP's cost-benefit analysis (CBA),
- Appendix A9 includes insight on demand-side factors, and
- Appendix A10 contains analysis on gas development projections.

The Draft 2026 ISP's **Generation and Storage Outlook Workbooks**[4] provide details of the capacity developments, energy generated, and retirement outlook for all relevant NEM regions. The workbooks also present emissions outcomes and comparisons of outcomes between different CDPs for each scenario.

[4] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

A2.1 Introduction

This appendix of the Draft 2026 ISP provides detailed insights on the ISP development opportunities for electricity generation, storages, and electrolysers to help meet both consumer needs and government policies, at least cost, for at least the next 20 years in each ISP scenario. In particular:

- A2.2 summarises the generation, storage, and electrolyser developments that would be needed across the three ISP scenarios,
- A2.3 provides more detailed examination of these developments for each scenario, and
- A2.4 details the impact to those development opportunities of the various sensitivity analyses to key assumptions.

This appendix presents a NEM-wide view and regional breakdowns, where appropriate, of these developments. The Draft 2026 ISP examines several candidate development paths (CDPs) in determining the optimal development path (ODP). The outcomes presented in this appendix are based on the proposed ODP in the Draft 2026 ISP. See Appendix A6 for details on the justification of the proposed ODP.

The glossary at the end of this appendix provides a number of definitions. Terms defined in the NER, Australian Energy Regulator (AER) guidelines or the *ISP Methodology* have the meanings given in those documents. Some key terms used in this, and other relevant appendices are summarised below for reference:

- **Actionable ISP projects** are transmission projects (or non-network options) identified as part of the ODP and have a delivery date within an actionable window. More information on this is in Appendix A6.
- **Future ISP projects** are transmission projects (or non-network option) that addresses an identified need in the ISP, that is part of the ODP and is projected to be actionable in the future. More information on this is in Appendix A6.
- An **ISP development opportunity** is a development identified in the ISP that does not relate to a transmission project (or non-network option) may include generation, storage, demand-side participation, or other developments such as distribution network projects.
- **Distribution investment opportunities** are efficient investments in distribution network that specifically enable greater export of CER from consumers' homes and businesses into the distribution network, unlocking latent CER capacity to benefit all consumers. More information on this is in Appendix A9.
- **Gas development projections** identify combinations of investments that may be developed by the gas industry to address the investment opportunities highlighted in the 2025 *Gas Statement of Opportunities* (GSOO) and support the availability and operation of flexible gas in the NEM**.** More information on this is in Appendix A10.

In this appendix, all dates are on a financial year basis. For example, 2024-25 represents the financial year starting 1 July 2024 and ending 30 June 2025.

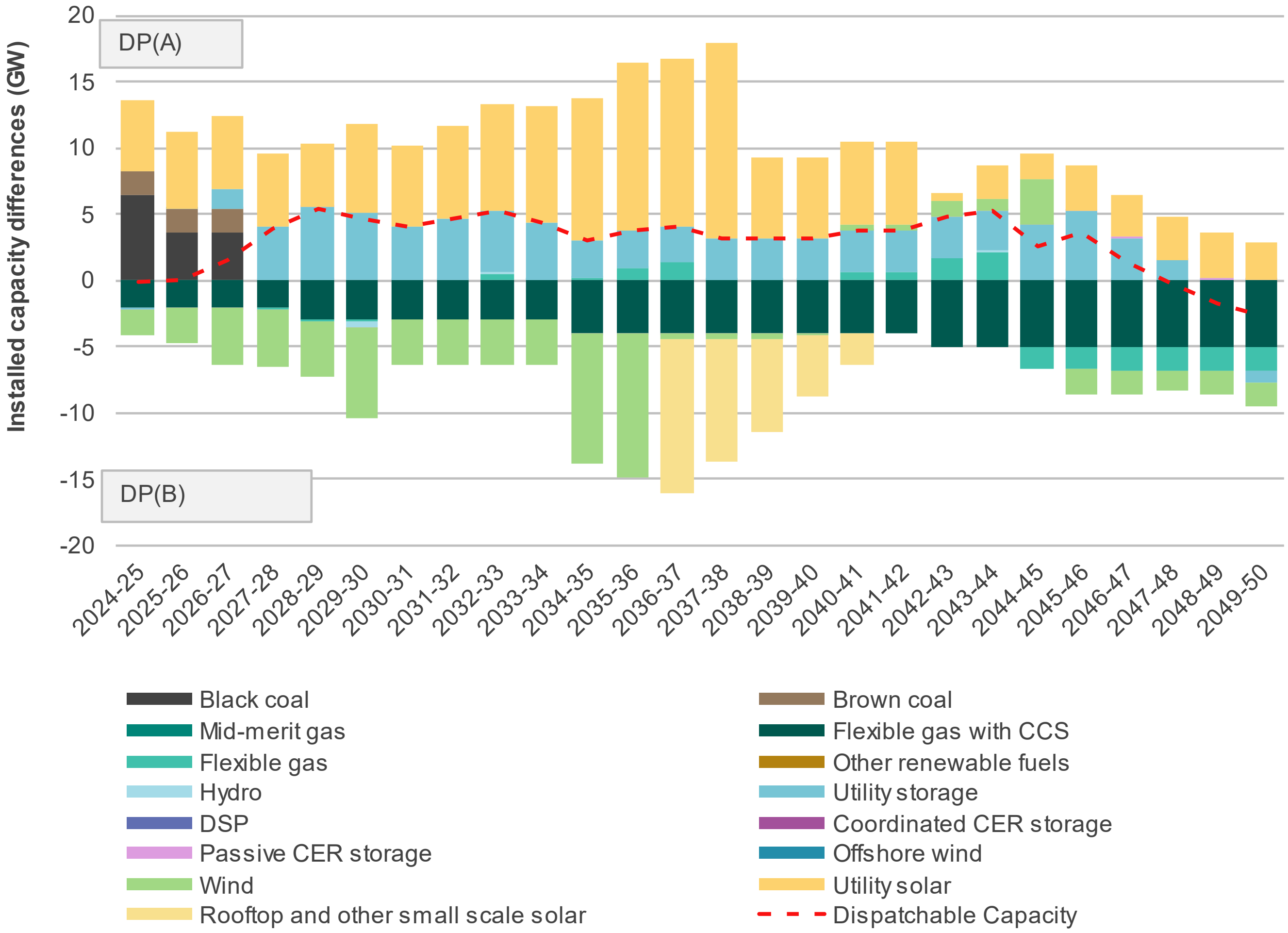
A2.1.1 Interpreting the graphics in this appendix

This appendix presents a number of charts comparing the projected capacity and generation over the outlook period of two different CDPs, or of a sensitivity and a CDP, as shown in the example figure below.

When interpreting the sample chart in **Figure 3:**

- The stacked columns show the projected values for different technologies on an annual basis.
- A positive value indicates the higher total capacity in the first development path, DP(A), relative to DP(B) –which in some cases, is the 'no transmission' counterfactual development path or the impact of a sensitivity. A negative value indicates higher capacity in DP(B). For example, the yellow bar indicates there is higher capacity of utility-scale solar in DP(A) relative to DP(B).
- The line represents the projected difference in total dispatchable capacity between the two development paths.

Figure 3 Example interpretation of projected capacity differences used in this appendix



A2.1.2 Key changes since the 2024 ISP and summary impacts

AEMO has applied several changes to its 2026 ISP models since the publication of the 2024 ISP in response to stakeholder feedback, legislative changes, rule changes, and market developments. These have required reasonable extensions to AEMO's modelling approach, particularly when considering gas and distribution network development opportunities.

This section describes the key changes in assumptions and approach that have been made in this ISP and the impact these changes have had on generation and storage development opportunities. A summary of stakeholder engagement and key themes raised is presented in Appendix A1. Distribution network development opportunities are newly examined in this Draft 2026 ISP, and are presented in Appendix A9. Gas development projections are important to support operating needs for gas generators, and are also presented for the first time in Appendix A10.

Key changes since the 2024 ISP

Salient changes seen in this Draft 2026 ISP most relevant to ISP development opportunities for generation and storage developments, following extensive stakeholder feedback, include:

- Updated committed and anticipated projects as per the July 2025 Generation Information update – an additional 4 GW each of wind, utility-scale solar, and utility-scale storage, along with 1 GW of flexible gas, that are committed or anticipated and have been incorporated since the 2024 ISP.
- Included the latest policy updates including the expansion of the 2030 CIS generation and dispatchable targets, the South Australia Firm Energy Reliability Mechanism, the increase to the New South Wales Government Electricity Infrastructure Investment (EII) Act, and Australia's Nationally Determined Contribution (NDC) for 2035, and the repeal of the Queensland renewable energy target.
- Updated the NEM's temperature-linked emissions budgets assumed for each scenario.
- Updated capital costs of new entry generation and storage technologies, to reflect the latest GenCost report.
- Implemented technology-specific weighted average costs of capital (WACCs) to account for the different financial risks and assumptions appropriate for each technology. The WACC used in this ISP also reflects the varying risk assumptions under each scenario.
- Modelled electrolyser load within candidate REZs, as opposed to load centres as in previous ISPs. This was in response to stakeholder feedback and information received from external studies which identified pipelines as the least-cost option for transporting hydrogen in majority of cases.
- Included two new types of constraints for the Draft 2026 ISP which reflect the capability of existing distribution networks to support higher levels of operation of CER and 'other distributed resources'. 'Other distributed resources' means new-entrant solar and batteries that are distribution-connected with installation sizes ranging from 5-30 MW.
- The Victorian region was split into three sub-regions in the Draft 2026 ISP, and the Central South Australia (CSA) sub-region split into two to separate Northern South Australia (NSA). This provided better transmission network representation.
- Updated transmission options based on the 2025 *Electricity Network Options Report*.
- Expanded consideration of gas market investments and the availability of gas as a generation fuel, with consideration of gas development projections developed using inputs applied from the 2025 GSOO. The gas

development projections provide alternative gas investment pathways to identify the impact of gas availability on electricity investment development needs in this Draft 2026 ISP. This change was in response to the 2024 ISP review and subsequent rule changes.

- Updated renewable energy resource traces based on stakeholder feedback which increased capacity factors for wind generation in some REZs, representing a higher level of production per MW of installed capacity.

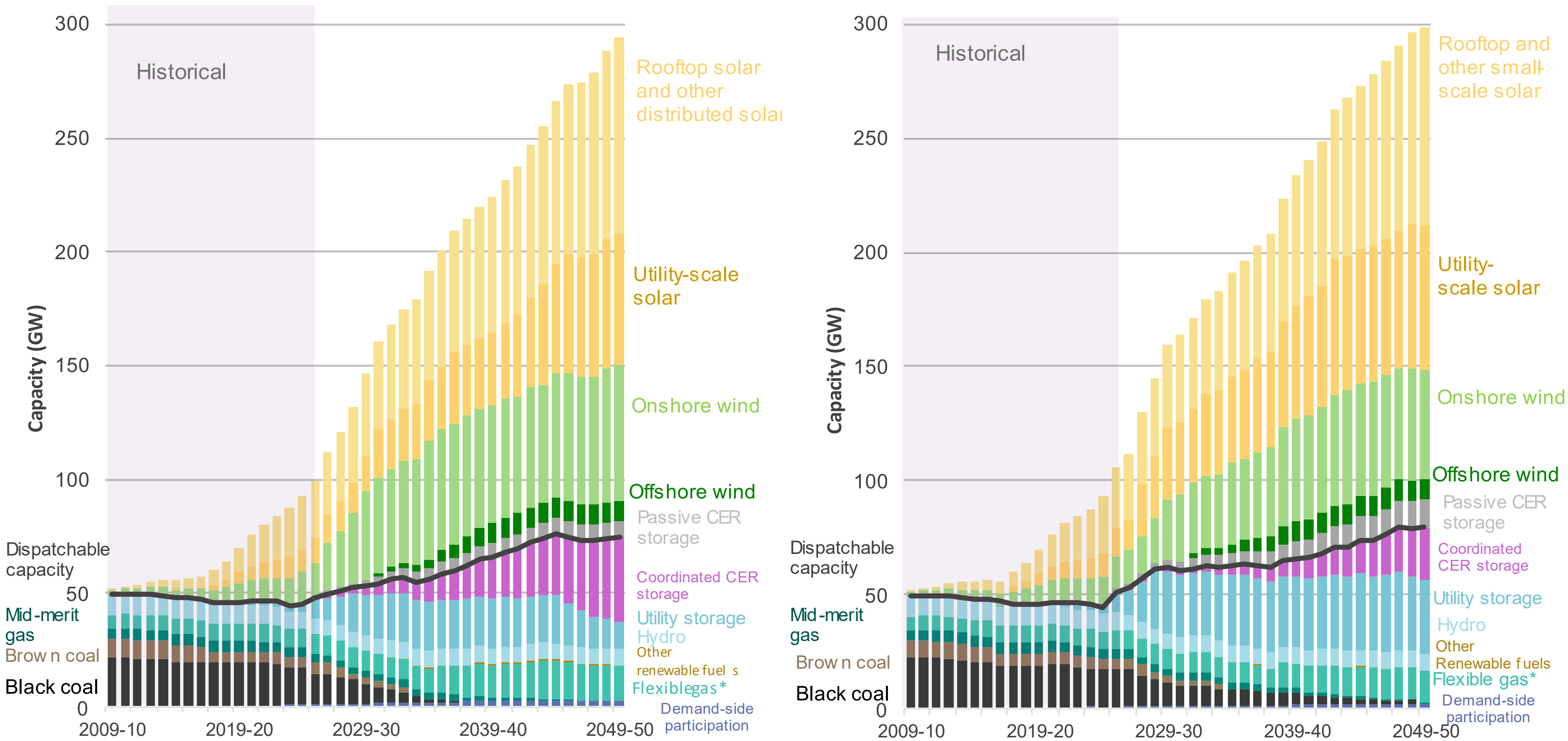
More information on these changes and other assumptions can be found in the 2025 IASR.

The impact of these changes since the 2024 ISP vary by scenario. Key changes and their impacts include:

- Shallow and medium-depth utility-scale storage capacity is higher in the Draft 2026 ISP largely due to additional committed and anticipated storage projects reported in the July 2025 Generation Information update, and as a result of relevant government policies and targets, including the expanded CIS.
- Utility-scale solar capacity is higher across the outlook period, as solar generation is an efficient pairing to the additional storages to meet demand when needed, with additional committed or anticipated projects and a reduction in forecast capital costs for utility-scale solar relative to 2024 ISP cost assumptions.
- In contrast, the projected wind capacity development is lower, with higher relative capital costs for wind in this ISP, and a higher WACC relative to utility-scale solar. Counteracting these assumption changes, some locations across the NEM now assume higher energy yield from wind farms due to updated wind traces that reflect higher hub heights in this Draft 2026 ISP.
- Coal-fired generation capacity remains operational for longer in the Draft 2026 ISP, reflecting the intent of the Queensland Energy Roadmap. To retain these plants, more flexible operation is required, with increasingly frequent periods where coal plants are offline for hours, days, or even months at a time, to complement high solar generation periods.
- There is a reduction in the projected level of consumer investment in rooftop and other small-scale solar capacity between 2031-32 to 2043-44, and VPP and V2G capacity has also reduced. These reductions have contributed to higher utility-scale solar and utility-scale storage capacity.
- While energy consumption is lower in the Draft 2026 ISP due to the large reduction in hydrogen demand assumed, the higher development of utility-scale solar – which has a lower level of production per megawatt (MW) compared with other technologies – results in a higher capacity needed to produce similar amount of energy generation.

Figure 4 compares the generation and storage development opportunities in the ODP in *Step Change* in the 2024 ISP versus the Draft 2026 ISP.

Figure 4 Generation and storage development opportunities in the ODP in *Step Change* in the 2024 ISP (left) versus the Draft 2026 ISP (right) (GW)



Notes: Projections for "Rooftop and other small-scale solar" and "CER storage" are forecast as outlined in the 2025 *Inputs, Assumptions and Scenarios Report* (IASR).
Rooftop and other small-scale solar includes forecast residential and commercial rooftop photovoltaic (PV) systems as well as larger distributed PV systems referred to as PV non-scheduled generation (PVNSG) systems.
"Utility solar" also includes other distributed PV systems. "CER storage" means consumer energy resources such as batteries and EVs.
"Flexible gas" includes gas-powered generation and potential hydrogen capacity.

A2.2 Summary of proposed ODP development opportunities for generation and storage across the scenarios

A2.2.1 A changing generation mix

The Draft 2026 ISP considers the range of policies, alongside technical and market drivers, to identify the least-cost way to supply secure and reliable electricity to consumers through to 2050, as coal plants retire and while meeting government policies. A range of policies exist across all governments that influence the generation and storage development opportunities for the NEM's transition. As a result, significant capacity of new VRE generation is projected, across all scenarios. **Table 1** presents the capacity mix (development opportunities) for each of the three scenarios where the transmission investments under each scenario follow the transmission development identified in the ODP. See Appendix A5 and Appendix A6 for more details on the cost-benefit analysis of the transmission developments that are included in the ODP.

The table shows that utility-scale VRE (including solar and wind technologies) increases from 23 GW in 2024-25 to 120 GW in the *Step Change* scenario by 2049-50, and to 81 GW and 219 GW, respectively, in *Slower Growth* and *Accelerated Transition*. This reflects 42%, 40%, and 47% of the total installed capacity for 2049-50 for *Step Change, Slower Growth,* and *Accelerated Transition*, respectively. Rooftop and other small-scale solar are projected to have the greatest capacity of any technology, demonstrating the significant role that consumers are expected to continue to play in the transition.

Alongside the three scenarios in **Table 1** is a key sensitivity that AEMO has included in this Draft 2026 ISP that examines the impact of a slower rate of delivery for generation, storage and transmission developments in the near term.

Constrained Delivery sensitivity

The *Constrained Delivery* sensitivity explored the impact of delivery constraints on the development of generation, storage, and electricity network developments in the *Step Change* scenario. There may be many reasons for delivery delays – through planning approvals and the need for social licence, the supply chain, or construction – but the sensitivity only limited the rate of build, not what determined the delays. Project costs were assumed to rise on average by 30%, due to these constraints in this sensitivity.

In this sensitivity, with the development of generation, storage and network slowed by delivery constraints, some policy outcomes would take longer to be achieved. For example, the Victorian Offshore Wind Target was assumed to be delivered three years later in this sensitivity, and the NEM would generate approximately 75% from renewable energy by 2029-30, below the Powering Australia Plan's target of 82%.

This sensitivity is outlined in more detail in Section A2.4.1.

Table 1 Installed capacity in 2024-25, 2029-30, 2039-40, and 2049-50 (GW)

Technology	Actual	*Slower Growth*			*Step Change*			*Accelerated Transition*			*Constrained Delivery*		
	2024-25	2029-30	2039-40	2049-50	2029-30	2039-40	2049-50	2029-30	2039-40	2049-50	2029-30	2039-40	2049-50
Black coal	16.4	8.5	5.3	0.0	10.5	5.3	0.0	3.8	0.0	0.0	10.5	3.8	1.7
Brown coal	4.8	2.2	0.0	0.0	2.8	0.0	0.0	2.2	0.0	0.0	3.4	0.0	0.0
Mid-merit gas	4.2	3.2	2.2	0.4	3.2	2.2	0.4	3.2	2.2	0.4	3.2	2.2	0.4
Flexible gas with carbon capture and storage (CCS)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flexible gas	7.5	8.6	7.9	13.3	8.6	10.5	14.3	8.6	12.3	16.0	8.7	11.9	13.3
Hydro	7.7	6.9	7.3	7.3	6.9	7.3	7.3	6.9	7.3	7.3	6.9	7.3	7.3
Shallow utility-scale storage	2.8	13.2	13.1	5.1	13.2	13.0	5.8	13.2	13.1	9.9	2.7	2.5	0.9
Medium utility-scale storage	0.0	10.7	11.7	9.1	10.7	12.5	21.6	11.1	28.8	34.6	8.8	17.1	11.2
Deep utility-scale storage	0.0	3.3	5.3	5.3	3.3	5.3	5.3	3.3	5.3	5.3	3.3	5.3	5.3
Coordinated CER storage	0.2	0.6	2.6	7.1	1.6	7.8	22.8	2.5	14.0	40.1	1.6	7.8	22.8
Passive CER storage	1.3	3.4	5.7	7.7	3.6	7.6	12.5	4.2	9.0	13.4	3.6	7.6	12.5
Offshore wind	0.0	0.0	9.0	9.0	0.0	9.0	9.0	0.0	12.8	14.6	0.0	6.0	9.0
Wind	12.0	22.4	26.1	37.3	26.2	44.7	47.8	35.8	57.1	69.7	24.6	49.6	48.8
Utility-scale solar	10.5	30.6	31.2	34.7	31.7	49.8	63.4	32.7	98.2	134.9	24.6	57.8	62.1
Rooftop and other small-scale solar	25.0	32.1	39.3	52.8	35.8	57.0	86.7	38.3	66.3	108.5	35.8	57.0	86.7
Other renewable fuels	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Demand side participation	1.0	0.9	1.1	1.2	1.2	1.8	2.3	1.5	3.3	5.4	1.2	1.8	2.3

Note: the generation mix includes generation and storage projects classified as committed and anticipated in the July 2025 Generation Information dataset. For definitions of each technology, refer to the Glossary section at the end of this appendix.

Transitioning from reliance on coal and mid-merit gas generation for bulk generation

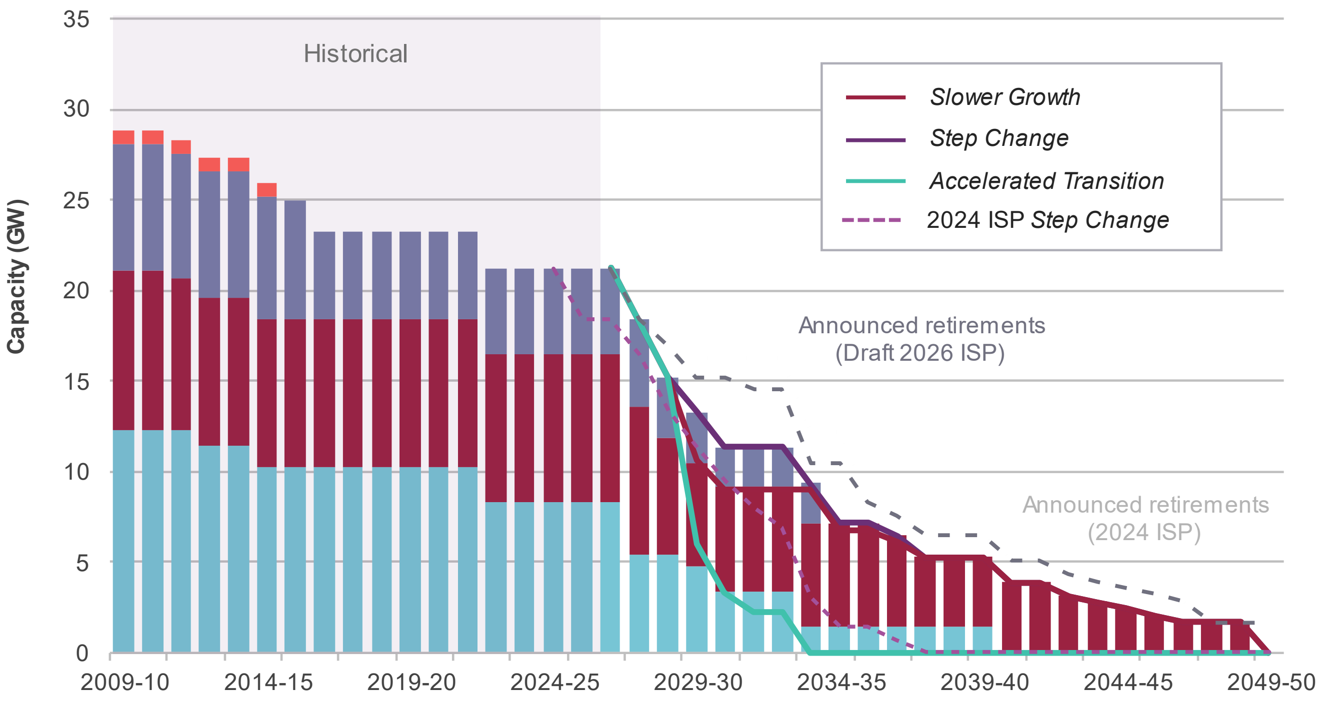
The Federal Government has committed to an economy-wide emissions reduction target of 43% below 2005 levels by 2030, 62% to 70% below 2005 levels by 2035, and a net zero emissions economy by 2050. At the same time, electrification of households, transport, and industries – as well as the emergence of data centres and domestic hydrogen production – is increasing electricity consumption, leading to a doubling of underlying consumption by 2050 as a key decarbonisation pathway for households, businesses and industry.

To meet government energy and emissions policies and the rising needs to supply new electricity consumption, the *Step Change* scenario projects development of 214 GW of small- and utility-scale generation capacity across the NEM which includes approximately 130 GW of utility-scale renewable energy, and 90 GW of investments made by consumers in their rooftop and other small-scale solar. In addition, 70 GW of storage capacity (including committed and anticipated projects) is projected by 2049-50. These new generation and storage capacities are offsetting the retirement of approximately 20 GW of coal-fired and mid-merit gas generation.

Coal-fired capacity is projected to decline slower across all ISP scenarios compared to the 2024 ISP, and some coal operators are assumed to increase their capability to operate in more flexible operating modes than was expected in the 2024 ISP. Recent operating behaviours of some coal-fired generators demonstrate this shift towards more flexible operating levels, including two-shifting[5] when commercially and technically appropriate, and operating more seasonally.

Figure 5 demonstrates the historical and projected coal closure outlook in *Step Change* against the announced retirement schedule for the NEM's coal-fired generation fleet and compares it with other scenario projections in the Draft 2026 ISP. In the *Step Change* scenario, nearly 66% of coal-fired generation capacity is projected to be retired by 2034-35, driven by retirements in New South Wales, with some Queensland coal-fired generation capacity remaining in operation to align with the intent of the Queensland Energy Roadmap before closing in 2049-50.

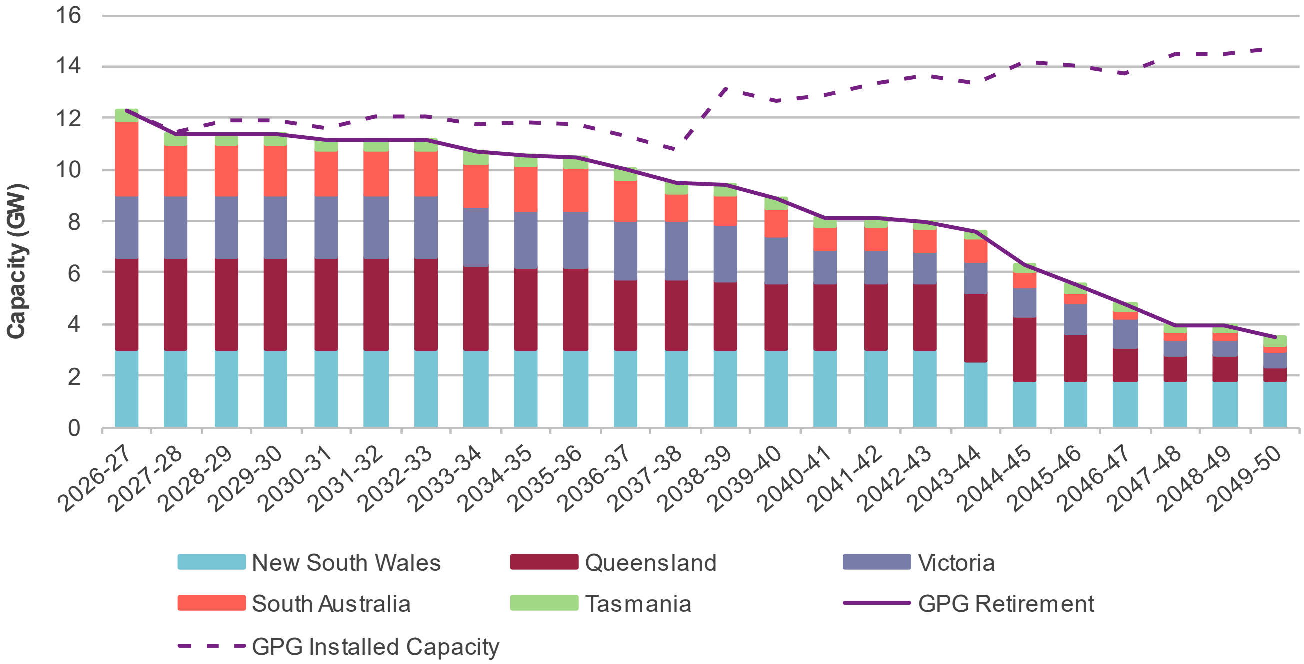
Figure 5 Historical and projected coal retirements, 2009-10 to 2049-50 (GW)



Mid-merit gas generation is also projected to decline as plants approach their retirement dates, but some gas capacity is expected to remain in operation through to 2049-50, and the gas generation fleet is expected to expand with flexible gas capacity installed to backup storage developments and firm the highly renewable generation mix. **Figure 6** shows the total gas capacities being retired from the NEM; the dashed line is the total installed capacity after new entry flexible gas developments are considered. The difference between the stacked columns (the existing fleet considering retirements) and the dashed line (the installed capacity) shows the newly built flexible gas in *Step Change*.

[5] Two-shifting means switching off during the daytime peaks of solar generation and returning for the evening peak and through the night and morning.

Figure 6 Projected flexible gas retirement, *Step Change*, 2026-27 to 2049-50 (GW)



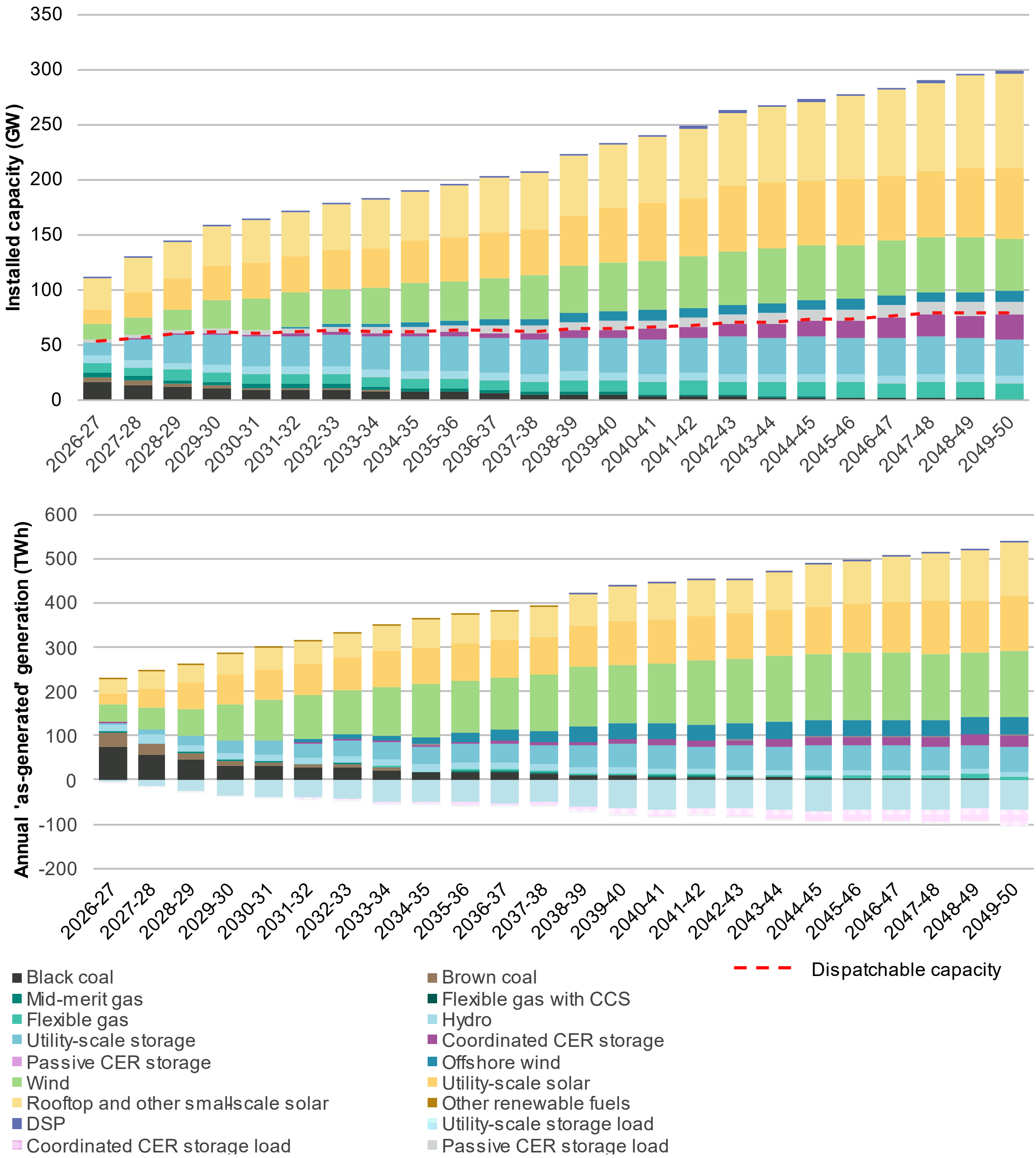
The chart at the top of **Figure 7** shows *Step Change*'s installed capacity and demonstrates that utility-scale VRE (solar and wind) are projected to have the strongest development opportunity, alongside projected rooftop and other small--scale solar[6]. To meet a renewable energy target of 82% by 2030, about 35 GW of utility-scale solar and wind would need to be added. This is greater than the current 24 GW[7] that are progressing through the connections process, and on average take four years from connection application to full output.

The bottom chart of **Figure 7** also shows that the energy generated from renewable generators is projected to increase, and by 2029-30, projected total generation from all solar generation (utility-scale solar, rooftop and other small-scale solar) is 44% (113 TWh) of the NEM's total generation, traditional hydro is projected to make up 6% (14 TWh), and wind generation makes up 32% (81 TWh).

[6] Also referred to as distributed PV.

[7] Projects totalling 27 GW have applied, but historically 10% of connection applications do not progress through to output.

Figure 7 NEM-wide installed capacity (top) and energy generation (bottom), *Step Change*, 2026-27 to 2049-50 (GW and TWh)



Generation from flexible gas[8] is also projected to increase over the outlook period as it provides a critical role in firming the intermittency of utility-scale wind and solar generation and providing dispatchable resources when required,

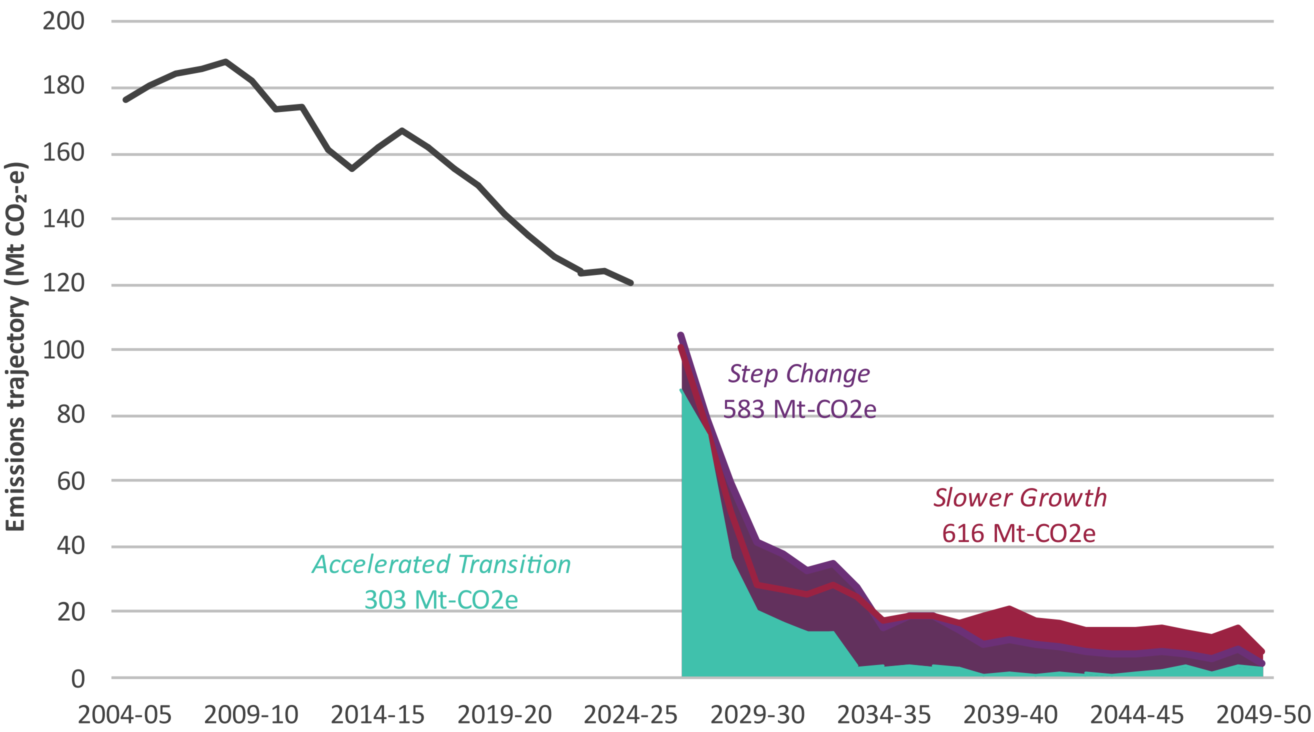
[8] Flexible gas units are open-cycle gas turbine technologies which can quickly ramp-up and -down to balance the grid and back-up renewable generation.

complementing storage devices of various depths. This is most evident during periods of low renewable resource availability such as during winter which is more prone to renewable energy lulls. See Appendix A4 for NEM operability insights.

A2.2.2 Emissions trajectory and renewable share

The transformation of the NEM to support Australia's transition to a net zero emissions economy by 2050 depends on rising investment in renewable generation at utility scale (wind and solar) to complement the high continued investment expected in CER. The shift from coal-fired generators and mid-merit gas generation to a high penetration of renewable energy will reduce the electricity sector's emissions intensity under all ISP scenarios, as shown below in **Figure 8** and **Figure 9**. The developments in renewable generation are supported by various eligible public policies, which are applied across all scenarios, shaping the emissions trajectory of each scenario.

Figure 8 Actual and projected annual NEM-wide emissions by scenario, 2004-05 to 2049-50 (Mt CO_2-e)



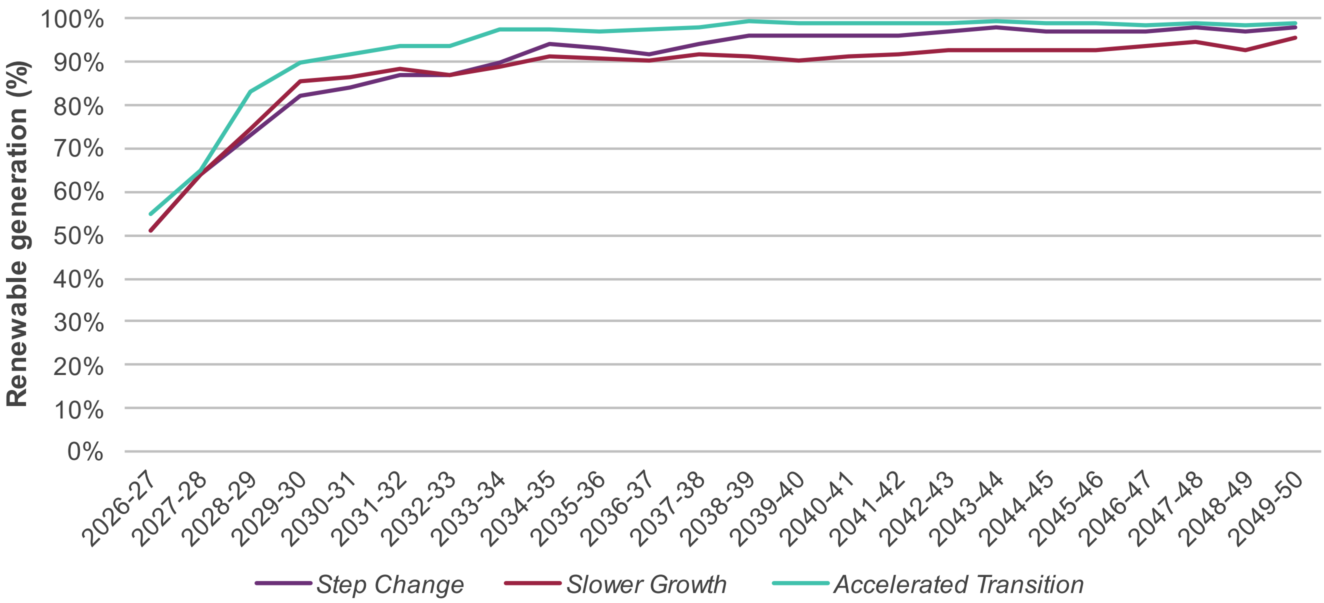
In the *Step Change* and *Slower Growth* scenarios, strong policy support and rapid uptake of utility wind and solar drive steep and consistent emissions reductions to achieve the 2030 and 2035 emissions targets. After these policies are met, emissions still decline, but at a differing pace between each scenario. *The Slower Growth* scenario achieves higher emissions reduction relative to *Step Change* in the early years of the outlook period due to lower energy consumption, but the reduction slows significantly from 2030 onwards due to more modest investments in renewables.

In contrast, the *Accelerated Transition* scenario represents the most ambitious pathway to a net zero economy, with early retirements of coal-fired generation capacity and rapid expansion of renewables required to meet the lowest emissions budget in the NEM among the three scenarios. The *Accelerated Transition* scenario achieves net zero emissions a decade earlier than the net zero target, with renewable generation accounting for nearly all of the total NEM generation by the end of the outlook period.

By 2029-30, NEM emissions are projected to reduce by 77% in *Step Change* (from 176 Mt CO_2-e in 2004-05 to 41 Mt CO_2-e in 2029-30), and by 88% in *Accelerated Transition* (from 176 Mt CO2-e in 2004-05 to 20 Mt CO_2-e in 2029-30). With lower relative consumption but renewable generation developments aligned with policy targets, the *Slower Growth* scenario sees an 84% reduction in emissions by 2029-30 (from 176 Mt CO_2-e in 2004-05 to 29 Mt CO_2-e in 2029-30).

Complementing **Figure 8** above, **Figure 9** below presents the projected level of renewable energy penetration to 2049-50 by scenario. It demonstrates the increasing role of wind and utility-scale solar as well as other renewable generation sources to reduce emissions to 2050. All scenarios achieve the Powering Australia Plan objective of 82% renewable energy by 2029-30, and by 2034-35 NEM emissions are reduced by 84% in *Step Change*, 86% in *Slower Growth* and 98% in *Accelerated Transition* compared to 2004-05 levels. This demonstrates the high contribution that the NEM is projected to provide in terms of the overall economy-wide emissions reduction activities, particularly in the short to medium term. In *Step Change*, the share or renewable generation is projected to reach 98% by 2049-50.

Figure 9 Evolution of the annual share of total generation from renewable sources including rooftop and other small-scale solar, by scenario to 2049-50 (%)



A2.2.3 Energy storage needs

Energy storage has a crucial role in firming a high penetration renewable grid. To guide investment decisions across consumer, distribution, and transmission levels, AEMO considers a range of storage types:

- **CER storages** typically offer approximately two hours of storage capacity. These assets may be part of **coordinated CER storage** that are managed by aggregators in VPPs, enabling response to market signals, or operate as **passive CER storage** that are behind-the-meter and operating to service the household's needs in isolation.
- **Utility-scale storages** are grid-connected and classified by their storage duration: **shallow** (less than four hours), **medium-depth** (four to 12 hours) or **deep** (more than 12 hours). Shallow utility-scale storage includes utility-scale storage and those connected in the medium voltage network of the distribution network. Shallow and medium-depth

storages are used for intra-day energy-shifting, discharging during morning or evening peak hours. In contrast, deep utility-scale storages are designed to support energy management across seasons, helping to meet extended periods of low renewable generation availability during renewable energy lulls.

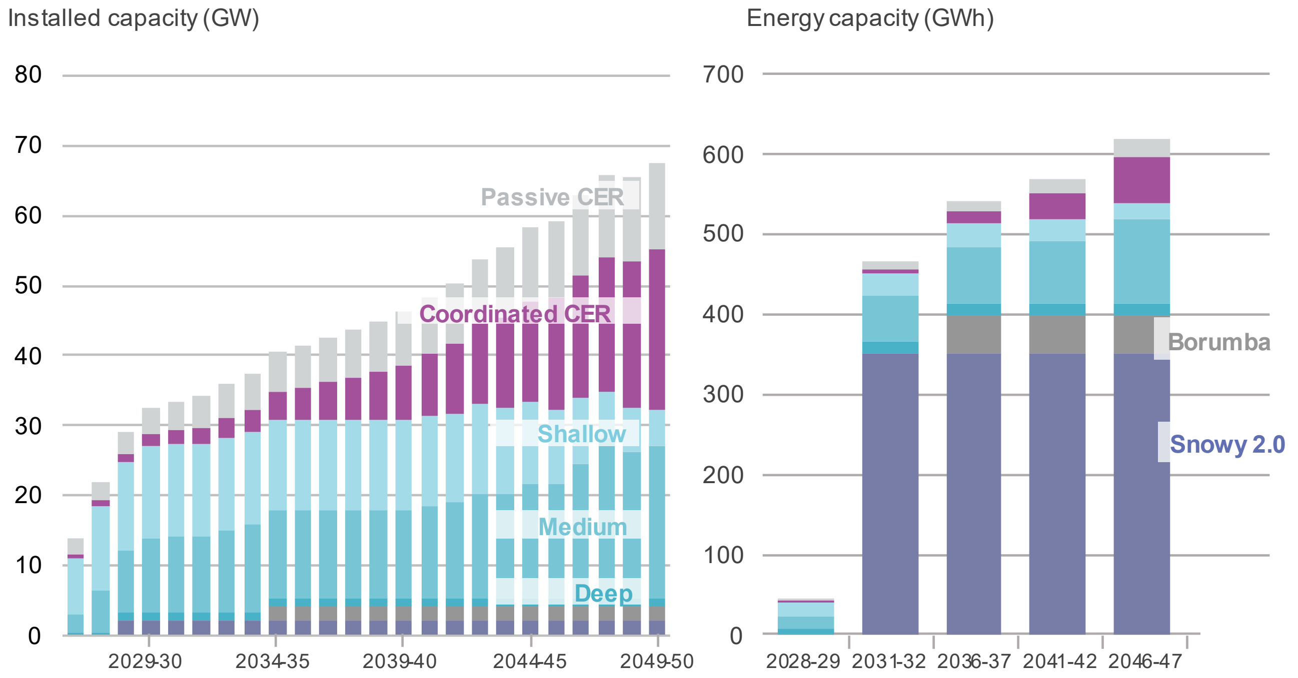
In all scenarios, the increased uptake of storage systems is primarily driven by existing commitments and the need to complement high VRE penetration to reliably and securely meet growing energy consumption. Storage systems enable energy-shifting by soaking excess generation throughout the day and across seasons and discharging during periods of peak demand. The growth in energy consumption from electrification including the adoption of electric vehicles (EVs), and the retirement of synchronous generators such as coal-fired power plants, place additional strain on grid management. Storage systems play a critical role in providing firming capacity and can assist in maintaining grid stability through provision of essential services such as system strength (that is, providing a stable voltage waveform), inertia, frequency control, and voltage support.

Figure 10 presents projected NEM-wide storage capacity by depth to 2049-50 in *Step Change*:

- A high level of storage capacity, most frequently of medium duration, is currently committed or anticipated. Some of these developments are supported by government schemes, such as the CIS.
- Utility-scale storage capacity is projected to reach 27 GW/451 GWh by 2029-30 with a projected mix of 3.3 GW/366 GWh as deep, 10.7/57 GWh GW as medium and 13.2 GW/28 GWh as shallow storage. In addition, CER storage is projected to reach 5.2 GW/10 GWh. The fastest growth occurs in medium-depth utility-scale storage and coordinated CER storage.
- Deep storage will be a critical contributor to system reliability, accounting for only 9% of installed capacity but about 80% of energy storage capacity[9] in 2029-30. Technologies such as pumped hydro energy systems can provide discharge duration exceeding 12 hours with appropriate reservoir developments, and several projects such as the Snowy 2.0 and Borumba Pumped Hydro projects are under development to expand deep storage capacity.
- Traditional hydro schemes (currently 7 GW installed capacity) can also provide a critical role in storing water for future use in producing electricity (as well as servicing other users, such as water irrigation).

[9] Traditional reservoir hydro schemes are not included in this calculation of energy storages.

Figure 10 NEM-wide storage installed capacity (right) and energy storage capacity (left), *Step Change*, 2026-27 to 2049-50 (GW and GWh)



A2.3 Generation and storage development opportunities across scenarios

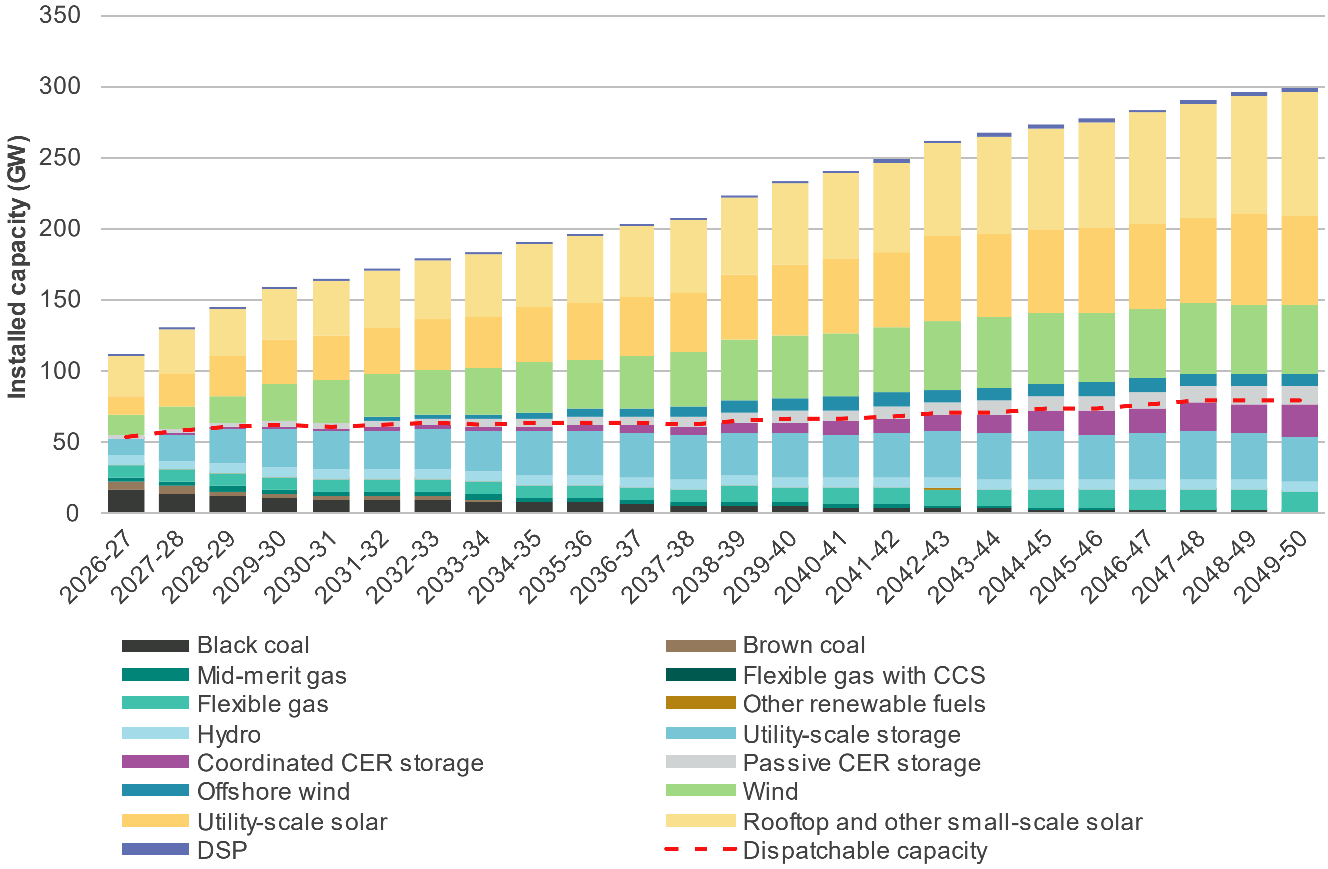
This section outlines the optimal mix of generation and storage for each scenario. The installed capacity projection differs between each scenario depending on the speed of emissions reduction, retirements of coal-fired generation capacity, and projected energy consumption. The magnitude of utility-scale VRE developments is driven by various renewable energy targets, and total installed capacity for utility-scale solar and wind (including existing, committed and anticipated developments) reach 53 GW, 58 GW, and 69 GW by 2029-30 in *Slower Growth*, *Step Change*, and *Accelerated Transition*, respectively. By 2049-50, utility-scale VRE developments diverge across scenarios more significantly and reach 81 GW, 120 GW, and 220 GW in *Slower Growth*, *Step Change*, and *Accelerated Transition* of installed capacity, respectively. In *Step Change* under the proposed ODP, utility-scale wind and solar capacity would rise from its current 23 GW to 58 GW by 2030, then double to 120 GW by 2050.

A2.3.1 Step Change

Step Change presents a scenario where Australia achieves government policy objectives and transitions the energy system to support limiting global temperature rise below 2°C, with moderate economic and population growth, strong consumer investment in electrification and CER, and material new loads from transport and industry but limited domestic hydrogen industry growth.

Figure 11 below presents the projected capacity mix for the NEM across the outlook period to 2049-50 in *Step Change*.

Figure 11 Projected NEM installed capacity, *Step Change*, 2026-27 to 2049-50 (GW)



Renewables to replace coal as bulk generation

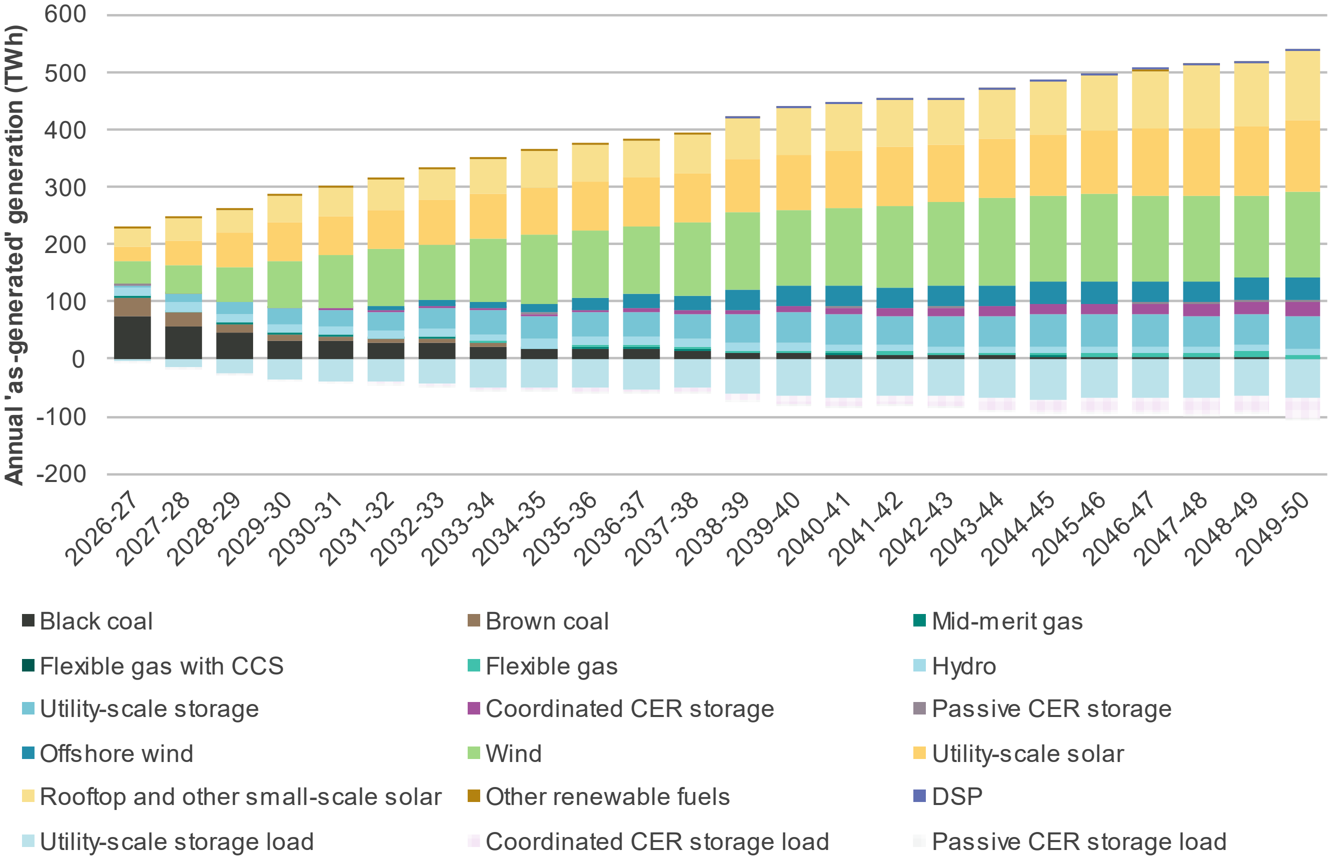
A large proportion of renewable energy developments are projected in New South Wales and Victoria, an outcome of high relative load, retiring generators, supporting policy targets, and high relative resource quality for utility-scale wind and solar developments.

Significant volumes of committed, and anticipated generation, particularly in storage devices, are currently under development, and various targeted state policies are supporting storage and VRE developments. The high development of storage capacity enables surplus renewable energy to be stored and shifted to be used when needed, meaning that supply is better matched to demand. The storage uptake supports a high level of utility-scale solar build, being the lowest cost renewable generation capacity that will complement storage capacity. By 2029-30, NEM-wide storage capacity including CER storage is 32.4 GW/ 461 GWh, majority of which are located in New South Wales.

In *Step Change*, 8 GW of coal-fired generation capacity is projected to retire by 2029-30, and all coal and mid-merit gas generation is projected to retire by 2049-50, to meet the scenario's emissions budget. This generation is replaced with renewable energy generation, storage and flexible gas capacity. VRE represents the most cost-efficient solution for new energy supply when firmed by storage and flexible gas and connected with appropriate network developments. Utility-scale solar capacity is projected to increase to 63 GW and wind capacity to 48 GW, with the majority located in New South Wales. Complementing utility-scale developments are consumer's own investments in PV and battery solutions. By 2049-50, CER storages are projected to reach 35 GW/100 GWh and rooftop and other small-scale solar developments are projected to reach 87 GW, or 29% of NEM capacity.

Figure 12 demonstrates the high degree of change expected to affect the NEM's generation mix, including the high penetration of renewable energy generation. Utility-scale wind and solar capacity is projected to rise from its current 23 GW to 58 GW by 2030, then double to 120 GW by 2050. *Step Change* develops sufficient renewable energy capacity in 2029-30 to meet the 82% target set in Powering Australia Plan, and the share of VRE generation is projected to increase to 94% by 2034-35 and 98% by 2049-50. The remaining 2% of non-renewable generation is provided by flexible gas, with 7.5 TWh of generation from flexible gas[10] in 2049-50.

Figure 12 Projected annual generation, *Step Change*, 2026-27 to 2049-50 (TWh)



Dispatchable capacity to firm renewables

Firming capacity is required to ensure a reliable power supply and maintain grid stability. As coal-fired generation capacity retires in the NEM, a combination of CER storages, flexible gas, utility-scale storage, hydro, and pumped hydro energy systems will be required, complementing activities that consumers can take to shift load away from peak load conditions such as may be available with industrial loads such as electrolysers. While operators are required by the Rules to meet minimum notice of closure requirements, timely investment in replacement assets is needed to ensure sufficient generation and firm capacity developments are online in-time to maintain reliability of supply for consumers.

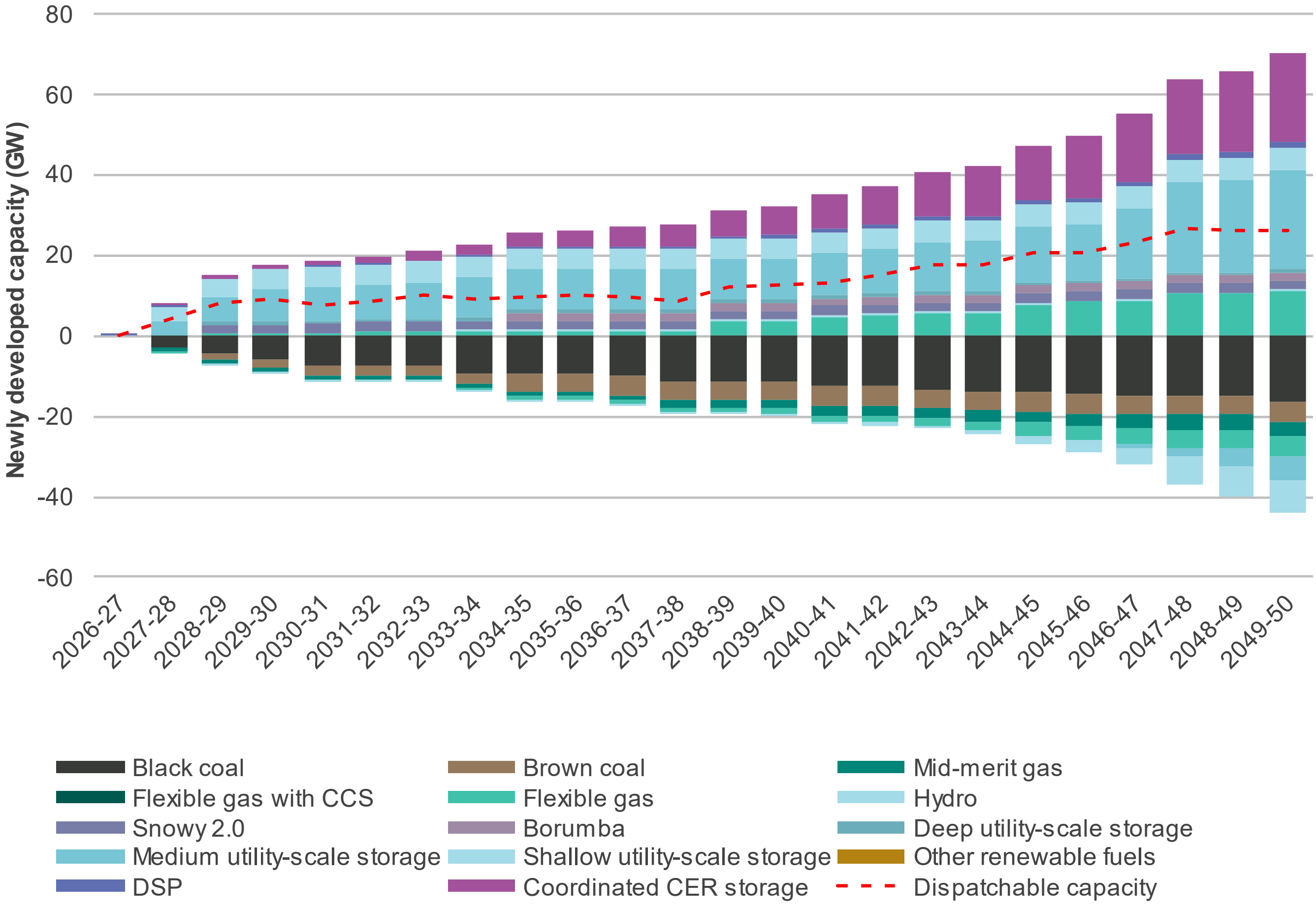
[10] Weather conditions will influence the total level of generation from most generation sources, but gas generation in particular is expected to compensate for renewable energy availability variation and firm periods of high electricity demand, during periods of extreme heat and cold. As such, generation forecasts for gas generation are more likely to vary than other technologies.

In *Step Change*, flexible gas and storages provide dispatchable capacity during peak demand intervals. Flexible gas is projected to increase from 8 GW in 2026-27 to 14 GW in 2049-50 to ensure firm capacity requirements are met, such that retiring coal and mid-merit gas capacity is offset by flexible gas and storages. Utility-scale storage capacity increases from 11 GW in 2026-27 to 27 GW in 2029-30 and 32 GW in 2049-50. While installed capacity is projected to grow by 5 GW in total between 2029-30 and 2049-50, additional storage development is required to replace storage projects that reach their end of technical life in this time.

Coordinated CER storage capacity increases from 1 GW in 2026-27 to 23 GW in 2049-50 under this scenario, providing a significant contribution to maintaining reliability.

Figure 13 demonstrates the change in dispatchable capacity projected in the *Step Change* across the outlook period.

Figure 13 Projected relative change compared with 2024-25 in dispatchable capacity, *Step Change*, 2026-27 to 2049-50 (GW)



Coal retirement schedule

In this scenario, all coal-fired generation capacity is projected to retire by 2049-50 in the NEM, but the pace at which coal retires varies by region:

- In Victoria, the majority of brown coal is retired by 2030-31 (earlier than currently announced), with the remaining capacity retiring by 2035.

- In New South Wales, several generators are closed consistent with their currently announced closure schedule (for example, Eraring Power Station is scheduled to retire in 2027); the majority of the remaining coal-fired generators are projected to retire by 2033-34 to meet the emissions targets of the scenario.
- In Queensland, 50% of existing coal capacity in Queensland is projected to retire by 2037-38, with some capacity available to 2049-50.

Coal retirements may occur even faster than these projections. Higher operating costs, reduced fuel security, high maintenance costs and greater competition from renewable energy in the wholesale market are challenging the financial viability of some power stations. To extend their availability, many coal plant operators are investigating their operating capability to enable ‘two-shifting’[11] and other more flexible operations. In some cases, coal generators may operate only during peak seasons – remaining active in summer and winter while shutting down during the shoulder periods. This shift to flexible operation is assumed in this 2026 ISP, particularly in Queensland, to enable consistency with the intent of the Queensland Energy Roadmap, allowing coal-fired generation capacity to generate for longer.

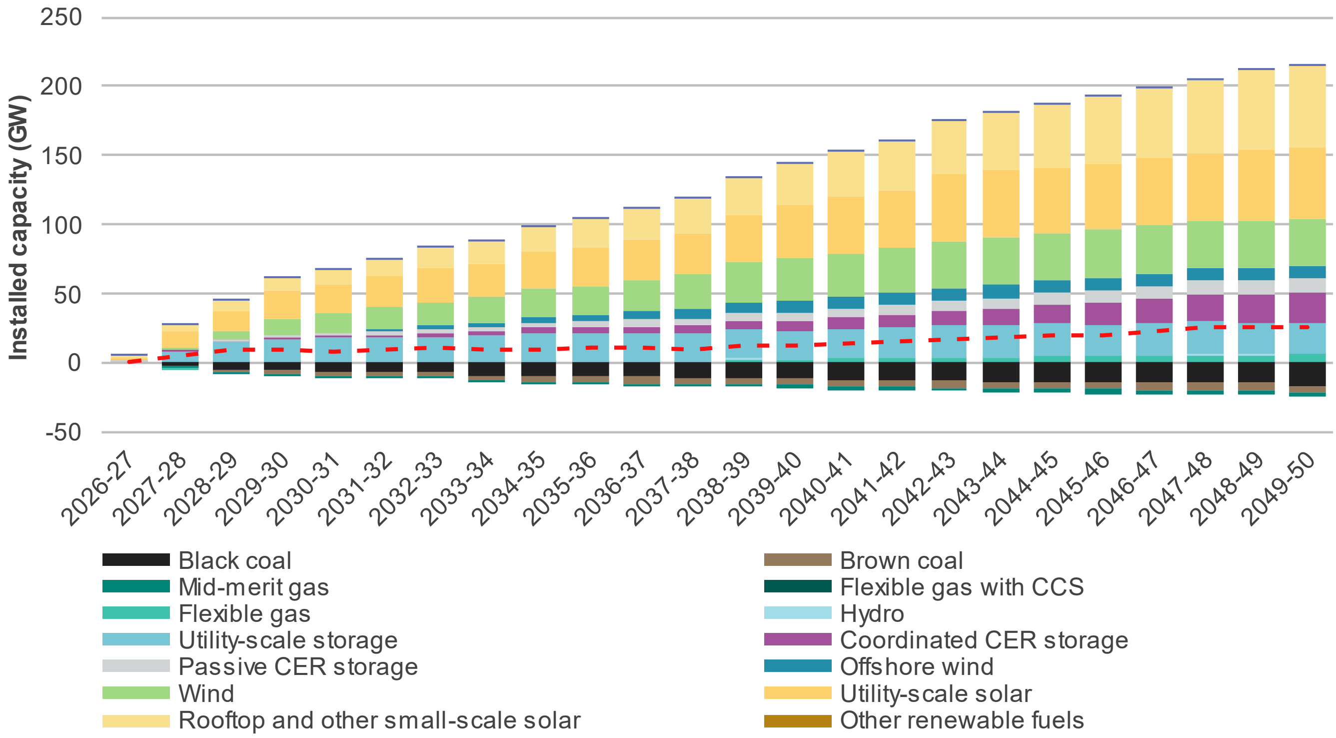
New developments and closures

Figure 14 shows the change in installed capacity over time. VRE capacity is projected to need to increase rapidly to meet renewable energy targets and policies, resulting in 94 GW of VRE capacity NEM-wide by 2029-30. This is comprised of 32 GW of utility-scale solar, 26 GW of onshore wind, and 36 GW of rooftop and other small-scale solar. Approximately 45% of utility-scale VRE capacity in 2029-30 is in New South Wales, driven by the New South Wales and CIS generation target, as well as the increase in utility-scale storage.

NEM-wide VRE development continues to grow to 207 GW in 2049-50 to replace the generation no longer provided by retiring thermal generation capacities. This is comprised of 87 GW of rooftop and other small-scale solar, 63 GW of utility-scale solar, 48 GW of onshore wind, and 9 GW of offshore wind.

[11] Two-shifting means switching off during the daytime peaks of solar generation, and returning for the evening peak and through the night and morning.

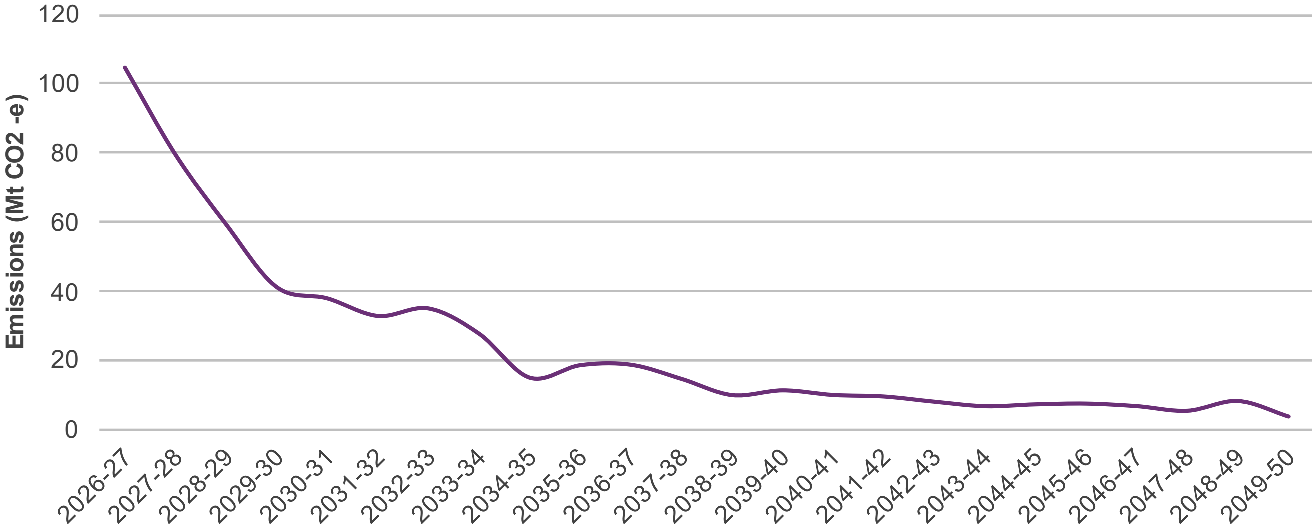
Figure 14 Projected relative change in new installations and closures compared to 2024-25 installed capacity, *Step Change*, 2026-27 to 2049-50 (GW)



Impact on emissions

As a result of the changing energy mix, emissions are projected to decline rapidly between 2026-27 and 2029-30 due to renewable energy generations' increasing role in supplying energy consumption. By 2034-35, emissions are projected to reduce by 84% compared to 2005 levels in the *Step Change* scenario (from 176 million Mt CO_2-e in 2004-05 to 28 Mt CO_2-e in 2034-35) driven by policies and the 2030 emissions budget that has been allocated to the electricity sector in the 2025 IASR. Emissions continue to reduce after 2034-35, but more gradually. **Figure 15** shows the decrease of emissions across the outlook period.

Figure 15 Projected NEM emissions trajectory, *Step Change*, 2026-27 to 2049-50 (Mt CO_2-e)

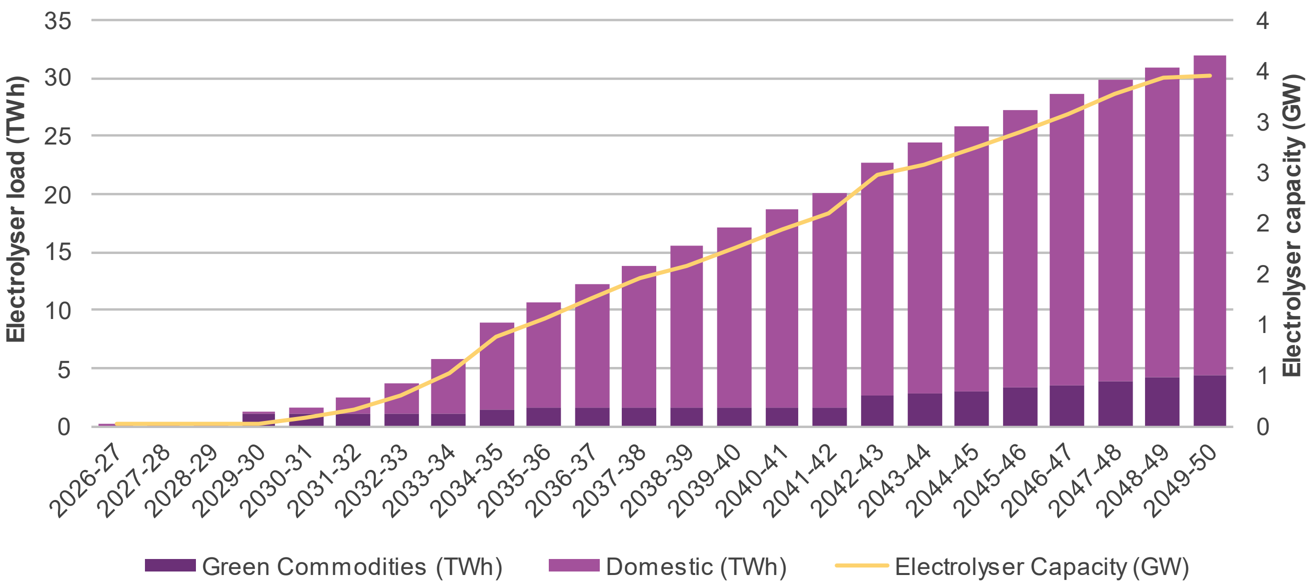


Hydrogen developments

The ISP modelling considered hydrogen developments for domestic use and for the production of green commodities. The assumed demands are modelled as separate flexible loads, and it was assumed that there is hydrogen storage that is sufficiently large to store a week's worth of hydrogen.

Figure 16 presents the assumed total electricity consumption to 2049-50 for hydrogen production in *Step Change*. By 2049-50, 3.5 GW of electrolyser capacity is developed, operating with an average utilisation factor of 94% over the outlook period.

Figure 16 Electricity consumption associated with hydrogen production, *Step Change*, 2026-27 to 2049-50 (TWh)



Electrolysers are mostly developed in REZs that are closely located to end users (for domestic markets), and to export hubs (for green commodities that service domestic and international customers) to minimise costs of transporting hydrogen, particularly in Queensland, New South Wales, Victoria and South Australia. Electrolysers operating regime are projected such that they follow the diurnal pattern of the cheapest form of energy that have access to – in this case, mostly utility solar – as this helps minimise the impact on the supply demand balanced and the usage of the network

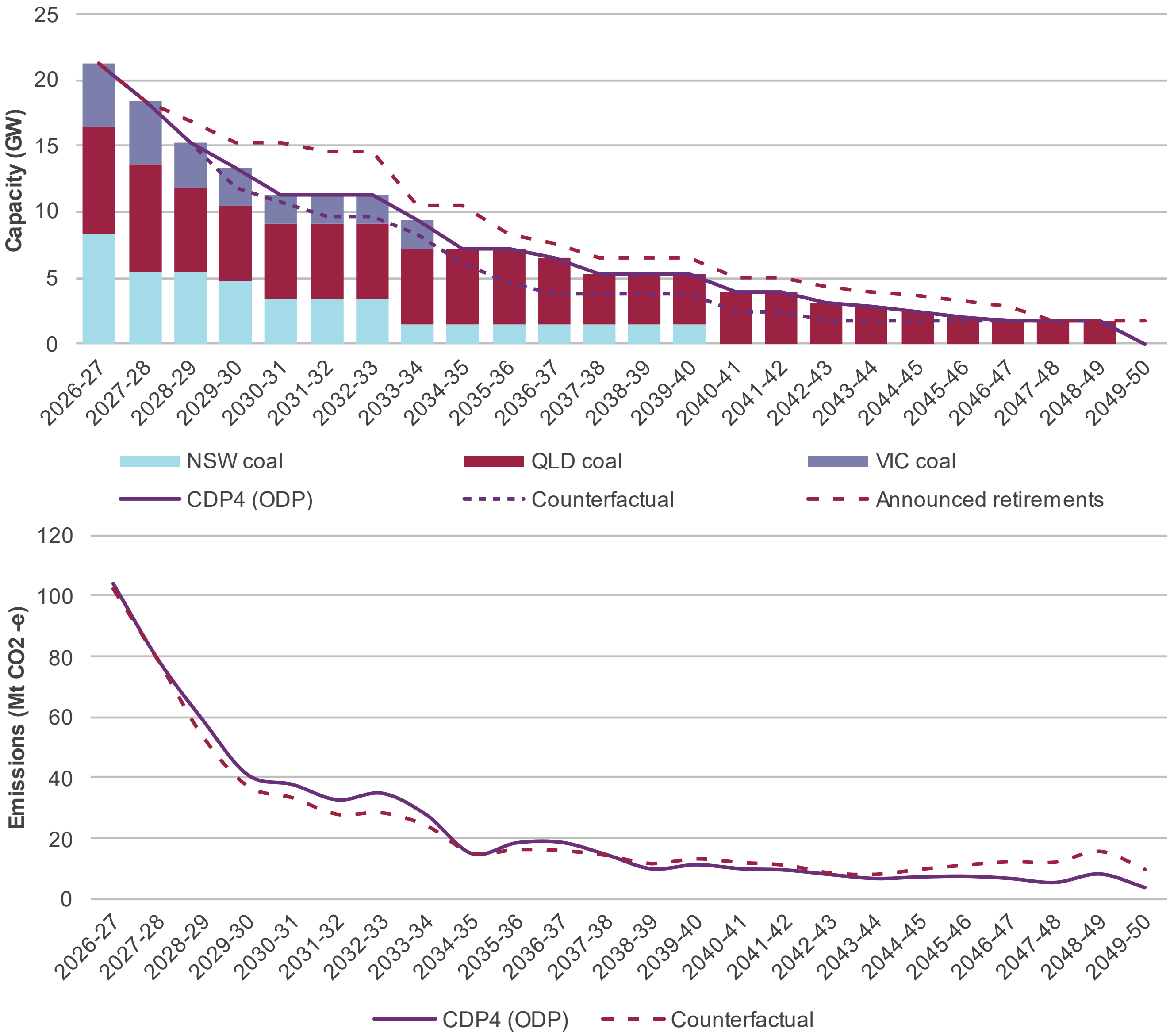
Contrasting the ODP's development opportunities with the 'no transmission' counterfactual development path in *Step Change*

The Draft 2026 ISP identifies material system cost savings through the expansion of the transmission network (see Appendix A6 for more details). Transmission investments help transition to a lower emissions energy system by improving access to renewable energy resources developed in REZs and reducing potential VRE curtailment due to transmission limitations. At times of VRE curtailment due to network limitation, higher cost generation may need to generate, increasing overall costs and increasing emissions.

Impact of transmission development on retirements of coal-fired generation capacity

Figure 17 shows a comparison between retirements of coal-fired generation capacity between the 'no transmission' counterfactual development path which does not feature expansion of major transmission (bars) and the proposed ODP in the Draft 2026 ISP (solid line), contrasted with the announced closure dates (dashed line). Below the first chart is a comparison of the emissions trajectory between the 'no transmission' counterfactual development path and the proposed ODP. To ensure that emissions targets can still be achieved under the 'no transmission' counterfactual development path, several black coal-fired generators in New South Wales and Queensland are retired earlier which results in up to 6 GW of wind capacity development being brought forward into existing REZs with available capacity.

Figure 17 Projected retirements of coal-fired generation capacity (top) and emissions trajectory (bottom) to 2049-50, *Step Change* 'no transmission' counterfactual development path (GW and Mt CO_2-e)

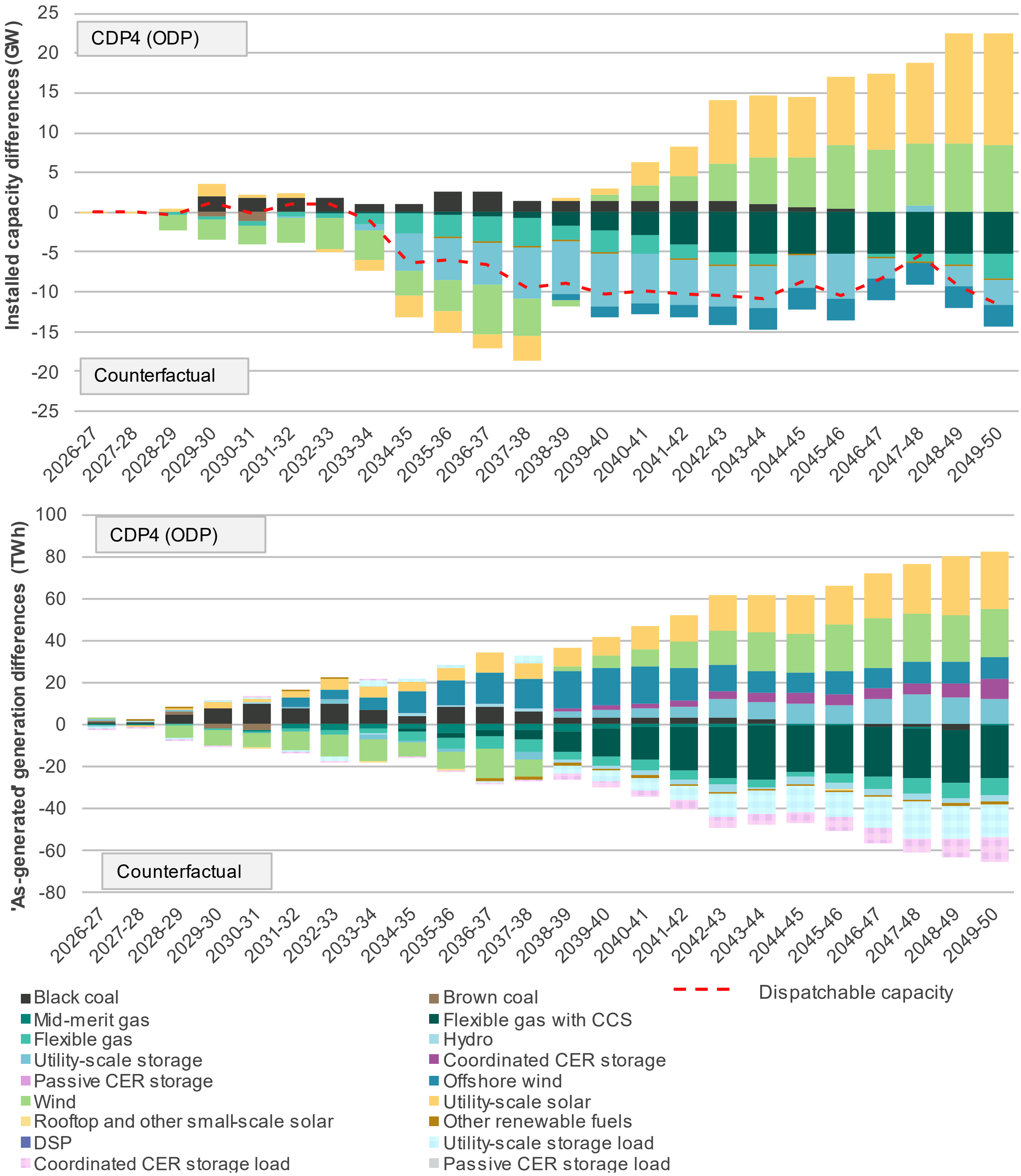


Impact of transmission development on capacity and generation mix

In the 'no transmission' counterfactual development path, limited availability of connection locations with strong transmission capacity results in a more diverse mix of technologies to meet the future needs of the NEM. With less ability to develop REZs, investments would be needed as early as 2032-33 in flexible gas with carbon capture and storage (CCS) capabilities to provide dispatchable capacity that can generate sufficient energy while achieving the emissions budget, if major transmission expansion is not developed. Additional offshore wind capacity is developed in New South Wales as an alternative to augmenting transmission lines. Offshore wind generation overall however is reduced as while the capacity is built to meet the Victorian Offshore Wind Target, the generation is constrained by the capability of existing transmission.

Figure 18 shows the differences in capacity and generation developments in *Step Change* between the ODP and the 'no transmission' counterfactual development path. A positive value indicates higher total installed capacity or generation in the ODP.

Figure 18 Projected capacity developments (top) and generation (bottom) to 2049-50 under 'no transmission' counterfactual development path compared with *Step Change* (GW and TWh)

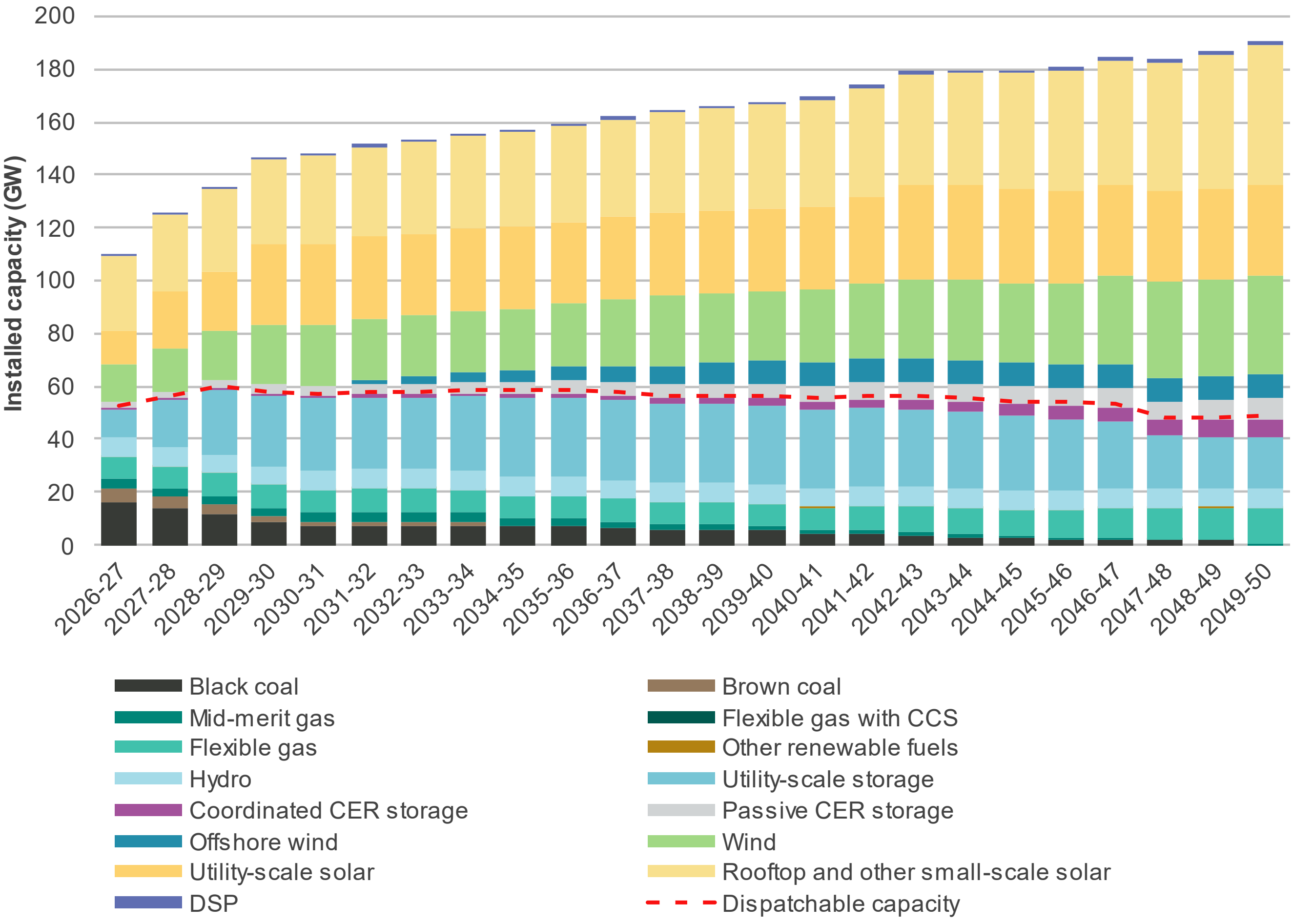


A2.3.2 Slower Growth

The *Slower Growth* scenario features a future where Australia reaches net zero emissions by 2050 amid weak economic conditions, slower technology cost declines, and more limited consumer and commercial business capacity to support the transition in a more challenging investment environment.

Figure 19 presents the projected capacity mix for the NEM across the outlook period to 2049-50.

Figure 19 Projected NEM installed capacity, *Slower Growth*, 2026-27 to 2049-50 (GW)



Renewables to replace coal as bulk generation

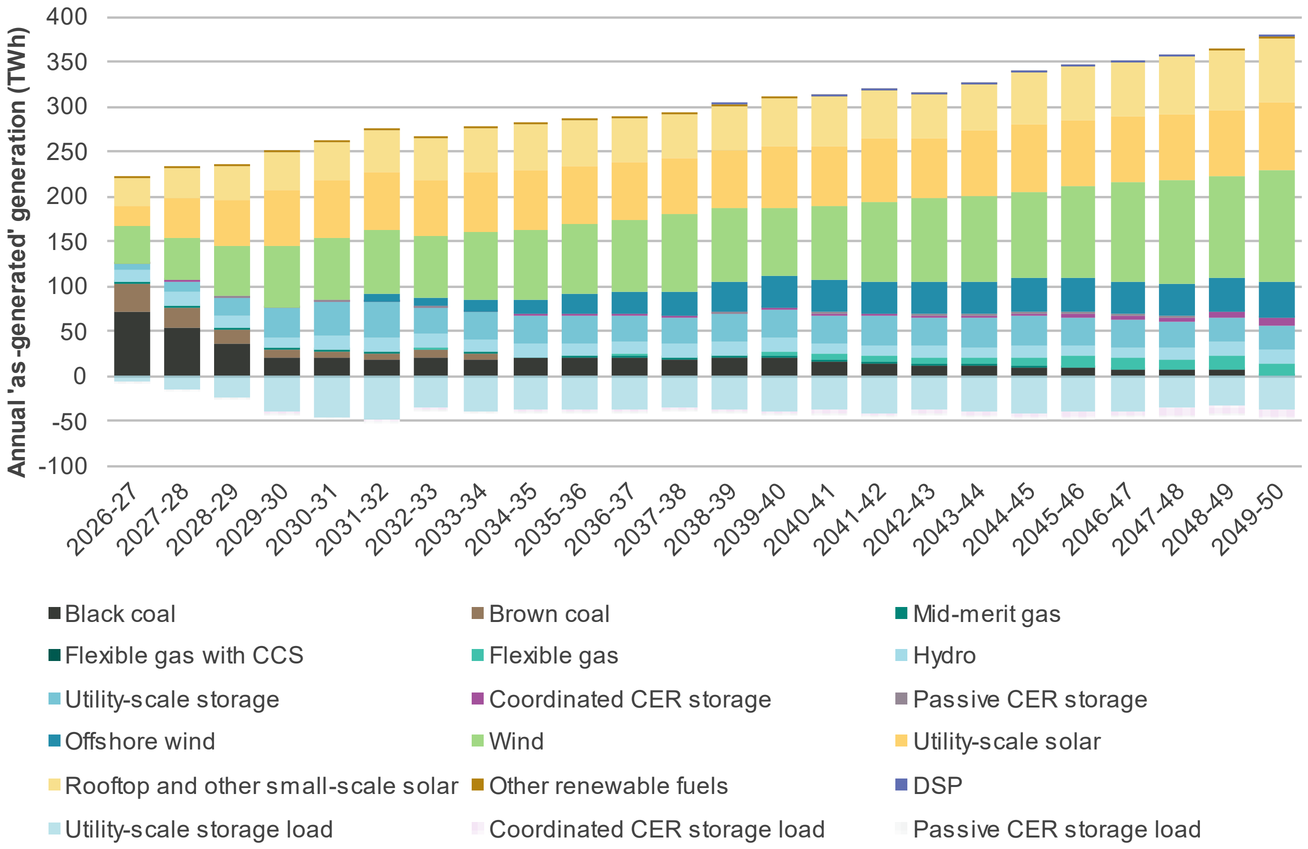
In all scenarios, renewable energy policies at both the federal and state levels are driving significant investment in VRE developments across the NEM, particularly utility-scale solar and wind. Although the reduction in coal-fired generation capacity is expected to occur more gradually than in the *Step Change* scenario, it is still projected to decrease by approximately half of current levels by 2029-30 due to a lower energy consumption projected driven by industrial closures assumed in this scenario, and as ongoing investments in new renewable energy projects and additional storages come online. New South Wales and Victoria experience the most significant reductions in coal-fired generation capacity, while Queensland is expected to have coal plants continuing to operate, aligned with to the Queensland Energy Roadmap.

This *Slower Growth* scenario still incorporates significant volumes of committed and anticipated generation, particularly in storage devices, and various targeted state policies which are supporting storage and VRE developments, such as offshore wind in Victoria. In the medium term, the greatest change to the regional generation mix is in New South Wales and Victoria, with utility-scale solar reaching 17.4 GW and wind reaching 5 GW by 2029-30 in New South Wales, which accounts for 57% and 22% of total utility-scale solar and wind in the NEM, respectively.

By 2049-50, all coal-fired generation capacity is projected to have retired and replaced by a mix of renewable energy, connected by transmission and distribution, firmed with storage and backed up by gas. The NEM's generation mix in this scenario is made up mostly of utility-scale solar (17%), wind (20%), and rooftop and other small-scale solar capacities (28%). Flexible gas generation continues to provide a key role in maintaining reliability and operability over the long term, supporting extended periods of low utility-scale wind and solar output.

Figure 20 demonstrates the high degree of change expected to affect the NEM's generation mix in this scenario. Renewable generation is projected to account for 86% of generation by 2029-30, driven by the Federal Government's 82% renewable energy target, 91% by 2034-35, and 96% by 2049-50. The projected mix of VRE by the end of the outlook period is approximately 52% wind, 25% utility--scale solar, and 23% rooftop and other small-scale solar by 2049-50.

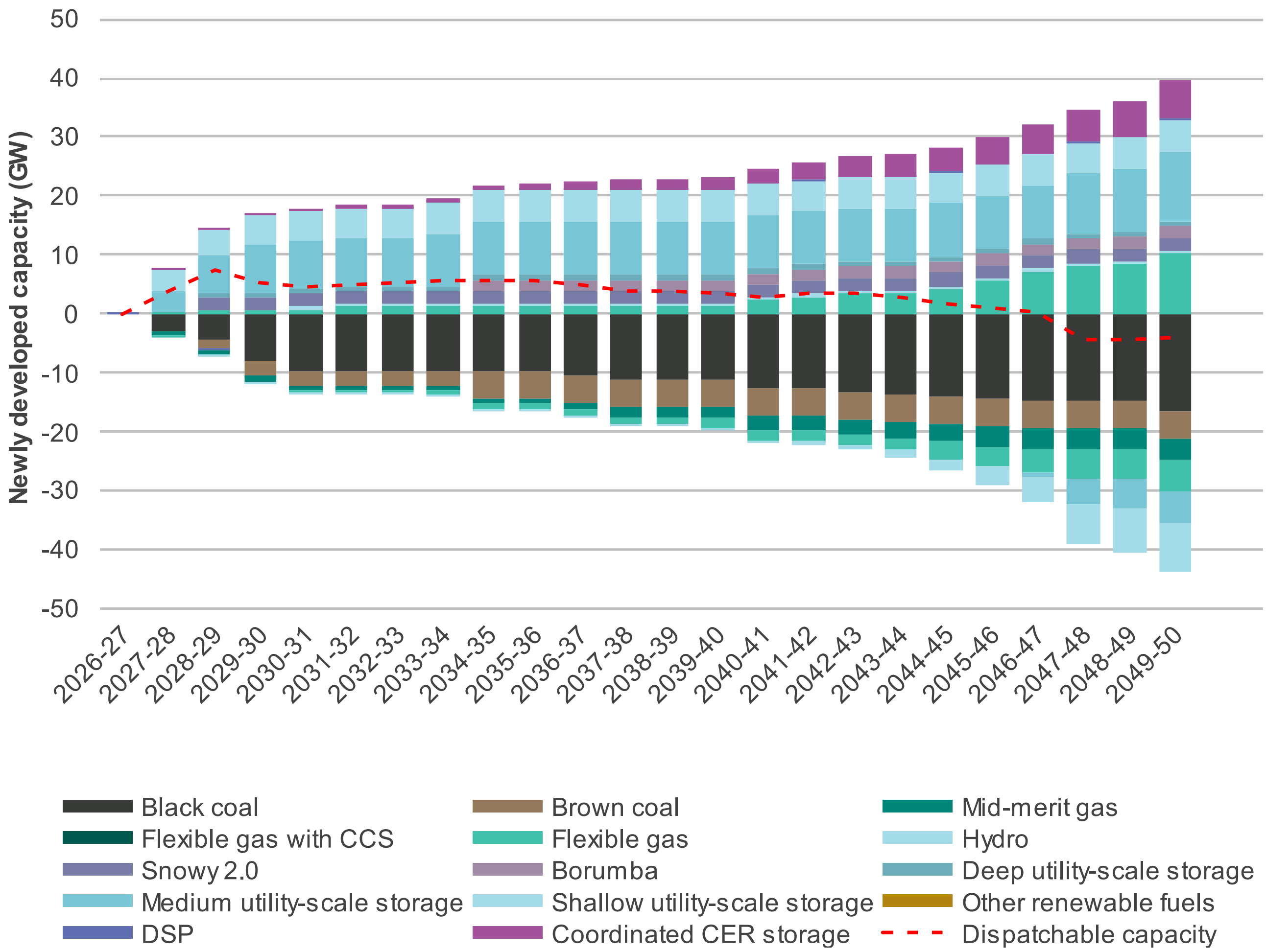
Figure 20 Projected annual generation, *Slower Growth*, 2026-27 to 2049-50 (TWh)



Dispatchable capacity to firm renewables

As VRE generation increases, dispatchable capacity is required to firm the significant penetration of renewable generation and ensure ongoing reliability. While the total level of dispatchable capacity is not projected to increase significantly over time in this scenario, its technology make-up changes throughout the outlook period, and much of the retiring dispatchable capacity (coal and mid-merit gas generation) will need to be replaced. Medium-depth and deep utility-scale storage capacities, including pumped hydro energy systems and utility-scale storage, are critical for balancing the variability of VRE and maintaining system reliability. This is in addition to flexible gas which provides new dispatchable capacity and complements the variable energy generated by VRE developments. **Figure 21** demonstrates the change in dispatchable capacity projections across the outlook period.

Figure 21 Projected relative change compared with 2024-25 in dispatchable capacity, *Slower Growth*, 2026-27 to 2049-50 (GW)



Coal retirement schedule

All coal-fired generation capacity is projected to retire by 2049-50 in the NEM, but the pace at which it retires varies by region:

- In Victoria, 50% of coal-fired generation capacity is projected to retire by 2029-30, with 100% of coal-fired generation capacity projected to retire by 2034-35.
- In New South Wales, retirements of coal-fired generation capacity start from as early as 2027-28, and by 2040-41, all coal-fired generation capacity in the region is projected to retire. This early retirement is primarily driven by significant

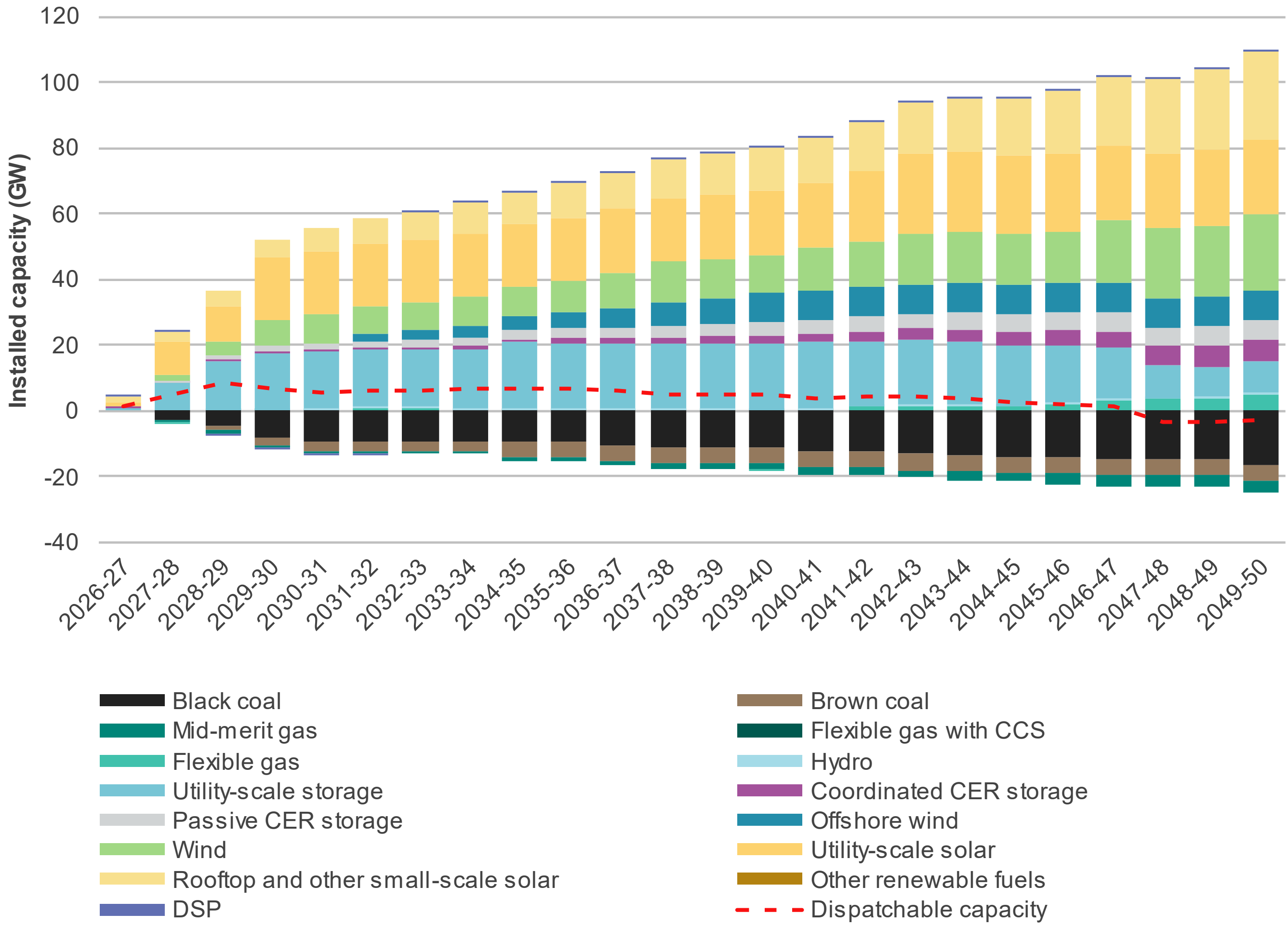
investment in VRE technologies supported by state policies such as the New South Wales Electricity Infrastructure Investment (EII) Act and CIS generation target.

- In Queensland, 50% of existing coal capacity in Queensland is projected to retire by 2037-38, with some capacity available to 2049-50[12].

New developments and closures

Figure 22 shows the cumulative change in investments and withdrawal by technology type projected over the outlook period. Due to the lower demand growth in this scenario relative to other ISP scenarios and assumed industrial closures, the level of development opportunity beyond that which is committed, anticipated or supported by various government policies is lower.

Figure 22 Projected relative change in new installations and closures compared to 2024-25 installed capacity, *Slower Growth*, 2025-26 to 2049-50 (GW)



In the *Slower Growth* scenario by 2029-30, the NEM is projected to consist of 30.6 GW of utility-scale solar, 22.4 GW of wind, and 32.1 GW of rooftop and other small-scale solar to replace retiring coal. Including anticipated and committed

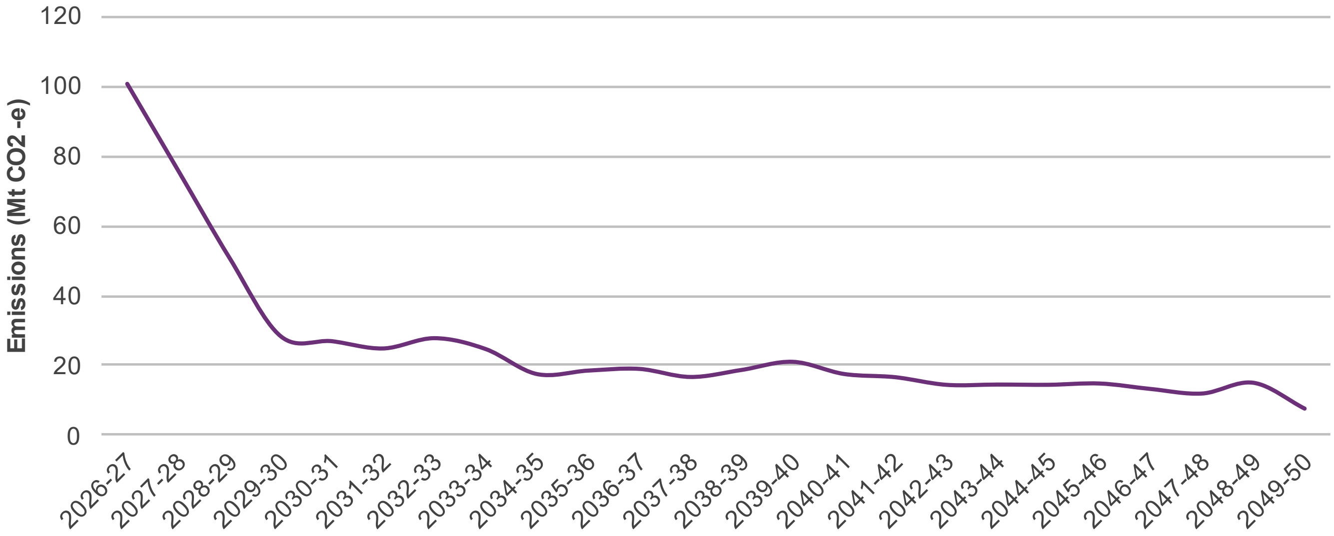
[12] Two-shifting means switching off during the daytime peaks of solar generation, and returning for the evening peak and through the night and morning.

projects, the NEM is projected to add 34.7 GW of utility-scale solar, 37.3 GW of wind, 9 GW of offshore wind, and 52.8 GW of rooftop and other small-scale solar to replace the existing capacity and meet increasing energy consumption by 2049-50. The majority of VRE generation is in New South Wales, largely driven by tendering processes to develop generation aligned with infrastructure investments objectives aligned with the *Electricity Infrastructure Investment Act 2020* (NSW).

Impact on emissions

Emissions decline most steeply in the years leading up to 2034-35 – reaching 25 Mt CO_2-e, an 86 % decrease from 2004-05 levels – mostly due to government emissions reduction targets. By 2049-50, emissions are projected to be as low as 8 Mt CO_2-e. **Figure 23** shows projected emissions trajectories to 2049-50 for the *Slower Growth* scenario.

Figure 23 Projected NEM emissions trajectory, *Slower Growth* 2026-27 to 2049-50 (Mt CO_2-e)

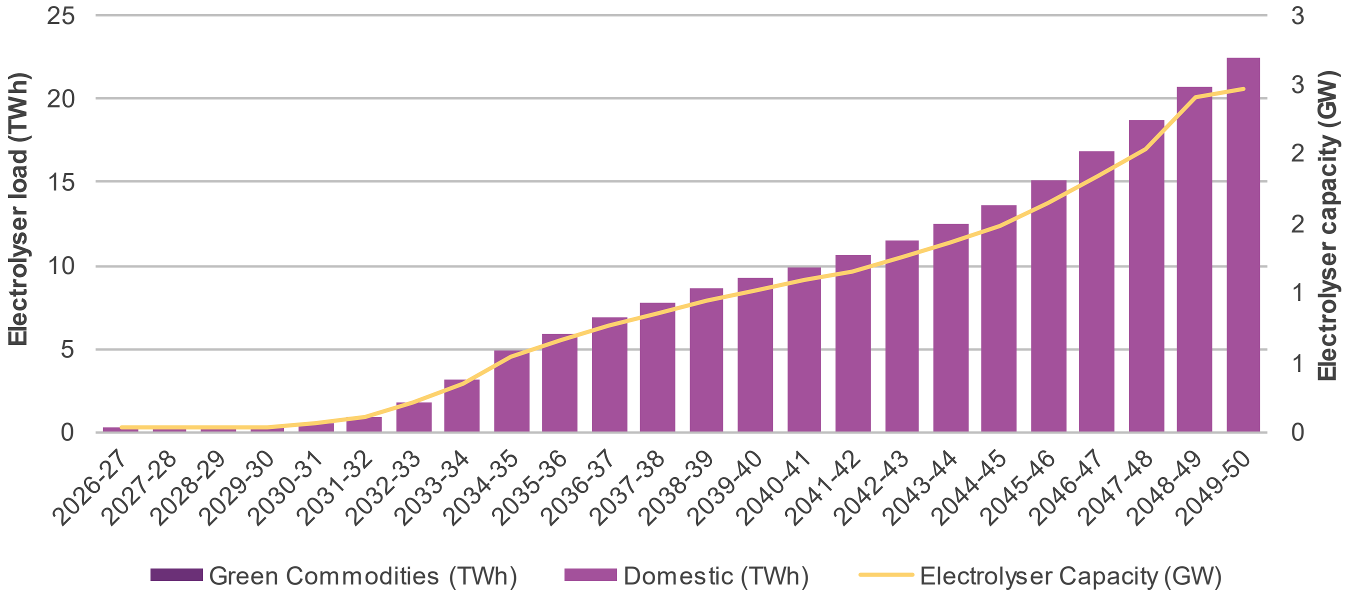


Hydrogen developments

In the *Slower Growth* scenario, hydrogen developments over the outlook period are for domestic use in the transport and industrial sectors, with minimal demand for hydrogen in green commodities and no hydrogen export, as discussed in the 2025 IASR.

Figure 24 demonstrates the projected scale of electricity consumption for hydrogen production requirements. The majority of hydrogen production is allocated to South-West Victoria REZ and Illawarra REZ, with 1.1 GW and 0.6 GW of electrolyser capacities allocated by 2049-50, respectively. South-West Victoria and Illawarra REZs are preferred locations due to being located near assumed domestic hydrogen demand centres, in combination with high REZ import limits.

Figure 24 Electricity consumption associated with hydrogen production, *Slower Growth*, 2026-27 (TWh and GW)



Contrasting the ODP's development opportunities with the 'no transmission' counterfactual development path in *Slower Growth*

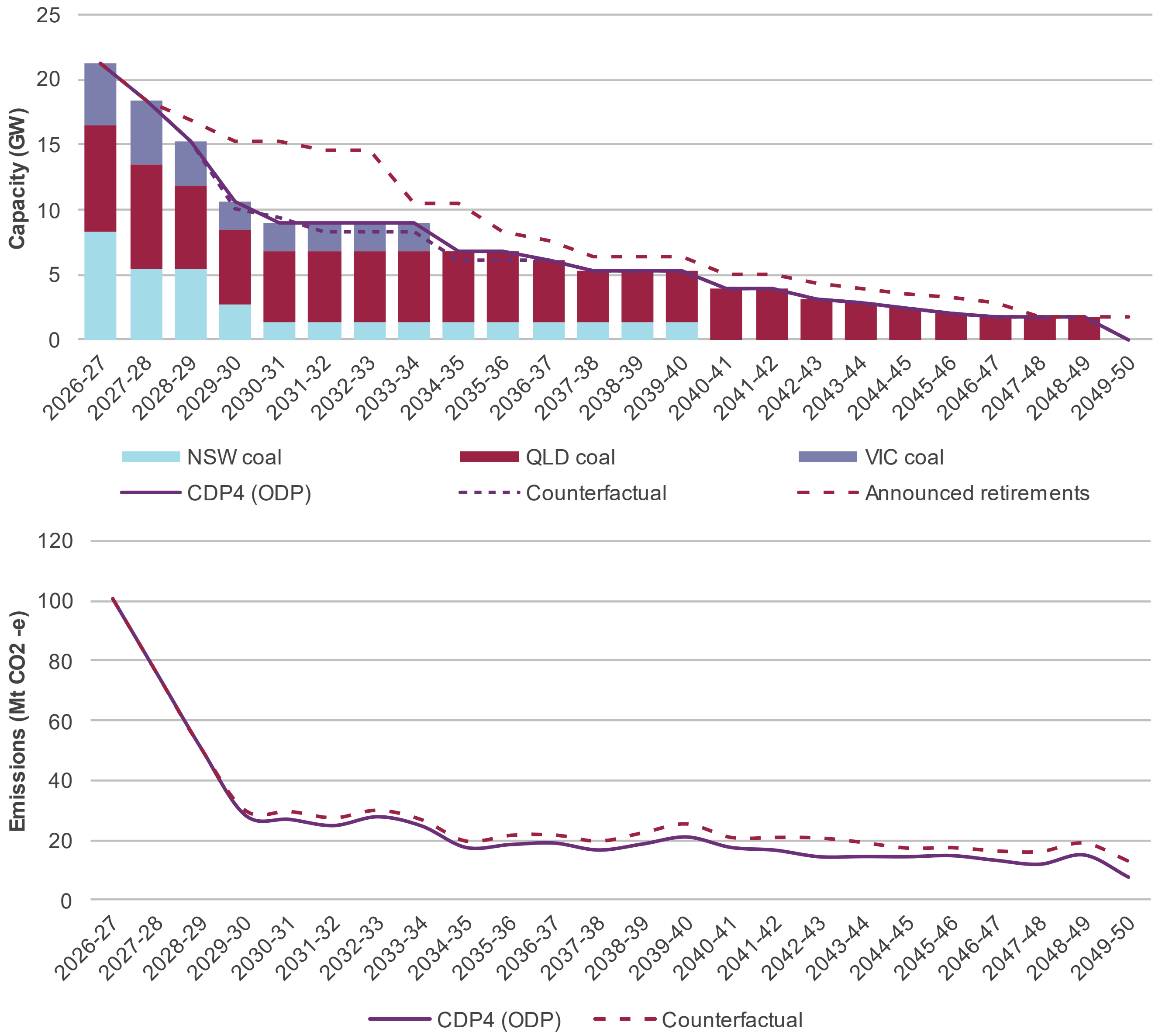
The Draft 2026 ISP identifies material savings to consumers through the expansion of the transmission network (see Appendix A6 for more details). Transmission investments help transition to a lower emissions energy system by improving access to renewable energy developed in REZs and reducing potential VRE curtailment due to transmission limitations. At times of VRE curtailment due to network limitation, higher cost generation may need to generate, increasing overall costs and increasing emissions.

Impact of transmission development on retirements of coal-fired generation capacity and capacity mix

Figure 25 shows the equivalent coal-fired generation capacity retirement schedule in the 'no transmission' counterfactual development path (where there is no major transmission network augmentation) compared with the ODP in *Slower Growth*.

Without major transmission augmentation, coal-fired generation capacity would need to retire faster to provide headroom on the NEM emissions budget so this can be used by flexible gas later in the outlook period, as without transmission expansion greater utilisation of gas-powered generation is required. Additionally, there is a higher reliance on flexible gas generation over the outlook period as VRE generation is curtailed due to lack of additional transmission network augmentation. This leads to a slightly higher emissions trajectory to 2049-50 but still within the NEM emissions budget. The emissions trajectory is projected to be slightly higher than the ODP in *Slower Growth*, reaching 13 Mt CO_2-e compared to 8 Mt CO_2-e, with more gas used to maintain system reliability and meet demand.

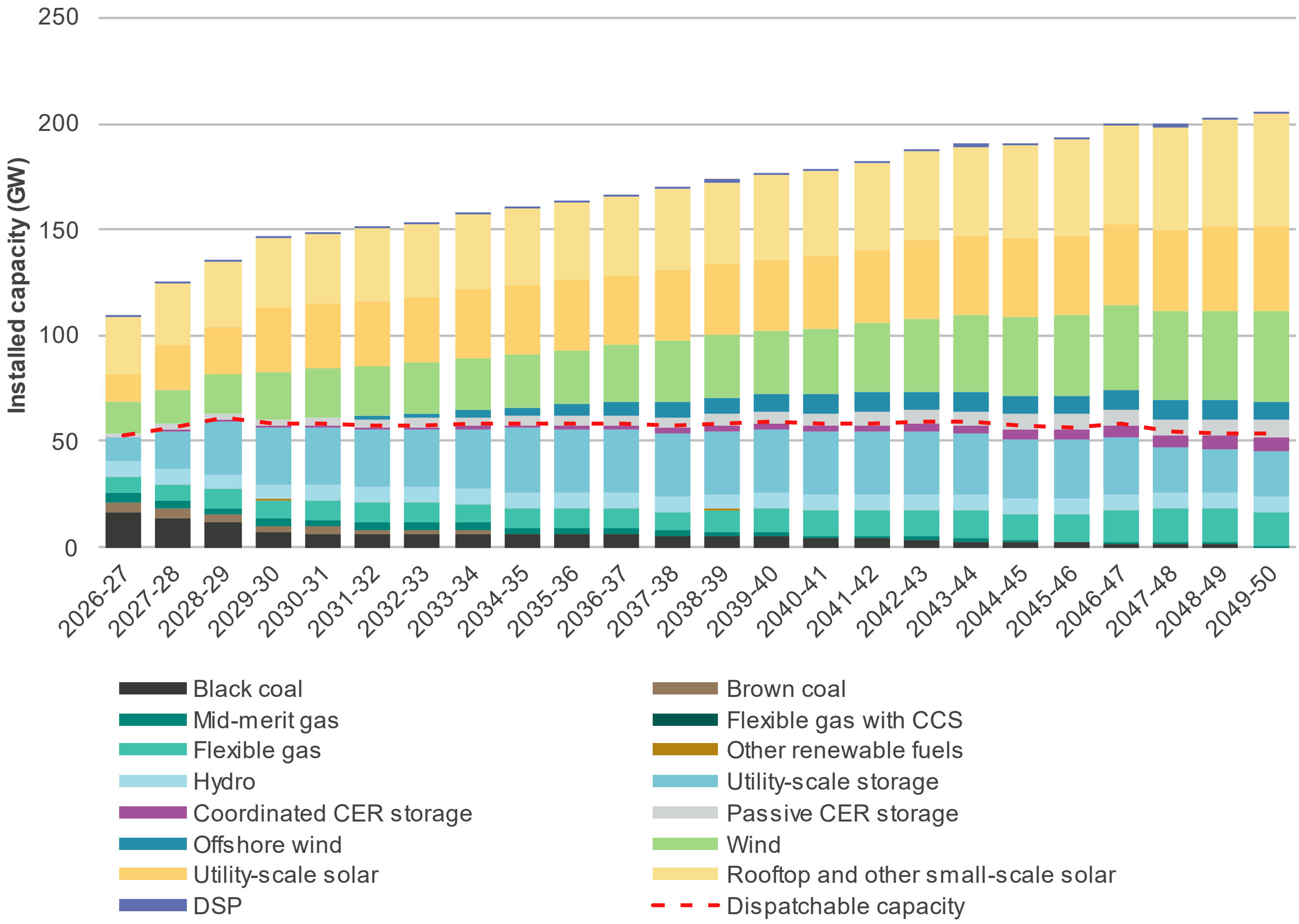
Figure 25 Projected retirements of coal-fired generation capacity (top) and emissions trajectory (bottom) to 2049-50, *Slower Growth* 'no transmission' counterfactual development path (GW and Mt CO_2-e)



Impact of transmission development on generation mix

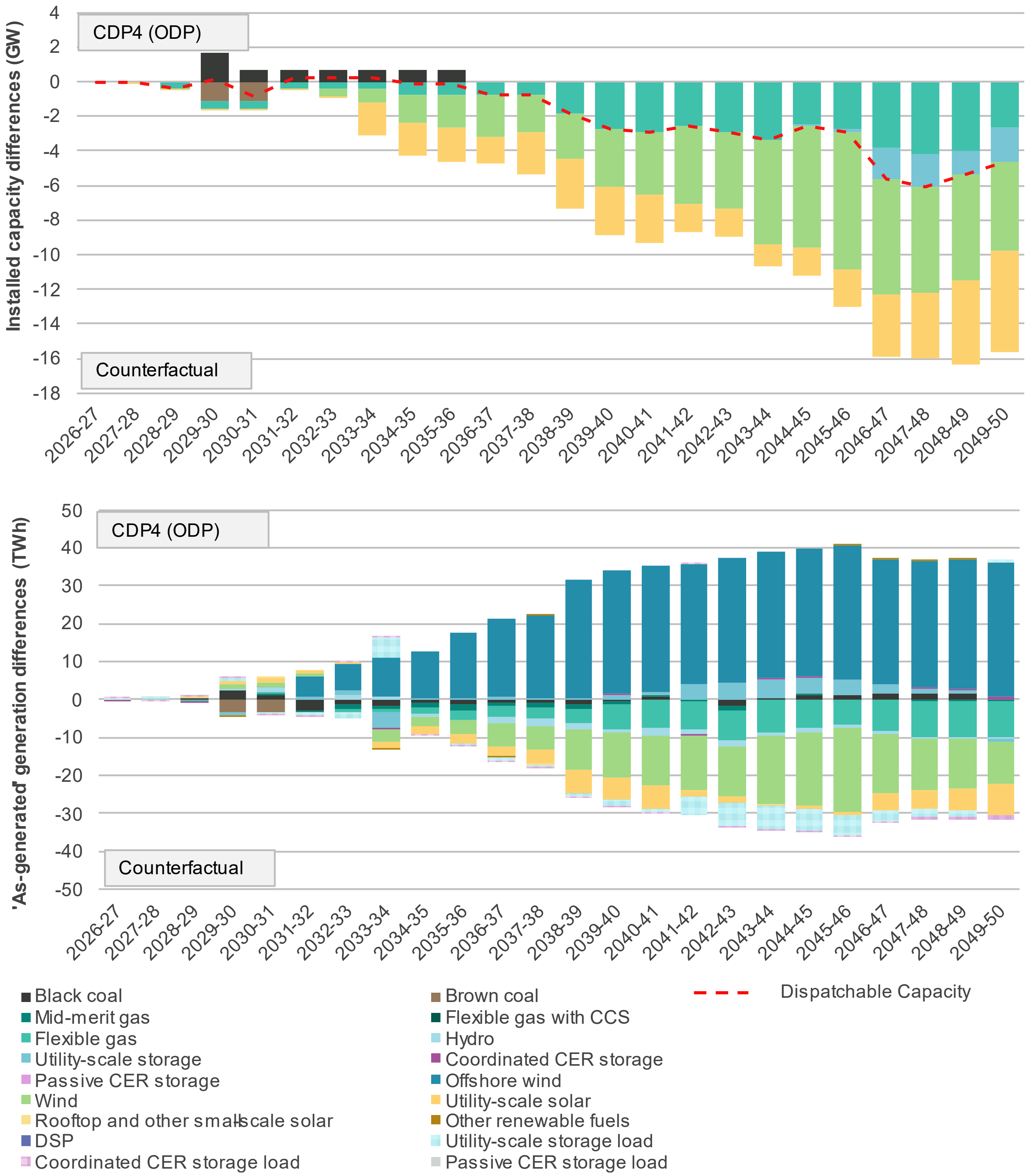
Figure 26 below shows that the 'no transmission' counterfactual development path incorporates rapid development of VRE from 2029-30 onwards, particularly wind and utility-scale solar generation, as it is needed to replace coal generation at a faster rate to meet emissions targets and carbon budgets.

Figure 26 Projected NEM installed capacity, *Slower Growth* 'no transmission' counterfactual development path, 2026-27 to 2049-50 (GW)



For comparison, **Figure 27** presents the difference in installed capacity and dispatched generation between the ODP and the 'no transmission' counterfactual development path. From the early 2030s, flexible gas generation plays an increasing role in meeting projected energy consumption. Transmission limitations lead to greater reliance on other technologies that can be connected to existing transmission network near demand centres or within regions with available network capacity, rather than being optimised for resource quality. Generation from technologies like offshore wind which rely heavily on transmission is significantly reduced likely due to frequent curtailment of VRE generation. This is particularly present in Victoria where without transmission upgrades there would be high levels of curtailment of offshore wind and additional generation development would be required to service energy consumption.

Figure 27 Projected capacity developments (top) and generation (bottom) to 2049-50 under 'no transmission' counterfactual development path compared with *Slower Growth* (GW and TWh)



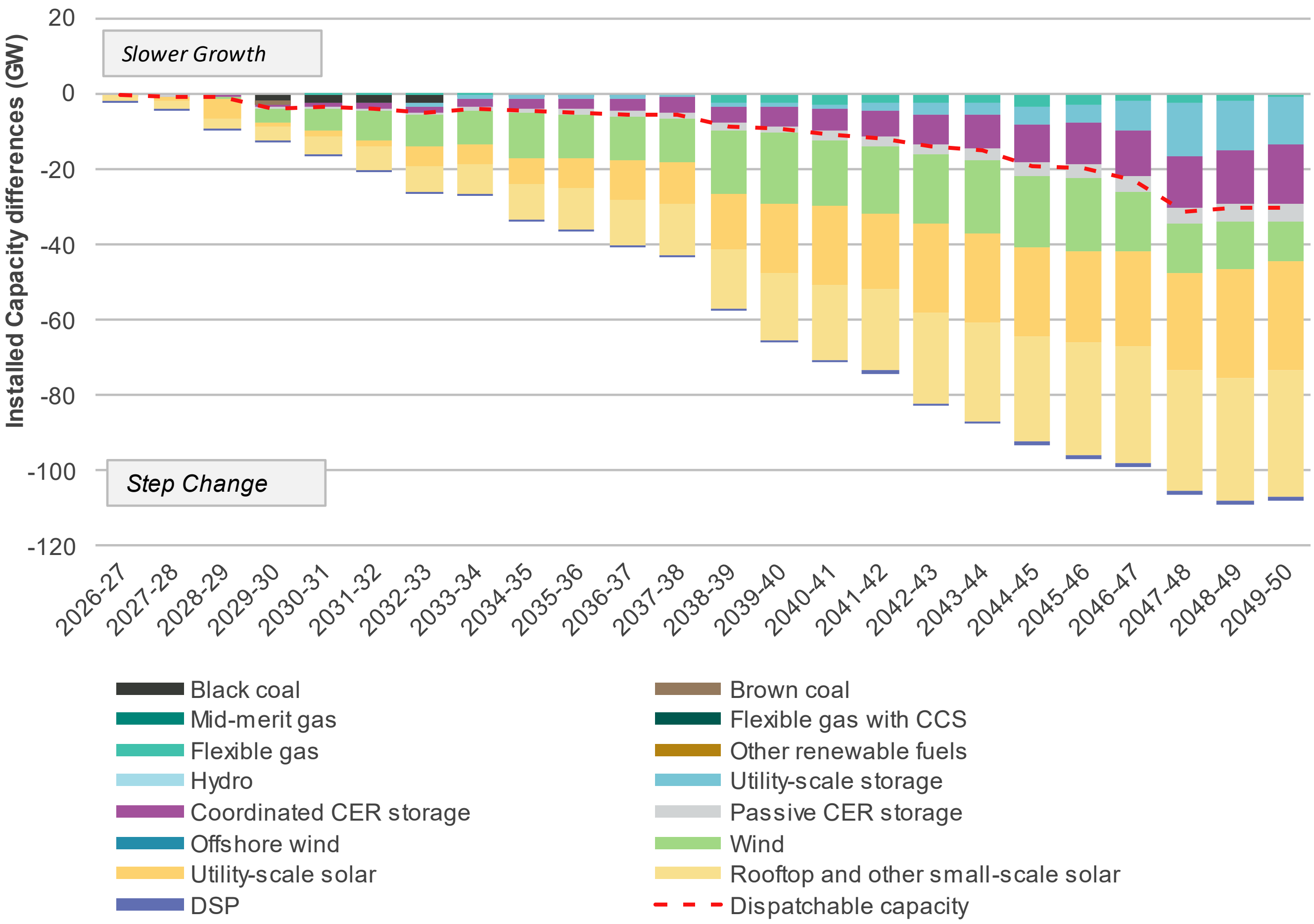
Contrasting the ODP's development opportunities in *Slower Growth* and *Step Change*

Figure 28 below presents the capacity difference between results for the *Slower Growth* scenario and the *Step Change* scenario. By the end of the outlook period, the difference between scenarios reflects the strong contribution from consumers with higher coordinated CER storage and higher rooftop and other small-scale solar uptake in the *Step Change* scenario. *Slower Growth* features a lower economic outlook, lowering generation requirements, with less industrial load relative to business and residential loads in the longer term.

The key differences from the results in *Step Change* are:

- VRE development is at a much slower rate, as lower economic and population growth reduces the overall scale of change required to achieve net zero by 2050. By the end of the outlook period, the difference in VRE capacity between scenarios increases, due to differences in projected energy consumption and tighter emissions budget leading to more VRE developments in *Step Change*.
- *Slower Growth* is characterised by lower uptake of CER storage technologies, from lower residential battery systems and EVs that are capable of V2G operation and slightly less reliance on flexible gas and storage capacities to meet firming requirements.

Figure 28 Projected capacity development to 2049-50 under *Slower Growth* compared to *Step Change* (GW)

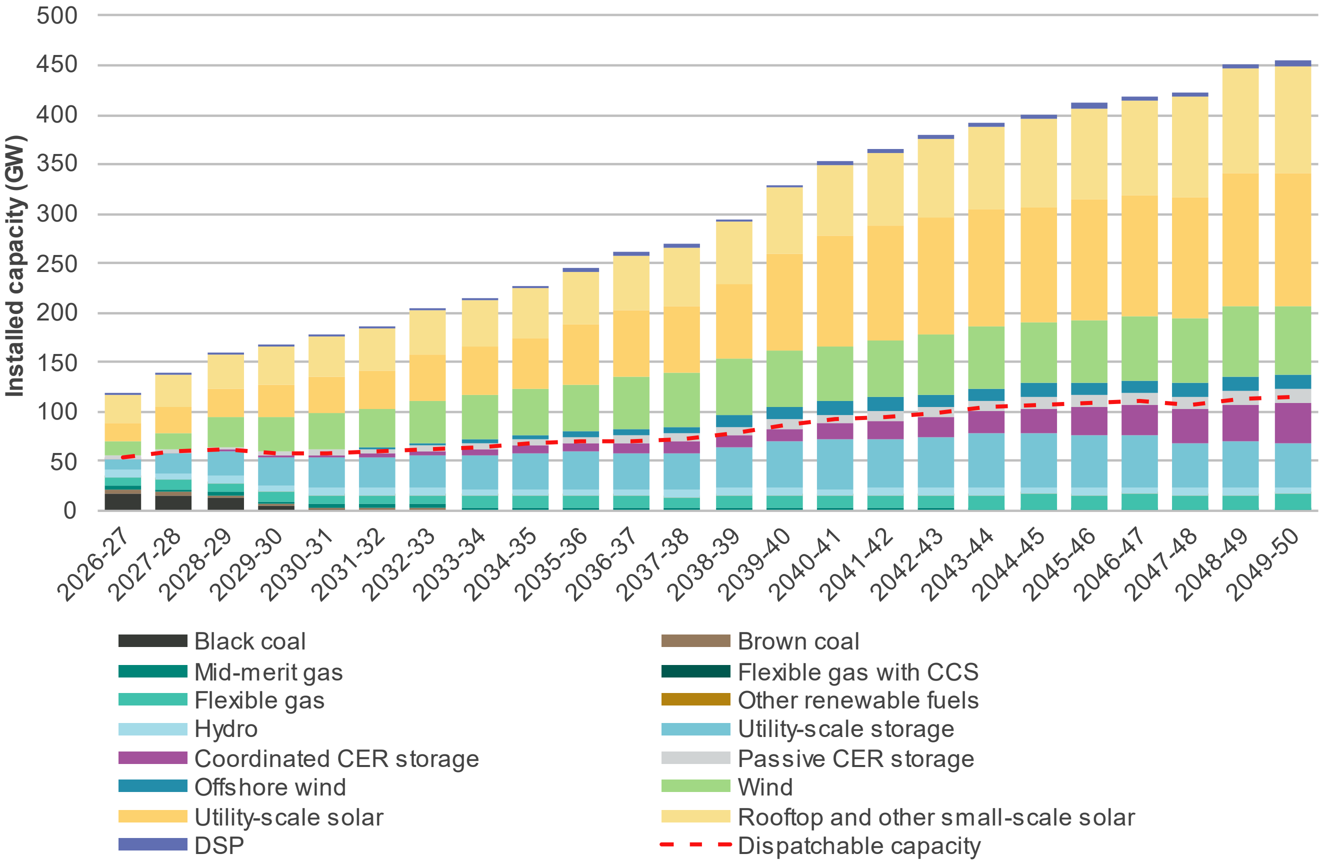


A2.3.3 Accelerated Transition

The *Accelerated Transition* scenario features faster economic growth and stronger commitment to decarbonise the economy which drives rapid energy sector transformation through electrification, green commodity production, and high consumer uptake of CER and increased CER coordination.

The scenario features the quickest rate of transformation, with the greatest need for the development of infrastructure compared with the *Step Change* scenario. **Figure 29** presents the projected capacity mix for the NEM across the outlook period to 2049-50 in *Accelerated Transition*.

Figure 29 Projected NEM installed capacity, *Accelerated Transition*, 2026-27 to 2049-50 (GW)



Renewables to replace coal as bulk generation

In all scenarios, renewable energy policies at both the federal and state levels are driving significant investment in VRE developments across the NEM, particularly utility-scale solar and wind. A large proportion of renewable energy developments are projected in New South Wales, Queensland and Victoria, influenced by policy drivers and significant load developments in this higher growth scenario.

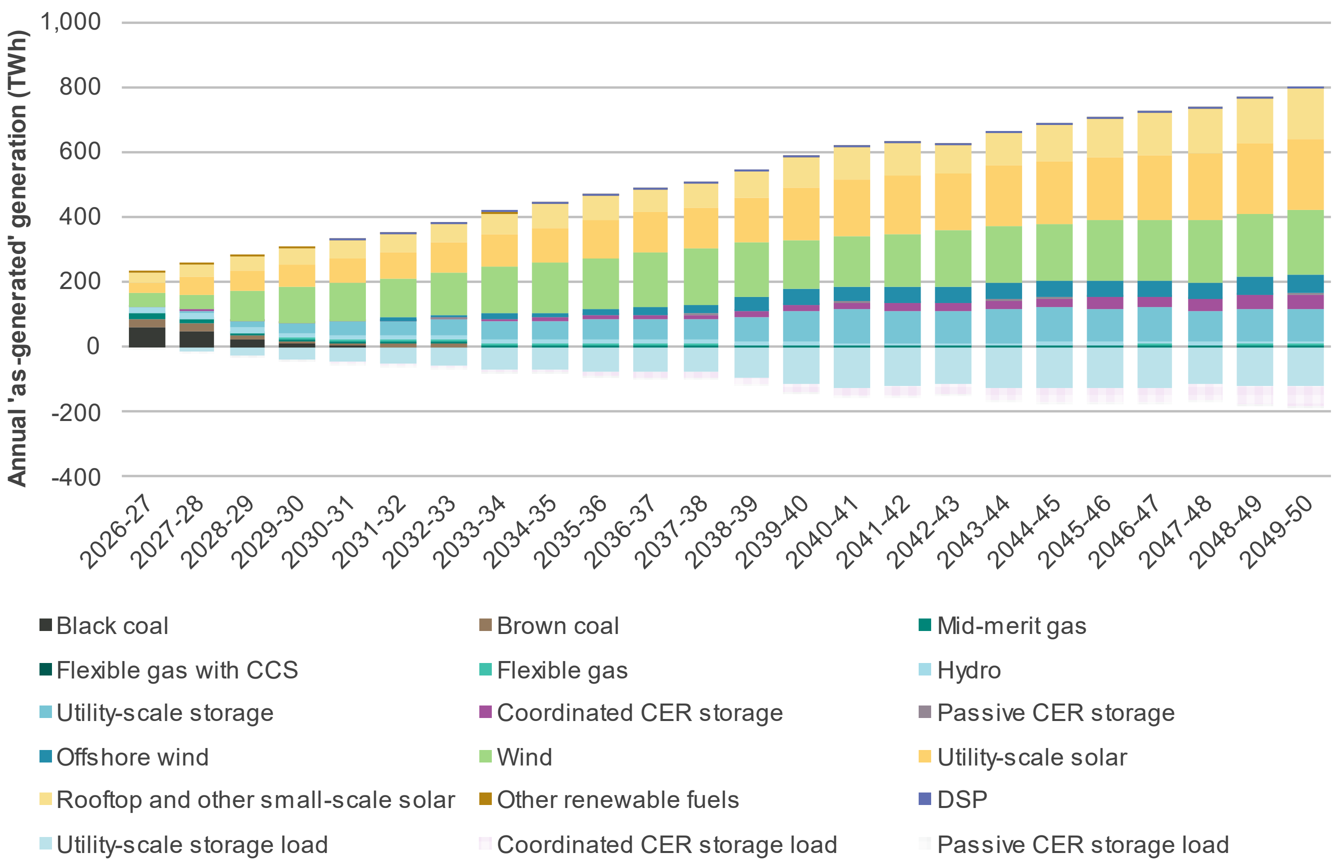
In *Accelerated Transition*, the relatively small emissions budget leads to rapid retirement of coal-fired generation capacity, with only 6 GW of coal-fired generation capacity projected to be operational by 2029-30. High uptake of utility-scale VRE replaces the generation no longer provided by coal-fired power stations, supported by a high contribution from CER.

Storage of various depths are needed to support reliability and grid stability, including opportunities for developments within the distribution network.

By 2049-50, approximately 220 GW of utility-scale VRE and over 109 GW of rooftop and other small-scale solar of total installed capacity will be needed. At a regional level, capacity expansion is most significant in New South Wales, followed by Queensland and Victoria. South Australia is projected to experience the fastest relative growth from 2030, particularly to support high industrial load developments projected in the scenario.

Similar to the *Step Change* scenario, significant new VRE capacity is projected to transform the NEM into a low-emissions energy system, underpinning the strong decarbonisation of Australia's economy. Renewable energy generation from wind and solar technologies is projected to grow throughout the outlook period, complementing the assumed development of CER (see **Figure 30**). By 2049-50, the projected share of renewable generation has increased to 99% of all generated electricity; the remaining 1% is provided by flexible gas, which provides back-up supply during extreme demand periods and renewable energy lulls.

Figure 30 Projected annual generation, *Accelerated Transition*, 2026-27 to 2049-50 (TWh)



Dispatchable capacity to firm renewables

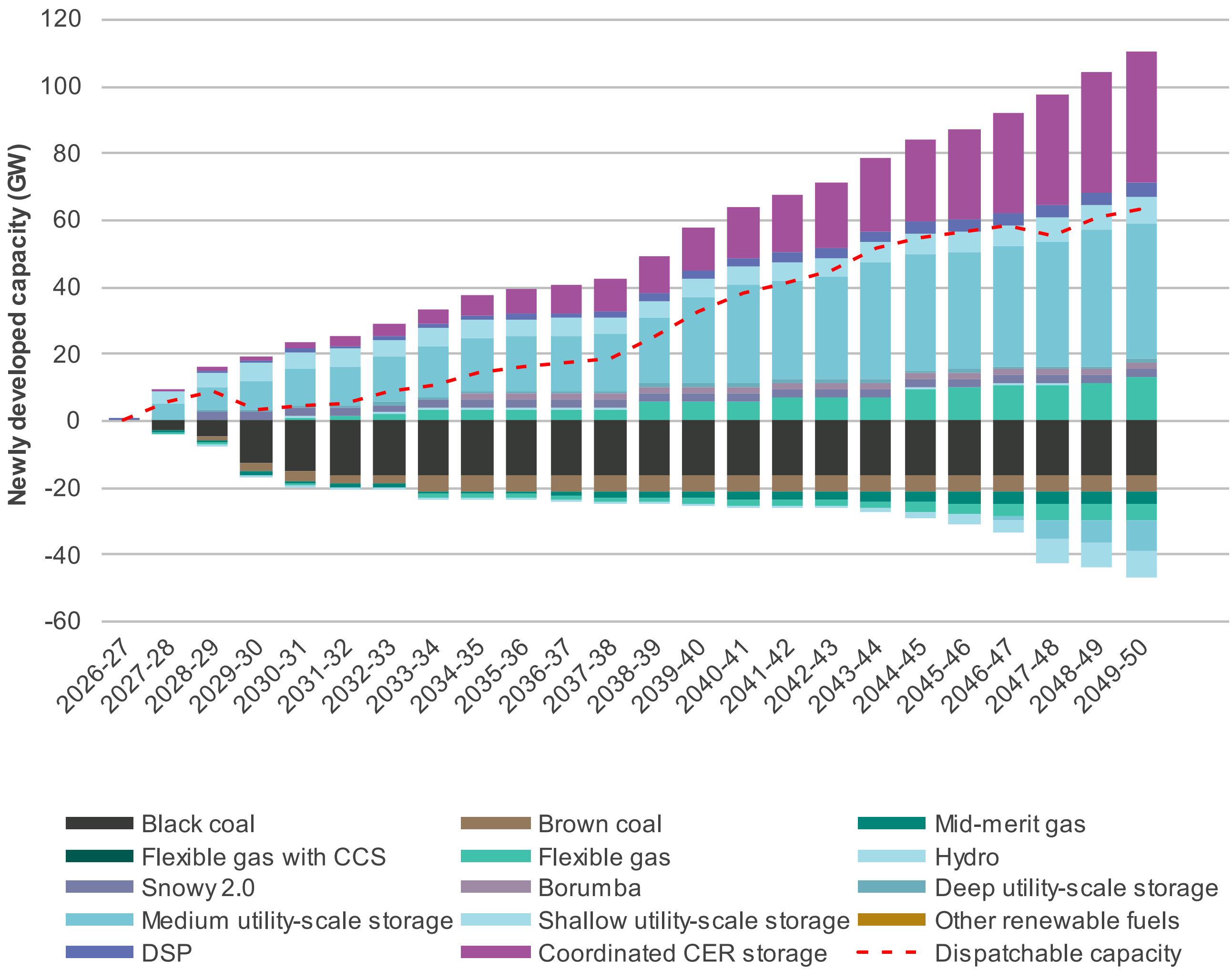
Dispatchable capacity is projected to increase steadily across the outlook period, reflecting ongoing need for firming resources to support the growing share of renewable energy and growing customer demand.

Figure 31 demonstrates the projected change in capacity across the outlook period. Consistent with the findings for *Step Change*, significant expansion of various storage technologies is projected. Total storage dispatchable capacity – which includes coordinated CER storages, utility-scale storages, and pumped hydro energy systems – mainly provide sufficient dispatchable capacity to maintain reliability as coal-fired generation capacity retires. Dispatchable capacity is projected to account for about 25% of the total capacity in the NEM by 2049-50.

Towards the end of the outlook period, CER storage is expected to grow at a faster rate than utility-scale storage, driven by increased investments from households seeking to maximise the value of rooftop and other small-scale solar generation.

Retiring gas-powered generation capacities are largely being replaced by new flexible gas which further complements the energy generated by variable renewable energy technologies.

Figure 31 Projected relative change compared with 2024-25 in dispatchable capacity, *Accelerated Transition*, 2026-27 to 2049-50 (GW)



Coal retirement schedule

All black and brown coal-fired generation capacities are projected to need to exit the market by 2032-2033 under the *Accelerated Transition* scenario to meet the rapid emissions reduction requirements (in addition to the emissions targets, this scenario has the smallest emissions budget of 303 Mt CO_2-e from period 2026-27 to 2049-50). In 2029-30, only 6 GW of coal-fired generation capacity is projected to be operational (72% lower than existing coal-fired generator capacity).

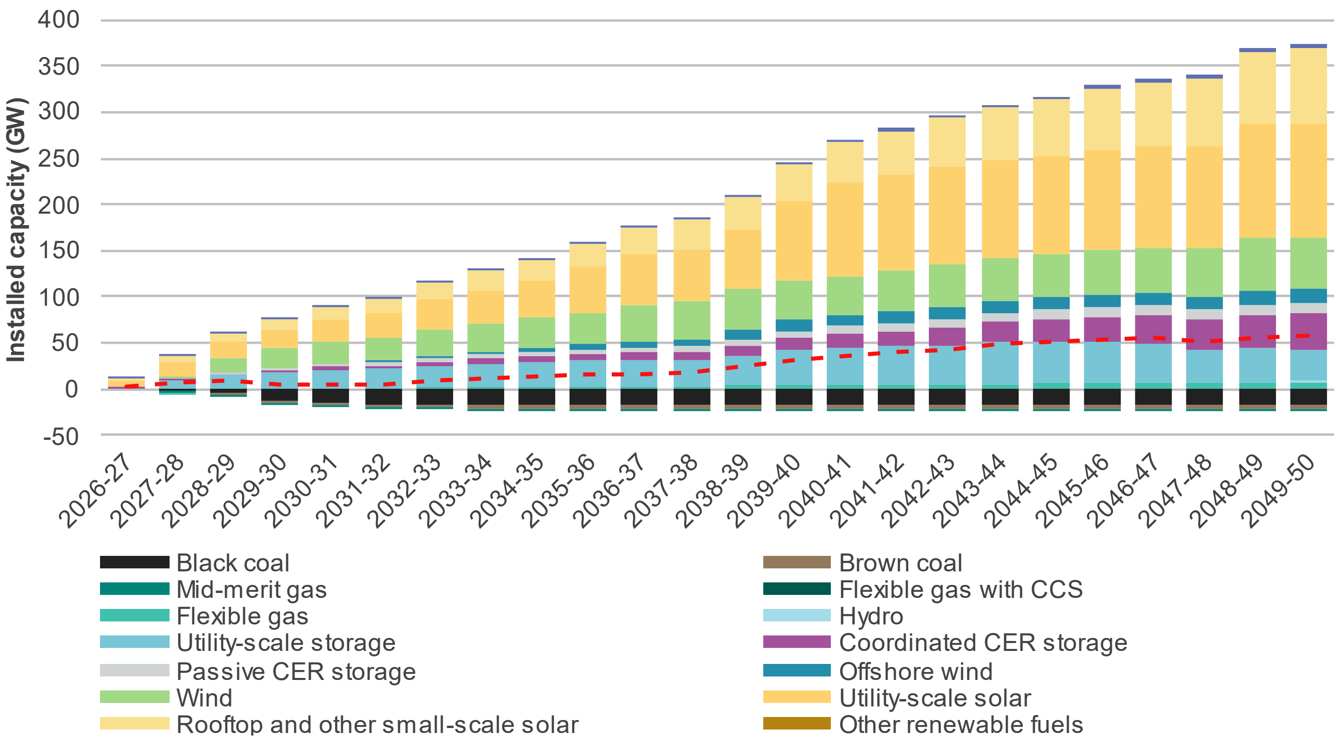
New developments and closures

Figure 32 shows the cumulative change in technology type over time. Significant development in new VRE capacities is projected throughout the outlook period, replacing retiring coal-fired generation and to meet projected growth in energy consumption. Utility-scale VRE is growing from 21 GW currently to 220 GW by 2049-50 (50% of the total installed capacity) in the *Accelerated Transition* scenario, with a projected split of approximately 38% wind, 62% utility-scale solar, and the remainder from rooftop and other small-scale solar.

The projected growth in rooftop and other small-scale solar is driven by strong consumer participation in the scenario's inputs, complemented by a relatively high coordination of CER storages.

VRE developments are highest in New South Wales, supporting increasing electricity consumption in the NEM's largest region, including strong assumed growth in data centres.

Figure 32 Projected relative change in new installations and closures compared to 2024-25 installed capacity, *Accelerated Transition*, 2026-27 to 2049-50 (GW)

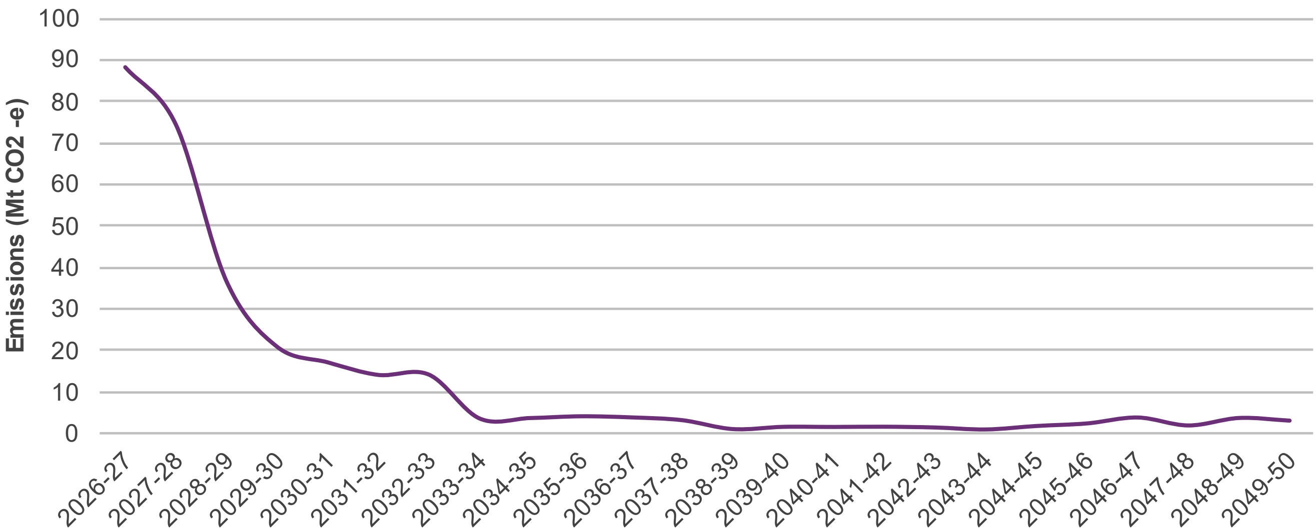


Impact on emissions

Due to the strong decarbonisation goal in *Accelerated Transition*, its emissions trajectory is significantly lower than the other two scenarios.

By 2029-30, emissions are expected to reach about 20 Mt CO_2-e, or 50% of what is projected in the *Step Change* scenario. In 2034-35, emissions are projected to reduce by 98% compared to 2005 levels (from 176 million Mt CO_2-e in 2004-05 to 3 Mt CO_2-e in 2034-35). The low emissions budget drives the early retirements of coal-fired generation capacity and the expansion of renewable energy. **Figure 33** shows projected emissions trajectories to 2049-50 for the *Accelerated Transition* scenario.

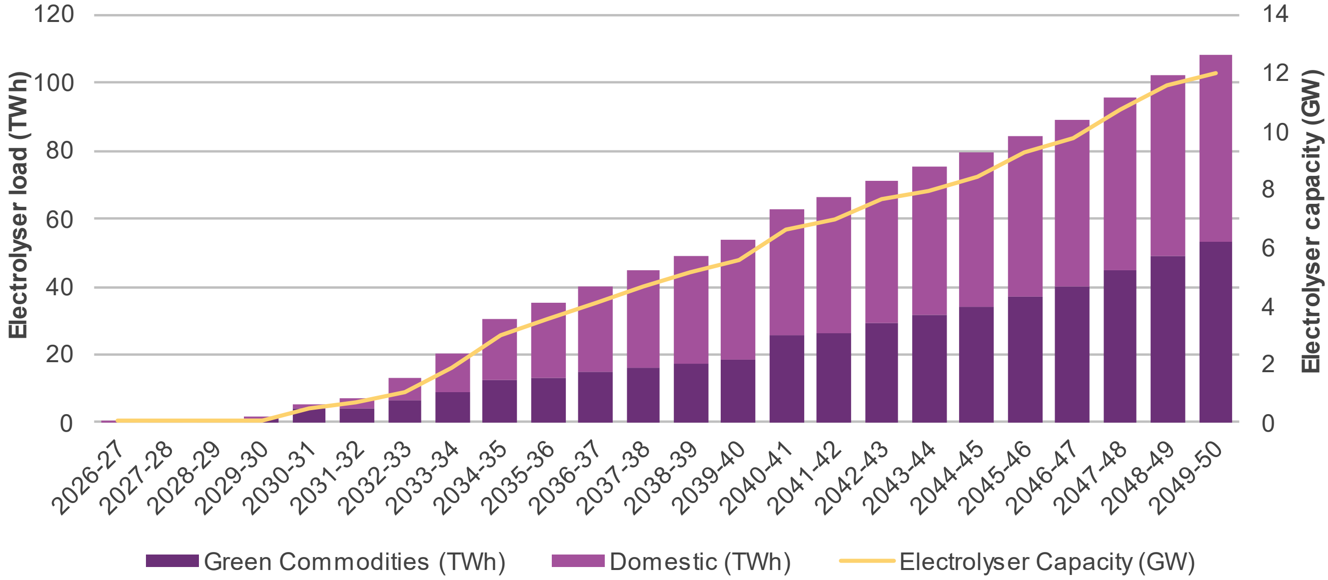
Figure 33 Projected NEM emissions trajectory, *Accelerated Transition*, 2026-27 to 2049-50 (Mt CO_2-e)



Hydrogen developments

Figure 34 presents the assumed total electricity consumption to 2049-50 for hydrogen production that is used for domestic use and green commodities production (including that used for electric-arc furnaces for green-steel manufacturing). In the *Accelerated Transition* scenario, electricity consumption for hydrogen production is projected to be 108 TWh by 2050, substantially lower than the nearly 600 TWh in the *Green Energy Exports* scenario in the 2024 ISP, but it still reflecting a significant opportunity at approximately half the current NEM operational consumption. The scenario assumed over 75 TWh more consumption for hydrogen production than in *Step Change* by 2049-50. To service the hydrogen demand, over 12 GW of electrolysers are developed, with electrolysers operating at 90% utilisation on average.

Figure 34 Electricity consumption associated with hydrogen production, *Accelerated Transition*, 2026-27 to 2049--50 (TWh and GW)



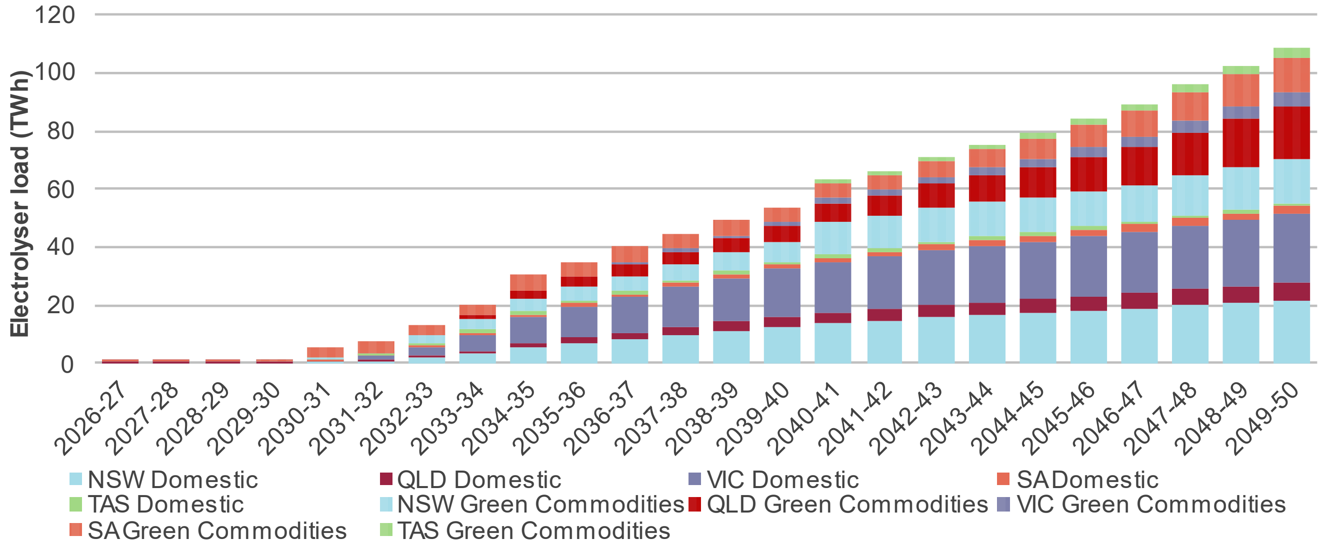
The 2025 IASR provided forecast geographical diversity of hydrogen loads in this scenario – Victoria and New South Wales have the highest domestic hydrogen production requirements, while hydrogen production for green commodity is concentrated in Queensland, New South Wales and South Australia.

By 2049-50, over 12 GW of electrolyser capacity is installed to meet almost 110 TWh of hydrogen load, with 96 TWh of flexible operations and approximately 13 TWh for less flexible operations, including electric arc furnace load.

Electrolysers are expected to locate in areas that have good access to both renewable energy supply and the customers most likely to consume their product, to minimise the cost of transportation. For green commodities that can be consumed by domestic and international customers, access to export facilities will also be a locational influence.

A large portion of electrolysers that are built to serve demand for green commodities are in Wide Bay, Mid-North South Australia and New England REZs as they are sufficiently close to export terminals and potential domestic consumers. As **Figure 35** shows, the locational growth in hydrogen consumption that has been assumed in this scenario in the 2025 IASR.

Figure 35 Regional hydrogen consumption, *Accelerated Transition*, 2026-27 to 2049-50 (TWh)



Contrasting the ODP's development opportunities with the 'no transmission' counterfactual development path in *Accelerated Transition*

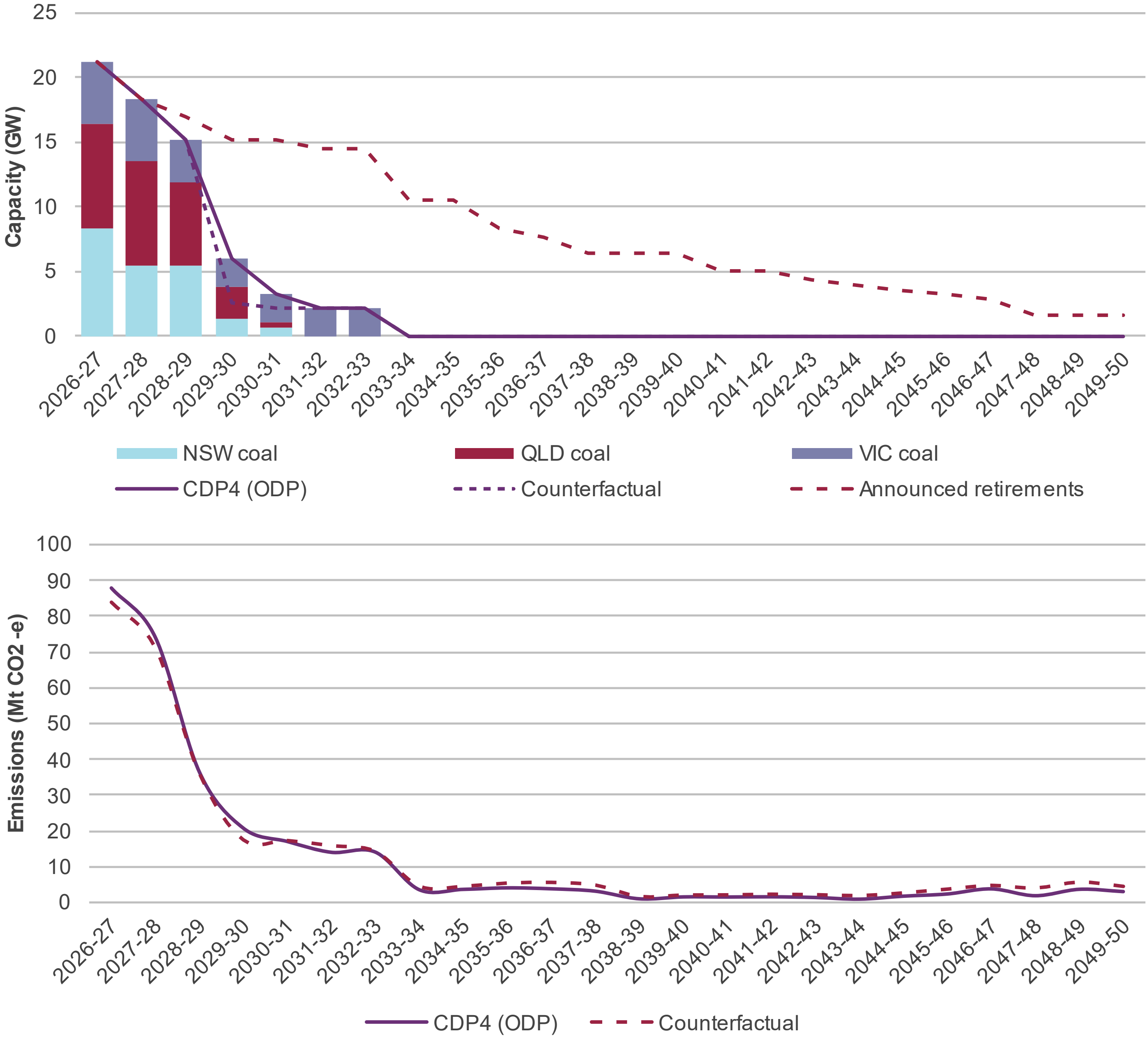
The Draft 2026 ISP identifies material savings to consumers through the expansion of the transmission network (see Appendix A6 for more details). Transmission investments help transition to a lower emissions energy system by improving access to renewable energy developed in REZs and reducing potential VRE curtailment due to transmission limitations. At times of VRE curtailment due to network limitation, higher cost generation may need to generate, increasing overall costs and increasing emissions.

Impact of transmission development on retirements of coal-fired generation capacity

Figure 36 below shows a comparison between retirement schedule of coal-fired generation capacity in the 'no transmission' counterfactual development path which does not feature major transmission network augmentation (solid line) and in the ODP (bars), contrasted with the announced closure dates (dashed line). Below the first chart is a comparison of the emissions trajectory between the counterfactual development path and ODP.

In the 'no transmission' counterfactual development path, without major transmission expansion and limited access to VRE, black coal plants in Queensland and New South Wales retire earlier. In both cases, coal utilisation declines as utility-scale wind and solar, storages, and flexible gas increase operation. The two cases present minor differences in terms of overall emissions outcomes.

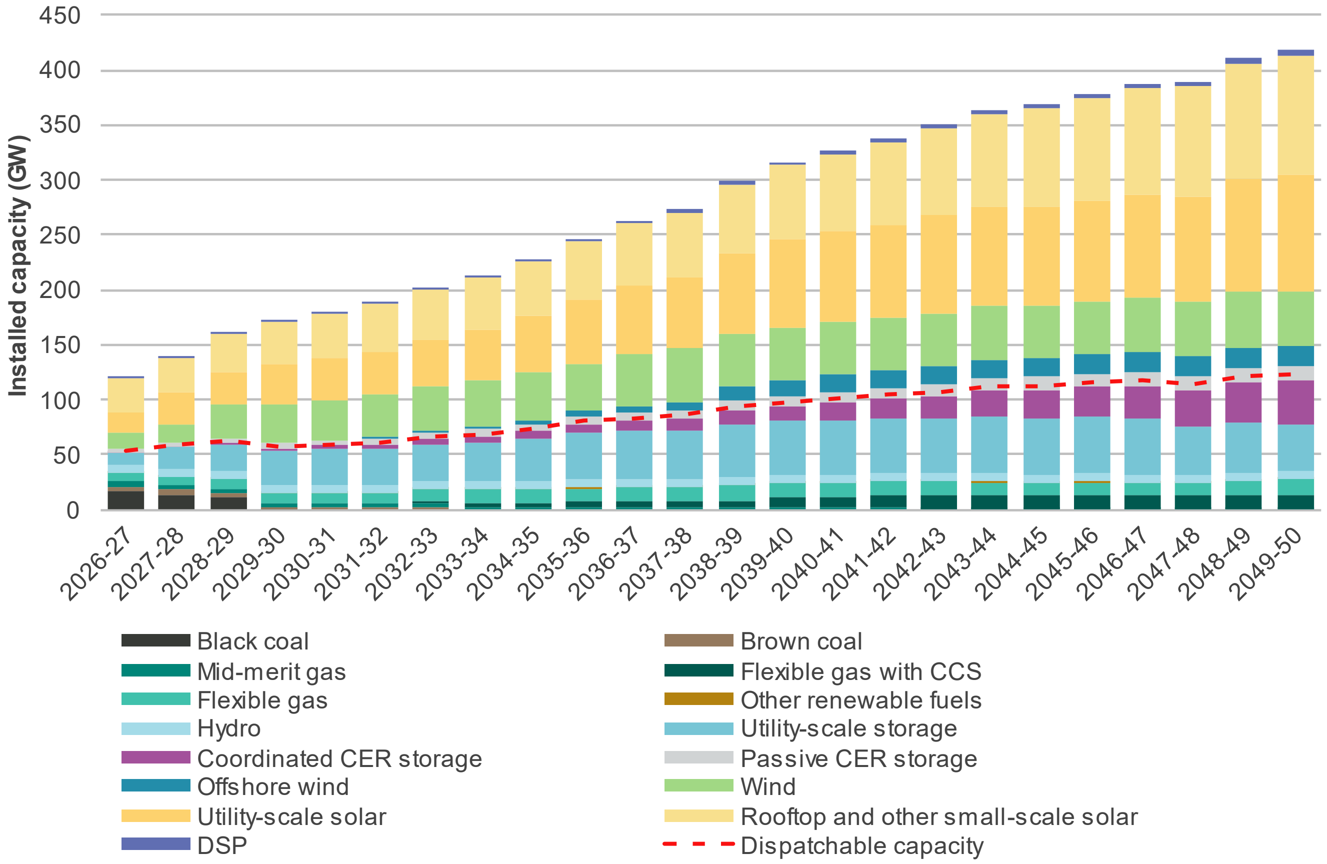
Figure 36 Projected retirements of coal-fired generation capacity (top) and emissions trajectory (bottom) to 2049-50, *Accelerated Transition* 'no transmission' counterfactual development path (GW and Mt CO_2-e)



Impact of transmission development on capacity and generation mix

Figure 37 shows the projected capacity mix in the 'no transmission' counterfactual development path.

Figure 37 Projected NEM installed capacity, *Accelerated Transition* 'no transmission' counterfactual development path, 2026-27 to 2059-50 (GW)

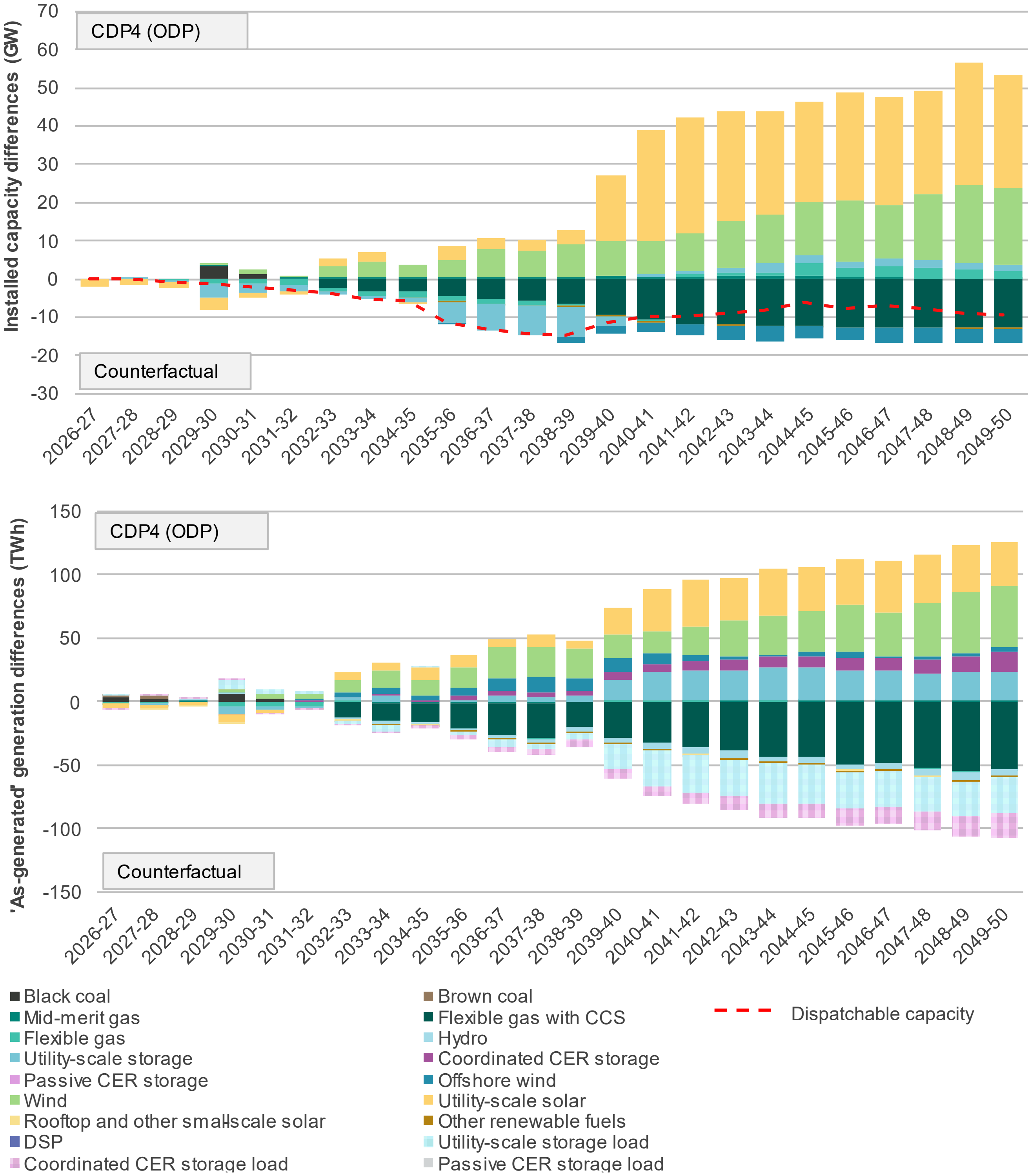


Under the *Accelerated Transition* scenario, in the 'no transmission' counterfactual development path, which represents a future without major transmission augmentation, a more diverse mix of low-emissions technologies is needed to meet future energy consumption. To continue to supply a growing NEM with limited capability to expand the network to connect new renewable generation locations, the 'no transmission' counterfactual development path installs flexible gas with CCS from 2032-33. As shown in **Figure 38**, utility-scale solar, utility-scale storage, and flexible gas with CCS across the NEM provide capacity while keeping emissions within the emissions budget. As CCS technologies do not capture all emissions, coal plant retirements are brought forward to ensure sufficient emissions budget is available to operate flexible gas with CCS across the outlook period.

In the 'no transmission' counterfactual DP, the retirement of the Gladstone power station would cause significant system reliability risks in Gladstone Grid as there is not enough local generation options in the sub-region, due to fuel limitations. AEMO does not consider this credible, hence the gas supply limit applied to flexible gas development in Gladstone Grid was assumed to be lifted. AEMO will continue to examine whether the level of gas investment in other parts of the East Coast Gas Market are appropriate for this 'no transmission' counterfactual as the 2026 ISP is finalised.

Greater use of solar and storages connected to the distribution network are also a feature of the 'no transmission' counterfactual development path (bundled within solar and storage categories in the figure). Further, broader development of Australia's offshore wind potential is needed beyond the Victorian Offshore Wind Target where the network at point of onshore connection can accommodate the additional capacity.

Figure 38 Projected capacity developments (top) and generation (bottom) to 2049-50 under 'no transmission' counterfactual development path compared with *Accelerated Transition* (GW and TWh)



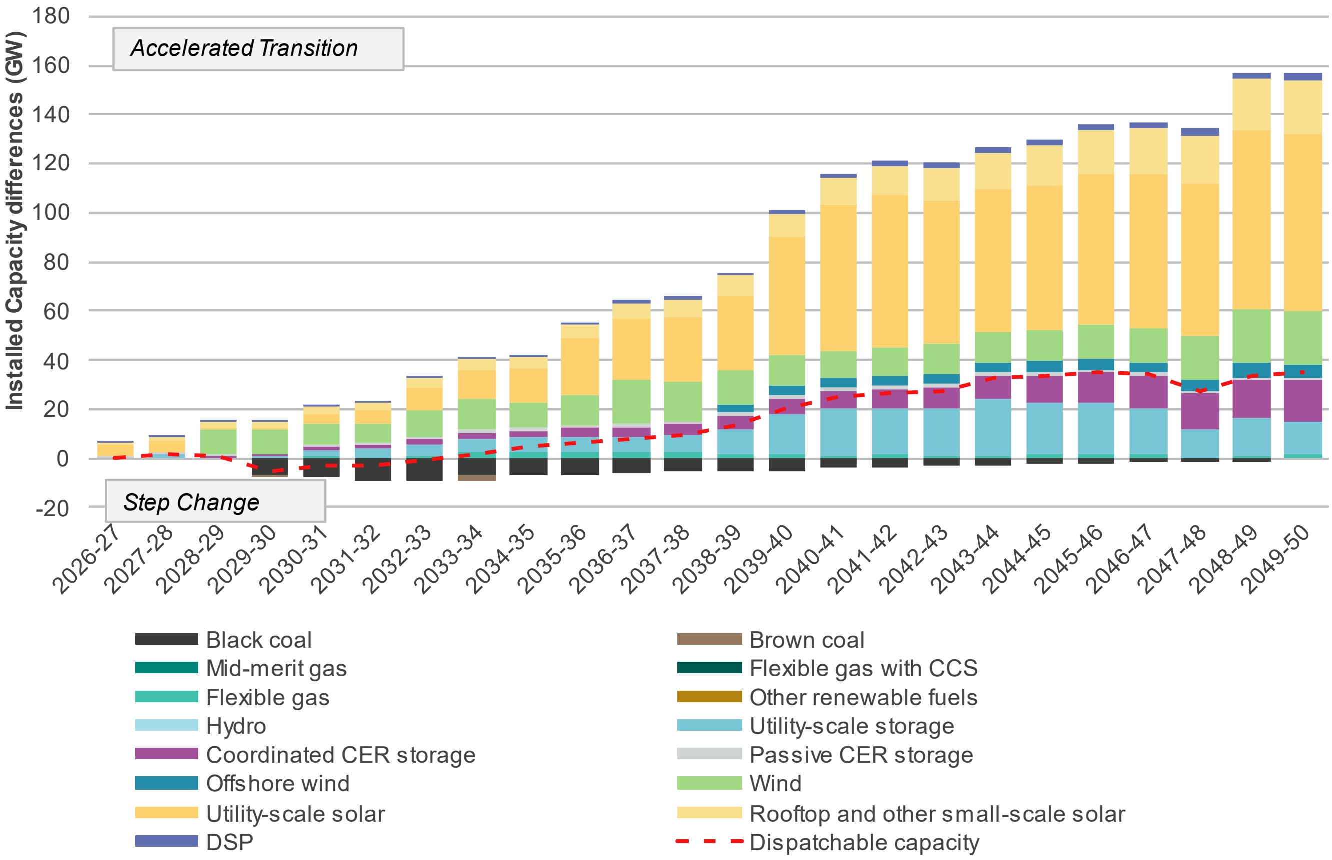
Contrasting the ODP's development opportunities in Accelerated Transition and in Step Change

Figure 39 presents the capacity difference between the developments for *Accelerated Transition* and *Step Change*.

By the end of the outlook period, total installed capacity is about 190 GW (50%) more relative to *Step Change,* due primarily to the higher electricity consumption (around 170 TWh or 41% greater) associated with the *Accelerated Transition* scenario, particularly from industrial loads and electrified transportation's charging demand.

The *Accelerated Transition* scenario's smaller emissions budget drives earlier retirements of coal-fired generation capacity than *Step Change*. To offset these retirements and meet higher energy consumption, significant utility-scale VRE and utility--scale storages are projected, alongside higher investments in CER developments. A similar trend is observed in generation, which is about 42% (191 TWh) higher than *Step Change*.

Figure 39 Projected capacity development to 2049-50 under *Accelerated Transition* compared to *Step Change* (GW)



A2.4 The influence of sensitivities on generation and storage development opportunities

This section outlines the impact of changes in key assumptions made in the *Step Change* scenario on the generation and storage developments in the Draft 2026 ISP. Each sensitivity explores the effect of a specific uncertainty on the generation and storage developments. The impact on net market benefits is explored in Appendix A6, which explores the cost-benefit analysis of the ISP.

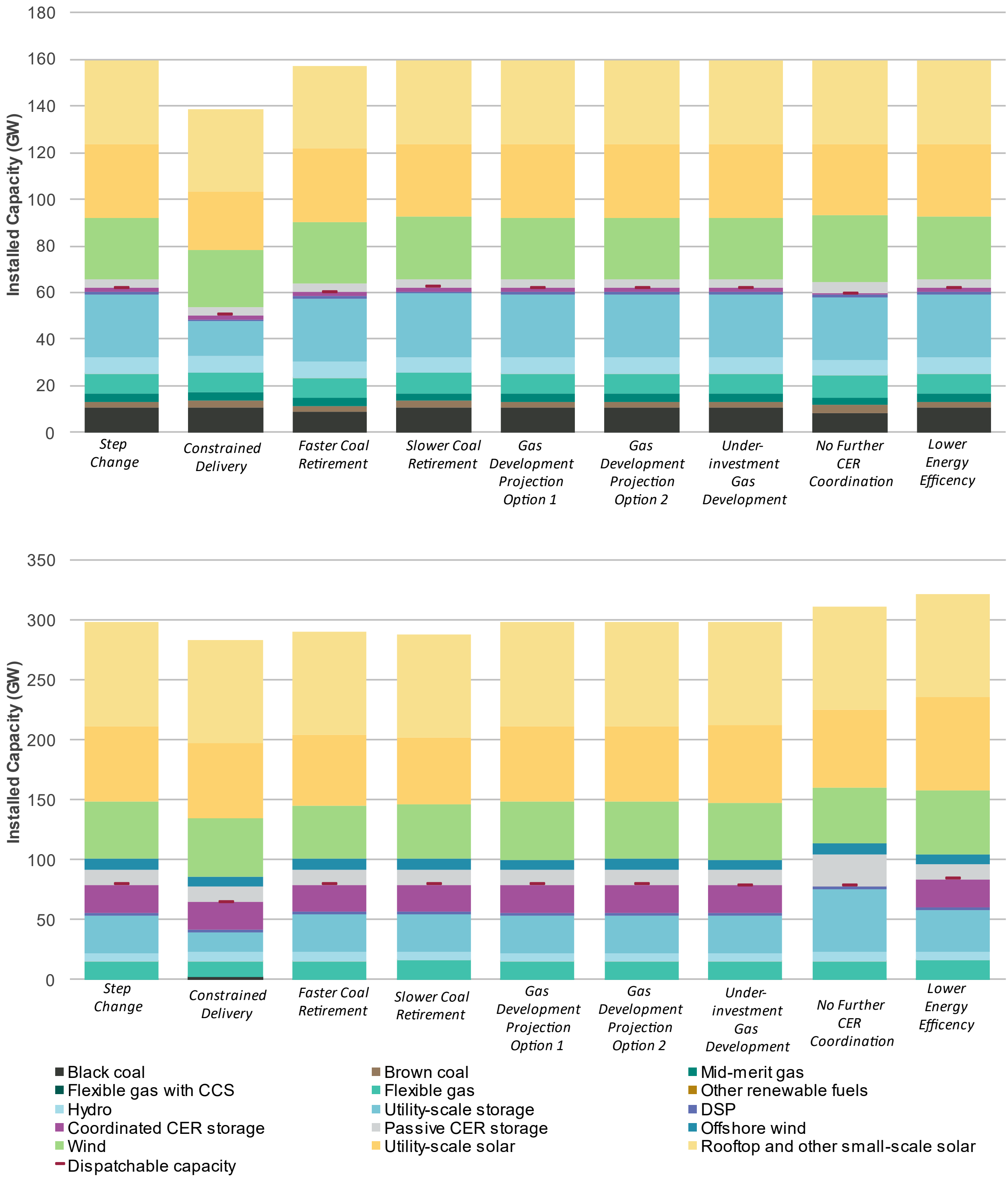
The Draft 2026 ISP presents a range of sensitivities, including:

- *Constrained Delivery* which explores the impact of limitations in supply chain, workforce availability, or other factors affecting the cost and timing of delivery of energy infrastructure,
- alternative coal retirement scenarios which assess how the pace for coal-fired generation capacity retirements affect the development opportunities in the NEM,
- alternative gas development projections (GDPs) that explore the impact of different gas supply volumes available to support flexible gas generation operations in the NEM power system, and
- alternative assumptions on demand-side factors such as *No Further CER Coordination* and *Lower Energy Efficiency*.

Additional information on the capacity developments, energy generated, retirement outlook, and emissions outcomes for the sensitivities are also included in the **Generation and Storage Outlook Workbooks,** including regional and sub-regional outlooks.

As shown in **Figure 40,** the scale of wind and utility-scale solar development is resilient to alternative assumptions tested in the sensitivity analysis. Compared to *Step Change*, supply chains constraints (or equivalent) in the *Constrained Delivery* sensitivity limit the capability to develop sufficient VRE capacities by 2030 to meet policy targets, but otherwise the developments are similar over the next decade, given policy drivers apply consistently in these sensitivities.

Figure 40 Generation and storage capabilities by 2029-30 (top) and 2049-50 (bottom) in *Step Change* and sensitivities to *Step Change* (GW)



A2.4.1 Constrained Delivery

The *Step Change* scenario projects a high level of new investment in generation, storage and other energy infrastructure. The pace of delivery of these new assets depends on a range of factors including supply chains, social licence, planning approval, construction, materials, and workforce. The *Constrained Delivery* sensitivity whether the transmission projects proposed in the ODP would still deliver material benefits to consumers if transmission as well as generation and storage projects were unable to be delivered at the pace required. There may be many reasons for delivery delays – through planning approvals and the need for social licence, the supply chain, or construction – but the sensitivity only limited the rate of build, not what determined the delays.

In this sensitivity, as a result of energy infrastructure development constraints:

- Capital costs for generation, storage, and electricity networks were assumed to rise, and were set 30% higher than *Step Change*. There may be many reasons for that rise – competing for skills and equipment as global demand rises, the delays themselves, more costly conditions to meet planning requirements – but the sensitivity modelled the rise in cost only.
- NEM-wide limits were imposed on additional wind, utility-scale solar, and utility-scale storages until 2034-35. The delivery of committed and anticipated projects as well as other new entrant projects are assumed to be impacted by the same supply chain limitations. The limit reflects an extension of the trend in pace of connection in individual technologies observed over the past five years (see **Figure 41** below).
- Delays to the earliest-in-service date (EISD) for transmission flow path and REZ network augmentation options of up to three years (including committed and anticipated projects) were assumed, to test impact if industry is unable to build capability to deliver above recent transmission line build rates. It was assumed that committed projects would be delayed six months, anticipated projects 12 months, and actionable projects an average of two years. These assumptions were set to allow a 5% year-on-year increase from recent transmission line build history (approximately 365 km/year during the construction of Stage 1 of Project EnergyConnect and Eyre Peninsula Link).
- Offshore wind projects are also impacted by the development constraints delaying the delivery of 9 GW of capacity by three years.
- With slower development of VRE, coal generators may need to operate for longer in this sensitivity (but not beyond their announced closure dates). After delivery constraints are assumed to alleviate and as more VRE capacity is delivered, coal generation in this sensitivity retires faster than in *Step Change* to remain aligned with long-term emissions targets.

With these constraints slowing renewable energy and storage developments, various federal and state emissions reduction targets and renewable energy policies prior to 2035 are not met to the timetable that each policy intends.

Figure 41 shows the NEM's annual build capability for utility-scale solar, wind, and utility-scale storage assumed in the *Constrained Delivery* sensitivity, relative to the *Step Change* scenario.

Figure 41 ***Constrained delivery* annual build in the next decade considering build limits influenced by historical commissioning rate for onshore wind and utility-scale solar generation (GW)**

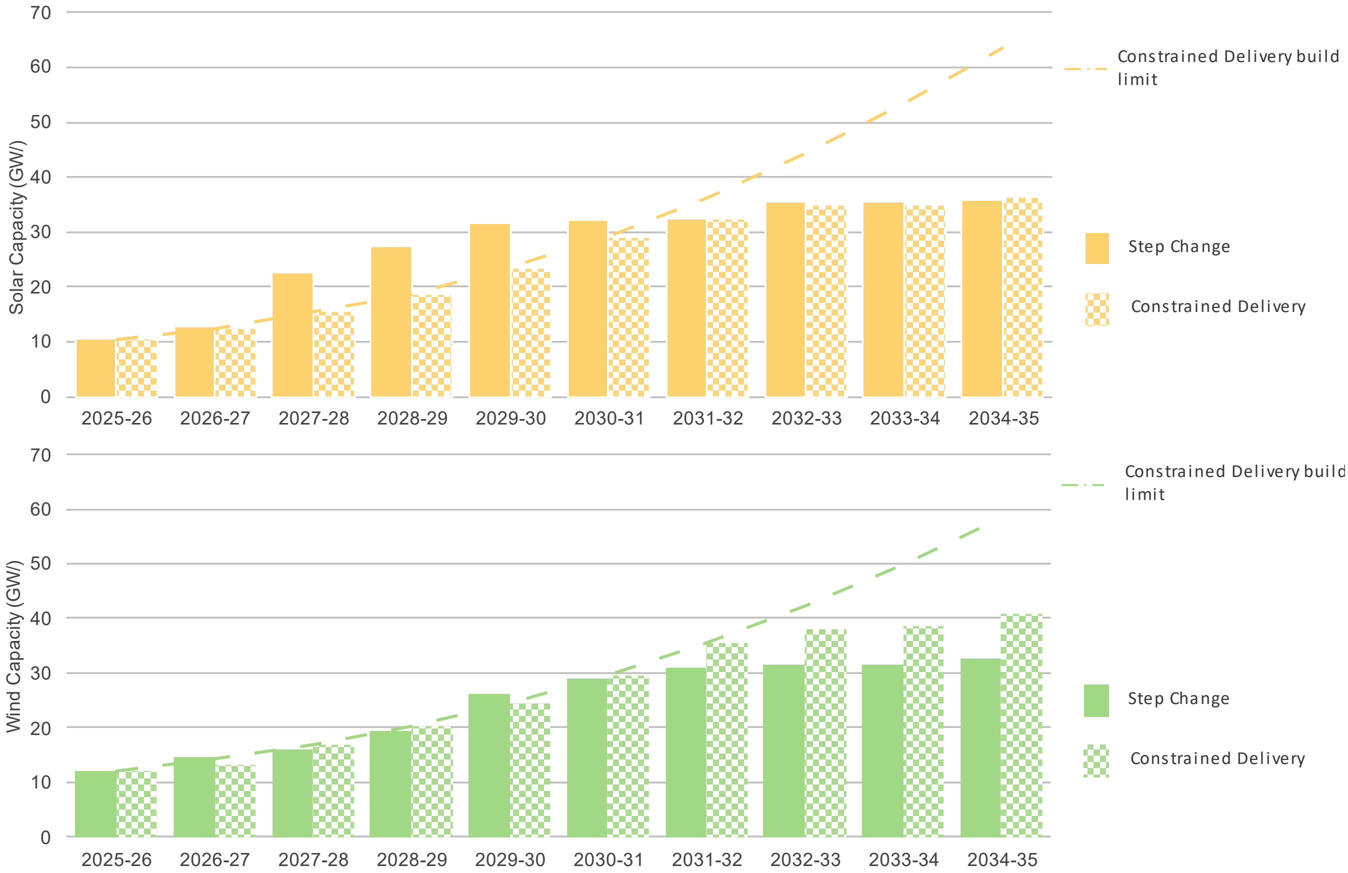
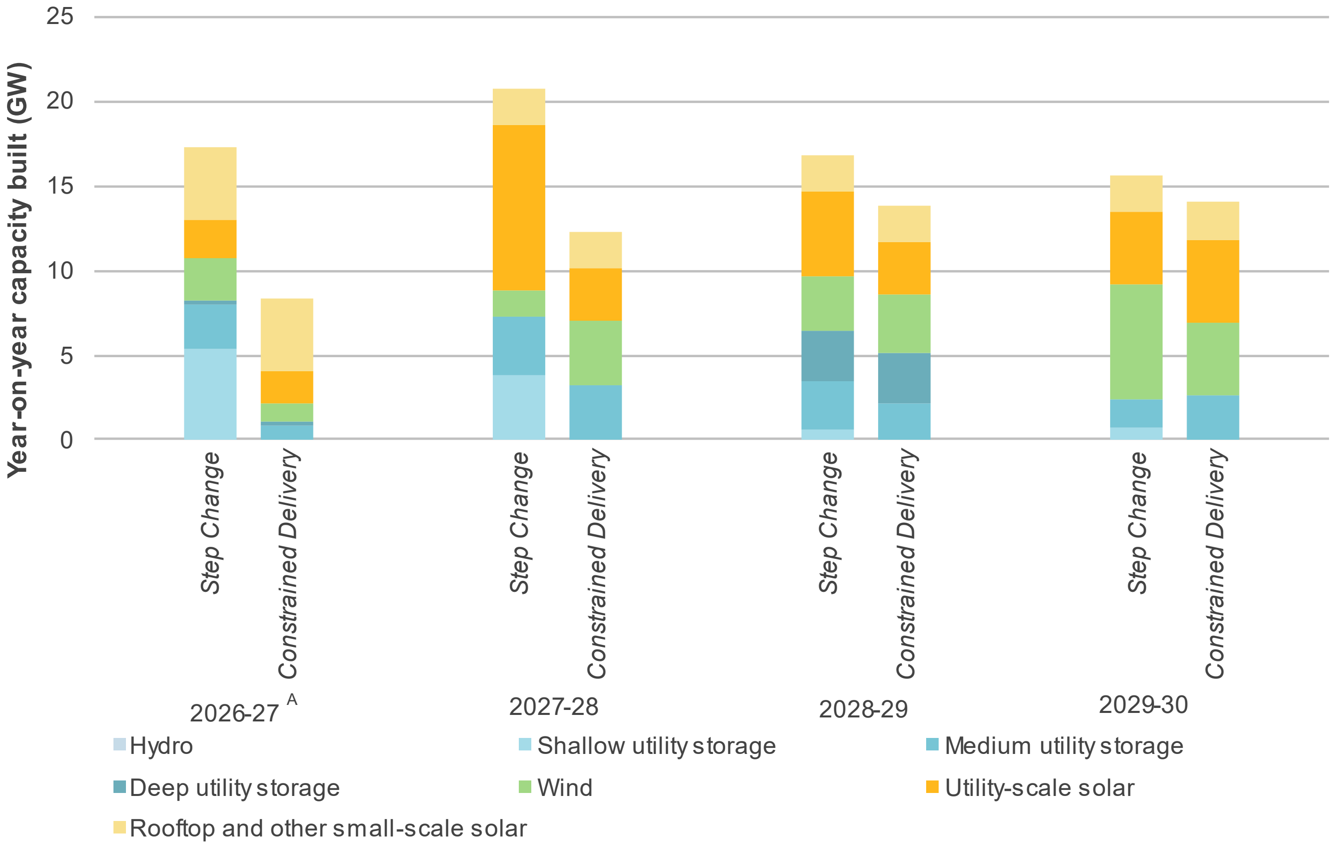


Figure 42 shows the annual build development for utility-scale renewable energy and utility-scale storage capacities to 2029-30 in the *Constrained Delivery* sensitivity.

In this sensitivity, where the delivery of additional energy infrastructures is limited by various factors affecting the pace of asset development, slower rollout of generation, storage, and transmission and distribution networks limits the pace of the transition and some of the 2030 policy targets would not be achieved such as missing both the 2030 renewable energy target and the electricity sector's contribution to the national emissions target. In this sensitivity with development constraints, the NEM only builds an average of 5.3 GW per year of utility-scale VRE during the period 2025-26 to 2029-30 – including 2.8 GW per year of utility-scale solar and 2.5 GW per year of wind. This translates to about 14 GW additional utility-scale solar and 12.7 GW of wind by 2030.

Figure 42 NEM renewable annual build capacities, *Step Change* versus *Constrained Delivery* sensitivity, 2026-27 to 2029-30 (GW)



A. Note the values for 2026-27 are presenting the capacity growth compared to 2024-25 installed capacity. All other years present the year-on-year growth.

Figure 43 presents historical and projected installed capacity between the *Constrained Delivery* sensitivity and the *Step Change* scenario up to 2049-50. It shows the near-term increase in build required in *Step Change* relative to recent history, and the impact that the delivery constraints would have on the *Step Change* development of these technologies. Applying these trajectories, *Constrained Delivery* builds approximately 20 GW less than *Step Change* to 2029-30, before broadly catching up to the *Step Change* scenario in the longer term.

This reduction in installed capacity impacts the ability to meet federal and state policies and carbon budgets in near term. From 2029-30 to 2037-38, the sensitivity has approximately 5 GW less capacity installed compared to *Step Change*. More coal generation in this sensitivity is needed to operate for longer than the *Step Change* scenario (but not beyond any generator's currently announced closure date), due to the slower delivery of new replacement generation from VRE. Coal still needs to reduce operation to achieve the emissions reduction targets by 2035 and 2050. Renewable energy and storage development would scale up to help meet the 2035 emission targets with utility-scale solar capacity reaching 38 GW and wind reaching 43 GW by 2035.

Figure 43 Projected installed capacity to 2049-50 under the *Constrained Delivery* sensitivity and *Step Change* (GW)

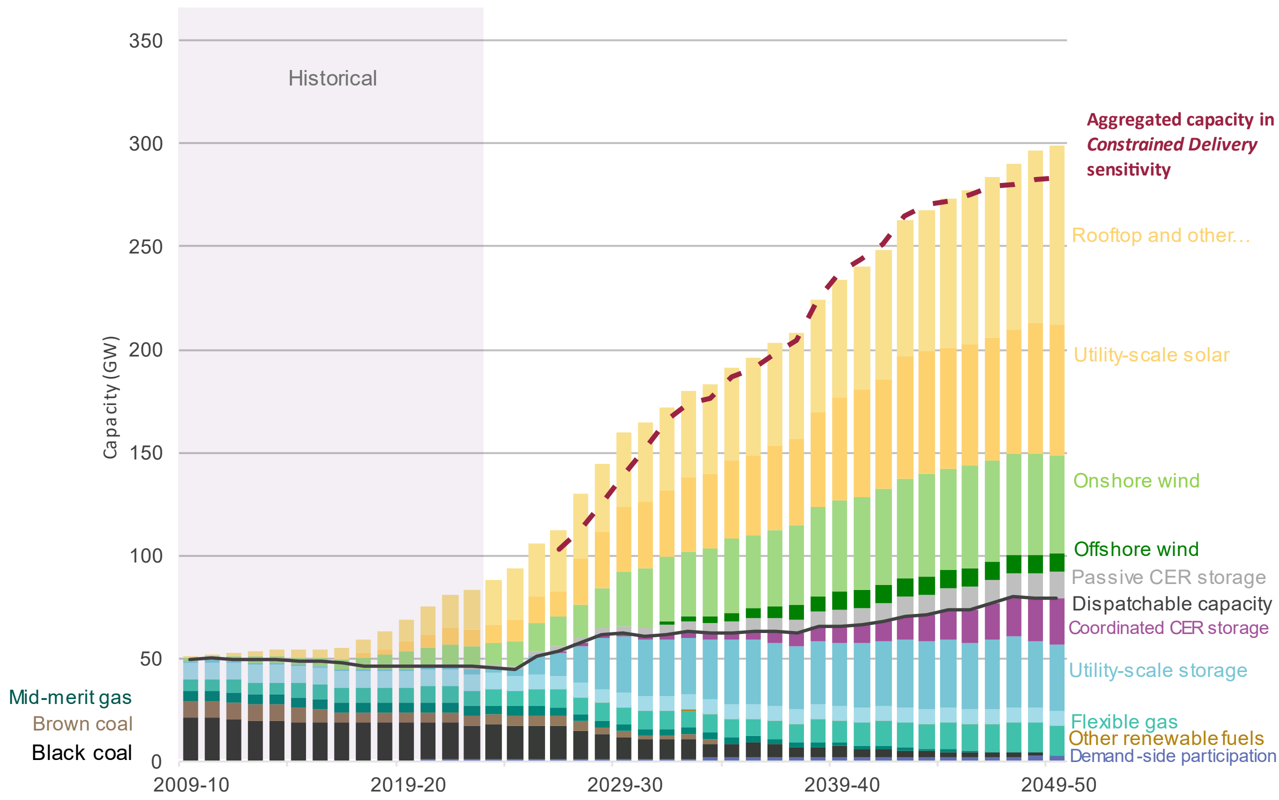


Figure 44 compares the generation and storage capacity developments in the *Constrained Delivery* sensitivity with *Step Change* and shows a significant reduction in the delivery of utility-scale storage and utility-scale solar until 2029-30. The maximum infrastructure development rate assumed that the NEM could build not only limits the development of utility-scale storage, it also impacted the capacity development and generation from utility-scale solar that usually is best supported by utility-scale storage development to maximise generation utilisation. However, the lesser capacity developed for utility-scale storages persists even beyond 2034-35 when supply chain limitations were assumed to have already been addressed. With increased wind generation capacities and other alternative forms of generation technologies developed by 2034-35 (but within the delivery constraints that have been assumed), there is reduced need for some utility-scale storage.

Figure 44 Projected capacity developments to 2049-50 under the *Constrained Delivery* sensitivity compared with *Step Change* (GW)

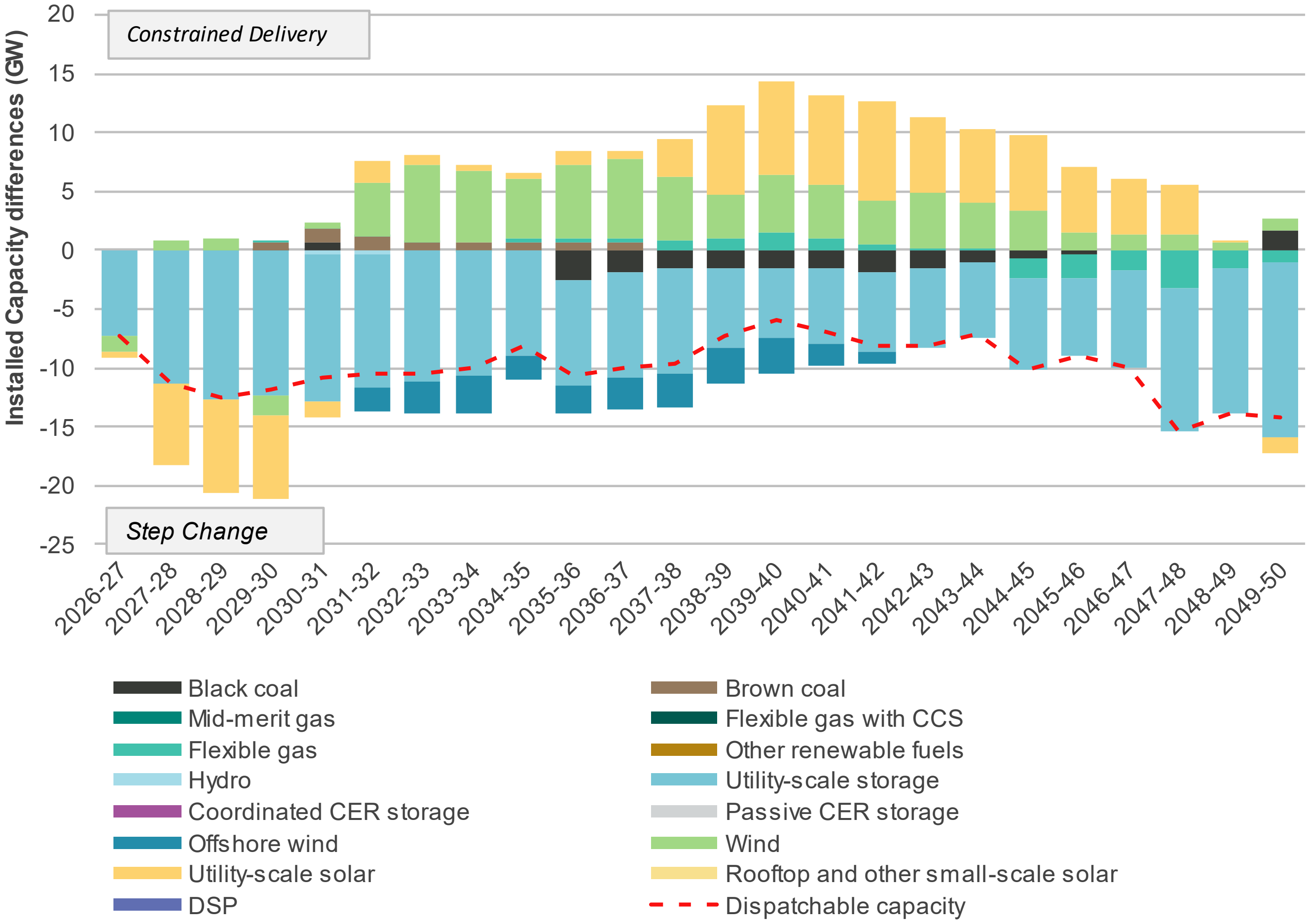
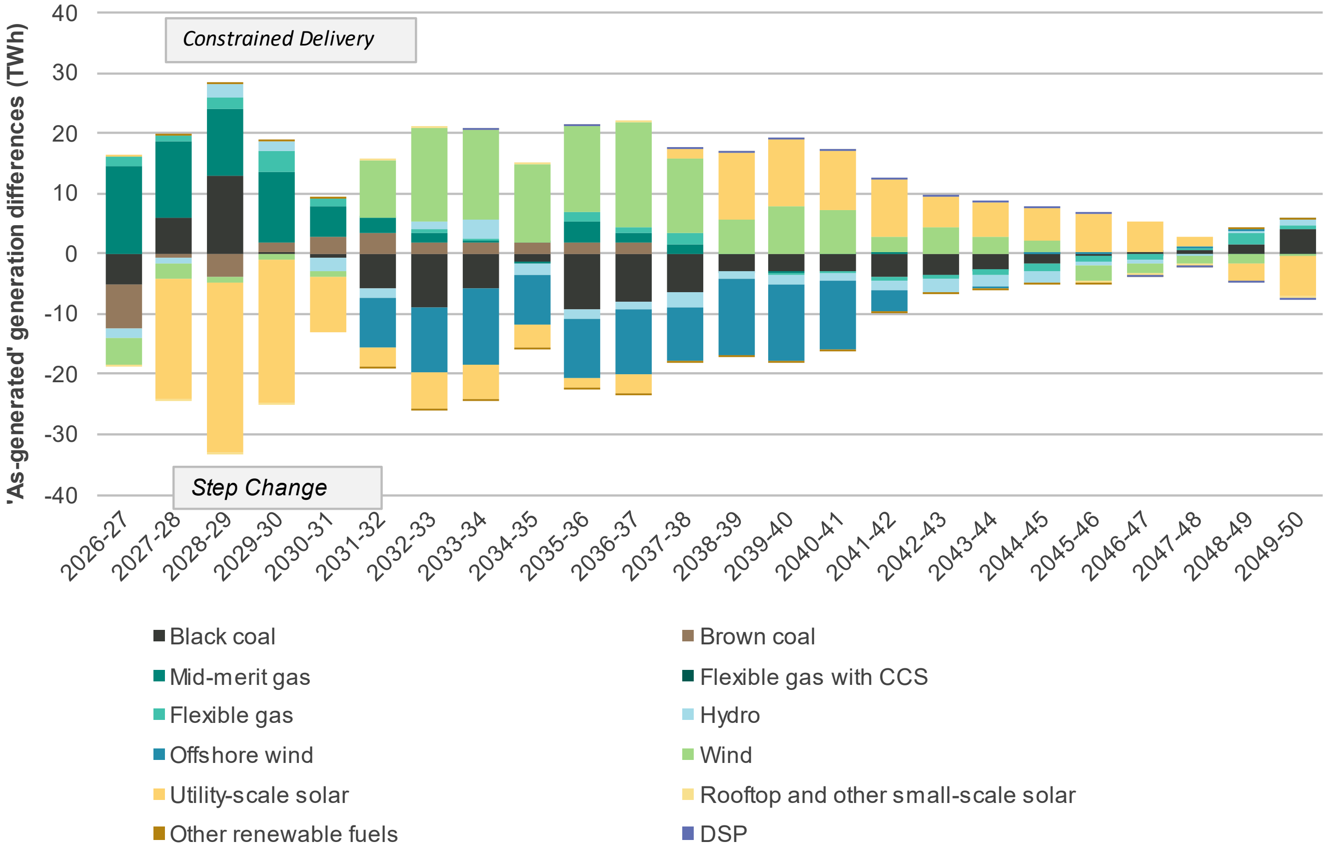


Figure 45 presents the generation mix difference between the *Constrained Delivery* sensitivity and *Step Change*. With slower development of renewable capacity, more thermal generation is dispatched in the sensitivity to meet projected energy consumption prior to 2034-35. NEM emissions are therefore slightly higher while development is delayed, and to meet 2050 carbon budgets, some capacity and generation differences endure over the long term.

In the *Constrained Delivery* sensitivity, the total renewable energy contributes to 75% of total energy consumption in the NEM by 2029-30, less than the 82% renewable energy target. The emissions reduction target in 2030 is exceeded by 5.5 Mt CO_2-e (achieving 75% of the assumed electricity sector share of that target). Other targets and policies, such as the CIS generation and dispatchable targets by 2030, the TRET in Tasmania and the Victorian offshore wind target are all slower than intended to achieve their stated objectives, at approximately 2-3 years later.

Figure 45 Projected generation to 2049-50 under the *Constrained Delivery* sensitivity compared with *Step Change* (TWh)



A2.4.2 Gas development projections

AEMO identifies a critical role for flexible gas generation in all scenarios to support storages to provide back-up supplies for reliability and security needs, requiring fuel supplies to be sourced from the East Coast Gas Market[13]. The Draft 2026 ISP includes gas development projections that represent plausible pathways for gas investments, including the timing for when the different options may be developed to service the needs of all gas consumers, including flexible gas and mid-merit gas generators. Each projection commences with a set of initial investments, based on analysis in the 2025 GSOO[14], to address near-term gas supply adequacy challenges.

This section discusses the impact of the three assessed gas development projections for the *Step Change* scenario on the development of electricity investments in the NEM, given the variations in gas supply volumes available to support gas generation operations in each gas projection. The differences between the gas development projections include the initial investment, and then the capacity, timing and location of subsequent gas infrastructure investments. These investments include transport, storage, production, and regasification infrastructure identified through the *Gas Infrastructure Options Report*[15].

[13] Australia's East Coast Gas Market services gas consumers in all NEM jurisdictions, as well as in regions outside of the NEM, including the Northern Territory and central Australia.

[14] See Chapter 5, 2025 GSOO, at https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2025/2025-gas-statement-of-opportunities.pdf?la=en.

[15] See https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-gas-infrastructure-options-report-consultation.

This section also examines the impact of a 'what-if' analysis – the under-investment gas development projection – where gas developments only respond to projected residential, commercial, and industrial gas demand. This analysis serves as a proxy for a delayed or slow gas development, resulting in a significant reduction in gas fuel availability for the NEM.

Table 2 lists the initial gas infrastructure option that is built in each of the gas development projections. See Appendix A10 for additional detail.

Table 2 Gas development projections and the initial gas infrastructure options predetermined for each projection

Gas development projection	Initial gas infrastructure option
Option 1 – Southern Supply	Development of currently uncertain 2C[A] gas production in southern states. Includes the 2C Gunnedah development from 2030-31 with the Hunter Gas Pipeline.
Option 2 – Pipeline Expansions and Upgrades	Pipeline expansions and upgrades to improve the north to south flow capacity. Includes the development of East Coast Grid Expansion Stage 3 from 2027-28.
Option 3 – LNG Regasification Terminal ***(Used as the Step Change gas development projection)***	An LNG regasification terminal. Port Kembla Energy Terminal operates from 2026-27 with Eastern Gas Pipeline reversal Stages 1 and 2.
Under-investment	Projected developments meet residential, commercial and industrial gas demand but not additional developments required to meet projected gas generation demand.

A. Contingent (2C) resource is a best estimate of a quantity of gas that is less certain, and potentially less commercially viable, than 2P. *Option 1* includes the development of 2C resources in the Gunnedah, Otway, Gippsland, Bass and Cooper basins.

The results indicate that variations in the location and timing of gas investments can still enable regional requirements for flexible gas developments, although specific locations of future gas generators may need to adapt to gas fuel availability. As an example, existing gas supply to Newcastle allows for very limited gas supply to new entrant gas generation, and gas development projection Option 1 includes the development of gas production and a pipeline which increases gas supply availability in Newcastle. This would facilitate more flexible gas generation in this location. At the NEM level, the impact of varying gas development projection sensitivities on the capacity mix remains minimal, with changes observed primarily within regions (such as in Sydney, Newcastle, and Wollongong (SNW) and Central New South Wales (CNSW) sub-regions).

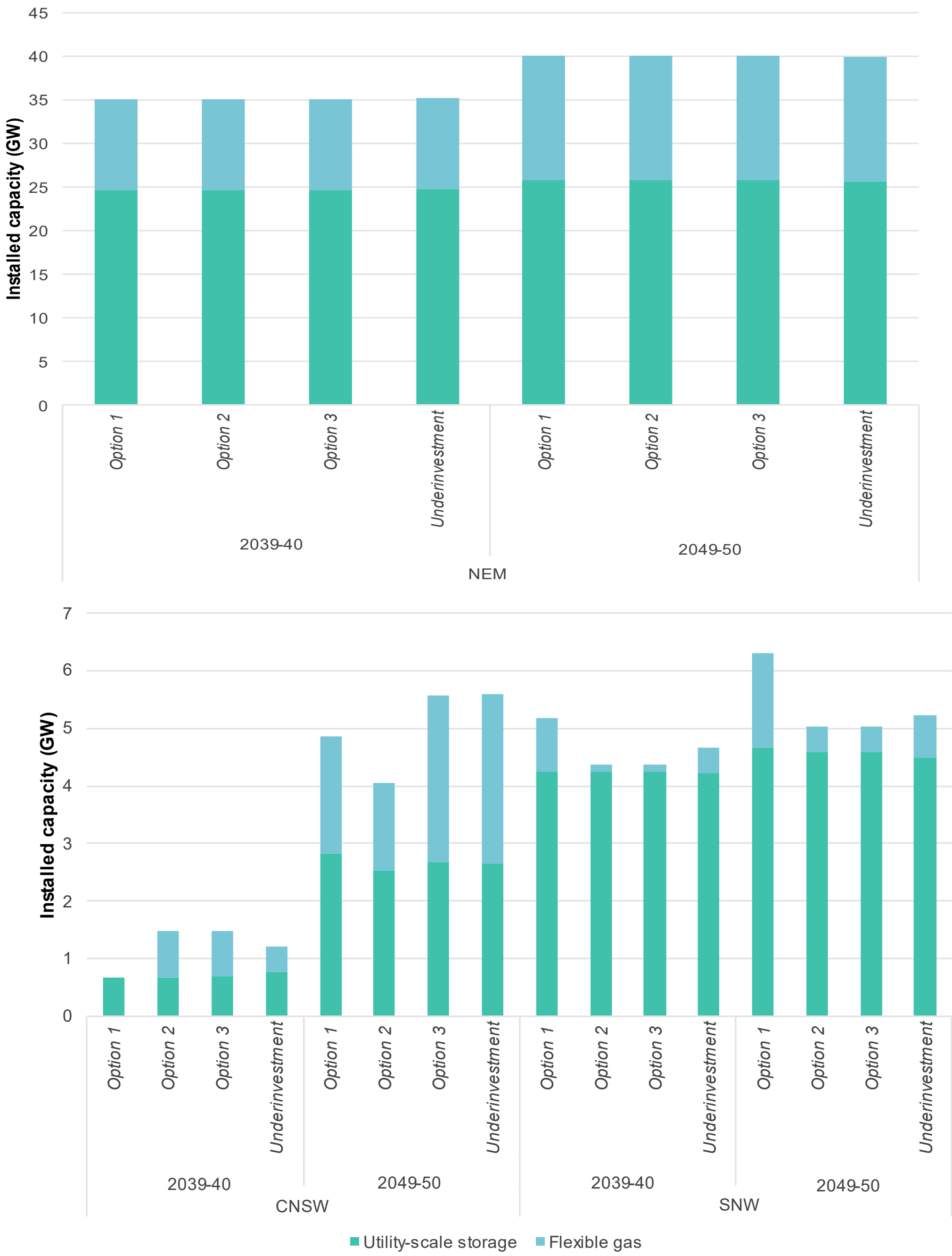
Figure 46 presents the capacity development changes for Sydney, Newcastle, and Wollongong and Central New South Wales sub-regions, focussing on flexible gas and utility-scale storage. The impacts on the capacity requirements driven by gas fuel availability are concentrated toward the end of the outlook period.

For gas development projection *Option 1*, increased gas fuel availability in Newcastle increases gas builds (1 GW) in the SNW sub--region, while reducing the additional gas capacity (1.4 GW) requirements in the CNSW sub-region. Gas development projection *Option 2* provides a similar overall level of gas fuel availability in the long term, so minimal impact is projected on the capacity mix compared to *Option 3*.

If there was under-investment in gas infrastructure, such that it was broadly insufficient to meet the projected fuel needs for gas generation, NEM generation capacities are similar, but gas generators would rely more on secondary fuels to continue to provide their key role. The only notable difference is the relocation of approximately 300 MW of new entrant GPG from New South Wales to Queensland, where gas supply remains more abundant.

A full co-optimisation of both gas and electricity infrastructure has not been undertaken to determine which combination of gas and electricity development opportunities is least cost for both gas and electricity consumers.

Figure 46 Capacity developments for the different gas development projection sensitivities in the NEM (left) and Sydney, Newcastle, and Wollongong (SNW) and Central New South Wales (CNSW) sub-regions (right), 2039-40 and 2049-50 (GW)



A2.4.3 Coordination of CER storages

Coordination of CER storages, which include residential and commercial storages, transforms the operation of passive CER storages to having more active participation in the NEM dispatch process. Coordination is predominately managed by aggregators in VPP arrangements with CER storage owners and enables CER to respond to market signals. The behaviour of stationary passive CER storage and EVs is solely based on consumer charging and discharging behaviours without regard to the management of the wider electricity system.

This sensitivity sought to assess the impacts of different levels of assumed coordination of CER storage on generation and storage development opportunities in *Step Change*. There are two variations to this assumption in *Step Change*:

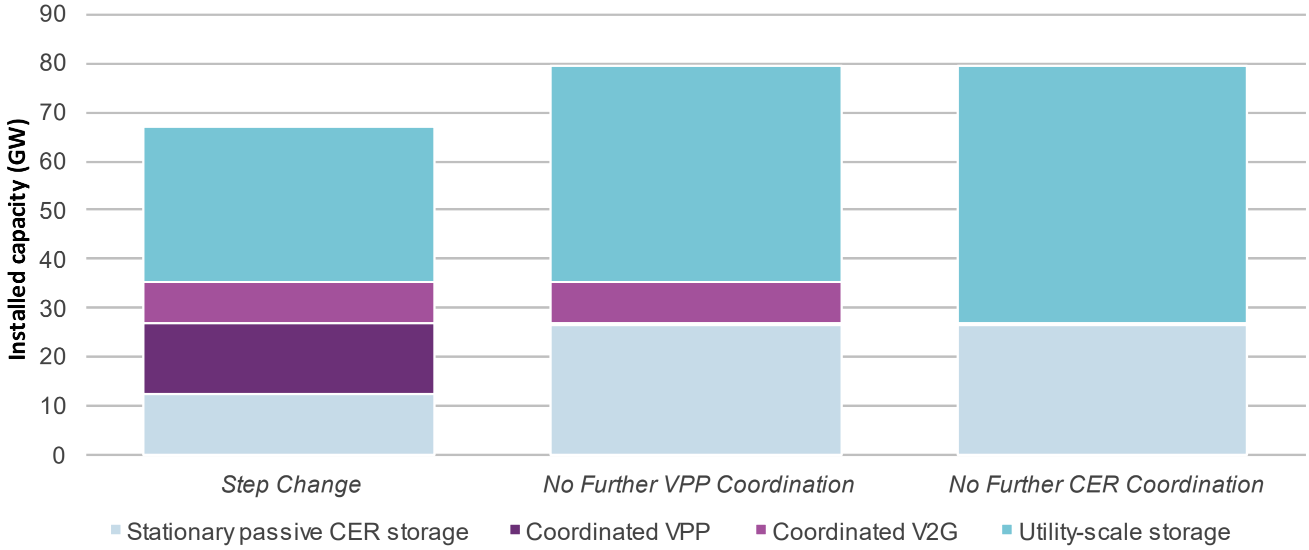
- *No Further VPP Coordination*, which assumed no additional VPP coordination in the NEM beyond 2025, and
- *No Further CER Coordination*, which assumed no additional VPP and V2G coordination in the NEM beyond 2025.

It should be noted that the total level of CER uptake assumed in these sensitivities remains aligned with the *Step Change* scenario. The differences therefore are isolated to the ratio of passive CER storage to coordinated CER storage between the sensitivities.

For *Step Change*, the proportion of stationary CER storages (that is, household and small commercial batteries) that are forecast to be coordinated (via a VPP for example) increases from approximately 15% of CER storages in 2025-26 to approximately 53% of CER storages by 2049-50. In addition, V2G capacity in *Step Change* grows from effectively zero in 2025-26 to 8.5 GW in 2049-50. Combined, this represents a significant increase in devices that can be operated and potentially avoid broader investments by using them to maximise both their system impacts and benefits for CER owners, so long as appropriate technical, communications, and operational solutions are developed, and social licence grows.

Figure 47 summarises the variation of VPP and V2G capacity assumption in each sensitivity and the resulting utility--scale storage development, highlighting the additional utility-scale storage required with reduction in coordinated CER.

Figure 47 Summary of utility-scale storage required in the CER coordination sensitivities in 2049-50 (GW)



No Further VPP Coordination

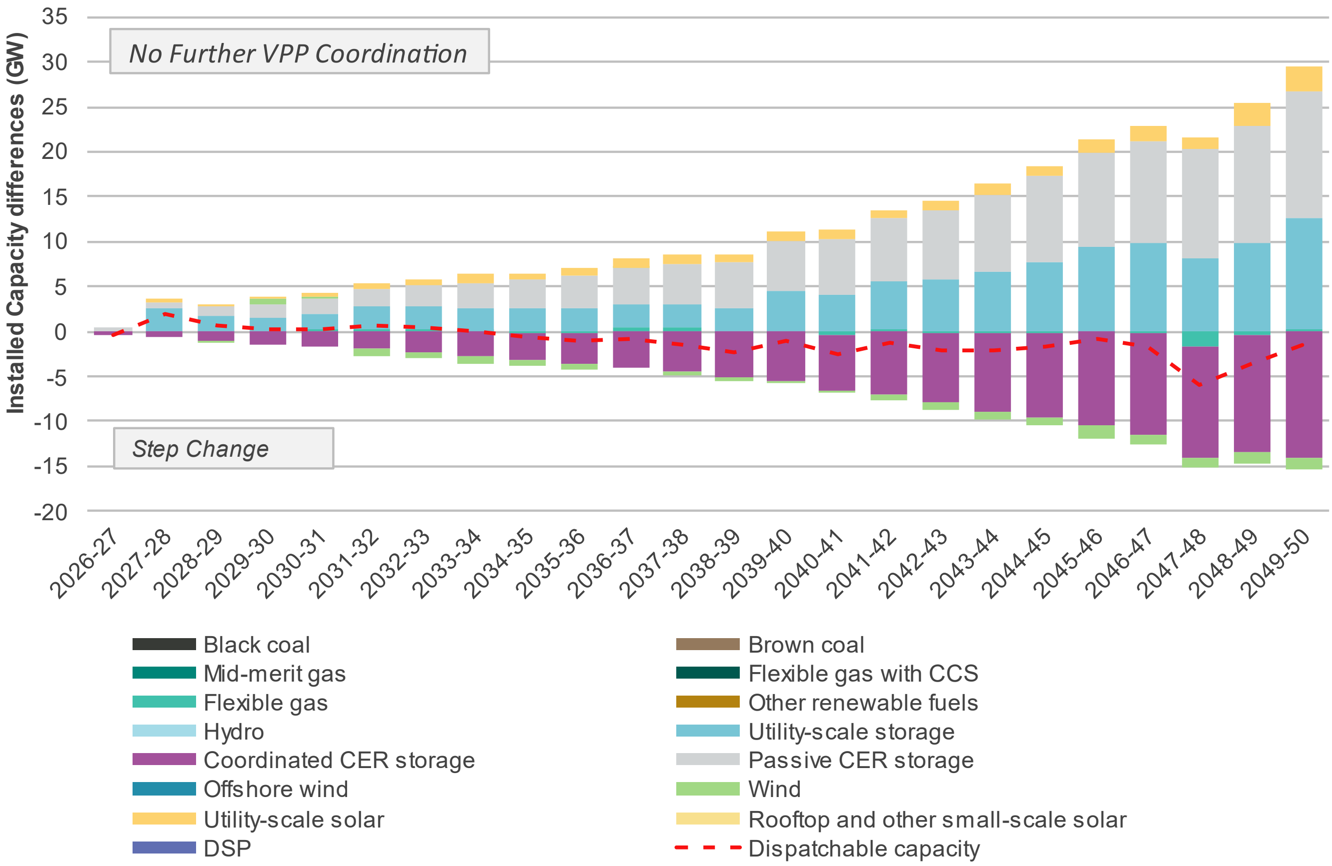
The *No Further VPP Coordination* sensitivity examined the impact of lower coordination of stationary household batteries that can be coordinated into VPPs. In this sensitivity it was assumed there is no further coordination of VPP beyond 2026-27 levels of 225 MW of VPP capacity, while V2G coordination was projected to follow the same trajectory as in *Step Change.* This sensitivity explored the extent of utility-scale investments needed if the forecast level of coordination in the *Step Change* scenario is not achieved.

This sensitivity allows for comparison to the *Reduced CER coordination* sensitivity presented in the 2024 ISP, noting that the VPP capacity in *Step Change* in the Draft 2026 ISP is lower than that in the 2024 ISP.

If there is no further coordination of forecast stationary CER storage – that is, if the forecast 23 GW of coordinated stationary CER storage by 2049-50 in *Step Change* was assumed to operate passively instead to meet individual consumer needs – additional utility-scale investments would be needed. Additional dispatchable capacity is needed to support the passive stationary CER storage, including medium-depth and deep utility-scale storage (12 GW/43 GWh), flexible gas (0.2 GW), and utility-scale solar capacity (2.8 GW) by 2049-50.

There is a small increase in utility-scale solar and reduction in wind generation across the horizon, and minimal change in flexible gas generation compared with the base case.

Figure 48 Projected capacity developments to 2049-50 under the *No Further VPP Coordination* sensitivity compared with *Step Change* (GW)



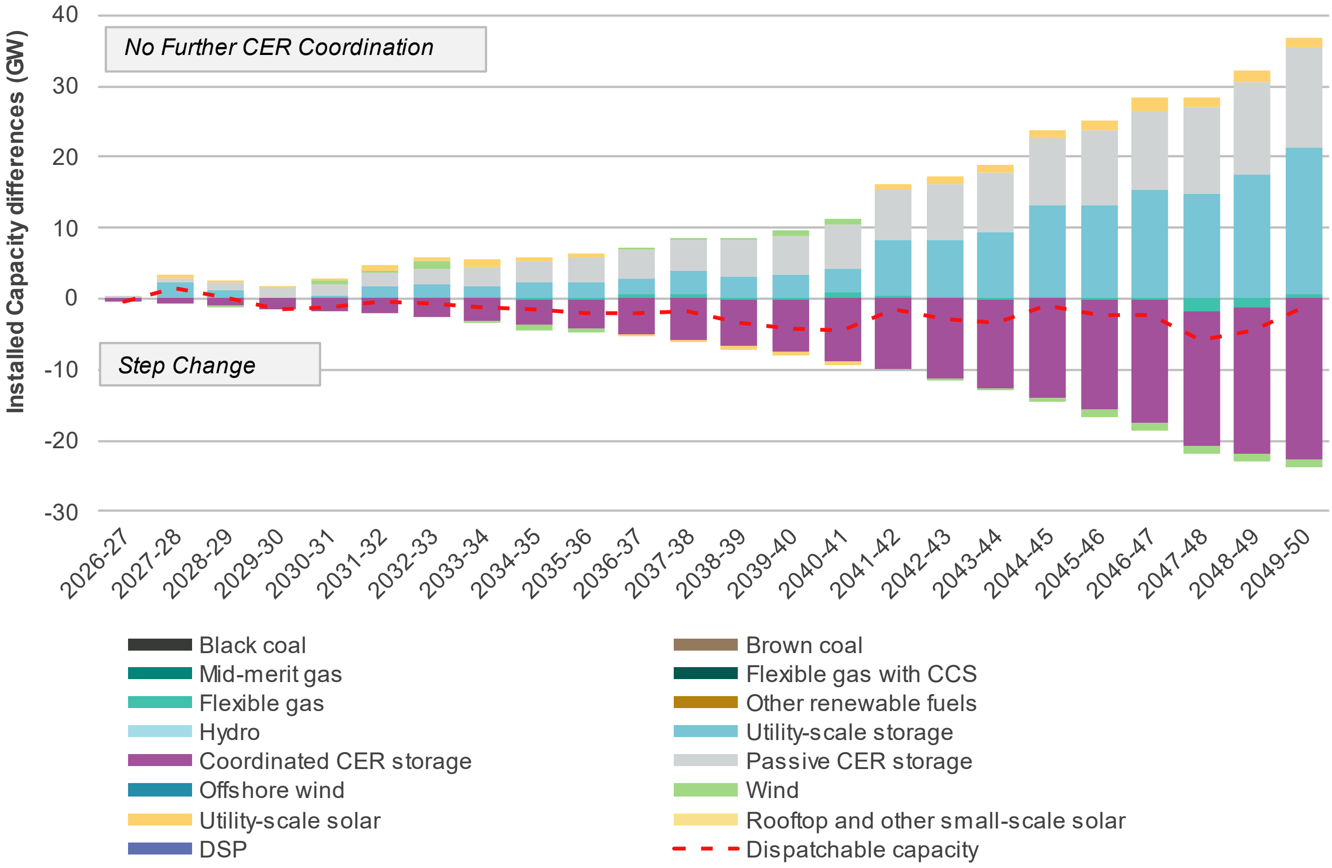
Note: Coordinated CER storage includes VPP and V2G capacity. Passive CER storage includes passive stationary battery capacity only; it does not include passive EV capacity.

No Further CER Coordination

This sensitivity featured no further coordination of stationary and non-stationary CER storages (that is, household and small commercial batteries plus EVs with coordinated charging via V2G arrangements) beyond 2026-27 levels of 225 MW of VPP capacity and zero V2G capacity. It projects that 20.5 GW of additional utility-scale investments are required by 2049-50 in lieu of the amount of coordinated CER storages that were assumed to operate in a passive manner in this sensitivity.

There is minimal change in the capacity development and generation output of utility-scale solar, wind, and flexible gas compared with the base case, while there is an increase in other distributed solar in early years of the outlook period.

Figure 49 Projected capacity developments to 2049-50 under the *No Further CER Coordination* sensitivity compared with *Step Change* (GW)



Note: Coordinated CER storage includes VPP and V2G capacity. Passive CER storage includes passive stationary battery capacity only; it does not include passive EV capacity.

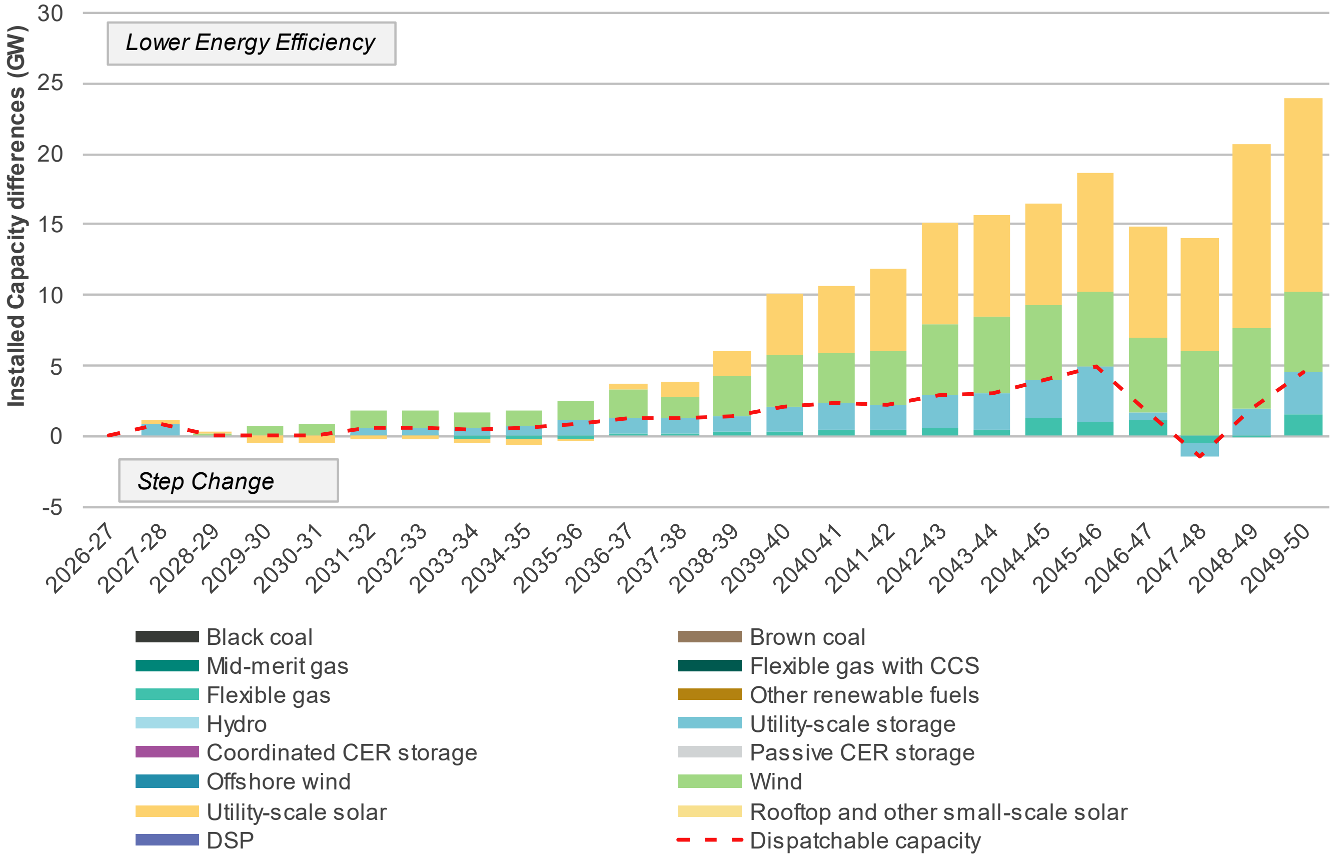
A2.4.4 Lower energy efficiency

The *Lower Energy Efficiency* sensitivity examined the effect of higher consumption with less energy savings from consumers' investments in building and appliance compared with *Step Change*. Much of the energy efficiency investment by consumers (residential, business, and industry) is anticipated through technology improvements, building improvements, and other economic choices supported by policy. In AEMO's scenarios, energy efficiency growth includes policy-led and market-led investments; this sensitivity achieves only current policy targets, removes potential subsidy extensions, and retains market-led growth only, which represents an almost 34% reduction in energy efficiency savings relative to *Step Change* by 2049-50. By 2049-50, approximately 27 TWh greater energy consumption is included in this sensitivity compared with *Step Change*.

Figure 50 shows that with the increase in electricity consumption, there is a need for more utility-scale solar (14 GW) and wind (5.6 GW) firmed up with utility-scale storage (3 GW) and flexible gas (1.5 GW) capacities by 2049-50 compared with *Step Change.*

With reduced investments in energy efficiency, it is possible to expect that consumers may invest instead in CER; this sensitivity has not explored a corresponding change in CER investments, keeping that component steady between the scenario and sensitivity.

Figure 50 Projected capacity developments to 2049-50 under the *Lower Energy Efficiency* sensitivity compared with *Step Change* (GW)

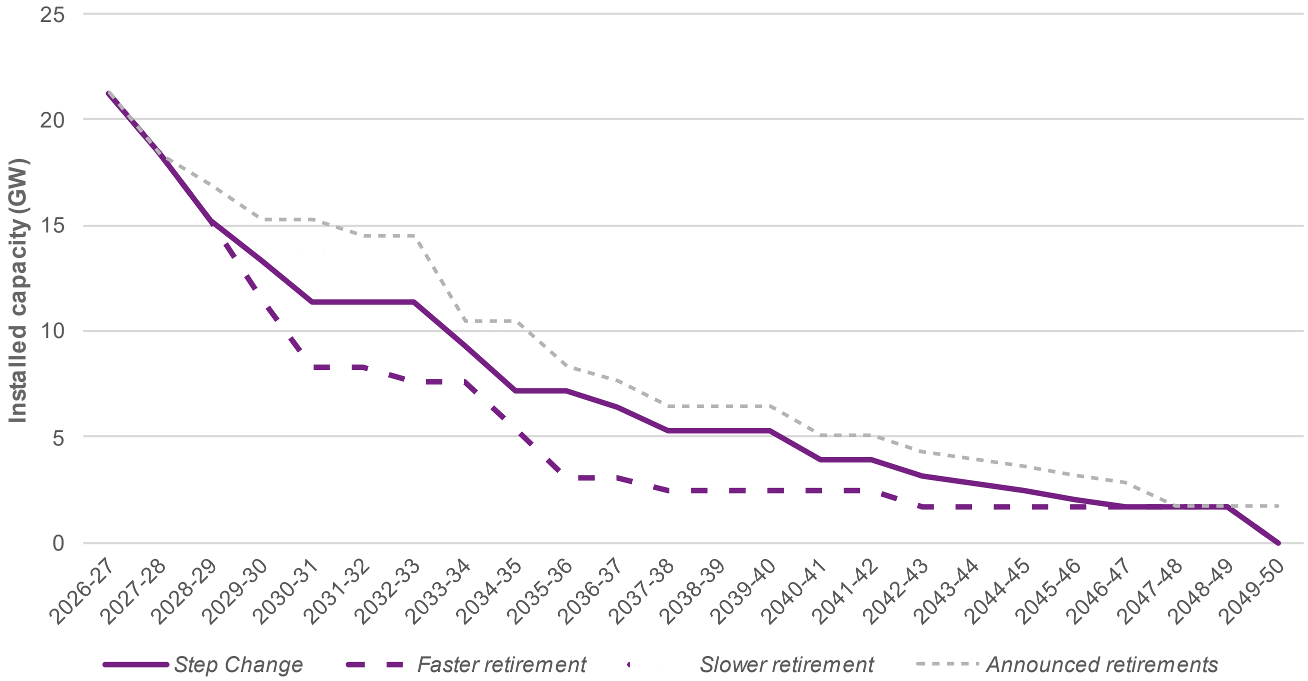


A2.4.5 Coal retirement schedule

A key influence and uncertainty on the power system's development is the ongoing availability of coal generators. To examine this in detail, two sensitivities- *Faster and Slower Coal Retirement Sensitivities* have been developed, relative to *Step Change* and applying to the proposed ODP's network investment path.

In these sensitivities, AEMO assumed higher and lower levels of minimum energy generation requirements for coal, enabling more or less flexibility for coal generators. Lower minimum energy generation requirements effectively represent a future with coal generators configured to operate even more flexibly, potentially through seasonal operation or two-shifting (typically switching off during the peak solar-generation midday period), while higher energy generation requirements represent less capacity for the generator to operate flexibly, and requiring instead to operate at high volumes (or shut down). The impact of these changes on coal-fired generation capacity compared to the core scenario are shown in **Figure 51**.

Figure 51 Black and brown coal-fired generation capacities in *Step Change*, and the *Faster Coal Retirement* and *Slower Coal Retirement* sensitivities (GW)

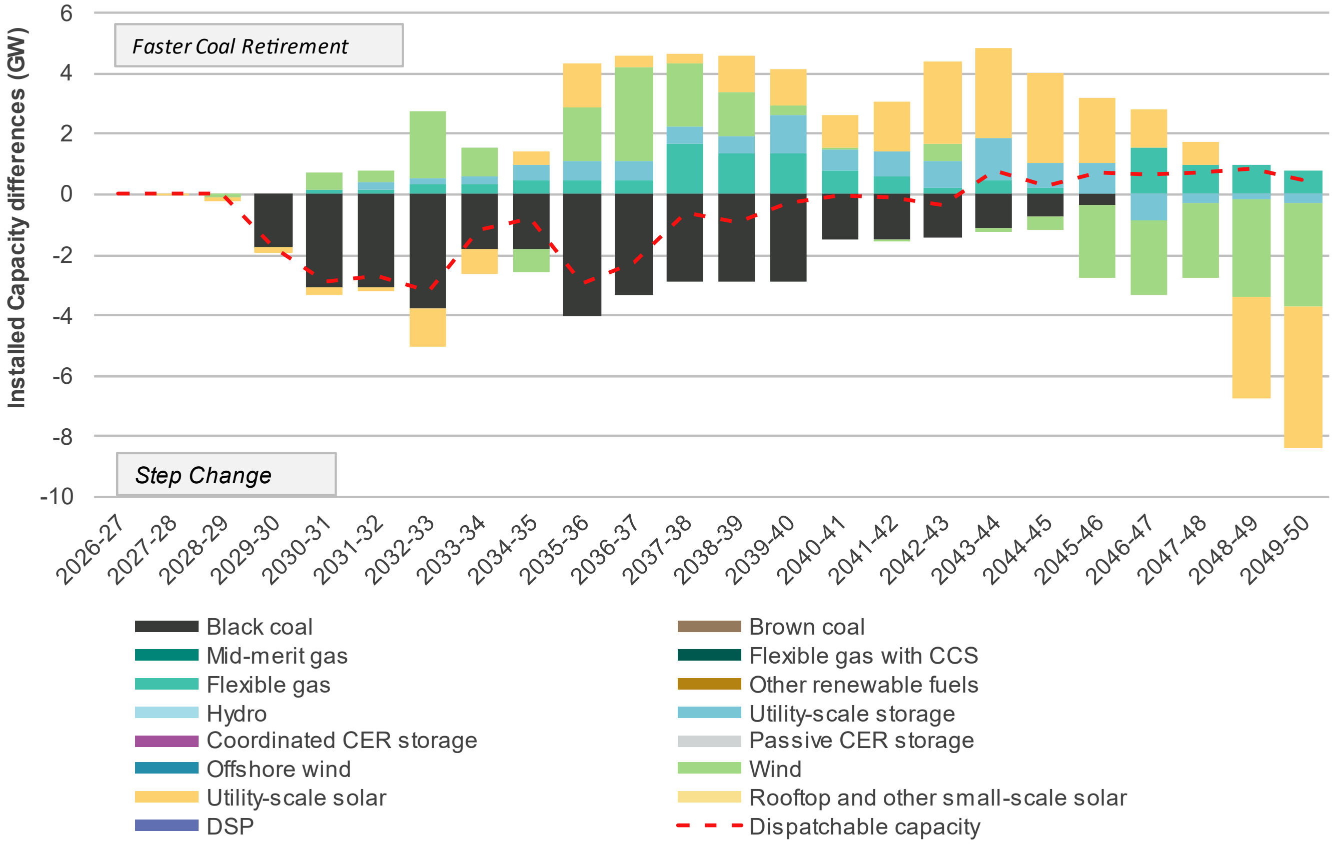


Faster Coal Retirement

In the *Faster Coal Retirement* sensitivity, with higher minimum energy generation requirements assumed, the majority of coal-fired generation capacity is retired more rapidly than *Step Change*, with most retired by 2044-45 and some capacity remaining to 2048-49, as per *Step Change*. **Figure 52** shows the capacity difference for this sensitivity compared to *Step Change*, demonstrating that the faster retirement of coal-fired generation capacities leads to higher uptake of wind and utility-scale solar, complemented by utility-scale storage and flexible gas as firming technologies to complement VRE generation.

In New South Wales, coal generators are projected to retire by 2037-38, three years faster than in *Step Change.* As a result of the faster retirements, emissions are slightly lower than in *Step Change* (3.62 Mt CO_2-e lower total cumulative emissions). However, the savings in emissions up to 2039-40 would allow for higher generation levels from flexible gas and other coal-fired generation post 2039-40, which leads to a slightly softer development of utility-scale VRE late in the outlook period.

Figure 52 Projected capacity developments to 2049-50 under the *Faster Coal Retirement* sensitivity compared with *Step Change* (GW)



Slower Coal Retirement

In the *Slower Coal Retirement* sensitivity, 1.4 GW of black coal-fired generation capacity is delayed from retirement by three years, and some black and brown coal-fired generation capacity remains in the system until 2048-49, with greater assumed coal flexibility that prolongs the operating life of these assets.

Greater coal plant flexibility in this sensitivity allows for higher wind capacity and generation instead of utility-scale solar in the short term, due to less need for daytime generation. Greater coal flexibility and wind penetration helps reduce emissions in the short to medium term (lower by 19 Mt CO_2-e from 2026-27 to 2034-35 compared with *Step Change*), which enables greater generation from coal-fired generation and flexible gas capacities in the longer term. As a result, VRE capacity is lower in the longer term with greater retention of coal capacity compared with *Step Change*, as shown in **Figure 53**.

Figure 53 Projected capacity developments to 2049-50 under the *Slower Coal Retirement* sensitivity compared with *Step Change* (GW)

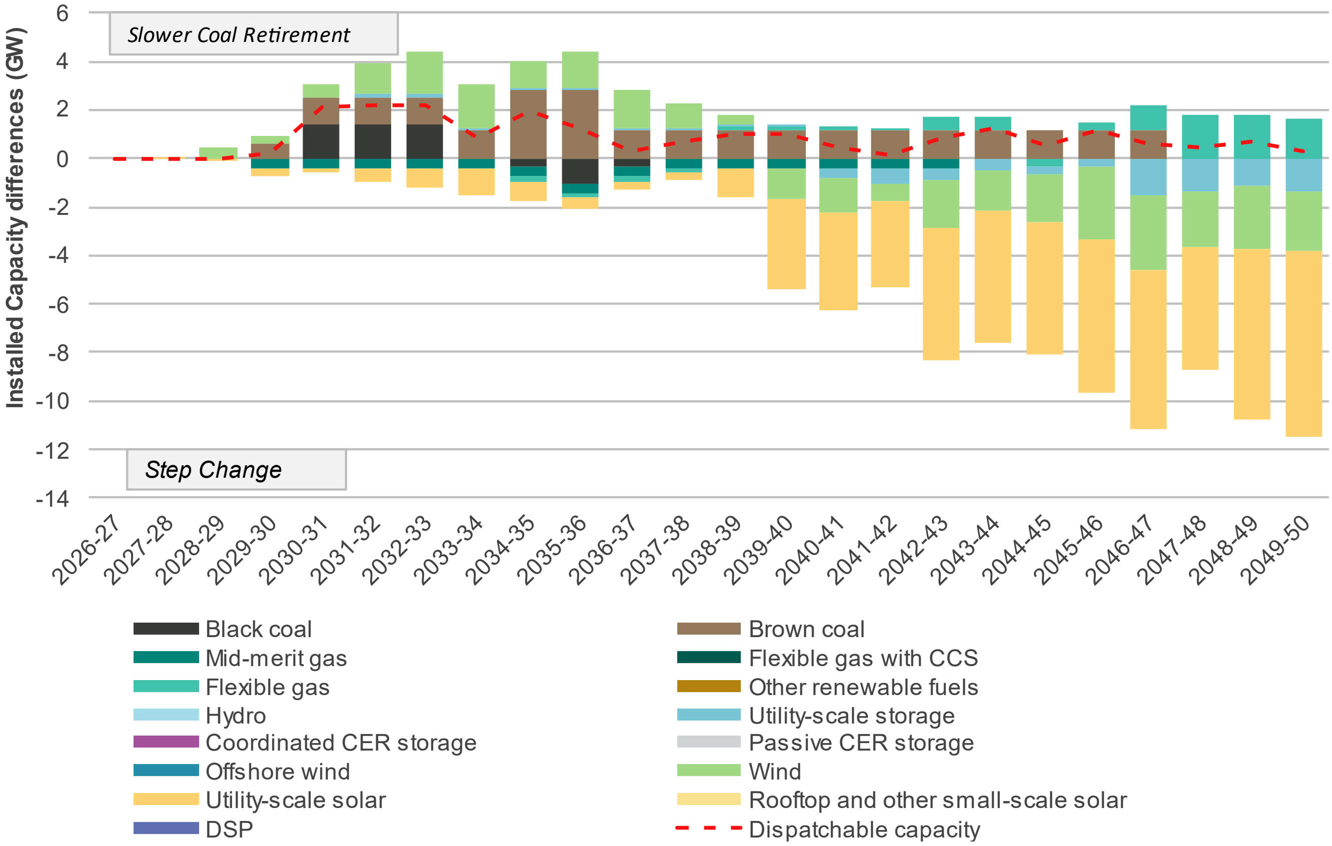


Figure 54 Projected NEM emissions trajectory for coal retirement sensitivities compared to *Step Change* (Mt CO_2-e)

Glossary

This glossary has been prepared as a quick guide to help readers understand some of the terms used in the ISP. Words and phrases defined in the National Electricity Rules (NER) have the meaning given to them in the NER. This glossary is not a substitute for consulting the NER, the AER's Cost Benefit Analysis Guidelines, or AEMO's *ISP Methodology*.

Term	Acronym	Explanation
Actionable ISP project	-	Actionable ISP projects optimise benefits for consumers if progressed before the next ISP. A transmission project (or non-network option) identified as part of the ODP and having a delivery date within an actionable window. For newly actionable ISP projects, the actionable window is two years, meaning it is within the window if the project is needed within two years of its earliest in-service date. The window is longer for projects that have previously been actionable. Project proponents are required to begin newly actionable ISP projects with the release of a final ISP, including commencing a RIT-T.
Actionable project progressing under a jurisdictional framework	-	A transmission project (or non-network option), other than an actionable ISP project, which optimises benefits for consumers if progressed before the next ISP, is identified as part of the ODP, and which will progress under a jurisdictional policy that AEMO considers under NER 5.22.3 (b) and includes in the ISP.
Actionable New South Wales project and actionable Queensland project	-	A transmission project (or non-network option) that optimises benefits for consumers if progressed before the next ISP, is identified as part of the ODP, and is supported by or committed to in New South Wales Government or Queensland Government policy and/or prospective or current legislation.
Anticipated project	-	A generation, storage or transmission project that is in the process of meeting at least three of the five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Anticipated projects are included in all ISP scenarios.
Candidate development path	CDP	A collection of development paths which share a set of potential actionable projects. Within the collection, potential future ISP projects are allowed to vary across scenarios between the development paths. Candidate development paths have been shortlisted for selection as the ODP and are evaluated in detail to determine the ODP, in accordance with the ISP Methodology.
Capacity	-	The maximum rating of a generating or storage unit (or set of generating units), or transmission line, typically expressed in megawatts (MW). For example, a solar farm may have a nominal capacity of 400 MW.
Committed project	-	A generation, storage or transmission project that has fully met all five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Committed projects are included in all ISP scenarios.
Consumer energy resources	CER	Generation or storage assets owned by consumers and installed behind-the-meter. These can include rooftop solar, batteries and electric vehicles. CER may include demand flexibility.
Consumption	-	The electrical energy used over a period of time (for example a day or year). This quantity is typically expressed in megawatt-hours (MWh) or its multiples. Various definitions for consumption apply, depending on where it is measured. For example, underlying consumption means consumption being supplied by both CER and the electricity grid.
Cost-benefit analysis	CBA	A comparison of the quantified costs and benefits of a particular project (or suite of projects) in monetary terms. For the ISP, a cost-benefit analysis is conducted in accordance with the AER's Cost Benefit Analysis Guidelines.
Demand	-	The amount of electrical power consumed at a point in time. This quantity is typically expressed in megawatts (MW) or its multiples. Various definitions for demand, depending on where it is measured. For example, underlying demand means demand supplied by both CER and the electricity grid.

Term	Acronym	Explanation
Demand-side participation	DSP	The capability of consumers to reduce their demand during periods of high wholesale electricity prices or when reliability issues emerge. This can occur through voluntarily reducing demand, or generating electricity.
Development path	DP	A set of projects (actionable projects, future projects and ISP development opportunities) in an ISP that together address power system needs.
Dispatchable capacity	-	The total amount of generation that can be turned on or off, without being dependent on the weather. Dispatchable capacity is required to provide firming during periods of low variable renewable energy output in the NEM.
Distribution network service provider	DNSP	A business which owns, controls or operates a distribution system (including a distribution network).
Economic offloading	-	Refers to a generator being dispatched below its maximum availability, because some or all of its output was bid into price bands greater than the regional reference price. This may also be referred to as economic 'spill' or 'spilled energy' as generators reduce output due to low market prices or lack of available demand.
Firming	-	Grid-connected assets that can provide dispatchable capacity when variable renewable energy generation is limited by weather, for example storage (pumped-hydro and batteries) and flexible gas.
Future distribution project	-	A distribution project that is part of the ODP and forecast to be needed in the future. The project is an ISP development opportunity and does not address an identified need specified in the ISP. The ISP cannot make a distribution project 'actionable' or require commencement of the Regulatory Investment Test for Distribution (RIT-D).
Future ISP project	-	A transmission project (or non-network option) that addresses an identified need in the ISP, that is part of the ODP, and is forecast to be actionable in the future.
Identified need	-	The objective a TNSP seeks to achieve by investing in the network in accordance with the NER or an ISP. In the context of the ISP, the identified need is the reason an investment in the network is required, and may be met by either a network or a non-network option.
ISP development opportunity	-	A development identified in the ISP that does not relate to a transmission project (or non-network option) and may include generation, storage, demand-side participation, or other developments such as distribution network projects.
National Electricity Rules	NER	The Rules are legally binding rules made under the National Electricity Law, which govern the operation of the National Electricity Market and the ways in which AEMO manages power system security. The Rules also provide the regulatory framework for network connections and access, national transmission planning and pricing for network services. The Rules are mainly made by the AEMC having regard to the National Electricity Objective.
Net market benefits	-	The present value of total market benefits associated with a project (or a group of projects), less its total cost, calculated in accordance with the AER's Cost Benefit Analysis Guidelines.
'No transmission' counterfactual development path	-	The 'no transmission' counterfactual development path represents a future without major transmission augmentation. AEMO compares candidate development paths against the Counterfactual DP to calculate the economic benefits of transmission.
Non-network option	-	A means by which an identified need can be fully or partly addressed, that is not a network option. A network option means a solution such as transmission lines or substations which are undertaken by a Network Service Provider using regulated expenditure.
Optimal development path	ODP	The development path identified in the ISP as optimal and robust to future states of the world. The ODP contains actionable projects, future ISP projects and ISP development opportunities, and optimises costs and benefits of various options across a range of future ISP scenarios.
Regulatory Investment Test for Transmission	RIT-T	The RIT-T is a cost benefit analysis test that TNSPs must apply to prescribed regulated investments in their network. The purpose of the RIT-T is to identify the credible network or non-network options to address the identified network need that maximise net market benefits to the NEM. RIT-Ts are required for some but not all transmission investments.

Term	Acronym	Explanation
Reliable (power system)	-	The ability of the power system to supply adequate power to satisfy consumer demand, allowing for credible generation and transmission network contingencies.
Renewable energy	-	For the purposes of the ISP, the following technologies are referred to under the grouping of renewable energy: "solar, wind, biomass, hydro, and hydrogen turbines". Variable renewable energy is a subset of this group, explained below.
Renewable energy zone	REZ	An area identified in the ISP as high-quality resource areas where clusters of utility-scale renewable energy projects can be developed using economies of scale.
Renewable drought / Renewable energy lull	-	A prolonged period of very low levels of variable renewable output, typically associated with dark and still conditions that limit production from both solar and wind generators.
Rooftop and other small-scale solar	-	Solar photovoltaic (PV) generation assets that are not centrally controlled by AEMO dispatch. Examples include residential and business rooftop PV as well as larger commercial or industrial "non-scheduled" PV systems.
Scenario	-	A possible future of how the NEM may develop to meet a set of conditions that influence consumer demand, economic activity, decarbonisation, and other parameters. For the Draft 2026 ISP, AEMO has considered three scenarios: *Slower Growth*, *Step Change* and *Accelerated Transition*.
Secure (power system)	-	The system is secure if it is operating within defined technical limits and is able to be returned to within those limits after a major power system element is disconnected (such as a generator or a major transmission network element).
Sensitivity analysis	-	Analysis undertaken to determine how modelling outcomes change if an input assumption (or a collection of related input assumptions) is changed.
Spilled energy	-	Energy from variable renewable energy resources that could be generated but is unable to be delivered. Transmission curtailment results in spilled energy when generation is constrained due to operational limits, and economic spill occurs when generation reduces output due to market price. This can also be referred to as 'economic offloading'.
Transmission network service provider	TNSP	A business that owns, controls or operates a transmission network.
Utility-scale or utility		For the purposes of the ISP, 'utility-scale' and 'utility' refers to technologies connected to the high-voltage power system rather than behind the meter at a business or residence.
Value of greenhouse gas emissions reduction	VER	The VER estimates the value (dollar per tonne) of avoided greenhouse gas emissions. The VER is calculated consistent with the method agreed to by Australia's Energy Ministers in February 2024.
Virtual power plant	VPP	An aggregation of resources coordinated to deliver services for power system operations and electricity markets. For the ISP, VPPs enable coordinated control of consumer-scale batteries.
Variable renewable energy	VRE	Renewable resources whose generation output can vary greatly in short time periods due to changing weather conditions, such as solar and wind.