Gross market benefit assessment of Queensland system strength portfolios

Powerlink Queensland

1 November 2024

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Release notice

Ernst & Young ("EY") was engaged on the instructions of Queensland Electricity Transmission Corporation Limited trading as Powerlink Queensland ("Powerlink" or the "Client") undertake market modelling of system costs and benefits to forecast the gross market benefits of the selected portfolios to support Powerlink System Strength RIT-T (the "Project"), in accordance with the contract dated 20 March 2024 ("the Engagement Agreement").

The results of EY's work are set out in this report ("Report"), including the assumptions and qualifications made in preparing the Report. The Report should be read in its entirety including this release notice, the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report.

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Readers are advised that the outcomes provided are based on many detailed assumptions underpinning the scenarios, and the key assumptions are described in the Report. These assumptions were selected by Powerlink. The modelled scenarios represent many possible future options for the development and operation of the National Electricity Market, and it must be acknowledged that many other alternative futures exist. Alternative futures beyond those presented have not been evaluated as part of this Report.

EY's liability is limited by a scheme approved under Professional Standards Legislation.

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1. Executive summary

Powerlink engaged EY to undertake market modelling of system costs to the National Electricity Market (NEM) to support the Powerlink System Strength Regulatory Investment Test for Transmission (RIT-T). Powerlink is seeking to compare and rank several portfolios of solutions designed to meet both the forecast minimum and efficient system strength requirements.

This Report describes the key modelling outcomes and insights as well as the assumptions and input data sources and the modelling methods used. It forms a supplementary report to the broader Project Assessment Draft Report published by Powerlink[1] which needs to be read in conjunction with this Report.

EY computed the least-cost generation dispatch and capacity development plan for the NEM for a single scenario and several sensitivities. Inputs were largely aligned with the Step Change scenario from the Australian Energy Market Operator's (AEMO's) 2024 Integrated System Plan (ISP)[2], as selected by Powerlink. In particular:

- Policies, costs and generator technical parameters from AEMO's 2023 Inputs Assumptions and Scenarios (IAS) workbook[3] (which details input assumptions to the Draft 2024 ISP)
- Demand projections consistent with the 2024 ISP
- Assumed timing of major transmission augmentations based on the 2024 ISP Step Change scenario optimal outcomes, or proponents' advised earliest in-service date if later, with some timings for Queensland network augmentations advised by Powerlink
- Coal-fired generator retirement dates based on the outcomes of the 2024 ISP Step Change scenario under the optimal development path (ODP).

Key policy settings which drive the forecast speed of decarbonisation of the NEM are the Federal Government's renewable energy target of 82% by 2030 and the assumed carbon budgets[3].

The market modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator (AER).[4] Simulations computed a generation development plan without any capacity specifically for system strength remediation (the Base Case), and with five different combinations of open-cycle gas turbine (OCGT), pumped hydro energy storages (PHES), grid-forming battery energy storage systems (BESS), and synchronous condensers for the system strength support across the Queensland network as follows:

- Portfolio 1 consists of two OCGTs, seven synchronous condensers and nine 2-hr grid-forming BESS
- Portfolio 1a consists of a 4-hr grid-forming BESS, two OCGTs, six synchronous condensers and nine 2-hr grid-forming BESS
- Portfolio 2 consists of nine synchronous condensers and nine 2-hr grid-forming BESS
- Portfolio 3 consists of four OCGTs, five synchronous condensers and nine 2-hr grid-forming BESS

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[1] Powerlink, November 2024, *Addressing System Strength Requirements in Queensland from December 2025*, Project Assessment Draft Report. Available at: https://www.powerlink.com.au/addressing-system-strength-requirements-queensland-december-2025.
[2] AEMO, June 2024, *2024 ISP*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp. Accessed 30 September 2024.
[3] AEMO, December 2023, *Draft 2024 ISP Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 30 September 2024.
[4] AER, October 2023, *Regulatory investment test for transmission*. Available at: https://www.aer.gov.au/system/files/2023-10/AER%20-%20RIT-T%20guidelines%20-%20final%20amendments%20%28marked%20up%29%20%20-%206%20October%202023_0.pdf. Accessed 30 September 2024.

- Portfolio 4 consists of three 24-hr PHES units, two OCGT, four synchronous condensers and nine 2-hr grid-forming BESS.

EY used linear programming techniques to compute a least-cost, whole-of-NEM, hourly time-sequential dispatch and development plan over a 25-year period (the Modelling Period), from 2025-26 to 2049-50. From the hourly time-sequential modelling we computed the following costs, as defined in the RIT-T guidelines:[5]

- Capital costs of new generation and storage capacity installed (capex)
- Total fixed operation and maintenance (FOM) costs of all generation and storage capacity
- Total variable operation and maintenance (VOM) costs of all generation and storage capacity
- Total fuel costs of all generation capacity
- Total cost of voluntary (demand-side participation, DSP) and unserved energy (USE)
- Transmission expansion costs associated with renewable energy zone (REZ) development
- Cost of emissions, calculated as a post-process to the optimisation based on the annual emissions as modelled and cost of emissions based on the AER's assumed costs in their May 2024 *Valuing emission*s reduction guidance note.[6]

The forecast gross market benefits capture the impact of transmission losses to the extent that losses across interconnectors affect the generation that needs to be dispatched in each dispatch interval. The forecast gross market benefits also capture the impact of differences in cyclic efficiency losses in storages, including PHES and BESS.

For each simulation, we computed the sum of these cost components and compared the difference between the portfolio cases and the Base Case. The difference in the calculated present value of costs is the forecast gross market benefits[7] due to the portfolio. The forecast gross market benefits presented are discounted to 1 July 2023 using a 7% real, pre-tax discount rate, consistent with the value applied by AEMO to the Step Change scenario in the 2024 ISP.[8]

Forecast gross market benefits over the Modelling Period across all portfolios in the Step Change scenario and several sensitivities are summarised in Table 1. These forecast benefits are those assessed through the capacity expansion and dispatch modelling and emission benefits calculated from hourly dispatch outcomes. They do not include Powerlink's estimation of avoided USE based on an assessment of system strength in the hourly dispatch outcomes from the simulations, which is not covered in this Report. The forecast gross market benefits also do not include payments from Powerlink to proponents of non-network solutions which are an operating expense to Powerlink, but a benefit to non-network proponents.

[5] AER, October 2023, *Regulatory investment test for transmission*. Available at: https://www.aer.gov.au/system/files/2023-10/AER%20-%20RIT-T%20guidelines%20-%20final%20amendments%20%28marked%20up%29%20%20-%206%20October%202023_0.pdf. Accessed 30 September 2024.
[6] AER, 22 May 2024, *Valuing emissions reduction: AER guidance and explanator statement*, Available at: https://www.aer.gov.au/industry/registers/resources/guidelines/valuing-emissions-reduction-final-guidance-may-2024. Accessed 30 September 2024.
[7] In this Report we use the term *gross market benefit* to mean "market benefit" as defined in the AER's *RIT-T guidelines*, and "net economic benefit" in the same manner defined in the guidelines.
[8] AEMO, December 2023, *Draft 2024 ISP Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 30 September 2024.

Table 1: Overview of scenarios and sensitivities with associated forecast gross market benefits for each portfolio as assessed through market modelling and post-calculation of emissions benefits; present value discounted to 1 July 2023 in millions of real June 2023 dollar terms

Portfolio	Step Change scenario	Alternative Queensland coal retirement trajectory	Borumba delay	Gas fuel cost high	Gas fuel cost low	BESS capex high	BESS capex low
1	917	903					
1a	1,508	1,485	1,579	1,510	1,512	1,550	1,316
2	636	620					
3	1,089	1,084					
4	3,111	3,064					

The forecast gross market benefits of each portfolio must be compared to the cost of the portfolio to determine the forecast net economic benefits, which was not within the scope of this Report. That evaluation is performed by Powerlink outside of this Report using the forecast gross market benefits from this Report and other inputs[9].

All portfolios are forecast to have positive gross benefits compared to the Base Case as the additional storage, gas and/or PHES units that form the portfolios reduce the need to build more capacity to meet the demand.

Figure 1 displays the forecast gross market benefits for the Step Change scenario and all sensitivities, broken down by benefit category. In all portfolios, the forecast gross benefits are primarily driven by capex saving across the NEM, followed by FOM cost saving. Overall, the amount of BESS capacity in a portfolio causes bigger variations in forecast gross market benefits than the amount of OCGT capacity.

Figure 1: Composition of forecast gross market benefits for each portfolio for the Step Change scenario; present value discounted to 1 July 2023 in millions of real June 2023 dollar terms

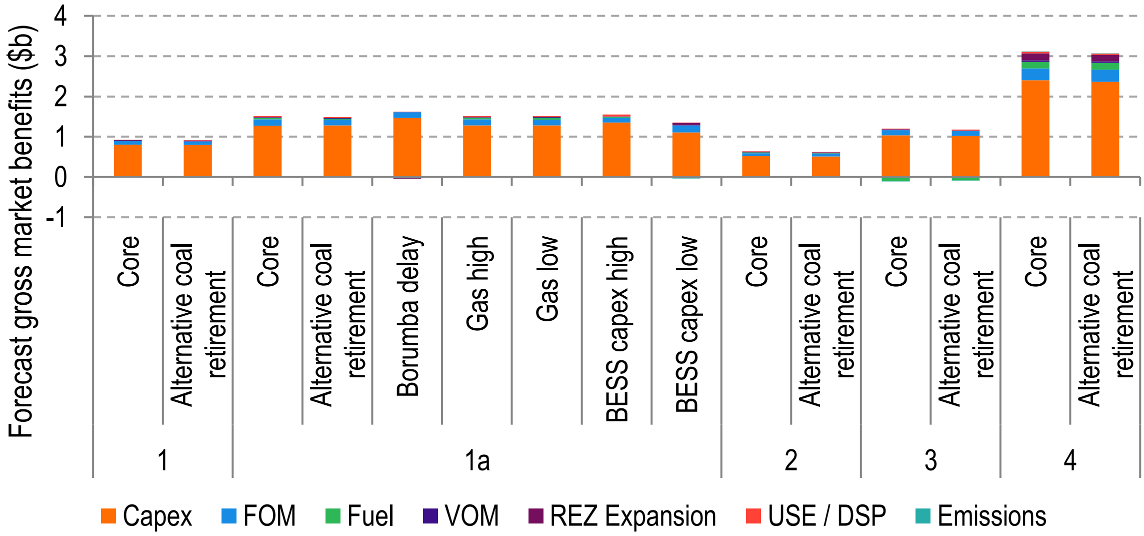

Table 2 compares the forecast gross market benefits of portfolio 1a across the core Step Change scenario and modelled sensitivities. This table also includes the change in system cost with

[9] Powerlink, November 2024, *Addressing System Strength Requirements in Queensland from December 2025*. Available at: https://www.powerlink.com.au/addressing-system-strength-requirements-queensland-december-2025.

portfolio 1a to give a sense of how each sensitivity impacts total system cost, as well as forecast gross market benefits.

Table 2: Overview of changes in forecast system cost of portfolio 1a and forecast gross market benefits relative to the Base Case in the selected sensitivities; present value discounted to 1 July 2023 in millions of real June 2023 dollar terms

Sensitivity	Description	Change in forecast system cost of portfolio 1a relative to core scenario ($m)	Forecast gross market benefits ($m)	Change in forecast gross market benefits ($m)
Core Step Change scenario	n/a	n/a	1,508	n/a
Alternative Queensland coal retirement trajectory	Change in Queensland coal-fired generator retirements	-835	1,485	-23
Borumba PHES delay	Two-year delay in assumed entry of Borumba PHES from 1/9/2031 to 1/9/2033	+413	1,579	+71
Gas fuel cost higher	Gas fuel prices from AEMO 2023 IAS workbook[10] Progressive Change scenario	+1,187	1,510	+2
Gas fuel cost lower	Gas fuel prices from AEMO 2023 IAS workbook[10] Green Energy Exports scenario	-1,680	1,512	+3
BESS capex higher	BESS capex from AEMO 2023 IAS workbook[10] Progressive Change scenario	+643	1,550	+42
BESS capex lower	BESS capex from AEMO 2023 IAS workbook[10] Green Energy Exports scenario	-1,572	1,316	-192

All sensitivities change the system cost of portfolio 1a and the Base Case relative to the core Step Change scenario. Assuming lower gas fuel cost causes the largest decrease in the system cost while assuming higher gas fuel cost has the largest increase in the system cost.

Gross market benefits are the *difference* in forecast system costs between simulations costs with portfolio 1a relative to the Base Case and the sensitivities are forecast to have varying impacts on forecast gross benefits. Overall, delaying Borumba is estimated to cause the largest increase in forecast gross market benefits amongst all sensitivities while the gross market benefit is forecast to stay relatively constant for the increase/decrease in assumed gas fuel costs. Assumed lower BESS capex is estimated to cause the largest decrease in forecast gross market benefits.

[10] AEMO, December 2023, *Draft 2024 ISP Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 30 September 2024.

2. Introduction

Powerlink engaged EY to undertake market modelling of system costs to the NEM to support the Powerlink System Strength RIT-T. Powerlink is seeking to compare and rank several portfolios of solutions designed to meet both the forecast minimum and efficient system strength requirements.

This Report describes the key modelling outcomes and insights as well as the assumptions and input data sources and the modelling methods used. It forms a supplementary report to the broader Project Assessment Draft Report published by Powerlink[11] which needs to be read in conjunction with this Report.

EY computed the least-cost generation dispatch and capacity development plan for the NEM for a single scenario and several sensitivities. The core scenario combined input assumptions on policies, costs and generator technical parameters, as well as demand projections from AEMO in the 2023 IAS workbook Step Change scenario.[12] The coal-fired generator retirement dates are based on the 2024 ISP outcomes of the Step Change scenario under the ODP.[13] Major transmission network augmentations were also based on the 2024 ISP Step Change scenario optimal outcomes with some changes in Queensland advised by Powerlink. The modelling methodology follows the RIT-T guidelines published by the AER.[14]

The descriptions of outcomes in this Report are focussed on identifying and explaining the key sources of forecast gross market benefits. The categories of gross market benefits modelled are changes in:

- Capex of new generation and storage capacity installed
- Total FOM costs of all generation and storage capacity
- Total VOM costs of all generation and storage capacity
- Total fuel costs of all generation capacity
- Total cost of voluntary and involuntary load curtailment
- Transmission expansion costs associated with REZ development
- Transmission and storage losses which form part of the demand to be supplied, which are calculated dynamically within the model
- Total cost of emissions.

Each category of gross market benefits is computed across the 25-year Modelling Period, from 2025-26 to 2049-50. Benefits presented present values discounted to 1 July 2023 using a 7% real, pre-tax discount rate, consistent with the value applied by AEMO to the Step Change scenario in the 2024 ISP.[12]

This modelling considers a Base Case and five portfolios as defined by Powerlink. The Base Case does not include any capacity specifically for system strength remediation. Each portfolio includes different combinations of OCGT, PHES, grid-forming BESS, and synchronous condensers for the system strength support across the Queensland network as follows (refer to Table 4 for details):

[11] Powerlink, November 2024, *Addressing System Strength Requirements in Queensland from December 2025*. Available at: https://www.powerlink.com.au/addressing-system-strength-requirements-queensland-december-2025.
[12] AEMO, December 2023, *Draft 2024 ISP Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 30 September 2024.
[13] AEMO, June 2024, *2024 ISP*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp. Accessed 30 September 2024.
[14] AER, October 2023, *Regulatory investment test for transmission*. Available at: https://www.aer.gov.au/system/files/2023-10/AER%20-%20RIT-T%20guidelines%20-%20final%20amendments%20%28marked%20up%29%20%20-%206%20October%202023_0.pdf. Accessed 30 September 2024.

- Portfolio 1 consists of two OCGTs, seven synchronous condensers and nine 2-hr grid-forming BESS
- Portfolio 1a consists of a 4-hr grid-forming BESS, two OCGTs, six synchronous condensers and nine 2-hr grid-forming BESS
- Portfolio 2 consists of nine synchronous condensers and nine 2-hr grid-forming BESS
- Portfolio 3 consists of four OCGTs, five synchronous condensers and nine 2-hr grid-forming BESS
- Portfolio 4 consists of three 24-hr PHES units, two OCGT, four synchronous condensers and nine 2-hr grid-forming BESS.

Forecast gross market benefits presented in this Report are changes in system cost relative to the relevant Base Case before consideration of portfolio costs. Total forecast gross market benefits were calculated in three steps:

- Capex, FOM, VOM, fuel, voluntary and involuntary load curtailment and REZ expansion transmission costs were calculated within the market capacity and dispatch model.
- Hourly dispatch outcomes from the simulations were used to compute yearly emission cost.
- Powerlink used hourly dispatch outcomes from the simulations to estimate an additional benefit of avoided USE based on an assessment of system strength. This calculation by Powerlink is not covered in this Report and gross market benefits presented do not include this additional component of forecast market benefits.

The operation of synchronous condensers was not included in the market modelling but instead was also considered in post-modelling analysis by Powerlink in their assessment of system strength based on hourly dispatch outcomes.

The forecast gross market benefits of each portfolio must be compared to its related cost to determine the forecast net economic benefit for each portfolio. This calculation is performed by Powerlink outside of this Report using the forecast gross market benefits from this Report and other inputs.[15]

The Report is structured as follows:

- Section 3 describes the input assumptions and scenarios modelled in this study.
- Section 4 presents the NEM capacity and generation outlook for the Base Case.
- Section 5 presents the forecast gross market benefits associated with each portfolio. It is focussed on identifying and explaining the key sources of forecast gross market benefits for all portfolios in the modelled scenario and sensitivities.
- Appendix A provides an overview of the methodology applied in the modelling and computation of forecast gross market benefits.
- Appendix B outlines model design and input data related to representation of the transmission network and transmission losses.
- Appendix C outlines model design and input data related to demand.
- Appendix D provides an overview of model inputs and methodologies related to supply of energy and capacity.

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[15] Powerlink, November 2024, *Addressing System Strength Requirements in Queensland from December 2025*. Available at: https://www.powerlink.com.au/addressing-system-strength-requirements-queensland-december-2025.

3. Scenario assumptions

3.1 Overview of input assumptions

The forecast gross market benefits of Powerlink's system strength portfolios were computed under a scenario largely aligned with the Step Change scenario from the 2024 ISP, as selected by Powerlink.

A key input assumption to this assessment is the schedule for the retirement of coal-fired generators in Queensland. This was based on the outcomes of the 2024 ISP Step Change scenario under the ODP for transmission development.[16]

Other input assumptions including those on policies, costs, generator technical parameters and demand projections are from the AEMO 2023 IAS workbook.[17]

Powerlink also selected dates for intra-regional transmission augmentations within Queensland. Assumed timing of other major transmission upgrades are based on the 2024 ISP Step Change optimal timing[18], with some changes in Queensland advised by Powerlink. Where transmission investment timing in the ODP was earlier than the in-service date advised by the project proponent, Powerlink elected to adopt the later date.

A more comprehensive list of assumptions and their sources is summarised in Table 3. All input assumptions were selected by Powerlink in accordance with the AER's guidelines.[19]

Table 3: Overview of key input parameters selected by Powerlink in the Step Change scenario

Input parameter	Detail and data source
Underlying consumption	2024 ISP[20] - Step Change.
Committed and anticipated generation	Committed and anticipated generators from Draft 2024 ISP which is based on the July 2023 AEMO Generation Information.[17] Queensland projects updated based on the May 2024 Generation Information[21].
New entrant capital cost for wind, solar PV SAT[22], OCGT, CCGT[23], PHES, BESS and hydrogen turbine	2023 IAS workbook v5.3[17]- Step Change.

[16] AEMO, June 2024, *2024 ISP*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp. Accessed 30 September 2024.
[17] AEMO, December 2023, *Draft 2024 ISP Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 30 September 2024.
[18] AEMO, June 2024, *2024 ISP*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp. Accessed 30 September 2024.
[19] AER, October 2023, *Regulatory investment test for transmission*. Available at: https://www.aer.gov.au/system/files/2023-10/AER%20-%20RIT-T%20guidelines%20-%20final%20amendments%20%28marked%20up%29%20-%206%20October%202023_0.pdf. Accessed 30 September 2024.
[20] AEMO, *National Electricity and Gas Forecasting*. Available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/electricity-forecasting-data-portal. Accessed 30 September 2024.
[21] AEMO, May 2024 Generation Information. Available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed 30 September 2024.
[22] Single-axis tracking
[23] Combined-cycle gas turbine

Input parameter	Detail and data source
Retirement of coal-fired power stations	2024 ISP Results Workbook[24]- Step Change ODP. Retirement dates based on closure year outcomes. Eraring retired in accordance with May 2024 Generation Information[21].
Gas fuel price	2023 IAS workbook v5.3[17] - Step Change.
Coal fuel price	2023 IAS workbook v5.3[17] - Step Change.
NEM carbon budget to achieve Federal Government's 2030 emissions reduction target	2023 IAS workbook v5.3[17] - Step Change: 630 Mt CO_2-e 2024-25 to 2029-30.
NEM carbon budget to achieve 2050 temperature-linked emissions levels	2023 IAS workbook v5.3[17] - Step Change: 681 Mt CO_2-e 2024-25 to 2051-52.
Federal Government Renewable Energy Target	2023 IAS workbook v5.3[17]: 82% share of renewable generation by 2029-30.
Victoria Renewable Energy Target (VRET), storage target and offshore wind target	VRET - 40% by 2025, 65% by 2030 and 95% by 2035. Victoria Energy Storage Target - 2.6 GW by 2030 and 6.3 GW by 2035. Victoria Offshore Wind Target - 2 GW by 2032, 4 GW by 2035 and 9 GW by 2040. Consistent with 2023 IAS workbook v5.3[17].
Queensland Renewable Energy Target (QRET)	50% by 2029-30, 70% by 2031-32 and 80% by 2034-35 renewable generation as a percentage of total Queensland demand. Consistent with 2023 IAS workbook v5.3[17].
New South Wales Electricity Infrastructure Roadmap	5,547 TWh of eligible renewable generation in 2024-25 increasing to 33.6 TWh renewable generation in 2029-30. 2 GW of long duration storage (8 hrs or more) by 2029-30. Consistent with 2023 IAS workbook v5.3[17].
Tasmanian Renewable Energy Target (TRET)	15,750 GWh by 2030 and 21,000 GWh by 2040. Consistent with 2023 IAS workbook v5.3[17].
EnergyConnect	2024 ISP Committed and anticipated project[24]. Stage 1: commissioned by December 2024. Stage 2: commissioned by July 2027.
Western Renewables Link	2024 ISP Committed and anticipated project[25]: commissioned by July 2027.
HumeLink	2024 ISP Actionable project. 2024 ISP - Step Change optimal timing[25]: commissioned by July 2029.
Victoria-New South Wales Interconnector (VNI) West	2024 ISP Actionable project. Earliest in-service date advised by proponent: commissioned by December 2029 (later than 2024 ISP Step Change optimal timing)[25].
Queensland-New South Wales interconnector (QNI) Connect	2024 ISP Actionable project. 2024 ISP - Step Change optimal timing[25]: commissioned by July 2034.

[24] AEMO, June 2024, *2024 ISP*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp. Accessed 30 September 2024.
[25] AEMO, June 2024. *Appendix 5: Network Investments (Appendix to 2024 ISP for the National Electricity market)*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a5-network-investments.pdf?la=en . Accessed 30 September 2024.

Input parameter	Detail and data source
Gladstone Grid Reinforcement	2024 ISP Actionable project. Powerlink assumption: commissioned by March 2029 (earlier than 2024 ISP Step Change optimal timing of July 2030)[25].
CopperString 2032 (Ross-Hughenden-Mt Isa link)	2024 ISP Committed and anticipated project[25]: commissioned by June 2029.
Queensland SuperGrid South (QEJP Stage 2) (South Queensland -Central Queensland (SQ-CQ) Upgrade)	2024 ISP Actionable project. Powerlink assumption: commissioned by September 2031 (later than 2024 ISP Step Change optimal timing of July 2031)[25].
CQ-North Upgrade	2024 ISP Future ISP project - Powerlink assumption to include. 2024 ISP - Step Change optimal timing[25]: commissioned by July 2033.
Darling Downs REZ Expansion	2024 ISP Future ISP project - Powerlink assumption to include. 2024 ISP - Step Change optimal timing[25]: commissioned by July 2034.
North-Ross Upgrade	Powerlink assumption: commissioned by July 2035.
New-England REZ Transmission	2024 ISP Actionable projects. Earliest in-service date advised by proponent: ► New England REZ Transmission Link 1 commissioned by June 2031 (later than 2024 ISP Step Change optimal timing)[25]. ► New England REZ Upgrade commissioned by June 2031 (later than 2024 ISP Step Change optimal timing)[25]. 2024 ISP - Step Change optimal timing: ► New England Transmission Link 2 commissioned by July 2034[25].
Central-West Orana REZ Transmission Link	2024 ISP Committed and anticipated project[25]: commissioned by August 2028.
Project Marinus Stage 1	2024 ISP Actionable project. Earliest in-service date advised by proponent: commissioned by December 2030 (later than 2024 ISP Step Change optimal timing)[25].
Project Marinus Stage 2	2024 ISP Actionable project. 2024 ISP - Step Change optimal timing[25]: commissioned by July 2037.
Snowy 2.0	Commissioned by December 2028, consistent with the May 2024 Generation Information[26].
Discount rate	7% real, pre-tax[16].
Cost of emissions	AER's *Valuing emissions* reduction guidance note[27].

3.2 Sensitivities

Powerlink selected six sensitivities:

- ► Alternative Queensland coal-fired generator retirement trajectory

[26] AEMO, May 2024 Generation Information. Available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed 30 September 2024.
[27] AER, 22 May 2024, *Valuing emissions reduction: AER guidance and explanator statement*, Available at: https://www.aer.gov.au/industry/registers/resources/guidelines/valuing-emissions-reduction-final-guidance-may-2024. Accessed 30 September 2024.

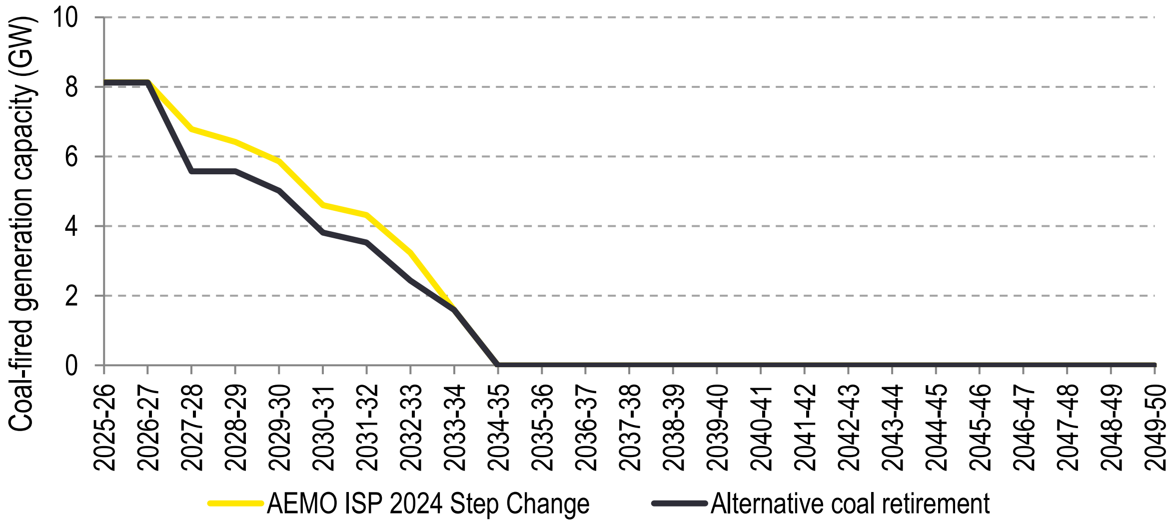
- Delay in commissioning of Borumba PHES
- Gas fuel cost sensitivities (higher and lower)
- BESS capex sensitivities (higher and lower).

Further details on each of these sensitivities is given in remainder of this section.

3.2.1 Alternative Queensland coal-fired generator withdrawal sensitivity

Powerlink inferred coal-fired generator retirement dates in Queensland from the AEMO 2023 System Strength report[28] outcomes to simulate as a sensitivity study. The difference in the coal capacity in Queensland between the 2024 ISP outcomes and 2023 System Strength report is shown in Figure 2. It is evident that the System Strength report incorporates a faster withdrawal of coal capacity relative to the ISP Step Change outcomes. Furthermore, the speed of withdrawal in South Queensland (SQ) and Central Queensland (CQ) differs as shown in Figure 3 and Figure 4. The System Strength report assumed a slower withdrawal of coal-fired generators in CQ, and faster in SQ.

Figure 2: Coal-fired generator capacity in Queensland by year sourced from 2024 ISP and alternative Queensland coal retirement trajectory



[28] AEMO, December 2023, *2023 System Strength Report*: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning Accessed 30 September 2024.

Figure 3: Coal-fired generator capacity in CQ by year sourced from 2024 ISP and alternative Queensland coal retirement trajectory

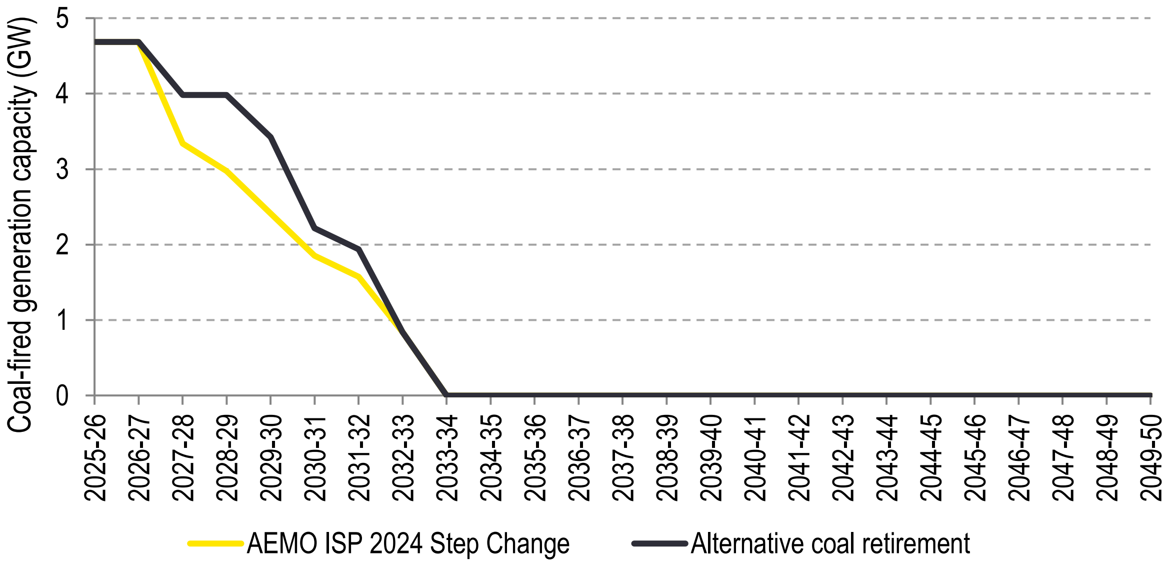
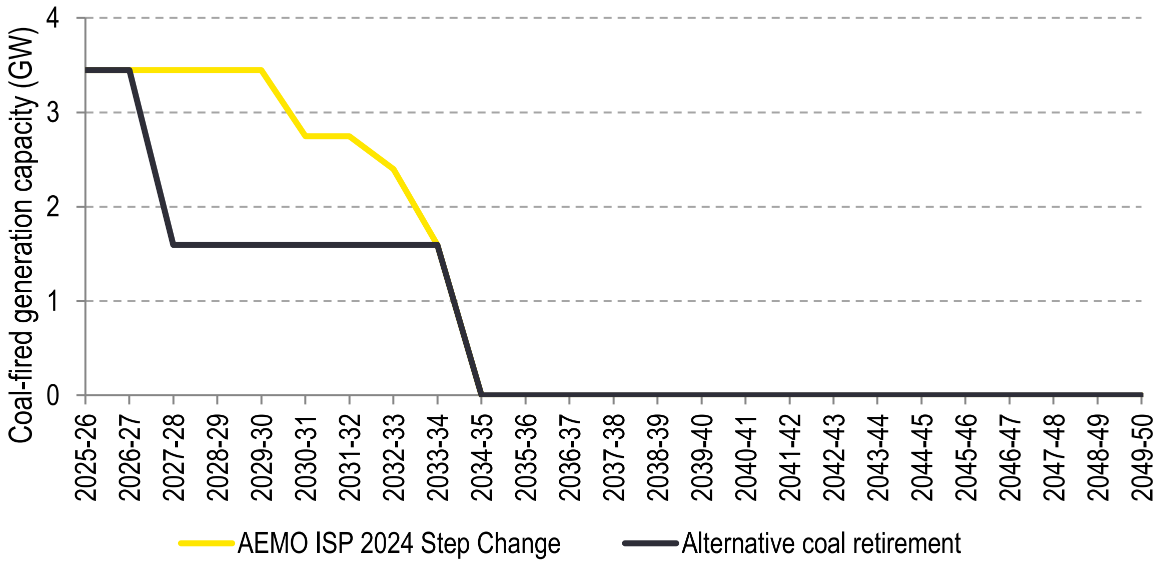


Figure 4: Coal-fired generator capacity in SQ by year sourced from 2024 ISP and alternative Queensland coal retirement trajectory



3.2.2 Borumba delay sensitivity

Powerlink requested to analyse the impact of delaying the assumed commissioning date of Borumba PHES by two years. Accordingly, the commissioning date was changed from 1 September 2031 to 1 September 2033.

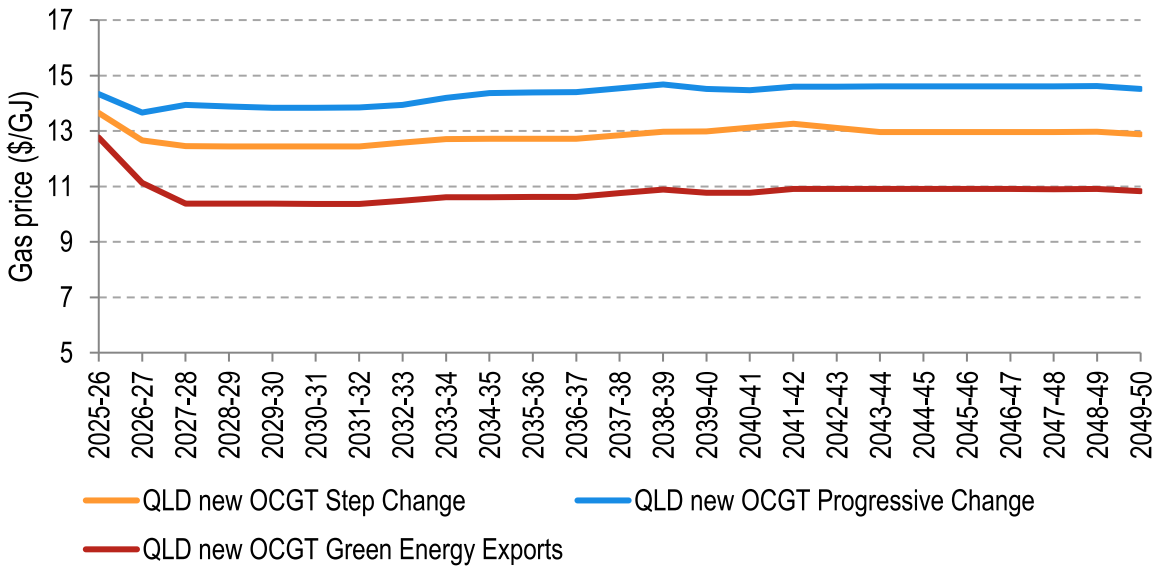
3.2.3 Gas fuel cost sensitivities (higher and lower)

Powerlink requested to study the sensitivity of outcomes to the assumed gas fuel price. They elected to assume the gas price from the AEMO 2023 IAS workbook[29] Progressive Change scenario to assess the effect of a higher gas price, and to assume the gas price from Green Energy Exports scenario to assess of the effect of a lower gas price. The gas price trajectories in the core scenario

[29] AEMO, December 2023, *Draft 2024 ISP Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 30 September 2024.

and high and low gas fuel cost sensitivities for Queensland new entrant peaking gas units are shown in Figure 5.

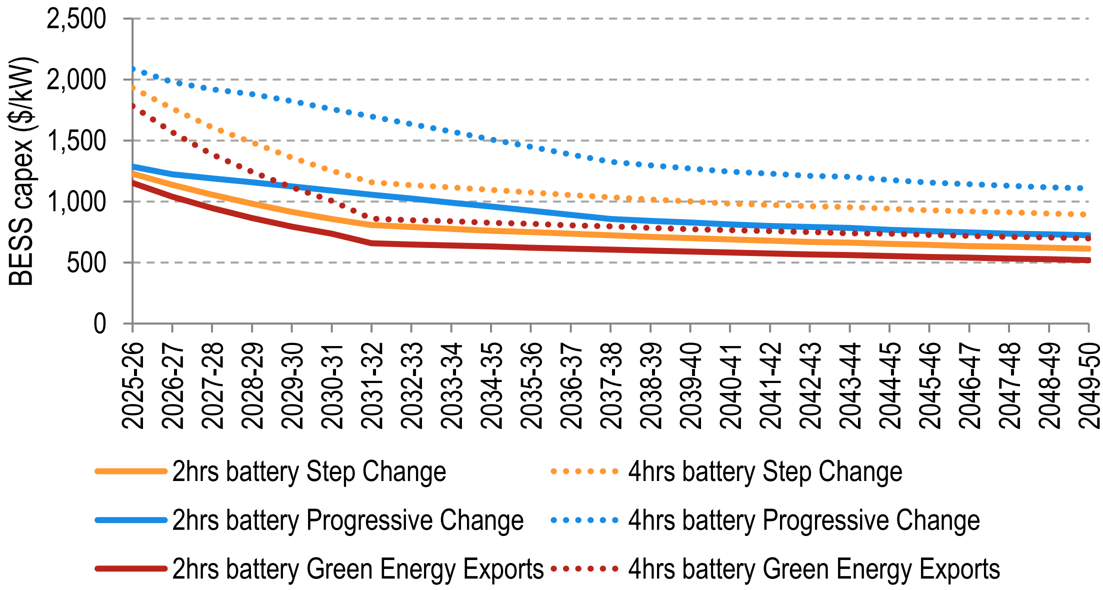
Figure 5: Assumed gas fuel cost trajectories in the core modelling and the high and low gas price sensitivities



3.2.4 BESS capex sensitivities (higher and lower)

Powerlink requested to study the sensitivity of outcomes from changes in BESS capex. They elected to assume capex for BESS units from AEMO 2023 IAS workbook[30] Progressive Change scenario to assess the effect of a higher capex and the trajectory from the Green Energy Exports scenario to assess the effect of lower BESS capex. The BESS capex trajectory in the core scenario and the high and lower BESS capex sensitivities is shown in Figure 6.

Figure 6: Assumed BESS capex trajectories in the core modelling and the high and low BESS capex sensitivities



[30] AEMO, December 2023, *Draft 2024 ISP Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 30 September 2024.

3.3 Differences in assumptions across system strength portfolios

Powerlink sought to assess the impact of five different system strength portfolios. These comprised of different combinations of OCGT, PHES, grid-forming BESS, and synchronous condensers. The portfolios and how they are captured in the market modelling is summarised in Table 4. Only some of these technologies impact the forecast gross market benefits as assessed through the capacity expansion and dispatch modelling; namely, synchronous condensers were assumed not to influence dispatch. The effect of their operation on system strength was evaluated on an hourly basis by Powerlink outside of this Report.[31]

Table 4: Modelled differences between the Base Case and system strength portfolios, supplied by Powerlink

Technology	Assumed commissioning date	Location	Base Case	Portfolios				
				1	1a	2	3	4
BESS (4-hrs)	1/07/2028	CQ			√			
OCGT	1/07/2028	CQ		√	√		√	√
OCGT	1/07/2028	CQ					√	
OCGT	1/07/2029	CQ		√	√		√	√
OCGT	1/07/2029	CQ					√	
PHES (24-hrs)	1/07/2028	CQ						√
PHES (24-hrs)	1/07/2028	CQ						√
PHES (24-hrs)	1/07/2028	CQ						√
BESS (2-hrs)	1/11/2026	NQ	√	√	√	√	√	√
BESS (2-hrs)	1/02/2024	SQ	√	√	√	√	√	√
BESS (2-hrs)	1/12/2025	SQ	√	√	√	√	√	√
BESS (2-hrs)	1/03/2027	CQ	√	√	√	√	√	√
BESS (2-hrs)	1/09/2024	SQ	√	√	√	√	√	√
BESS (2-hrs)	1/07/2027	CQ		√	√	√	√	√
BESS (2-hrs)	1/07/2028	CQ		√	√	√	√	√
BESS (2-hrs)	1/07/2028	CQ		√	√	√	√	√
BESS (2-hrs)	1/07/2028	GG		√	√	√	√	√
Synchronous condenser	1/07/2028	CQ		√	√	√		
Synchronous condenser	1/07/2028	CQ		√	√	√		
Synchronous condenser	1/07/2028	CQ		√		√	√	
Synchronous condenser	1/07/2029	CQ		√	√	√	√	√
Synchronous condenser	1/07/2029	CQ				√		
Synchronous condenser	1/07/2029	CQ				√		
Synchronous condenser	1/07/2032	CQ		√	√	√	√	√

[31] Powerlink, November 2024, *Addressing System Strength Requirements in Queensland from December 2025*. Available at: https://www.powerlink.com.au/addressing-system-strength-requirements-queensland-december-2025.

Technology	Assumed commissioning date	Location	Base Case	Portfolios				
				1	1a	2	3	4
Synchronous condenser	1/07/2033	CQ		√	√	√	√	√
Synchronous condenser	1/07/2029	SQ		√	√	√	√	√

4. Forecast NEM capacity and generation outlook

Before presenting the forecast benefits of the system strength portfolios, it is useful to understand the expected capacity and generation outlooks in the modelled Base Case scenario, and the underlying input assumptions driving these outcomes. The Base Case is the counterfactual case without any solution for system strength support.

The NEM-wide capacity mix forecast in the Base Case is shown in Figure 7 and the corresponding generation mix in Figure 8. In this scenario, the forecast generation capacity of the NEM shifts towards increasing capacity of wind and solar, complemented by grid-scale BESS, PHES, and gas. This outcome is broadly consistent with the 2024 ISP outcomes for this scenario.

Figure 7: NEM capacity mix forecast for the Base Case

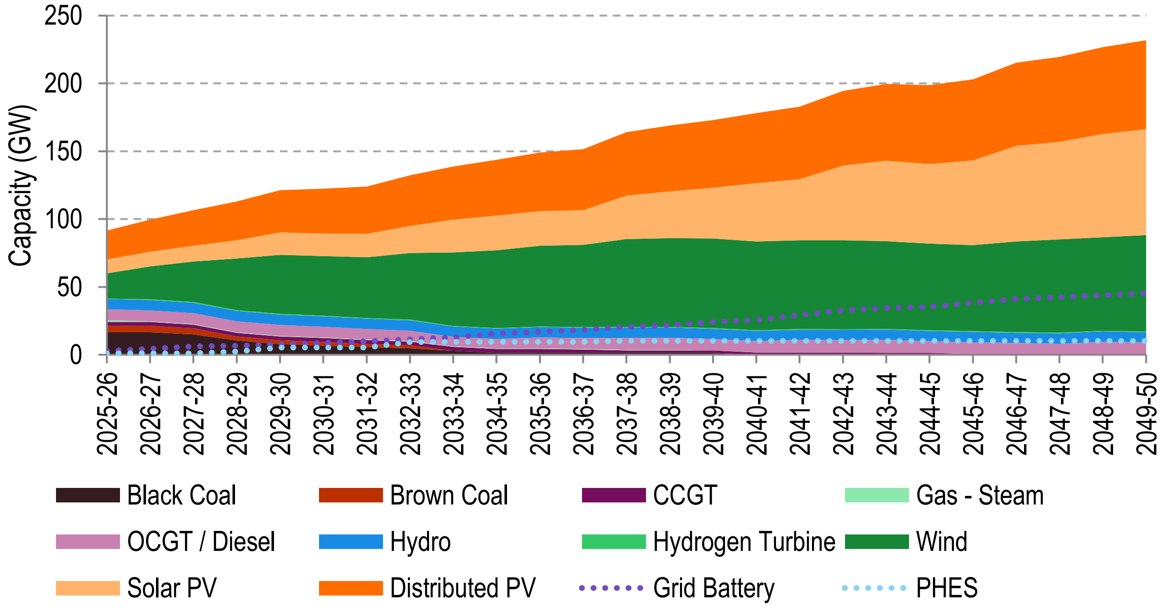
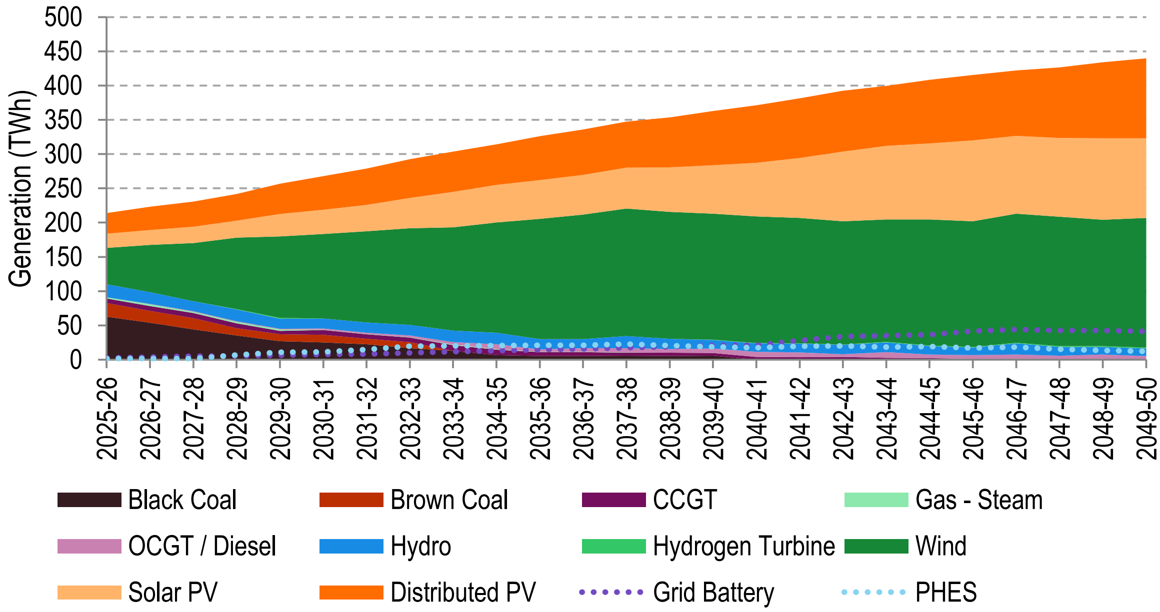


Figure 8: NEM generation mix forecast for the Base Case



The forecast pace of the transition is predominantly determined by a combination of assumed carbon budgets, renewable energy targets (federal, New South Wales Electricity Infrastructure Roadmap, VRET, QRET, TRET and Victoria offshore wind target), demand outlook and end-of-life for existing assets in a system developed and dispatched at least cost. AEMO's 2024 ISP model forecasts the entire coal capacity retires and withdraws from the grid by 2040 for the Step Change scenario and that ISP outcome was adopted by Powerlink as an input assumption to the modelling in this Report.

Up to 2030, forecast wind and solar build are largely driven by the assumed federal renewable energy target. During this period, the federal renewable energy policy drives outcomes ahead of state-based renewable energy targets and entry of renewable capacity to replace coal retirements to achieve the assumed carbon budget. To replace the retiring capacity, wind capacity is predominantly forecast to be installed throughout the mid-to-late 2020s, along with grid-scale BESS and PHES capacity in line with the assumed state-based storage targets. Borumba PHES forms a significant part of the total PHES generation from 1 September 2031; it is assumed to be committed in accordance with the May 2024 Generation Information.[32] Solar PV capacity is also forecast to increase from the late 2030s complementing other technologies. The forecast new gas-fired capacity provides energy at times of low wind and solar availability (while respecting the assumed renewable energy targets and carbon budget) and supports reserve requirements. In Queensland, the capacity build is closely aligned with the trend of the NEM with black coal retirements assumed to start in 2027-28 and all units assumed to be retired by 2034-35. Wind is forecast to be built more than solar PV while there is a big forecast uptake in grid BESS. Overall, the NEM is forecast to have 285 GW total (generation and storage) capacity by 2049-50 while Queensland is forecast to have roughly 95 GW total (generation and storage) capacity by 2049-50, including distributed PV, which is an input assumption.

[32] AEMO, May 2024 Generation Information. Available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information Accessed 30 September 2024.

5. Forecast gross market benefit outcomes

5.1 Summary of forecast gross market benefit outcomes

Table 5 shows the forecast gross market benefits of Powerlink's system strength portfolios and sensitivities over the 25-year Modelling Period from 2025-26 to 2049-50. These benefits are those assessed through the capacity expansion and dispatch modelling and emission benefits calculated from hourly dispatch outcomes. They do not include Powerlink's estimation of avoided USE based on an assessment of system strength in the hourly dispatch outcomes from the simulations, which is not covered in this Report. The forecast gross market benefits also do not include payments from Powerlink to proponents of non-network solutions which are an operating expense to Powerlink, but a benefit to non-network proponents.

Table 5: Overview of scenarios and sensitivities with associated forecast gross market benefits for each portfolio as assessed through market modelling and post-calculation of emissions benefits; present value discounted to 1 July 2023 in millions of real June 2023 dollar terms

Portfolio	Step Change scenario	Alternative Queensland coal retirement trajectory	Borumba delay	Gas fuel cost high	Gas fuel cost low	BESS capex high	BESS capex low
1	917	903					
1a	1,508	1,485	1,579	1,510	1,512	1,550	1,316
2	636	620					
3	1,089	1,084					
4	3,111	3,064					

The forecast gross market benefit of each portfolio is calculated relative to a matched Base Case. The calculations for the net economic benefit for each portfolio is performed by Powerlink outside of this Report using the forecast gross market benefits from this Report and other inputs.[33]

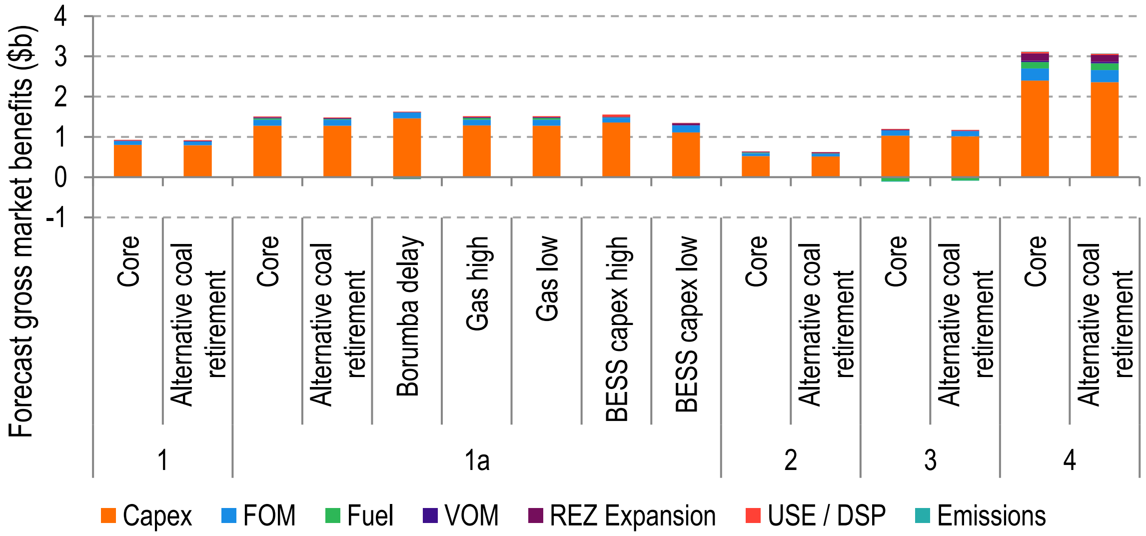
All portfolios are forecast to have positive gross benefits compared to the Base Case as the additional storage, gas and/or PHES units that form the portfolios reduce the need to build more capacity to meet the demand. The cost of the additional capacity is considered in the cost side of the net economic benefit calculation by Powerlink outside of this Report.[33]

Figure 9 displays the forecast gross market benefits for the Step Change scenario and all sensitivities, broken down by benefit category. In all portfolios, the forecast gross benefits are primarily driven by capex saving across the NEM, followed by FOM cost saving.

Overall, the amount of BESS capacity in a portfolio causes bigger variations in forecast gross market benefits than the amount of OCGT capacity.

[33] Powerlink, November 2024, *Addressing System Strength Requirements in Queensland from December 2025*. Available at: https://www.powerlink.com.au/addressing-system-strength-requirements-queensland-december-2025.

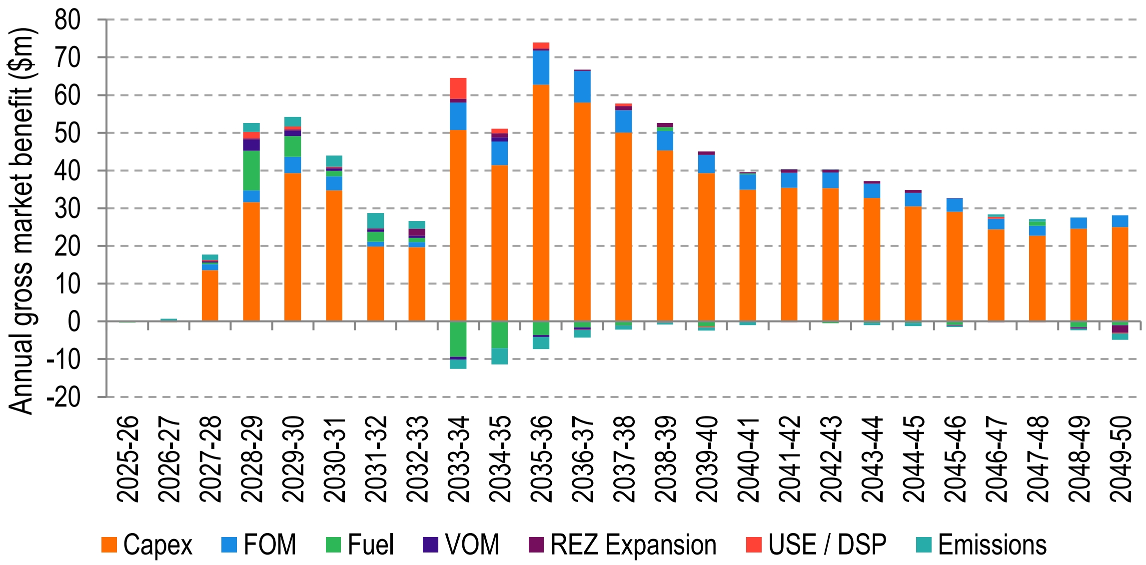
Figure 9: Composition of forecast gross market benefits for each portfolio for the Step Change scenario; present value discounted to 1 July 2023 in millions of real June 2023 dollar terms



5.2 Market modelling outcomes for portfolio 1

The gross market benefits forecast for portfolio 1 are shown in Figure 10 on an annual, discounted basis. Over the Modelling Period, portfolio 1 has $917m in forecast gross market benefits in present value terms discounted to 1 July 2023 (in real June 2023 dollars).

Figure 10: Annual gross market benefit forecast for the Step Change scenario, portfolio 1; present value discounted to 1 July 2023 in millions of real June 2023 dollar terms



Gross market benefits are predominantly forecast to occur after 2027-28 which is when the first group of 2-hr grid-forming BESS in portfolio 1 are assumed to be commissioned.

Most of the gross benefit is forecast to be from the reduction in expected capex, followed by reduced FOM costs.

The differences in the forecast capacity and generation between portfolio 1 and the Base Case are shown in Figure 11 and Figure 12, respectively. These charts show:

- An additional 350 MW of OCGT capacity in 2028-29 and 700 MW in 2029-30 which corresponds to the units in portfolio 1 (as summarised in Table 4). Also visible is 1.05 GW additional BESS capacity by 2028-29, which corresponds to units in portfolio 1. Capex and FOM savings are primarily due to the delayed investment in storage (generic BESS and PHES) due to the presence of multiple BESS and gas units in portfolio 1.

- With more grid-scale BESS assumed in portfolio 1, wind capacity is forecast to be reduced and investment made in cheaper solar capacity instead. However, this difference in wind and solar capacity mix is not sustained to the same degree throughout the Modelling Period. Differences in forecast generation by wind and solar as shown in Figure 12 generally follow the same trends in differences in capacity.
- Further into the Modelling Period, the amount of gas and BESS capacity forecast in the Base Case starts to converge with that in the portfolio 1 case.
    - By 2035-36, forecast gas capacity in the Base Case has 'caught up' with the portfolio 1 forecast.
    - In contrast, the capacity outlook for BESS with portfolio 1 maintains 0.6-0.9 GW of additional BESS capacity relative to the Base Case. The forecast BESS capacity increases in the outlook with and without portfolio 1 but they do not completely converge. The difference in storage depth of the BESS units in portfolio 1 (2-hr) relative to the generic BESS units in Base Case (8-hr) is likely a factor here.
    - As the gas and BESS capacity converge, differences in wind and solar capacity and dispatch also decrease.
- Despite differences in gas capacity from 2028-29 to 2034-35, there is minimal difference in forecast total NEM-wide gas generation during this period (Figure 12). This is driven by the assumed federal government renewable energy target and the carbon budget which limit increases in gas generation.

Figure 11: Forecast capacity difference between the portfolio 1 and the Base Case

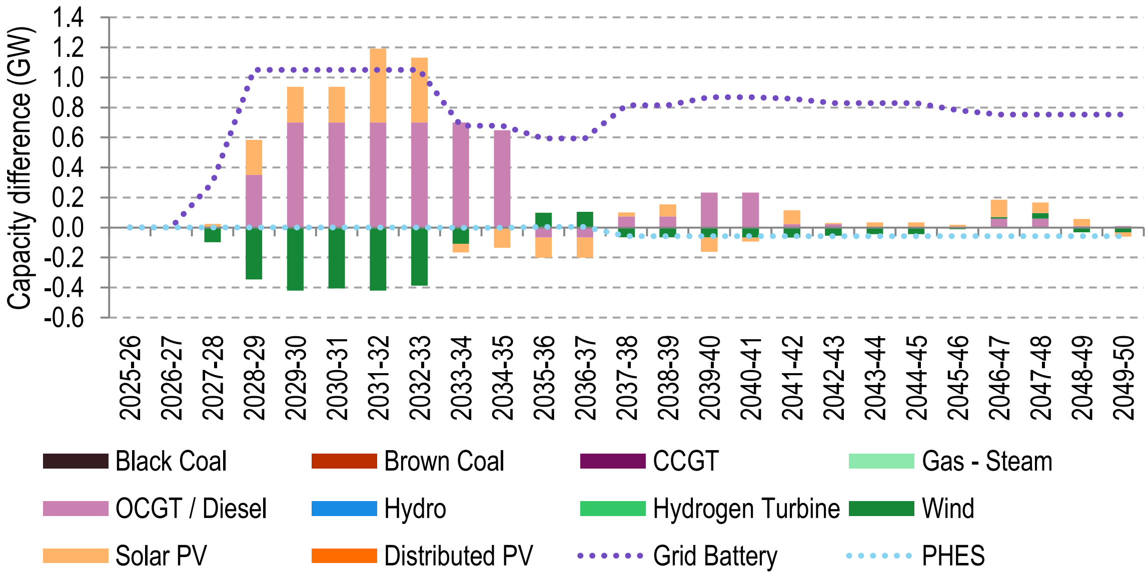
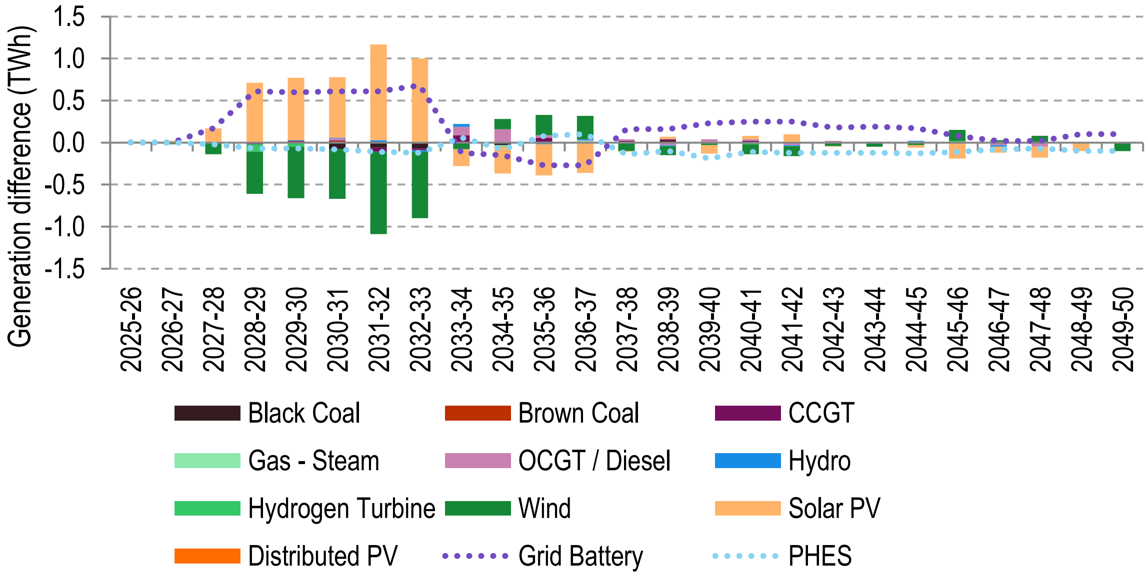


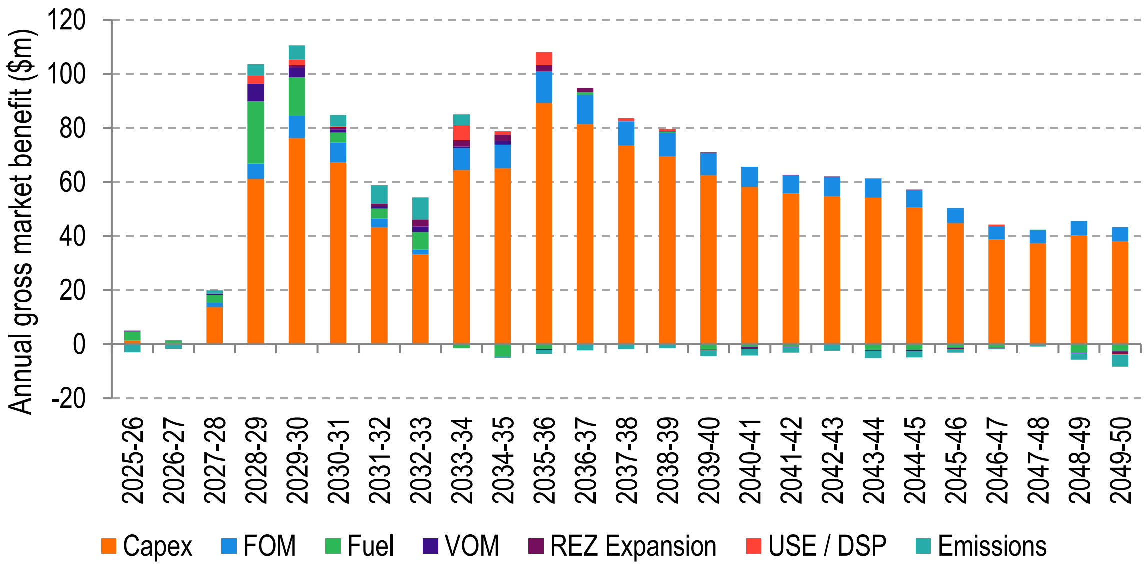
Figure 12: Forecast generation difference between portfolio 1 and the Base Case



5.3 Market modelling outcomes for portfolio 1a

The gross market benefits forecast for portfolio 1a are depicted in Figure 13 on an annual, discounted basis. Over the Modelling Period, portfolio 1a has $1,508m in forecast gross market benefits in present value terms discounted to 1 July 2023 (in real June 2023 dollars).

Figure 13: Annual gross market benefit forecast for the Step Change scenario, portfolio 1a; present value discounted to 1 July 2023 in millions of real June 2023 dollar terms



Gross market benefits are predominantly forecast to occur after 2027-28 which is when the first group of 2-hr grid-forming BESS in portfolio 1a are assumed to be commissioned. However, a small quantity of forecast benefits accrues prior to that due to small pre-emptive differences in the least-cost generation outlook forecast in a model with perfect foresight.

Comparing portfolio 1a to 1 (as summarised in Table 4), the only difference is 1a has an additional 600 MW 4-hr BESS from 1 July 2028. Additional portfolio BESS results in higher gross market benefits due to an increase in offset investment in generic BESS.

Overall trends in the forecast annual gross market benefits are similar to those forecast for portfolio 1 (Figure 13 c.f. Figure 10). This is driven by similar trends in the underlying differences in capacity and generation relative to the Base Case (respectively Figure 14 c.f Figure 11, Figure 15 c.f. Figure 12). However, the magnitude of differences in solar and wind capacity is increased in portfolio 1a as it has an extra 600 MW 4-hr portfolio BESS.

Figure 14: Forecast capacity difference between portfolio 1a and the Base Case

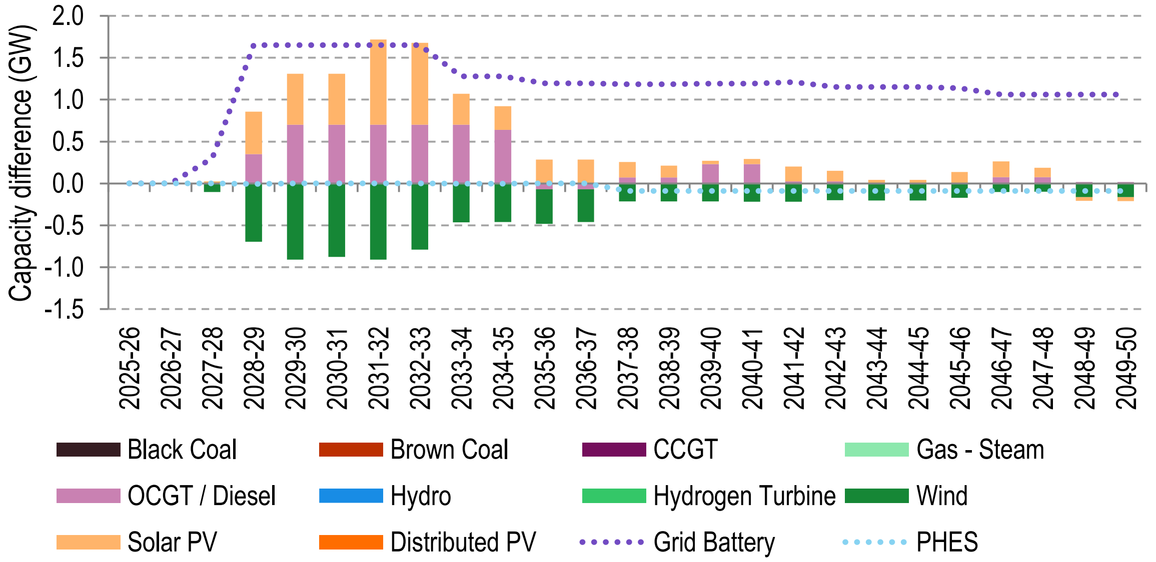
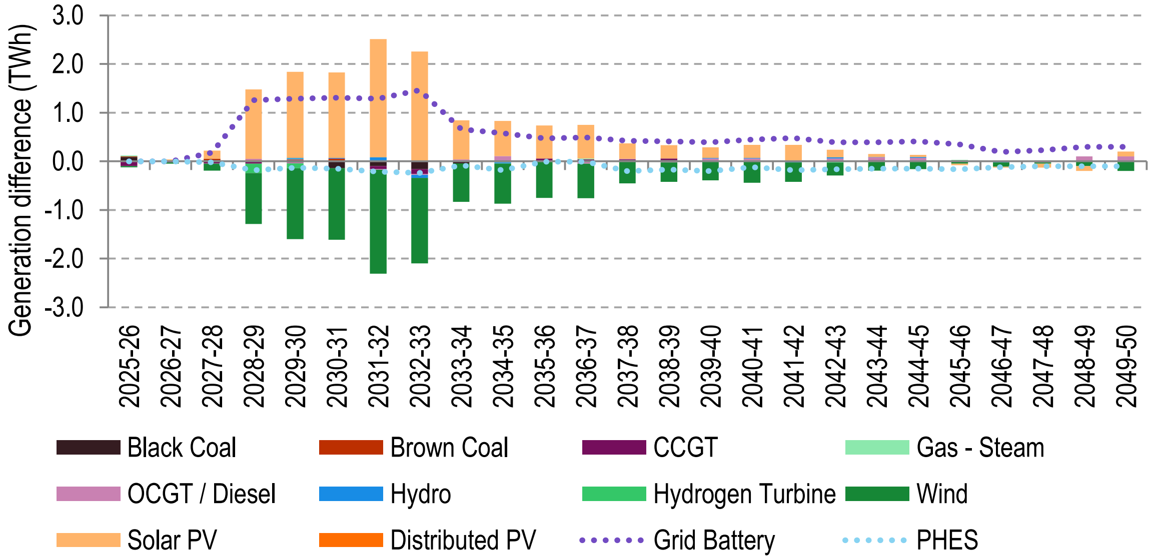


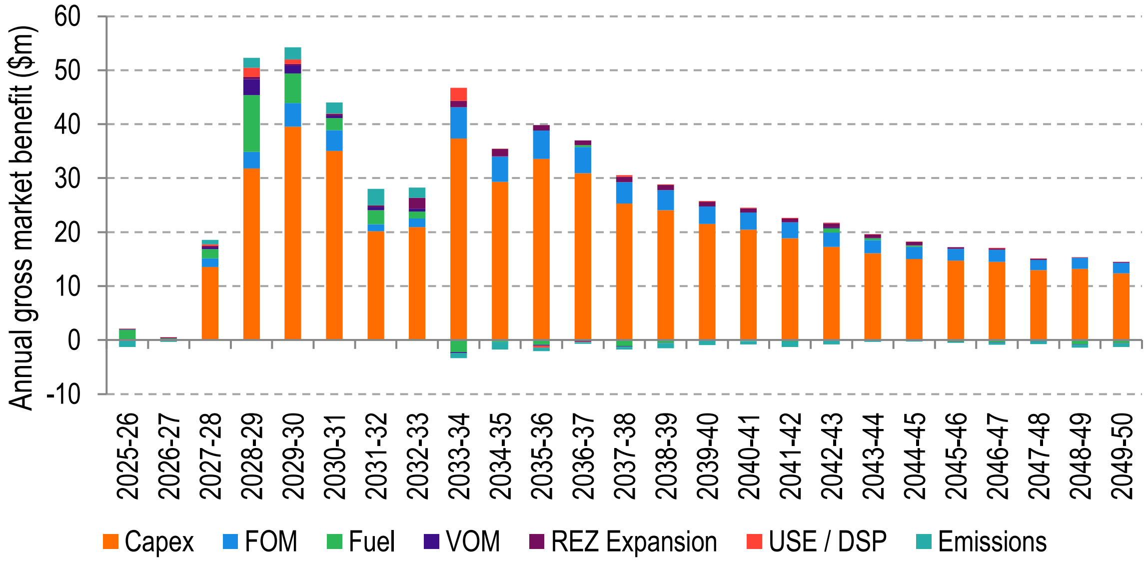
Figure 15: Forecast generation difference between portfolio 1a and the Base Case



5.4 Market modelling outcomes for portfolio 2

The gross market benefits forecast for portfolio 2 are depicted in Figure 16 on an annual, discounted basis. Over the Modelling Period, portfolio 2 has $636m in forecast gross market benefits in present value terms discounted to 1 July 2023 (in real June 2023 dollars).

Figure 16: Annual gross market benefit forecast for the Step Change scenario, portfolio 2; present value discounted to 1 July 2023 in millions of real June 2023 dollar terms



As with portfolios 1 and 1a, gross market benefits are predominantly forecast to occur after 2027-28 which is when the first group of 2-hr grid-forming BESS in portfolio 2 are assumed to be commissioned.

Comparing portfolio 2 to 1 and 1a (as summarised in Table 4), the differences are:

- There is no 4-hr BESS installed as part of portfolio 2 whereas portfolio 1a had one 4-hr BESS
- There are no extra OCGTs in portfolio 2 whereas portfolio 1 and 1a had two OCGTs each
- An extra two synchronous condensers are added relative to portfolio 1 and three relative to portfolio 1a, instead of the BESS and gas units, increasing total number of synchronous condensers in portfolio 2 to nine. These do not influence in the capacity outlook and dispatch modelling in this Report.

The overall smaller size of portfolio 2 in terms of units that influence dispatch and investment outcomes results in lower forecast gross market benefits for portfolio 2.

The differences in the forecast capacity and generation between portfolio 2 and the Base Case are shown in Figure 17 and Figure 18, respectively. Comparing outcomes for portfolio 2 and 1,forecast solar and wind capacity and generation are similar (Figure 17 c.f. Figure 11 and Figure 18 c.f. Figure 12). This is consistent with these two portfolios containing the same amount of BESS capacity. The two fewer OCGTs in portfolio 2 relative to 1 do not have a significant impact on forecast build of wind and solar.

Comparing portfolio 2 to 1a (Figure 17 c.f. Figure 14 and Figure 18 c.f. Figure 15), forecast solar capacity and generation are lower due to portfolio 2 having 600 MW less BESS capacity than portfolio 1a. This also results in more wind capacity and generation in portfolio 2 compared to 1a.

Figure 17: Forecast capacity difference between portfolio 2 and the Base Case

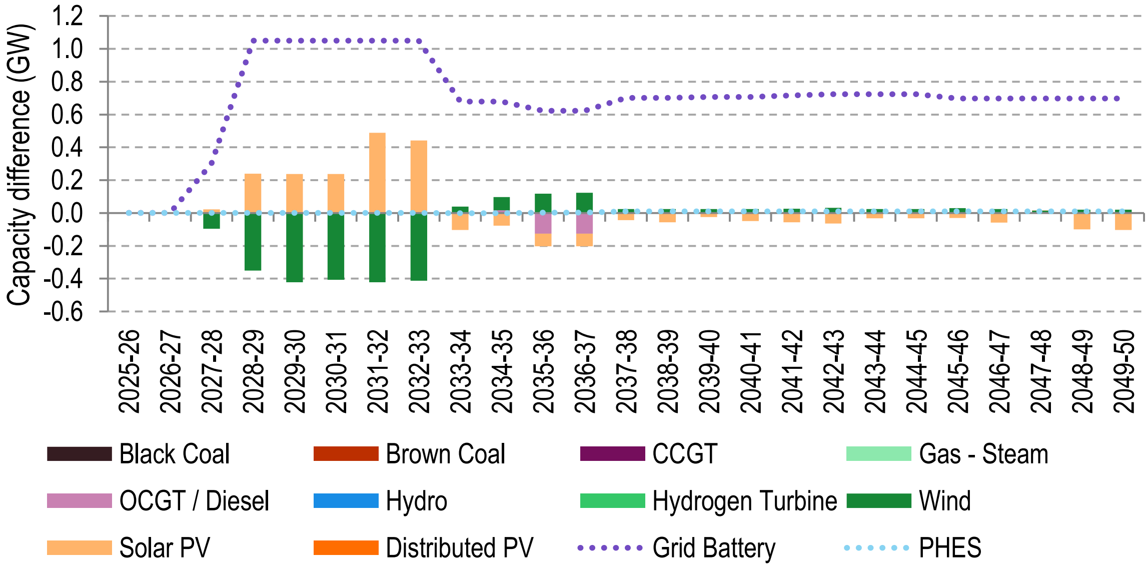
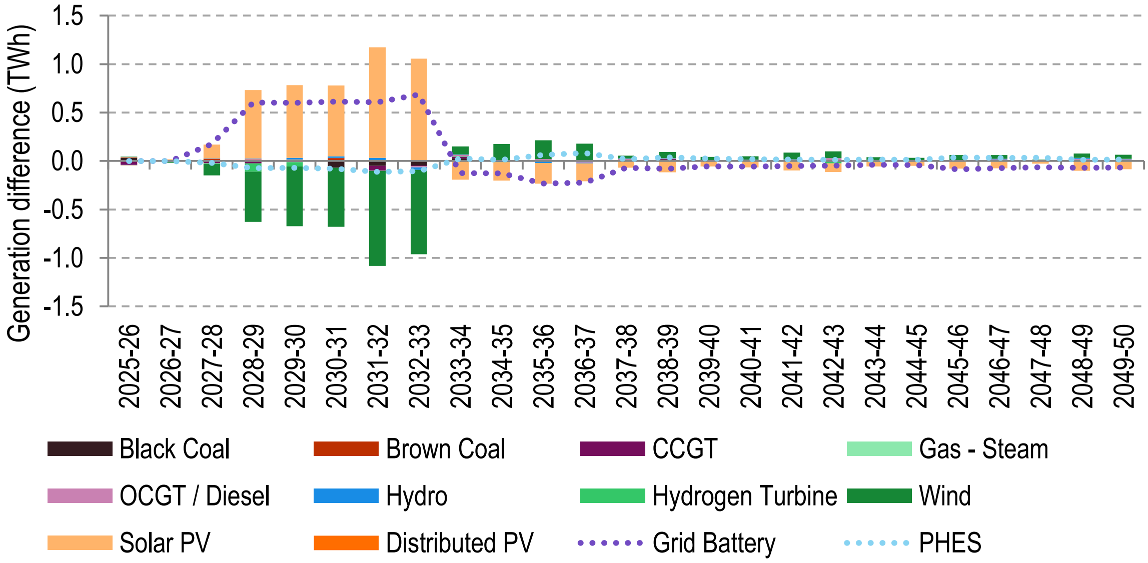


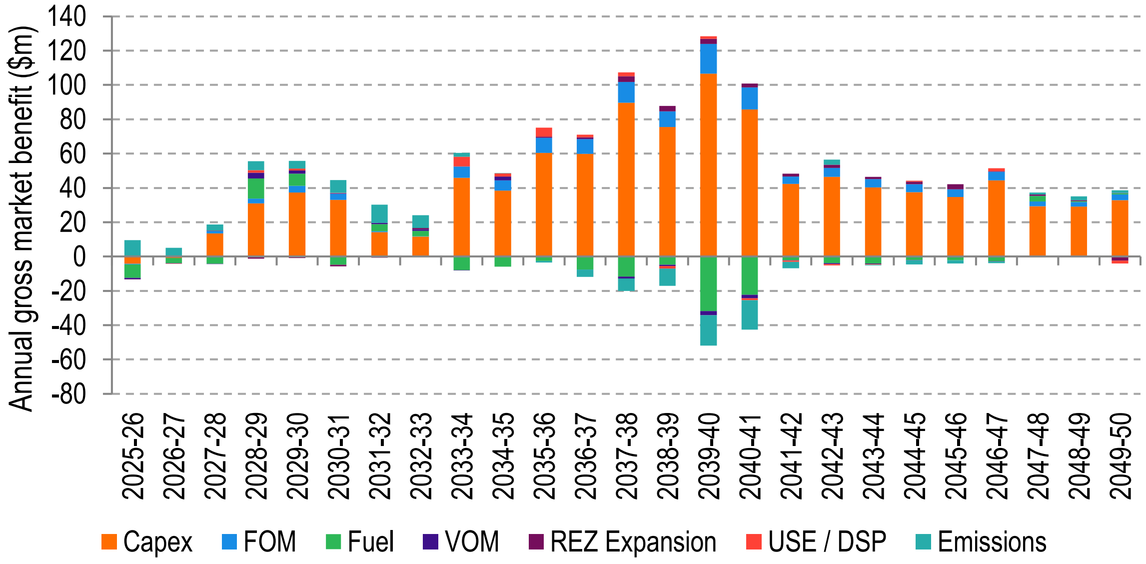
Figure 18: Forecast generation difference between portfolio 2 and the Base Case



5.5 Market modelling outcomes for portfolio 3

The gross market benefits forecast for portfolio 3 are depicted in Figure 19 on an annual, discounted basis. Over the Modelling Period, portfolio 3 has $1,089m in forecast gross market benefits in present value terms discounted to 1 July 2023 (in real June 2023 dollars).

Figure 19: Annual gross market benefit forecast for the Step Change scenario, portfolio 3; present value discounted to 1 July 2023 in millions of real June 2023 dollar terms



In portfolio 3, there is a significant amount of OCGT capacity added as compared to the other portfolios with 350 MW installed in 2028-29 and a cumulative 1,400 MW installed by 2029-30 (as summarised in Table 4). It also contains the least amount of storage capacity (equal to portfolios 1 and 2).

The differences in the forecast capacity and generation between portfolio 3 and the Base Case are shown in Figure 20 and Figure 21, respectively. Figure 20 shows that in contrast to the other portfolios, forecast gas capacity in the Base Case never completely catches up with the amount assumed with portfolio 3. As a result, while forecast BESS capacity with portfolio 3 is higher than the Base Case throughout the Modelling Period, the gap is smaller than forecast with the other portfolios. The changes in both assumed and forecast OCGT and BESS capacity also alters the forecast wind and solar capacity mix in the longer term.

Overall, the forecast gross market benefits of portfolio 3 are higher than portfolio 1, but not by much considering the significant quantity of gas capacity in portfolio 3. The amount of BESS capacity in portfolio 3 is the same as portfolio 1 and portfolio BESS capacity has a larger influence on the forecast gross benefits than the amount of gas capacity.

Figure 20: Forecast capacity difference between portfolio 3 and the Base Case

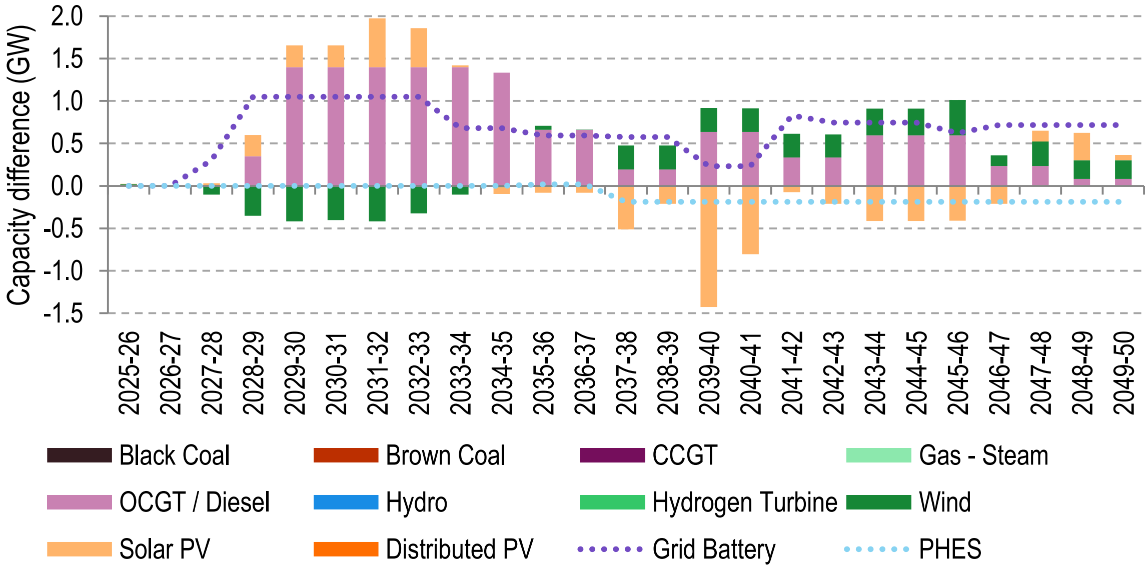
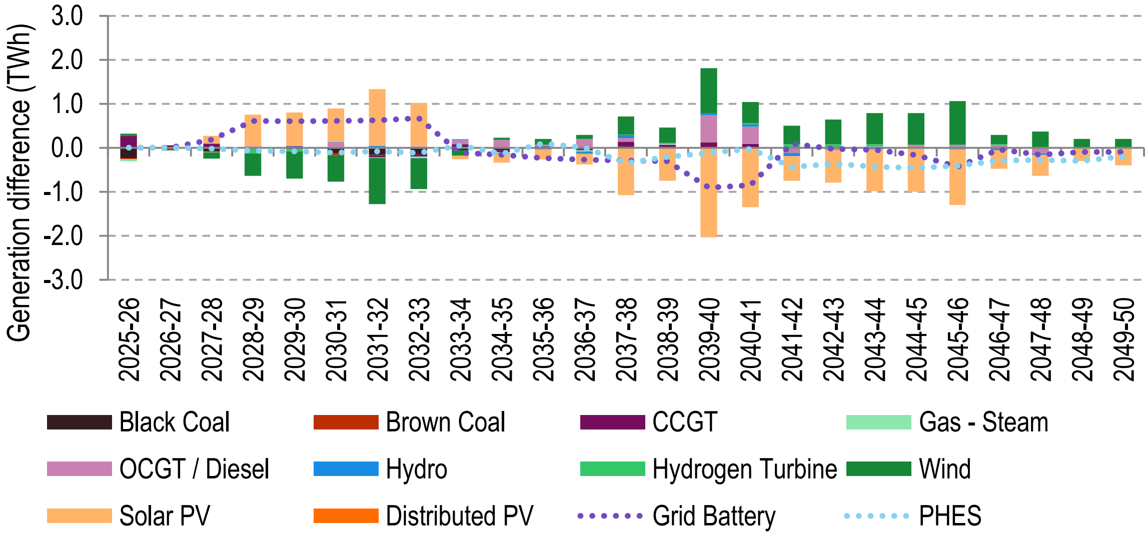


Figure 21: Forecast generation difference between portfolio 3 and the Base Case

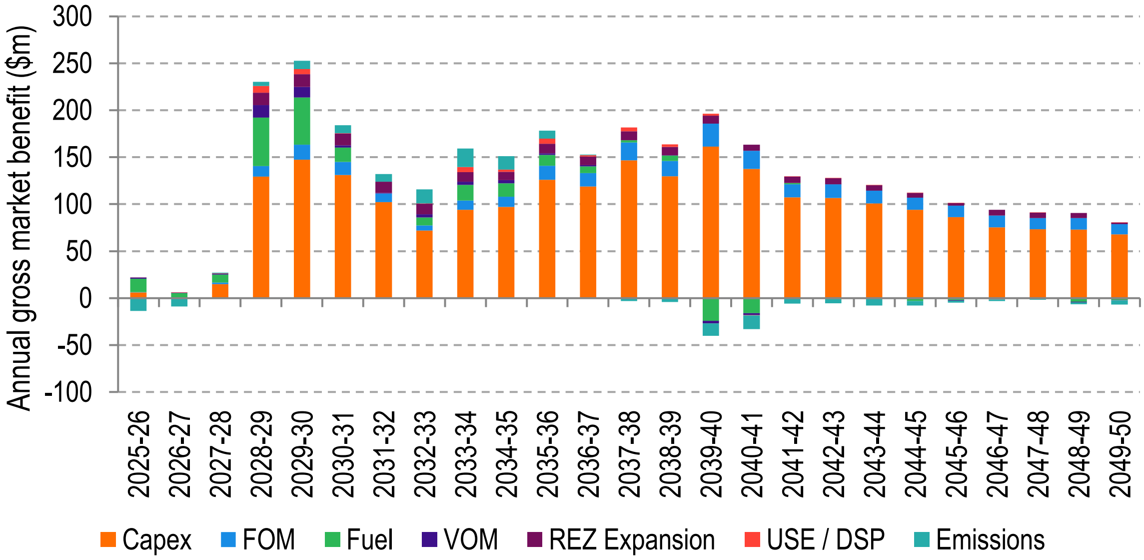


The sustained differences in forecast capacity outlook relative to the Base Case are reflected in the differences in forecast generation mix as shown in Figure 21. It is evident that the additional OCGT capacity does not translate into a significant increase in forecast gas-fired generation. This is because the assumed carbon budget limits increases in gas generation.

5.6 Market modelling outcomes for portfolio 4

The gross market benefits forecast for portfolio 4 are depicted in Figure 22 on an annual, discounted basis. Over the Modelling Period, portfolio 4 has $3,111m in forecast gross market benefits in present value terms discounted to 1 July 2023 (in real June 2023 dollars).

Figure 22: Annual gross market benefit forecast for the Step Change scenario, portfolio 4; present value discounted to 1 July 2023 in millions of real June 2023 dollar terms



Portfolio 4 is forecast to the highest benefit across the portfolio options assessed. This is due to having three 24-hr PHES units, which significantly reduces forecast capital investment in other generation and storage technologies and REZ expansion, and also reduces forecast fuel costs.

The differences in the forecast capacity and generation between portfolio 4 and the Base Case are shown in Figure 23 and Figure 24, respectively. They show:

- The PHES assumed as part of portfolio 4 results in BESS capacity in the Base Case entirely 'catching up' with BESS capacity in the outlook with portfolio 4 by 2039-40, and exceeding BESS capacity in the outlook with portfolio 4 in the late 2040s.
- The portfolio PHES also reduces investment in gas so that forecast OCGT capacity in the portfolio 4 outlook is lower than that in the Base Case in most years from 2037-38 to the end of the Modelling Period.
- There are flow-on impacts on the forecast wind and solar capacity mix throughout the Modelling Period. From when the PHES is installed until the late 2030s, there is greater investment in solar than wind for energy, which is cheaper and helps reduce overall cost of meeting demand.

Figure 23: Forecast capacity difference between portfolio 4 and the Base Case

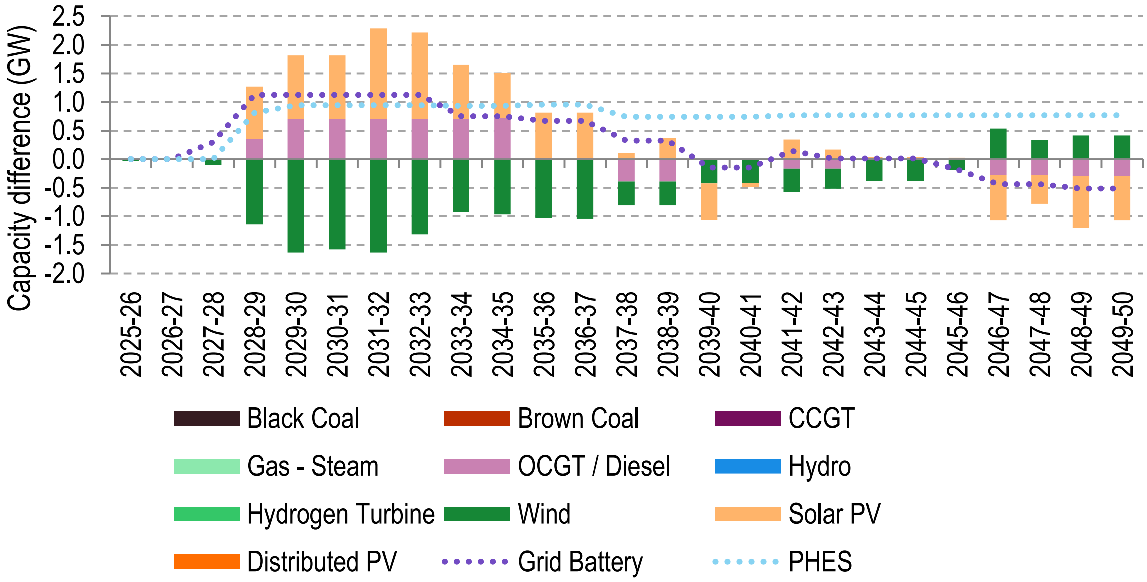
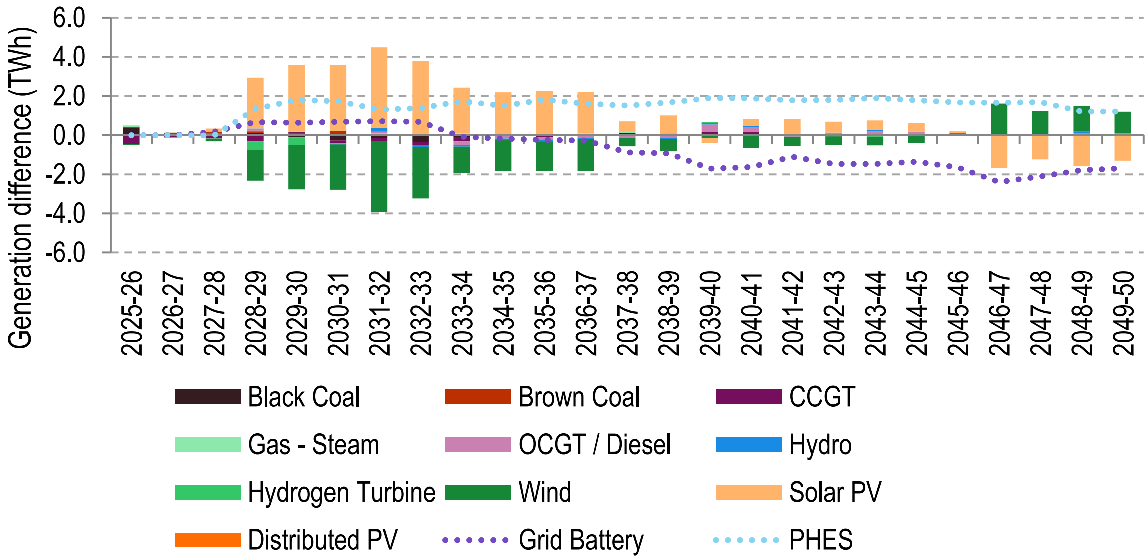


Figure 24: Forecast generation difference between portfolio 4 and the Base Case



5.7 Market modelling outcomes in sensitivities

This section presents and compares the forecast gross market benefits of portfolio 1a across the core Step Change scenario and several sensitivities. This is summarised in Table 6. This table also includes the change in system cost relative to the core Step Change scenario (both with portfolio 1a) to give a sense of how each of the sensitivities impacts total system cost, as well as gross market benefits (which are the *difference* in system cost between a simulation with portfolio 1a and a matching Base Case).

Table 6: Overview of changes in forecast system cost of portfolio 1a and forecast gross market benefits relative to the Base Case in the selected sensitivities; present value discounted to 1 July 2023 in millions of real June 2023 dollar terms

Sensitivity	Description	Change in forecast system cost of portfolio 1a relative to core scenario ($m)	Forecast gross market benefits ($m)	Change in forecast gross market benefits ($m)
Core Step Change scenario	n/a	n/a	1,508	n/a
Alternative Queensland coal retirement trajectory	Change in Queensland coal-fired generator retirements	-835	1,485	-23
Borumba PHES delay	Two-year delay in assumed entry of Borumba PHES from 1/9/2031 to 1/9/2033	+413	1,579	+71
Gas fuel cost higher	Gas fuel prices from AEMO 2023 IAS workbook[3] Progressive Change scenario	+1,187	1,510	+2
Gas fuel cost lower	Gas fuel prices from AEMO 2023 IAS workbook[3] Green Energy Exports scenario	-1,680	1,512	+3
BESS capex higher	BESS capex from AEMO 2023 IAS workbook[3] Progressive Change scenario	+643	1,550	+42
BESS capex lower	BESS capex from AEMO 2023 IAS workbook[3] Green Energy Exports scenario	-1,572	1,316	-192

5.7.1 Alternative Queensland coal-fired generator withdrawal sensitivity

This sensitivity assumed a different coal retirement in Queensland in line with the AEMO 2023 System Strength report (slower in CQ and faster in SQ)[34]. This increases the forecast generation from gas and the remaining coal-fired generators, including gas and coal in regions outside Queensland (while still respecting the carbon budget and federal and state renewable energy targets).

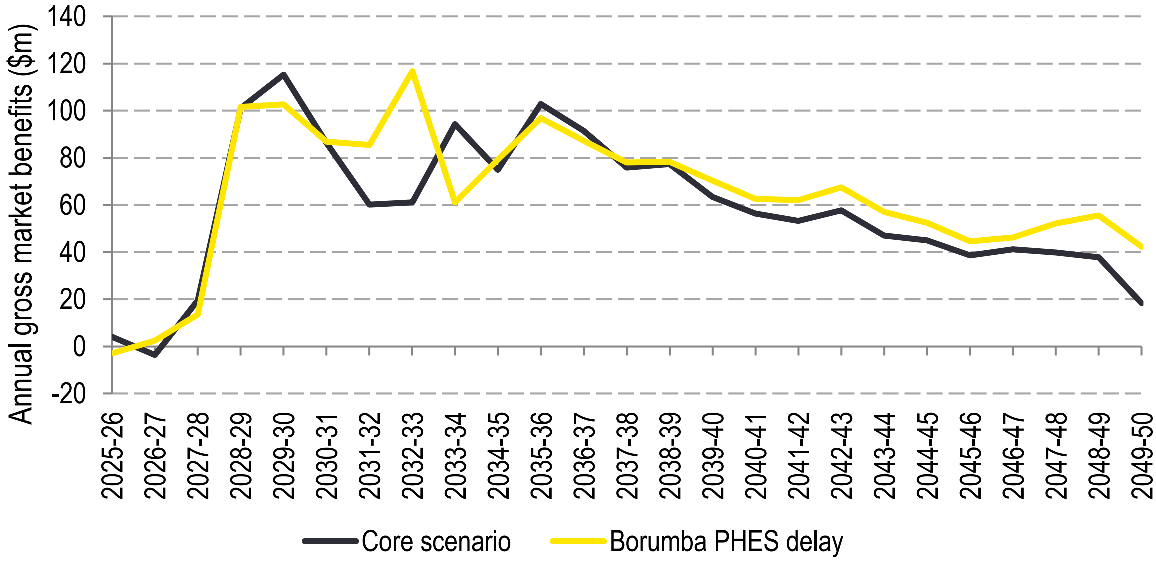
Overall, this decreases forecast total system cost both with portfolio 1a and in the Base Case. There is a small decrease in forecast gross market benefits for portfolio 1a from $1,508m to $1,485m. Similar magnitude decreases in forecast gross market benefits were observed for the other portfolios (Table 5).

5.7.2 Borumba PHES delay sensitivity

This sensitivity examines the impact on gross market benefits of portfolio 1a of a two-year delay in assumed commissioning of Borumba PHES from 1 September 2031 to 1 September 2033. The effects of this delay on the difference in capacity and generation outlook between the portfolio 1a case and the matched Base Case is mostly contained to the few years around the assumed Borumba delay. Consequently, differences in forecast gross market benefits are also mostly contained to these years as shown in Figure 25.

[34] AEMO, December 2023, *2023 System Strength Report*: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning. Accessed 30 September 2024.

Figure 25: Annual gross market benefit forecast for the Borumba PHES delay sensitivity and Step Change scenario, portfolio 1a; present value discounted to 1 July 2023 in millions of real June 2023 dollar terms

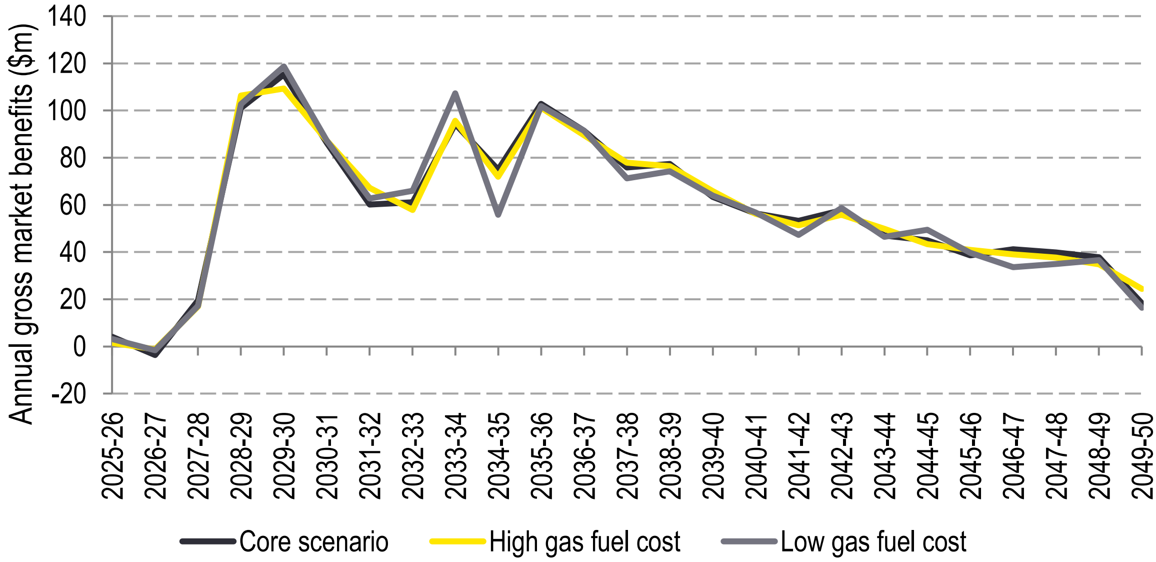


During this period there is a decrease in forecast investment in solar and increase in forecast investment in wind combined with an increase in forecast generation from existing coal and gas-fired generators. Overall, the forecast system cost in both the Base Case and portfolio 1a case increases with an assumed Borumba PHES delay. However, in the sensitivity Base Case, the assumed delay creates an opportunity for 234 MW of PHES to be built in CQ in 2028-29 and also accelerates the build of 200 MW BESS by one year in each of CQ and Gladstone in 2032-33. This build is avoided in the sensitivity with portfolio 1a. Consequently, the gross market benefits of portfolio 1a are forecast to increase by $71m with an assumed delay in Borumba from $1,508m to $1,579m.

5.7.3 Gas fuel cost sensitivities

In the modelled scenario and sensitivities, forecast gas generation is limited by assumed renewable energy targets and carbon budgets. As a result, changes in the assumed gas fuel cost (higher or lower) do not significantly impact the forecast market benefits of portfolio 1a. Differences in forecast gross market benefits annually are shown in Figure 26.

Figure 26: Annual gross market benefit forecast for the high and low gas fuel cost sensitivities and Step Change scenario, portfolio 1a; present value discounted to 1 July 2023 in millions of real June 2023 dollar terms

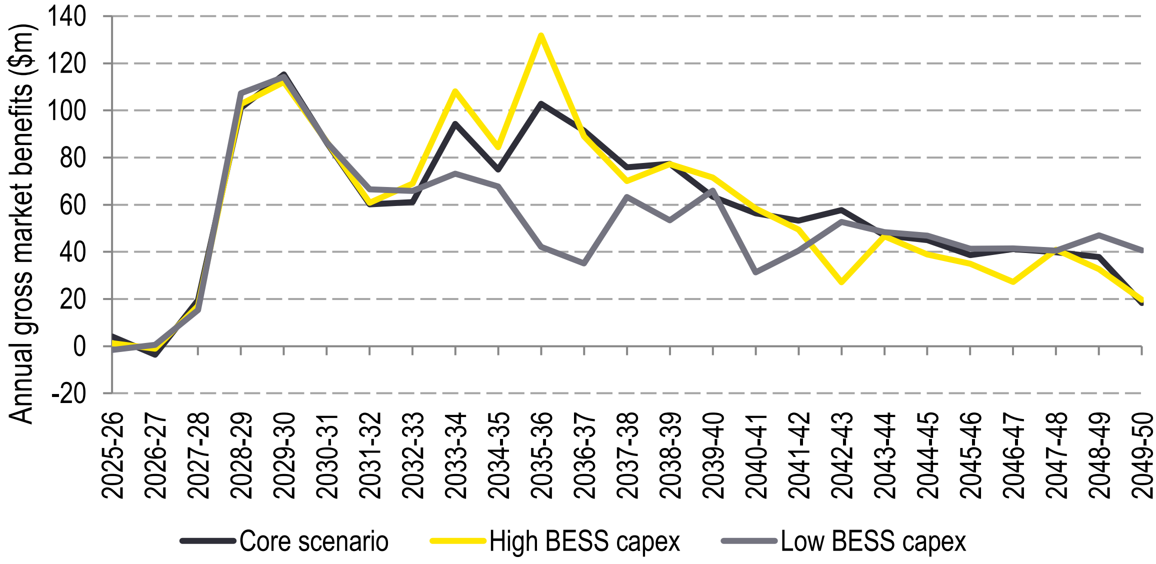


5.7.4 BESS capex sensitivities

Two sensitivities examined the impact of changes in assumed BESS capex on the gross market benefits of portfolio 1a. Higher assumed BESS capex causes less forecast investment in generic BESS which decreases forecast solar investment and increases forecast wind and PHES investment. Overall, system cost is higher in both the Base Case and with portfolio 1a with assumed higher BESS capex compared to the core Step Change scenario.

With higher assumed BESS capex, the *difference* between portfolio 1a relative to its matched Base Case (i.e. the forecast gross market benefits) is forecast to stay relatively constant. In the core Step Change scenario, the difference in BESS capacity in the Base Case converges somewhat over the Modelling Period (Figure 11). This does not occur when BESS capex is assumed to be higher. With higher assumed BESS capex, portfolio 1a causes greater delays in forecast investment in PHES and wind capacity and causes more sustained higher solar and gas capacity throughout the Modelling Period. These capacity differences drive an increase in forecast market benefits that is counterbalanced by higher emissions costs so that the overall gross market benefits with higher assumed BESS capex is slightly higher than the core scenario (+$42m). Annual forecast gross market benefits are shown in Figure 27.

Figure 27: Annual gross market benefit forecast for the high and low BESS capes sensitivities and Step Change scenario, portfolio 1a; present value discounted to 1 July 2023 in millions of real June 2023 dollar terms



The opposite trend can be noted for lower assumed BESS capex. That is, system cost is lower in both the Base Case and with portfolio 1a compared to the core scenario. Under assumed lower BESS capex, there is greater convergence in BESS capacity between portfolio 1a and the Base Case from the 2030s. From this time, portfolio 1a delays forecast investment in solar and causes sustained higher investment in wind. Overall, a reduction in future BESS capital costs leads to a reduction in forecast gross market benefits of portfolio 1a compared to the core scenario. Annual forecast market benefits are shown in Figure 27.

Appendix A Methodology

A1. Long-term investment planning

EY has used linear programming techniques to perform hourly time-sequential, least-cost, long-term NEM development optimisation modelling spanning 25 years from 2024-25 to 2049-50. The modelling methodology follows the AER RIT-T guidelines[35] to assess gross market benefits. The forecast gross market benefits of each portfolio are calculated as the difference in forecast system cost with the portfolio compared to the Base Case.

The categories of market benefits assessed include:

- Avoided generation dispatch costs
- Avoided voluntary load curtailment
- Involuntary load shedding
- Reduction in greenhouse gas emissions.

Based on the full set of input assumptions, the model makes decisions that minimise the overall cost to supply the electricity demand for the NEM over the entire Modelling Period, with respect to:

- Capex of new generation and storage capacity installed
- FOM costs of all generation and storage capacity
- VOM costs of all generation and storage capacity
- Fuel costs of all generation capacity
- Cost of DSP and USE
- Transmission expansion costs associated with REZ development
- Transmission[36] and storage losses which form part of the demand to be supplied and are calculated dynamically within the model.

To determine the least-cost solution, the model makes decisions for each hourly[37] dispatch interval in relation to:

- The generation dispatch level for each power plant along with the charging and discharging of storage. Generators are assumed to be dispatched according to their short-run marginal cost (SRMC), which is derived from their VOM and fuel costs, as well as technical parameters. The generation for each dispatch interval is subject to the modelled availability of power stations in each hour (subject to planned or unplanned outages or variable renewable availability), network limitations and energy limits (e.g., storage levels).
- Commissioning new entrant capacity for wind, offshore wind, solar PV SAT, CCGT, OCGT, grid-scale BESS and PHES.

These hourly decisions take into account constraints that include:

- Supply must equal demand in each region for all dispatch intervals, while maintaining a reserve margin, with USE costed at the value of customer reliability (VCR)

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[35] AER, October 2023, *Regulatory investment test for transmission*. Available at: https://www.aer.gov.au/system/files/2023-10/AER%20-%20RIT-T%20guidelines%20-%20final%20amendments%20%28marked%20up%29%20%20-%206%20October%202023_0.pdf. Accessed 30 September 2024.
[36] For the transmission elements modelled, described in Appendix B.
[37] Whilst the NEM is dispatched on five-minute intervals, the model resolution is hourly as a compromise between managing computation time while still capturing the renewable and storage resources in sufficient detail for the purposes of the modelling.

- Minimum loads for some generators
- Transmission interconnector flow limits (between regions)
- Maximum and minimum storage reservoir limits (for conventional storage hydro, PHES, Virtual Power Plant or VPPs and BESS)
- New entrant capacity transmission and resource limits for wind and solar in each REZ and costs associated with increasing these limits, and PHES in each region
- Emission and carbon budget constraints, as defined for each scenario
- Renewable energy targets where applicable by region or NEM-wide.

The model includes key intra-regional constraints in Queensland through modelling of zones with intra-regional limits and loss equations. Within these Queensland zones and within other regions, the only other element of the transmission network considered are REZ transmission constraints.[38] There are also inter-regional transfer limits (between regions). Further detail of the network model is given in Appendix B.

The model factors in the annual costs, including annualised capex, for all new generator capacity and the model optimises how much new capacity, storage and REZ transmission to build in each region to deliver the least-cost market outcome.

The model meets the specified carbon budget at least cost, which may be by either building new lower emissions plant or reducing operation of higher emissions plant, or both.

There are three main types of generation that are scheduled by the model:

- Dispatchable generators, typically coal, gas and liquid fuel which are assumed to have unlimited energy resource in general. The running cost for these generators is the sum of the VOM and fuel costs. Coal generators and some CCGTs have minimum loads to reflect operational stability limits and high start-up costs and this ensures they are always online when available. This is consistent with the self-commitment nature of the design of the NEM. On the other hand, peaking generators have no minimum operating level and start whenever the cost of supply is at or above their variable costs and operate for a minimum of one hour.
- Wind and solar generators are fully dispatched according to their available variable resource in each hour, unless constrained by oversupply or network limitations.
- Storage plant of all types (conventional hydro generators with storages, PHES, grid-scale BESS and VPPs) are operated to minimise the overall system costs. This means they tend to generate at times of high cost of supply, e.g., when the demand for power is high, and so dispatching energy-limited generation will avoid utilisation of high-cost plant such as gas-fired or liquid fuel generators. Conversely, at times of low supply cost, e.g., when there is a prevailing surplus of renewable generation capacity, storage hydro preserves energy and PHES and BESS operate in pumping or charging mode.

A2. Reserve constraint in long-term investment planning

As per the AEMO ISP methodology[39], the least-cost planning model ensures there is sufficient dispatchable capacity in each region to meet peak demand by enforcing regional minimum reserve levels to allow for generation contingencies, which can occur at any time.

[38] including an additional cost for transmission upgrades to facilitate REZ development where this forms part of the input data.
[39] AEMO, June 2023, *ISP Methodology*, available at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en. Accessed 30 September 2024.

All dispatchable generators in each region are eligible to contribute to reserve (except storage[40]), as is headroom that is available from interconnectors. The hourly modelling accounts for load diversity and sharing of reserves across the NEM and so minimises the amount of reserve carried, and provides reserve from the lowest cost providers, including allowing for each region to contribute to its neighbours' reserve requirements through interconnectors.

In the modelling presented in this Report, a single contingency reserve requirement was applied with a high penalty cost. This amount of reserve is intended to allow sufficient capacity for operational reliability in the event that conditions vary from the perfect-foresight optimisation model (e.g., variability in production from variable renewable energy sources, different forced outage patterns, sub-optimal operation of storage).[41]

There are two geographical levels of reserve constraints applied:

- Reserve constraints are applied to each region.
- The model ensures that interconnector headroom is backed by spare capacity in the neighbouring regions through an additional reserve constraint.

A3. Valuing emissions

The cost of emissions was calculated as a post-process to the optimisation based on the annual emissions as modelled and cost of emissions based on the AER's assumed costs in their May 2024 *Valuing emissions* reduction guidance note.[42] This is consistent with the methodology applied in the 2024 ISP.[43]

A4. Cost-benefit analysis

From the hourly time-sequential modelling, the categories of costs as listed in Appendix A1 are computed as defined in the RIT-T.

For each scenario and sensitivity with a portfolio, a matched without portfolio counterfactual (referred to as the Base Case) long-term generation and investment plan is simulated. The changes in each of the cost categories are the forecast gross market benefits due to the portfolio.

Each component of forecast gross market benefits is computed annually over the 25-year Modelling Period. In this Report, we summarise the forecast benefit and cost streams using a single value computed as the present value, discounted to 1 July 2023 at a 7% real, pre-tax discount rate, consistent with the 2023 IAS workbook.[44]

Forecast market benefits presented in this Report are changes in system cost relative to the relevant Base Case before consideration of portfolio costs. Total forecast gross market benefits were calculated in three steps:

- Capex, FOM, VOM, fuel, voluntary and involuntary load curtailment and REZ expansion transmission costs were calculated within the market capacity and dispatch model.

[40] PHES, VPPs and BESS storages are usually fully dispatched during the peak demand periods and thus will be unable to contribute to reserve. In the event that they are not dispatched fully, it is likely that they will have insufficient energy in storage.
[41] This constraint is applied to only a subset of simulation hours when demand is high to reduce the optimisation problem size.
[42] AER, 22 May 2024, *Valuing emissions reduction: AER guidance and explanator statement*, Available at: https://www.aer.gov.au/industry/registers/resources/guidelines/valuing-emissions-reduction-final-guidance-may-2024. Accessed 30 September 2024.
[43] AEMO, June 2024, *2024 ISP*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp. Accessed 30 September 2024.
[44] AEMO, December 2023, *Draft 2024 ISP Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 30 September 2024.

- Hourly dispatch outcomes from the simulations were used to compute yearly emission cost as a post-dispatch calculation.
- Powerlink used hourly dispatch outcomes from the simulations to compute an additional benefit of avoided USE based on an assessment of system strength. This calculation by Powerlink is not covered in this Report.

Appendix B. Transmission

B1. Regional definitions

Powerlink requested to split Queensland into sub-regions or zones in the modelling presented in this Report, as listed in Table 7. This network representation differs from the one used in the 2024 ISP[45], providing a higher resolution view of Queensland and aligning with Powerlink's internal modelling configuration.

Table 7: Regions, zones and reference nodes

Region	Zone	Zonal Reference Node
Queensland	Far North (FN)	Woree 275 kV
	Ross	Ross 275 kV
	Hughenden	Hughenden 500 kV
	North	Nebo 275 kV
	Central Queensland (CQ)	Calliope River 275 kV
	Gladstone (GG)	Gladstone 275 kV
	Southern Queensland (SQ)	South Pine 275 kV
NSW	New South Wales (NSW)	Sydney West 330 kV
Victoria	Victoria (VIC)	Thomastown 66 kV
South Australia	South Australia (SA)	Torrens Island 66 kV
Tasmania	Tasmania (TAS)	George Town 220 kV

B2. Interconnector and intra-connector loss models

Dynamic loss equations for the existing network are sourced from the 2023 IAS workbook.[46]

We also computed dynamic loss equations were computed for several links including:

- Intra-regional links in Queensland
- When transmission upgrades involving a conductor change are modelled e.g. VNI West, Marinus Link.

The network snapshots to compute loss equations were provided by Powerlink.

B3. Interconnector and intra-connector capabilities

The notional limits imposed on interconnectors are shown in Table 8. The following interconnectors are included in the left-hand side of constraint equations which may restrict them below the notional limits specified in this table:

[45] AEMO, June 2024, *2024 ISP*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp. Accessed 30 September 2024.
[46] AEMO, December 2023, *Draft 2024 ISP Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 30 September 2024.

- Heywood + EnergyConnect has combined transfer export and import limits of 1,300 MW and 1,450 MW. The model will dispatch across the two links to minimise costs.[47]
- Basslink + Marinus Link has combined transfer export and import limits of 1,344 MW and 978 MW after Marinus Link Stage 1 is completed. The export and import limits increase to 2,094 MW and 1,728 MW after Marinus Link Stage 2.[48]

Table 8: Notional interconnector capabilities used in the modelling (sourced from AEMO 2023 IAS workbook[47])

Interconnector (From node - To node)	Import[49] notional limit	Export[50] notional limit
QNI	1,165 MW summer/1,170 MW winter After QNI Connect - Option 2: 2,865 MW summer/2,870 MW winter	745 MW summer/winter After QNI Connect - Option 2: 2,005 MW summer/winter
N-Q-MNSP	150 MW summer/200 MW winter	50 MW
EnergyConnect (NSW-SA)	150 MW after stage 1 (1/12/2024) 800 MW after stage 2 (1/7/2027)	150 MW after stage 1 (1/12/2024) 800 MW after stage 2 (1/7/2027)
Heywood (VIC-SA)	650 MW before EnergyConnect 750 MW after EnergyConnect (1/7/2027)	650 MW before EnergyConnect 750 MW after EnergyConnect (1/7/2027)
Murraylink (VIC-SA)	200 MW	220 MW
Basslink (TAS-VIC)	478 MW	594 MW
Marinus Link (TAS-VIC)	750 MW after stage 1 (1/12/2030) 1,500 MW after stage 2 (1/12/2032)	750 MW after stage 1 (1/12/2030) 1,500 MW after stage 2 (1/12/2032)
VIC-NSW	Initial limit: 400 MW After VNI West: 2,069 MW (1/12/2029)	Initial limit: 1,000 MW After VNI West: 2,935 MW (1/12/2029)

Queensland has been split into zones with the following limits imposed between the zones defined in Table 9.

Table 9: Intra-connector notional limits imposed in modelling for Queensland, defined by Powerlink

Intra-connector (From node - To node)	Import notional limit	Export notional limit
Ross-FN	800 MW	700 MW
Ross-Hughenden	2,800 MW after CopperString (1/6/2029)	2,800 MW after CopperString (1/6/2029)
North-Ross	1,400 MW 3,550 MW after upgrade (1/7/2035)	1,500 MW 3,550 MW after upgrade (1/7/2035)
CQ-North	1,300 MW 3,000 MW after upgrade (1/7/2033)	1,400 MW 3,000 MW after upgrade (1/7/2033)

[47] AEMO, December 2023, *Draft 2024 ISP Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 30 September 2024.
[48] AEMO, July 2024, *2024 ISP Inputs, assumptions and scenarios workbook v6*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp. Accessed 30 September 2024.
[49] Import refers to power being transferred from the 'To node' to the 'From node' and follows NEM convention where the 'From node' is the most southerly or easterly node, and the 'To node' is the most northerly or westerly node. e.g., import along QNI implies southward flow and import along Heywood and EnergyConnect implies eastward flow.
[50] Export refers to power being transferred from the 'From node' to the 'To node' and follows NEM convention where the 'From node' is the most southerly or easterly node, and the 'To node' is the most northerly or westerly node. e.g., export along QNI implies northward flow and export along Heywood and EnergyConnect implies westward flow.

Intra-connector (From node – To node)	Import notional limit	Export notional limit
CQ-GG	unlimited	unlimited
SQ-CQ	2,100 MW 2,700 MW after QEJP Stage 2 (1/7/2031)	1,100 MW 2,700 MW after QEJP Stage 2 (1/7/2031)

B4. REZ free transmission limit capabilities

The REZ transmission limit capabilities before and after transmission upgrades are shown in Table 10 for Queensland REZs and other REZs with assumed augmentations. Transmission limits for other REZs are as per the 2023 IAS workbook.[51] Most REZs have the option to further expand transmission limits beyond these values at an assumed cost, in accordance with the 2023 IAS workbook.[51]

Table 10: REZ free transmission limit capabilities used in the modelling (sourced from AEMO 2023 IAS workbook[51])

REZ transmission constraint	REZ ID of affected REZs	REZ free transmission limit
Far North QLD	Q1	750 MW
North Qld Clean Energy Hub	Q2	700 MW 2,200 MW after CopperString (1/6/2029) 3,000 MW after QEJP Stage 3 (1/7/2034)
Barcaldine	Q5	85 MW
SWQLD	Q8	5,300 MW 5,800 MW after Darling Downs REZ Expansion (1/7/2034)
Banana	Q9	150 MW
New England	N2	577 MW 3,577 MW after New England REZ Network Infrastructure Project – REZ Option 1 (1/7/2031) 6,577 MW after New England REZ Network Infrastructure Project – REZ Option 2 (1/7/2034)
Central-West Orana	N3	900 MW 5,400 MW after Central-West Orana REZ Transmission Link (1/8/2028)
South West NSW	N5	215 MW 1,015 MW after Project EnergyConnect - Stage 2 (1/7/2027) 1,815 MW after HumeLink (1/7/2029) 2,715 MW after VNI West – Option 1 (1/12/2029)
Murray River	V2	440 MW Summer / 640 MW Winter 552 MW Summer / 752 MW Winter after VIC RDP network augmentation project (1/10/2025) 2,132 MW Summer / 2,332 MW Winter after VNI West – Option 1 (1/12/2029)

[51] AEMO, December 2023, *Draft 2024 ISP Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 30 September 2024.

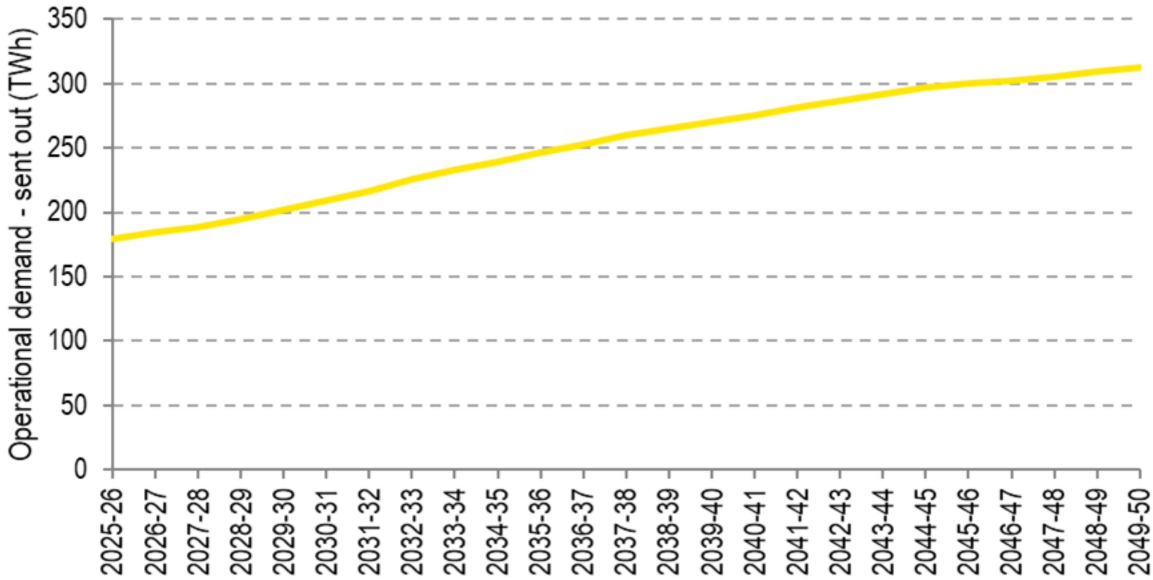
REZ transmission constraint	REZ ID of affected REZs	REZ free transmission limit
V3WEST	V3	780 MW Summer / 980 MW Winter 2,240 MW Summer / 2,440 MW Winter after Western Renewables Link (1/07/2027) 2,440 MW Summer / 2,640 MW Winter after VNI West – Option 1 (1/07/2029)
SWV	V4, V8	1,850 MW 1,931 MW after VIC Govt RDP network augmentation project (1/12/2024) 3,031 MW after Mortlake turn-in project (1/10/2025)
Central North VIC	V6	650 MW Summer / 1,300 MW Winter 612 MW Summer / 1,312 MW Winter after VIC RDP network augmentation project (1/12/2024)
Riverland	S2	130 MW 930 MW after Project EnergyConnect - Stage 2 (1/7/2027)

Appendix C. Demand

The least-cost planning model captures forecast demand diversity across regions by basing the overall shape of hourly demand on nine historical financial years ranging from 2010-11 to 2018-19.

Demand timeseries were based on AEMO's Electricity Statement of Opportunities (ESOO) 2023[52] Central scenario which was adopted by AEMO for the 2024 ISP Step Change scenario. Figure 28 shows the assumed NEM operational demand for the Step Change scenario inclusive of hydrogen demand.

Figure 28: Assumed annual operational demand in the NEM in the Step Change scenario



The nine reference years are repeated sequentially throughout the Modelling Period as shown in Table 11.

Table 11: Sequence of demand reference years applied to forecast

Modelled year	Reference year
2024-25	2015-16
2025-26	2016-17
2026-27	2017-18
2027-28	2018-19
2028-29	2010-11
2029-30	2011-12
2030-31	2012-13
2031-32	2013-14
2032-33	2014-15

[52] AEMO, August 2023, *2023 Electricity Statement of Opportunities*. Available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo. Accessed 30 September 2024.

Modelled year	Reference year
2033-34	2015-16
2034-35	2016-17
2035-36	2017-18
2036-37	2018-19
...	...
2048-49	2012-13
2049-50	2013-14

This method ensures the timing of high and low demands across regions reflects historical patterns, while accounting for projected changes in rooftop PV generation and other behind-the-meter loads and generators that may alter the size of peaks and their timing across regions. Overall, due to distributed PV uptake, we generally see the peak operational demand dispatch intervals shifting later in the day throughout the Modelling Period.

The reference year pattern is also consistent with site-specific hourly large-scale wind and solar availability (see Appendix D7) and hydro inflows. This maintains correlations between weather patterns, demand, wind, large-scale solar and distributed PV availability.

Appendix D. Supply

D1. Committed and anticipated generator and storage projects

Several generators and storage projects not yet built are committed in all simulations. For projects in Queensland, this is based on projects with existing, committed or anticipated status in AEMO's May 2024 Generation Information.[53] This source was released during the course of the modelling engagement. Committed and anticipated projects in other regions are aligned with the Draft 2024 ISP which is based on AEMO's July 2023 Generation Information.[54]

D2. Wind and solar energy projects and REZ representation

Existing, committed, anticipated and new generic wind and solar projects are modelled based on nine years of historical weather data[55] and the methodology for each category of wind and solar project is summarised in Table 12. All large-scale wind and solar availability profiles are developed by EY.

Table 12: Summary of wind and solar availability methodology

Technology	Category	Capacity factor methodology	Reference year treatment
Wind	Existing	Specify long-term target based on nine-year average in AEMO ESOO 2019 traces[56], where available, otherwise past meteorological performance.	Capacity factor varies with reference year based on site-specific, historical, near-term wind speed forecasts.
	Committed new entrant	Reference year specific targets based on capacity factor of nearest REZ, medium quality tranche in AEMO's 2023 IAS workbook[57]	
	Generic REZ new entrants	Reference year specific targets based on AEMO's 2023 IAS workbook[57]. One high quality option and one medium quality option per REZ.	

[53] AEMO, May 2024 Generation Information. Available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed 30 September 2024.
[54] AEMO, December 2023, *Draft 2024 ISP Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 30 September 2024.
[55] As described by Australian Government Bureau of Meteorology, *ACCESS NWP Data* Information. Available at: http://www.bom.gov.au/nwp/doc/access/NWPData.shtml. Accessed 30 September 2024.
[56] AEMO, *2019 Electricity Statement of Opportunities: 2019 Wind Traces* and *2019 Solar Traces*. Available at: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo Accessed 30 September 2024.
[57] AEMO, December 2023, *Draft 2024 ISP Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 30 September 2024.

Technology	Category	Capacity factor methodology	Reference year treatment
Solar PV Fixed Flat Plate	Existing	Annual capacity factor based on technology and site-specific solar insolation measurements.	Capacity factor varies with reference year based on historical, site-specific insolation measurements.
Solar PV SAT	Existing		
	Committed new entrant	Reference year specific targets based on capacity factor of nearest REZ, in AEMO's 2023 IAS workbook[57].	
	Generic REZ new entrant	Reference year specific targets based on AEMO's 2023 IAS workbook[57].	

All existing and committed large-scale wind and solar farms in the NEM are modelled on an individual basis. Each project has a location-specific availability profile based on historical resource availability. The availability profiles are derived using nine years of historical weather data covering financial years between 2010-11 and 2018-19 (inclusive) and synchronised with the hourly demand profile. Wind and solar availability profiles used in the modelling reflect generation patterns occurring in the nine historical years, and these generation patterns are repeated throughout the Modelling Period as shown in Table 11.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[58] at a representative hub height. Wind speeds are converted into power using a generic wind farm power curve. The wind speed profiles are scaled to achieve the average target capacity factor across the nine historical years. The profiles reflect inter-annual variations, but at the same time achieve long-term capacity factors in line with historical performance (existing wind farms) or the values used in the AEMO 2019 ESOO and 2023 IAS workbook[59] for each REZ.

The availability profiles for solar are derived using solar irradiation data from satellite imagery processed by the Australian Bureau of Meteorology. As for wind profiles, the solar profiles reflect inter-annual variations over nine historical years, but at the same time achieve long-term capacity factors in line with historical performance (existing solar farms) or target AEMO's capacity factor for each REZ.

Wind and solar capacity expansion in each REZ is limited by four parameters based on the AEMO 2023 IAS workbook.[59]

- Transmission-limited total build limit (MW) representing the amount of dispatch supported by current intra-regional transmission infrastructure.
- A transmission expansion cost ($/MW) representing an indicative linear network expansion cost to develop a REZ beyond current capabilities and connect the REZ to the nearest major load centre.
- Resource limits (MW) representing the maximum amount of capacity expected to be feasibly developed in a REZ based on topography, land use etc at the given capex.
- A resource limit violation penalty factor ($/MW) to build additional capacity beyond the resource limit. This represents additional capex to build on sites with higher land costs.

[58] As described by Australian Government Bureau of Meteorology, *ACCESS NWP Data* Information. Available at: http://www.bom.gov.au/nwp/doc/access/NWPData.shtml. Accessed 30 September 2024.
[59] AEMO, December 2023, *Draft 2024 ISP Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 30 September 2024.

The least-cost planning model incurs the additional transmission expansion cost to build more capacity up to the resource limit, and potentially beyond the limit at cost, if it is part of the least-cost development plan.

Solar PV and wind generation are dispatched at their available resource limit unless curtailed economically (when sufficient sources of must-run generation and generation with cost at or below their VOM are available) or by other constraints such as transmission limits.

D3. Generator forced outage rates and maintenance

Full and partial forced outage rates for all generators as well as mean time to repair used in the modelling are based on the AEMO 2023 IAS workbook.[60]

All unplanned forced outage patterns are set by a random number generator for each existing generator. The seed for the random number generator is set such that the same forced outage pattern exists between the Base Case and with the portfolios. New entrant generators are de-rated by their equivalent forced outage rate.

Planned maintenance events for existing generators are scheduled during low demand periods and the number of days required for maintenance is set based on the AEMO 2023 IAS workbook.[60]

D4. Generator technical parameters

Technical generator parameters applied are as detailed in the AEMO 2023 IAS workbook[60] for AEMO's long-term planning model, except as noted in the Report.

D5. Coal-fired generators

Coal-fired generators are treated as dispatchable between minimum load and maximum load. Must run generation is dispatched whenever available at least at its minimum load. As with the AEMO 2023 IAS workbook[60], maximum loads vary seasonally. This reduces the amount of available capacity in the summer periods.

D6. Gas-fired generators

Gas-fired CCGT plant also typically have a must-run component and so are dispatched at or above their minimum load to deliver efficient fuel consumption.

In line with the AEMO 2023 IAS workbook[60], a minimum load of 46% of capacity for all new CCGTs has been applied to reflect minimum load conditions for assumed efficient use of gas and steam turbines in CCGT operating mode.

OCGTs are assumed to operate with no minimum load. As a result, they start and are dispatched for a minimum of one hour when the cost of supply is at or above their SRMC.

D7. Wind, solar and run-of-river hydro generators

Intermittent renewables, in particular solar PV, wind, and run-of-river hydro are dispatched according to their resource availability as they cannot store energy. Intermittent renewable production levels are based on nine years of hourly measurements and weather observations across the NEM including all REZ zones. Using historical reference years preserves correlations in weather patterns, resource availability and demand. Modelling of wind and solar PV is covered in more detail in Section D1.

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[60] AEMO, December 2023, *Draft 2024 ISP Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 30 September 2024.

Solar PV and wind generation are dispatched at their available resource limit unless curtailed economically, when the marginal cost of supply falls to less than their VOM, or by other constraints such as transmission limits.

D8. Storage-limited generators

Conventional hydro with storages, PHES and grid-scale BESS are dispatched in each interval such that they are most effective in reducing the costs of generation up to the limits of their storage capacity.

Hourly hydro inflows to the reservoirs and ponds are computed from monthly values sourced from the AEMO 2023 IAS workbook[61] and the median hydro climate factor trajectory for the respective scenario applied.

[61] AEMO, December 2023, *Draft 2024 ISP Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 30 September 2024.

Appendix E. Glossary of terms

Abbreviation	Meaning
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Capex	Capital Expenditure
CCGT	Combined-Cycle Gas Turbine
CO_2	Carbon Dioxide
CQ	Central Queensland
DSP	Demand-Side Participation
ESOO	Electricity Statement of Opportunities
FN	Far North
FOM	Fixed Operation and Maintenance
GW	Gigawatt
ISP	Integrated System Plan
IAS workbook	Inputs Assumptions and Scenarios workbook (AEMO workbook)
$m	Million dollars
Mt	Mega Ton
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
NQ	North Queensland
NSW	New South Wales
OCGT	Open-Cycle Gas Turbine
ODP	Optimal Development Path
PHES	Pumped Hydro Energy Storage
PV	Photovoltaic
QLD	Queensland
QNI	Queensland-New South Wales interconnector
QRET	Queensland Renewable Energy Target
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
SA	South Australia
SAT	Single Axis Tracking

Abbreviation	Meaning
SQ	Southern Queensland
SRMC	Short-Run Marginal Cost
TAS	Tasmania
TRET	Tasmanian Renewable Energy Target
USE	Unserved Energy
VCR	Value of Customer Reliability
VIC	Victoria
VNI	Victoria-New South Wales Interconnector
VOM	Variable Operation and Maintenance
VRET	Victoria Renewable Energy Target
VPP	Virtual Power Plant

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